2026 Wholesale Electricity Market Electricity Statement of Opportunities

June 2026

A 10-year outlook of investment requirements to maintain reliability in the Wholesale Electricity Market in Western Australia's South West Interconnected System

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

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

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

AEMO is proud to have launched its Innovate Reconciliation Action Plan (RAP) in June 2026. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

The Australian Energy Market Operator (AEMO) publishes the Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) under clause 4.5.11 of the Electricity System and Market Rules.

This publication is generally based on information available to AEMO as at 11 June 2026 unless otherwise indicated.

Disclaimer

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

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

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Version control

Version	Release date	Changes
1	23/06/2026	Initial release
2	15/07/2026	Replaced Figure 1, Figure 7, Figure 9, Figure 23, Figure 38, and Figure 40. Revised note A for Table 22, added explanatory note for Figure 8 and Figure 9, and corrected a small number of typographical errors.

Executive summary

In Western Australia, AEMO operates the state's main power system, the South West Interconnected System (SWIS) and its associated Wholesale Electricity Market (WEM).

Each year, AEMO publishes the WEM Electricity Statement of Opportunities (WEM ESOO), which examines whether there is adequate existing and committed new electricity generation, storage and demand side programmes (DSPs) to meet forecast annual electricity consumption and peak demand over a 10-year outlook. The WEM ESOO does this by considering a range of possible futures, featuring *Low*, *Expected*, and *High* demand scenarios.

The WEM has a Reserve Capacity Mechanism (RCM), which is designed to ensure sufficient capacity is available to satisfy the WEM Planning Criterion:

A. Meet the one-in-ten-year peak demand plus a reserve margin to cover risk of concurrent Outages.
B. Keep average annual unserved energy (USE) below 0.0002% of annual consumption.
C. Respond to major ramping events over a four-hour period.

The WEM ESOO sets the required amount of reserve capacity for the WEM two years in advance to ensure there is adequate capacity to satisfy all three limbs of the Planning Criterion. The greater of Limb A, Limb B and Limb C sets the Peak Reserve Capacity Requirement (RCR). Limb C sets the Flexible RCR.

The WEM ESOO, in conjunction with the WA Government's *Whole of System Plan* (WOSP) and Western Power's *Transmission System Plan*, helps inform planning and decision making by Market Participants, investors and policy-makers.

The 2026 WEM ESOO presents an improved outlook compared to the 2025 WEM ESOO. Highlights include:

- **A capacity surplus is forecast for the first three years of the outlook, with a surplus of 347 MW (based on existing and committed capacity) against the Peak RCR of 6,323 MW in 2028-29**, largely driven by:
  - Investment in new and expanded battery storage and generation Facilities, with a further 889 MW of committed generation and storage expected to be operational by 2028-29 supported by Priority Project status under the new State Development Act 2025 (WA) and the Commonwealth Government's Capacity Investment Scheme;
  - Bluewaters Power Station is forecast to remain available until 2030-31, aligning with the recently announced extension of the Griffin Coal Mine State Agreement to 2031.
- **Average annual USE is forecast to be within tolerance through to 2029-30**, being below Limb B of the Planning Criterion's threshold of 0.0002% of annual consumption.
- **More capacity will be needed from 2029-30 to meet demand growth and retirement of thermal generation, with investment required in advance to meet this timeframe.**
  - A total of 1,661 MW of thermal generation is expected to exit the SWIS by 2035-36. More than half of this capacity is assumed to become unavailable or retire from 2031-32.
  - While strong investment has been observed to date, more investment will be needed to meet the Reserve Capacity Target (RCT) from 2029-30 through to the end of the outlook period in 2035-36.

  - There is more than 600 MW of anticipated capacity in the pipeline which could delay potential shortfalls to 2031-32, if delivered to proposed timelines.
  - Without this investment, average unserved energy is projected to exceed the Planning Criterion threshold of 0.0002% of annual consumption.
  - Further indications of strong investment interest in the SWIS include more than 2,000 MW of additional potential projects submitting an expression of interest (EOI) in this year's Reserve Capacity Cycle.
- **Virtual Power Plants (VPPs) are forecast to drive reduction in demand**
  - Consumers are playing a critical role in the energy transition through investments in rooftop solar, household batteries (supported by both the Western Australian and Commonwealth Governments) and other distributed energy resources (DER), such as electric vehicles (EVs).
  - The 2026 WEM ESOO forecasts VPPs to reduce annual peak demand in 2028-29 by 200 MW.
- **A significant increase in grid scale battery storage is forecast to further flatten the peak.** To meet a longer and flatter peak, the battery storage ESR Duration Requirement is increasing from six hours in 2027-28 to seven hours in 2028-29**.**
- **AEMO has made improvements to its approach to deriving key components of the Peak RCT, which satisfy the Planning Criterion requirements and reduce the RCT from what it would otherwise be.** This has the potential to reduce the Reserve Capacity Price (RCP) and, in turn, costs to consumers by:
  - revising the way the reserve margin (capacity kept in reserve) is determined to reflect the increasing reliability of Facilities in the WEM, and
  - reflecting the forecast contribution of VPPs to reducing peak demand.
- **The improved near-term outlook to 2028-29 is sensitive to committed projects being delivered on time, alongside planned transmission network augmentations.**
- Targets for flexible capacity, such as thermal generation and storage that can ramp up output to meet changes in demand, are forecast to be met.
  - The Flexible RCT for the forecast period rises steadily from 2,539 MW in 2027-28 through to 3,204 MW in 2035-36.
  - Flexible capacity over that period is forecast to remain in surplus over the horizon.
- **Current projections would not require Supplementary Capacity (SC) to be procured for the 2026-27 Hot Season**. AEMO will continue to monitor the progress of committed projects due to be in Commercial Operation for October 2026, and consider any delays, major Outages, or fuel disruptions that could cause a shortfall closer to 1 October 2026.

Supply and demand forecast overview from 2026-27 to 2035-36

As shown in **Table 1** and **Figure 1** below, the reliability targets are forecast to be met for the coming three years, with risks of widening capacity shortfalls from 2029-30. If anticipated grid-scale battery storage and generation projects are developed and government-led initiatives in small-scale storage and VPPs continue to scale, then the WEM could remain balanced until at least 2030-31.

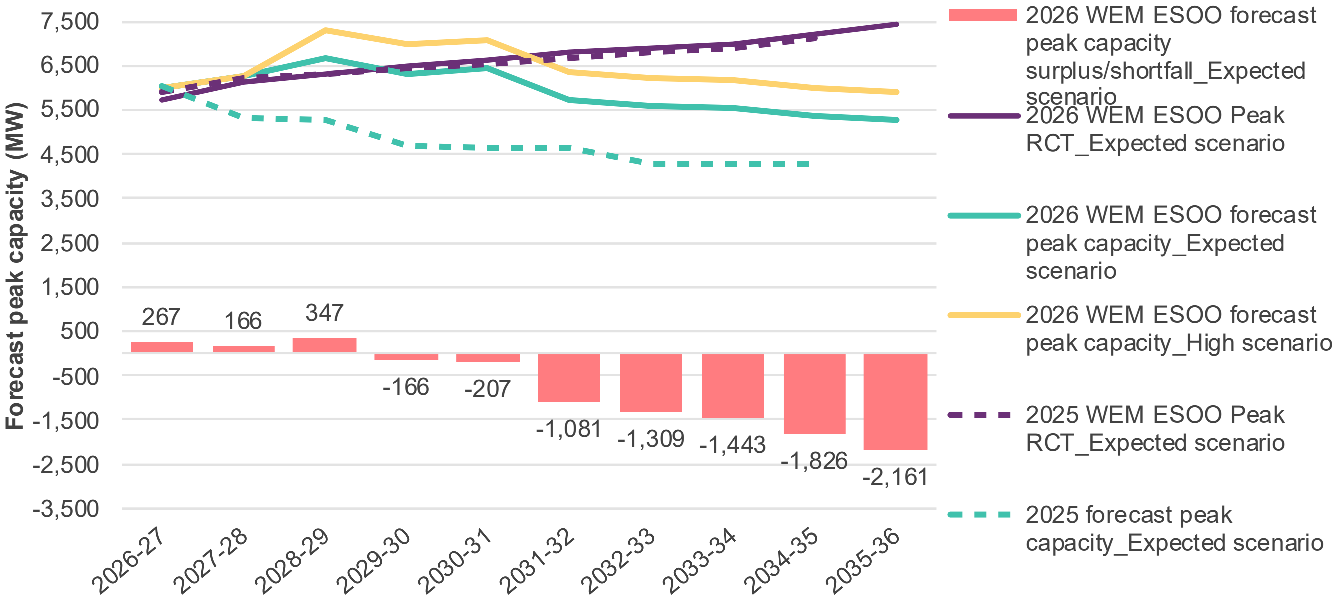
Table 1 brings these trends together by showing how forecast consumption, capacity targets, and available supply change across the outlook period.

Table 1 WEM forecast supply and demand through to 2035-36, *Expected* scenario (MW)

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Forecast underlying consumption (TWh)	21.1	22.0	22.9	24.1	25.3	26.3	27.3	28.6	30.2	32.1
Forecast Peak Reserve Capacity Target	5,720	6,121	6,323	6,475	6,644	6,807	6,897	6,997	7,197	7,454
Forecast existing and committed peak capacity	5,987	6,287	6,670	6,310	6,438	5,727	5,588	5,554	5,371	5,293
Surplus / shortfall	**267**	**166**	**347**	**-166**	**-207**	**-1,081**	**-1,309**	**-1,443**	**-1,826**	**-2,161**
Forecast anticipated peak capacity	0	0	622	675	661	648	636	623	610	596
Surplus / shortfall	**267**	**166**	**969**	**510**	**454**	**-432**	**-673**	**-820**	**-1,216**	**-1,565**

Note: All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.

Figure 1 Forecast supply-demand balance of forecast peak capacity, *Expected* and *High* scenarios, 2026-27 to 2035-36 (MW)



A total of 1,666 MW of existing and committed battery storage is forecast to be operational on the SWIS by 2028-29 and a further 1,119 MW of committed generation and battery storage is forecast to be operational by 2030-31.

If the 661 MW of anticipated projects are delivered in a timely manner, then capacity is forecast to be sufficient through to 2030-31. More investment will be required to mitigate potential shortfalls from 2031-32 onwards.

At a system level, the 2026 WEM ESOO shows how forecast demand growth, committed investment and project timing shape the forecast supply-demand balance over the next decade.

- Total annual consumption to rise steadily from 20.4 TWh in 2025-26 to 32.1 TWh in 2035-36, similar to last year's forecast.
- The Peak RCT (forecast of peak supply capacity required in the SWIS after taking into account the impact of DER is forecast to rise from a 5,720 MW in 2026-27 to 6,323 MW in 2028-29, then to 7,454 MW in 2035-36.
- Capacity from existing and committed projects to rise from 5,987 MW in 2026-27 to 6,670 MW in 2028-29, meeting the Peak RCT. Throughout the Long Term (LT) Projected Assessment of System Adequacy (PASA) horizon, demand is forecast to continue to grow and thermal generation exits leading to a forecast shortfall from 2029-30.

The discussion below first considers the overall outlook, then explains the key factors shaping capacity needs and available supply.

Consumption continues to grow

Electricity consumption is forecast to rise 57% to 32.1 TWh in 2035-36, representing steady growth throughout the 10-year outlook.

- **Residential electricity use is forecast to rise steadily.** The rise in forecast annual consumption from 6.8 TWh in 2025-26 to 9.3 TWh in 2035-36 reflects population growth and the take up of EVs and electric appliances. Households are also becoming more likely to use climate control ('set and forget') for air-conditioning, using more electricity than manual controls. Rooftop Photovoltaic (PV) in combination with residential battery use continues to act to partially meet this consumption, with 68% residential consumption forecast to be served by DER by 2035-36.
- **EVs (including battery EVs and plug-in hybrids) continue to be a consumption driver,** with households forecast to use 1 TWh to charge them in 2035-36**.** The current EV fleet of approximately 68,000 vehicles in 2025-26 (about 3% of the total) is expected to rise to about 717,000 vehicles over the decade.
- **Businesses continue to use more electricity**. Recent moderate rises in business consumption are forecast to continue, due to a number of drivers including economic growth and the switch from petrol, diesel and gas to electricity for their processes and transport. (In the forecast, some 'business mass market' sectors have been transferred to the new data centres category or re-categorised as Large industrial loads.)
- **Large industrial loads forecast consumption may be slightly lower than forecast last year.** Some industrial operators have advised that they will pause or defer proposed developments. AEMO has also lowered its estimates for large industrial loads to reflect observed trends in actual usage, and to reflect a tempered outlook for green hydrogen and other green commodities sectors.
- **Data centres are emerging as a potentially significant source of demand; however, the 2026 forecast is for relatively conservative growth given a limited number of committed projects.** Data centres appear as a separate category for the first time in the 2026 WEM ESOO, reflecting growing interest in the sector. The 2026 forecast is for conservative growth given the limited number of known projects. A higher forecast may emerge when there is more evidence of development.

These consumption trends are only part of the story, because peak demand is also being reshaped by consumer-owned rooftop solar, batteries and their coordination through VPPs.

Residential batteries and rooftop solar projected to materially reduce peak demand when coordinated

The forecast of annual SWIS unscheduled operational peak demand is slightly higher than in last year's WEM ESOO, reaching 4,937 MW in 2028-29 and 6,016 MW in 2035-36.

- **Peak demand from the grid is being reduced by distributed, consumer-owned energy resources.** Distributed rooftop solar PV capacity is forecast to almost double from ~3,100 MW in 2026-27 to ~6000 MW by 2035-36, and distributed battery capacity is forecast to grow from ~550 MW in 2026-27 to ~2,300 MW by 2035-36.
  - Battery take-up is rising due to government incentives (the WA Residential Battery Scheme (WARBS) and Commonwealth Cheaper Home Batteries Program (CHBP)), cost reductions, and packaging with solar PV for a more effective consumer system.
  - The strong growth in household batteries is reducing evening peak demand as well as increasing daytime demand via battery charging, as these batteries are increasingly being coordinated to charge or inject into the grid by aggregators acting as a VPP. This often soaks up excess solar energy, even as rooftop solar continues to reduce daytime demand. These trends are forecast to continue.
- **Coordinating DER through VPPs is expected to reduce the need for grid-scale investment by approximately 200 MW in 2028-29**. AEMO projects 640 MW of installed distributed batteries will be able to be coordinated through Synergy's VPPs in 2028-29. To account for uncertainties around remote control and operational behaviour due to the early stage of development, AEMO assumed a 50% availability factor.
  - Achieving this benefit will depend on reliable communications and control systems, and effective integration of DER into market and operational processes. AEMO will monitor the performance of the VPP operations over the 2026-27 Hot Season and use the insights inform next year's WEM ESOO VPP forecast.

Having outlined the drivers of peak demand, the next section explains how AEMO converts that outlook into the Peak RCR.

The Peak Reserve Capacity Requirement for 2028-29 is 6,323 MW

The WEM Planning Criterion is the market's reliability standard and underpins AEMO's 10-year LT PASA.

- **Limb A tests whether there is enough peak capacity to meet peak demand and required margins.**
- **Limb B tests whether reliability can be maintained to the expected unserved energy standard.**
- **Limb C tests whether there is enough flexible capacity to meet changes in demand over a four-hour period.**

The Peak RCR is set by the higher of Limb A, Limb B or Limb C, while Limb C sets the Flexible RCR. Table 2 shows the outcome of each limb across the outlook period, and which limb determines the target in each year.

Table 2 shows the three limbs of the Planning Criterion for all years of the outlook. For 2028-29, the Peak RCR is set by Limb A at 6,323 MW and the Flexible RCR is set by Limb C at 2,617 MW.

Table 2 Three limbs for Planning Criterion, *Expected* scenario, for 2026-27 to 2035-36 (MW)

Capacity Year	Limb A	Limb B	Limb C
2026-27	5,702	5,720	2,529
2027-28	6,121	5,865	2,539
2028-29	**6,323**	**6,248**	**2,617**
2029-30	6,475	6,310	2,738
2030-31	6,644	6,631	2,882
2031-32	6,807	6,562	3,037
2032-33	6,897	6,620	3,004
2033-34	6,997	6,682	3,061
2034-35	7,197	6,821	3,093
2035-36	7,454	7,108	3,204

Note: The RCT for the relevant Capacity Year is highlighted in pink shaded cells.

Having identified which limb sets the target in each year, the next step is to show how the 2028-29 Peak RCR is built up from its component parts.

Table 3 Components of the Limb A assessment, *Expected* scenario (MW)

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Forecast 10% POE peak demand	4,709	4,878	4,937	5,072	5,224	5,385	5,472	5,568	5,763	6,016
Intermittent Loads	3	3	3	3	3	3	3	3	3	3
Reserve margin	880	864	861	858	855	853	850	847	845	842
Regulation Raise requirement	110	120	130	150	171	175	180	187	194	201
ESR Duration Requirement Uplift	0	256	392	392	392	392	392	392	392	392
Limb A requirement	5,702	6,121	6,323	6,475	6,644	6,807	6,897	6,997	7,197	7,454

Note: All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.

Four components contribute to the Peak RCT to ensure reliable supply in 2028-29:

- **Forecast peak demand, that is based on a 10% POE forecast** and includes residential, industrial and business demand. The components of this forecast are based on consumption and demand drivers and the scenarios set out in the Inputs, Assumptions and Scenarios Report (IASR).
- **A reserve margin of 861 MW**, reduced from 958 MW in the 2025 WEM ESOO. The reserve margin is set to cover the largest plausible supply Outage event for the WEM. Previously, AEMO set the margin to cover the risk that the WEM's largest three generators were unavailable at the same time. This year, based on detailed analysis of historical Forced Outage, AEMO has reduced the reserve margin to the capacity of the two largest generators plus 70% of the third largest Facility, which aligns with the margin for operational contingencies.
- **An uplift of 130 MW to maintain frequency operating standards (the Regulation Raise requirement).** AEMO is required to increase the capacity target to enable the system to respond to variability in renewable generation output.

- **An uplift of 392 MW (ESR Duration Requirement Uplift)** to cover the reduced impact of shorter duration batteries in meeting a larger and longer period of demand over peak**.**

Further detail on the determination of these components can be found in Section 3 of the 2026 WEM ESOO.

Limb B Reliability

Table 4 shows the outcomes of reliability modelling for the existing and committed fleet across the outlook horizon. These outcomes are reported as average annual unserved energy.

Significant new entry of committed capacity ensures forecast annual unserved energy, modelled without network constraints, remains under the 0.0002% threshold through to 2029-30 inclusive, with increasing risk emerging from the early 2030s as demand grows and thermal generation retires.

From 2030-31, forecast annual unserved energy is projected to exceed the 0.0002% threshold, as limited new capacity is available from this point to offset forecast demand growth, and reductions associated with the phased retirement of Pinjar gas generators and assumed unavailability of Bluewaters Power Station.

Table 4 Unserved Energy outcomes under Limb B assessment, *Expected* scenario

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Average annual USE (MWh)	5	0	0	8	129	6,427	11,438	20,103	96,576	225,596
USE as % of annual consumption	0.00003	0	0	0.00004	0.00063	0.03041	0.05246	0.08871	0.40370	0.88857

The existing and committed fleet from 2026-27 to 2028-29 exceeds the Limb A requirement. By modelling reliability outcomes with a reduction in the fleet capacity, AEMO identified that in 2026-27 the Peak RCT is set by Limb B, requiring a capacity of 5,720 MW to achieve the reliability standard.

For all other years of the outlook period, including 2028-29, Limb A is forecast to set the Peak RCT. Having established the 2028-29 capacity requirement is set by Limb A, the next question is whether forecast supply is sufficient to meet it.

Existing and committed capacity for 2028-29 is forecast to exceed the Reserve Capacity Requirement by 347 MW

Table 5 below shows the WEM's total projected capacity is forecast to reach 6,670 MW in 2028-29, assuming timely delivery of committed projects. After that, further investment is forecast to be needed.

The components that contribute to total reserve capacity in the *Expected* scenario are discussed below the table. The contribution of each technology to that capacity is shown in **Figure 2**.

Bluewaters Power Station is shown separately, reflecting a change from the 2025 WEM ESOO, which modelled this capacity as unavailable from 2027-28 due to uncertainties over the availability of local coal supply as the State Agreement for Griffin Coal Mine had not been renewed at that time and was due to lapse.

A subsequent State Government announcement of the extension of the State Agreement up to June 2031 improves AEMO's confidence in the availability of fuel supply for Bluewaters Power Station and, as a result, Bluewaters Power Station is modelled in the 2026 WEM ESOO as available until 2030-31.

Table 5 WEM forecast peak capacity, *Expected* scenario (MW)[A]

Capacity Year[B]	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
RCT	5,720	6,121	6,323	6,475	6,644	6,807	6,897	6,997	7,197	7,454
Forecast existing peak capacity (ex-Bluewaters)	5,291	5,142	5,107	4,669	4,644	4,375	4,245	4,217	4,041	3,971
Bluewaters Power Station	434	434	434	434	434	0	0	0	0	0
Forecast committed peak capacity	262	711	889	967	1,119	1,111	1,103	1,097	1,090	1,081
Estimated RLM uplift capacity	-	-	240	240	240	240	240	240	240	240
Total forecast peak capacity[C]	5,987	6,287	6,670	6,310	6,438	5,727	5,588	5,554	5,371	5,293

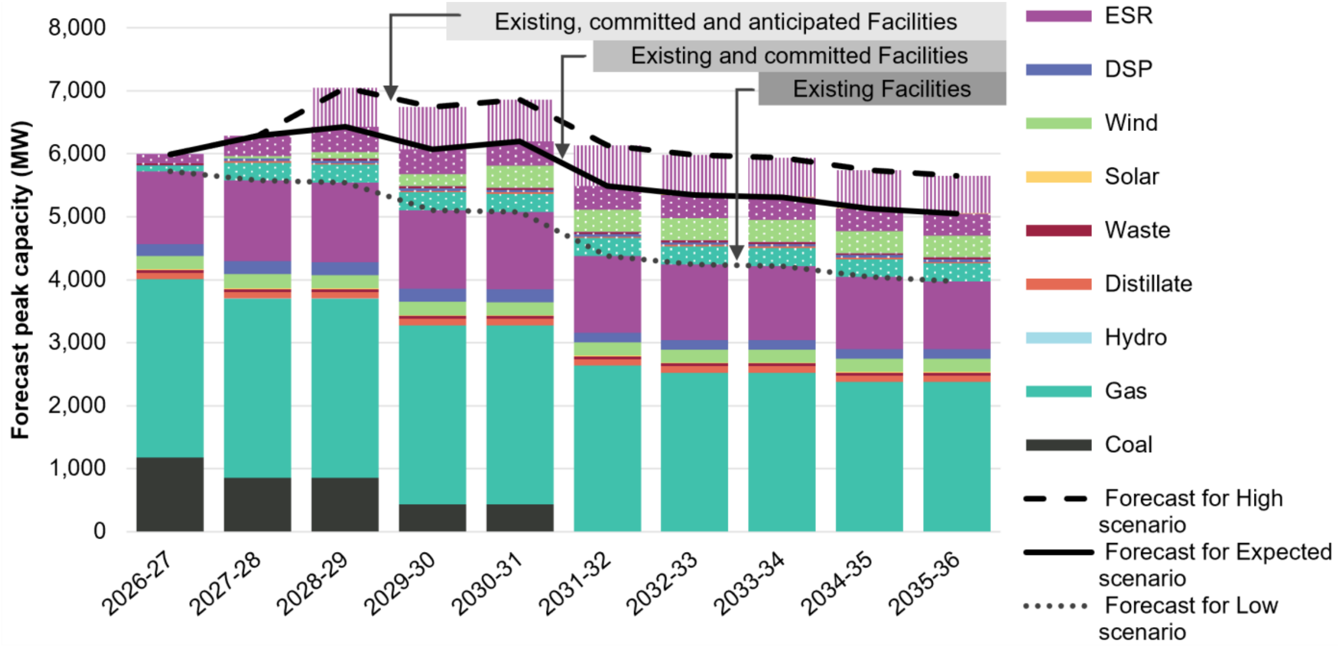
A. All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.
B. For 2026-27 and 2027-28, Capacity Credits have been assigned. For 2028-29, the Capacity Credits are expected to be assigned over the next months. For 2029-30 and onwards, the Reserve Capacity Cycles have not commenced.
C. This includes Facilities with existing obligations such as Facility's obligation for providing Capacity Credits and Peak Demand Non-Co-optimised Essential System Service (NCESS).

Based on a combination of public and industry-provided information, AEMO has assumed 1,661 MW of coal and gas-fired generation will retire or become unavailable over the outlook period.

New committed Facilities are forecast to deliver 889 MW in 2028-29, rising to 1,119 MW in 2030-31. This includes projects expected to start operations in 2028-29, and several projects supported by WA Government Priority Project status and Commonwealth Government's Capacity Investment Scheme, which underpins investment in new available capacity from 2029-30 onwards.

A revised Relevant Level Methodology (RLM) assigns a further 240 MW of Capacity Credits to intermittent generators. The RLM is used to assign Credits to intermittent generators, reflecting their contribution, as a fleet, to system capacity. This is explored in further detail in Section 3.4.

Figure 2 **Forecast peak capacity by technology type, under three scenarios, 2026-27 to 2035-36 (MW)**



Notes:

- The components of hybrid Facilities are split by their respective technology types accordingly in this presentation.
- Solid colours are used to present technology types for existing Facilities. Corresponding dot and line patterned colours are used to present technology types for committed and anticipated Facilities respectively.

AEMO has improved its approach to deriving key components of the Peak Reserve Capacity Target

AEMO continues to refine its approach to forecasting and determining the Peak RCTs as described in this ESOO, including reflecting the anticipated contribution of VPPs to reducing peak demand.

Due to uncertainties around remote control and operational behaviour of VPPs in the early stage of development, AEMO has assumed a reduced availability factor, so as to forecast a reasonable estimate of VPPs' impact at this stage.

This approach meets the requirement for assessing required capacity against the Planning Criterion and reduces the Peak RCT from what it would otherwise have been without these changes.

Other improvements have been made to WEM ESOO assumptions and methodology since 2025

After extensive stakeholder consultation, AEMO has made changes to demand assumptions to include a more accurate outage factor for large industrial loads; higher residential consumption trends; revised forecasts for rooftop PV, batteries, EVs and their coordination (acknowledging the impact of battery incentives).

Other changes detailed in the report include improved approaches to variable renewable energy (VRE) weather traces, the RLM, gas infrastructure constraints, project assessments, system services, the minimum demand threshold, and hydrogen production.

Forecasting supply and demand factors through the energy transition is inherently uncertain. AEMO works with stakeholders to make assumptions about the economic, technology, regulatory, social and environmental factors that may influence investment decisions and system outcomes through the Energy Demand Forecasting Methodology.

Stakeholders play an important role in the WEM ESOO

AEMO thanks all stakeholders, in particular those who have contributed to the WEM ESOO forecasting process, for their support and contributions. These contributions improve the accuracy of forecasts and promote the security and reliability of the power system throughout the energy transition.

AEMO looks forward to working in collaboration with consumers, industry and government to ensure secure and reliable power for the next decade.

Contents

1 Introduction

The 2026 WEM ESOO provides AEMO's 10-year outlook on the electricity supply-demand balance in Western Australia's SWIS. It assesses capacity needs and reliability to guide investment and policy decisions. The WEM ESOO report brings together updated demand forecasts, supply assumptions, and regulatory changes to support secure and efficient power system planning.

- The report uses three demand growth scenarios (*Low, Expected, High*), which are aligned with the 2025 *Inputs, Assumptions and Scenarios Report* (IASR) and accounts for evolving technologies like DER and VPPs.
- Key regulatory updates include the new RLM, which affects Capacity Credits for existing intermittent generation, and government programs designed to support residential battery uptake.

1.1 Purpose and scope

The WEM ESOO provides an outlook on the electricity supply-demand balance in the SWIS for the next 10 Capacity Years. Its purpose is to help Market Participants, investors and policymakers identify the investment required in generation, storage and DSP capacity to support a secure and reliable electricity supply over the next decade.

The WEM ESOO presents the outcomes of AEMO's annual LT PASA study for the SWIS, which is a vital input to the Reserve Capacity Mechanism (RCM). The study informs key parameters for the current Reserve Capacity Cycle[1], including the Reserve Capacity Requirement (RCR) two years ahead, which for this WEM ESOO is **2028-29**. It provides information on and projections of the following:

- annual electricity consumption and peak demand across a range of weather conditions and growth scenarios,
- expected available electricity supply from generation, storage, and DSPs,
- forecasts of power system reliability and the balance between electricity supply and demand including expected unserved energy (USE) under various scenarios,
- RCTs, including the Peak RCT, which identifies the total capacity needed to meet the Planning Criterion[2], and the Flexible RCT, which identifies the flexible capacity needed to manage the largest expected Four-Hour Demand Increase (FHDI),
- Electric Storage Resources (ESRs)[3] and DSP requirements, including the ESR Duration Requirement and DSP Dispatch Requirement, and
- potential investment needed to maintain power system reliability and security.

AEMO develops these forecasts and assessments in accordance with the requirements of the Electricity System and Market Rules (ESM Rules), forming part of AEMO's broader planning and reliability functions for the SWIS.

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[1] For more information on the Reserve Capacity Cycle, the RCM and how it works, see https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism.

[2] As defined in clause 4.5.9 of the ESM Rules.

[3] Electric Storage Resources (ESRs) is the term used under the ESM Rules to describe utility-scale battery storage systems.

1.1.1 The Planning Criterion

The Planning Criterion, defined in clause 4.5.9 of the ESM Rules, is the reliability standard AEMO uses to assess whether the SWIS has enough electricity capacity and flexibility to meet demand and mitigate the risk of supply shortfall. It sets strict parameters for factors such as available capacity and USE, with the aim of ensuring the power system can meet demand within the prescribed tolerance level. Reliability standards vary between power systems depending on each system's risk appetite and characteristics[4].

The Planning Criterion has three limbs, designed to:

- ensure there is sufficient capacity to meet the forecast 10% probability of exceedance (POE) peak demand forecasts, plus allowances for Intermittent Loads, Regulation Raise, a reserve margin[5], and the ESR Duration Requirement Uplift (Limb A)
- limit expected USE to less than 0.0002% of the annual forecast operational consumption, for which AEMO uses unscheduled operational consumption (Limb B), and
- ensure there is sufficient supply flexibility to meet the highest forecast highest FHDI plus a reserve margin (Limb C).

Explaining expected unserved energy

USE is electricity demand that cannot be supplied to consumers. This can occur when there is not enough generation, demand response, or transmission capacity within or between regions to meet demand.

AEMO forecasts expected USE by modelling many different weather and Forced Outage conditions, then calculating the average amount of USE across those simulations.

Figure 3 shows the three limbs of the Planning Criterion. Peak RCT is set by the highest requirement across the three limbs of the Planning Criterion. While it is typically driven by Limb A or Limb B, Limb C will set the Peak RCT where it is more constraining. Limb C is used to set the Flexible RCT, which reflects the capacity needed to manage the largest expected demand increase over a four-hour period.

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

[5] The reserve margin is the greater of: (i) the size of the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand, and (ii) the forecast peak demand multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages.

Figure 3 The limbs of the Planning Criterion

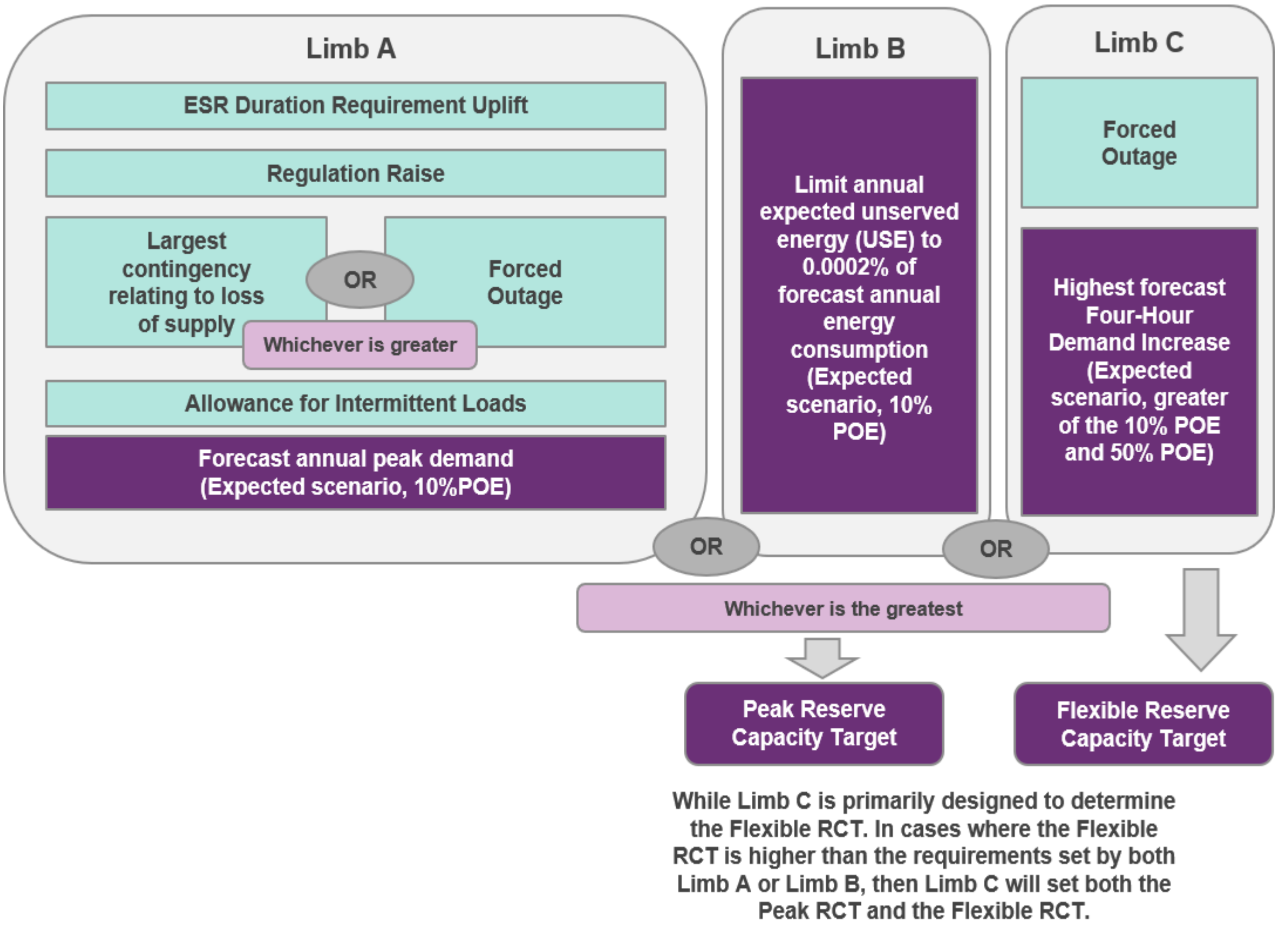


Table 6 Three limbs for the Planning Criterion, *Expected* scenario, 2026-27 to 2035-36 (MW)

Capacity Year	Limb A	Limb B	Limb C
2026-27	5,702	5,720	2,529
2027-28	6,121	5,865	2,539
2028-29	**6,323**	**6,248**	**2,617**
2029-30	6,475	6,310	2,738
2030-31	6,644	6,631	2,882
2031-32	6,807	6,562	3,037
2032-33	6,897	6,620	3,004
2033-34	6,997	6,682	3,061
2034-35	7,197	6,821	3,093
2035-36	7,454	7,108	3,204

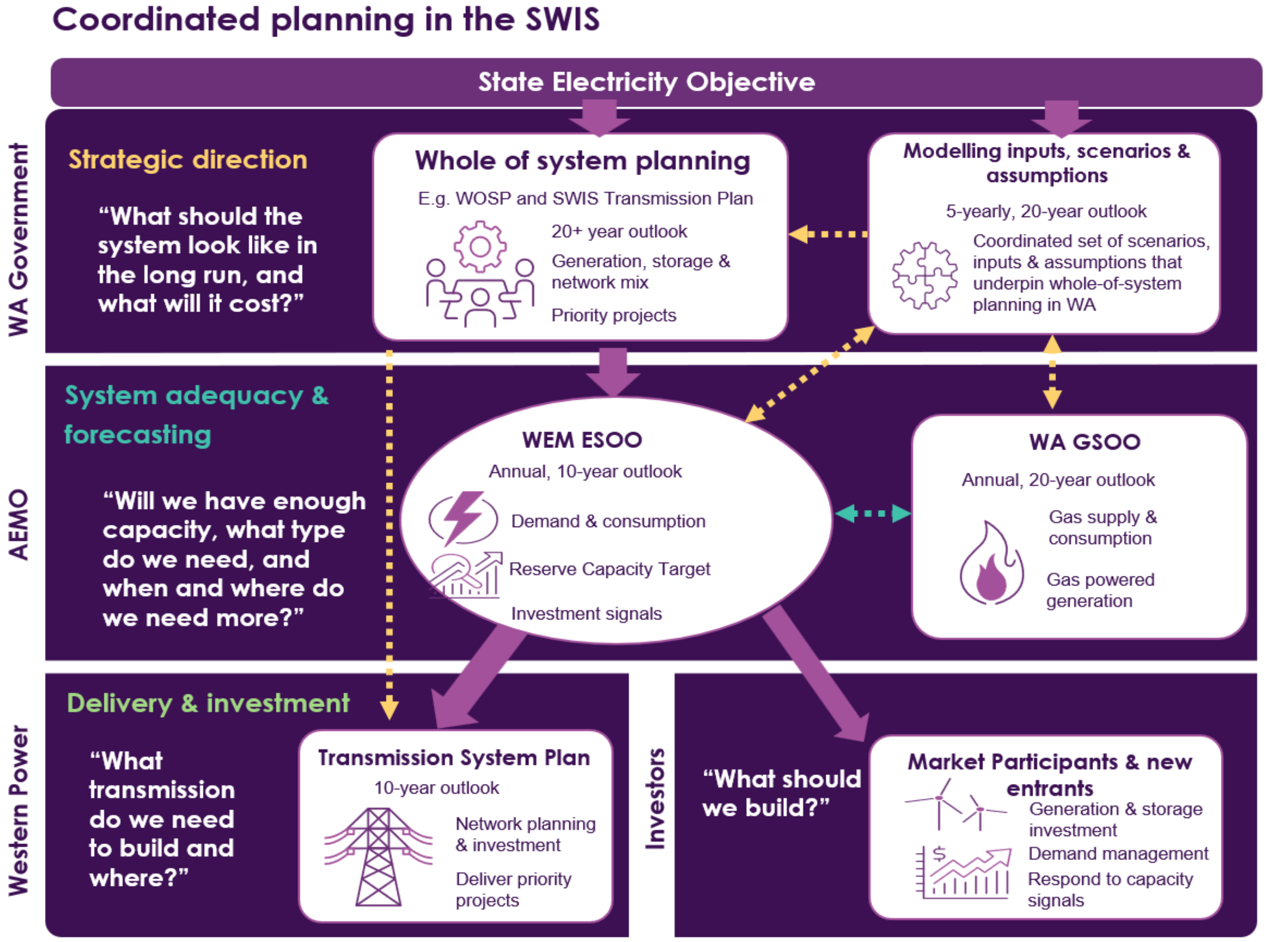
Note: The RCT for the relevant Capacity Year is highlighted in the pink shaded cells.

Table 6 above shows the three limbs of the Planning Criterion from 2026-27 to 2035-36. For 2028-29, the Peak RCR is set by Limb A at 6,323 MW and the Flexible RCR is set by Limb C at 2,617 MW. Further details can be found in Section 5.

1.1.2 Role of the WEM ESOO in SWIS planning

The WEM ESOO is a key component of coordinated energy planning in the SWIS. **Figure 4** shows how different planning processes work together.

Figure 4 Overview of how the WEM ESOO features in SWIS planning



The Western Australian Government sets the long-term direction for the SWIS through the Whole of System Plan (WOSP) and related policy and investment frameworks, including modelling inputs, scenarios and assumptions. Within this framework, the WEM ESOO is AEMO's reliability and capacity planning tool. It assesses future supply adequacy, capacity needs and the timing of new investment across the SWIS.

The WEM ESOO draws on WOSP assumptions and scenarios and works alongside the Western Australian *Gas Statement of Opportunities* (WA GSOO) to support coordinated energy planning. Its findings help inform decisions by Western Power, generators, storage providers and other Market Participants. AEMO seeks to maintain reliability while avoiding unnecessary costs to consumers.

AEMO updates the WEM ESOO methodology to reflect changing system conditions, better data and operational experience, including refinements relating to VPPs and reserve margin determination. The WEM ESOO also informs RCM capacity settings by assessing whether sufficient capacity and operational flexibility expected to be available during peak demand and contingency conditions.

About the WEM ESOO

AEMO produces a broad suite of public reports and documents across electricity forecasting, planning, operations, and market performance. Together, these documents provide insight and information to help guide investment in Australia's power systems and maintain a secure reliable supply of electricity.

Here are some of AEMO's key publications, and how they work together.

AEMO document	What it covers	What it tells us
NEM ESOO	Annual reliability assessment for the NEM	**Do we have enough energy and capacity, and what more do we need?**
WEM ESOO	Annual reliability assessment for the WEM (WA)	
Integrated System Plan	Whole-of-system, long-term development roadmap for the NEM	
ST PASA	Short term operational assessment of system adequacy (days to weeks)	**How can reliability be maintained in the near term?**
MT PASA	Medium term assessment of system adequacy (out to 2 years)	
Quarterly Energy Dynamics	Market trends, prices, emissions, outages in the NEM	**What just happened in the market?**
WA Quarterly Report	Equivalent report for the WEM	
Engineering Roadmap	Long-term operational and technical changes in the NEM and WEM to support very high levels of intermittent generation	**Can the system operate securely and what risks are emerging?**
Transition Plan for System Security	Annual NEM-focused security planning report	
Inputs, Assumptions & Scenarios Report	Modelling inputs, assumptions and scenarios used across the above publications	**What assumptions are driving the forecast?**

The WEM ESOO:

Because the SWIS is an isolated power system, the WEM uses a Reserve Capacity Mechanism to ensure enough capacity is available to maintain reliability. As a result, the WEM ESOO has a strong focus on future capacity requirements and reserve margins.

Like the NEM ESOO, the WEM ESOO assesses future reliability and supply adequacy, but within a different market framework.

Extreme temperatures

Isolated grid

Lots of rooftop solar

WEM ESOO = What capacity is needed to maintain reliability in the SWIS?

NEM ESOO = What reliability risks are emerging across the NEM?

1.2 Structure of this document

The following table outlines the structure of the 2026 WEM ESOO report, with a link to relevant sections.

Table 7 WEM ESOO structure

Section	What it covers	Specific item	Clause	Section
Section 1	Context, the forecasting scenarios, methodologies and the scope of the reliability assessment.	Modelling scenarios	4.5.13(a)	1.3
		Methodology changes	4.5.13(a)	1.5
		Definitions	4.5.13(a)	1.6
Section 2	Electricity consumption and demand projections, with consideration for the uptake and impact of DER.	Energy consumption forecast	4.5.10(a)	2.2
		Demand forecast	4.5.10(a)	2.3
		Peak demand forecast	4.5.10(a)	2.3.1
		Impact of coordinated DER on demand	4.5.10(a)	2.5
		Updated demand and consumption inputs	4.5.13(a)	2.7
Section 3	The supply outlook for the SWIS, including an overview of capacity assumptions, retirements and any changes to the supply forecasting methodology.	Forecast peak capacity	4.5.10(aA)	3.4
		Forecast flexible capacity	4.5.10(aA)	3.5
		Reserve margin	4.5.9(a)	3.7
		Regulation Raise requirements	4.5.9(a)	3.8
Section 4	ESR and DSP requirements. Presents the ESR Duration Requirement, ESR Obligation Intervals (ESROIs) and the ESR Duration Requirement Uplift.	ESR Duration Requirement	4.5.10(bC),4.5.12(d)	4.1.1
		Availability Duration Gap	4.5.12(e)	4.1.1
		ESR Duration Requirement Uplift	4.5.12(e)	4.1.2
		Mid Peak ESROI	4.11.3A(a), 4.11.3A(b)	4.1.3
		Flexible ESROI	4.11.3A(aA), 4.11.3A(b)	4.1.4
		Indicative DSP Dispatch Threshold	4.5.12(f)	4.2.1
		Peak DSP Dispatch Requirement	4.5.12(g)	4.2.2
		Flexible DSP Dispatch Requirements	4.5.12(h)	4.2.2
Section 5	The reliability assessment for the SWIS, including LT PASA results, expected USE projections and RCTs.	Intermittent Loads	4.5.2A	5.3
		Planning Criterion – Limb A requirement	4.5.9(a), 4.5.10(b)	5.3
		Planning Criterion – Limb B requirement	4.5.9(b), 4.5.10(b)	5.4
		Planning Criterion – Limb C requirement	4.5.9(c), 4.5.10(bA)	5.5
		Peak RCT	4.5.10(b)	5.6
		Flexible RCT	4.5.10(bA)	5.6
		Supply-demand assessment	4.5.10(aA)	5.7
		Capability Class assessment	4.5.12(i)	5.8
		Availability Curves	4.5.10(e)	5.9
Section 6	The reliability assessment considering network congestion, including sub-regional expected USE.	Regional capacity shortfalls	4.5.10(c)	6
Section 7	Identifies investment opportunities for maintaining system reliability and security.	Alleviation options for network constraints	4.5.10(d)	7

1.3 Scenarios

The ESM Rules require AEMO to prepare three demand growth scenarios: *Low*, *Expected*, and *High*. These three scenarios are based on different levels of economic growth and incorporate different rates of decarbonisation, fuel-switching, carbon offsets, and energy efficiency in the WEM as shown in **Figure 5**. Key parameters by scenario are summarised in **Table 8**.

