2023 Wholesale Electricity Market Electricity Statement of Opportunities

August 2023

A report for the Wholesale Electricity Market

Important notice

Purpose

AEMO publishes the Wholesale Electricity Market Electricity Statement of Opportunities under clause 4.5.11 of the Wholesale Electricity Market Rules. This publication is generally based on information available to AEMO as of May 2023 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	17/08/2023	Initial release.
2.0	15/09/2023	Added opening bracket to "limb A" on p. 70. Updated battery maximum capacity for 2029-30 and 2030-33 in Table 34.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Executive summary

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

Its primary purpose is to identify the investment in capacity from generation, storage, and demand side management (DSM) needed to ensure a secure and reliable electricity supply for the SWIS over the coming 10 years.

The ESOO plays an important role in the Reserve Capacity Mechanism (RCM) process in the WEM. The 2023 WEM ESOO forecasts the Reserve Capacity Target (RCT) for each Capacity Year between 2023-24 and 2032-33, and, specifically, determines the Reserve Capacity Requirement (RCR) – the amount of capacity to be procured through the RCM – for the 2025-26 Capacity Year[1].

This WEM ESOO highlights the urgency of advancing generation, storage, DSM, and transmission projects to bolster reliability and support a rapid and orderly energy transition.

- Its findings emphasise the need for additional capacity procurement and expedited progress of capacity projects in the SWIS. This will pave the way for a robust and resilient power system capable of meeting future demand and facilitating the transition to a cleaner and more sustainable energy future.
- **The supply-demand outlook indicates an urgent need for investment by capacity providers to supply the SWIS to meet the WEM reliability standard** – the Planning Criterion:
  - The **peak demand and energy consumption forecasts[2] show strong growth** driven by electrification, electric vehicle uptake, and new energy-intensive industries including green hydrogen production – to meet the WA and Federal Governments' emissions reduction targets.
  - A recent change to the WEM Rules **broadens the scope of emerging supply risks considered by AEMO**, ensuring a more comprehensive coverage of assessed supply risk in the RCT determination.
  - The anticipated **exit of coal-fired power generation capacity** within the next decade will result in a substantial reduction in overall supply capacity.
- **Procurement of additional capacity is required to address near-term reliability gaps projected for 2023-24 and 2024-25.**
- **To meet the reliability gap and satisfy the RCR for 2025-26, expedited progress of a robust pipeline of probable projects is necessary.**
- **Beyond 2025-26, the outlook for long-term reliability is expected to improve** due to strong capacity investment signals and planned transmission expansion, demonstrating a commitment to achieve a sustainable energy future and maintain power system security and reliability.

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

[2] Unless otherwise indicated, demand forecasts in this executive summary are based on the expected demand growth scenario.

The **RCM** ensures that there is sufficient generation capacity in the SWIS by:

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

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

- meet the forecast 10% probability of exceedance (POE) peak demand under the expected demand growth scenario and a reserve margin, and
- limit expected unserved energy to 0.002% of annual energy consumption.

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

Capacity, for the purposes of the RCM, means **CRC**, which is usually less than the nameplate capacity of a Facility. The methodology for assessing and assigning CRC and Capacity Credits is based on the Facility Technology Type:

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

The rapid energy transition and the evolving energy landscape are fuelling demand growth and introducing diverse capacity supply risks as coal-fired generation is phased out

The progress of the energy transition has gained momentum at global, national, and state levels since the 2022 WEM ESOO. Globally, the transition to deploy renewable energy has been accelerated by strong motivation to ensure secure access to energy resources[3]. This has created a strong demand for minerals that are critical to the energy transition, and new emerging industries including green hydrogen and ammonia. Nationally, the Australian Federal Government pledged in September 2022 to lower emissions by 43% by 2030 and achieve net zero emissions by 2050[4].

In WA, the state government intends to introduce climate change legislation this year to reduce government emissions by 80% below the 2020 level by 2030, and to meet net zero by 2050[5]. Collaboration between the WA

[3] International Energy Agency, *World Energy Outlook 2022,* at https://www.iea.org/reports/world-energy-outlook-2022.