Figure 5 2025 *Inputs, Assumptions and Scenarios Report* scenarios

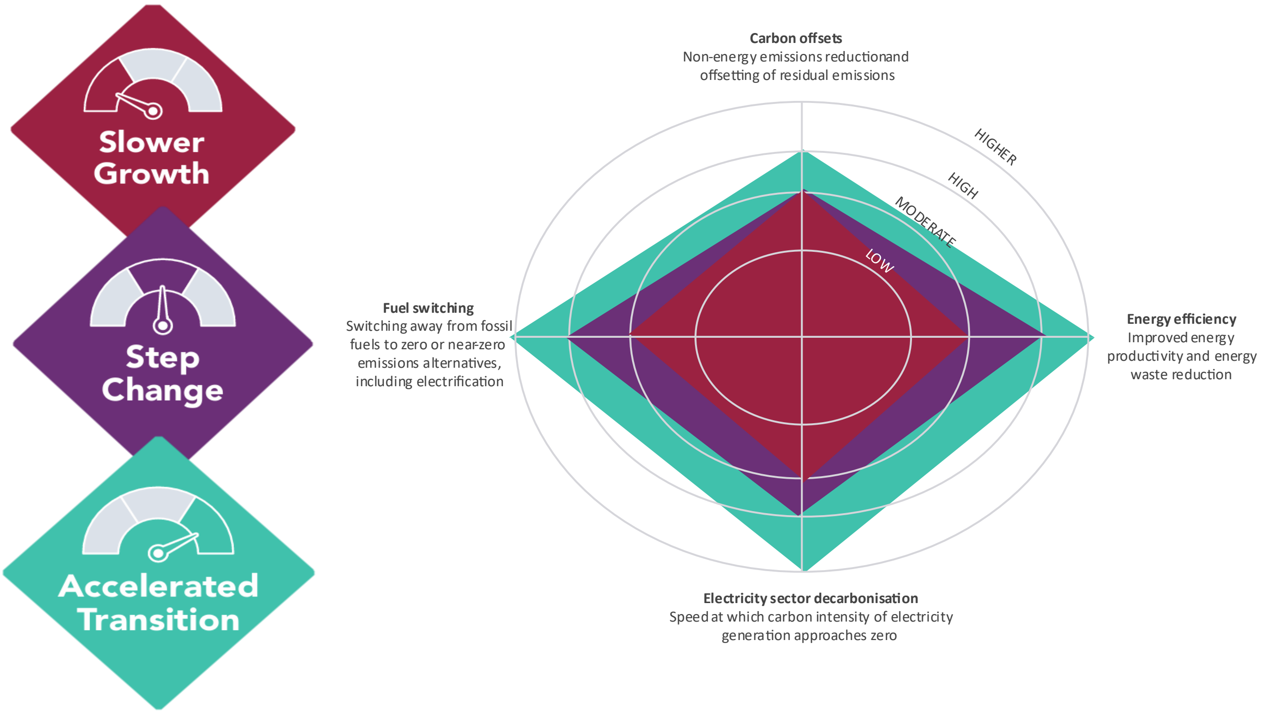


Table 8 Key parameters by scenario

Parameter	*Slower Growth (Low)*	*Step Change (Expected)*	*Accelerated Transition (High)*
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	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)
Global economic growth and policy coordination	Slow economic growth and lesser coordination	Moderate economic growth and stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower growth featuring tough economic conditions	Moderate	Higher
Electrification	Meeting existing emissions reductions commitments	High	Higher
Emerging commercial loads (such as data centres)	Lower	Moderate	Higher
Energy efficiency across all energy forms	Moderate	High	Higher

Parameter	*Slower Growth (Low)*	*Step Change (Expected)*	*Accelerated Transition (High)*
DER uptake (rooftop solar, energy storage systems, and electric vehicles)	Lower	High	Higher
Hydrogen use and availability	Low production for domestic use, no export hydrogen	Moderate-low production for domestic use, with no export hydrogen	Moderate production for domestic use, and green commodities with no export hydrogen
Supply chain strength influencing demand forecasts	Low	Moderate	High
Storage aggregation and coordination (such as VPPs)	Low	Moderate	High
Equivalent scenario in 2025 WEM ESOO	*Progressive Change*	*Step Change*	*Green Energy Exports*

For the 2026 WEM ESOO, AEMO has adopted the equivalent scenarios from the 2025 IASR[6]. These scenarios provide a suitable range of demand growth outcomes and capture key uncertainties affecting the energy transition in Western Australia and the broader domestic economy. All three IASR scenarios are consistent with achieving 43% emissions reduction by 2030 and net zero emissions by 2050. The scenarios are summarised as follows:

- *Slower Growth* (formerly *Progressive Change* in the Draft 2025 IASR, *Low* scenario) – explores a future where Australia meets its existing emissions reduction commitments, including a 43% reduction by 2030, under more challenging economic conditions[7]. The scenario is characterised by slower economic growth, higher technology costs and ongoing supply chain constraints, which together delay the pace of the energy transition. These conditions increase the risk of reduced industrial activity and weaker demand growth relative to other scenarios, while still requiring continued investment to meet policy objectives. The slower technology advancement may support longer use of gas for power generation, prior to a transition to renewables.
- *Step Change* (*Expected* scenario) – is based on achieving a scale of energy transformation consistent with achieving net zero emissions by 2050, with strong policy support and coordinated investment driving rapid decarbonisation. The scenario features high levels of consumer participation, accelerated electrification across the economy, and significant uptake of distributed energy resources.
- *Accelerated Transition* (formerly *Green Energy Industries* in the Draft 2025 IASR, *High* scenario) – reflects a rapid and globally coordinated decarbonisation pathway, with strong policy support and enabling conditions driving accelerated transformation of Australia's energy system. The scenario features high levels of electrification and very strong growth in renewable generation, alongside significant domestic and international interest for new production opportunities, including new industries such as hydrogen and green steel. Also, emerging trends in artificial intelligence and other data-heavy applications encourage higher growth in data centres in Australia. These assumptions are consistent with a reduced reliance on gas-fired generation over time as the system transitions toward lower-emissions sources.

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[6] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en.

[7] In September 2025, Australia's 2035 emissions targets were announced at 62% to 70% reduction on 2005 levels. Although 2035 targets were not directly considered under the Final IASR published in July 2025, all scenarios are aligned to net zero by 2050.

1.4 Regulatory changes since the 2025 WEM ESOO

Several changes to Western Australia's energy regulatory framework have come into effect since the 2025 WEM ESOO was published. **Table 9** summarises key changes and their impact on this year's WEM ESOO.

Table 9 Key regulatory and rule changes since the 2025 WEM ESOO

Regulatory/rule change	Summary	Impact on the 2026 WEM ESOO
Australian Government 2035 emissions reduction target	In September 2025, the Commonwealth Government announced Australia's 2035 emissions target to reduce emissions by 62-70% from 2005 levels by 2035. The policy is included in the Australian Energy Market Commission's (AEMC's) Emissions Targets Statement.	The 2026 WEM ESOO electrification forecasts are consistent with the emissions reduction requirements of the built environment, transport, industry and resources sectors, as modelled by the Federal Treasury as part of the 2035 emissions target[A]. Further details on electrification forecasts can be found in Appendix A1.
Cheaper Home Batteries Program (CHBP)[B]	Australian households, businesses and community organisations can now get a discount of around 30% on the upfront cost of installing small-scale battery systems (5 to 100 kilowatt hours [kWh]). In December 2025, the Commonwealth Government announced it would expand the CHBP from original estimates of $2.3 billion to $7.2 billion over the next four years. This is expected to see more than 2 million Australians install a battery by 2030, delivering around 40 gigawatt hours of additional storage capacity.	The 2026 WEM ESOO incorporates the expected impact of the new subsidy program, resulting in higher uptake of DER. Further details can be found in Section 2.4 and Appendix A1.
WA Residential Battery Scheme[C] (WARBS)	From 1 July 2025, one-off rebates and no interest loans were made available to help households purchase residential batteries. The scheme will run until a fixed number of rebates are exhausted (100,000), and as of December 2025 it is expected to be available until 2027. It also includes an obligation to install a battery capable and available for participation in a VPP for at least two years. The WARBS is in addition to the Commonwealth Government's CHBP.	The 2026 WEM ESOO incorporates the expected impact of the new subsidy program, resulting in higher uptake of DER and a higher proportion of coordinated DER. Further details can be found in Section 2.4 and Appendix A1.
Revised Relevant Level Method	On 1 April 2026, Schedule 5 of the RCM Reviews Sequencing Rules commenced, introducing a new RLM from the 2026 Reserve Capacity Cycle. The new RLM better reflects the average contribution of intermittent generation to capacity during peak demand periods and will affect the Capacity Credits assigned to intermittent generation, such as wind and solar.	The 2026 WEM ESOO reflects these requirements. Further details can be found in Section 3.4.2.
Transmission Node Identifier (TNI) for DSP	On 1 January 2026, Schedule 2 of the RCM Reviews Sequencing Rules commenced. From the 2026 Reserve Capacity Cycle, AEMO must determine the Transmission Nodes where Market Participants seeking certification for Demand Side Programmes (DSPs) under clause 4.10.1B cannot locate Associated Loads[D].	The 2026 WEM ESOO does not reflect these requirements. The outcomes of the assessment will be determined through the 2026 Reserve Capacity Cycle.

A. See https://treasury.gov.au/sites/default/files/2025-11/p2025-700922.pdf.
B. See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.
C. See https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme.
D. The TNI Exclusion List for DSP is available on https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/network-access-quantities.

1.5 Methodology changes since the 2025 WEM ESOO

AEMO's forecasting approach for 2026 is broadly consistent with previous years, with some targeted updates to reflect recent changes in the ESM Rules (including the RLM) and evolving consumer behaviour. As the market develops and new trends emerge, AEMO will continue to evolve and refine its forecasting methodology in consultation with stakeholders. In preparing its forecasts, AEMO's approach has regard to the following principles:

- **accuracy** – to adopt best practice methodologies and monitor lead indicators of change,

- **transparency** – to ensure inputs and forecast methodologies are well understood, and
- **engagement** – to consult with stakeholders and keep them informed.

The reliability assessment to inform Limb B of the Planning Criterion has been conducted in-house. This includes development of demand traces, variable renewable energy (VRE) traces, and Constraint Equations. Bringing modelling in-house gives AEMO greater flexibility to run sensitivities and test different scenarios while also enhancing visibility of underlying assumptions and supporting more detailed insights for Market Participants.

The following sections summarise the key forecasting adjustments that have been made for the 2026 WEM ESOO.

1.5.1 Changes to the demand and consumption approach

The 2026 WEM ESOO forecasts for unscheduled operational demand[8] and consumption are aligned with the methodologies outlined in AEMO's *Forecasting Approach – Electricity Demand Forecasting Methodology* (EDFM) paper (Methodology Paper), published in July 2025[9] and the *Draft 2026 Forecasting Assumptions Update* issued in December 2025[10]. The final 2026 Forecasting Assumptions Update will be published in August 2026.

The forecasting approach for this 2026 WEM ESOO remains broadly consistent with the 2025 methodology, but there are some notable improvements[11]:

- **Large industrial load outage factor** – based on a comparison of actual versus forecast consumption over the past four years, large industrial loads have tended to overestimate how much electricity they will use. In the 2026 WEM ESOO, a new outage factor has been introduced to reflect this. It looks at the past four years of survey forecasts compared to actual usage and applies a correction to future projections. This helps avoid over-forecasting by accounting for the fact that industrial loads do not always operate at forecast levels, due to both planned and unplanned outages. Further details are in Appendix A1.
- **Residential consumer behaviour impact** – The 2026 WEM ESOO incorporates consumer behaviour trends observed in recent data. Analysis of residential customer consumption indicates a clear upward trend in average household electricity use over time, even after accounting for other forecast components such as energy efficiency, electrification, the PV rebound effect[12] and EV uptake. These increases are evident across temperature-dependent cooling and heating loads, as well as base load consumption. The newly incorporated trends result in higher consumption in the short to medium term, consistent with recent observations, before gradually tapering as the influence of other forecast components, such as electrification, becomes more pronounced. Further details are in Appendix A1.

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[8] Unscheduled operational demand – annual unscheduled operational demand forecasts include delivered demand for all consumer sectors, plus transmission and distribution losses and excludes any consumption/demand associated with load scheduled through market dispatch (such as large-scale battery charging). For details, please see Section 1.6.1 Key definitions of consumption and demand.

[9] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf?la=en&rev=683642cd0a264f11b0e5d1c7ef9aefde&sc_lang=en&hash=2C506A485F0627CBBACDE552D7F37984.

[10] See https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-forecasting-assumptions-update.

[11] These improvements summarise new components within the *Electricity Demand Forecasting Methodology*, the *NEM Forecast Accuracy Report* and its *Forecasting Improvement Plan* or reflect improvements specific to WEM forecasting considering the high penetration of coordinated batteries and the estimated approach to coordinating their operation observed from recent Synergy trials.

[12] PV rebound effect refers to the phenomenon where electricity customers who install distributed PV systems increase their overall electricity consumption, even after accounting for the PV generation they produce. This happens because the savings from PV generation can lead to increased appliance use, or a delay in energy efficiency upgrades.

- **New data centre consumption forecast component** – in the 2026 WEM ESOO, data centres are being reported as a separate category for the first time. Data centres are any loads associated with serving IT infrastructure for data storage, computation and networking. The significant global investment in data centres and potential for data centre development in Western Australia supports dedicated reporting for this sector in this WEM ESOO. The forecast uses a mix of modelling for smaller sites (less than 10 MW) and industry input for larger, known projects (10 MW or more). Growth is modelled to ramp up over time as new developments come online.
- **Demand trace development** – the half-hourly demand trace method is updated to include synthetic trace development. The forecast uses an actual half-hourly demand pattern as a starting point, based on how electricity demand has behaved in the past. This base data is then modelled using machine learning techniques to consider future forecast assumptions, reflecting the changing composition of demand-side generation and load types. The adjustments make sure the final demand profile still looks and behaves like real-world electricity use, rather than an artificial or overly simplified shape.
- **DER forecasts update** – the forecasts for distributed PV, distributed batteries, and EVs have been updated using a combination of AEMO's modelling and external inputs[13]. These forecasts reflect different levels of battery uptake and VPP participation across scenarios, ranging from slower growth to continued strong adoption. The higher uptake scenarios also account for the impact of the WA Residential Battery Scheme. This update captures the growing role of consumer batteries and VPPs in helping manage peak demand. Further details can be found in the Draft 2026 *Forecasting Assumptions Update*[14].
- **New forecast approach for VPPs** – the forecast models that VPPs consisting of residential distributed batteries installed under the WA Residential Battery Scheme will be actively coordinated during peak demand periods. This reflects the incentive under the RCM for Market Participants to reduce peak demand, which can reduce the amount of capacity needed to meet that peak and may shift its timing. These impacts are considered in addition to the impact of uncoordinated DER on demand. Further details are in Section 2.5.

In addition to these changes, supporting forecasts (such as economic and population outlook) have been updated to reflect contemporary data.

1.5.2 Changes to the supply and Long Term PASA approach

Changes to reflect recent rule changes

As summarised in **Table 9** above, several relevant recent rule changes are factored into this year's LT PASA and reliability assessment, including:

- **Revised RLM** – used to estimate the reliability contribution of intermittent generation (in any Facility Class) to the system in 2028-29. It introduces numerical models that simulate system conditions and better evaluate the contribution of different forms of generation and storage under system stress scenarios. The new RLM is expected to affect the amount of Capacity Credits assigned to intermittent generators. The final RLM results data will be published on 9 September 2026[15] for the 2026 Reserve Capacity Cycle. Further details are in Section 3.

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[13] Forecasts from the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Green Energy Markets (GEM).

[14] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/draft-2026-forecasting-assumptions-update.pdf?rev=eb147bbbe8c147dcb8a64f7a8b94e329&sc_lang=en.

[15] The publication date is specified in the ESM Rules clause 4.1.16 and is subject to modification or extension in accordance with the Rules.

Other changes

Other notable improvements in forecasting are outlined below. These changes collectively improve the accuracy, consistency and representativeness of forecasting and reliability assessments.

- **Reserve margin** – AEMO reviewed the largest contingency determination to ensure all eligible technologies, including ESRs, are captured and to align with Medium Term (MT) PASA and Short Term (ST) PASA methodologies. This enhances consistency across planning horizons and better reflects the evolving generation mix.
- **VRE traces development** – AEMO has developed a resource-to-power model using an empirical machine learning approach for wind generators, which captures the specific power curve for each wind farm at high wind and high temperature conditions. System Advisor Model (SAM) from the National Laboratory of the Rockies[16] is used to develop traces for large-scale solar generators. Historical meteorological data and energy conversion models are incorporated across all trace time periods, with temporal (day) shifts between generation and demand traces. This improves the modelling of renewable generator output under weather conditions that also affect demand. Further details are in **Appendix A4.3**.
- **New supply project assessment criteria** – previously, projects were assessed against three key factors: environmental approvals, network connection and finance. For the 2026 WEM ESOO, this has been expanded to five criteria: land, Western Power connection status, planning, finance approvals and construction. This better aligns with how projects are assessed in the NEM[17] and supports greater consistency and comparability across markets, benefiting proponents operating in both jurisdictions. Further details are in **Section 3**.
- **Co-optimisation of Essential System Services (ESS) and energy dispatch** – the model co-optimises energy dispatch with the provision of ESS, including:
  - Contingency Reserve Raise
  - Contingency Reserve Lower
  - Regulation Raise
  - Regulation Lower, and
  - Rate of Change of Frequency Control Service.
- AEMO assesses requirements for these services over five-minute intervals for Regulation services and 15-minute intervals for Contingency Reserve services, reflecting market dispatch requirements.
- **Hydrogen production as a flexible load** – hydrogen production is now modelled as a flexible load with a fixed energy target, rather than as fixed demand. This allows hydrogen consumption to be reduced or shifted during peak periods, reflecting its potential to operate flexibly and support system reliability.
- Further information on modelling assumptions and methods is in **Appendices A1**, **A2**, and **A4**.

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[16] See System Advisor Model – SAM https://sam.nlr.gov/.

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

1.6 Definitions

This section explains some of the key definitions used in this WEM ESOO.

1.6.1 Key definitions of consumption and demand

Consumption and demand can be measured at different points in the electricity system to describe different power system needs. The WEM ESOO reports unscheduled operational consumption and demand. This differs from Operational Demand as defined in the ESM Rules, which is an instantaneous, end-of-Dispatch Interval measurement used for dispatch purposes. Commonly used consumption and demand definitions are listed below.

- **Electricity consumption** is the amount of energy 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. In this report, demand is typically reported at times of maximum and minimum demand.
- **Underlying consumption** – the total amount of electricity used by consumers at their power points. This electricity can be sourced from the grid, distributed PV, batteries or on-site backup power such as diesel generators. Underlying consumption includes business and residential consumption.
- **Business underlying consumption** comprises large industrial loads and business mass market, commercial EV charging, electricity for data centre services, electricity for hydrogen production, electrification[18], and energy efficiency measures[19].
- **Residential underlying consumption** considers population growth, dwellings and connections growth[20], appliance uptake, PV rebound effect, EV uptake, electrification[21] and energy efficiency measures.
- **Delivered consumption** – the electricity supplied to customers from the grid, which excludes the portion of their consumption that is met by behind-the-meter (typically distributed PV) generation.
- **Operational consumption/operational demand** – sent-out generation supplied by all market-registered Energy Producing Systems, which includes load scheduled through market dispatch (such as large-scale battery charging) and both distribution and transmission losses.
- **Unscheduled operational consumption/demand** – annual unscheduled operational consumption/demand forecasts include delivered consumption/demand for all consumer sectors, plus transmission and distribution losses and excludes any consumption/demand associated with load scheduled through market dispatch (such as large-scale battery charging).

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[18] 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.

[19] Energy efficiency measures reduce the energy required to perform a given task; for example, building insulation reduces the energy required for heating or cooling.

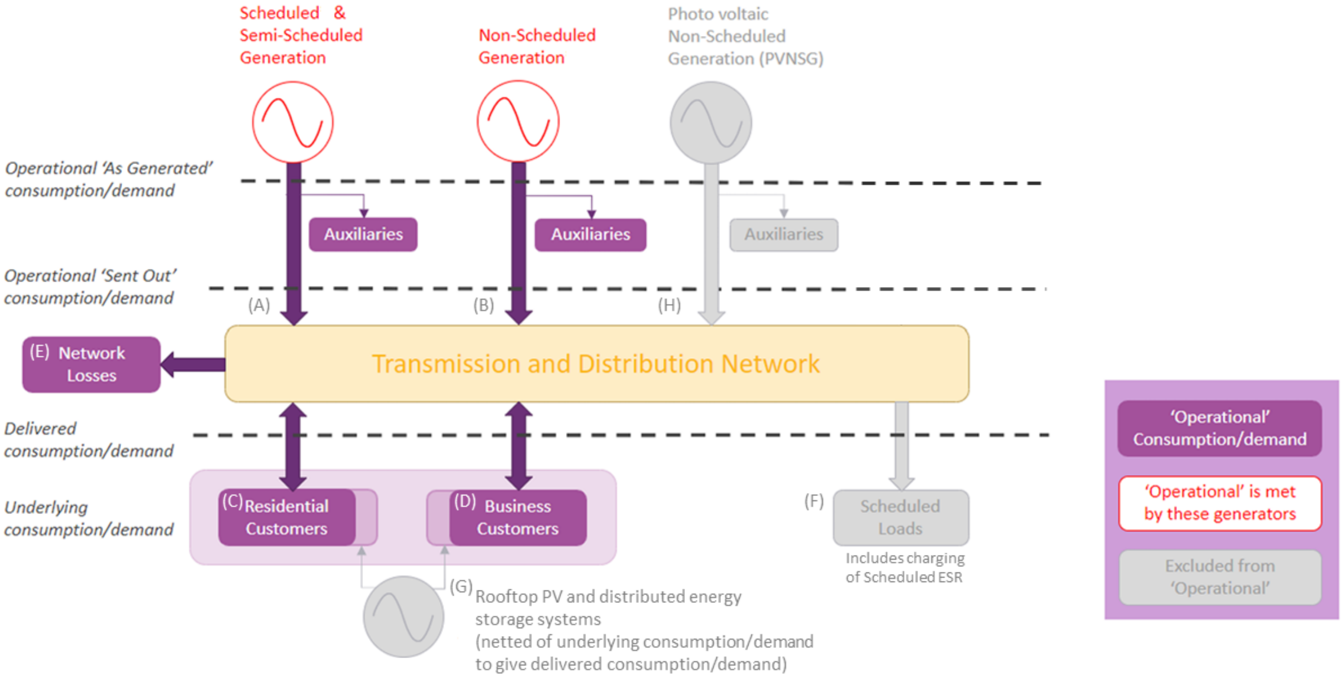
[20] Residential base forecasts capture the growth in consumption with respect to new connection points, reflecting population increase.

[21] 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.

- **Operational maximum (peak) and minimum demand**[22] – 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), winter (June to August), or shoulder months (April, May, September to November).
- **Unscheduled operational maximum (peak) and minimum demand** – the operational peak and minimum demand forecasts that exclude the impact of scheduled load operations (such as large-scale ESR charging).

Figure 6 summarises the links between consumption and demand definitions. Operational demand is the sum of injections by Scheduled Facilities, Semi-Scheduled Facilities and Non-Scheduled Facilities into the network (A + B). It is equivalent to (C + D + E + F) – (G + H), where A to H represent the components illustrated in **Figure 6**. Forecast unscheduled operational demand is operational demand excluding the impact of Scheduled Loads (F).

Figure 6 Relationship between the components of consumption and demand



Notes: '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.

Underlying and operational demand forecasts are prepared as a probability distribution, from which the 10%, 50% and 90% POE forecasts for three seasons (summer, shoulder and winter) are taken.

Unscheduled operational maximum and minimum demand forecasts are presented with:

- a **50% POE**[23], 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), and

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[22] Peak and minimum demand refers to unscheduled operational demand, unless otherwise specified.

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

- a **90% POE** (for maximum demand) or **10% POE** (for minimum demand), based on less extreme conditions that could be exceeded nine years in 10.

1.6.2 Key definitions of supply

- **Capability Class 1, 2, and 3** – Capability Class 1 is firm capacity that is not energy-limited, such as gas-fired generation, and meets the 14-hour fuel availability requirements[24]. Examples of Capability Class 1 capacity include gas turbines and coal-fired power stations. Capability Class 2 is capacity with energy or availability limitations, including Demand Side Programmes and Electric Storage Resources. Capability Class 3 is non-firm capacity, such as wind and solar with no associated firming capacity.
- **Peak Capacity** – refers to the Peak Reserve Capacity, equal to the Capacity Credits assigned to Facilities following trade declarations and the determination of Network Access Quantities (NAQs) through the 2025 Reserve Capacity Cycle. Forecast peak capacity includes assigned Peak Reserve Capacity as well as capacity procured in the 2024-26 and 2025-27 Peak Demand NCESS.
- **Flexible Capacity** – refers to Flexible Reserve Capacity, introduced from the 2025 Reserve Capacity Cycle and capped at the level of Peak Reserve Capacity. Forecast flexible capacity includes all technology types that are potentially eligible for assignment of Flexible Capacity. Eligibility requirements differ by technology type and are based on the maximum output the Facility can achieve within four hours from a cold state, with the quantity of forecast flexible capacity capped at the level of forecast peak capacity.
- **Hybrid Facility** – refers to a Facility consisting of two or more separately certified components, including any combination of a Non-Intermittent Generating System (NIGS), an Intermittent Generating System (IGS) or a grid-scale storage. Forecast supply from hybrid Facilities include all components of Facilities that are potentially eligible for assignment of Peak Reserve Capacity or Flexible Reserve Capacity.

1.7 Additional information in the 2026 WEM ESOO

The following information should be considered part of the 2026 WEM ESOO:

- the 2026 WEM ESOO report and appendices,
- supplementary information published on the 2026 WEM ESOO page, including the 2026 Reserve Capacity Information Pack, the 2026 WEM ESOO Data Register, the 2026 WEM ESOO Demand Traces and the 2026 WEM ESOO Visual Overview,
- the demand forecasting data portal[25],
- the 2025 IASR[26], accompanying assumptions workbooks and supplementary material, and
- the draft 2026 *Forecasting Assumptions Update*[27], accompanying assumptions workbook and supplementary material.

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[24] Capability Class 1 Availability Assessment Interval is defined as a Trading Interval occurring between 08:00 and 22:00 on a Business Day under ESM Rules, in which the Non-Intermittent Generating Systems as a component of Scheduled Facility or Semi-Scheduled Facility have to fulfil the above 14 hours fuel requirements.

[25] See https://aemo.com.au/energy-systems/data-dashboards/electricity-and-gas-forecasting/.

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

[27] See https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-forecasting-assumptions-update.

1.8 Notes for reading this report

- This WEM ESOO uses many terms that have meanings defined in the ESM Rules. Terms defined in the ESM Rules are capitalised. Other terms are defined throughout the report and in the Glossary.
- An HH:MM Trading Interval means the Trading Interval commencing at HH:MM.
- The WEM ESOO modelling resolution is 30-minute Trading Intervals.
- All data in this WEM ESOO is based on Capacity Years unless otherwise specified. A Capacity Year commences in the 08:00 Trading Interval on 1 October and ends at the completion of the 07:30 Trading Interval on 1 October of the following calendar year.
- All references to a single year, such as 2026, refer to a calendar year.
- Unless otherwise specified, references to consumption and demand in this WEM ESOO are to operational consumption and unscheduled operational demand, as defined in Section 1.6.
- Key definitions of operational consumption and demand, as well as reliability assessment related terminology, can be found in **Section 1** and in the Glossary.
- The three seasons reported in this WEM ESOO are
  - summer (Trading Months from December to March, aligned with the Hot Season defined in the ESM Rules as commencing on Trading Days beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April)
  - winter (Trading Months from June to August), and
  - shoulder (Trading Months of April, May, and September to November).
- 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 ESM 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 2026 LT PASA Study Horizon, which covers the 2026-27 to 2035-36 Capacity Years, also referred to as the 10-year outlook period. The first half of the outlook period refers to 2026-27 to 2030-31, and the second half refers to 2031-32 to 2035-36.
- The compound annual growth rate was used to calculate the average annual growth rate (AAGR). AEMO uses 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. AEMO used 2025-26 and 2030-31 as year 0 to calculate the five-year average annual growth rates for the first half and second half of the outlook period, respectively.

2 Consumption and demand forecasts

This section presents forecasts of annual energy consumption and peak demand across the outlook period. The overall forecast narrative is broadly consistent with the 2025 WEM ESOO, with sustained growth in both energy consumption and peak demand across the SWIS, driven mainly by electrification across the residential, business and industrial sectors. The 2026 WEM ESOO incorporates updated actuals and introduces new forecast components for data centres and new industries, including emerging hydrogen and green steel.

These forecasts are a key input to the LT PASA. The *Expected* scenario shows:

- Forecast consumption continues to rise at a similar rate to last year's forecast. Underlying consumption is forecast to increase 57%, from around 20.4 TWh in 2025-26 to 32.1 TWh by 2035-36, with faster growth in the second half of the outlook period driven mainly by business consumption.
- Annual peak demand is higher than in the 2025 WEM ESOO, increasing around 29%, from 4,681 MW in 2025-26 to 6,016 MW by 2035-36, while delivered energy consumption increases around 48% from 16.4TWh in 2025-26 to 24.4TWh in 2035-36.
- Because delivered energy consumption is growing faster than annual peak demand, the SWIS will need more bulk energy supply and transmission capacity to support higher utilisation of the system.
- Growth in consumption and peak demand is increasingly driven by industrial electrification, emissions reduction policies (such as the Safeguard Mechanism), and emerging loads such as data centres, hydrogen and green steel, particularly from 2030-31.
- By 2035-36, distributed PV generation from residential installations is forecast to offset the equivalent of 68% of total forecast underlying residential consumption.
- Data centres are an emerging and uncertain source of load, with strong growth potential, and significant early-stage investor interest in Western Australia. A small number of well-progressed projects are included in the *Expected* scenario but data centres are forecast to contribute only a small share of total SWIS consumption, reaching approximately 0.8 TWh by 2035-36.
- For 2028-29, coordinated operation of distributed residential batteries through the VPP is forecast to reduce annual peak operational demand in the 10% POE *Expected* scenario by around 200 MW, from 5,136 MW to 4,937 MW, a 4% reduction.
- Rapid uptake of residential batteries is lifting minimum demand relative to the 2025 WEM ESOO. Minimum demand remains an operational risk, but more than 1,000 MW of existing and committed utility-scale storage is expected to support secure operation as DER uptake continues to reshape demand profiles.

2.1 Consumption and demand drivers

The main drivers of electricity consumption and demand forecasts considered in this 2026 WEM ESOO are:

- economic and population growth, including new household connections,

- appliance uptake and consumer behaviour trends,
- electrification of homes and businesses,
- electrification of transport across the residential and business sectors,
- DER, such as distributed PV and batteries, including the impact of coordinated batteries through a VPP,
- large industrial load activities, and
- energy efficiency measures.
- Two additional consumption and demand categories also contribute to the forecasts:
- data centres, previously included in the business mass market (BMM) category, and
- potential emerging hydrogen and green steel production industries.

A summary of the forecasts resulting from these drivers is discussed in the following sections. More detailed analysis is in Appendix A1.

2.2 Energy consumption forecasts

Energy consumption is projected to grow across all three modelled scenarios, driven by ongoing population and economic growth, electrification of homes and businesses, and updated consumer behaviour trends. Recent data indicates increasing residential electricity consumption in response to higher temperatures, which has been incorporated into the 2026 WEM ESOO forecasts.

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.

2.2.1 *Low* scenario

In the *Low* scenario, operational and underlying consumption are projected to increase at a similar rate to the 2025 WEM ESOO forecast, but from a higher starting point following the inclusion of 2025 actuals. Consumption in 2024-25 was higher than forecast in the 2025 WEM ESOO, primarily driven by growth in residential underlying consumption.

The *Low* scenario features slower economic growth and lower investment in DER relative to the *Expected* scenario.

2.2.2 *Expected* scenario

In the *Expected* scenario, underlying annual consumption rises from about 20.4 TWh in 2025-26 to 32.1 TWh by 2035-36. Although the growth trend is similar to the 2025 WEM ESOO, the overall increase is slightly higher than the 9.6 TWh projected last year.

This stronger growth is largely driven by higher residential consumption, including the recent uplift in actuals and updated consumer behaviour assumptions, and higher business consumption, which includes the addition of data centre forecasts. By the end of the outlook period, residential and business consumption are forecast to increase by 2.4 TWh and 9.0 TWh respectively, relative to the start of the forecast horizon.

Distributed PV is expected to offset nearly 20% of underlying consumption in 2026, increasing to around 30% by 2035-36 when combined with energy efficiency. This contributes to delivered consumption rising at a lower rate than underlying consumption, from 16.4 TWh in 2025-26 to 24.4 TWh in 2035-36.

The *Expected* scenario features higher DER investments, stronger electrification and wider adoption of energy efficiency measures relative to the *Low* scenario.

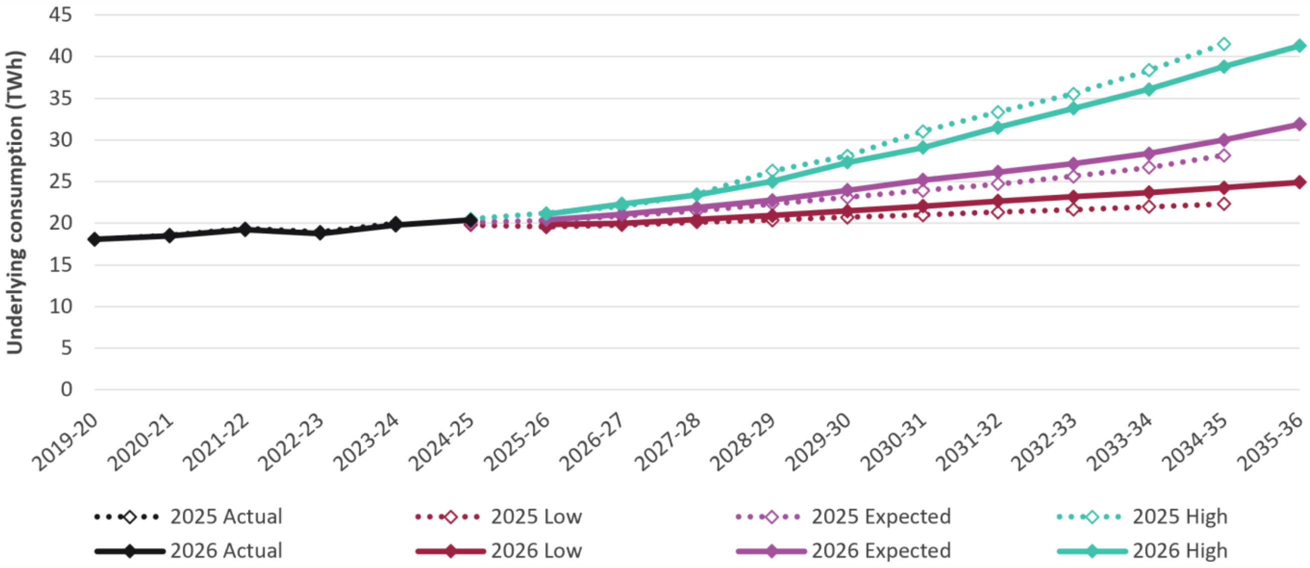
2.2.3 *High* scenario

The *High* scenario projects significant consumption growth. This reflects faster electrification of household, business and industrial loads, higher economic growth, and stronger growth from data centres and new industries such as hydrogen and green steel.

However, consumption is projected to grow more slowly than in last year's *High* scenario. This reflects more conservative industrial expansion assumptions following finalisation of the 2025 IASR, including slower hydrogen uptake and the exclusion of hydrogen export assumptions. Hydrogen consumption is now included in the new industries category, which covers hydrogen and green steel.

Figure 7 shows historical and forecast underlying consumption[28] for the outlook period.

Figure 7 Actual and forecast underlying consumption under three scenarios from 2025 and 2026 WEM ESOOs, 2019-20 to 2035-36 (TWh)



2.2.4 Underlying consumption grows strongly, while distributed PV offsets operational consumption

Underlying consumption growth is driven by population growth, economic growth, electrification of homes, transport, business and industry, and changing consumer behaviour. Consumption increases across both the residential and business sectors. However, residential consumption declines as a share of total underlying consumption because business

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[28] For numerous large industrial loads with complex generation arrangements behind the meter in the SWIS, AEMO is unable to forecast underlying consumption, hence underlying is set to equal delivered for these customers. True underlying consumption is therefore higher in the SWIS than it is able to be represented.

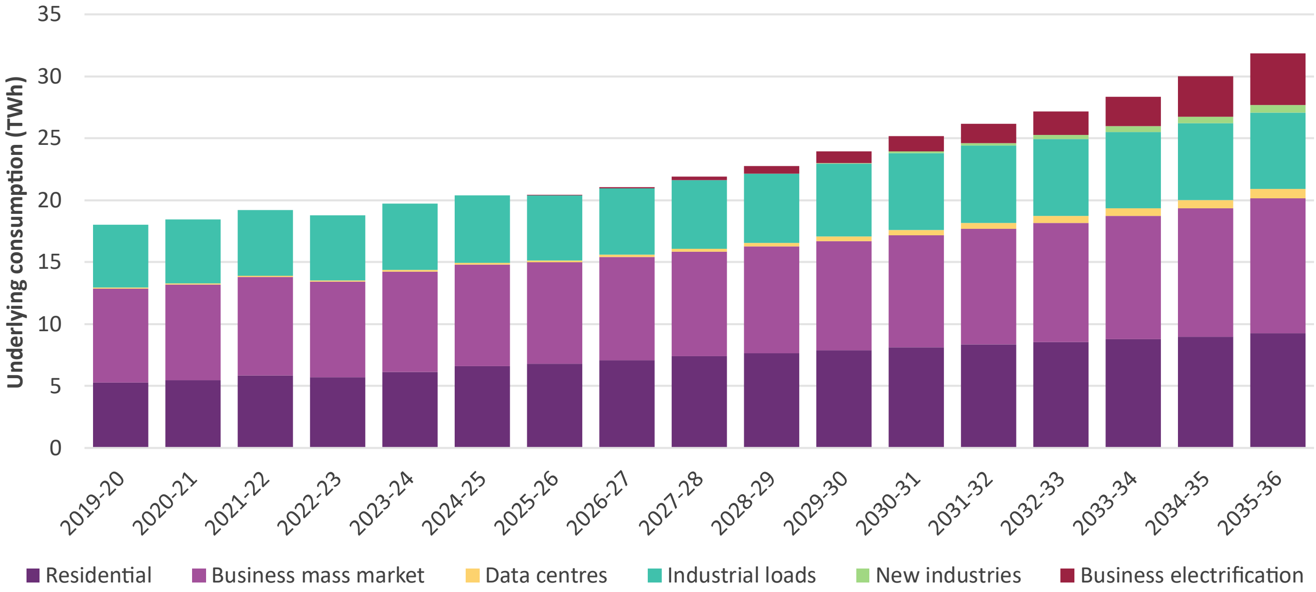
consumption grows faster, driven mainly by electrification and, to a lesser extent, growth in large industrial loads and data centres.

Over the outlook period for the *Expected* scenario:

- Residential consumption[29] declines from around 33% of total underlying consumption in 2025-26 to 29% in 2035-36, and from 21% to 12% of total delivered consumption.
- Business consumption is expected to increase, largely driven by business electrification as businesses respond to the Safeguard Mechanism and other emissions reduction incentives.
- Data centre consumption is forecast separately for the first time, reflecting significant growth relative to the current scale of operational data centres in the SWIS. Data centres had previously been included in the BMM category.
- Consumption from hydrogen and green steel is projected to increase from 2030-31, but remains a key uncertainty across scenarios.
- Large industrial load consumption is slightly lower than in the 2025 WEM ESOO, reflecting advice from some industrial operators that proposed developments will be paused or deferred. AEMO has also adjusted its forecasting methodology to account for persistent over-forecasting from industrial operators.

Figure 8 shows the underlying consumption[30] forecast for the *Expected* scenario across six modelled forecast categories. **Figure 10** and **Figure 11** in the following sections show the contribution of distributed PV to residential and business consumption respectively.

Figure 8 Actual and forecast underlying electricity consumption by component, *Expected* scenario, 2019-20 to 2035-36 (TWh)



Notes:

- For numerous large industrial loads with complex behind-the-meter generation arrangements, AEMO is unable to forecast underlying consumption, hence underlying is set to equal delivered for these customers. True underlying consumption is therefore higher in the SWIS than it can be represented.
- Values presented in this figure do not include residential and business battery loss adjustments, reflecting the inclusion of these battery adjustments in underlying consumption, in line with forecast methodology.

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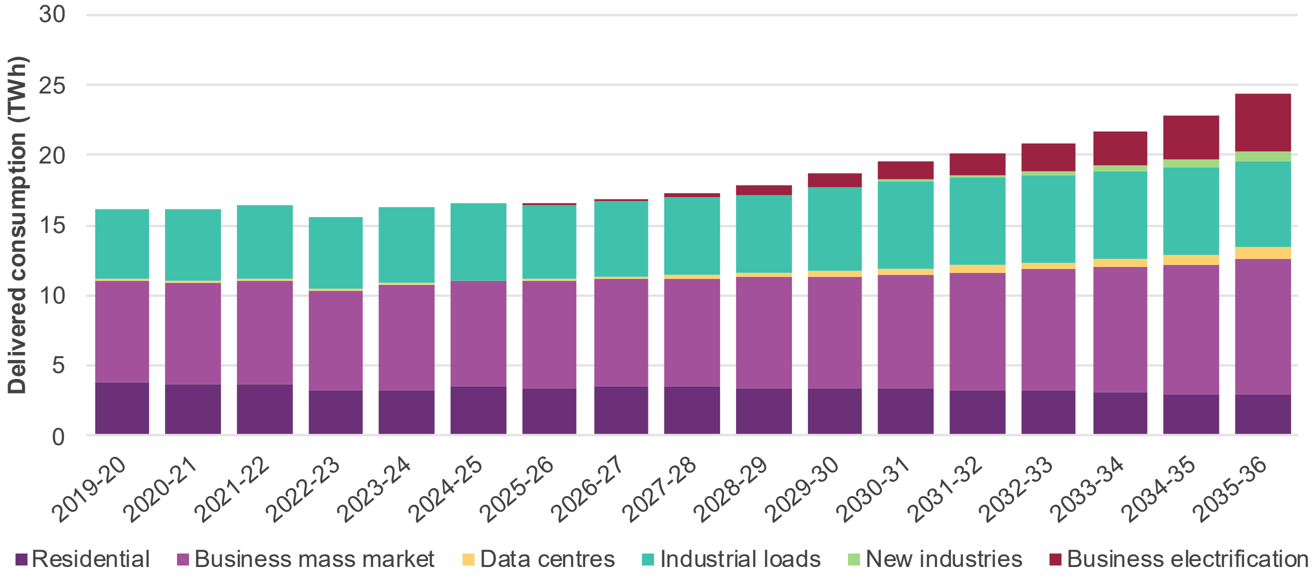
[29] Residential and business mass market consumption forecasts include EV consumption for each sector.

[30] Note that transmission losses are not included in the definition of underlying consumption.

Figure 9 shows the delivered consumption forecast for the *Expected* scenario, noting that distributed PV contributes an increasingly significant role in satisfying underlying consumption.

Figure 9 Actual and forecast delivered consumption by component, *Expected* scenario, 2019-20 to 2035-36 (TWh)



Note: Values presented in this figure do not include residential and business battery loss adjustments, reflecting the inclusion of these battery adjustments in underlying consumption, in line with forecast methodology.

The following sections describe forecast trends in underlying consumption at the residential and business level, presenting the *Expected* scenario[31] only.

2.2.5 Residential underlying consumption grows at a higher rate than the 2025 forecast

Consistent with the 2025 forecast, underlying residential consumption is projected to increase over the 10-year outlook period, more than offsetting reductions driven by energy efficiency gains. Rising residential EV charging contributes to higher electricity consumption.

Residential consumption is higher due to adjustments for actual consumption during 2025 and greater consideration of recent consumer behaviour trends. Analysis of residential consumption data indicates that households are using more electricity for both cooling and heating year on year. A similar upward trend is observed in non-temperature-dependent residential consumption, with increased use on mild temperature days associated with higher appliance uptake, residential electrification and changing consumer usage patterns.

By 2035-36, distributed PV generation from residential installations is forecast to offset the equivalent of 68% of underlying residential consumption. Distributed PV generation exceeding residential demand may be consumed by other loads.

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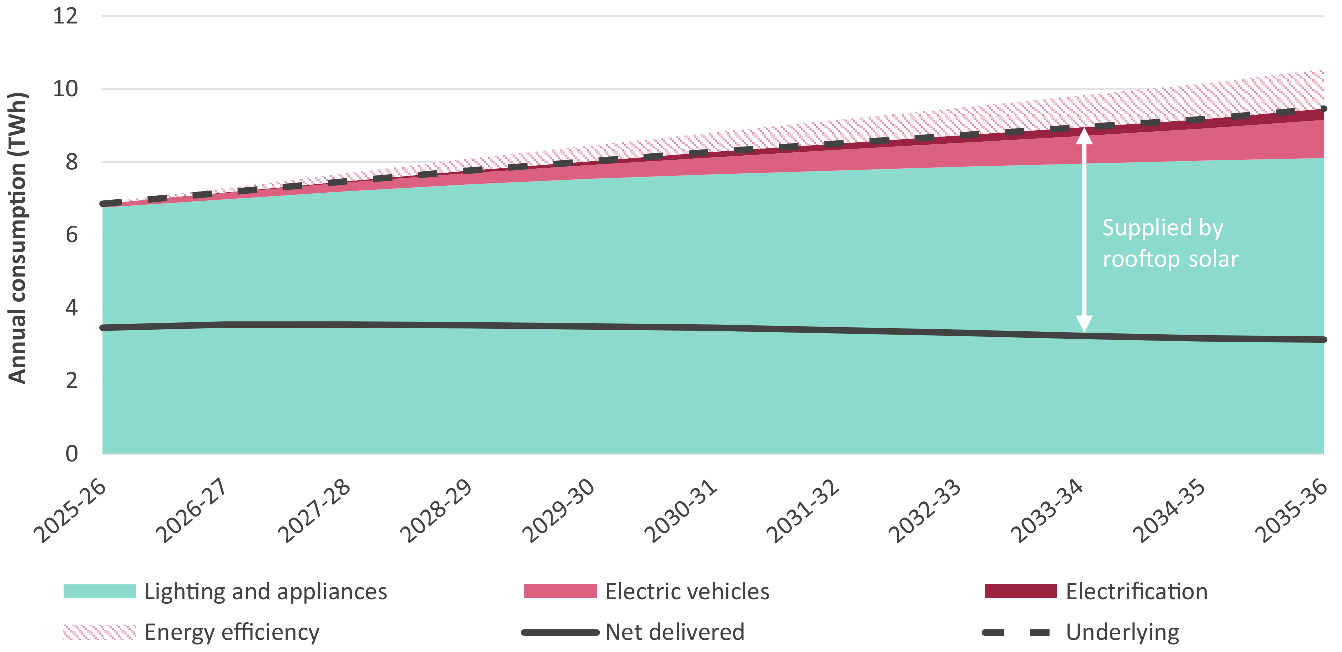
[31] Other scenarios are downloadable via AEMO's Forecasting data portal. See https://aemo.com.au/energy-systems/data-dashboards/electricity-and-gas-forecasting/.

Figure 10 Forecast underlying residential consumption by component, *Expected* scenario, 2025-26 to 2035-36 (TWh)



Notes:

- Residential delivered consumption presented here excludes battery storage to reflect the forecast methodology.
- Transmission and distribution losses are presented as a net delivered total to reflect forecast methodology and are not shown separately here.

Residential forecasts account for the Commonwealth Cheaper Home Batteries Program and the Western Australian Government's Residential Battery Scheme, both introduced on 1 July 2025. Battery uptake in 2025 has been higher than originally expected. AEMO expects these schemes, together with Synergy's Battery Rewards residential VPP scheme, to support continued high uptake of residential batteries. The addition of residential batteries in the SWIS is forecast to contribute to higher underlying consumption due to charging and discharging round-trip energy losses.

2.2.6 Business underlying consumption increases, driven by electrification and Large industrial load growth

Figure 11 shows forecast underlying consumption for business consumers, including large industrial loads[32], data centres, and business mass market[33] consumers. The forecast also includes business electrification, business EVs, and grid-connected hydrogen producers.

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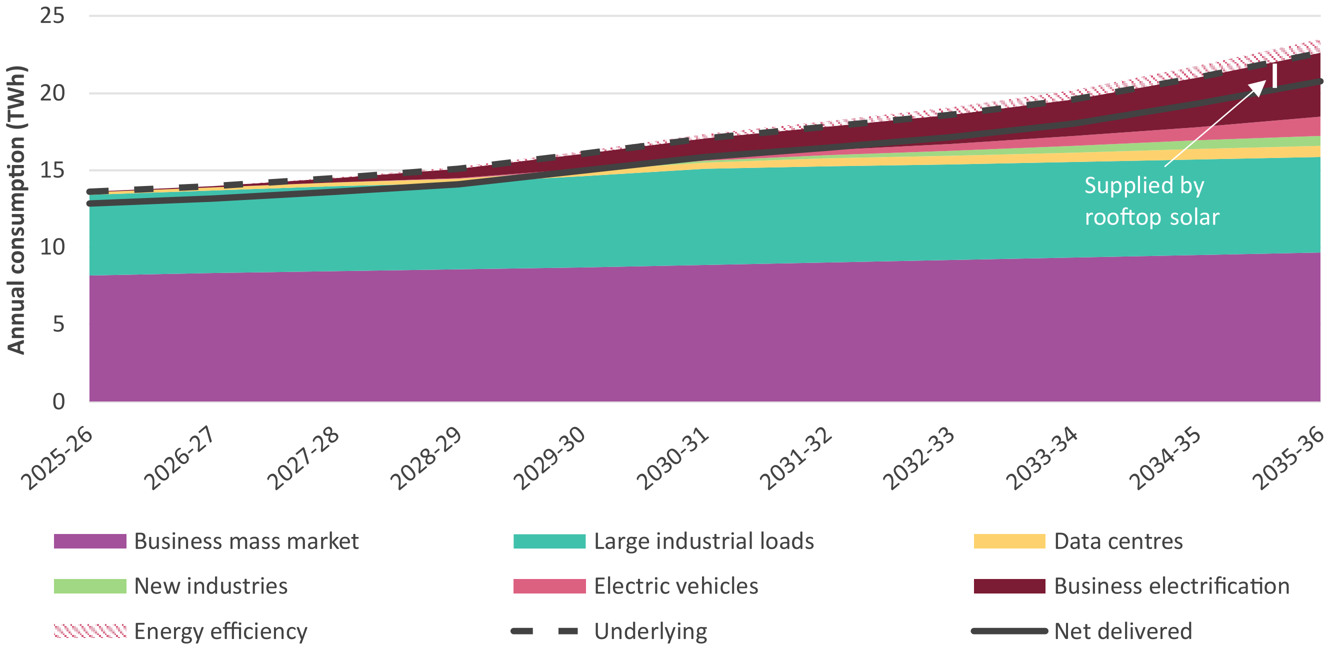
[32] For the large industrial load threshold definition, please refer to Appendix Section A1.9.

[33] BMM covers businesses not classified as large industrial loads, data centres or new industries.

Figure 11 Forecast business underlying consumption by component, *Expected* scenario, 2025-26 to 2035-36 (TWh)



Notes:

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

Business mass market

The BMM category includes most business customers, excluding large industrial loads, data centres and new industries. In this year's forecast, projected underlying BMM consumption growth is similar to the 2025 WEM ESOO. However, the 2026 BMM forecast starts from a lower base because some consumers have been reclassified into a new data centres category, given growing interest in this sector, or large industrial loads[34], resulting in an associated reduction in consumption, with actuals revised to reflect this re-categorisation.

Large industrial loads

The 2026 large industrial loads forecast is lower than the 2025 forecast due to a combination of input and methodology changes. These include the projected closure or mothballing of some loads, slower progress for other proposed developments, and the introduction of an outage factor to address persistent over-forecasting in survey responses from industrial operators.

Data centres

Data centres are included as a standalone forecast category for the first time in the 2026 WEM ESOO, having previously been captured within the BMM category.

Data centres are currently a small but potentially fast-growing source of future consumption and demand in Western Australia. In the *Expected* scenario, data centres are forecast to contribute less than 0.8 TWh of total SWIS consumption by

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[34] This reclassification has resulted in a reduction of base year BMM sector underlying consumption of approximately 0.2 TWh, with a corresponding increase to the large industrial loads sector.

2035-36. However, the development pipeline is at an early stage and starts from a low base, so a small number of large projects could materially change the outlook.

To reflect this uncertainty, and to avoid overestimating future requirements which may impose unnecessary costs on the market, the 2026 WEM ESOO balances evidence from current project developments with broader growth trends observed in eastern Australia and globally. Historical consumption has been separated by identifying existing SWIS data centre loads, while future projections use the methodology applied in the 2025 NEM ESOO.

This forecast combines two complementary views:

- **project based view** – reflects identified SWIS developments and connection enquiries, including existing operators and projects progressing through connection and development stages, and
- **economic view** – reflects broader underlying demand for data centre services in Australia, based on projections provided by Oxford Economics.

The final forecast is derived by averaging the project-based and economic views. Given the limited number of advanced projects currently identified in Western Australia, the economic view has a larger influence on projected growth. The economic view shows that growth stronger than historical trends is plausible, reflecting the potential for more projects to proceed over time than are currently advancing through connection and development stages.

AEMO is working with stakeholders and contributing to relevant policy initiatives to better understand:

- the impact of data centre location decisions on transmission capacity,
- supply and consumption requirements resulting from rapid project developments – one or two material projects would shift the outlook from the *Expected* to the *High* forecast,
- system strength and reliability impacts from supply outages and potentially volatile loads, and
- the role of demand-side response in managing data centre demand.

Electrification, business EVs and new industries

The electrification category includes electrification of minerals processing, such as alumina, commercial EV uptake, and new industries such as hydrogen and green steel. Business electrification and EV uptake are forecast to occur in response to the Safeguard Mechanism and other incentives to meet Federal and State decarbonisation ambitions. Together, these drivers are forecast to increase business consumption by 6 TWh by the end of the outlook period.

Consistent with last year's forecasts, growth in electrification and hydrogen production is forecast to occur primarily in the second half of the outlook horizon, reflecting moderate progress on electrification investments and limited advancement in hydrogen projects[35].

Compared to the 2025 WEM ESOO, the forecast amount of business consumption offset by distributed PV generation has been revised upwards, reducing the delivered business consumption outlook[36].

Energy efficiency activities are projected to increase at a similar rate to 2025 WEM ESOO forecast.

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[35] Please refer to Appendix A1.11 for further detail on drivers.

[36] Distributed PV generation exceeding business needs is made available to all consumers via the grid (instantaneously) at the time of generation.

2.3 Demand forecasts

Peak summer and peak winter unscheduled operational demand are forecast to grow throughout the outlook period, broadly in line with rising energy consumption driven by population growth, economic activity and increasing electrification[37].

In the 2026 WEM ESOO, annual peak unscheduled operational demand in the *Expected* scenario is projected to increase by around 29%, from 4,681 MW in 2025-26 to 6,016 MW by 2035-36.

Growing uptake of behind-the-meter distributed PV and batteries continues to reshape unscheduled operational demand profiles. Increased distributed PV capacity is expected to further reduce daytime unscheduled operational demand, with 90% POE minimum unscheduled operational demand in the *Expected* scenario forecast to decline from an actual of 384 MW in 2025-26 to -93 MW by 2035-36.

At the same time, rapid growth in storage capacity, including grid-scale and residential batteries, is expected to improve the ability to manage both peak operational demand and minimum unscheduled operational demand conditions (see Section 2.6.1 and 2.6.2). Residential batteries will provide the greatest system benefit when they can be coordinated, such as through aggregation into a VPP. Under the 10% POE *Expected* scenario, coordinated residential battery discharge is forecast to reduce peak unscheduled operational demand by 422 MW by 2035-36.

AEMO expects system security risks associated with low minimum unscheduled operational demand conditions to remain manageable through growing storage capability and operational mechanisms, including existing NCESS contracts and Emergency Solar Management[38].

Demand

The amount of power consumed at a point in time, measured in MW or GW. In this report, demand is generally reported as a 30-minute average for periods of maximum or minimum demand.

Operational demand

Electricity supplied from market-registered energy producing systems to meet demand in the SWIS. It includes transmission and distribution losses and large-scale battery charging.

Unscheduled operational demand

Operational demand after excluding scheduled load, such as large-scale battery charging.

Table 10 Peak and minimum unscheduled operational demand, *Expected* scenario

	Most recent actual (MW)	Forecast (MW)	Forecast next two years (MW)		End of outlook period (MW)	% change by end of outlook period
	2024-25	2025-26	2026-27	2027-28	2035-36	
Summer peak (10% POE)	4,551	4,681	4,709	4,878	6,016	29%
Winter peak (10% POE)	3,953	3,994	4,102	4,203	5,537	39%
Minimum (90% POE)	456 (384[A])	208	235	140	-93	-145%

A. The 384 MW minimum occurred on 16 November 2025, within 2025-26, and is valid up to the date of 2026 WEM ESOO publication.

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[37] AEMO maximum and minimum unscheduled operational demand forecasts assume the absence of unserved energy from directed load curtailment or significant network outages, demand side participation, including reserve capacity mechanism, and supplementary reserve capacity and calls for voluntary reduction in demand.

[38] The State Government introduced Emergency Solar Management (ESM) to support system security during periods of high solar generation and low demand. ESM allows new and upgraded distributed PV systems to be remotely switched off and on when needed. See Emergency Solar Management https://www.synergy.net.au/Your-home/Solar-and-battery/Emergency-Solar-Management.

The 2026 WEM ESOO unscheduled operational demand forecasts incorporate recent weather conditions, observed peak demand outcomes and changes in underlying load behaviour. Peak unscheduled operational demand in the SWIS is strongly influenced by extreme summer temperatures and multi-day heatwaves. While the 2024-25 Hot Season included four of the 10 highest demand days on record, weather conditions during the 2025-26 Hot Season were comparatively mild, resulting in lower observed peak demand. As a result, no load reduction activations were required during the 2025-26 Hot Season through existing DSP, SC arrangements or NCESS mechanisms.

Table 11 summarises observed peak and minimum unscheduled operational demand conditions during the 2024-25 winter season and 2025-26 Hot Season.

Table 11 Actual unscheduled operational demand compared with 2025 WEM ESOO *Expected* scenario forecasts

Actuals	Winter maximum 2024-25	Annual minimum 2024-25	Summer maximum 2025-26
Trading Interval starting	Monday, 28 July 2025 18:30	Sunday, 27 September 2025 13:00	Monday, 2 February 2026 18:30
Temperature (°C)[A]	9.6	20.4	33.3
Daily max temperature (°C)	13.3	20.8	41.3
Daily min temperature (°C)	6.6	10.5	25.0
Operational sent out (OPSO) (MW)	3,953	456	4,219
2025 WEM ESOO forecast			
10% POE (MW)	3,776	510	4,734
50% POE (MW)	3,641	402	4,440
90% POE (MW)	3,526	271	4,089

A. Temperatures were recorded by Perth Metro Weather Station.

The 2024-25 winter season saw unusually cold conditions in Western Australia, including one of the lowest average apparent (‘feels-like’) temperatures and the coldest day observed in the past 15 years of half-hourly weather data. Winter peak demand occurred on Monday, 28 July 2025 at around 18:30.

Persistently cold weather conditions occurred throughout the day, and at the time of the peak, the temperature was 9.6°C with a daily maximum of 13.3°C and a minimum of 6°C. These conditions drove strong heating demand, with winter peak demand reaching 3,953 MW, around 177 MW above the corresponding 10% POE forecast of 3,776 MW.

The 2025-26 Hot Season was comparatively mild overall. Summer peak demand occurred on Monday, 2 February 2026 at 18:30, with unscheduled operational demand reaching 4,219 MW. Although temperatures that day reached 41.3°C, the extreme heat did not persist into the evening peak period, falling to 33.3°C at 18:30 and to a 25°C overnight minimum. This resulted in unscheduled operational demand outcomes between the 50% and 90% POE forecast levels from the 2025 WEM ESOO.

Overall, the 2025-26 Hot Season ranked as the second lowest summer maximum temperature over the past 10 years.

Annual minimum unscheduled operational demand occurred during the 2025 spring shoulder period on Saturday, 27 September 2025 at 13:00, during high DPV generation conditions. Mild weather and reduced weekend business activity contributed to lower underlying demand, with minimum unscheduled operational demand reaching 456 MW. Actual OPSO demand fell between the 10% and 50% POE minimum unscheduled operational demand forecast levels from the 2025 WEM ESOO.

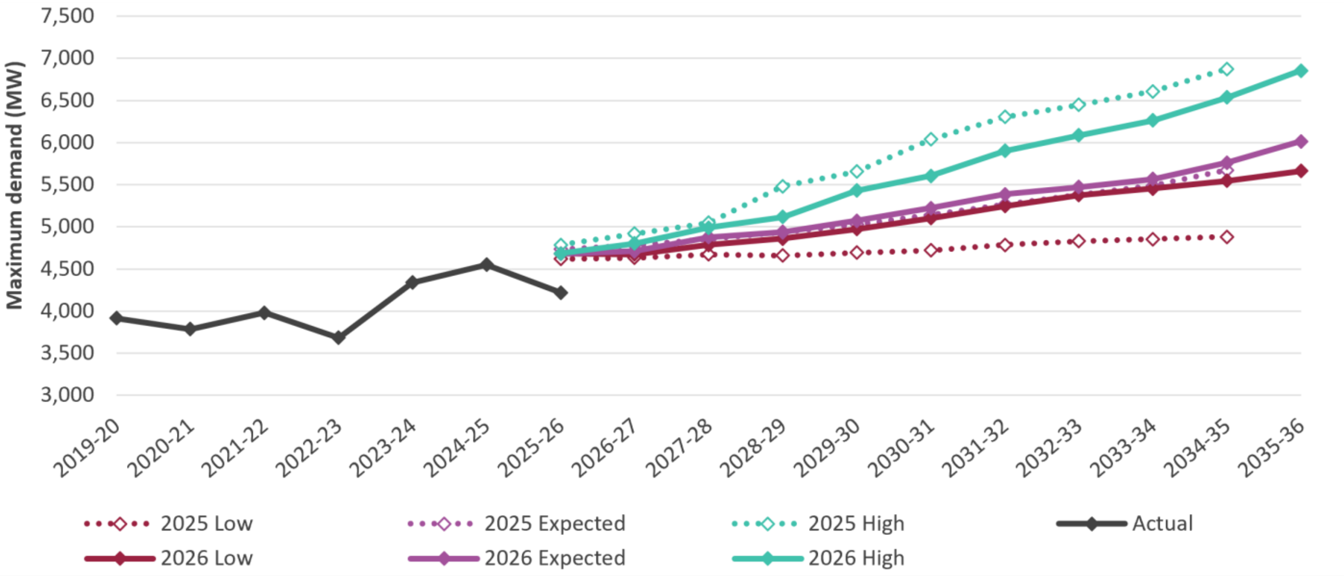
2.3.1 Summer peak unscheduled operational demand continues to increase

Summer peak demand is forecast to rise as electricity consumption grows, but battery discharge helps reduce the size of the increase.

Figure 12 shows the 10% POE peak unscheduled operational demand forecasts across the three scenarios in the 2026 WEM ESOO. Peak unscheduled operational demand is projected to grow steadily over the forecast horizon, driven by increases in underlying consumption across residential, BMM, and large industrial loads, as well as contributions from electrification and EVs.

Compared with the 2025 WEM ESOO, the *Low* scenario forecast is higher, reflecting stronger growth across residential, business mass market, large industrial loads and electrification. The *High* scenario forecast is lower than in the 2025 WEM ESOO, reflecting a weaker consumption outlook, with lower projected growth in large industrial loads a key contributor.

Figure 12 Actual peak demand and forecast 10% POE summer peak unscheduled operational demand under three scenarios from 2025 and 2026 WEM ESOOs, 2019-20 to 2035-36 (MW)



Note: The actuals displayed reflect observed unscheduled operational demand under the prevailing weather conditions and include load reduction activation actuals. Summer peak unscheduled operational demand forecasts include hydrogen demand and include peak demand reductions resulting from coordinated (VPP) residential battery operation.

For the *Expected* scenario, peak unscheduled operational demand in the near term is broadly consistent with the 2025 WEM ESOO, reflecting similar underlying assumptions. The 2026 WEM ESOO incorporates updated modelling of behind-the-meter battery behaviour, including coordinated VPP operation, which has a material impact on peak demand outcomes (see Sections 2.4 and 2.5).

- The Commonwealth Cheaper Home Batteries Program[39] and WA Residential Battery Scheme[40], both introduced on 1 July 2025, have stimulated higher-than-expected uptake of residential batteries across Western Australia. The Western Australia scheme requires subsidised batteries to participate in a VPP for at least the first two years.
- As more residential batteries connect to the SWIS and participate in VPPs, coordinated battery discharge during peak periods is forecast to reduce peak unscheduled operational demand more than passive battery operation. As a result,

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[39] See https://cer.gov.au/schemes/renewable-energy-target/small-scale-renewable-energy-scheme/small-scale-renewable-energy-systems/solar-batteries.

[40] See https://www.wa.gov.au/government/announcements/the-wa-residential-battery-scheme-now-open.

VPP participation lowers peak demand in the *Expected* scenario, particularly towards the end of the outlook period (see Section 2.4 and 2.5).

The 10% POE forecast represents demand under a one-in-10-year summer weather event, drawn from simulations using 16 historical weather reference years. This probabilistic approach captures plausible peak conditions while smoothing out short-term variability such as the cooler 2025 winter.

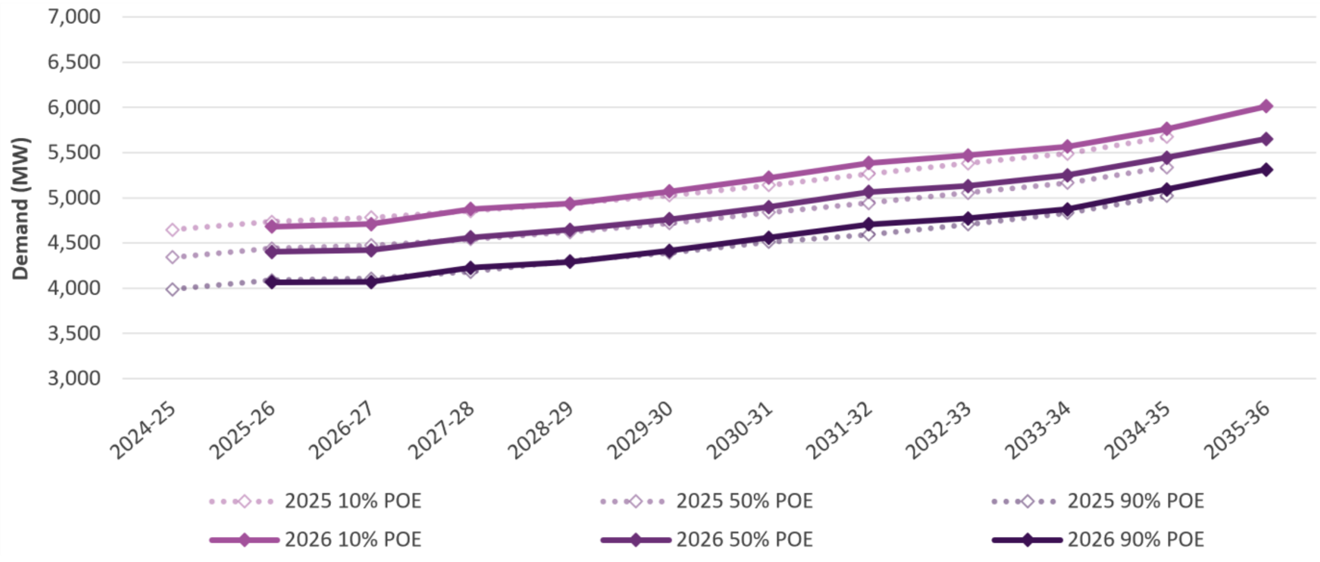
Table 12 summarises the summer peak unscheduled operational demand growth rates and key growth drivers. Across all three scenarios, forecast growth for 10% POE summer peak unscheduled operational demand shows steady growth.

Table 12 Summer peak unscheduled operational demand change rates and assumptions, by scenario

	Low	*Expected*	*High*
Average annual growth rate			
Whole period (2025-26 to 2035-36)	1.9%	2.5%	3.9%
First half (2025-26 to 2030-31)	1.7%	2.2%	3.7%
Second half (2031-32 to 2035-36)	2.1%	2.9%	4.1%
Forecast growth drivers relative to the 2025 WEM ESOO	Steady increase in demand following the trend in residential, BMM, large industrial loads, and electrification.	Comparatively higher trajectory due to higher consumption forecasts from residential, BMM, and electrification categories.	The lower '*High* scenario' is due to lower corresponding consumption forecast of which a lower growth in large industrial loads is a significant contributor.

Figure 13 compares the *Expected* scenario peak unscheduled operational demand forecasts with the 2025 WEM ESOO. The spread between the 10%, 50% and 90% POE forecasts remain consistent throughout the outlook period. Peak unscheduled operational demand growth generally follows growth in underlying energy consumption, with limited offset from DPV as operational peaks typically occur in the early evening when solar generation is low.

Figure 13 10%, 50% and 90% POE summer peak unscheduled operational demand forecasts, *Expected* scenario, 2024-25 to 2035-36 (MW)



Notes:

- Forecasts assume ~90% curtailment of hydrogen load during peak unscheduled operational demand, and peak unscheduled operational demand reductions resulting from coordinated operation of residential batteries through the VPP.
- 2025 WEM ESOO forecasts do not include reductions resulting from coordinated VPP residential battery operation.

2.4 Coordinated distributed energy resources in the SWIS

Coordinated DER in the SWIS builds on the Western Australia Government's DER Roadmap[41] and related trials, including Project Symphony and Project Encore. In early 2025, Project Jupiter was launched to support large-scale integration of DER across the SWIS through VPPs.

The commencement of the WA Residential Battery Scheme in July 2025 has accelerated this progress. Batteries installed under the scheme are required to participate in a VPP for a minimum of two years, leading to a significant forecast increase in coordinated DER over the outlook period.

To capture these developments, and the potential benefits from DER coordination, the 2026 WEM ESOO forecasts the impact of the VPP on SWIS unscheduled operational demand, as described in **Section 2.5**.

In the SWIS, customers that consume no more than 50 MWh of electricity each year cannot be supplied by a retailer other than Synergy. These customers are referred to as 'non-contestable customers'.

Synergy is the 'Parent Aggregator' for non-contestable customers, and any third party wishing to provide services to the network operator or market through non-contestable DER will be required to form agreements with Synergy.

In this document, '"the VPP" therefore refers to the VPP coordinated by Synergy as the Parent Aggregator.

2.5 The impact of virtual power plants on unscheduled operational demand and the Reserve Capacity Target

The strong uptake in residential battery capacity (see **Appendix A1.6**) means that the VPP is forecast to materially reduce SWIS peak unscheduled operational demand[42]. For 2028-29, coordinated operation of DER is forecast to reduce annual peak unscheduled operational demand in the 10% POE *Expected* scenario by around 200 MW, from 5,136 MW to 4,937 MW, a 4% reduction.

Figure 14 presents the forecast impact of the VPP on unscheduled operational demand under the 10% POE *Expected* scenario.

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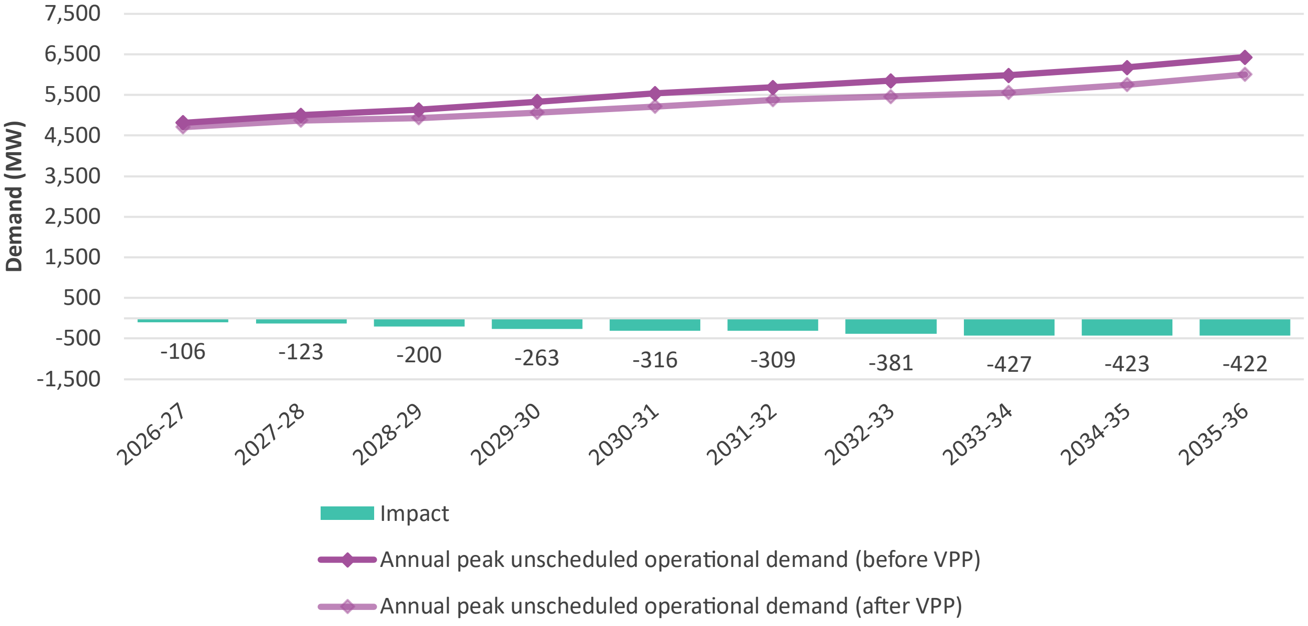
[41] See https://www.wa.gov.au/government/distributed-energy-resources-roadmap.

[42] Examples of coordinated DER responses at scale include a 29 July 2025 event in California, where aggregated dispatch from more than 100,000 batteries reduced peak demand by an average of 539 MW between 19:00 and 21:00, and a 20 June 2024 event in New England, where aggregated dispatch of batteries, EVs and residential loads reduced peak demand by an average of 375 MW between 17:00 and 20:00. See www.brattle.com/wp-content/uploads/2025/12/The-Demand-Side-Grid-Support-Program-An-Assessment-of-Scale-and-Value-December-2025-Update.pdf and www.wbur.org/news/2024/08/28/virtual-power-plants-eversource-massachusetts-batteries-ev-chargers.

Figure 14 Modelled reduction of SWIS annual peak unscheduled operational demand due to the virtual power plant, 10% POE *Expected* scenario, 2026-27 to 2035-36 (MW)



The forecast impact of the VPP on annual peak demand lowers the requirement of Limb A, which, together with Limb B and Limb C, informs determination of the Peak RCT. A lower Peak RCT means fewer Capacity Credits need to be assigned for SWIS reliability purposes. This can reduce the cost of Reserve Capacity secured by AEMO and the Individual Reserve Capacity Requirement (IRCR), which is the cost of Reserve Capacity recovered from customers.

A lower Peak RCT can also reduce the need for investment in large-scale generation, storage and network infrastructure across the SWIS.

The 2026 WEM ESOO models the impact of the VPP on operational demand for the first time. The modelling was informed by discussions with relevant stakeholders on the intended operation of the VPP and followed the methodology presented by AEMO in the Forecasting Reference Group on 30 March 2026[43].

The modelling focuses on the Synergy-operated VPP and simulates the VPP discharge during peak demand periods across the 30 highest-demand days in Summer (December to March) to reduce exposure to IRCR costs.

The modelling uses DER forecasts presented in **Appendix A1**, as well as unscheduled operational demand[44] profiles developed under *AEMO's Electricity Demand Forecasting Methodology*[45]. These profiles represent demand before the impact of the VPP. The modelled impact of the VPP is then subtracted from these profiles to produce post-VPP unscheduled operational demand profiles.

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[43] See www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/wa_meetings/wem-esoo-frg/2026/wem-esoo-frg---meeting-papers---30-march-2026.pdf.

[44] These profiles represent forecast unscheduled operational demand. This is operational demand exclusive of operational withdrawals, Demand Side Programmes, or the impact of the Emergency Solar Management scheme.

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

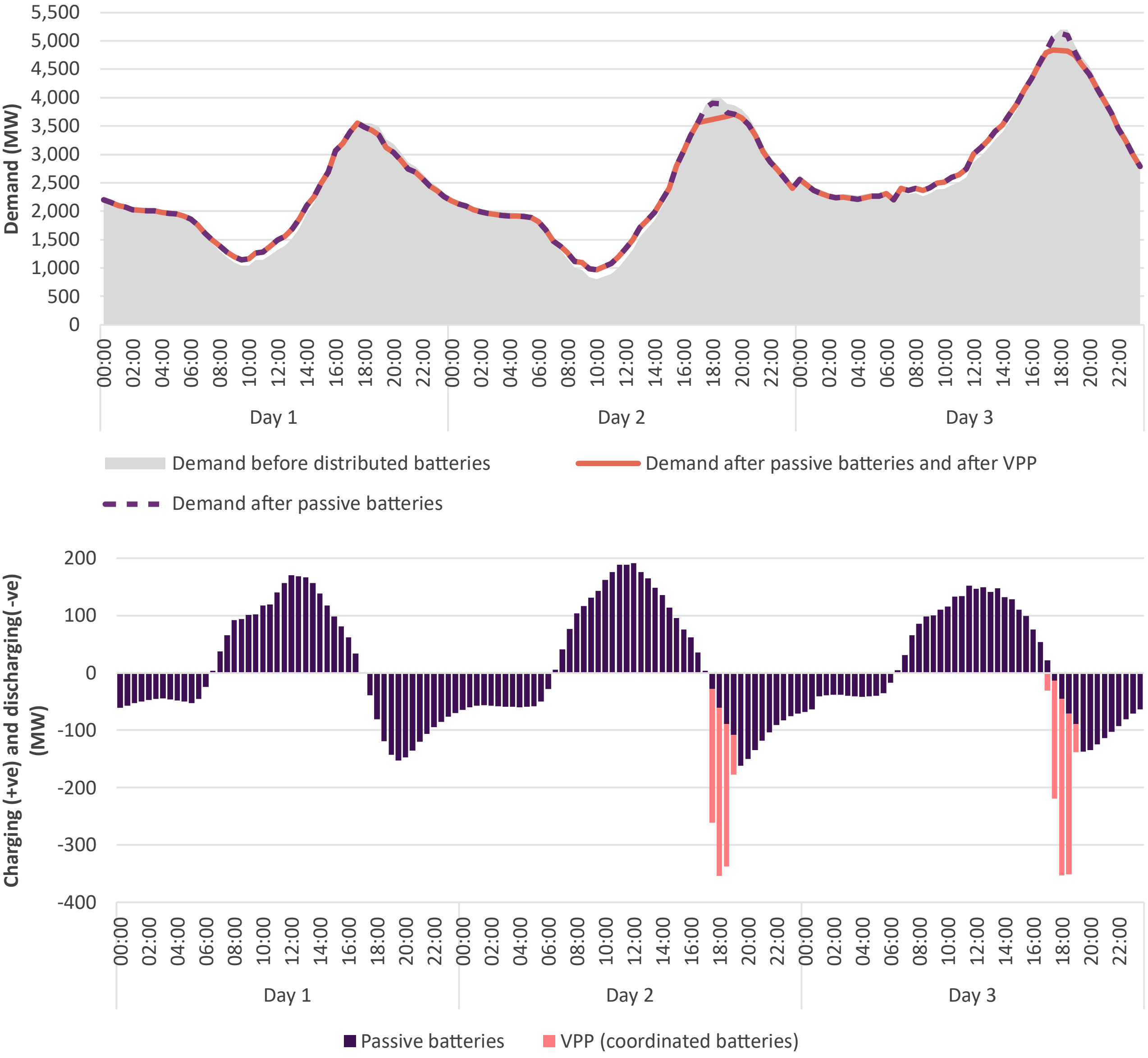
These post-VPP profiles are used in the modelling of Limb B and Limb C, which, together with Limb A based on post-VPP annual peak demand, inform determination of the Peak RCT (see **Section 5**).

Further detail on the VPP modelling methodology is presented in **Appendix A1.13**.

Figure 15 illustrates the modelled behaviour of the VPP on a per-interval basis across three consecutive days. On Day 1, the VPP is not activated because peak demand is lower than on Day 2 and Day 3, so residential batteries operate passively. On Day 2 and Day 3, higher peak demand triggers VPP activation, with a portion of the residential battery fleet coordinated to discharge during peak periods. This targeted response reduces peak demand more than passive battery operation alone.

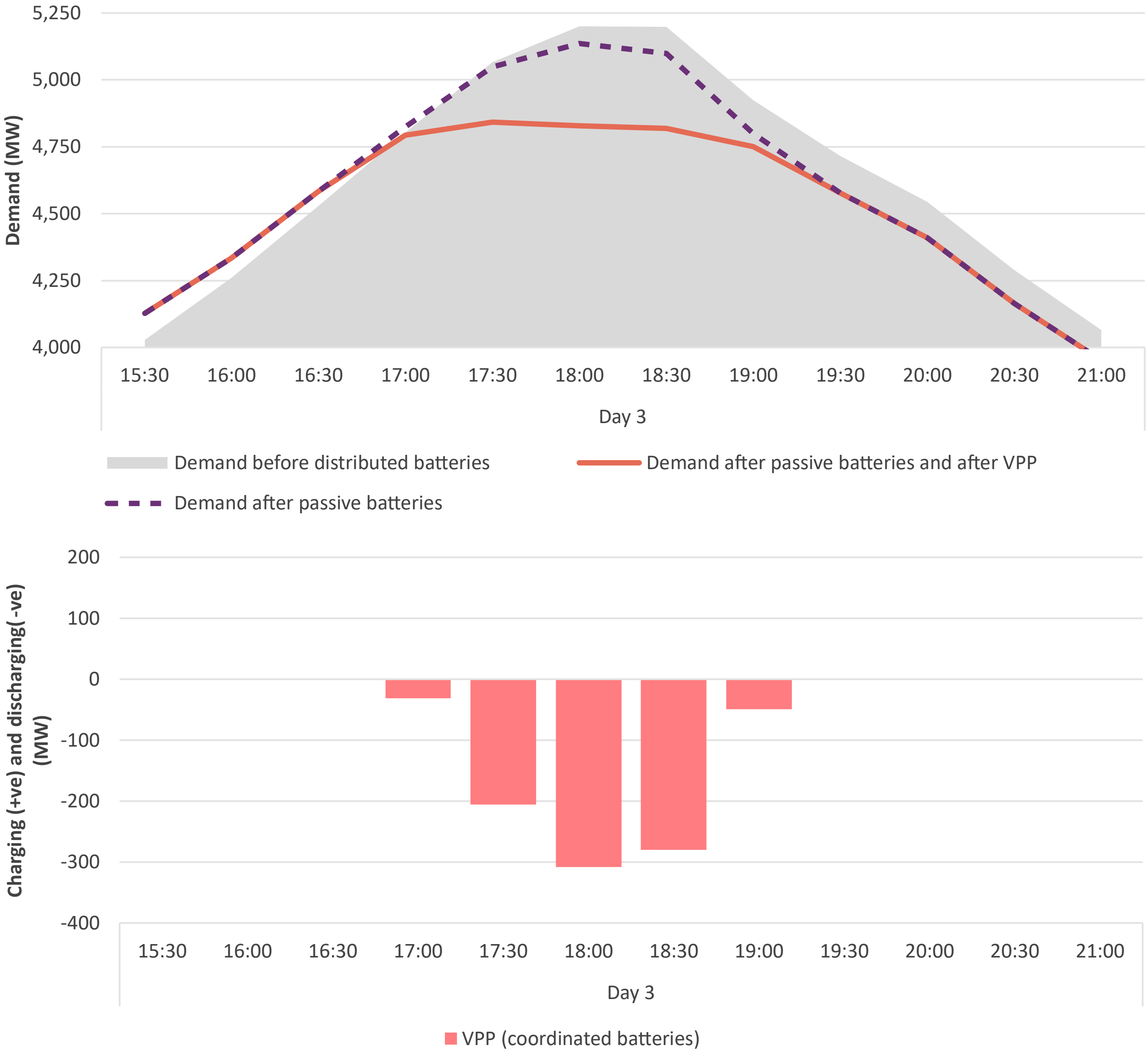
Figure 16 provides a closer view of the modelled VPP behaviour on Day 3.

Figure 15 Illustration of the modelled behaviour and impact of passive distributed batteries and the virtual power plant on SWIS peak unscheduled operational demand, 2028-29 (based on Reference Year 2024-25) (MW)



Note: The VPP includes residential batteries. Passive batteries include residential batteries and business batteries. Passive (uncoordinated) operation means DER operate to meet the energy needs of an individual behind-the-meter system, without regard for and response to the operating conditions of the broader, front-of-the-meter power system, and the coinciding electricity market outcomes.

Figure 16 Zoom-in on the illustrative modelled behaviour of the virtual power plant, and its impact on SWIS unscheduled peak operational demand, 2028-29 (based on reference year 2024-25) (MW)



The modelled VPP-driven reduction in annual peak unscheduled operational demand shown in **Figure 14** is calculated as the difference between annual peak demand before and after VPP operation. The pre-VPP and post-VPP annual peaks may occur:

- on the same day, in the same interval, (e.g., 18:00 on 17 December),
- on the same day, but in different intervals, (e.g., 16:30 and 18:00 on 17 December),
- on different days, in the same interval (e.g., 18:00 on 17 December, and 18:00 on 6 January),
- on different days and different intervals (e.g., 18:00 on 17 December, and 16:30 on 6 January).

This differs from the same-interval contribution of passive and coordinated batteries, which measures the difference between pre-VPP and post-VPP demand in the same Trading Interval (e.g., 18:00 on 17 December). For peak unscheduled operational demand periods of 2028-29 under the 10% POE *Expected* scenario, the same-interval analysis shows that[46]:

- VPP operation reduces peak demand by 124 MW on average.
- passive distributed batteries reduce peak demand by 29 MW on average.

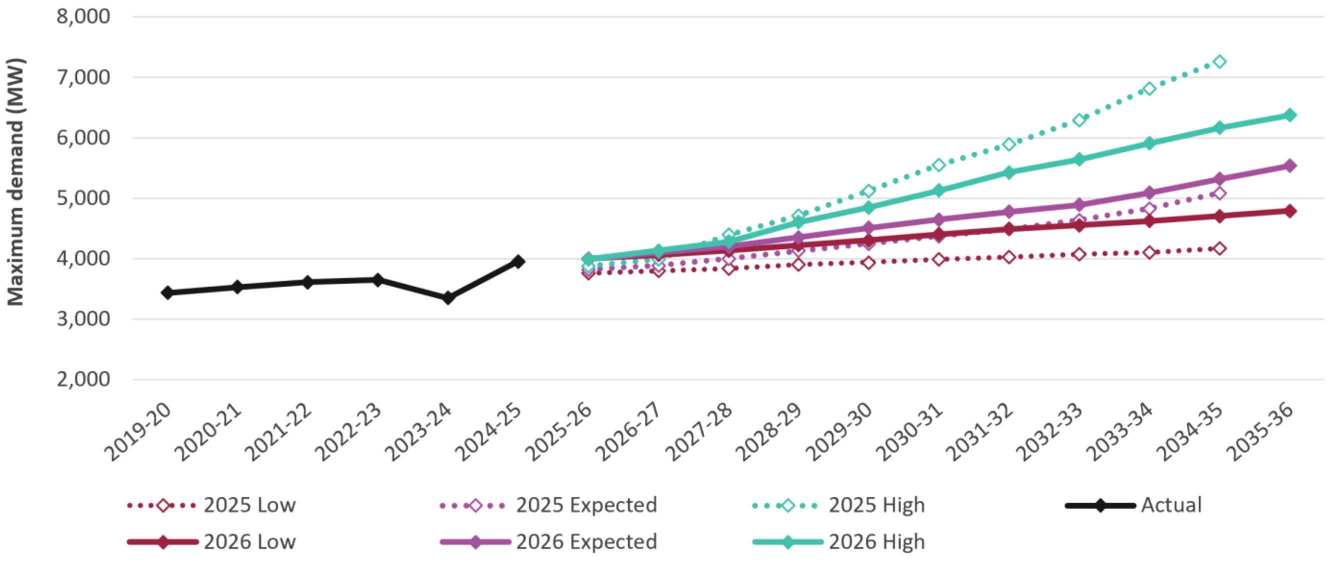
As a counterfactual, if all distributed batteries operated passively and the VPP was not activated, the average reduction in peak unscheduled operational demand in 2028-29 would be 39 MW.

2.6 Winter peak unscheduled operational demand continues to grow

Figure 17 presents the 10% POE winter peak unscheduled operational demand forecasts across all three scenarios for 2025 and 2026 WEM ESOOs, alongside actual outcomes from 2019-20 to 2024-25. Winter peak unscheduled operational demand is projected to increase steadily over the outlook period, driven by growth in underlying consumption from electrification, large industrial loads, residential consumption and business mass market consumption.

While winter peak unscheduled operational demand is expected to grow, it remains lower than summer peak unscheduled operational demand throughout the outlook period.

Figure 17 Actual and forecast 10% POE winter peak unscheduled operational demand under three scenarios, from 2025 and 2026 WEM ESOOs, 2019-20 to 2035-36 (MW)



Notes:

- The actuals displayed reflect observed unscheduled operational demand under the prevailing weather conditions.
- Winter peak unscheduled operational demand forecasts include hydrogen demand.

The 10% POE forecast represents demand under a one-in-10-year winter weather event. Differences between actual 2024-25 outcomes and the 2025-26 10% POE forecast are expected and consistent with the forecasting methodology[47].

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[46] The calculations are based on Trading Intervals where VPPs were modelled to discharge. Passive batteries were discharging in 75% of these intervals and charging in 25%; both interval types are included in the calculation.

[47] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf?la=en

Table 13 summarises winter peak unscheduled operational demand growth rates and key drivers across the scenarios. Under the *Low* and *Expected* scenarios, winter peak demand growth remains broadly consistent with the 2025 WEM ESOO, although the forecast starts from a slightly higher baseline reflecting recent actual demand outcomes. Winter peak demand is not forecast to grow faster than summer peak demand over the outlook period.

Table 13 Winter peak unscheduled operational demand growth by scenario

	Low	*Expected*	*High*
Average annual growth rate			
Whole period (2025-26 to 2035-36)	1.8%	3.3%	4.8%
First half (2025-26 to 2030-31)	1.9%	3.1%	5.1%
Second half (2031-32 to 2035-36)	1.7%	3.6%	4.4%
Forecast growth drivers relative to the 2025 WEM ESOO	Steady demand growth, broadly following trends in electrification, residential consumption, business mass market consumption and large industrial loads.	Similar trajectory to the 2025 WEM ESOO, with steady growth from electrification, residential consumption, business mass market consumption and large industrial loads.	Lower than the 2025 WEM ESOO High scenario, reflecting a lower consumption forecast, with slower growth in large industrial loads a key contributor.

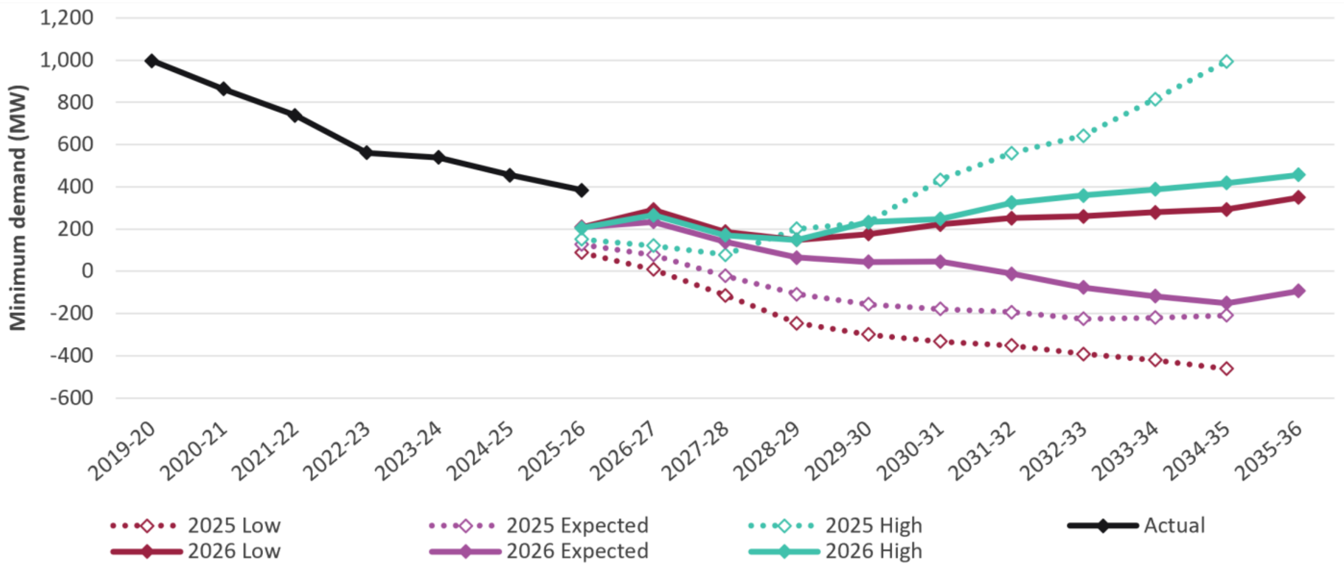
2.6.1 Minimum demand forecasts are higher than in 2025, but continue to decline over time

Minimum unscheduled operational demand forecasts in the 2026 WEM ESOO are generally higher than the 2025 WEM ESOO forecasts for the *Low* and *Expected* scenarios. This primarily reflects higher forecast unscheduled battery capacity and associated battery charging during low demand periods, which places upward pressure on minimum demand.

In the 2026 WEM ESOO, both the *Low* and *High* scenario forecasts sit above the *Expected* scenario. This is primarily driven by lower projected distributed PV growth in the *Low* scenario, which reduces the extent to which distributed PV suppresses demand during minimum demand periods, and higher battery uptake in the *High* scenario.

Despite higher forecasts relative to the 2025 WEM ESOO, minimum unscheduled operational demand in the SWIS is forecast to continue declining as distributed PV uptake increases. Maintaining Power System Security during low-demand conditions will remain an important operational challenge as minimum demand continues to decline.

Figure 18 Actual and forecast 90% POE minimum unscheduled operational demand, under three scenarios, 2019-20 to 2035-36 (MW)

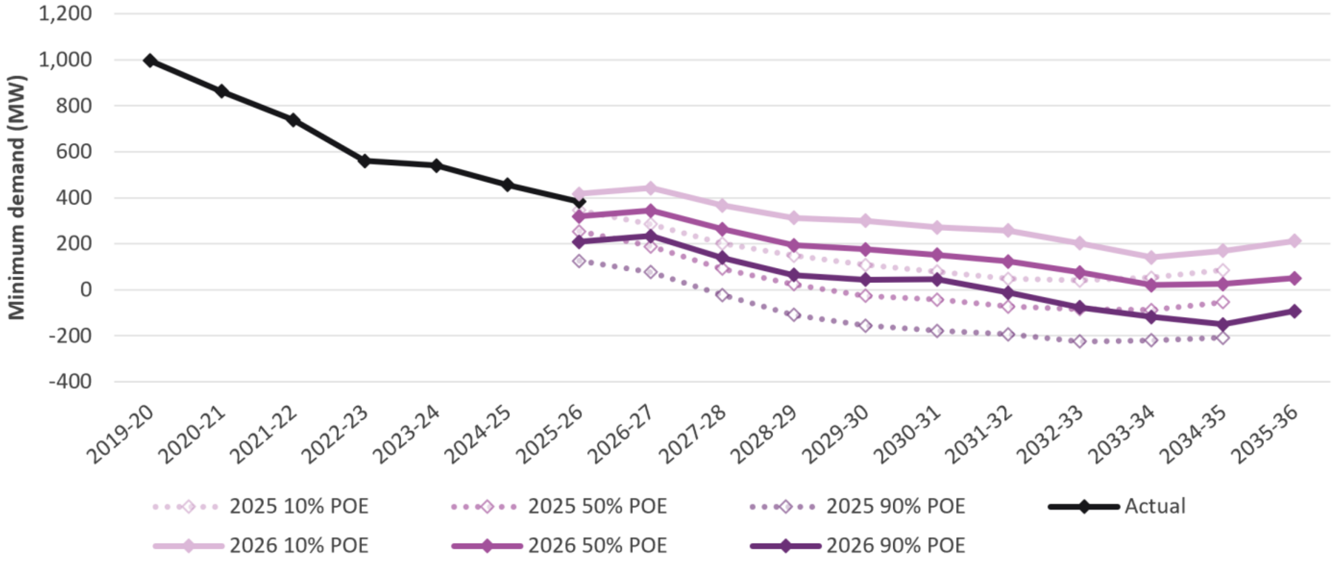


Notes:

- This chart represents unscheduled operational demand i.e. it does not include the impacts of charging utility scale storage.
- Forecast minimum operational demand includes hydrogen loads. Actuals reflect observed unscheduled operational demand under prevailing weather conditions.

Figure 19 compares the 10%, 50% and 90% POE minimum operational demand forecasts for the *Expected* scenario in the 2025 and 2026 WEM ESOOs, together with actual outcomes since 2018-19. Under the 50% POE forecast, minimum unscheduled operational demand declines from 319 MW in 2025-26 to 193 MW by 2028-29, and further to 50 MW by 2035-36. Negative unscheduled operational demand would indicate periods where distributed PV generation exceeds operational demand, creating surplus energy for storage or curtailment.

Figure 19 Actual and 10%, 50% and 90% POE minimum unscheduled operational demand forecasts, from 2025 and 2026 WEM ESOOs, *Expected* scenario, 2019-20 to 2034-35 (MW)



Notes:

- The starting point is lower than actual, mainly due to higher DPV forecast in 2026 compared to actual 2025.
- Forecast minimum demand represents unscheduled demand, i.e. it does not include the impacts of charging utility scale storage or any services to add additional demand. Forecast minimum demand includes hydrogen loads.
- The actuals displayed reflect observed demand under the prevailing weather conditions.

2.6.2 Storage supports secure operation as minimum demand declines

As high distributed PV uptake continues in the SWIS, minimum operational demand is forecast to decline further and to become negative later in the second half of the outlook period. Without effective management of low demand conditions, this trend is expected to increase system security risks as minimum operational demand approaches the minimum demand threshold.

Further to existing market signals, the introduction of battery storage through NCESS, together with the rapid deployment of grid-scale storage, and residential battery uptake across the SWIS, has materially improved the ability to securely manage minimum demand conditions.

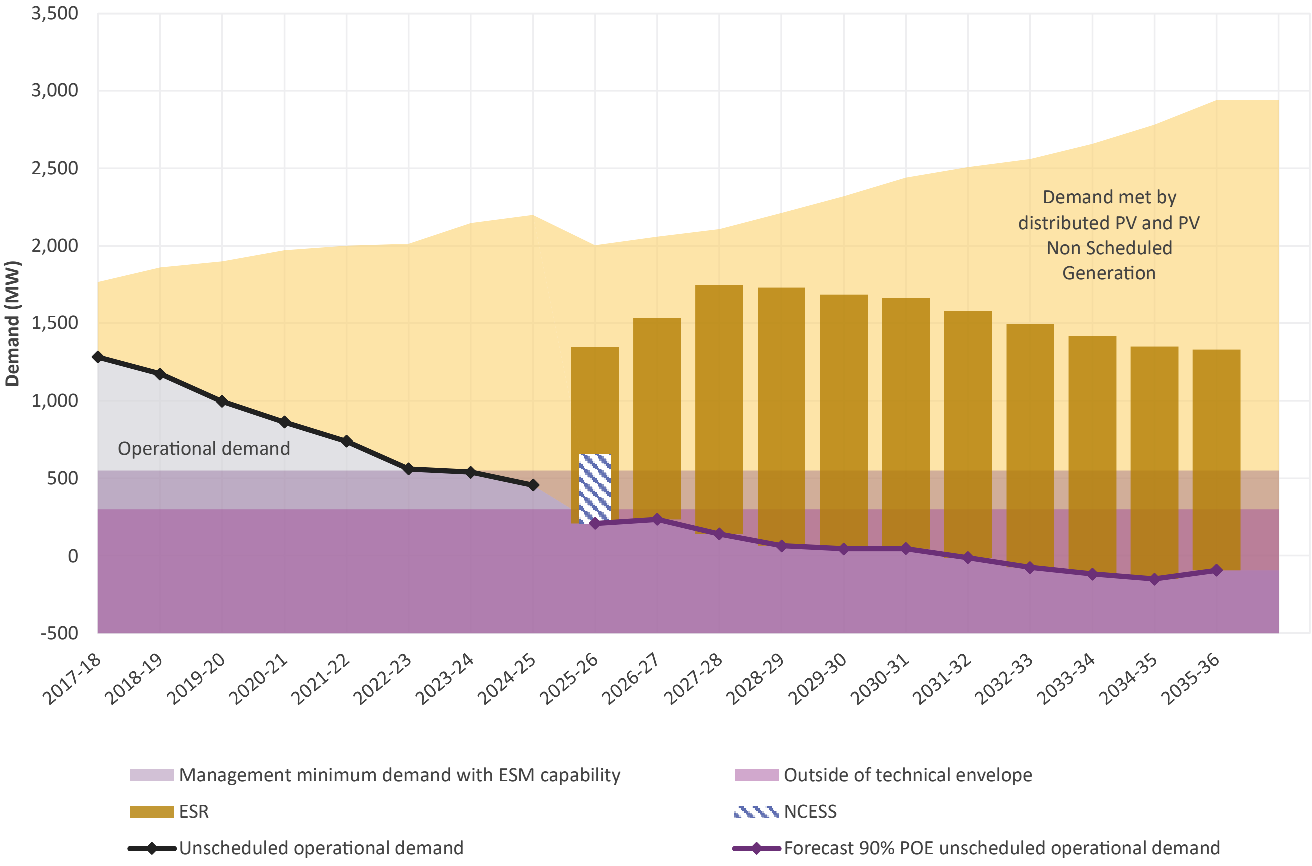
Battery storage can help manage minimum demand by absorbing excess solar generation during low demand periods, which typically occur in the middle of the day. That energy can then be discharged during later peak periods, when solar generation is lower. Coordinated DER may provide additional value by improving how these consumer assets support secure and reliable supply.

As minimum unscheduled operational demand declines with continued distributed PV uptake, active management of system security during low-demand periods will remain important.

AEMO’s existing 446 MW of minimum demand NCESS contracts have helped manage system security risks and expire at the end of 2025-26. With the addition of up to 399 MW of committed grid-scale ESR by 2028-29 above the already existing grid scale storage of more than 1,000 MW in 2025-26, AEMO expects to be able to continue to support secure and reliable system operation as minimum demand declines. On that basis, and having regard to both cost and risk, AEMO does not intend to extend these contracts.

Ongoing management of battery storage minimum demand services will include monitoring for grid-scale ESR outages and state of charge. If market-based controls are unable to manage system security risks, AEMO may use emergency management powers to direct battery operations and may also activate the Emergency Solar Management scheme. AEMO will continue to monitor any emerging capabilities to manage Power System Security and Power System Reliability.

Figure 20 Minimum operational demand forecast and committed Electric Storage Resource entry, 90% POE *Expected* scenario, 2017-18 to 2035-36 (MW)



Notes:

- The difference between 2024-25 actuals and forecast arises due to the comparison of actuals to a 90% POE forecast.
- A minimum demand threshold of 300 MW corresponds to Western Power's Limit Advice 27[48].
- When unscheduled operational demand falls below the minimum demand threshold, Power System Security may need to be managed through market price signals, scheduled demand from ESR, or operational actions such as Emergency Solar Management.
- Forecast minimum unscheduled operational demand does not include the impacts of charging utility scale storage or any services to add additional demand. Forecast minimum unscheduled operational demand includes hydrogen loads.
- Grid-scale ESR capacity presented in the chart corresponds to effective storage MW that is assigned through AEMO's Certification of Reserve Capacity (CRC) under the Linear Derating Capacity (LDC) Methodology.

2.7 Updates to demand and consumption input assumptions

Table 14 summarises the key inputs that support the consumption and demand forecasts in the 2026 WEM ESOO, and how these differ from last year's WEM ESOO report.

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[48] 'Western Power Limit Advice 27 - Generator Reactive Reserve Requirements' results in a lower limit operational demand that does not fall below 300 MW. It assures that the minimum number of synchronous units in both the south and north regions are online for the minimum megavolt-amperes reactive (MVAr) requirements. As operator, AEMO ensures the correct amount of synchronous generation remains online. In the operational timeframe the minimum demand threshold is managed based on fleet availability. See https://www.aemo.com.au/-/media/files/electricity/wem/congestion-information/Western%20Power%20Non-Thermal%20Limit%20Advice%2027%20-%20v2-0.pdf

Table 14 Summary of updates to input assumptions

Input	Update from previous WEM ESOO
Economy	In 2025, AEMO contracted Deloitte Access Economics (DAE) to assess emerging economic conditions and provide an update to DAE's 2024 Economic Forecasts. DAE found there had been no material changes to Australia's economic conditions since the publication of the 2024 Economic Forecast but highlighted the following minor updates: • Global economic environment and trade policy: Previous forecasts did not account for the tariff policy changes announced by the United States administration in early April 2025 and over subsequent weeks. The downward revisions to Australian economic growth because of tariffs are minor, in part because of an assumption that Chinese policymakers implement stimulus measures to support the economy, in turn cushioning the Australian economy. • Population growth: Western Australia is anticipated to receive a larger share of Australia's net overseas migration in the revised forecasts. • Domestic economic conditions: While global trade tensions and weaker international demand continue to weigh on trade-exposed industries, the broader domestic economy is expected to perform slightly better in the near term than previously forecast. The weaker global economic backdrop weighs more heavily on export-oriented states such as Western Australia, however, the stronger outlook for population growth in the state is anticipated to partly offset these external headwinds. • AEMO is monitoring developments for potential impacts to economic activity following the commencement of the Middle East conflict on 28 February 2026. At this stage it is considered too early to provide a meaningful update.
Distributed PV forecasts	• Reassignment of some residential historical installations to the business sector, uplifting the business sector forecast. • Revised actuals and forecast in 2026 WEM ESOO to better account for unit replacements. • 2026 WEM ESOO forecast updated to latest inputs and assumptions and revised to better represent historical relationship between distributed PV payback and uptake and market saturation effects.
EV forecasts	• 2026 WEM ESOO EV forecast assumptions were refined, aligning with the consultation Draft 2026 Forecast Assumption Update[49] section 2.1.3, reflecting latest actual growth and fleet projections and charging assumptions for battery EV and plug-in hybrid EV vehicle sales. These updates did not result in material EV energy consumption changes in the outlook period. • As a result of the Middle East conflict commencing on 28 February 2026 and rising fuel prices, evidence of increased EV uptake has received media coverage. While AEMO is monitoring developments, it is considered too early to include any revisions for the 2026 WEM ESOO.
Distributed energy storage systems (DESS), or distributed batteries	• The WA Residential Battery Scheme was introduced on 1 July 2025 and is forecast to bring forward the installation of batteries at residential properties. The impact is forecast to accelerate ~1,150 MW of battery uptake by 2028-29. • The WA Residential Battery Scheme has been complemented by the Commonwealth Government's Cheaper Home Batteries Program, which was launched on 1 July 2025, providing a subsidy on the upfront cost of installing eligible small-scale batteries (5 kWh to 100 kWh) for households and businesses.
Large industrial loads	• All scenarios: The 2026 forecast is lower than the 2025 forecast, driven mainly by inclusion of an outage factor to improve the previously and frequently observed over-forecast of large industrial load operations. • Lower consumption is based on advice from some industrial operators that they will pause or defer some proposed industrial developments to later in the forecasting period.
Electrification	• Electrification follows a similar trend to the 2025 WEM ESOO which projected electrification to be lower for both households, industrial and commercial sectors than previously forecast. • Rate of electrification is based on draft 2024 multi-sectoral modelling [50], which featured improved detailed and explicit modelling of large industrial load processes.
New industries (Hydrogen and Green Steel)	• With the finalisation of the 2025 IASR there has been a slight change to scenario narratives, in particular in the 2025 WEM ESOO the *High* scenario corresponded to *Green Energy Exports*, and with finalisation this has been renamed as *Accelerated Transition* in the 2026 WEM ESOO.
Data centres	• Data centres, which were previously captured within the BMM category, feature as a new category in the 2026 WEM ESOO. Consumption forecasts combine underlying economic demand for Data Centre services and project status from proponent inputs sourced from surveys and key stakeholders including Western Power and Department of Energy and Economic Diversification (DEED).

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[49] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/draft-2026-fau/draft-2026-forecasting-assumptions-update.pdf?rev=eb147bbbe8c147dcb8a64f7a8b94e329&sc_lang=en.

[50] The draft 2024 MSM forecast is identical to the final MSM forecast for the *Expected* and *Low* scenarios.

3 Supply forecasts

This section presents the supply forecasts for each Capacity Year from 2026-27 to 2035-36. As the energy transition in the SWIS continues, intermittent generation and duration-limited battery storage with different operating characteristics, are forecast to increasingly replace thermal generation. In the *Expected* scenario:

- Supply from the existing and committed Facilities is forecast to increase from 5,987 MW in 2026-27 to 6,670 MW in 2028-29, sufficient to meet forecast peak demand over this three-year period.
- Over the 10-year outlook period, 1,661 MW of thermal generation is forecast to retire or become unavailable.
- A total of 1,119 MW of committed capacity[51] is forecast to enter the market over this 10-year period, including 399 MW of grid-scale storage, plus a mix of renewables, thermal generation and DSP.
- A potential supply gap emerges from 2029-30, driven by demand growth and phased thermal generation retirements.
- Mitigating this potential gap will require a mix of investment in long-duration battery storage, dispatchable capacity and sufficient generation to support storage charging.
- In the *High* scenario, 675 MW of anticipated projects is forecast to come online from 2028-29 extending the forecast surplus to up to 2030-31. More than 98% of these projects are grid-scale storage.

3.1 Classification of forecast supply capacity

Supply forecasts incorporate existing capacity in the SWIS and new projects that have progressed sufficiently through the development pipeline, covering capacity from generation, ESR and DSP. AEMO assesses project maturity using responses to formal information requests (FIRs) from Market Participants and Western Power, and the 2026 Expressions of Interest (EOIs)[52] for Certified Reserve Capacity (CRC). All new projects are assessed using the following five[53] criteria:

1. **Land** – evidence of a project proponent's status towards purchase, acquisition or settlement of land for the project.
2. **Planning** – evidence of a project proponent’s status in obtaining environmental and development approvals.
3. **Western Power connection status** – evidence of SWIS connection progress, based on information provided by Western Power.
4. **Finance approvals** – evidence that a new project proponent is progressed towards a final investment decision (FID).
5. **Construction** – evidence of a new project proponent’s construction progress towards completion.

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[51] Distinct from nameplate capacity. While 3,072 MW of total nameplate capacity is committed for the outlook period, this includes a large proportion of new wind and solar generation. The lower committed capacity forecast of 1,119 MW reflects the estimated contribution of these projects to meeting peak demand and system reliability requirements. This value is lower than nameplate capacity because it accounts for factors such as the intermittent nature of wind and solar generation, storage duration limits for batteries along with their degradation, Declared Sent Out Capacity and operational constraints, and network limitations.

[52] See *2026 EOI summary report*, 2026, at https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2026/2026-expression-of-interest-summary-report.pdf.

[53] This is an expansion of assessment applied for the 2026 WEM ESOO compared to 2025 WEM ESOO. This approach considers broader development criteria in assessing and categorising new projects and aligns closely with the NEM approach for new Facility assessment and scoring. Previous WEM ESOOs only used three criteria: 1. environmental approval, 2. connection progress, 3. progress towards FID, in which projects were classified as ‘committed’, ‘probable’ or ‘proposed’. A comparison of approach used in 2026 and 2025 WEM ESOOs is included in Appendix A2.

Many of these significant project milestones are unlikely to be achieved until the new project proponent has confidence that Capacity Credits will be assigned. Therefore, for each new project (or upgrade) planning to be operational for the current Reserve Capacity Cycle or later, AEMO calculates a percentage score based on how advanced it is against these evaluation criteria.

A project with a score of 80% or higher is classified as **committed**, a project with a score between 60% and 80% as **anticipated**, and the remainder of new projects as **proposed**. New projects that have assigned Capacity Credits through to 2027-28 or are contracted for 2024-26 and 2025-27 Peak Demand Non-Co-optimised Essential System Service – Reliability Services (Peak Demand NCESS), are classified as **committed** (unless already operational).

Forecast supply capacity

Forecast supply capacity includes all Facilities (generation, ESR, and DSP) that are projected to contribute to meeting forecast demand across the year.

Forecast peak capacity is the capacity mix that is projected to meet demand in peak periods and is eligible for assignment of Peak Reserve Capacity.

Forecast flexible capacity is a subset of the peak capacity mix that is projected to also meet the minimum criteria for the assignment of Flexible Reserve Capacity.

AEMO monitors delivery timing of all committed projects through progress reports[54]. For further details on the evaluation methodology, refer to Appendix A2.

Table 15 summarises the Facility classifications and how they are treated in modelling scenarios[55].

Table 15 Description of capacity categories and inclusion in the 2026 WEM ESOO scenarios

Capacity classification	Description	Scenario inclusion
Existing capacity	Registered Facilities that are currently operational and have been: • assigned Capacity Credits for 2027-28 and reflecting any announced or modelled retirements, or • contracted for the 2024-26 peak demand NCESS[A], or • contracted for the 2025-27 peak demand NCESS[B].	All scenarios (*Low*, *Expected*, *High*)
Committed capacity[C]	New projects that are not yet operational and have: • been assigned Capacity Credits for 2027-28, or • scored 80% or higher in the new project status evaluation, or • been contracted for the 2025-27 peak demand NCESS.	*Expected* and *High* scenarios
Anticipated capacity	New projects that are a candidate for registration and have submitted a valid 2026 LT PASA FIR or 2026 EOI and scored between 60% and 80% in the new project status evaluation.	*High* scenario only
Proposed capacity	All new projects that have been proposed but scored less than 60%, so have not met the criteria to be in the existing, committed, or anticipated capacity categories.	None
Relevant Level Method (RLM) uplift capacity[D]	An aggregated forecast capacity that reflects an estimated increase of Capacity Credits assigned to the intermittent generators for 2027-28	*Expected* and *High* scenarios

A. For 2024-26 Peak Demand NCESS (the procurement of Reliability Services for 2024-25 and 2025-26), capacity is forecast to be available for Registered Facilities and upgrades of Registered Facilities for the contract period.
B. For 2025-27 Peak Demand NCESS (the procurement of Reliability Services for 2025-26 and 2026-27), capacity is expected to be available for Registered Facilities and upgrade of Registered Facilities for the contract period.
C. For 2024-26 and 2025-27 Peak Demand NCESS capacity, the forecast capacity limited to contract period is overridden if any of the Facilities meet the score requirement in the new status evaluation or assigned Capacity Credits for 2026-27.
D. The RLM uplift capacity is considered at an aggregated level and applied from 2028-29 onwards. See details in **Section 3.4.2**.

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[54] Market Participants holding Capacity Credits for Facilities that are not yet operational are required to submit a report on their progress as per clause 4.27.10 of the ESM Rules.

[55] This section uses information available as of 11 May 2026, for each project in the criteria for evaluation of projects.

Forecast supply from capacity categories input into reliability assessment and projected supply-demand balance

The 2026 WEM ESOO reliability assessment is based on the *Expected* scenario, which includes forecast supply from only **existing and committed** capacity (further detail on how forecast supply capacity is used in the reliability assessment is included in Appendix A3). Forecast supply from anticipated capacity is shown separately to demonstrate the importance of timely project delivery for the forecast supply-demand balance in the SWIS (see Section 7). Forecast supply for the *Low* and *High* scenarios are developed to show a range of possible supply outcomes.

3.2 Forecast committed and anticipated capacity

This section summarises the modelling of forecast committed and anticipated capacity at times of peak demand for the 2026 WEM ESOO outlook period. To preserve the confidentiality of information provided to AEMO by Market Participants, the following tables present aggregated values by Capability Class. The forecast supply capacity presented in this section does not include any uplift associated with the new RLM, as AEMO is currently unable to reliably estimate the contribution of RLM uplift capacity for new projects based on available information.

Section 3.2.1 summarises the assignment of Capability Class by a Facility's technology type and how they are assessed for the assignment of Peak and Flexible CRC and Capacity Credits. Section 3.2.2 and Section 3.2.3 summarise modelling method of forecasting committed and anticipated capacity included in this WEM ESOO to meet peak demand. Further detail on forecast existing, committed and anticipated capacity is included in Appendix A3.

3.2.1 Capability Class assignment by Facility technology type

AEMO assigns CRC and Capacity Credits to the Facilities that are eligible to provide peak and flexible capacity, based on each Facility's expected contribution of supply at times of peak demand, which largely depends on their respective technology type[56]. Assigned Capacity Credits are less than or equal to the nameplate capacity for the respective Facilities. AEMO must assign a Capability Class to each Facility (or relevant component) when assigning CRC in the 2026 Reserve Capacity Cycle.

Table 16 summarises the CRC and Capacity Credits assignment methodology by a Facility's technology type and Capability Class. All assessments are based on the information available to AEMO as of April 2026.

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[56] The methodology used for assessing and assigning CRC and Capacity Credits may differ depending on Facility Class as outlined in clause 4.10 of the ESM Rules.

Table 16 CRC and Capacity Credit assignment method by Capability Class and technology type

Facility technology type	Capability Class	Technology description and examples	CRC and Capacity Credit assignment method
Non-Intermittent Generating Systems	Capability Class 1	Thermal generation that uses fuel 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[A].
Electric Storage Resources (ESR)	Capability Class 2	Electric storage systems, such as batteries and pumped hydro storage.	Assessed based on estimated ability to sustain a level of output at 41°C, accounting for derating of the technology over the ESR Duration Requirement (between four and seven hours, depending on the requirement at the time the Facility is first certified for Reserve Capacity) after netting off capacity required for serving Loads associated with the technology and observed performance of the technology[B].
Demand Side Programmes (DSP)	Capability Class 2	Demand Side Programmes are Facilities that reduce load or increase injection from non-dispatchable loads or embedded generation associated with a load. They can include DER aggregators comprising behind-the-meter electric storage systems, or response from single or aggregated industrial loads. DSPs have a limited window of operation between 08:00 and 20:00 and a limited number of running hours per year. For 2026-27, 2027-28 and 2028-29, minimum running hours are 50 hours, 23.75 hours and 28.625 hours per year, respectively. Frequent use of DSP resources may lower annual energy consumption and effective peak demand.	For the 2025 Reserve Capacity Cycle, its assessed based on the amount of load reduction or generation increase from their standard operation. From the 2026 Reserve Capacity Cycle, AEMO must determine the Transmission Nodes where Market Participants seeking certification for DSPs under clause 4.10.1B cannot locate Associated Loads. The outcome of this assessment will be determined through the 2026 Reserve Capacity Cycle and will be applied in future WEM ESOOs.
Intermittent generators	Capability Class 3	Renewable generation, such as solar, wind, and landfill gas.	Assessed based on the RLM[C], which estimates contribution during periods of high demand, or actual contribution (for operational Facilities).

A. The CRC quantity may be reduced if the Forced Outage rate calculated as per clause 3.21.7 of the ESM Rules exceeds Forced Outage Threshold of 10%, see clause 4.11.1A of the ESM Rules.

B. For a Non-Scheduled Facility comprising only an ESR, it is assessed based on the RLM as per clause 4.11.1(bD) of the ESM Rules.

C. RLM as per Appendix 9 of the ESM Rules. The new RLM will be applied to Facilities in the 2026 Reserve Capacity Cycle.

3.2.2 Committed peak capacity

A total of 3,072 MW of new generation and storage capacity (based on nameplate capacity) is forecast to be **committed** projects and serve the SWIS during this outlook period. **Table 17** presents a list of committed projects forecast to be available in the *Expected and High* scenarios, based on their nameplate capacity.

Table 17 Committed projects and storage capacity developments, by Capability Class, 2026-27 to 2035-36

Commitment status	Capacity provided by	Capability Class[A]	Nameplate capacity (MW) [B]	Storage capacity (MWh) [B]	Anticipated full commercial operation date[C]
Forecast committed capacity	2025-27 Peak Demand NCESS – DSP[D]	Capability Class 2	9	N/A	October 2026
	East Rockingham RRF Project Co Pty Ltd	Capability Class 1	29	N/A	October 2026
	Narrogin Wind Farm	Capability Class 3	168	N/A	September 2028
	Kondinin Wind Farm	Capability Class 3	130	N/A	December 2028
	Parron Wind Farm	Capability Class 3	484	N/A	December 2028
	Alinta Marri Wind Farm	Capability Class 3	550	N/A	December 2029
	Other Facilities operated by gas and distillate, as assessed with 2026 WEM ESOO FIR and 2026 EOI information	Capability Class 1	442	N/A	October 2026 to October 2028
	ESR Facilities as assessed with 2026 WEM ESOO FIR and 2026 EOI information	Capability Class 2	781	3,828	October 2026 to January 2029
	Other DSP Facilities as assessed with 2026 WEM ESOO FIR and 2026 EOI information	Capability Class 2	41	N/A	October 2027
	Other Facilities operated by solar and wind, as assessed with 2026 WEM ESOO FIR and 2026 EOI information	Capability Class 3	439	N/A	October 2027 to January 2029
Total			**3,072**	**3,828**	

A. Capability Classes 1, 2 and 3 are as detailed in **Section 3.2.1**.
B. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
C. Dates are either provided by the Market Participants or a Facility's obligation date for meeting assigned Capacity Credits and Peak Demand NCESS. AEMO assesses the timing of these projects through progress reports, advice from Western Power, and market research. AEMO's WEM ESOO methodology may apply delays to completion assumed after the proponent-advised dates, with delays reflected in progress reports.
D. For detail on Facilities contracted for the 2025-27 Peak Demand NCESS services, see https://aemo.com.au/consultations/tenders/expressions-of-interest-and-tender-for-ncess-reliability-services-2025-27-wa. Nameplate capacity for these Facilities is as per their contracted quantities.

3.2.3 Anticipated peak capacity

A total of 1,020 MW of new generation and storage capacity (based on nameplate capacity) is forecast to be available as **anticipated** supply in the SWIS during this outlook period. **Table 18** presents anticipated projects included in the *High* scenario.

Table 18 Anticipated projects and storage capacity developments, by Capability Class, 2026-27 to 2035-36

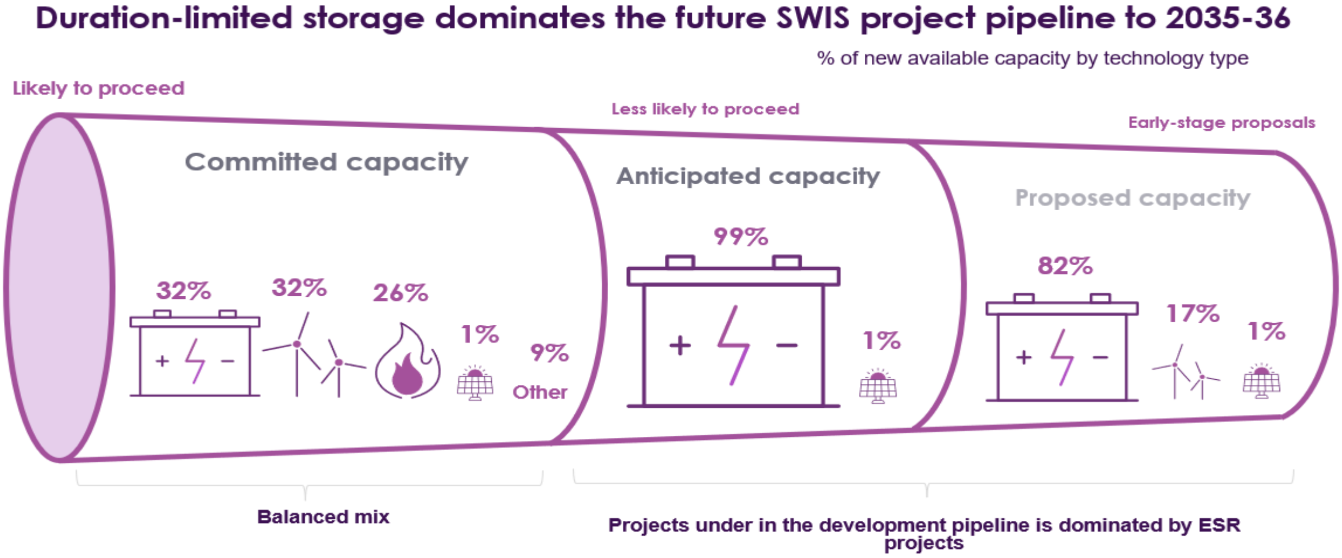
Commitment status	Capacity provided by	Capability Class[A]	Nameplate capacity (MW) [B]	Storage capacity (MWh) [B]	Forecast date of commencement by[C]
Forecast anticipated capacity	Solar Facilities as assessed with 2026 WEM ESOO FIR and 2026 EOI information	Capability Class 3	129	N/A	October 2029
	ESR Facilities as assessed with 2026 WEM ESOO FIR and 2026 EOI information	Capability Class 2	891	4,908	October 2028 to October 2029
Total			**1,020**	**4,908**	

A. Capability Classes 1, 2 and 3 are as detailed in **Section 3.2.1** of this section.
B. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
C. Forecast commencement dates are either provided by the Market Participants or a Facility's obligation date for meeting assigned Capacity Credits and Peak Demand NCESS. AEMO assesses the timing of these projects through progress reports, advice from Western Power, and market research. AEMO's WEM ESOO methodology may apply delays to completion assumed after the proponent-advised dates, with delays reflected in progress reports.

In addition to the forecast committed and anticipated peak capacity included in this WEM ESOO, AEMO considered several proposed projects in the development pipeline. These include new thermal, renewable, storage and hybrid projects, totalling more than 1 GW of nameplate capacity. AEMO assessed these projects using information received from the 2026 WEM ESOO FIRs, Western Power, and the 2026 EOIs, and concluded that they are currently too speculative to include in the 2026 WEM ESOO modelling. AEMO will continue to monitor the development of these projects for possible inclusion in future WEM ESOOs.

Figure 21 presents the forecast proportion of new projects in the pipeline for development using the capacity classifications discussed in **Section 3.1**. It shows that the projected fleet mix is relatively balanced for the committed capacity mix, but anticipated and proposed capacity mix is dominated by duration-limited storage.

Figure 21 Forecast proportion of new capacity by technology type, 2035-36 (%)



Notes:

- The “Other” grouping includes Facilities operated by hydro, cogeneration and retired Facilities.
- Proposed capacity grouping is based on information received through the 2026 WEM ESOO FIR and 2026 EOIs for CRC.

3.3 Generator retirement and unavailability assumptions

AEMO modelled that all coal-fired generators will retire or become unavailable during the outlook period. There is also potential for some ageing gas-fired generation to exit the market. **Table 19** summarises the retirement and unavailability assumptions in this year’s WEM ESOO modelling. By the end of the 10-year outlook period, a total of 1,661 MW of thermal generation is forecast to leave the system.

Table 19 Generator retirements or unavailability modelled in the 2026 WEM ESOO

Facility	Owner	Latest assigned Capacity Credits	Modelled retirement or unavailability date	Reason for unavailability
Tesla Northam unit	Tesla Northam Pty Ltd	9.9 MW	1 October 2026	Announced
Collie Power Station	Synergy	317.2 MW	1 October 2027	Announced
Tesla Geraldton unit	Tesla Geraldton Pty Ltd	9.999 MW	1 October 2027	Announced
Muja D Power Station units 7 and 8	Synergy	422 MW	1 October 2029	Announced
Bluewaters Power Station units 1 and 2	Bluewaters Power	434 MW	1 October 2031	Assumed (discussed below)
Pinjar gas turbines 1, 2, 3, 4, 5, and 7	Synergy	206.836 MW	1 October 2031	Assumed (discussed below)
Pinjar gas turbine 9	Synergy	114.314 MW	1 October 2032	Assumed (discussed below)
Pinjar gas turbine 10	Synergy	110.5 MW	1 October 2034	Assumed (discussed below)
Tiwest cogeneration plant	Tronox Management Pty Ltd	36.0 MW	31 December 2034	Assumed (discussed below)
Total capacity assumed to exit the market	**1,661 MW**			

These closure assumptions were based on the following information:

- On 31 October 2025, AEMO received formal notifications[57] from Tesla Northam Pty Ltd and Tesla Geraldton Pty Ltd of their intention to cease operating the Northam unit on 1 October 2026 and Geraldton unit on 1 October 2027.
- In June 2022, the Western Australian Government announced the retirement of the Synergy-owned coal-fired power stations, and on 27 September 2024, AEMO received formal notification from Synergy of its intention to cease operating Collie Power Station on 1 October 2027[58].
- The Pinjar gas turbines are between 30 and 37 years old. Their assumed retirement in the 2026 WEM ESOO is made for modelling purposes only, reflecting the ageing nature of these thermal generation assets. These assumptions are made in consultation with Synergy, however, do not reflect any formal decision by Synergy to retire the generation plant.
- Tiwest cogeneration plant was also assumed to retire during this outlook period. Similarly, its assumed retirement in this WEM ESOO was made for modelling purposes only and does not reflect any formal decision made by Tronox Management Pty Ltd to retire the cogeneration plant.
- In January 2026, the current Western Australian Government State Agreement with The Griffin Coal Mining Company Pty Ltd, which supplies the Bluewaters Power Station, was extended by up to five years from July 2026[59]. Based on this extension, Bluewaters Power Station was assumed to be available up to 2030-31. With the uncertainty that Bluewaters may not be able to establish a new coal supply arrangement past this point, AEMO considered it prudent not to assume the availability of this power station from 2031-32 onwards in the reliability assessment.

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[57] AEMO received formal notification of intentions to cease operation from Market Participants, see https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/notifications-of-facilities-ceasing-operation-in-the-wem.

[58] 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. AEMO also received formal notification of intentions to cease operation from the Market Participant.

[59] See https://www.wa.gov.au/government/media-statements/Cook%20Labor%20Government/Griffin-Coal-extension-delivers-certainty-for-jobs-and-energy-20260121.

Importantly, the potential unavailability of any Facility does not restrict any proponent from submitting a CRC application nor does it pre-empt a particular CRC assessment outcome for these Facilities. AEMO will consider any CRC applications provided as part of the 2026 Reserve Capacity Cycle and will undertake assessments in accordance with the relevant ESM Rules and WEM Procedure.

3.4 Forecast peak capacity included in each scenario

Forecast peak capacity for the first two years of this WEM ESOO outlook period, 2026-27 and 2027-28, is based on assigned Peak Capacity Credits and 2025-27 Peak Demand NCESS contract quantities, adjusted for forecast full commercial operation dates using progress reports, Western Power advice and market research. For later years, AEMO forecasts peak capacity by technology type, applying adjustments where Facilities have historically exceeded the Forced Outage Threshold and have not addressed this through significant maintenance or upgrades[60].

The forecast peak capacity analysis for the *Low*, *Expected*, and *High* scenarios is structured as below:

- Section 3.4.1 presents the forecast peak capacity mix by technology type for all three scenarios, excluding the impact of estimated RLM uplift capacity.
- Section 3.4.2 summarises the new RLM and presents the impact of aggregated estimates of RLM uplift capacity on forecast peak capacity, including how it is treated across the three scenarios.
- Section 3.4.3 summarises forecast peak capacity under the *Low*, *Expected* and *High* scenarios and compares these forecasts with the 2025 WEM ESOO.

The forecast peak capacity for the *Expected* scenario, including the RLM uplift capacity, is used in the 2026 WEM ESOO reliability modelling discussed in Section 5.

3.4.1 Forecast peak capacity mix by technology type, excluding estimated RLM uplift

Figure 22 presents the forecast peak capacity mix by technology type for the *Low*, *Expected* and *High* scenarios. Forecast peak capacity increases from 2026-27 to 2028-29 in the *Expected* and *High* scenarios, before decreasing overall during the outlook period. In the *Low* scenario, forecast supply starts to decrease from 2027-28, following assumed thermal generator retirements and unavailability.

Key observations across the scenarios are:

- The increase in forecast peak capacity is primarily driven by higher Peak Capacity Credits assigned for 2027-28 in the 2025 Reserve Capacity Cycle, compared with the Capacity Credits assigned for 2026-27 in the 2024 Reserve Capacity Cycle. Additionally, the forecast supply from new projects that are projected to supply over the 10-year horizon, and the continued availability of Bluewaters to 2030-31 following the Western Australian Government's announced extension of the Griffin Coal State Agreement, contribute to this increase.
- This increase in forecast peak capacity is more than offset by the retirement or unavailability of thermal generators in later years, as detailed in **Section 3.3**.

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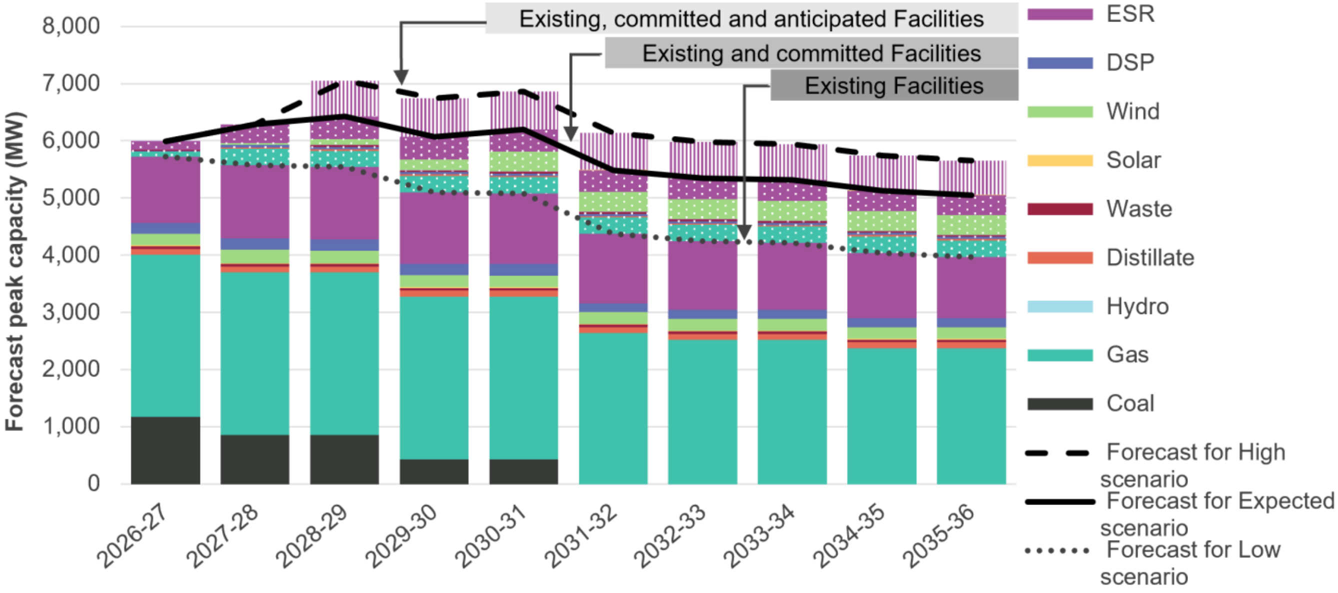
[60] Under clause 4.11.1A of ESM Rules, if a Facility or Separately Certified Component has been in Commercial Operation for at least 12 months and has had a Forced Outage rate above the Forced Outage Threshold over the past 36 months, AEMO must adjust its Peak Certified Reserve Capacity, unless it has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

- Across this outlook period, gas-fired Facilities continue to provide around 50% of the total forecast peak capacity. The proportion of coal-fired generation decreases steadily to 2030-31, after which all coal-fired generation is forecast to retire or become unavailable. Duration-limited storage capacity is projected to increase from 22% to 27% of the total forecast peak capacity over the outlook period, while renewable generation increases up to 15% of the total forecast peak capacity in 2035-36. The remaining forecast peak capacity is provided by a mix of waste-to-energy, distillate and DSP Facilities.

Further detail is provided in **Section 3.4.3**.

Figure 22 Forecast peak capacity by technology type, under three scenarios, 2026-27 to 2035-36 (MW)



Notes:

- The components of hybrid Facilities are split by their respective technology types.
- Solid colours are used to present technology types for existing Facilities. Corresponding dot and line patterned colours are used to present technology types for committed and anticipated Facilities respectively.

3.4.2 Impact of new Relevant Level Method on forecast peak capacity

A new RLM came into effect on 1 April 2026 and will apply from the 2026 Reserve Capacity Cycle. Under this new method, AEMO estimates an additional 240 MW of Capacity Credits that could be made available for Capability Class 3 Facilities and components (intermittent generators, such as wind and solar Facilities as well as hybrid technologies) from 2028-29 onwards. AEMO highlights this increase reflects a change in the amount of Capacity Credits assigned to these technologies to better reflect their contribution during peak demand periods. It however does not represent an additional 240 MW of new physical generation capacity.

This estimated RLM uplift capacity is treated as equivalent to an additional committed capacity in the supply forecasts and included only in the *Expected* and *High* scenarios.

Relevant Level Method

Intermittent generators have variable, weather-dependent output.

This variability must be considered when determining the extent to which they can be relied on to have capacity available when needed to meet peak demand periods and support reliability in the SWIS.

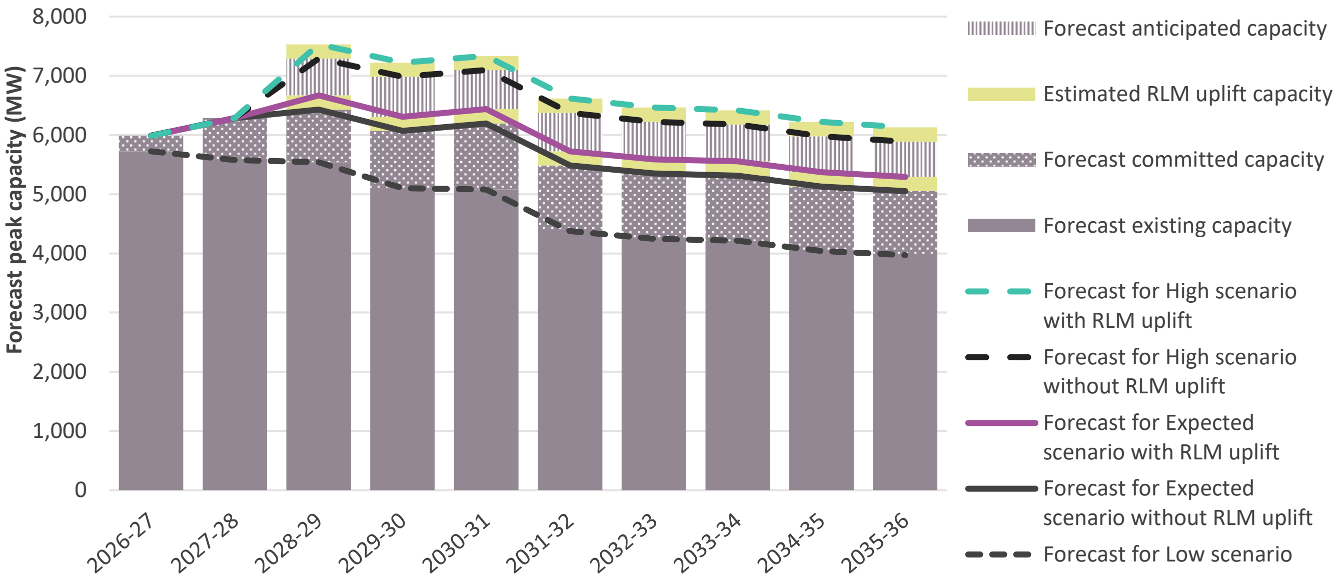
The RLM is the framework used to determine the quantity of Peak CRC assigned to intermittent generators in the Reserve Capacity Mechanism (RCM).

This latest estimate, under Appendix 9 of the ESM Rules, is subject to further revision based on the DER Adjusted Demand Profile, updated outage rates for Non-Candidates[61], and updated independent expert report data received in the 2026 CRC applications.

The new RLM introduces enhanced numerical modelling to simulate system conditions and better evaluate the contribution of different forms of generation and storage under system stress scenarios. The RLM is expected to improve the assessment of available capacity and support a more economically efficient assignment of Peak Capacity Credits, particularly for Capability Class 3 Facilities and components. This allows the contribution of intermittent generators to be assessed dynamically, reflecting changing demand patterns and the performance of different technologies under system stress scenarios.

Figure 23 presents forecast peak capacity including RLM uplift capacity and compares it with forecast peak capacity without RLM uplift capacity for all three scenarios. Further detail on the impact of new RLM uplift capacity is included in Appendix A3.3.

Figure 23 Forecast peak capacity with and without Relevant Level Method uplift capacity, under three scenarios, 2026-27 to 2035-36 (MW)



Note: Solid colours are used to present total of all technology types for existing Facilities. Corresponding dot and line patterned colours are used to present total of all technology types for committed and anticipated Facilities respectively.

3.4.3 Forecast peak capacity is overall higher than the 2025 WEM ESOO across all three scenarios

Table 20 summarises the key observations for forecast supply capacity from 2026-27 to 2035-36. It also identifies the drivers of overall higher forecast supply in the 2026 WEM ESOO compared with the 2025 WEM ESOO forecasts. The 2026 WEM ESOO forecast peak capacity presented here includes the estimated RLM uplift capacity from 2028-29 onwards, as used in the Limb A reliability assessment detailed in Section 5.

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[61] Non-Candidates in the RLM context are Facilities or components of Facilities that are not assessed under the RLM, but have previously received, and are expected by AEMO to continue receiving, Peak Capacity Credits.

Table 20 Forecast Peak Capacity supply and key drivers by scenario, 2026-27 to 2035-36

Scenario	*Low* scenario	*Expected* scenario	*High* scenario
First five-year AAGR[A]	-2.3%	2.4%	4.4%
Second five-year AAGR[A]	-4.8%	-3.8%	-3.7%
10-year AAGR[A]	-3.6%	-0.8%	0.3%
Observations for 2026 WEM ESOO	• Forecast peak capacity increases slightly in 2026-27, following higher Peak Capacity assigned to existing Facilities. • Maximum forecast peak capacity is 5,725 MW in 2026-27, with 50% provided by gas-fired Facilities. • Net capacity is projected to decrease from 2027-28 onwards with the assumed retirement or unavailability of thermal generators.	• Forecast peak capacity increases up to 2028-29, driven by committed capacity included in the *Expected* scenario. • Maximum forecast peak capacity is 6,670 MW in 2028-29 with: – additional 889 MW of committed capacity, 45% of which are contributed by ESR. – additional 240 MW of estimated RLM uplift capacity. • Projected overall net capacity decrease from 2029-30 and onwards with assumed retirement or unavailability of thermal generators.	• Forecast peak capacity increases to 2028-29, driven by anticipated capacity included in the *High* scenario. • Maximum forecast peak capacity is 7,292 MW in 2028-29, with – additional 622 MW of anticipated capacity, solely contributed by ESR. – additional 240 MW of estimated RLM uplift capacity. • Projected net capacity is projected to decrease overall from 2029-30 onwards with the assumed retirement or unavailability of thermal generators.
Forecast growth drivers relative to the 2025 WEM ESOO	• Significantly higher forecast supply across this outlook period. This is following commencement of operation of Facilities assigned Peak Capacity Credits for 2025-26 and contracted for 2025-27 Peak Demand NCESS. • Total existing capacity for 2025-26 is 5,705 MW, with an addition of 851 MW from 2025 WEM ESOO existing fleet for this year.	• Forecast supply is slightly lower in 2026-27 due to forecast delays in the commencement of committed capacity. • Forecast supply is significantly higher from 2027-28 onwards. This is due to Peak Capacity Credits assigned to new Facilities for 2027-28 and a higher existing capacity mix. It is also supported by the assumed extended availability of Bluewaters and the estimated RLM uplift capacity.	• Forecast supply is slightly lower in 2026-27 due to forecast delays in the commencement of committed capacity. • Forecast supply is significantly higher from 2027-28 onwards, with slightly higher anticipated capacity forecast across the outlook period. The other factors driving the higher forecast in the *Expected* scenario also apply in the *High* scenario.

A. The first five-year, second five-year and 10-year AAGRs are calculated in accordance with the definitions in **Section 1.8**.

3.5 Forecast flexible capacity

The total flexible capacity from existing and committed Facilities is forecast to peak at 4,721 MW in 2030-31 before declining as gas-fired generation retires.

On average, over this outlook period, 54% of the forecast flexible capacity is projected to be provided by gas-fired Facilities, followed by 35% from ESRs. The remainder is forecast to come from wind, distillate and DSP Facilities.

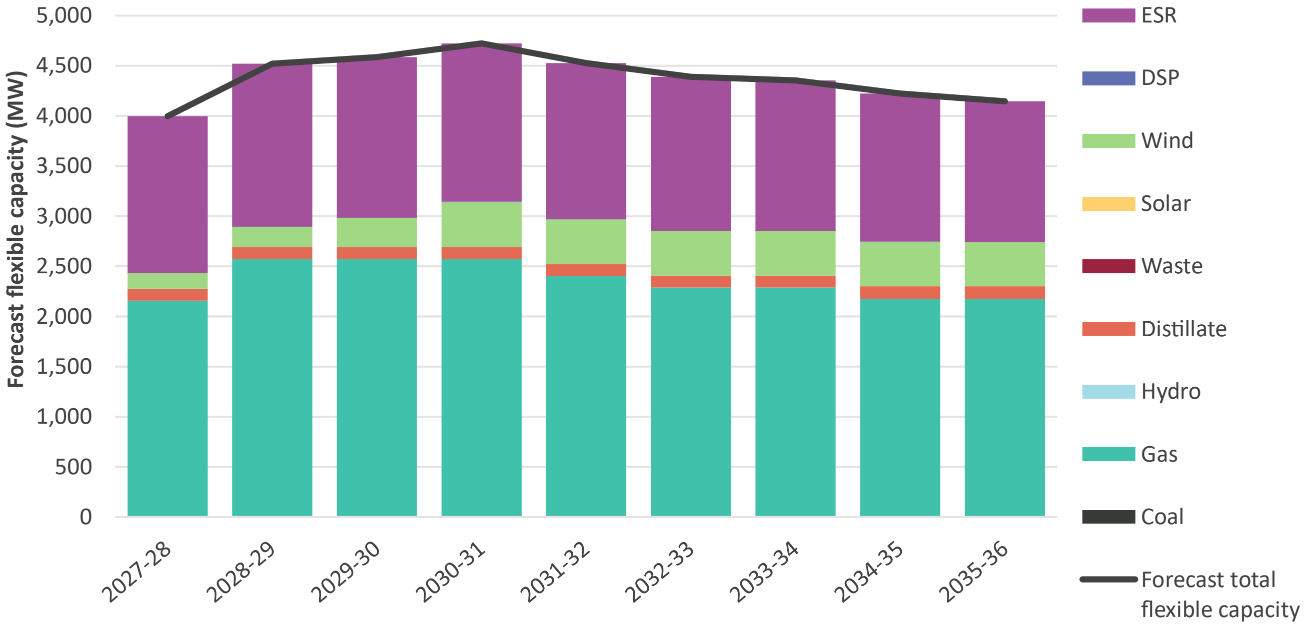
Flexible Reserve Capacity was introduced in the 2025 Reserve Capacity Cycle and was first assigned in 2027-28. This provides an incentive for Market Participants to connect Facilities that can adequately start, stop, ramp up and ramp down within a four-hour period.

All technology types may be eligible for assignment of Flexible Capacity Credits, subject to meeting minimum eligibility requirements specific to each technology[62]. AEMO assigns Flexible Capacity Credits based on the maximum output a Facility can achieve within four hours from a cold start, with the assigned quantity capped at its Peak Capacity Credits.

Figure 24 presents the forecasts of existing and committed flexible capacity mix by generation and storage types for the *Expected* scenario over the 2026 WEM ESOO outlook period.

In this WEM ESOO, the forecast assumes that all technologies that have been assigned Flexible Capacity Credits in the 2025 Reserve Capacity Cycle will continue to apply in future Reserve Capacity Cycles. Actual outcomes may differ depending on Certified Reserve Capacity applications and the application of clause 4.20.5A(a) of the ESM Rules to those applications.

Figure 24 Forecast flexible capacity by technology type, *Expected* scenario, 2027-28 to 2035-36 (MW)



Note: The components of hybrid Facilities are split by their respective technology types.

3.6 Drivers of forecast peak capacity

Forecast supply capacity for the *Expected* scenario during the 2026 WEM ESOO outlook period is primarily driven by the following factors:

- **Assigned Peak Capacity Credits and AEMO-contracted Peak Demand NCESS** – Peak Capacity Credits assigned to the existing and committed Facilities for 2026-27 and 2027-28, together with contracted capacity under the 2025-27 Peak Demand NCESS. Capacity procured under the 2024-26 and 2025-27 Peak Demand NCESS is forecast to exit by 2026-27 unless those Facilities are subsequently assigned Peak Capacity Credits for 2026-27 or in later Reserve Capacity Cycles. This represents a net 31 MW of capacity forecast to become unavailable from the SWIS by 2026-27.

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[62] For the minimum eligibility requirement for the Flexible Certified Reserve Capacity, see https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/certification-of-reserve-capacity/flexible-certified-reserve-capacity.

- **Assumed unavailability and retirement of Facilities** – Facilities that are assumed to be unavailable or to retire are projected to reduce supply from existing generation, with 1,661 MW forecast to retire or become unavailable over the outlook period.
- **Forecast peak capacity outside the procured Peak Capacity Credits and Peak Demand NCESS** – this includes estimated RLM uplift capacity, forecast to become available from 2028-29 onwards, and new Facilities classified as committed capacity.

The impacts of these factors on forecast capacity are detailed below. The changes in assigned Peak Capacity Credits for 2027-28 are detailed in Appendix A2.2.

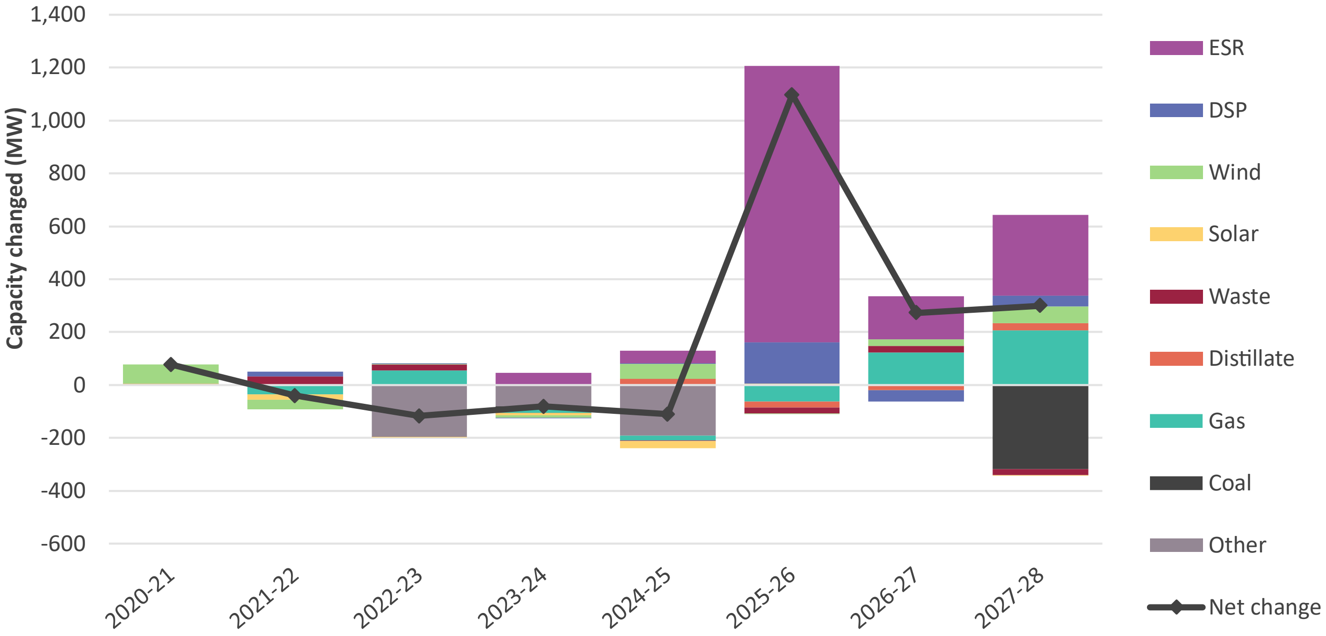
3.6.1 Assigned Peak Capacity Credits and Peak Demand NCESS significantly influence forecast supply capacity

A total of 6,375 MW of Capacity Credits were assigned to 93 Facilities for 2027-28, compared with 5,953 MW assigned to 72 Facilities for 2026-27. Of the capacity procured under the 2025-27 Peak Demand NCESS contracts, more than 376 MW (nearly 98%) from new Facilities and upgrades to existing Facilities and is now online.

A net increase of 300 MW of existing and committed capacity is forecast for 2027-28 compared with 2026-27. This increase is primarily driven by additional forecast capacity from ESR Facilities (306 MW), gas-fired Facilities (207 MW), wind Facilities (64 MW), DSP Facilities (40 MW), and distillate Facilities (26 MW). These additions are forecast to more than offset a 343 MW reduction in capacity from the retirement of coal-fired Facilities (317 MW), forecast delays to waste-to-energy Facilities commencing operation (24 MW), and solar Facilities (2 MW).

Figure 25 shows the changing technology mix in the WEM from 2020-21 to 2027-28. This period includes the retirement of thermal generation, including Muja C Unit 6 from 2024-25 and Tesla Northam from 2026-27, and the commissioning of new ESR, DSP, gas-fired and waste-to-energy projects. The largest annual increase in supply capacity was recorded in 2025-26, with many new projects supported through the 2024-26 and 2025-27 Peak Demand NCESS contracts and Capacity Credit assignments.

Figure 25 Change in actual (2020-21 to 2025-26) and forecast peak capacity in the 2026 WEM ESOO *Expected* scenario (2026-27 to 2027-28), by technology type (MW)



Notes:

- From 2020-21 to 2023-24, values represent only assigned Capacity Credits. From 2024-25 to 2026-27, values include assigned Capacity Credits as well as procured 2024-26 and 2025-27 Peak Demand NCESS for Reliability Services, considering any potential delay in commencement of operation of a Facility. The values presented here also account for assumed retirements of Facilities in the 2026 WEM ESOO.
- For detail on Facilities contracted for the 2024-26 Peak Demand NCESS services, see https://www.aemo.com.au/consultations/tenders/tenders-and-expressions-of-interest-for-ncess-reliability-services-wa and for 2025-27 Peak Demand NCESS services, see https://aemo.com.au/consultations/tenders/expressions-of-interest-and-tender-for-ncess-reliability-services-2025-27-wa. Peak Capacity for these Facilities are as per their NCESS contracted quantities.
- The components of hybrid Facilities are split by their respective technology types, while the "Other" grouping includes Facilities operated by hydro, cogeneration and retired Facilities.

3.6.2 Reduction in forecast capacity following Network Access Quantity assessment

The Network Access Quantity (NAQ) framework considers assigned Certified Reserve Capacity (CRC) and network constraints to determine the appropriate NAQ for each Facility. A Facility's NAQ is determined by three key factors: its physical capability, network access limit and priority order in the NAQ model.

The impact of the NAQ framework has varied across Reserve Capacity Cycles, depending on prevailing network constraints and the location of new Facility additions. **Table 21** summarises how NAQ reductions affect forecast supply in the 2026 WEM ESOO.

Network Access Quantity

The NAQ accounts for Network limitations when assigning Capacity Credits and provides greater investment certainty for Facilities delivering capacity. The NAQ model determines Capacity Credits and is run after CRC has been assigned and the trade declaration process is complete.

Table 21 Recent Network Access Quantity outcomes and impact on forecast supply

Reserve Capacity Cycle	Number of Facilities affected	Total NAQ reduction (MW)	Description of reduction	Impact on 2026 WEM ESOO forecast supply
2023	Three Facilities	15	Minor reductions applied due to network constraints.	Assigned Peak Capacity Credits, after applying NAQ, are reflected in the estimated supply for corresponding Facilities in 2025-26.
2024	10 Facilities	166	Reductions applied to Facilities located at Wagerup, Pinjarra, Collie, Binningup, and Kemerton.	Assigned Peak Capacity Credits, after applying NAQ, are reflected in the forecast supply for corresponding Facilities in 2026-27.
2025	None	0	No NAQ reductions applied, so assigned Peak Capacity Credits equalled assigned CRC.	Assigned Peak Capacity Credits, after applying NAQ, are reflected in the forecast supply for corresponding Facilities in 2027-28 onwards.

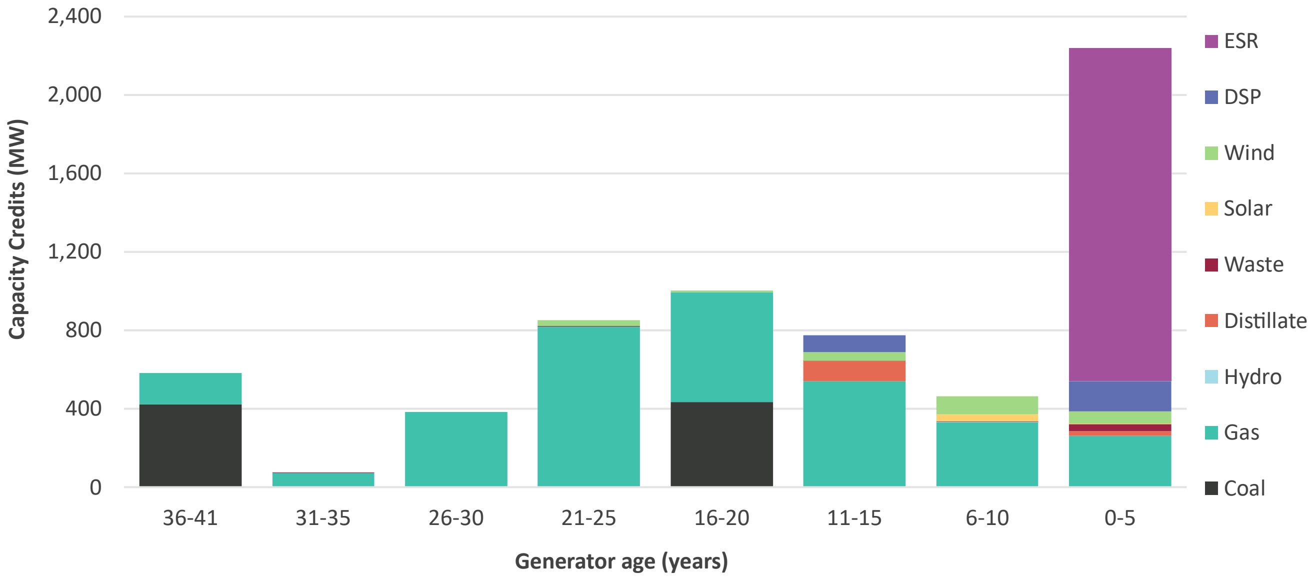
Note: Forecast supply for all Facilities accounts for assumed retirements, unavailability and ESR degradation.

3.6.3 Ageing Facilities impact forecast supply and Forced Outages

Figure 26 summarises the Peak Capacity Credits assigned for 2027-28, categorised by Facility age and technology type. An ageing Facility may experience more frequent or larger Forced Outages and may be subject to a reduction in Peak Capacity Credits unless it has re-entered service after significant maintenance or an upgrade within the previous 12 months, as set out in clause 4.11.1A of the ESM Rules. This provides an incentive for Facilities to maintain reliability and avoid possible reductions in forecast peak capacity, as reflected in the 2026 WEM ESOO modelling.

The Facility mix in the SWIS is shifting from a fleet dominated by ageing thermal generators, which have experienced significant Outages over recent Hot Seasons, to a mix of intermittent generation and duration-limited battery storage with different operating characteristics (as illustrated in Section 3.2). Several ageing generators were assumed to gradually retire during the outlook period, as summarised in **Table 19** in Section 3.3. While these retirements are expected to reduce Forced Outage rates across the SWIS fleet, they introduce new reliability challenges, as detailed in Section 5, and create investment opportunities, as discussed in Section 7.

Figure 26 Peak Capacity Credits for 2027-28, by Facility age and technology type, as of 7 May 2026, *Expected* scenario (MW)



Note: The components of hybrid Facilities are split by their respective technology types.

The following are key insights for ageing Facilities assigned Peak Capacity Credits for 2027-28:

- Facilities aged more than 35 years account for only 9% of the Facility fleet. These Facilities comprise a mix of coal- and gas-fired generation, totalling 583 MW of Peak Capacity Credits. Most of this capacity is forecast to retire over the 2026 WEM ESOO outlook period, as shown in **Table 19** in Section 3.3.
- Facilities aged more than 20 years account for 30% of the fleet mix and are predominantly thermal generators, accounting for 1,893 MW of Peak Capacity Credits in 2027-28. These Facilities are more likely to experience more frequent or larger Forced Outages, discussed further in Section 3.7.2.
- Gas-fired generation has the broadest age profile, with most Facilities aged between 11 and 30 years. Gas-fired Facilities also account for the largest share of Peak Capacity Credits assigned in 2027-28, totalling 3,127 MW.
- The newest Facilities, aged less than five years, represent the largest share of the fleet mix for 2027-28. Storage Facilities account for the largest contribution within this category, totalling 1,699 MW. The remaining capacity comprises a mix of thermal, renewable and DSP Facilities.

3.6.4 Relevant Level Method uplift capacity is a driver for forecast supply from 2028-29 and onwards

The estimated RLM uplift capacity, which forecast to increase Peak Capacity Credits for intermittent generators from the 2026 Reserve Capacity Cycle, is detailed in Section 3.4.2. AEMO will continue to monitor the impact of the new RLM uplift capacity through assignments of Peak Capacity Credits in the future Reserve Capacity Cycles.

3.7 Setting the reserve margin

The reserve margin is 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 (including transmission losses and allowing for Intermittent Loads). It is a component of the Limb A reliability assessment (discussed in Section 5.3).

The 2026 WEM ESOO sets the reserve margin by considering:

1. **historical Forced Outages** – this reflects the performance of the SWIS generation fleet. AEMO analysis supports the need to maintain reserves equivalent to the two largest generating units in the SWIS, and
2. **the need for AEMO to maintain real-time reserves for Contingency Reserve Raise** – this is required while operating with the two largest generating units unavailable and resulting in an additional capacity equivalent to 70% of the third largest Facility in the SWIS.

The reserve margin is therefore equivalent to the loss of the two largest generating units plus 70% of the third largest unit for each Capacity Year over this 10-year outlook period. For 2028-29, this results in a reserve margin of 861 MW. This is 97 MW lower than the reserve margin applied in the 2025 WEM ESOO for 2028-29 as it was considered equivalent to the loss of three largest generating units and was based on historical Forces Outages only.

The revised approach of setting reserve margin in this WEM ESOO:

- reflects a more detailed assessment of the reserves required to manage contingencies during peak demand events (historical market data on the Contingency Reserve Raise requirement indicate that reserve requirements during extreme peak conditions are typically below 70% of the largest contingency),

- aligns more closely with MT Projected Assessment of System Adequacy (PASA) and ST PASA operational reserve requirements and supports maintaining the SWIS in a normal operating state without requiring AEMO intervention to maintain power system security and reliability, and
- reflects the requirements of clause 4.5.9(a)(i) of the ESM Rules.

Section 3.7.1 outlines the assessment of the largest contingency. Section 3.7.2 presents the analysis of historical Forced Outage trends and the calculation of the Forced Outage allowance. Further methodology detail is provided in Appendix A5.2.1.

3.7.1 Discussion on Forced Outages in determination of the largest contingency

Extreme summer conditions in Western Australia place significant stress on the SWIS generation fleet. High temperatures and elevated electricity demand, typically driven by cooling load, can increase utilisation of thermal generation and contribute to Forced Outages when equipment is under stress.

To determine the largest contingency for the 2026 WEM ESOO, AEMO analysed the frequency of total Forced Outages exceeding the capacity of the largest single generating unit, the two largest generating units, and the three largest generating units in the SWIS during peak intervals across the 2020-21 to 2025-26 Hot Seasons.

Figure 27 shows that Forced Outages exceeding the capacity of the two largest generating units occurred consistently across recent Hot Seasons and are considered a credible operational risk. Forced Outages exceeding the capacity of the three largest generating units occurred only once during the review period and are considered less likely to recur.

In 2025-26, the scale and frequency of Forced Outages decreased significantly compared with recent years, with both the magnitude (MW) and frequency of outages returning closer to pre-2022-23 levels. While outages exceeding the capacity of the largest and two largest units continued to occur, there were no instances in 2025-26 where outages exceeded the capacity of the three largest units.

Based on this assessment, AEMO determines that the reserve margin should reflect the simultaneous loss of the two largest Facilities. An additional margin equivalent to 70% of the third largest Facility is considered to maintain real-time reserves for Contingency Reserve Raise under peak demand conditions as mentioned earlier.

Based on the assigned Peak Capacity Credits for 2027-28, the largest Facilities therefore considered for determining the largest contingency are:

- NewGen Neerabup (331 MW) from 2026-27 to 2035-36,
- NewGen Kwinana (328 MW) from 2026-27 to 2035-36,
- 70% of Collie Power Station (317 MW) for 2026-27, and
- 70% of Neoen Collie ESR Stage 2 (294 MW) from 2027-28 to 2035-36[63], following Collie Power Station's assumed retirement on 1 October 2027.

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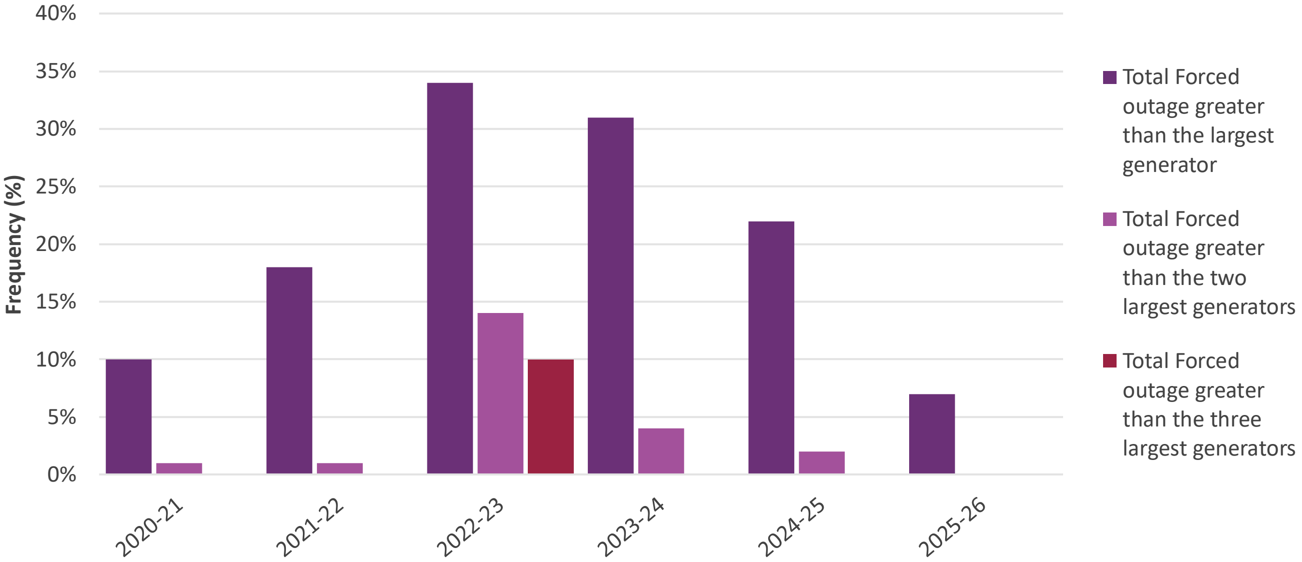
[63] The forecast contingency quantity for Neoen Collie ESR Stage 2 accounts for forecast degradation of the storage Facility.

Figure 27 Frequency of Forced Outage exceeding the single, two, and three largest generators during the peak intervals from 2020-21 to 2025-26 Hot Seasons (%)



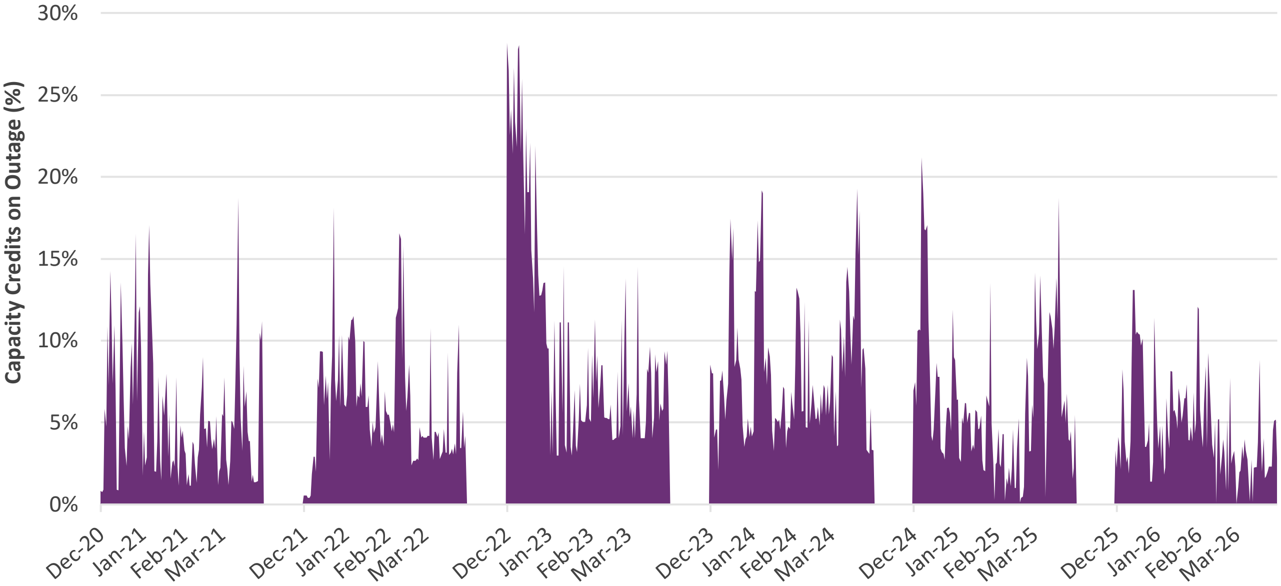
Notes:

- Peak intervals applied for the 2020-21 to 2023-24 Hot Seasons were the 16:30 to 20:00 Trading Intervals, and the 17:30 to 21:00 Trading Intervals for the 2024-25 and 2025-26 Hot Seasons. The peak intervals are taken from the ESROIs determined for the corresponding Capacity Years.
- Small year-on-year differences in calculated frequency (%) compared with WEM ESOO 2025 reflect updated detailed calculations, including the largest generating units in each Capacity Year and Facilities' Commercial Operation dates.

3.7.2 Forced Outage allowance

AEMO analyses historical Forced Outage rates during peak demand conditions across the six most recent Hot Seasons. Elevated Forced Outages increase the risk of supply shortfalls during tight operational conditions, particularly during periods of high demand. **Figure 28** shows the daily maximum Forced Outages of Facilities as a percentage of assigned Capacity Credits from 2020-21 to 2025-26 Hot Seasons.

Figure 28 Daily peak percentage of Capacity Credits on Forced Outage during Hot Season for 2020-21 to 2025-26 (%)



Forced Outage levels were significantly elevated during the 2022-23 and 2023-24 Hot Seasons. In 2022-23 Hot Season, Outages exceeded 25% of assigned Capacity Credits, largely due to coal supply issues. Outage levels remained elevated in 2023-24 Hot Season, particularly at Pinjar Power Station.

Conditions improved in both 2024-25 and 2025-26 Hot Seasons. While outages in 2024-25 Hot Season remained above historical levels and peaked at 21% on 7 December 2024, the 2025-26 Hot Season recorded the lowest average Forced Outage level across the analysed Hot Seasons. Peak Outages in 2025-26 Hot Season reached 13% on 14 and 15 December 2025.

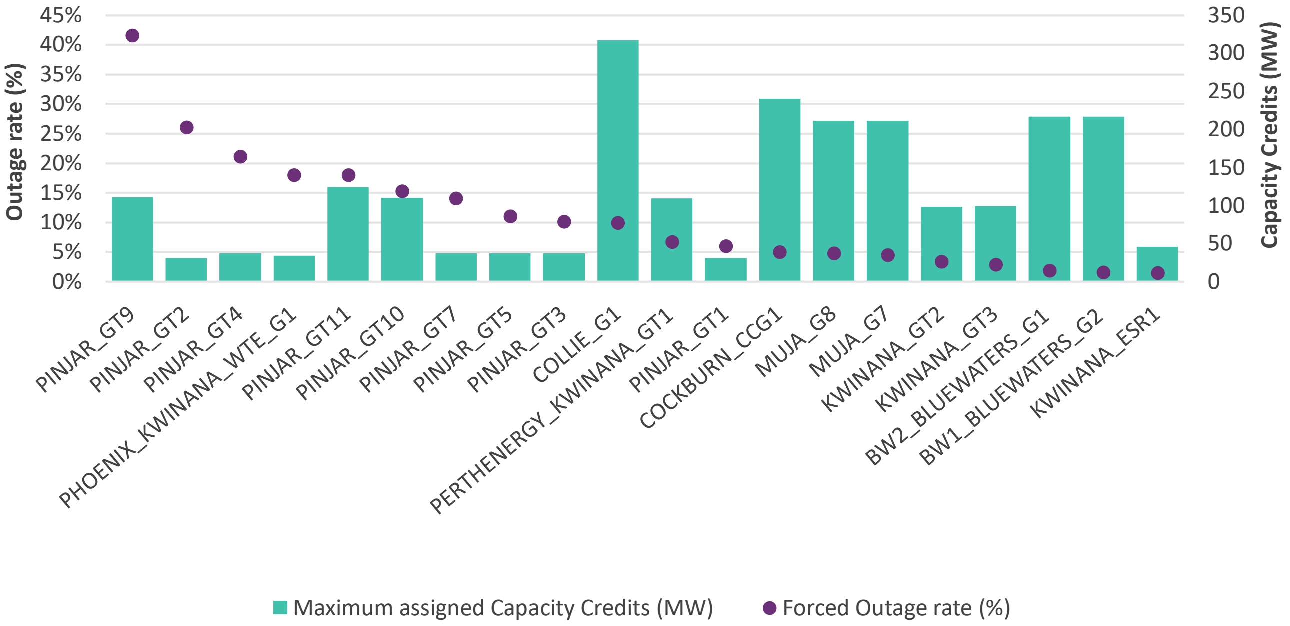
The improvement in 2025-26 Hot Season reflects several factors, including:

- milder summer conditions, with the number of days above 35°C decreasing from 32 in 2024-25 Hot Season to 26 in 2025-26 Hot Season, and the maximum summer temperature falling from 43.2°C to 41.8°C, and
- improved maintenance outcomes, with more planned maintenance undertaken as scheduled during the 2025-26 Hot Season, reducing the risk of Forced Outages.

Figure 29 shows the 20 Facilities with the highest Forced Outage levels and their maximum assigned Capacity Credits over the past 36 months ending 26 April 2026. Forced Outage rates reported in this WEM ESOO are generally lower across Facilities than those reported in 2025 WEM ESOO. The gas turbines at Pinjar are included among the 20 Facilities with the highest Forced Outage rates in the SWIS.

Consistent with clause 4.11.1A of the ESM Rules, AEMO will consider this performance in assessing Peak CRC, including whether reductions to assigned CRC will apply for these units in the upcoming Reserve Capacity Cycle.

Figure 29 Outage rate (%) and maximum assigned Capacity Credits (MW) by Facility for the past 36 months as of 26 April 2026



Notes:

- Outage rate was calculated by dividing the outage MW by the assigned Capacity Credits of the relevant year at each Trading Interval, then averaging this value over the 36-month period (2022-23 to 2025-26).
- 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.
- Retired Facilities and Facilities that have been operational for less than 12 months have not been included.
- Facilities that have not received Capacity Credits for 2025-26 are not included.

The minimum Forced Outage allowance is calculated under clause 4.5.9(a)(i)(1) of the ESM Rules, by multiplying the 10% POE peak demand forecast by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages. This proportion is based on Forced Outage rates averaged over the preceding 36 months.

An estimated fleet Forced Outage rate of 4.6% is applied to the 10% POE peak demand forecasts to determine the Forced Outage allowance for each Capacity Year. This results in a Forced Outage allowance of 215 MW in 2026-27, rising to 275 MW by 2035-36. As this allowance is lower than the determined largest contingency, the reserve margin is set by the largest contingency.

3.8 New renewables increase the Regulation Raise requirements

In addition to the reserve margin, the Limb A capacity adequacy assessment is driven by the 10% POE peak demand forecast, Regulation Raise Requirements and the Electric Storage Resource Duration Requirement (ESR Duration Requirement) Uplift components (detailed in **Section 4**). Regulation Raise Requirements are calculated by considering the current requirements to new capacity as:

- 3% of new wind capacity in the Northern SWIS (North Country, Mid West, Central Midlands and Neerabup),
- 1.8% of new wind capacity in other SWIS nodes,
- 5% of new grid-scale solar PV capacity, and
- 4% of new distributed PV capacity.

Regulation Raise

Regulation Raise is a Frequency Co-optimised Essential System Service used to help manage system frequency. Providers of Regulation Raise reserve headroom to frequently adjust the Injection or Withdrawal of a Facility in accordance with AEMO’s centralised control scheme, helping maintain SWIS Frequency within the Frequency Operating Standards.

For the 2026 WEM ESOO Regulation Raise calculations presented in **Table 22**, the distributed PV component is presented net of distributed batteries capacity. This reflects the growing uptake of behind-the-meter storage and its impact on absorbing surplus distributed PV output that would otherwise increase the volatility of operational demand and result in a higher Regulation Raise requirement.

The Regulation Raise requirement calculated for each Capacity Year is summarised in **Table 22.** The requirement increases across the outlook period, primarily driven by forecast increase of new wind capacity in the Northern SWIS regions and to a lesser extent, new distributed PV capacity net of new distributed batteries for each Capacity Year.

Table 22 Components of Regulation Raise requirement for each Capacity Year, 2026-27 to 2035-36 (MW)

Capacity Year	Frequency Regulation[A]	New wind capacity in Northern SWIS[B]	New wind capacity in other SWIS nodes[B]	New grid-scale solar PV capacity[B]	New distributed PV capacity[C]	Regulation Raise
2026-27	110	0	0	0	0	110
2027-28	110	216	105	7	30	120
2028-29	110	216	273	118	79	130
2029-30	110	700	403	118	155	150
2030-31	110	1,250	403	118	248	171
2031-32	110	1,250	403	118	358	175
2032-33	110	1,250	403	118	486	180
2033-34	110	1,250	403	118	652	187
2034-35	110	1,250	403	118	828	194
2035-36	110	1,250	403	118	1016	201

A. Frequency Regulation Raise component value is based on a benchmark, set at up to 110 MW between 05:30 and 20:30, when daytime peak demand is most likely to occur.

B. New wind and solar capacity is based on the nameplate capacity of committed wind and solar projects included in the 2026 WEM ESOO.

C. New distributed PV capacity represents distributed PV capacity that is not backed by new distributed energy storage systems. Non-negative values indicate higher distributed PV capacity than distributed energy storage system capacity for each Capacity Year.

4 Electric Storage Resource and Demand Side Programme requirements

- The SWIS increasingly requires longer duration Electric Storage Resource (ESR) and Demand Side Programme (DSP) to manage sustained evening peak demand periods. This section presents the requirements for ESR and DSP for the 2026 Reserve Capacity Cycle according to the ESM Rules.
- The ESR Duration Requirement increases from six hours in 2027-28 to seven hours in 2028-29.
- Sensitivity analysis indicates the ESR Duration Requirement may rise to around eight and a half hours later in the outlook period if anticipated capacity projects proceed.
- The increasing ESR Duration Requirement reflects both evolving system needs during sustained evening peak periods and Availability Duration Gap (ADG) between available ESR duration and the ESR Duration Requirement.
- Peak Demand Side Programme Dispatch Requirements and Flexible Demand Side Programme Dispatch Requirements for 2028-29 are set as 28.625 hours or 57.25 Trading Intervals.

4.1 Electric Storage Resource requirements and outcomes

The ESR requirements for peak capacity and flexible capacity include:

- the ESR Duration Requirement, which sets the requirement for new ESR for 2028-29 under the 2026 Reserve Capacity Cycle, and
- the timing for ESR Duration Requirement, which is set by the Mid Peak Electric Storage Resource Obligation Intervals (ESROI) which is the mid-point around which ESR must offer their capacity each day (according to their ESR Duration Requirement).
- The Mid Peak ESROI have been reviewed for 2026-27 and 2027-28 and determined for 2028-29.
- The Flexible ESROI have also been reviewed for 2027-28 and determined for 2028-29.

Table 23 summarises the related ESM Rules references of the requirements.

Table 23 Electricity System and Market Rules Requirement for Electric Storage Resource and Demand Side Programme requirements

Clause	Requirements
4.5.10(bC), 4.5.13(eC)	• Expected Electric Storage Resource Duration Requirement for 2026-27 to 2035-36
4.5.12(d), 4.5.13(eC)	• Determination of Electric Storage Resource Duration Requirement for 2028-29
4.5.12(e), 4.5.13(eC)	• Availability Duration Gap and Electric Storage Resource Duration Requirement Uplift for 2028-29
4.5.12(f)	• Indicative Demand Side Programme Dispatch Threshold for 2028-29
4.5.12(g)	• Peak Demand Side Programme Dispatch Requirement for 2028-29
4.5.12(h)	• Flexible Demand Side Programme Dispatch Requirement for 2028-29

Clause	Requirements
4.11.3A(a)	• Determination and publication of Mid Peak Electric Storage Resource Obligation Interval for 2028-29
4.11.3A(aA), 4.11.3A(aB)	• Determination and publication of Flexible Electric Storage Resource Obligation Intervals for 2028-29
4.11.3A(b)	• Review and publication of Mid Peak Electric Storage Resource Obligation Interval for 2026-27 • Review and publication of Mid Peak Electric Storage Resource Obligation Interval for 2027-28 • Review and publication of Flexible Electric Storage Resource Obligation Intervals for 2027-28
4.11.3A(c)	• WEM Procedures: Mid Peak and Flexible Electric Storage Resource Obligation Intervals[A]

A. See https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

4.1.1 Electric Storage Resource Duration Requirement for 2028-29

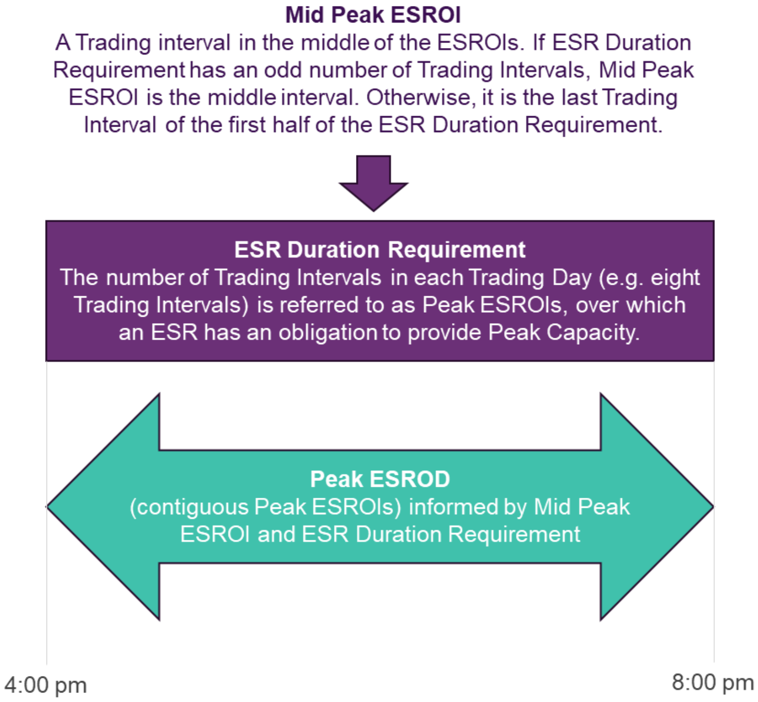
The meaning and relationship between the ESR Duration Requirement, Mid Peak ESROI and Peak Electric Storage Resource Obligation Duration (ESROD) are discussed in **Table 24** and conceptually presented in **Figure 30**.

Table 24 The relationship between Electric Storage Resource Duration Requirement, Availability Duration Gap, Mid Peak Electric Storage Resource Obligation Interval and Peak Electric Storage Resource Obligation Duration

Term	Expressed as	Meaning
ESR Duration Requirement	Number of contiguous Trading Intervals	The ESR Duration Requirement defines the minimum time (**in number of contiguous Trading Intervals in each Trading Day)** an Electric Storage Resource must sustain its rated discharge at full capacity. It ensures the resource can deliver the level of reliability and system support required for its intended role, particularly during peak demand periods or system stress events. In the 2026 WEM ESOO, the ESR Duration Requirement is determined for all new ESRs that are to be assigned Capacity Credit in the 2026 Reserve Capacity Cycle. The following applies to the ESRs that have been assigned Capacity Credits in earlier cycles: • For Reserve Capacity Cycles up to and including the 2024 Reserve Capacity Cycle, the ESR Duration Requirement remains eight Trading Intervals. • For the 2025 Reserve Capacity Cycle the ESR Duration Requirement remains 12 Trading Intervals.
Availability Duration Gap (ADG)	Number of Trading Intervals	The ADG is added to the 2027-28 ESR Duration Requirement to set the ESR Duration Requirement for 2028-29. This has the effect of increasing the ESR Duration Requirement.
Mid Peak Electric Storage Resource Obligation Interval (Mid Peak ESROI)	Trading Interval	The Mid Peak ESROI is the defined trading interval during which Electric Storage Resources are expected to be available to discharge and support the system during sustained, moderate demand conditions. It captures periods where system demand is elevated but not at peak extremes, ensuring storage contributes to reliability across a broader portion of the day. The Mid Peak ESROI is determined based on the WEM Procedure: Mid Peak and Flexible Electric Storage Resource Obligation Intervals[A]. Mid Peak ESROI is the middle of the ESR Duration Requirement if it has an odd number of Trading Intervals, otherwise it is the last Trading Interval of the first half of the ESR Duration Requirement. The Mid Peak ESROI will be reassessed to determine whether the most recent Mid Peak ESROI for each of the next eight Trading Days in Years 3 and 4 of Reserve Capacity Cycle remains appropriate.
Peak Electric Storage Resource Obligation Duration (Peak ESROD)	Timestamp from – timestamp to	Represents the contiguous Trading Intervals (with a specified starting timestamp and ending timestamp) over which ESR is required to be available. Each of the contiguous Trading Intervals are referred to as an Electric Storage Resource Obligation Interval (ESROI). The number of ESROIs making up Peak ESROD is equal to the ESR Duration Requirement.

A. See WEM Procedure https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

Figure 30 Illustration of the relationship between Mid Peak Electric Storage Resource Obligation Interval, Electric Storage Resource Duration Requirement, and Peak Electric Storage Resource Obligation Duration

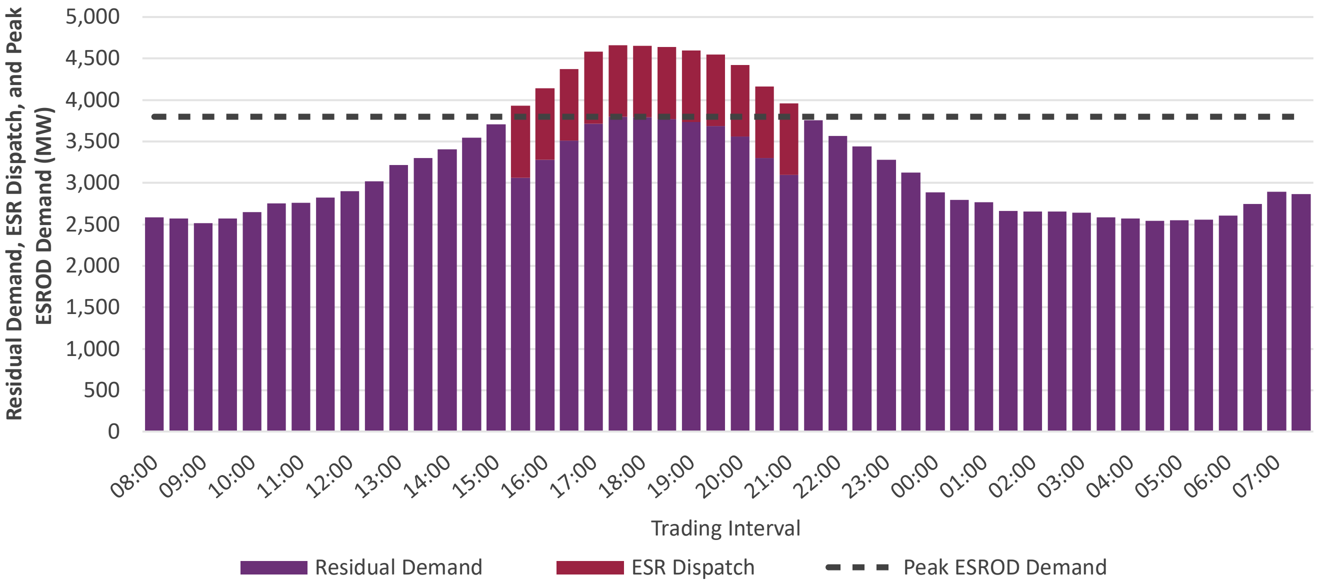


AEMO has determined the ESR Duration Requirement for each year of the outlook period, using demand traces developed for the assessment of Limb B of the Planning Criterion. The assessment was performed for the peak demand day of each of the 16 Reference Years developed for this WEM ESOO.

Figure 31 illustrates how the ESR Duration Requirement is assessed for a single peak demand day in one weather reference year. The assessment seeks to identify the duration over which ESR dispatch minimises residual demand (as calculated in B.1.4 of Appendix 11 of the ESM Rules), while avoiding the creation of higher demand in Trading Intervals outside the Peak ESROD.

All ESR assigned Capacity Credits in the most recent Reserve Capacity Cycle are assumed to dispatch at derated capacity. The derated capacity is calculated by dividing the total ESR capacity (MW) by the ESR Duration Requirement applying to the Reserve Capacity Cycle in which the ESR was first certified, for a period of 10 years.

Figure 31 Illustration of Residual Demand, ESR dispatch, and Peak ESROD Demand at each Trading Interval of ESR Duration Requirement assessment for a single peak demand day in a single weather reference year (MW)



The average assessed duration across all weather reference years is used to determine the ESR Duration Requirement for 2028-29. For each Capacity Year of this outlook period, AEMO calculates an indicative ESR Duration Requirement by taking the median values of the 16 weather reference years, presented in **Table 25**. The assessed duration for each weather reference year is also presented in the table. Across most weather reference years, assessed durations range between seven and seven and a half hours over the outlook period, although some weather reference years show durations increasing to up to nine and a half to 11.5 hours.

Under clause 4.14.1CB(a).ii.2 in the ESM Rules, the highest forecast ESR Duration Requirement over the outlook period is seven and a half hours in 2031-32 as in **Table 25**. This represents the minimum duration for which an ESR must be capable of maintaining output at its Peak Certified Reserve Capacity in each Trading Day to meet the eligibility requirements for classification as a Fixed Price Component for 10 Capacity Years.

Table 25 Reference_ESROD_QTY[A] in hours for each weather reference year across the outlook period

Weather reference year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
2009	6.0	6.0	6.5	6.5	7.0	8.5	6.5	6.5	9.5	6.5
2010	6.5	7.0	7.5	8.0	8.0	8.0	7.5	7.0	7.5	7.5
2011	6.0	7.0	7.0	6.5	7.0	9.5	9.5	9.5	6.5	6.5
2012	6.5	7.5	7.5	7.5	7.5	7.0	7.0	7.0	7.5	7.0
2013	6.0	7.0	7.0	7.0	7.5	7.5	7.0	7.0	7.0	7.5
2014	6.0	6.5	6.5	6.5	6.0	6.5	6.5	6.5	6.5	6.0
2015	6.0	7.0	7.0	7.5	7.0	7.0	7.5	7.5	7.5	6.5
2016	6.0	7.0	7.0	6.5	8.0	6.5	7.0	7.0	7.0	6.5
2017	7.5	7.0	7.0	7.5	7.5	8.0	7.5	7.5	7.0	7.5
2018	6.0	7.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.5
2019	6.5	7.0	7.0	7.0	7.0	7.0	7.0	7.5	6.5	7.0
2020	6.5	7.5	7.0	7.0	7.0	7.0	7.5	6.5	7.0	7.0

Weather reference year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
2021	6.5	7.0	7.0	7.5	7.0	7.5	7.0	6.5	6.5	6.5
2022	6.0	7.0	6.5	7.0	7.0	7.0	6.5	6.5	6.0	6.5
2023	7.0	8.0	8.0	7.5	8.0	8.0	7.0	7.0	8.0	8.0
2024	6.5	9.0	7.0	9.5	9.0	9.0	7.5	7.0	7.0	11.5
Median	**6.5**	**7.0**	**7.0**	**7.0**	**7.0**	**7.5**	**7.0**	**7.0**	**7.0**	**7.0**

A. Reference_ESROD_QTY is the number of Trading intervals in the Reference ESROD as defined in the clause B.1.4 of Appendix 11 of the ESM Rules. Reference ESROD is the contiguous set of Trading Intervals used for the determination of the Reference ADG as defined in the clause A.2(m) of Appendix 11 of the ESM Rules.

In this ESOO, AEMO has determined an Availability Duration Gap of two Trading Intervals (one hour). When added to the assessed ESR Duration Requirement of 12 Trading Intervals (six hours), this results in an ESR Duration Requirement of 14 Trading Intervals (seven hours) for 2028-29.

To assess the potential impact of anticipated ESR entrants, AEMO also modelled a sensitivity assuming peak capacity from all anticipated ESR (as detailed in Section 3.2.3) becomes available from 2028-29. The results are presented in **Table 26** indicating the ESR Duration Requirement (presented in median value of hours over the weather reference years for each Capacity Year in this outlook period), could increase to eight to eight and a half hours once these projects are operational and remain at that level for the remainder of the outlook period. Noting that degradation of forecast ESR capacity has been assumed, reflecting the potential reduction in projected capacity due to factors such as Facilities' ageing and performance degradation.

Table 26 Reference_ESROD_QTY[A] in hours for each weather reference year across the outlook period, including anticipated Facilities

Weather reference year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
2009	6.0	6.0	7.5	7.5	8.5	10.0	7.5	7.5	10.5	8.0
2010	6.5	7.0	8.5	9.0	8.5	8.5	8.5	8.0	8.5	8.5
2011	6.0	7.0	8.5	8.0	8.5	10.5	10.0	10.0	7.5	7.5
2012	6.5	7.5	8.5	8.5	8.0	8.0	8.0	8.0	8.0	7.5
2013	6.0	7.0	8.5	8.5	8.5	8.5	9.0	9.0	8.0	8.0
2014	6.0	6.5	8.0	8.0	7.0	8.0	7.5	7.5	7.5	6.5
2015	6.0	7.0	9.0	9.0	8.5	8.0	9.0	8.5	8.5	7.5
2016	6.0	7.0	8.5	8.0	9.5	8.0	8.0	8.0	8.0	7.0
2017	7.5	7.0	8.5	8.5	8.5	9.0	8.5	8.0	8.0	8.0
2018	6.0	7.5	8.0	8.5	8.0	8.0	8.0	8.0	8.0	7.5
2019	6.5	7.0	8.5	9.0	8.5	8.5	8.5	8.5	8.0	7.5
2020	6.5	7.5	8.5	8.5	9.0	8.5	8.0	7.5	8.0	8.0
2021	6.5	7.0	8.5	9.0	8.5	8.5	8.0	8.0	7.5	7.5
2022	6.0	7.0	8.0	8.0	8.0	8.0	7.5	7.0	7.0	7.0
2023	7.0	8.0	10.5	9.0	10.0	10.0	8.0	8.0	11.0	8.5
2024	6.5	9.0	8.0	11.0	10.5	9.5	10.0	9.5	8.0	12.0
Median	**6.5**	**7.0**	**8.5**	**8.5**	**8.5**	**8.5**	**8.0**	**8.0**	**8.0**	**7.5**

A. Reference_ESROD_QTY is the number of Trading intervals in the Reference ESROD as defined in the clause B.1.4 of Appendix 11 of the ESM Rules. Reference ESROD is the contiguous set of Trading Intervals used for the determination of the Reference ADG as defined in the clause A.2(m) of Appendix 11 of the ESM Rules.

4.1.2 Electric Storage Resource Duration Requirement Uplift

The ESR Duration Requirement Uplift accounts for the need for additional Reserve Capacity required measured in MW. The increase to the ESR Duration Requirement not being applied to ESR certified prior to 2025 Reserve Capacity Cycle due to a grandfathering arrangement in the ESM Rules. The ESM Rules provide protection for ESR certified prior to the 2025 Reserve Capacity Cycle, allowing these Facilities to continue to be certified for a period of 10 years with the shorter ESR Duration Requirement that was in place when they first received Capacity Credits. The ESR Duration Requirement Uplift was therefore introduced as a component of the Limb A of the Planning Criterion to reflect the overallocation of Capacity Credits to these grandfathered ESR.

- Based on 1,700 MW of ESR assigned Peak Capacity Credits and an increase in the ESR Duration Requirement from six to seven hours, the ESR Duration Requirement Uplift for 2028-29 is calculated as 392 MW in accordance with Appendix 11 of the ESM Rules and the methodology outlined in Appendix A4.2.4 of this WEM ESOO. This uplift has been applied to the Limb A requirement from 2028-29 onwards (see Section 5).

4.1.3 Mid Peak Electric Storage Resource Obligation Interval

Trading Interval demand forecasts for the *Expected* scenario at 10% POE and 50% POE were analysed to identify the Peak Demand Periods as defined in the WEM Procedure: Mid Peak and Flexible Electric Storage Resource Obligation Intervals [64]. These Peak Demand Periods are used as inputs to determine the indicative Mid Peak ESROI and are identified in **Table 27** and **Table 28**.

AEMO reviewed the preliminary ESROIs associated with the indicative Mid Peak ESROI and assessed their suitability by considering operational factors, including Intermittent Generating Systems forecasts and expected DSP availability.

This assessment determined that separate Mid Peak ESROIs should apply for Business Days and Non-Business Days to reflect differences in peak demand profiles between these days. The assessment also determined that the Mid Peak ESROI should be shifted by one Trading Interval early or later relative to the indicative Mid Peak ESROI. This adjustment reflects the expected contribution of utility-scale solar PV earlier in the peak demand period and reduced availability of DSP later in the evening peak.

AEMO may adjust any Mid Peak ESROI determined for each of the next eight Trading Days to ensure it remains appropriate, taking into account the latest ST PASA and any other relevant operational considerations. The most recent Mid Peak ESROI for the relevant Trading Day is published on the WEM Website by 06:50 (Western Standard Time) on each Scheduling Day under clause 6.3.1(a) of the ESM Rules.

For 2026-27, the outcome of the Mid Peak ESROI is summarised in **Table 27.**

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

Table 27 ESR Duration Requirement, Peak Demand Period, indicative Mid Peak ESROI, Mid Peak ESROI and Peak ESROD determined for 2026-27

Capacity Year	Season	ESR Duration Requirement (number of Trading Intervals)	Peak Demand Periods (Trading Intervals)	Indicative Mid Peak ESROI	Mid Peak ESROI (Business Days / Non-Business Days)	Peak ESROD (Business Days / Non-Business Days)
2026-27	Summer	8	17:00-20:30	18:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Shoulder	8	17:00-20:30	18:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
	Winter	8	17:00-20:30	18:30	19:00 / 18:30	17:30-21:00 / 17:00-20:30

For 2027-28 and 2028-29, the set of Mid Peak ESROIs are determined to be the same as those for 2026-27 (see **Table 28**). To identify the associated Peak ESROIs, **Table 28** reports outcomes for each ESR Duration Requirement applying by ESR Capacity Credit status group (grandfathered or not grandfathered as per Section 4.1.2 of this WEM ESOO) in the WEM. ESR Capacity Credit status group refers to the timing of the ESR first received Capacity Credits.

Table 28 ESR Duration Requirement, Peak Demand Period, indicative Mid Peak ESROI, Mid Peak ESROI and Peak ESROD determined for 2027-28 and 2028-29 by ESR Capacity Credit status group

Capacity year	ESR Capacity Credit status group	Season	ESR Duration Requirement (number of Trading Intervals)	Peak Demand Period (Trading Intervals starting)	Indicative Mid Peak ESROI (Trading Interval starting)	Mid Peak ESROI (Business Days / Non-Business Days)	Peak ESROD (Business Days / Non-Business Days)
2027-28	First received Capacity Credits in 2024 Reserve Capacity Cycle or earlier	Summer	8	17:00-20:30	18:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
		Shoulder	8	17:00-20:30	18:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
		Winter	8	16:30-20:00	18:00	19:00 / 18:30	17:30-21:00 / 17:00-20:30
	First received Capacity Credits in 2025 Reserve Capacity Cycle	Summer	12	16:00-21:30	18:30	19:00 / 18:00	16:30-22:00 / 15:30-21:00
		Shoulder	12	16:00-21:30	18:30	19:00 / 18:00	16:30-22:00 / 15:30-21:00
		Winter	12	15:30-21:00	18:00	19:00 / 18:30	16:30-22:00 / 16:00-21:30
2028-29	First received Capacity Credits in 2024 Reserve Capacity Cycle or earlier	Summer	8	17:00-20:30	18:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
		Shoulder	8	17:00-20:30	18:30	19:00 / 18:00	17:30-21:00 / 16:30-20:00
		Winter	8	16:30-20:00	18:00	19:00 / 18:30	17:30-21:00 / 17:00-20:30
	First received Capacity Credits in 2025	Summer	12	16:00-21:30	18:30	19:00 / 18:00	16:30-22:00 / 15:30-21:00
		Shoulder	12	16:00-21:30	18:30	19:00 / 18:00	16:30-22:00 / 15:30-21:00

Capacity year	ESR Capacity Credit status group	Season	ESR Duration Requirement (number of Trading Intervals)	Peak Demand Period (Trading Intervals starting)	Indicative Mid Peak ESROI (Trading Interval starting)	Mid Peak ESROI (Business Days / Non-Business Days)	Peak ESROD (Business Days / Non-Business Days)
	Reserve Capacity Cycle	Winter	12	15:30-21:00	18:00	19:00 / 18:30	16:30-22:00 / 16:00-21:30
	First received Capacity Credits in 2026 Reserve Capacity Cycle	Summer	14	15:30-22:00	18:30	19:00 / 18:00	15:30-22:00 / 15:00-21:30
		Shoulder	14	15:30-22:00	18:30	19:00 / 18:00	15:30-22:00 / 15:00-21:30
		Winter	14	15:00-21:30	18:00	19:00 / 18:30	15:00-21:30 / 14:30-21:00

4.1.4 Flexible Electric Storage Resource Obligation Interval

The Flexible ESROI defines the final Trading Interval in the Flexible Capacity Obligation Duration period. Together with the Flexible Capacity Obligation Duration of eight Trading Intervals specified in the ESM Rules, it determines the consecutive Trading Intervals during which an ESR with assigned Flexible Capacity Credits must be available for dispatch. AEMO assessed the likelihood of ESR being required to provide both forecast flexible capacity and forecast peak Capacity on the same day using demand trace forecasts across 16 historical weather reference years. This assessment indicated a very low likelihood of overlapping dispatch requirements.

Table 29 presents the Flexible ESROI determined for 2027-28 and 2028-29.

Table 29 Flexible ESROI determined for 2027-28 and 2028-29

Capacity Year	Season	Flexible Capacity Obligation Duration (number of Trading Intervals)	Flexible ESROI (Trading Interval starting)	Timestamps (Trading Intervals starting)
2027-28	Shoulder	8	18:00	14:30-18:00
	Winter	8	18:00	14:30-18:00
2028-29	Shoulder	8	18:00	14:30-18:00
	Winter	8	18:00	14:30-18:00

4.2 Demand Side Programme requirements and outcomes

The DSP threshold and requirements include:

- the Indicative Demand Side Programme Dispatch Threshold,
- the Peak Demand Side Programme Dispatch Requirement, and
- the Flexible Demand Side Programme Dispatch Requirement.

4.2.1 Indicative Demand Side Programme Dispatch Threshold

The Indicative Demand Side Programme Dispatch Threshold is the demand level at which DSP capacity is expected to be required, determined in accordance with clause 4.5.12(f) of the ESM Rules. For 2028-29, the threshold is calculated as the 50% POE peak demand forecast of 4,649 MW, less the 240 MW of Capacity Credits assigned to DSPs in 2027-28.

Accordingly, the Indicative Demand Side Programme Dispatch Threshold for 2028-29 is 4,409 MW.

4.2.2 Peak Demand Side Programme Dispatch Requirements and Flexible Demand Side Programme Dispatch Requirements

This section presents the requirements relating to DSPs, namely the Peak Demand Side Programme Dispatch Requirement and the Flexible Demand Side Programme Dispatch Requirement. These requirements set the obligations for DSPs providing peak capacity and flexible capacity by specifying the number of Trading Intervals for which DSP capacity may be dispatched by AEMO. These determinations replace the fixed quantities previously specified in the ESM Rules which apply only up to the 2024 Reserve Capacity Cycle (for 2026-27).

The Peak Demand Side Programme Dispatch Requirement is determined by assessing the Indicative Demand Side Programme Dispatch Threshold and calculating the average number of Trading Intervals, across each Capacity Year of the Reference Demand Profile (as determined under B.2.5 of Appendix 9 of the ESM Rules), in which demand exceeds that threshold.

The Flexible Demand Side Programme Dispatch Requirement is set as the greater of:

- the Peak Demand Side Programme Dispatch Requirement, and
- eight Trading Intervals.

The Reference Demand Profile is constructed in accordance with Appendix 9 of the ESM Rules using Observed Demand from the four highest peak demand Capacity Years within the preceding five-year period. The profile is adjusted to:

- account for demand-side reductions and growth in distributed PV, and
- align with the forecast10% POE peak demand and forecast annual energy consumption under the *Expected* scenario.

Figure 32 presents the resulting Reference Demand Profile as a duration curve for each of the four highest maximum demand Capacity Years within the DER Adjusted Demand Profile (determined in accordance with B.2.2 of Appendix 9 of the ESM Rules) for the five Capacity Years ending on 1 October 2025. For each assessed Capacity Year, the figure shows the number of Trading Intervals in which demand exceeds the Indicative Demand Side Programme Dispatch Threshold presented in **Table 30**.

Figure 32 Reference Demand Profiles for the four highest demand Capacity Years within the Reference Demand Profile Reference Period (MW)

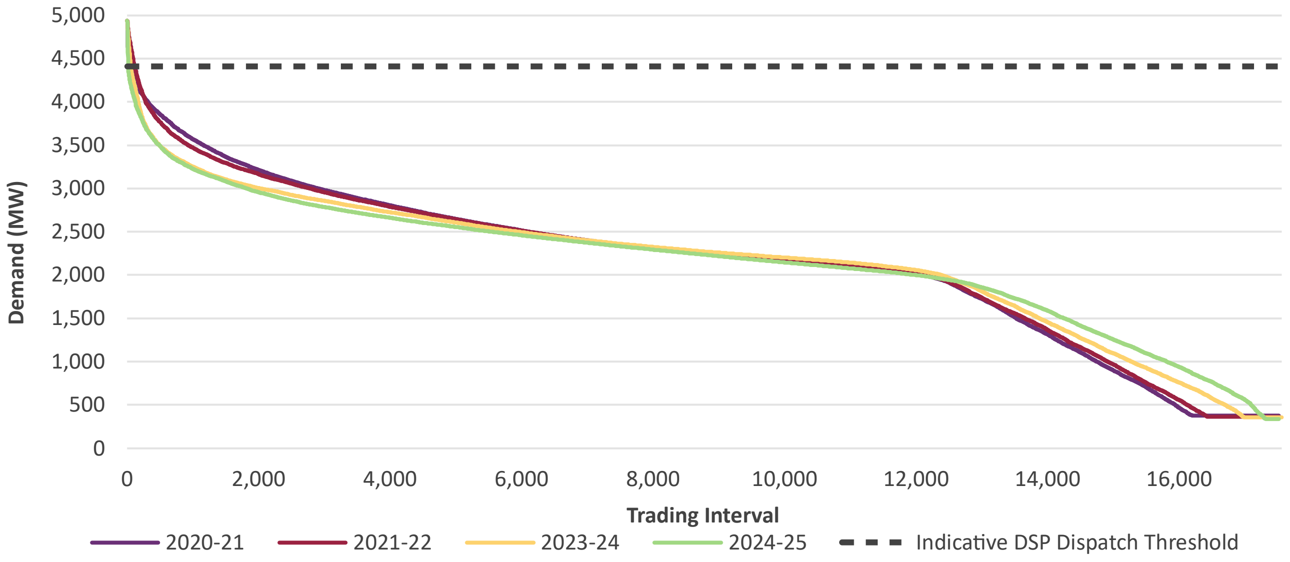

Table 30 Number of Trading Intervals above Indicative Demand Side Programme Dispatch

Capacity Year	Number of Trading Intervals above Indicative DSP Dispatch Threshold	Indicative DSP Dispatch Threshold (MW)	Maximum demand (MW)
2020-21	54	4,409	4,937
2021-22	107	4,409	4,937
2023-24	53	4,409	4,937
2024-25	15	4,409	4,937

Under clauses 4.5.12(g) and 4.5.12(h) of the ESM Rules, AEMO must determine the Peak Demand Side Programme Dispatch Requirement and the Flexible Demand Side Programme Dispatch Requirement for the third Capacity Year in the WEM ESOO study horizon. For the 2026 WEM ESOO, this is 2028-29. The Peak Demand Side Programme Dispatch Requirement and the Flexible Demand Side Programme Requirements are shown in **Table 31**.

Table 31 The Peak Demand Side Programme Dispatch Requirements and the Flexible Demand Side Programme Dispatch Requirements

Capacity Year	Expressed as	Peak Demand Side Programme Dispatch Requirement (Hours / Trading Intervals)	Flexible Demand Side Programme Dispatch Requirement (Hours / Trading Intervals)
2026-27	Number of hours / Trading Intervals	50 / 100	Not applicable
2027-28		23.75 / 47.5	23.75 / 47.5
2028-29		28.625 / 57.25	28.625 / 57.25

5 Peak and Flexible Reserve Capacity Target determination

This section presents the reliability assessment for 2026-27 to 2035-36. This includes determination of the Peak and Flexible RCTs for 2028-29.

The 2026 WEM ESOO presents an improved near-term forecast to 2028-29, compared to last year's report, but remains contingent on the timely delivery of new committed capacity and planned network augmentations.

- A Peak RCT of 6,323 MW and a Flexible RCT of 2,617 MW have been determined for 2028-29.
- Significant new entry of committed capacity ensures forecast annual USE, modelled without network constraints, remains under the 0.0002% threshold through to 2029-30 inclusive, with increasing risk emerging from the early 2030s as forecast demand grows and thermal generation retires.
- From 2030-31, forecast annual USE is projected to exceed the 0.0002% threshold, as limited new capacity is available from this point to meet demand growth, and offset reductions associated with the phased retirement of Pinjar gas generators and assumed unavailability of Bluewaters.
- In 2026-27, Peak RCT is set by the Limb B (energy adequacy) assessment. For the remaining years of the outlook period, Peak RCT is set by the Limb A (capacity adequacy) assessment.
- Adequate peak capacity is forecast until 2028-29 inclusive, exceeding the Peak RCT by up to 347 MW. From 2029-30, shortfalls of peak capacity against the Peak RCT are forecast.
- Adequate flexible capacity is forecast across the outlook period, with a surplus of 1,457 MW in 2027-28, declining to 941 MW by 2035-36.
- The ESR Duration Requirement for new ESR in the 2026 Reserve Capacity Cycle has been increased to seven hours.

5.1 Introduction

In this 2026 WEM ESOO, AEMO has used internal resources to deliver the electricity market dispatch modelling underpinning Limb B and the sub-regional reliability assessment. Previously, this modelling was conducted by external consultants.

Undertaking assessments in-house enables deeper interrogation of the modelled outcomes, and the ability to leverage insights into operability as part of AEMO's transition planning and associated actions under the SWIS Engineering Roadmap. Further detail on methodology and assumptions is provided in AEMO's 2026 WEM ESOO Appendices[65].

This section is structured as follows:

- Section 5.2 summarises the reliability assessment methodology and presents observed emerging challenges to reliability of supply in the SWIS,

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

- Sections 5.3, 5.4, 5.5 present the outcomes of the assessment against Limb A, Limb B and Limb C of the Planning Criterion, respectively,
- Section 5.6 presents the Peak RCT and Flexible RCT derived from the Limb A, Limb B and Limb C assessments,
- Section 5.7 presents the supply-demand balance of forecast peak capacity and forecast flexible capacity against Peak RCT and Flexible RCT, respectively,
- Section 5.8 comments on the Capability Class assessment,
- Section 5.9 presents the Availability Curves.

5.2 Reliability assessment methodology to determine the Peak Reserve Capacity Target and Flexible Reserve Capacity Target

AEMO sets the Peak RCT and Flexible RCT for each Capacity Year in the 10-year outlook period in accordance with the Planning Criterion (see Section 1.1.1 for more details).

The Peak RCT is AEMO's estimate of the total amount of generation, battery storage and DSP capacity required in the SWIS to satisfy Limbs A and B of the Planning Criterion. The Peak RCT is updated in each LT PASA Study for the relevant Capacity Years to reflect the current forecasts.

The Flexible RCT is AEMO's estimate of flexible capacity to cover the midday to evening demand ramp, conducted for each Capacity Year during each LT PASA Study horizon to satisfy Limb C of the Planning Criterion. The first determination of the Flexible RCT occurred in the 2025 WEM ESOO.

The Peak RCT is set by the highest of the requirements determined by Limb A, Limb B, and Limb C. The Flexible RCT is set by the requirement of Limb C.

The target for the third Capacity Year in the LT PASA Study Horizon is the Reserve Capacity Requirement (RCR), which for this WEM ESOO is 2028-29.

The methodology for determining the Limb A, B and C requirements is summarised in **Table 32**.

Table 32 Summary of methodologies used to determine Limb A, B and C of the Planning Criterion

Limb A (capacity adequacy)	Limb B (energy adequacy)	Limb C (ramping adequacy)
Sets the capacity required to meet the annual peak demand and margins (MW)	**Sets the capacity required to limit the allowable amount of USE (MWh)**	**Determines the amount of flexible capacity required for ramping (MW)**
Calculated using the following building blocks: • Annual peak demand, forecast for the *Expected* scenario under 10% POE. • An allowance for Intermittent Loads. • An allowance for Regulation Raise, which takes into account: – the current requirement for Regulation Raise, and – the impact of intermittent generators (wind, large-scale solar, distributed PV) on the forecast requirement of Regulation Raise.	USE is assessed by dispatch modelling of the WEM, taking into account forecast demand and supply: • Forecast demand taking into account a Minimum Demand Threshold (MDT) of 300 MW, as the current demand level which AEMO requires to maintain system security, including regional (Southern and Northern) reactive power management requirements. • Network constraints are not considered when determining the target for unconstrained capacity[A]. The impact on USE with transmission network constraints	Calculated using the following building blocks: • The highest FHDI which quantifies the expected maximum upwards ramp of SWIS demand over a period of contiguous four hours which needs to be satisfied by an adequate amount of flexible capacity. • The reserve margin is calculated as the highest FHDI multiplied by the proportion of flexible capacity expected to be unavailable at the time of the highest forecast FHDI due to Forced Outages. • Both the 10% POE and 50% POE demand is used in this assessment and the

Limb A (capacity adequacy)	Limb B (energy adequacy)	Limb C (ramping adequacy)
• A reserve margin, being the greater of: – the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand which AEMO estimates as the equivalent of the two largest generators and 70% of the third largest generator[66], and – Forced Outage allowance, expressed as the forecast peak demand multiplied by the proportion of peak capacity expected to be unavailable at the time of peak demand due to Forced Outages. • The ESR Duration Requirement Uplift which quantifies the overallocation of Peak Capacity Credits assigned to ESR with shorter duration than required by the ESR Duration Requirement (in accordance with grandfathering provisions).	added to the modelling is explored in Section 6. • For the purposes of modelling in this 2026 WEM ESOO, the capacity of non-intermittent generation is capped at the assigned Peak Capacity Credits in the previous Reserve Capacity Cycle, which includes any impact of NAQ (wind and solar are modelled according to their projected availability for each weather reference year). • The modelling involved 100 random (Monte Carlo) patterns of generator Forced Outages overlaid across 16 historical weather reference years. This produced 1,600 iterations for each Capacity Year and was used to inform the assessment of USE, capturing a range of weather variability and random Forced Outage patterns impacting the availability of supply. • All USE presented is the average of unserved energy from the 1,600 iterations modelled for each Capacity Year.	determination of FHDI based on the higher of the two.

A. Network congestion is accounted for by AEMO in the NAQ framework when assigning Capacity Credits to capacity providers.

5.3 Peak capacity requirement (Limb A)

Table 33 shows the building blocks of Limb A and the amount of peak capacity required to satisfy Limb A in each Capacity Year of the 10-year outlook period. The supply-demand balance is assessed in Section 5.7.

The building blocks of Limb A for each Capacity Year under the *Expected* scenario include:

- **10% POE annual peak demand**, representing the single Trading Interval for which the highest annual operational demand is forecast. See Section 2 for the peak demand forecasts and drivers.
  - For 2028-29, SWIS annual peak operational demand in the 10% POE *Expected* scenario is forecast to be reduced by 200 MW by coordinated DER (VPP), from 5,136 MW to 4,937 MW (4% reduction).
- The **reserve margin** represents the largest risk in relation to the loss of forecast supply as equivalent to the loss of two largest generating units and also holding a real-time reserve equivalent to 70% of the third largest Facility operating in the SWIS. This is detailed in Section 3.7.
- The **Regulation Raise** component accounts for the requirement of Regulation Raise and is escalated to account for the impact of increasing deployment of intermittent generators (wind, grid-scale solar, distributed PV) on the forecast requirement of Regulation Raise. The components driving it is detailed in Section 3.8.
- The **ESR Duration Requirement Uplift** accounts for the need for additional Reserve Capacity resulting from an increase to the ESR Duration Requirement, where existing batteries continue to be certified on the basis of a shorter duration requirement for which they were first certified.
- The **Intermittent Loads component** represents the estimate of the capacity required to cover the forecast requirements of Intermittent Loads, which are in addition to the 10% POE peak demand forecasts.

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[66] See Section 3.7 for a detailed discussion on the determination of the largest contingency.

The upward trend in the amount of forecast peak capacity required to satisfy Limb A is driven by the increasing trajectory of 10% POE peak demand, an increase in the Regulation Raise component (driven by increasing penetration of intermittent generation, in particular wind, see Section 3.8) as well as the addition of the ESR Duration Requirement Uplift component (see Section 4.1.2).

The approach to deriving building blocks of Limb A is detailed in Appendix A4.2.

Table 33 Limb A building blocks and the total amount of peak capacity needed to satisfy Limb A (MW)[A]

Capacity Year	10% POE annual peak demand	Intermittent Loads	Reserve margin	Regulation Raise	ESR Duration Requirement Uplift	Peak capacity required to satisfy Limb A
2026-27	4,709	3	880	110	-	**5,702**
2027-28	4,878	3	864	120	256	**6,121**
2028-29	4,937	3	861	130	392	**6,323**
2029-30	5,072	3	858	150	392	**6,475**
2030-31	5,224	3	855	171	392	**6,644**
2031-32	5,385	3	853	175	392	**6,807**
2032-33	5,472	3	850	180	392	**6,897**
2033-34	5,568	3	847	187	392	**6,997**
2034-35	5,763	3	845	194	392	**7,197**
2035-36	6,016	3	842	201	392	**7,454**

Note: All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.

To compare the impacts of AEMO's consideration of Limb A building blocks, **Table 34** compares these Limb A building blocks in the 2025 and 2026 WEM ESOOs. This shows a reduction across key components of Limb A for 2028-29, including:

- 40 MW reduction in Regulation Raise requirement, reflecting a revised approach to considering intermittent supply to procured quantities discussed in Section 3.8.
- 97 MW reduction in reserve margin, reflecting a revised approach discussed in Section 3.7.

This is partially offset by increases to the ESR Duration Requirement Uplift.

With near identical demand forecasts (noting significant contribution from VPP, 200 MW, as discussed in Section 2.5), the net impact to the forecast peak capacity required to satisfy Limb A is a 7 MW reduction from the 2025 WEM ESOO.

Table 34 Comparison of Limb A building blocks for 2028-29, 2025 and 2026 WEM ESOOs (MW)

Limb A RCT Component for 2028-29	2025 WEM ESOO	2026 WEM ESOO	Difference in 2026 WEM ESOO from 2025 WEM ESOO
10% POE annual peak demand	4,938	4,937	-1
Intermittent Loads	7	3	-4
Reserve margin	958	861	-97
Regulation Raise	170	130	-40
ESR Duration Requirement Uplift	256	392	136
Peak capacity required to satisfy Limb A	6,330	6,323	-7

Note: All figures are rounded to the nearest MW. Totals may have a 1 MW difference due to rounding.

5.4 Energy adequacy (Limb B)

USE, expressed in MWh, represents energy that cannot be supplied to consumers when demand exceeds supply, resulting in load curtailment.

These results show a noticeable improvement in modelled outcomes compared to the 2025 WEM ESOO. Across the first four years of the outlook, USE is below the reliability standard due to significant entry of new capacity and the assumed extended availability of Bluewaters Power Station.

In 2028-29, expected supply is 1,377 MW higher than projected in the 2025 WEM ESOO, reducing projected USE from 0.0106% (modelled in the 2025 WEM ESOO for that year) to zero.

From 2030-31, USE increases as the supply-demand balance worsens due to increasing demand and reduced supply. Limited committed new entrants are forecast to replace the assumed phased retirement of generators at the Pinjar Power Station and assumed unavailability of Bluewaters Power Station.

Table 35 presents the outcomes of the assessment for the *Expected* scenario, taking the average across 1,600 simulations for each Capacity Year. For the *Expected* scenario, modelled expected USE satisfies the 0.0002% reliability standard until 2030-31.

Table 35 Expected USE, *Expected* scenario, excluding any impacts of network constraints

Capacity Year	Average annual USE (MWh)	Annual consumption (MWh)[A]	USE as % of annual consumption	Reliability Standard
2026-27	5	17,861,671	0.00003 %	0.0002%
2027-28	0	18,282,245	0.00000 %	0.0002%
2028-29	0	18,837,511	0.00000 %	0.0002%
2029-30	8	19,707,855	0.00004 %	0.0002%
2030-31	129	20,597,180	0.00063 %	0.0002%
2031-32	6,427	21,133,909	0.03041 %	0.0002%
2032-33	11,438	21,804,662	0.05246 %	0.0002%
2033-34	20,103	22,661,554	0.08871 %	0.0002%
2034-35	96,576	23,922,494	0.4037 %	0.0002%
2035-36	225,596	25,388,820	0.88857 %	0.0002%

A. Annual consumption varies marginally between scenarios because distributed PV generation and hydrogen consumption are co-optimised within the model.

AEMO models expected USE by undertaking multiple simulations of the outlook period, each of which optimises the dispatch across each Capacity Year at a half hour granularity. To model the variability in generator availability and weather patterns, 100 Monte Carlo simulations were conducted, each using random generator Forced Outage profile across 16 historical weather reference years. This provides a data set of 1,600 simulations for each forecast year, allowing averaged outcomes to report against the Planning Criterion and single simulations for more detailed analysis of system stress periods.

Modelled occurrences of USE are generally driven by a combination of the following factors:

- Periods of high forecast unscheduled operational demand.
- Reduced supply, due to:
  - high Outage conditions, including both Planned and Forced Outages,

- reduced availability of intermittent generation due to weather conditions,
- limited availability of DSP, either due to exceedance of the DSP Dispatch Requirement or on non-business days, or
- insufficient duration of storage units during extended demand periods.

An extended analysis of USE is provided below (with further details presented in Appendix A4.6).

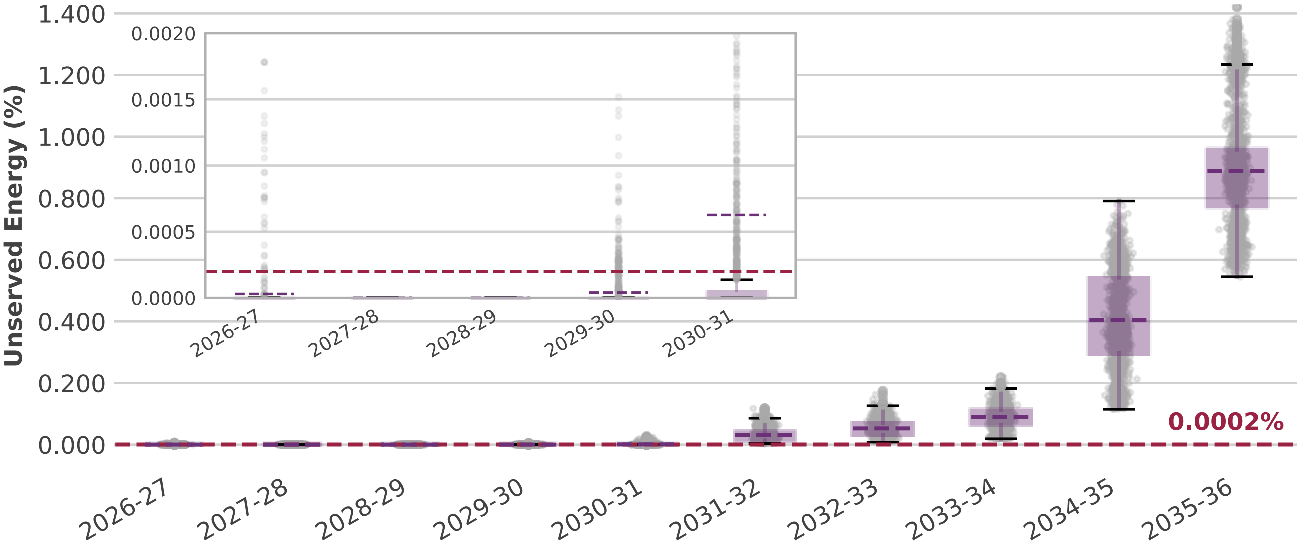
5.4.1 Analysis of expected unserved energy results

Distribution of expected unserved energy outcomes by Capacity Year

Figure 33 shows box-and-whisker plots of annual USE across the 1,600 simulations for each Capacity Year, highlighting the range of outcomes across simulations.

For the first four years of the outlook horizon, the distribution of USE indicates that, while average USE remains below the reliability standard, with the majority of simulations showing zero USE, some simulations do exceed the threshold under certain weather conditions and generator Outage patterns. From 2030-31, reduced supply coupled with escalating demand sees forecast average unserved energy to exceed the reliability standard.

Figure 33 Boxplot of annual unserved energy for 2026-27 to 2035-36, by iteration and reference years (%)



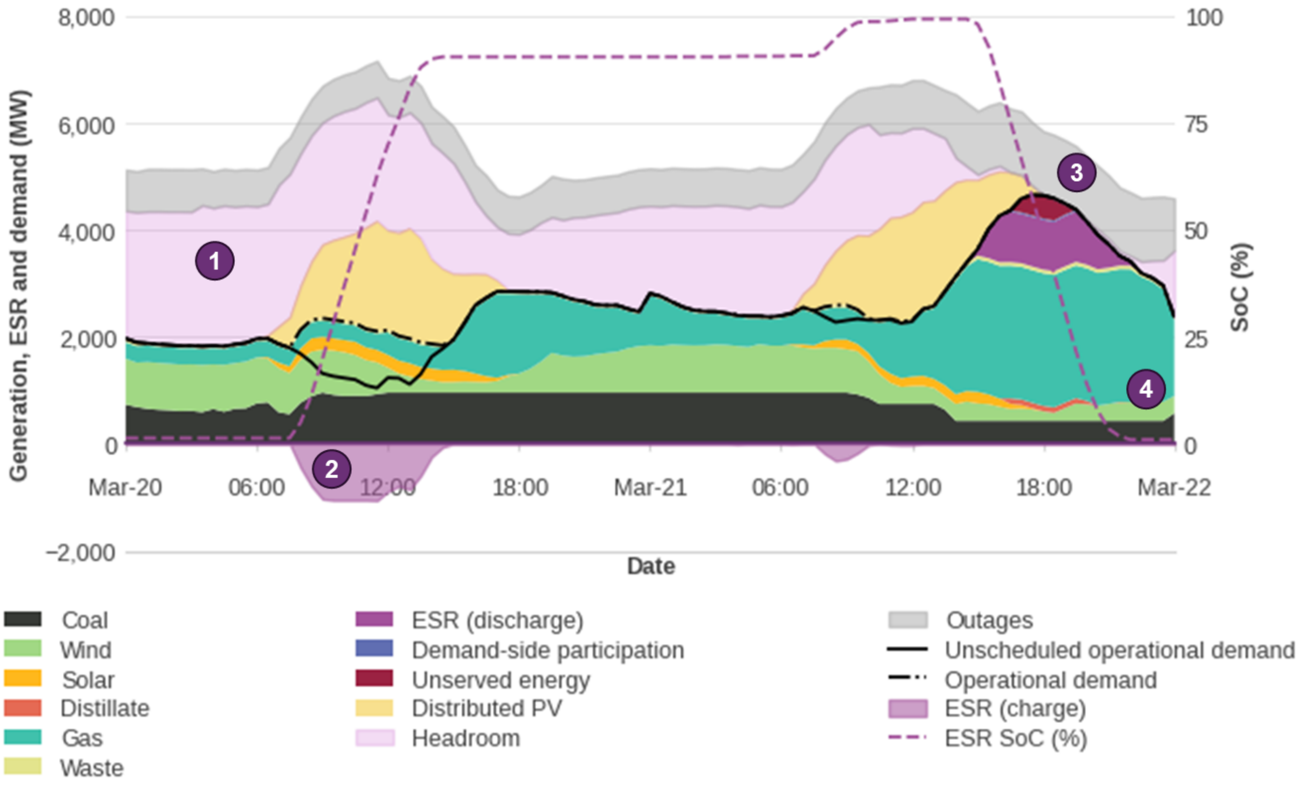
Note: The box and whisker plots for each year represent modelled annual USE (MWh), based on results of 1,600 modelled iterations for each Capacity Year (16 weather reference years x 100 Monte Carlo iterations of Forced Outages). The box represents the interquartile range (IQR), capturing the middle 50% of data. The dashed line represents the average value. The whiskers extend to values within 1.5 × IQR from the lower (Q1) and upper (Q3) quartiles. All individual datapoints are shown as dots to illustrate the relative density and spread, as well as the absolute minimum and maximum values.

In 2026-27, unserved energy is expected to occur during summer season peak events

In 2026-27, all modelled USE is observed in the evening under extreme heatwave conditions, with temperatures overnight remaining elevated, leading to sustained high demand periods.

Figure 34 highlights a sample forecast period in March 2027 where high demand coincides with low availability of wind in the late afternoon, resulting in USE. As shown in the figure, the day ahead of the USE event, the fleet maintains significant headroom (1), with storage charged (2) ahead of the USE event. As demand increases into the evening of the second day, all headroom[67] is exhausted, with DSP unavailable due to peak falling on a weekend, leading to USE (3). Batteries sustain injection across 15:00 to 22:00 Trading Intervals but have insufficient capacity to avoid shortfalls (4).

Figure 34 Modelled supply generation, demand profiles, and expected unserved energy over a two-day period capturing an unserved energy event, including the preceding day in 2026-27 (sample day in March 2027, weather reference year 2017-18) (MW)



Note: DSP includes those with assigned Capacity Credit or Peak Demand NCESS contract, making them available during their obligation periods. In 2026-27, March 21 falls on a Sunday, so no DSP with Capacity Credit is required to be available that day.

In AEMO's modelling, battery storage availability is not strictly limited to the Peak ESROI published in the WEM ESOO. This reflects both AEMO's ability to adjust these Trading Intervals operationally and observed battery storage behaviour, where storage can and does respond to system stress events outside of the formal obligation period.

Other notable features of this day, which sees USE in several Monte Carlo simulations, is the impact of Planned Outages. Typically, Outages are scheduled outside periods of peak system stress. If Planned Outages fall at times of system stress, deferral may be considered where demand can be forecast with sufficient confidence and the Outage can be rescheduled. It is also important to note that events of this nature align closely with the setting of Limb A of the Planning Criterion, occurring at peak demand with material Outage quantities. While Outage conditions exceeding those underpinning Limb A are credible, they are considered to have a low likelihood of occurrence. Further information relating to the modelled behaviour is discussed in **Appendix A4.6**.

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[67] Headroom for generation (that is, excluding storage) units refers to the capacity available for dispatch (injection) into the energy market to meet prevailing demand. Headroom is a product of installed capacity accounting for the impact of planned maintenance and Forced Outages, wind and solar resource availability, capacity held in reserve for ESS.

In 2027-28 and 2028-29, expected unserved energy is zero

The 2027-28 and 2028-29 Capacity Years saw zero incidents of USE across each of the 1,600 simulations.

In 2029-30 and 2030-31, unserved energy is forecast to occur in the evening during summer and to a lesser extent in the morning in winter

In 2029-30 USE is forecast to remain below the reliability standard, however, the frequency and magnitude of USE events are close to the USE threshold. In 2029-30, both Muja D (422 MW total) units are assumed to retire, only partially offset by the entry of 590 MW of wind generation capacity.

2030-31 sees a forecast demand increase of 152 MW alongside entry of 550 MW of wind generation capacity, with forecast USE exceeding the threshold. Further detail on the characteristics and drivers of these events is provided in **Appendix A4.6**.

From 2031-32, USE is forecast in both morning and evening peaks during summer and winter, increasing through the remaining years of the outlook

From 2031–32, supply is reduced due to the forecast unavailability of all remaining SWIS coal-fired capacity (434 MW[68]), as well as several Pinjar[68] gas units (207 MW). Coupled with escalating demand, the reduction in fleet capacity sees a marked increase in forecast USE.

Figure 35 shows modelled supply, demand profiles, and expected USE for a two-day period in 2031-32. The event occurs following a low temperature winter day with coincident low wind conditions. During the first day headroom is used to charge batteries (1) increasing operational demand relative to unscheduled operational demand, batteries are largely discharged through the evening peak (2). With persistently low renewable generation overnight and limited headroom available from the thermal fleet, insufficient energy is available to recharge storage by morning (3). As a result, the fleet is unable to meet the morning peak, leading to USE (4). All available headroom is used to charge storage into

Continued low wind and solar generation through the second day further limits the opportunity for storage to recharge sufficiently, resulting in additional USE during the evening peak period. This period sees sustained operation of the gas fleet, exceeding historic maximum utilisation levels. Events such as this further highlight the need for detailed assessments of adequacy of both contracted and physical gas supply and infrastructure, given the critical role gas will play during system stress periods.

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[68] See **Section 3.3** for further detail.

Figure 35 Modelled supply generation, demand profiles, and unserved energy over a two-day period, including the preceding day in 2031-32 (sample day in July 2032, reference year 2009-10) (MW)

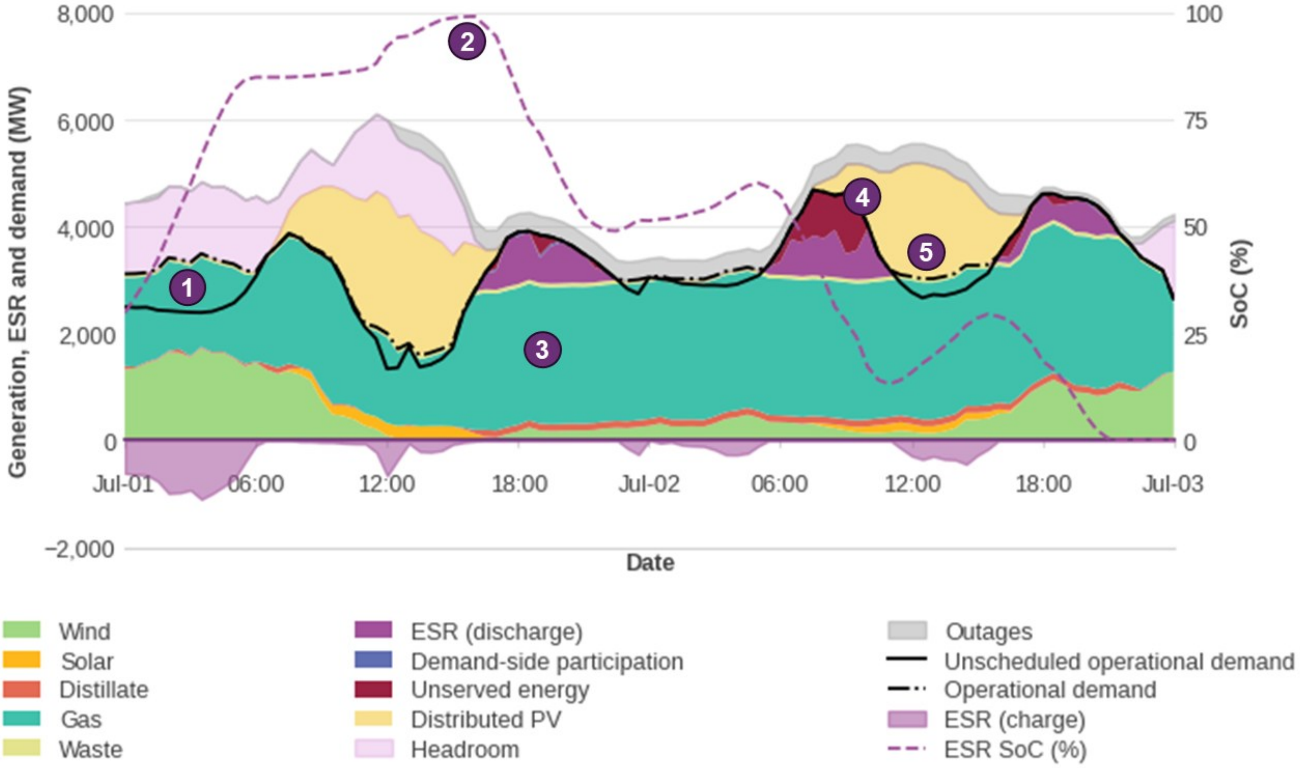
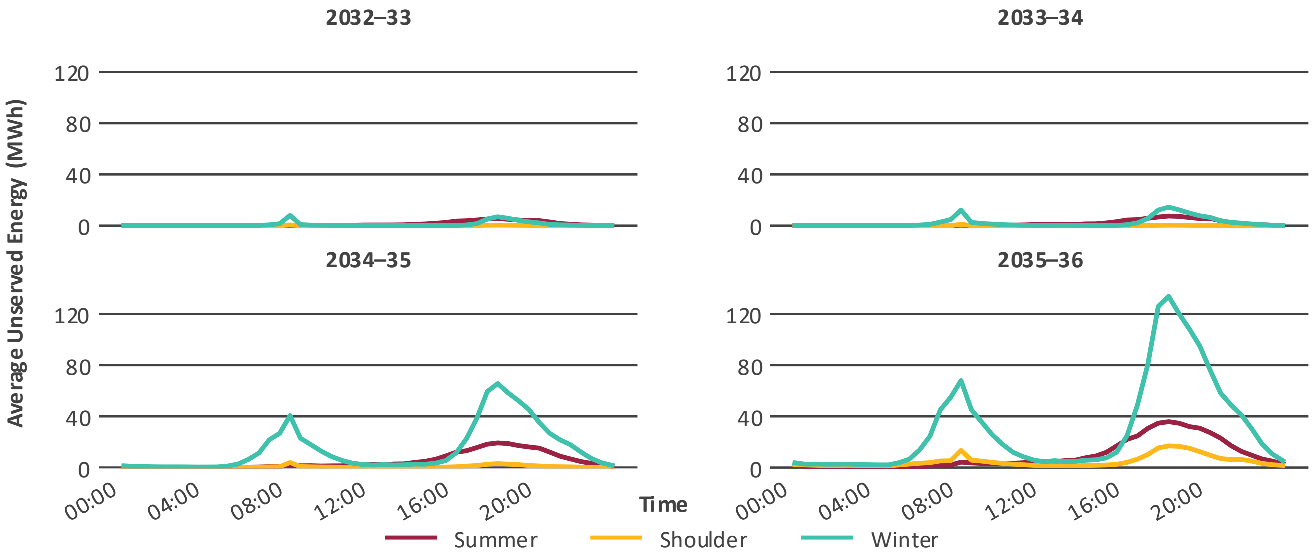


Figure 36 shows the resulting time-of-day distribution of unserved energy across the period from 2032-33 to 2035-36, highlighting the increasing magnitude of USE. By the end of the outlook period, winter USE events dominate due to increasing forecast winter operational demand.

Figure 36 Modelled time-of-day distribution of unserved energy across the period from 2032-33 to 2035-36 (MWh)



Recently observed challenges to reliability of supply in the SWIS

On 25 August 2025, a severe cold front drove a record lowest daily maximum temperature of 11.4 °C in Perth, lower than forecast. Heavy cloud cover with intermittent breaks caused low PV generation output and large intra-day PV fluctuations.

This produced rapid swings in forecast unscheduled operational demand of up to approximately 1 GW within an hour and led to significant short-term forecasting errors. These conditions materially increased electricity demand levels and volatility across both daytime and evening periods compared to forecasts, with the absence of a midday demand trough.

Consequently, there was a heavy reliance on gas-fired generation and grid-scale battery storage systems for both energy supply and the provision of Frequency Co-optimised Essential System Services (FCESS). The elevated daytime demand and high Energy Market Clearing Prices limited opportunities for batteries to charge at low prices. As a result, overall state of charge (SOC) for battery Facilities in the SWIS was less than 40% at the start of the ESROD period commencing at 17:30.

As the day progressed, the forecast error was compounded by Forced Outages to multiple thermal generators, and failure of some Facilities to convert Available Capacity to In-Service in response to forecast market shortfalls. During the evening peak, Unscheduled operational demand reached 3,917 MW, the second-highest winter peak on record.

Retrospective analysis identified that Lack of Reserve 1 (LOR1) conditions had been present. Post-peak, there was a sustained high gas-fired generation requirement, with gas transport volumes needed by gas-fired generation exceeding contractual and nominated quantities, causing insufficient pressure on the Dampier to Bunbury Natural Gas Pipeline (DBNGP). AEMO was required to intervene in the Real-Time Market to reduce gas-fired generation in the affected Kwinana region and increase output from alternative sources, to maintain Power System Security and the integrity of the gas network.

The events of 25 August 2025 highlighted the interdependency of the gas and electricity systems in Western Australia and how operational challenges of the gas system may impact power supply in the SWIS.

Under clause 3.8.3 of the ESM Rules, AEMO is required to publish a public report on such events. A full incident report on the events of 25 August 2025 is scheduled for publication later this year.

Events such as this highlight the increasing complexity of managing the SWIS under growing supply- and demand-side uncertainty. AEMO is actively progressing enhancements to its reliability modelling to better capture these conditions, including improved representation of imperfect foresight and its impact on storage behaviour. Enhancements to modelling of fuel limits and alternative fuels will also support assessment of similar events in future ESOOs.

5.5 Flexible capacity requirement (Limb C)

Table 36 shows the results of the assessment to determine whether there is adequate supply flexibility to cover the four-hour midday to evening demand ramp, and in line with the methodology described in Appendix A4.4.

The Flexible RCT is determined as the sum of the highest forecast FHDI expected in the relevant Capacity Year and a reserve margin. Both the 10% POE and 50% POE demand is used in this assessment and the determination of FHDI based on the higher of the two. The reserve margin is calculated as the highest FHDI multiplied by the proportion of flexible capacity expected to be unavailable at the time of the highest forecast FHDI due to Forced Outages. The proportion of flexible capacity expected to be unavailable at the time of the highest forecast FHDI due to Forced Outages is calculated by taking the average weighted historical Forced Outage rates for existing Facilities, or generic Forced Outage data for new Facilities. For more details on the methodology, see Appendix A4.4.

Table 36 Limb C building blocks and the total amount of capacity needed to satisfy the Flexible Reserve Capacity Target (MW)

Capacity Year	10% POE, Expected			50% POE, Expected			Flexible RCT
	FHDI	Equivalent demand ramp rate in MW/min	Reserve margin[A]	FHDI	Equivalent demand ramp rate in MW/min	Reserve margin[A]	
2026-27	2,437	10	92	2,362	10	89	2,529
2027-28	2,446	10	92	2,381	10	90	2,539
2028-29	2,531	11	86	2,472	10	84	2,617
2029-30	2,649	11	89	2,571	11	86	2,738
2030-31	2,792	12	90	2,719	11	88	2,882
2031-32	2,951	12	85	2,869	12	83	3,037
2032-33	2,956	12	48	2,891	12	47	3,004
2033-34	3,013	13	48	2,953	12	47	3,061
2034-35	3,047	13	46	3,006	13	45	3,093
2035-36	3,156	13	48	3,072	13	47	3,204

A. Refers to reserve margin under clause 4.5.9(c) of the ESM Rules.

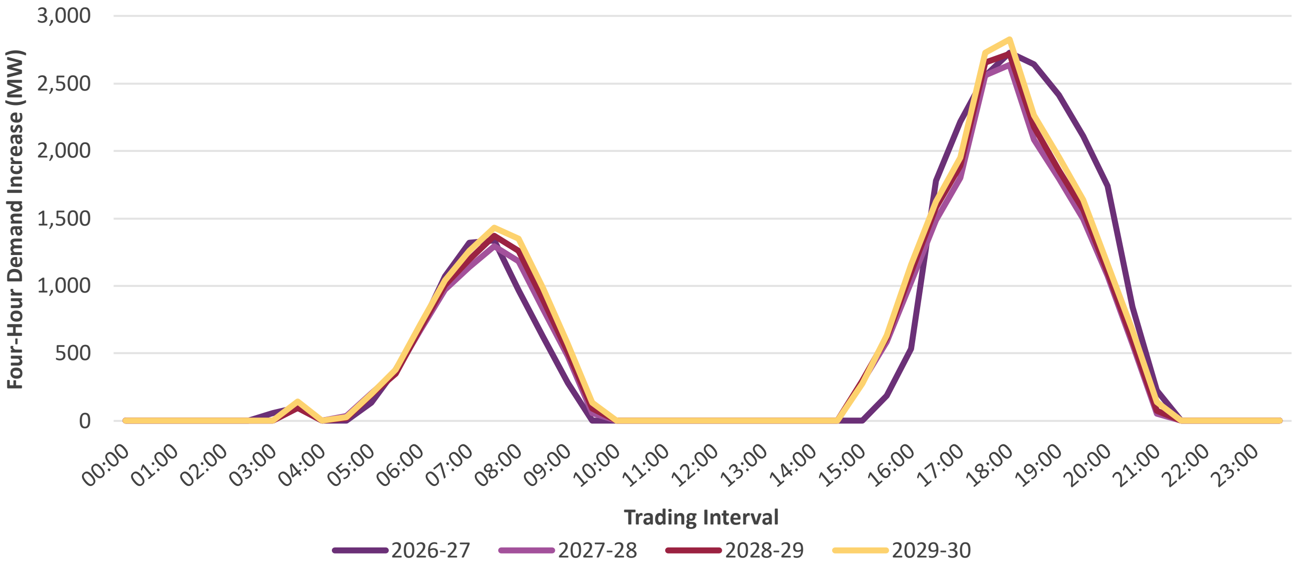
The growth in forecast FHDI is driven by the increasing spread between daily maximum and minimum operational demand, which in turn results in a greater slope (ramp) measured over the period of four contiguous hours.

Figure 37 shows the forecast FHDI for four selected Capacity Years, on days when the annual maximum FHDI was observed. The forecast FHDI exhibits two peaks, with a smaller morning peak and a larger evening peak.

The first peak in forecast FHDI occurs at the 7:30 Trading Interval, where demand gradually increases and reaches its morning peak. In contrast, the second peak forecast FHDI is significantly higher, by around 1,400 MW, with the maximum forecast FHDI recorded at the 18:00 Trading Interval. This increase in the forecast FHDI is driven by an increase in demand as distributed PV output declines with the onset of sunset.

The year-on-year increasing trend in the maximum FHDI indicates a growing need for flexible capacity to meet the upward ramp of operational demand. While batteries can ramp quickly and help alleviate the risk of a capacity shortfall, batteries are only effective if sufficiently charged to provide capacity and energy over a sufficient duration.

Figure 37 Annual maximum Four-Hour Demand Increase for 2026-27 to 2029-30 (MW)



Note: For a Trading Interval *i*, the FHDI is the maximum of 0 and the difference between demand at Trading Interval *i* and Trading Interval *i*-8.

5.6 Peak Reserve Capacity Target and Flexible Reserve Capacity Target

The Peak RCT for 2028-29 is 6,323 MW, which sets the RCR for the 2026 Reserve Capacity Cycle. This is 7 MW lower than the 2028-29 Peak RCT forecast in the 2025 WEM ESOO. The lower RCT for this Capacity Year is driven by the reduction in reserve margin and Regulation Raise components of Limb A which offset the increase in ESR Duration Requirement Uplift in this WEM ESOO, compared to the 2025 WEM ESOO.

Targets from 2029-30 are higher than that set in 2025 WEM ESOO, primarily due to the higher forecast peak demand and higher ESR Duration Requirement Uplift. There is a projected growing shortfall from 2029-30 (detail in Section 5.7 below) that highlights a sustained need for further capacity investment to satisfy Limb A.

Table 37 shows the Peak RCT and Flexible RCT determined for all Capacity Years of the 2026 WEM ESOO horizon. The pink shaded cells highlight the respective RCTs relevant for procurement of the Peak and Flexible Capacity Credits in the 2026 Reserve Capacity Cycle (thereby the RCR for 2028-29), occurring over the next months.

As stipulated in the Planning Criterion, all limbs must be satisfied. The determination of Limb A RCT is discussed in Section 5.3. The determination of Limb B RCT is required if USE exceeds 0.0002% as discussed in Section 5.4. The Peak RCT for each Capacity Year in the 2026 WEM ESOO outlook period is determined as the maximum of RCT determined by the Limb A and Limb B RCTs.

In this outlook period the Peak RCT, only for 2026-27 is set by Limb B. As already discussed, this is primarily driven by forecast increasing peak demand, with energy shortfalls largely occurring after 20:00 when DSP is no longer available and six-hour batteries are largely exhausted. The Peak RCT for all other Capacity Years is set by Limb A, primarily driven by the inclusion of the updated ESR Duration Requirement Uplift and forecast of increasing peak demand.

Table 37 Peak Reserve Capacity Target and Flexible Reserve Capacity Target (MW)

Capacity Year	Peak RCT set by	Peak RCT	Flexible RCT
2026-27	Limb B	5,720	2,529
2027-28	Limb A	6,121	2,539
2028-29	Limb A	6,323	2,617
2029-30	Limb A	6,475	2,738
2030-31	Limb A	6,644	2,882
2031-32	Limb A	6,807	3,037
2032-33	Limb A	6,897	3,004
2033-34	Limb A	6,997	3,061
2034-35	Limb A	7,197	3,093
2025-36	Limb A	7,454	3,204

5.7 Supply-demand balance for peak capacity and flexible capacity

5.7.1 Peak capacity

The comparison of the forecast Peak RCT with the forecast peak capacity for the 2026 WEM ESOO outlook period shows that more capacity will need to be procured through the RCM from 2029-30 and onwards to satisfy the Planning Criterion. **Table 38** and **Figure 38** present this comparison in each Capacity Year of this outlook period for the *Expected* scenario.

The *Expected* scenario considers only existing and committed capacity in the forecast supply. Under the *Expected* scenario, AEMO forecasts:

- A surplus of forecast peak capacity from 2026-27 to 2028-29 with maximum surplus at 347 MW in 2028-29. This surplus is subject to timely delivery of assumed committed projects, continuation of existing projects and retirement or unavailability as per assumptions in this WEM ESOO.
- Procurement of SC is not likely to be required for the 2026-27 summer. This follows AEMO's assessment of the likelihood that some delayed but committed projects will be able to connect and commission for the 2026-27 Hot Season, supplementing the available existing capacity. This provides sufficient forecast peak capacity to provide service during the coming Hot Season.
- A surplus of forecast peak capacity during the first three years of this outlook period is primarily driven by higher forecast supply of peak capacity from existing and committed Facilities, including a total of 3,127 MW gas-fired generators and 1,666 MW of large-scale batteries. This forecast supply is also supported by the extension of the State Agreement in Collie, which allows for continued operation of the Griffin Coal Mine and reduces uncertainty over coal supply in the Collie region in the short term.
- A growing shortfall from 166 MW in 2029-30 to 2,161 MW by the end of the outlook period in 2035-36, due to coincident increased demand and assumed:
  - Unavailability of Bluewaters Power Station from 2031-32, and
  - Progressive retirement of most of Synergy's Pinjar units from 2031-32.

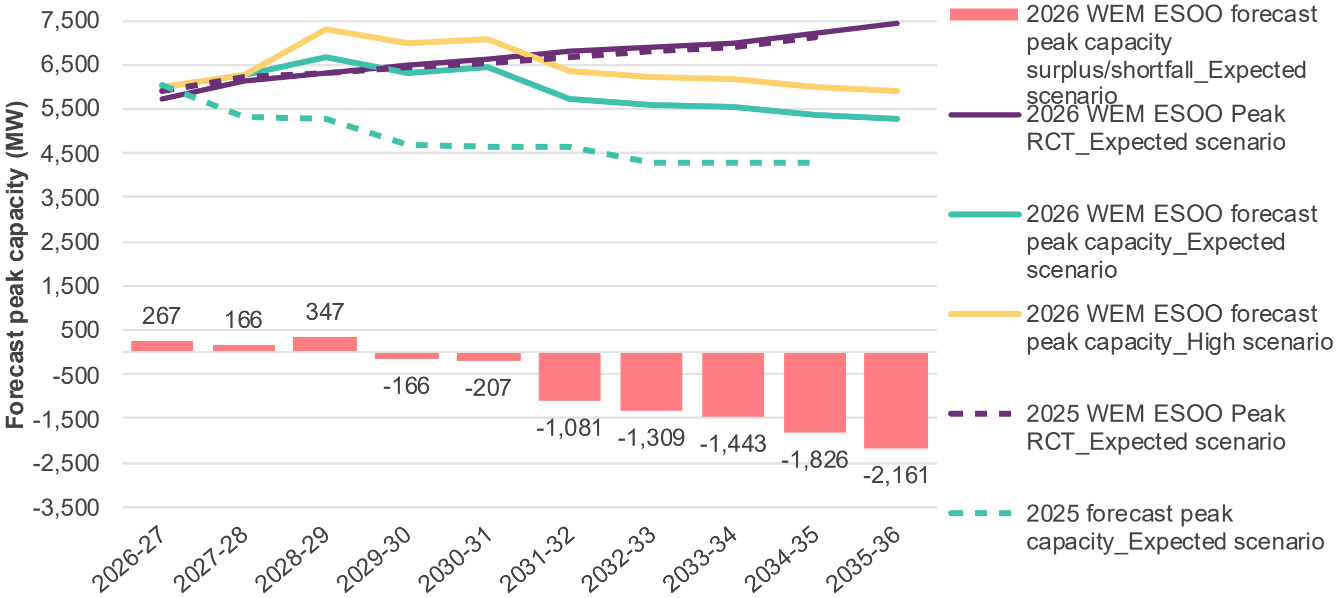
- If anticipated Facilities are assumed to be committed, the shortfall would be delayed until to 2031-32 but also be reduced by at least 596 MW from 2031-32 to 2035-36. This is further detailed after **Figure 38**.

Table 38 Supply-demand balance, forecast Peak Reserve Capacity Targets compared with forecast supply from existing, committed and anticipated Facilities, 2026-27 to 2035-36[A] (MW)

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Forecast Peak RCT[B] (MW)	5,720	6,121	6,323	6,475	6,644	6,807	6,897	6,997	7,197	7,454
Forecast capacity[C] from existing Facilities, without Bluewaters	5,291	5,142	5,107	4,669	4,644	4,375	4,245	4,217	4,041	3,971
Assumed availability of Bluewaters up to 2030-31	434	434	434	434	434	0	0	0	0	0
Forecast capacity[C] from committed Facilities	262	711	889	967	1,119	1,111	1,103	1,097	1,090	1,081
Estimated RLM uplift capacity	-	-	240	240	240	240	240	240	240	240
Total forecast peak capacity from existing and committed Facilities[C]	5,987	6,287	6,670	6,310	6,438	5,727	5,588	5,554	5,371	5,293
Peak capacity surplus / shortfall	**267**	**166**	**347**	**-166**	**-207**	**-1,081**	**-1,309**	**-1,443**	**-1,826**	**-2,161**
Forecast capacity from anticipated Facilities	0	0	622	675	661	648	636	623	610	596
Peak capacity surplus / shortfall with inclusion of anticipated Facilities	**267**	**166**	**969**	**510**	**454**	**-432**	**-673**	**-820**	**-1,216**	**-1,565**

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 for this outlook period. The RCTs for the 2026-27 and 2027-28 are updated in the 2026 LT PASA Study to reflect the current forecasts for reliability assessment of the SWIS. The RCRs for 2026-27 and 2027-28 are 5,696 MW and 6,238 MW, as determined in the 2024 and 2025 WEM ESOOs respectively. RCRs for these two years were the basis for procurement of Peak Capacity in the 2024 and 2025 Reserve Capacity Cycles. RCT determined for 2028-29 is the RCR for 2026 LT PASA and is the basis for procurement of Peak Capacity in the 2026 Reserve Capacity Cycle (set to occur over the next months). From 2029-30 and onwards, the Reserve Capacity Cycles have not commenced.
C. This forecast existing and committed capacity include Facilities with existing obligations such as Facility's obligation for providing Capacity Credits and Peak Demand NCESS or provided evidence for significant development towards providing forecast capacity. Forecast anticipated capacity include project that are evaluated as relatively less mature. The capacity categorisation and detail discussion is as provided in **Sections 3.1 and 3.2**.

Figure 38 Forecast supply-demand balance of peak capacity, *Expected* and *High* scenarios, 2026-27 to 2035-36 (MW)



If projects classified as 'anticipated' becomes committed for future Capacity Years, a surplus may be maintained through to 2031-32 with a surplus of at least 622 MW from 2028-29 to 2030-31. However, almost all of the anticipated Facilities currently in the pipeline for development are grid-scale battery storage, whose contribution to reliability is limited by the state of charge. This reinforces the need for additional energy-producing capacity to enter the SWIS.

EOIs received at the commencement of this 2026 Reserve Capacity Cycle demonstrated that investment interest in the WEM remains strong[69]. The majority of these are battery storage, and many are only in the early stages of project development, either with no network Access Proposal or incomplete land or development Approvals. These projects are too early stage to be included in the supply forecasts when measured against the capacity classification criteria defined in Section 3.1 and Appendix A2.1.

5.7.2 Flexible capacity

Flexible RCT is determined for the first time in the 2025 WEM ESOO, applicable from the 2025 Reserve Capacity Cycle onwards (from 2027-28 onwards). **Table 39** and **Figure 39** present the forecast supply-demand balance of flexible capacity across the outlook period, starting from 2027-28.

Table 39 Supply-demand balance of flexible capacity, *Expected* scenario, 2027-28 to 2035-36

	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Flexible RCT (MW)	2,539	2,617	2,738	2,882	3,037	3,004	3,061	3,093	3,204
Forecast flexible capacity (MW)	3,996	4,522	4,584	4,721	4,526	4,389	4,355	4,223	4,145
Flexible capacity shortfall (-) or surplus (MW)	1,457	1,905	1,847	1,839	1,490	1,385	1,294	1,130	941

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. Assignment of Flexible Capacity Credits has commenced in 2027-28. Thus, the Flexible RCT and forecast flexible capacity for 2026-27 are not presented.

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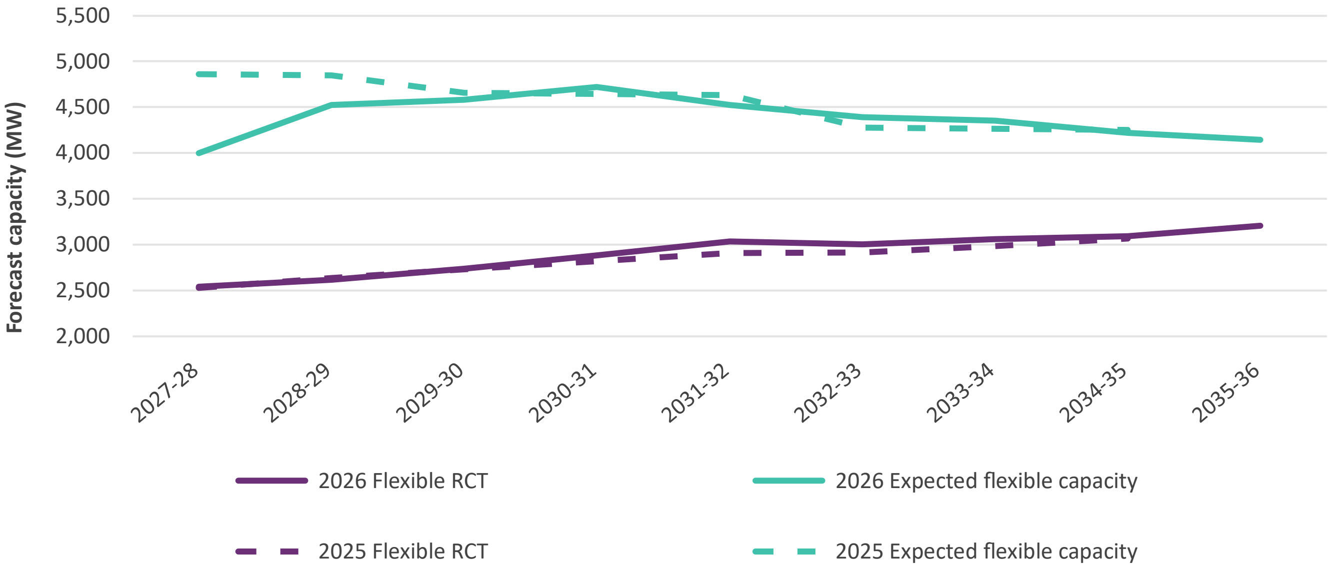
[69] See 2026 EOI summary report, 2026, at https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2026/2026-expression-of-interest-summary-report.pdf.

Figure 39 Forecast supply-demand balance of flexible capacity, *Expected* scenario, 2027-28 to 2035-36 (MW)



For further details on the technologies with flexible capacity assigned in the 2025 Reserve Capacity Cycle, please refer to **Section 5.5**. AEMO forecasts adequate flexible capacity for the entire outlook period, with the surplus more than 1,900 MW for 2028-29 and gradually reducing to about 900 MW by 2035-36. This reduction in surplus capacity is driven by the following factors:

- an increase in the forecast FHDIs, and
- the retirement of gas-fired generators, which contributes to around 400 MW of surplus capacity reduction.

The forecast flexible capacity fleet mix, presented in **Section 5.5**, showed that the majority of the Facilities forecast to provide flexible capacity in the *Expected* scenario are gas-fired generators. As thermal generation leaves the market, particularly gas (which is typically fast-starting and flexible), it must be replaced by capacity that has a quick ramp rate, low minimal stable loading levels, and fast start times.

Battery storage, which constitutes a significant portion of the forecast flexible capacity fleet mix (as detailed in **Section 5.5**), is able to ramp quickly but is only effective if sufficiently charged. As overall electricity consumption increases and peak demand rises, there is a risk grid-scale batteries will not be fully charged and ready to deploy to meet sudden increases in demand. Batteries therefore must be complemented with a sufficient energy-producing capacity to make sure batteries are charged, and that there is enough fast-start generation to deploy during high demand intervals.

5.8 Capability Class assessment

In the event of USE exceeding 0.0002%, the Capability Class assessment seeks to determine whether Capability Class 2 (Batteries and DSP) can mitigate the shortfalls and reduce USE below the threshold.

If Capability Class 2 resources alone are unable to reduce USE below the threshold new Capability Class 1 (dispatchable firm capacity) and Capability Class 3 (intermittent capacity) are prioritised in the RCM.

In the 2025 WEM ESOO, AEMO undertook a Capability Class assessment due to forecast USE exceeding the threshold in 2027-28. AEMO found the addition of batteries alone was unable to meet the USE threshold, leading to prioritisation of new generation in the 2025 Reserve Capacity Cycle.

In the 2026 WEM ESOO, forecast existing and committed capacity exceeds the RCR, and USE forecast for Limb B does not exceed the 0.0002% threshold for 2028-29. Therefore, no formal determination under the Capability Class assessment is required.

5.9 Availability Curves

The Availability Curve[70] is a two-dimensional duration curve of forecast minimum capacity requirement for each Trading Interval over a Capacity Year. It shows the demand arranged in a descending order for all Trading Intervals of a Capacity Year, with demand on the vertical axis and Trading Intervals on the horizontal axis. 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, Regulation Raise, and ESR Duration Requirement Uplift (for the applicable Capacity Years).

Availability Curves for the SWIS consistently show that extreme peaking capacity requirements are limited to only a small number of Trading Intervals, which provides an indication for Participants of the potential utilisation of capacity for the relevant Capacity Year. These curves reinforce the importance of the RCM to ensure fleet sufficiency across peak events of limited annual duration. Whilst the curves provide an indication of the need for capacity across a whole year, they do not consider the timing and duration of these needs.

The reliability results presented in previous sections highlight the additional complexity associated with supply side limits such as the variability and intermittency of renewable resources, storage duration limits, and prescribed availability windows and limits on the number of activations for DSP. These limits mean that there is a residual need for firm generation.

The Availability Curves for 2027-28 and 2028-29 are shown in **Figure 40**. These curves 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.

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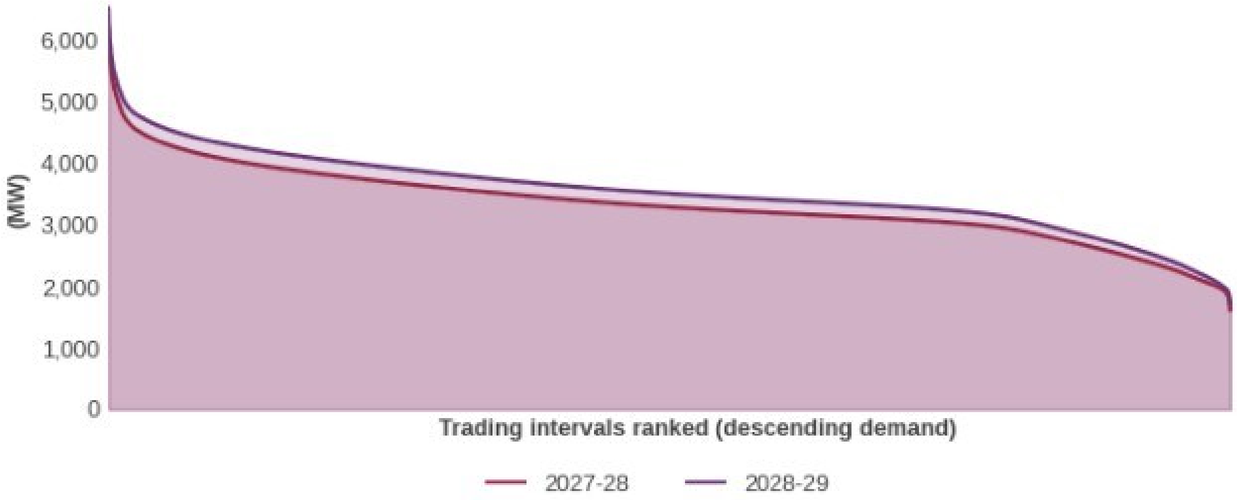
[70] The Availability Curve is defined in clause 4.5.10(e) of the ESM Rules, and is required for the second and third Capacity Year of the Long Term PASA Study Horizon under clause 4.5.13(f). The Availability Curves are determined by developing a half-hourly load profile, which is based upon a series 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. Note that for both Availability Curves (more noticeable for 2027-28) the lower end of demand remains constant at a minimum of 300 MW as a result of the implementation of a minimum demand threshold in reliability modelling.

Figure 40 Availability Curve, 2027-28 and 2028-29 (MW)



6 Network congestion and sub-regional reliability shortfall assessment

In addition to the reliability assessment presented in Section 5, AEMO undertakes reliability assessments with network constraints to provide an indication of the impacts of network congestion on the ability of supply to meet demand.

- Network congestion can limit the ability of generation and battery storage to export (and import) their full capacity. This assessment examines the impact of network congestion in SWIS sub-regions: North, East, Metro South and South.
- Across all sub-regions, generation curtailment due to network congestion is modelled to rise from 0.2% in 2026-27 to a maximum of 2.7% by 2031-32. However, unserved energy is expected to remain within the reliability standard.
- When considering the addition of sub-regional unserved energy, aligned with previous WEM ESOOs, total unserved energy is modelled to exceed the threshold in some regions throughout the outlook horizon.
- In the near term, sub-regional shortfalls are likely to be managed through operational measures by Western Power. Beyond this, some of these shortfalls are anticipated to be addressed through delivery of committed Clean Energy Link projects, or by future Clean Energy Link investments highlighted in the WA Government's *SWIS Transmission Plan*. Others may require a combination of solutions, including local generation (potentially supported through coordinated aggregation of DER and demand flexibility) and targeted transmission investment. Network limitations and mitigants are considered in Western Power's annual *Transmission System Plan*.

Please note, this network modelling presents a high level view of the system nodes. For more detail, see Western Power's *Transmission System Plan*.

6.1 Introduction

In addition to the unconstrained reliability outlook presented in Section 5, the ESM Rules require AEMO to assess reliability outcomes in the SWIS, taking into account network congestion.

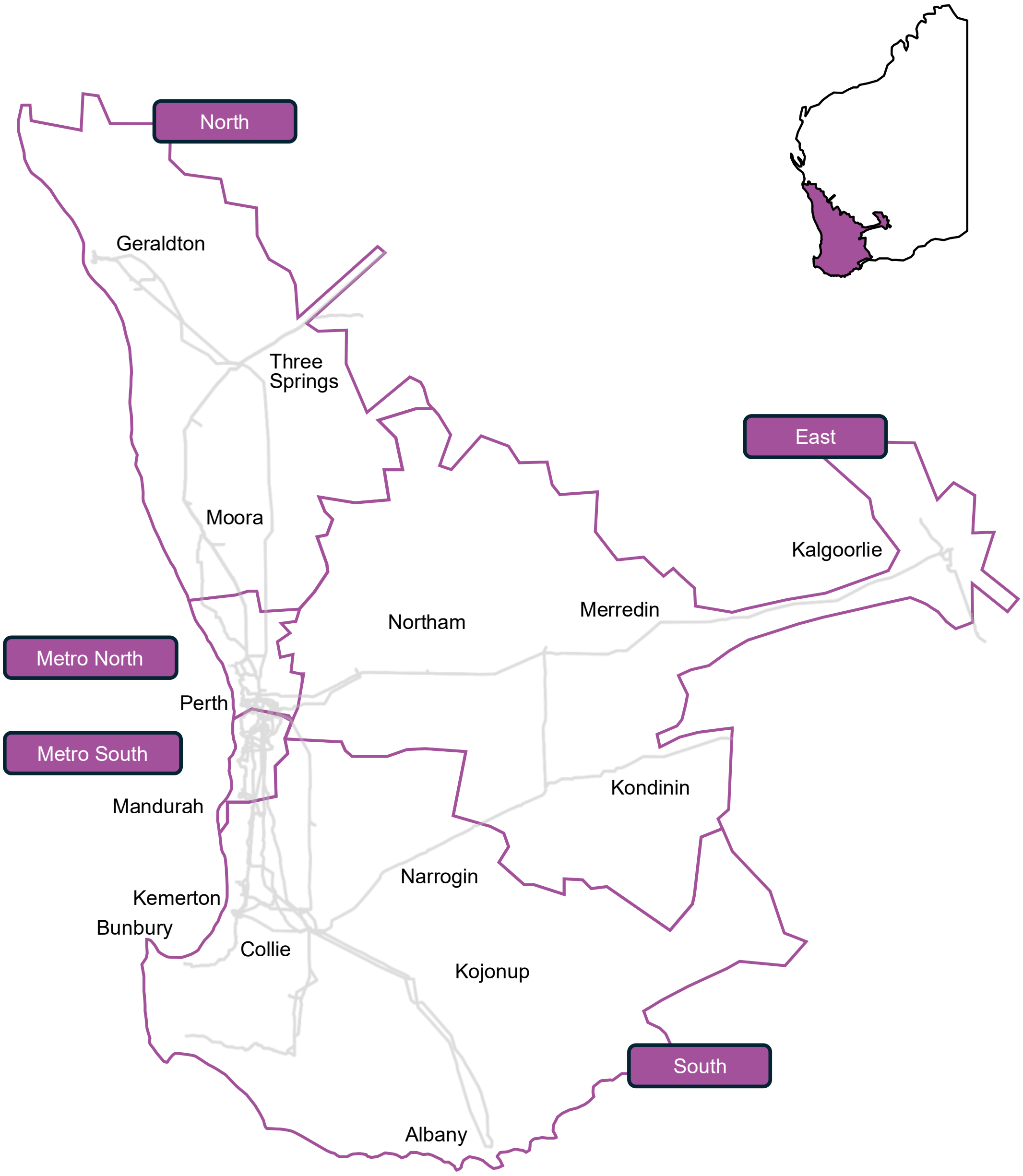
The ESM Rules also require AEMO to identify and assess any potential capacity shortfalls isolated to a sub-region of the SWIS resulting from forecast restrictions on transmission capability or other factors, which cannot be addressed by additional peak capacity outside that sub-region.

AEMO's assessment of the impact of network constraints relies on simplified assumptions relating to the tools available to manage the transmission network. As such, identified constraints will require more detailed assessment. The approach is described in the remainder of Section 6.1 and detailed further in Appendix A4.3. Western Power undertakes transmission planning through the annual Transmission System Plan.

This assessment of congestion uses the same electricity market dispatch modelling framework as the Limb B assessment in Section 5 but implements network constraint equations that are formulated in a similar way as the constraints used in AEMO's ST PASA and MT PASA.

These network constraints[71] can, at times, prevent power flows from one sub-region of the SWIS to another and potentially result in load curtailment in a specific sub-region. USE could be reduced in these instances either through investment in additional local supply within the sub-region, or through network augmentations to alleviate the constraints.

Figure 41 Sub-regions of the SWIS



The sub-regional assessment may also identify USE occurring at the SWIS Reference Node (RN), which is the 330 kV bus-bar of Southern Terminal. This may indicate a system-wide lack of supply, due to shortfalls in generation, including as a result of network congestion. Network congestion can limit the ability of generation and battery storage from exporting (and importing) their full capacity. The assessment also examines the impact of network congestion on facility dispatch in the different sub-regions of the SWIS.

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[71] Transmission network transfer limits due to thermal ratings of line circuits, or system stability requirements.

The WEM ESOO assumes a transmission augmentation project to be 'committed' if it has received confirmed funding. In the assessment, and based on input from Western Power, the following committed network augmentations have been included in the modelling:

- Clean Energy Link (CEL) North was modelled as a single stage that is assumed to be in service from 1 January 2028.
- CEL East Enhancement Stage 1 was modelled to be in service from 1 October 2026.
- Stage 2 of CEL East Enhancement was modelled to be in service from 1 January 2027.
- While the recently committed CEL East was not modelled, AEMO did not model any committed generation which would have benefitted from this augmentation. AEMO expects future WEM ESOOs will see new committed generation leveraging this augmentation.
- No other major network augmentations were considered committed, although AEMO notes that the CEL program includes several augmentations, including CEL Kwinana, which may be implemented in the outlook horizon and may materially improve the assessment findings[72].

6.1.1 Sub-regional modelled unserved energy

The reliability assessment undertaken under Limb B has forecast a growing capacity shortfall in all years from 2031-32. As discussed in the preceding sections, this is driven primarily by increasing forecast supply shortfalls against the RCT, due to increasing forecast demand and assumed unavailability and retirements of coal and gas power stations.

Sub-regional USE modelling results presented in **Figure 42** align with this observation, where the USE is predominantly observed for the Southern Terminal RN from 2031-32, indicating a general system-wide capacity shortfall that is not isolated to a specific sub-region. These results see slightly higher USE than the unconstrained results, with the increase potentially attributable to network congestion impacts on existing and committed Facilities.

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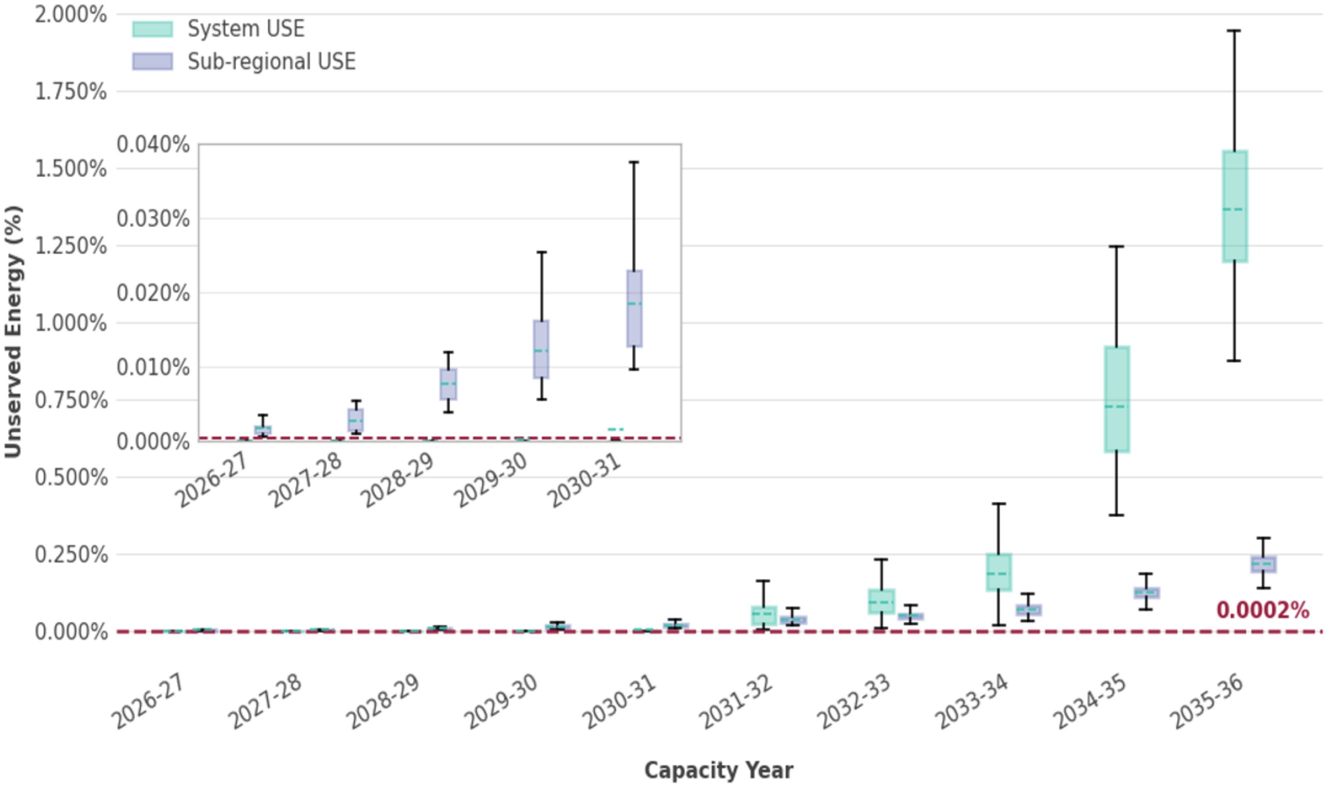
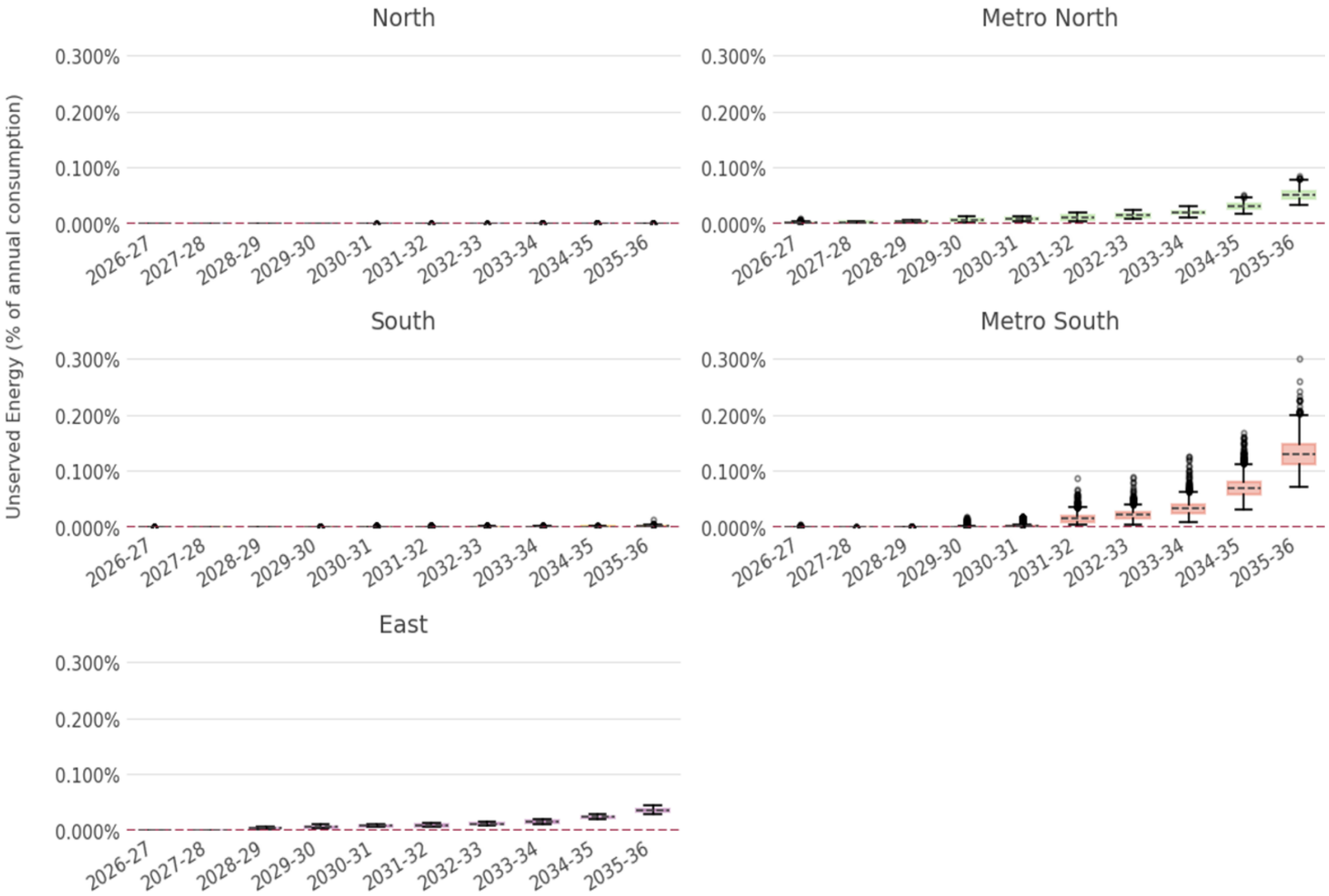
[72] For more details on the CEL program, refer to the *Transmission System Plan* (https://www.westernpower.com.au/resources-education/suppliers/tenders-and-registrations-of-interest/transmission-system-plan--network-opportunity-map/) and SWIS Transmission Plan (https://www.wa.gov.au/organisation/energy-policy-wa/the-south-west-interconnected-system-transmission-plan-future-ready-transmission-network-was-main-electricity-system).

Figure 42 Expected unserved energy at the Reference Node compared to all other network sub-regions, 2026-27 to 2035-36 (% annual consumption)



As **Figure 43** shows, the modelled USE volumes outside the Southern Terminal RN are observed in the East, Metro North, Metro South and South sub-regions.

Figure 43 Expected unserved energy in the East, Metro North, Metro South and South sub-regions (% annual consumption)



East sub-region

In the East sub-region of the SWIS, modelled USE is driven by a non-thermal network limit that constrains the import of electricity to the Eastern Goldfields (EGF) and periods of high demand[73]. It should be noted that AEMO's modelling likely overstates the level of USE in the region as there are several non-market mitigation measures that can alleviate this constraint in practice, for example a number of customers have connected on the basis that they will be supplied electricity when network capacity is available and curtailed when it is not. A protection scheme is in place that automatically notifies such customers that they need to reduce their load, and they are required to respond in a set amount of time. This helps to ensure other existing customer services are not put at risk.

Local generation, storage or targeted demand-side solutions could improve reliability in the region during high demand periods and islanding events. Longer term, transmission development in the Goldfields region could further improve reliability in the region. AEMO notes the WA Government is currently undertaking an expression of interest process for a Vanadium Battery Energy Storage System[74] (BESS) and Western Power is undertaking an NCESS procurement to improve reliability in this region.

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[73] The EGF non-thermal (rotor angle stability) power transfer limit that is managed by Western Power and not included as a real-time constraint in AEMO's Wholesale Electricity Market Dispatch Engine (WEMDE).

[74] See https://stateofenergy.wa.gov.au/wa-energy-system/kalgoorlie-vanadium-battery-energy-storage-system.

Metro North sub-region

The modelled USE in the Metro North sub-region of the SWIS is related to a number of constraints that impact power flows through the sub-region. These shortfalls are primarily load driven, arising during periods of high demand in the Metro North sub-region and are currently being managed by Western Power via operational measures[75]. Modelled USE in some areas is also expected to be resolved by completion of CEL North. Targeted deployment of VPPs and DSP in the region may further reduce modelled USE.

Metro South sub-region

Congestion in the Metro South sub-region is modelled to occur during periods of high demand. CEL East and CEL Kwinana, identified in the WA Government's SWIS Transmission Plan and soon to be named priority projects, may materially reduce modelled USE events.

South sub-region

The USE in the South sub-region of the SWIS is related to the known and pre-existing constraints binding in the area when demand is high. This could be addressed by local generation, battery storage, DSP or transmission. Expansion of the 330 kV transmission network through the CEL East project is expected to increase transfer capacity between eastern regions and major load centres.

6.1.2 Impact of network limitations on system-wide unserved energy

In the first four Capacity Years of the outlook period, network limitations do not contribute to a significant increase in modelled system-wide USE, presented in **Table 40**. SWIS-level USE modelled with Network limitations in these years remained below the reliability standard of 0.0002% set by the Planning Criterion. Instances of sub-regional USE exceeding the reliability standard were observed in all years of the outlook period.

While the determination of the RCT and the assessment of Limb B in the Planning Criterion is assessed without the modelling of transmission network congestion in accordance with the ESM Rules, the presence of transmission network congestion does occur, and can impact the ability of Facilities to be dispatched under particular operating conditions.

This is observed through higher volumes of USE and higher capacity shortfalls in the reliability simulations performed with network constraints compared against reliability simulations without. This means that investment in generation and storage capacity alone is not enough to ensure the WEM meets the reliability standard, as there are circumstances where USE may still occur due to network limitations.

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[75] Operational measures include distribution feeder load transfers and creating open points on the network to manage flows.

Table 40 Modelled unserved energy with and without network constraints, 2026-27 to 2035-36 (%)

Capacity Year	Unit	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35	2035-36
Unconstrained USE	% of annual consumption	0.0000	0.0000	0.0000	0.0000	0.0006	0.0304	0.0525	0.0887	0.4037	0.8886
Constrained system-level USE	% of annual consumption	0.0000	0.0000	0.0000	0.0000	0.0015	0.0521	0.0933	0.1866	0.7236	1.3623
Constrained sub-regional level USE only	% of annual consumption	0.0016	0.0025	0.0076	0.0121	0.0184	0.0366	0.048	0.0686	0.1249	0.218
Constrained USE	% of annual consumption	0.0016[A]	0.0025	0.0076	0.0121	0.0199	0.0887	0.1414	0.2542	0.8485	1.5803

A. This does not mean Limb B of the Planning Criterion is not satisfied in 2026-27. The Planning Criterion is modelled without network constraints.

In the absence of ongoing investment in generation and storage, the assumed unavailability and retirement of existing coal fired power stations in the South sub-region is a key driver of potential system-wide capacity shortfalls. Given that much of the existing 330 kV bulk transmission network has been built to transport power from the Muja/Collie regions to metropolitan demand centres, the retirement of existing coal-fired power stations will make network capacity available along these key 330 kV flow paths. New generation that is connected along these existing 330 kV pathways will be able to use network capacity headroom made available due to these retirements.

6.1.3 Impact of network congestion on Facility dispatch

Network Access Quantity (NAQ) and network congestion

This WEM ESOO modelling of network congestion is not directly comparable to current or future RCM outcomes. Congestion impacts highlighted in this analysis may not align with outcomes of the NAQ framework. The NAQ Framework, a key step in the RCM, is designed to quantify the impacts of network congestion on Facilities' ability to inject their CRC quantity during peak demand scenarios, and hence ensure Capacity Credits may be considered in the assessment against un-constrained Reserve Capacity Targets. The application of the NAQ is the reason AEMO's RCTs are determined without the impact of network congestion.

In the 2025 Reserve Capacity Cycle, there were no impacts of NAQ on assigned Capacity Credits to Facilities. This does not mean AEMO does not expect network congestion to occur, as the NAQ framework:

- assesses impacts only during peak demand intervals,
- only considers curtailment that occurs in more than 95% of possible dispatch profiles during peak events,
- only considers the impact on a Facility's CRC, which for intermittent Facilities is typically much lower than the level they may be capable of producing at other times,
- applies prioritisation steps to inclusion of Facilities, which diverges from operational dispatch which considers pricing and impact to constraints, and
- in some cases, considers the impact of dynamic line ratings, which are yet to be modelled in the WEM ESOO.

The application of network constraints to the market dispatch modelling framework also provides insight into the impact of transmission network congestion on facility dispatch. The preceding analyses identified circumstances in which network limitations impacted the ability of facilities to be dispatched, thus creating capacity shortfalls and USE both at sub-regional and system-wide level.

However, there are also circumstances where Network limitations can be addressed through facility re-dispatch without leading to USE. In market dispatch, facility re-dispatch may be due to binding constraints requiring curtailment of lower cost facilities behind a constraint in favour of dispatching higher cost unconstrained facilities.

Given the significant rise in system-wide capacity shortfalls observed from 2031-32, network congestion can arise in the model due to Facilities in heavily congested parts of the network being dispatched to meet system-wide shortfalls. This is not necessarily representative of the likely impacts of network congestion on facility dispatch, and therefore only outcomes for the period from 2026-27 to 2031-32 are reported.

East sub-region

Network congestion in the East sub-region is driven by thermal constraints on the 220 kV transmission corridor (primarily from flows into Muja via East sub-region generation) and the underlying 132 kV network around Merredin and Kondinin Terminals (see **Figure 44**).

Figure 44 Transmission network and Facilities in the East sub-region

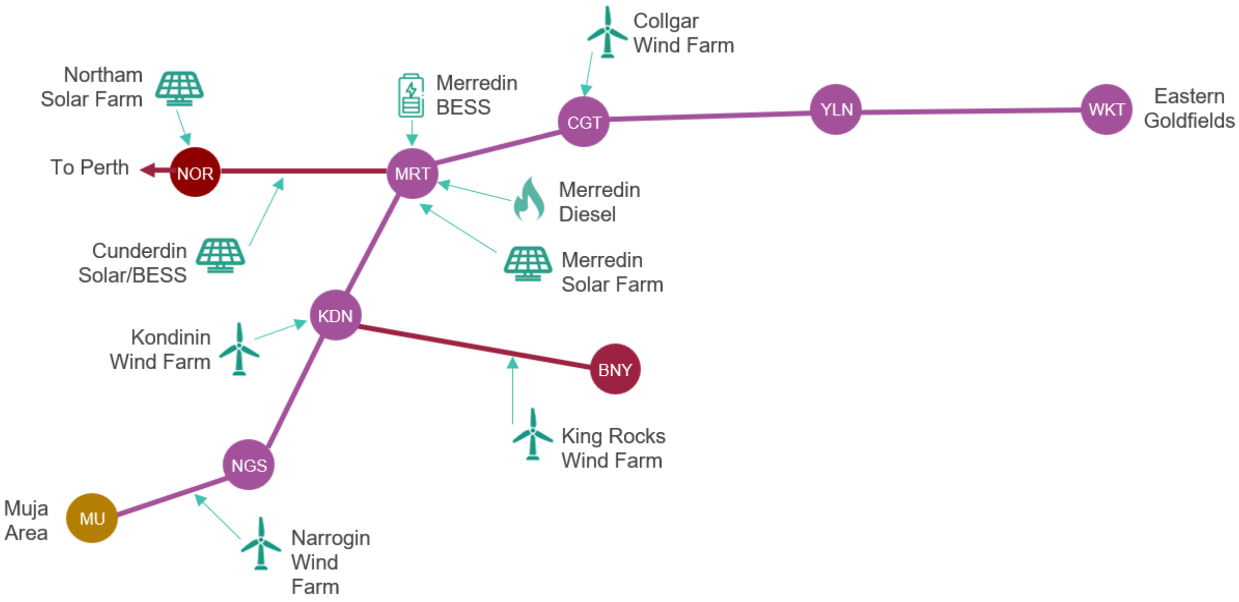

Table 41 presents the aggregate modelled facility curtailment due to network constraints in the East sub-region. Curtailments are negligible in 2026-27, but begin to rise as new entrant generation is connected to the network from 2027-28.

Table 41 Modelled aggregate facility curtailment levels in the East sub-region

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Aggregate Facility Curtailment (%)	0.02%	2.93%	2.45%	3.88%	4.31%	4.17%

Metro South sub-region

In the Metro South sub-region of the SWIS, network congestion is modelled to occur in the Kwinana area – see **Table 42** for the modelled aggregate facility curtailment due to network constraints. Curtailments are relatively low until 2029-30 after Muja D is assumed to retire and increase materially in 2031-32 after Bluewaters Power Station is assumed to be unavailable. This occurs because a large volume of generation is shifted from the Collie area to Kwinana after the assumed unavailability and retirement of the coal-fired generation facilities, which creates stress on the 132 kV network around Kwinana Terminal.

While not modelled in this WEM ESOO, AEMO expects the CEL Kwinana Strengthening project[76] planned for 2030 (Stage 1) and 2033 (Stage 2) to resolve the bottleneck in this area's 132 kV network. Furthermore, the recently announced CEL East project is expected to allow generation east of Collie to make use of the existing 330 kV transmission infrastructure in the Collie area to transport bulk power to the Perth metro area, moving generation away from Kwinana and helping to relieve congestion in the area.

Figure 45 Transmission network and facilities in the Kwinana area

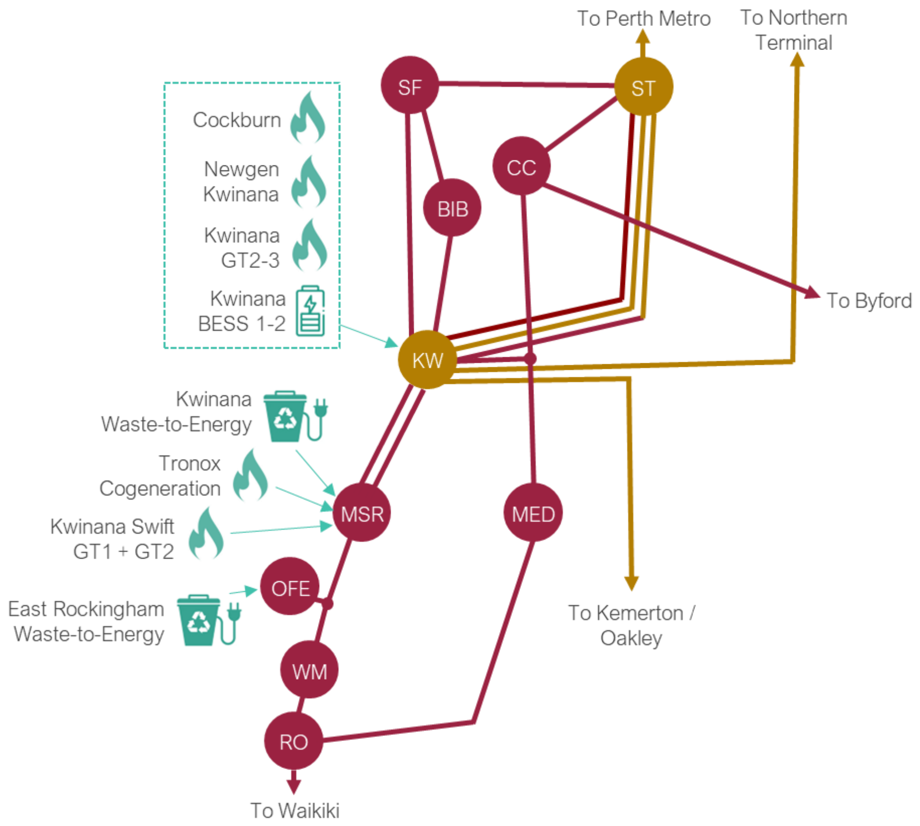

Table 42 Modelled aggregate facility curtailment levels in the Kwinana area (without CEL-Kwinana and CEL East)

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Aggregate Facility Curtailment (%)	0.09%	0.23%	0.27%	1.07%	1.0%	3.6%

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[76] This project is included in both the *SWIS Transmission Plan* and Western Power *Transmission System Plan* and is expected to soon be declared a priority project: see https://www.wa.gov.au/government/media-statements/Cook%20Labor%20Government/Government-plans-WA%27s-clean-energy-future-with-%241.4-billion-fund-20260427.

North sub-region

In the North sub-region of the SWIS, network congestion is modelled to occur in both the Mid West and North Country areas (see **Figure 46**), due to thermal constraints binding after the entry of new generation facilities and the impact of rising demand.

Figure 46 Transmission network and Facilities in the North sub-region

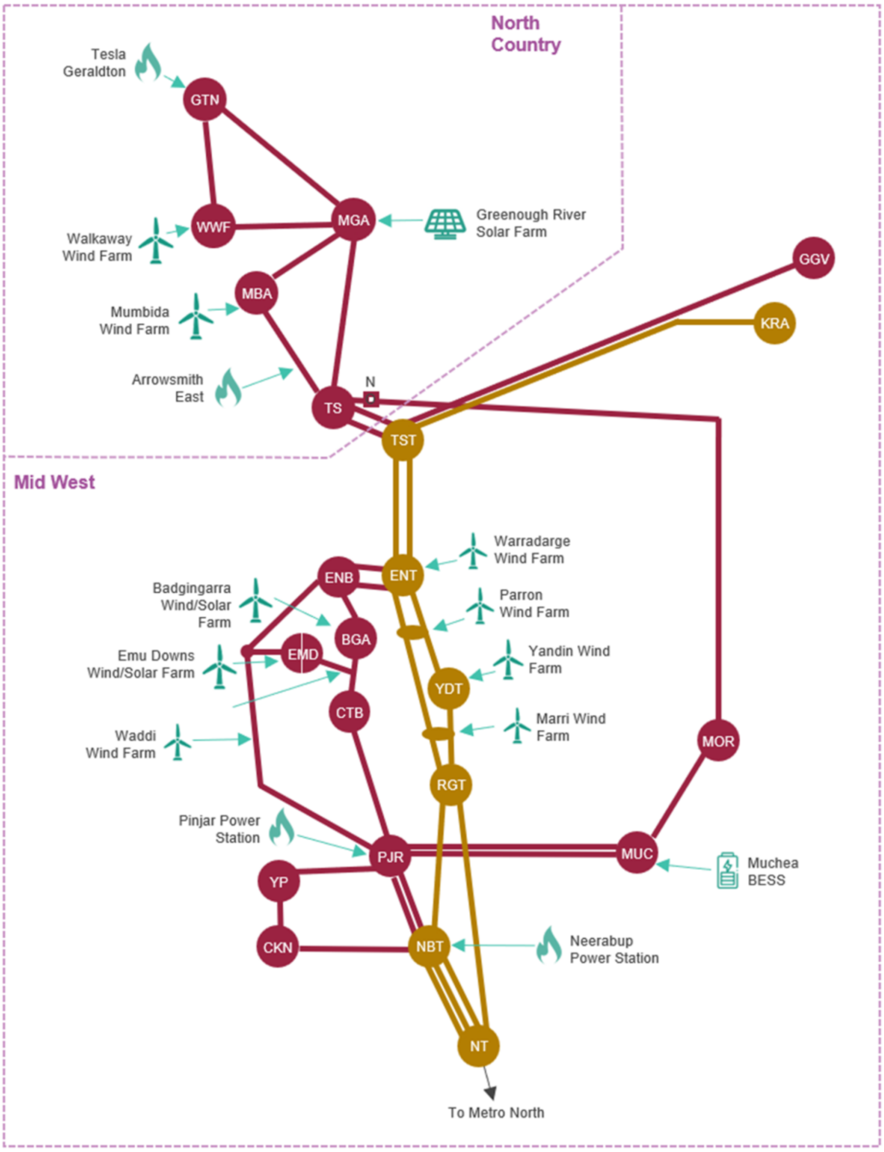

Table 43 presents the aggregate modelled curtailment for facilities connected to the 132 kV and 330 kV network in the Mid West area. There is a relatively small volume of curtailment in the 132 kV network for 2026-27, consistent with current levels of congestion in the area. There is a large increase in modelled congestion in 2027-28 that is attributed to projected new entrants. Congestion is modelled to decrease in 2028-29 after CEL North is completed, which alleviates congestion in the 132 kV network by re-directing power flows to the 330 kV corridor.

The aggregate modelled curtailment for facilities connected to the 330 kV network in the Mid West is negligible from 2026-27 to 2029-30, even after CEL North is completed and the first of the new entrant wind farms is connected. However, aggregate curtailment is modelled to increase on the 330 kV CEL North corridor from 2030-31 when further wind farms are projected to connect.

Table 43 Modelled aggregate curtailment levels for facilities connected to the 132 kV and 330 kV Mid West network

Capacity year/Voltage network (kV) curtailment (%)	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
132 kV	0.72%	4.66%	3.5%	3.48%	3.53%	3.5%
330 kV	0.0%	0.0%	0.08%	0.0%	4.19%	4.47%

Table 44 presents the aggregate modelled facility curtailment due to network constraints in the North Country area. There is a moderate level of congestion observed from 2026-27 to 2030-31. This congestion steadily worsens from 2031-32 due to an increased requirement for North Country generation as a result of generalised system-wide capacity shortfalls.

Table 44 Modelled aggregate Facility curtailment levels in the North Country area

Capacity Year	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Aggregate Facility Curtailment (%)	1.31%	2.35%	2.46%	3.24%	3.23%	4.73%

6.1.4 Potential transmission network options to support the SWIS

Transmission network development is driven by a combination of factors including (but not limited to) locations where new generation capacity is developed and where transmission network constraints may limit power to be transferred to sub-regional areas contributing to USE risk.

The WEM ESOO is required to identify potential supply and transmission capacity options that would alleviate shortfalls. Western Power further assesses the need for transmission network augmentations through its annual Transmission System Plan Process and network investment framework, while the WA State Government's *WOSP* and *SWIS Transmission Plan* also present a view of how new generation and network can be co-ordinated.

Potential options that may assist in mitigating capacity shortfalls on the SWIS are discussed in Section 7.

7 Opportunities for investment in supply and transmission

As electricity demand and consumption are forecast to continue to grow across the SWIS, substantial investment in generation, storage and transmission network infrastructure will be required over the next decade.

Recent investment in large-scale storage and the commitment of over 1,000 MW of wind generation projects has improved the near-term reliability outlook for the SWIS. However, maintaining reliability as coal-fired generation retires will require a mix of technologies and Facilities.

This section highlights opportunities and drivers for investment in the SWIS over the next 10 years. In summary:

- Forecast peak demand is higher in the 2026 WEM ESOO than in the 2025 WEM ESOO. Peak demand is forecast to increase approximately 29% over the 10-year outlook period, while delivered energy consumption is forecast to increase approximately 48%. The growth in demand and consumption will require investment in both supply capacity, and network capacity.
- A peak capacity shortfall of 166 MW is forecast from 2029-30, growing to 2,161 MW by 2035-36. Timely delivery of anticipated Facilities would delay the shortfall to 2031-32.
- A total of 1,139 MW of Capacity Credits was assigned to battery storage in the SWIS for 2025-26, and a further 399 MW of committed storage is forecast to be operational by 2028-29. However, the SWIS needs more generation capacity to complement storage and reduce the risk of batteries not being adequately charged when called on to meet demand.
- Key risks include delays to transmission and generation projects, fuel availability, operational complexity associated with a more diverse and distributed power system and changing consumer demand patterns which may increase the variability and uncertainty in peak demand.
- Timely delivery of the Clean Energy Link (CEL) – North project and other major transmission augmentations will be critical to support new generation entry, increase transfer capability and reduce network constraints across the SWIS.

The energy transition is creating significant investment opportunities across generation, storage and transmission infrastructure. The Western Australia Government, Western Power and AEMO are progressing system readiness and transition planning activities to support reliable and secure operation of the SWIS as the power system evolves. The Whole of System Plan, due in 2027, will provide additional long-term context on generation, storage, transmission and system security needs across the SWIS.

The following sections should be read in conjunction with Section 5 and Section 6, which present the reliability outlook for peak and flexible capacity, including sub-regional network constraints and expected unserved energy.

7.1 Peak and flexible capacity investment opportunities

The SWIS supply mix is changing. As coal-fired generation exits the SWIS, it is being replaced by a portfolio of variable renewable generation, battery storage and demand-side resources. While this portfolio can collectively maintain reliability, it introduces a shift from continuous, dispatchable energy to resources that are weather-dependent, time-limited, or behaviour-driven. This increases exposure to risks associated with:

- the availability and duration of energy during extended peak periods,
- the ability to recharge storage following periods of low renewable output,
- reliance on weather conditions and forecasting accuracy,
- dependence on the behaviour of elements of the system, especially storage, and
- uncertainty related to demand-side response during system stress events.

Maintaining reliability in this environment requires sufficient firming capacity, storage duration, and effective coordination of DER during forecast peak demand intervals.

7.1.1 Sufficient capacity to meet the reliability standard until 2028-29

As outlined in Section 5.7, AEMO forecasts a capacity surplus during the first three years of this outlook period, followed by a shortfall from 2029-30 onwards. The forecast capacity shortfall is 166 MW in 2029-30, growing to 2,161 MW by the end of the outlook period in 2035-36. If anticipated Facilities are included, the emergence of the shortfall is delayed until 2031-32.

The improved near-term outlook relative to the near-term outlook in the 2025 WEM ESOO is supported by over 1,000 MW[77] of newly committed wind generation projects across 2028-29 and 2029-30, underpinned by assignment of Priority Project status by the WA Government[78]. This outlook also assumes the availability of Bluewaters Power station until 2030-31, consistent with the recent extension of its coal supplier's State Agreement up to 2031.

The shortfall from 2031-32, from the start of the second half of the outlook period is largely due to the assumed unavailability of Bluewaters Power Station after 2030-31 and the assumed retirement of Pinjar units and Tiwest cogeneration plant from 2031-32 onwards as outlined in Section 3.

Continued investment in new capacity will be required to maintain reliability over the entire outlook period. Therefore, new capacity should include a balanced mix of generation and storage technologies, including firm generation (such as gas-powered generation meeting the 14-hour fuel requirement), renewable generation such as wind and solar, and longer-duration ESR capacity. The relative contribution of these technologies will depend on the level of uptake of complementary resources. For example, if there is significant renewable generation expected including wind and solar, together with longer-duration ESR capacity, the need for the firm generation could be reduced.

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[77] Nameplate capacity.

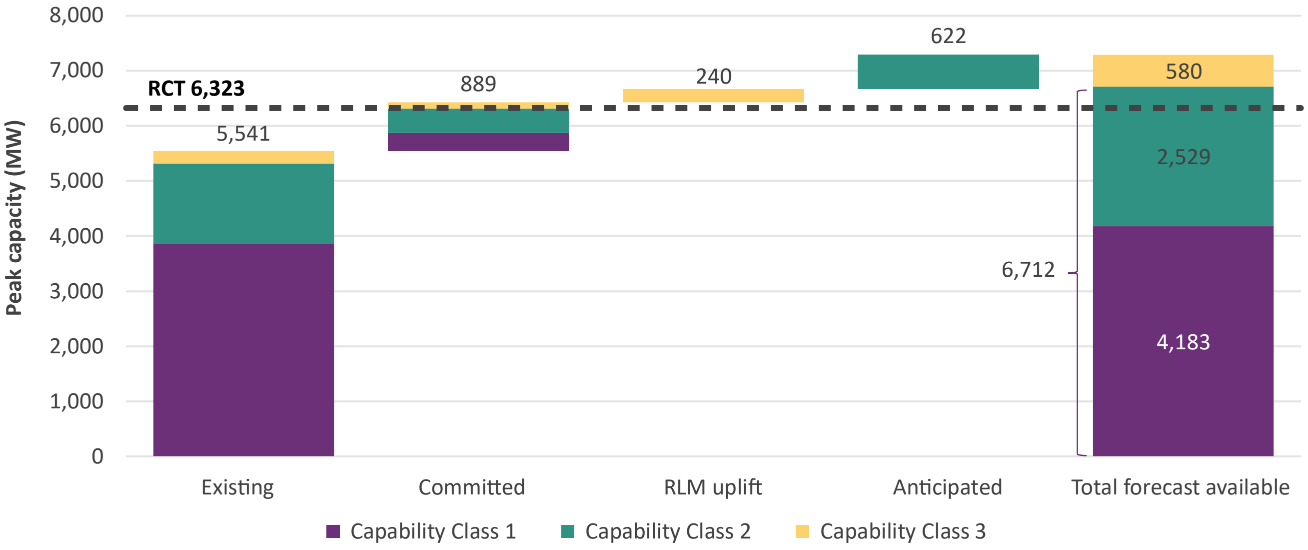
[78] See https://www.wa.gov.au/organisation/department-of-the-premier-and-cabinet/priority-projects.

7.1.2 Timely delivery of committed peak capacity is essential to meet the Reserve Capacity Requirements in 2028-29

The forecast surplus for 2028-29 depends on committed projects being delivered on time, which may be impacted by various factors including global supply chain and labour constraints. Additionally, the surplus may be reduced by unplanned outages from existing generation and increases in peak demand during critical periods. AEMO is closely monitoring the progress of the committed projects and encourages proponents to take early actions to mitigate any potential delays.

Figure 47 summarises existing, committed and anticipated capacity for 2028-29. The RCT for 2028-29 is 6,323 MW, which sets the RCR for the 2026 Reserve Capacity Cycle. A total of 6,670 MW of capacity is expected to be available, comprising 5,541 MW of existing capacity, 889 MW of committed capacity, and an estimated 240 MW of RLM uplift capacity for intermittent generators under the revised RLM. AEMO notes that the 240 MW RLM uplift capacity reflects an estimated increase in Capacity Credit assignments for intermittent generators (see Section 3.4.2), rather than additional physical generation capacity entering the SWIS. The resulting surplus above the RCT is therefore 347 MW. Of the total forecast capacity available, Capability Class 2 accounts for approximately 35%, including ESR and DSP, which represent firm capacity with energy or availability limitations. Within Capability Class 2, the total forecast capacity available is 2,529 MW, of which approximately 2,300 MW is ESR and the remainder is provided by DSP.

Figure 47 Forecast peak capacity for 2028-29 (MW)



Beyond existing, committed and anticipated projects, there are proposed projects[79] that could be developed in response to investment opportunities.

Figure 48 illustrates the broader development pipeline across the SWIS, currently totalling 24,433 MW of projects of varying stages of development. Whether and when these projects proceed will depend on timely planning and environmental approvals, network connection outcomes, and final investment decisions.

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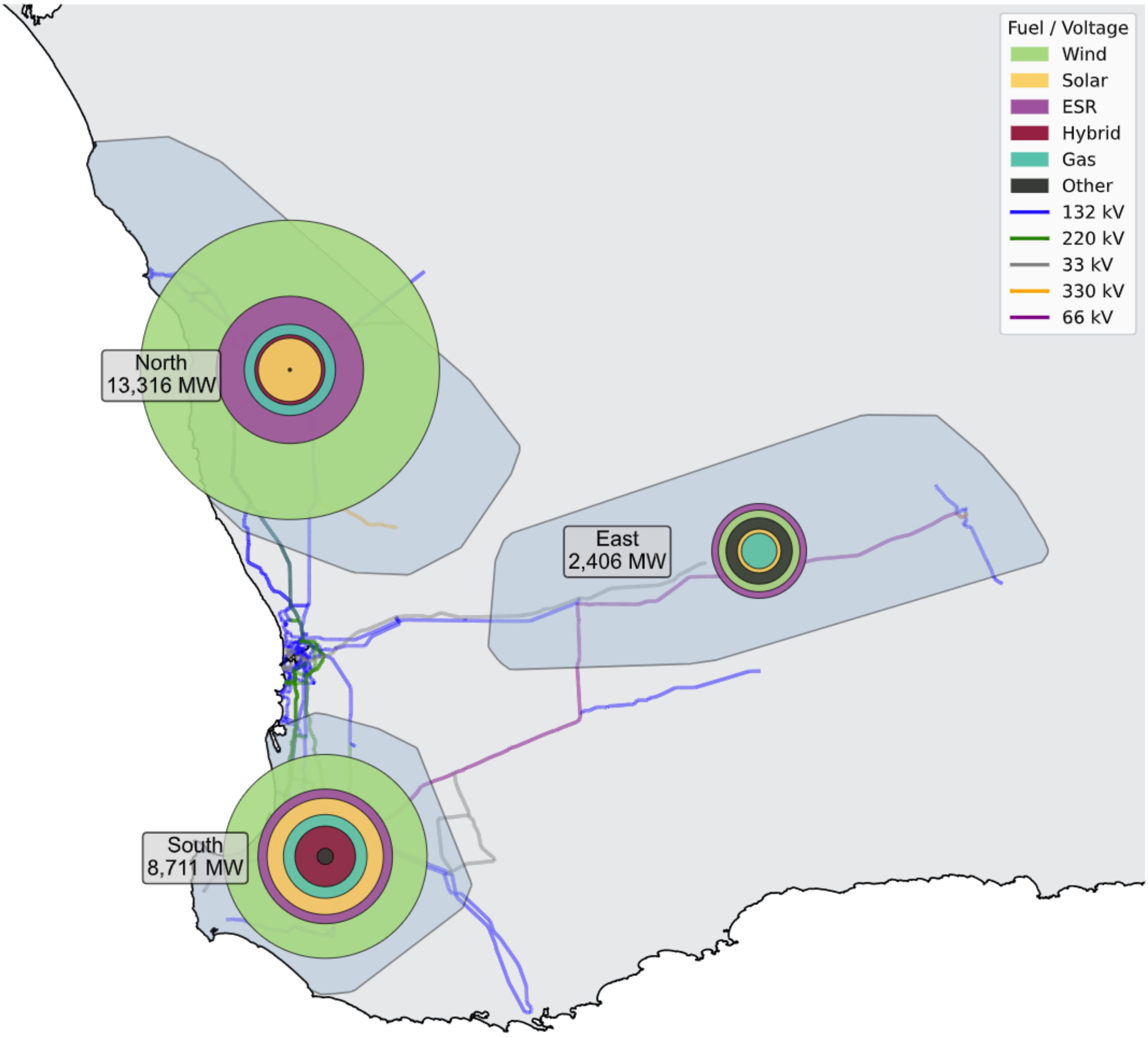
[79] A total of 3,747 MW of potential Peak Capacity was submitted through 85 valid nominated EOIs, as part of the 2026 EOI process. See https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2026/2026-expression-of-interest-summary-report.pdf?rev=290479f5b96747ae98e242283085e4af&sc_lang=en.

Figure 48 Declared Sent Out Capacity of new projects by regions in the SWIS (MW)



Source: 2026 LT PASA FIR – Western Power.

The above map highlights the significant concentration of proposed wind and ESR projects in the North and South regions of the SWIS. The proposed project pipeline is heavily weighted towards wind and ESR projects, reflecting strong investment interest in renewable generation and storage. Maintaining reliability and system security over the longer term, however, will require a balanced mix of technologies and sufficient transmission capability to support reliable system operation across the SWIS.

Delivery of major transmission augmentations, including CEL North, will be critical to support new generation entry, increase transfer capability and reduce the risk of network constraints limiting the ability of new projects to supply major demand centres.

7.1.3 Reserve Capacity Price

The Reserve Capacity Price (RC Price)

The RC Price is the price paid for Capacity Credits procured centrally through AEMO and is calculated annually in accordance with section 4.29. of the ESM Rules.

RC Prices (Peak and Flexible) are calculated annually with reference to the Peak Benchmark Reserve Capacity Price (Benchmark RC Price) and the percentage of Capacity Credit surplus or shortfall against the Reserve Capacity Requirements (RCRs).

For 2028-29, the Peak and Flexible Benchmark RC Price is $488,500.

Where the amount of assigned Peak Capacity Credits:

- Falls within a 5% surplus or shortfall of the Peak RCR, then the Peak RC Price is equal to the Peak Benchmark RC Price.
- Exceeds the Peak RCR by 15% or more, then the Peak RC Price is equal to the floor price, being 0.5 x Peak Benchmark RC Price.
- Falls short of the Peak RCR by 15% or more, then the Peak RC Price is equal to the ceiling price, being 1.5 x Peak Benchmark RC Price.
- is more than a 5% and less than a 15% surplus or shortfall, then the Peak RC Price is adjusted in proportion to the level of Peak Capacity Credit surplus or shortfall relative to the Peak RCR.

Market Participants can otherwise bilaterally trade Capacity Credits at a negotiated price.

The Flexible RC Price is also determined by the level of surplus or shortfall in assigned Flexible Capacity Credits relative to the Flexible RCR. Payments for Flexible Capacity Credits occur only when the Flexible RC Price exceeds the Peak RC Price.

The Benchmark RC Price for 2028-29 is $488,500/MW/year for both peak and flexible capacity, a 35% increase from the 2027-28 Benchmark RC Price.

The Economic Regulation Authority’s (ERA’s) determination is based on the estimated cost of constructing and connecting, a 200 MW/1,200 MWh six-hour duration BESS located along the CEL North transmission line, reflecting the increasing importance of longer-duration storage and transmission considerations in the evolving SWIS.

The Peak RC Price for 2027-28 was set at $360,700/MW/year for new Facilities and $177,636/MW/year for Transitional Facilities, following assignment of Capacity Credits in the 2025 Reserve Capacity Cycle.

The 2026 Certification of RC window for applications closes on **7 July 2026**. AEMO will assign Capacity Credits for 2028-29 on **13 October 2026,** in line with the updated RC timeline[80]. AEMO will determine the Peak and Flexible RC Price for 2028-29 in September 2026, following assignment of Capacity Credits and Flexible Capacity Credits, respectively.

The Flexible RC Price was set at $180,350/MW/year for 2027-28. In 2027-28, the Flexible RC Price was lower than the Peak RC Price, and therefore no top-up payments were made to Flexible Capacity Credit holders. Flexible Capacity Credit holders are eligible to receive a top-up payment where the Flexible RC Price exceeds the Peak RC Price. The Flexible Capacity is forecast to exceed Flexible RCT for the 10-year outlook period (see Section 5).

The ERA will update the Benchmark RC Price for the 2027 Reserve Capacity Cycle in accordance with clauses 4.16.11(b) and 4.16.12 of the ESM Rules, including any revised ESR Duration Requirement being published in the 2026 WEM ESOO, appropriate reference technology, uncongested network location and technical parameters specified in these clauses.

Figure 49 shows the historical trend for the Benchmark RC Price and Peak RC Price and excess/deficit from 2017-18 to 2028-29.

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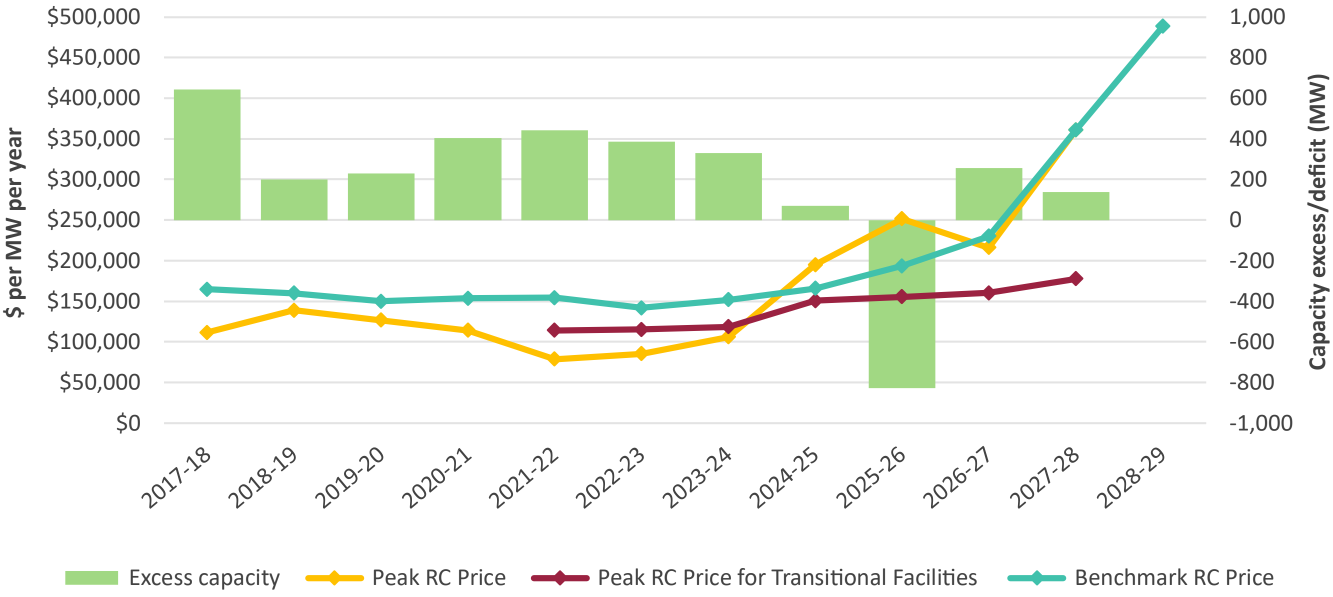
[80] See https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-timetable.

Figure 49 Reserve Capacity Price, Benchmark Reserve Capacity Price and capacity excess/deficit, 2017-18 to 2028-29



Notes:

- DSPs were paid according to the DSP RC Price prior to 2020-21. Since then, the DSP RC Price was removed and DSPs have been receiving the same RC Price as other new Facilities. See https://www.wa.gov.au/system/files/2021-11/RCM-Review-2021-Scope-of-works.PDF.
- The Benchmark RC Price determined for 2028-29 is applicable for both Peak and Flexible RC Price determination.
- The Flexible RC Price was set at $180,350 for 2027-28.

In summary:

- The Benchmark RC Price has increased significantly[81] in recent years, reflecting rising costs of building and connecting new capacity in the SWIS.
- Higher Benchmark RC Price, tighter supply-demand conditions and recent ESM Rule changes[82] have strengthened investment signals for new capacity in the SWIS. Peak RCP reached a long-term high of $360,700/MW/year for 2027-28, when there was a capacity surplus of 137 MW.

7.1.4 Investment certainty in the SWIS

A 10-year fixed price option was introduced into the ESM Rules in 2025 as part of the WEM Investment Certainty Review to provide stronger investment certainty for new capacity in the SWIS[83]. The mechanism allows eligible new Facilities to lock in Reserve Capacity Prices over a longer period, reducing exposure to year-on-year price variability.

Eligibility is targeted toward technologies expected to play an important role in the evolving SWIS, including firm and flexible generation, longer-duration ESR capacity, and Facilities supported by Eligible Renewable Energy Sources. By providing longer-term revenue certainty, the mechanism is intended to support investment in the mix of generation, storage and firming capacity required to maintain reliability as the SWIS evolves.

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[81] See https://www.erawa.com.au/sites/default/files/2026-benchmark-reserve-capacity-prices-2028-29-capacity-year-final-determination.PDF.

[82] The ESM Rules were amended on 22 February 2020 to implement the changes to the pricing curve to increase responsiveness to the excess or shortage of capacity from the 2019 Reserve Capacity Cycle. See https://www.wa.gov.au/government/document-collections/improving-reserve-capacity-pricing-signals.

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

7.2 Transmission network investment opportunities

Transmission network investment will play a critical role in maintaining reliability across the SWIS over the outlook period. As new generation and storage projects are increasingly developed in regions with strong renewable resources, additional transmission capability will be required to connect this capacity and transfer power to major demand centres across the SWIS.

Annual peak demand is higher in 2026 WEM ESOO than in the 2025 WEM ESOO. Peak demand is forecast to increase approximately 29% from 4,681 MW in 2025-26 to 6,016 MW by 2035-36 over the 10-year outlook period, while delivered consumption is forecast to increase approximately 48%, contributing to a material increase in transmission capacity requirements and the need for major transmission augmentations across the SWIS.

The 2026 WEM ESOO assumes delivery of the CEL North augmentation from 1 January 2028. This project is expected to support the connection and dispatch of significant new renewable generation and firming capacity in the northern sub-regions of the SWIS. Continued and coordinated transmission investment beyond CEL North will also be required to support future generation development and maintain reliable system operation as ageing thermal generation retires.

Future transmission investment is identified in the WA Government's SWIS Transmission Plan[84], which includes the CEL East project planned for 2030 (Stage 1) and the CEL Kwinana project planned for 2030 (Stage 1) and 2033 (Stage 2). CEL East enables the connection of renewable generation in the South[85], while CEL Kwinana enables the connection of thermal generation in Kwinana.

The sub-regional capacity shortfalls identified in the Eastern region may be addressed by new supply capacity in the Goldfields. Both an NCESS procurement process and an expression of interest process for a Vanadium Battery Energy Storage System are currently in progress for this region[86].

Sub-regional analysis highlights that existing and committed capacity is insufficient to meet forecast system needs over the longer term, with a system-wide capacity shortfall forecast from 2030-31 onwards. Transmission network investment will be required to connect new capacity and ensure sufficient transfer capability to supply major demand centres across the SWIS. Given the scale and lead times associated with major transmission infrastructure, timely planning and delivery of network augmentations and new builds will be critical.

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[84] For more details on the CEL program, refer to the *Transmission System Plan* https://www.westernpower.com.au/resources-education/suppliers/tenders-and-registrations-of-interest/transmission-system-plan--network-opportunity-map/ and *SWIS Transmission Plan* https://www.wa.gov.au/organisation/energy-policy-wa/the-south-west-interconnected-system-transmission-plan-future-ready-transmission-network-was-main-electricity-system.

[85] See https://www.wa.gov.au/government/media-statements/Cook%20Labor%20Government/Government-plans-WA's-clean-energy-future-with-$1.4-billion-fund-20260427.

[86] See https://www.wa.gov.au/system/files/2024-03/coordinator-of-energy-determination_reliability-and-security-service_march2024.pdf.

List of tables and figures

Tables

Figures

Glossary, measures, and abbreviations

Glossary

This document uses many terms that have meanings defined in the Electricity System and Market Rules (ESM Rules). The ESM meanings are adopted unless otherwise specified.

Term	Definition
10-year outlook period	2026-27 to 2035-36 Capacity Years, inclusive.
Anticipated capacity	Capacity from new projects that have submitted a valid 2026 Expression of Interest or other relevant project information and scored between 60% and 80% in AEMO's new project status evaluation. Anticipated capacity is included only in the *High* scenario.
Business mass market (BMM)	Business loads that are not classified as large industrial loads, data centres or new industries.
Business sector	Industrial and commercial electricity users, including large industrial loads and business mass market customers.
Committed and prospective large industrial loads	New large industrial loads are classified as committed or prospective based on AEMO's evaluation criteria, including final investment decision, environmental approval, network access status and decarbonisation. Committed large industrial loads are included in the *Expected* and *High* scenarios, while prospective large industrial loads are included only in the *High* scenario.
Committed capacity	Capacity from new projects that are not yet operational and have either been assigned Capacity Credits, scored 80% or higher in AEMO's new project status evaluation, or been contracted under the relevant Peak Demand NCESS. Committed capacity is included in the *Expected* and *High* scenarios.
Consumption	The amount of electrical energy used over a period of time, measured in megawatt hours (MWh), gigawatt hours (GWh) or terawatt hours (TWh). In this report, consumption is generally reported on an annual basis.
Delivered consumption (or demand)	Electricity supplied to customers from the grid, excluding electricity supplied from behind-the-meter resources such as distributed PV.
Demand	The amount of power consumed at a point in time, measured in megawatts (MW) or gigawatts (GW). In this report, demand is generally reported as a 30-minute average for periods of maximum or minimum demand.
Distributed energy resources (DER)	Smaller-scale, geographically dispersed, customer-owned electrical devices that generate, store or use electricity, and form a part of the local electricity distribution system. Examples include rooftop photovoltaics (PV) systems, battery storage systems (residential, business, community), electric vehicles (EV) or technologies to manage demand at a premises. DER are located "behind-the-meter", and used within residential or business premises to self-supply co-located loads such as air conditioners, heat pumps, or washing machines. If on-site supply exceeds on-site load, DER may export (inject) power to the broader system. If coordinated through a virtual power plant (VPP) arrangement, DER can support the operations of the broader power system. Subject to meeting criteria for Capacity Credits assignment, DER may hold Capacity Credits in the WEM.
Distributed energy storage systems (DESS), or distributed batteries	A sub-group of DER, DESS are behind-the-meter, smaller-scale battery energy storage systems installed by residential or business customers.
Distributed photovoltaics (PV)	A sub-group of DER, distributed PV are behind-the-meter, smaller-scale PV systems, including rooftop PV and PV non-scheduled generation (PVNSG).
Electric vehicles (EV)	A sub-group of DER, EV are vehicles with an on-board electricity storage system (battery) used for propulsion. EV include a broad range of vehicles, from motorbikes and passenger cars to commercial trucks and buses.
Electrification	Replacement of technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically-powered equivalents, such as electric vehicles or heat pumps.

Term	Definition
Operational consumption[87] (or demand)[88]	Electricity consumption or demand met by sent-out electricity injected into the network by all market-registered energy producing systems. Operational consumption or demand includes the charging and discharging of distributed batteries (which increases and decreases demand, respectively), as well as transmission and distribution losses. Operational consumption or demand does not include consumption or demand met by distributed PV generation.
Unscheduled operational consumption (or demand)[89]	Operational consumption or demand excluding scheduled loads, such as large-scale ESR charging.
Existing capacity	Capacity from Registered Facilities that have been assigned Capacity Credits or contracted under relevant Peak Demand NCESS arrangements, adjusted for announced or assumed retirements. Existing capacity is included in the *Low*, *Expected* and *High* scenarios.
Installed capacity	The generating capacity, in MW, of a generating unit or group of generating units.
Large industrial load	A load that consumes, or is forecast to consume, at least 10 MW for at least 10% of the time, approximately 875 hours a year, or at least 50 GWh per year.
Limb A	The limb of the Planning Criterion that requires sufficient available capacity in each Capacity Year to meet forecast peak demand plus a reserve margin.
Limb B	The limb of the Planning Criterion that requires sufficient available capacity in the SWIS to limit expected unserved energy to 0.0002% of annual energy consumption.
Limb C	The limb of the Planning Criterion that requires sufficient available capacity in the SWIS to meet the highest forecast Four-Hour Demand Increase plus a reserve margin in each Capacity Year.
Load curtailment	The controlled reduction of electricity supply to parts of the power system to protect system security and mitigate damage to infrastructure.
Maximum sent-out capacity	The maximum sent-out capacity of a Facility, based on its technical capability, contracted quantity or forecast capacity, depending on the context in which the term is used. 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 levels of electricity drawn from the grid, measured as a 30-minute average, during summer, winter or shoulder periods.
Peak demand	The highest amount of demand recorded or forecast at a point in time. In this report, peak demand refers to operational peak demand unless otherwise stated.
Photovoltaics (PV)	Systems that convert sunlight into electricity.
Probability of exceedance (POE)	A measure of the likelihood that a forecast value will be met or exceeded. For example, a 10% POE maximum demand forecast is expected to be met or exceeded, on average, one year in 10.
Proposed capacity	Capacity from proposed new projects that do not meet the criteria for existing, committed or anticipated capacity.
PV non-scheduled generation (PVNSG)	Non-scheduled photovoltaic generators larger than 100 kW but smaller than 10 MW that do not hold Capacity Credits in the WEM.
Reference year	A historical weather year used to model future half-hourly demand, wind generation and solar PV generation under different weather conditions.
Reliability standard	The Planning Criterion defined in clause 4.5.9 of the ESM Rules.
Residential sector	Non-contestable residential customers supplied by Synergy.

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[87] Historical operational consumption is measured as the Total Sent Out Generation (TSOG) over a 30-minute Trading Interval. It is a non-network-loss adjusted MWh value.

[88] 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.

[89] Unscheduled operational consumption/demand terms are also defined in the undertaking of the Long Term PASA WEM Procedure, at https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

Term	Definition
Rooftop photovoltaics (PV)	Photovoltaic systems installed on residential buildings or business premises.
Shoulder season	The period covering the Trading Months of April, May, September, October and November.
Summer	The Hot Season as defined in the ESM Rules, covering the Trading Months of December, January, February, and March.
Underlying consumption (or demand)	Total electricity consumption or demand used by consumers, including electricity supplied from the grid and electricity supplied from behind-the-meter resources such as distributed PV and battery storage.
Unscheduled operational maximum (peak) and minimum demand	Operational maximum and minimum demand excluding scheduled load, such as large-scale ESR charging.
Unserved energy (USE)	Energy that cannot be supplied to consumers when demand exceeds supply under certain circumstances for loss of customer supply.
Virtual power plant (VPP)	An aggregation (grouping) of DER that is actively controlled by an operator to coordinate their behaviour with consideration for, and in response to, the broader power system and electricity market conditions. VPPs use sophisticated software and communication platforms that coordinate and control DER to function as a single, unified facility. This enables the VPP to provide system and network services, participate in wholesale energy markets, and respond to real-time energy demand and supply fluctuations.
Winter	The period covering the Trading Months of June, July and August.

Units of measure

Abbreviation	Unit of measure
°C	Celsius
GW	Gigawatt/s
GWh	Gigawatt hour/s
kV	Kilovolt/s
kW	Kilowatt/s
MVA	Megavolt-ampere/s
MVAr	Megavolt-ampere/s reactive
MW	Megawatt/s
MWh	Megawatt hour/s
TW	Terawatt/s
TWh	Terawatt hour/s

Abbreviations

Abbreviation	Definition
AAGR	Average annual growth rate
ADG	Availability Duration Gap
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BESS	Battery energy storage system

Abbreviation	Definition
BMM	Business mass market
BRCP	Benchmark Reserve Capacity Price
CEL	Clean Energy Link
CHBP	Cheaper Home Batteries Program
CIS	Capacity Investment Scheme
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAE	Deloitte Access Economics
DEED	Department of Energy and Economic Diversification
DER	Distributed energy resources
DESS	Distributed energy storage systems
DPV	Distributed photovoltaics
DSP	Demand Side Programme
EDFM	Electricity Demand Forecasting Methodology
EGF	Eastern Goldfields
EOI	Expression of Interest
ERA	Economic Regulation Authority
ESM	Electricity System and Market
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resource
ESR Duration Requirement	Electric Storage Resource Duration Requirement
ESROD	Electric Storage Resource Obligation Duration
ESROI	Electric Storage Resource Obligation Interval
ESS	Essential System Services
EV	Electric vehicle
FCESS	Frequency Co-optimised Essential System Services
FHDI	Four-Hour Demand Increase
FID	Final Investment Decision
FIR	Formal Information Request
FRG	Forecasting Reference Group
GEM	Green Energy Market
GSOO	Gas Statement of Opportunities
IASR	Inputs, Assumptions and Scenarios Report
IGS	Intermittent Generating Systems
IQR	Interquartile Range
IRCR	Individual Reserve Capacity Requirement
LDC	Linear Derating Capacity
LOR	Lack of Reserve
LT	Long Term

Abbreviation	Definition
MDT	Minimum demand threshold
MT	Medium term
NAQ	Network Access Quantity
NCC	National Construction Code
NCESS	Non-Co-optimised Essential System Service
NEM	National Electricity Market
NIGS	Non-Intermittent Generating Systems
OPSO	Operational sent out
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
RLM	Relevant Level Method
RN	Reference Node
SAM	System Advisor Model
SC	Supplementary Capacity
SOC	State of Charge
SSF	Semi-scheduled Facility
ST	Short Term
SWIS	South West Interconnected System
TNI	Transmission Node Identifier
TSOG	Total Sent Out Generation
USE	Unserved energy
VPP	Virtual power plant
VRE	Variable renewable energy
WA	Western Australia
WARBS	WA Residential Battery Scheme
WEM	Wholesale Electricity Market
WEMDE	Wholesale Electricity Market Dispatch Engine
WOSP	Whole of System Plan