[4] A list of progressed commitments of the Australian Federal Government is available at https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia.

[5] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2023/01/McGowan-Government-to-introduce-climate-change-legislation.aspx.

Government and industry is underway to develop sectoral emissions reduction strategies and pathways to support the state government's net zero emissions target by 2050.

Strong growth in demand is forecast, driven by expansion in business and industrial activities, and electrification

Forecast demand growth in this report shows a significant increase compared to the 2022 WEM ESOO[6].

AEMO has adopted the *Step Change* scenario from AEMO's 2023 *Inputs, Assumptions, and Scenarios Report* (IASR)[7] as the expected demand growth scenario for this WEM ESOO. This scenario represents a commitment to mitigating climate change by limiting global temperature rise to below 2°C compared to pre-industrial levels. It accounts for moderate growth in both the global and domestic economy, with a focus on electrifying transportation and providing greater opportunities for electrifying industry, aligning with Australia's commitment to reduce carbon emissions by 43% by 2030 and achieve net zero emissions by 2050[8].

The 2023 WEM ESOO also incorporates the potential impact of green hydrogen production opportunities in WA across the three demand growth scenarios, reflecting growing interest and efforts to develop hydrogen production for both domestic consumption and export purposes.

AEMO forecasts the 10% POE peak demand will increase by 4.4% on average each year during the outlook period, from 4,253 megawatts (MW) in 2023-24 to 6,296 MW in 2032-33 (see Table 1). While this is significantly higher than the average annual growth rate of 0.9% projected in the 2022 WEM ESOO, the forecasts are broadly consistent with the WA Government's SWIS Demand Assessment[9] published in May 2023.

Operational consumption is forecast to grow at an average annual rate of 5.6% and reach 30.3 terawatt hours (TWh) in 2032-33, compared to the average annual growth rate of -0.4% forecast in the 2022 WEM ESOO (see Table 2). In the high demand growth scenario, which projects greater development of a green hydrogen sector, operational consumption is projected to triple to 58.9 TWh by the end of the outlook period.

The primary driver of this demand growth is business electrification, along with growth in cooling load (air-conditioning), electric vehicles (EVs), and the expansion of industrial loads.

Consistent with the SWIS Demand Assessment, AEMO's forecasts in the business sector reflect industry's commitments to electrify production processes as part of plans to decarbonise operations, particularly for alumina refineries. Notably, demand forecasts now factor in the demand associated with green hydrogen production, reflecting governments' growing commitment to developing a green hydrogen export industry.

Meanwhile, WA is poised to benefit from a new wave of critical mineral development, encompassing mining and processing activities that fuel the global and national energy transition. A variety of large industrial load projects are currently in various stages of development and are expected to be connected to the SWIS during this outlook period. Notable projects include lithium production and processing, as well as ammonia or hydrogen production.

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[6] AEMO, 2022 Wholesale Electricity Market Electricity Statement of Opportunities, 2022 at https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf.

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

[8] In 2022, while the *Step Change* scenario in the 2021 IASR was generally regarded as the most likely scenario and used as such in other AEMO planning, the *Progressive Change* scenario from the IASR was applied as the expected scenario in the 2022 WEM ESOO. At that time, AEMO did not have sufficient information about the pace of electrification in the SWIS to support the use of the *Step Change* scenario as the expected scenario for the SWIS. AEMO now has updated electrification information for the SWIS which confirms the appropriateness of *Step Change* being applied as the expected scenario in 2023 WEM ESOO and this incorporates an uplift in demand forecast compared to last year's forecast.

[9] WA Government, *SWIS Demand Assessment 2023 to 2042 A future ready grid*, 2023, at https://www.wa.gov.au/system/files/2023-05/swisda_report.pdf.

Rail projects and a newly proposed desalination project are also forecast to make contributions to demand growth.

Table 1 Peak demand forecasts for different weather scenarios, expected demand growth (MW)

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	5-year average annual growth	2032-33	10-year average annual growth
10% POE	4,112	4,253	4,315	4,418	4,580	4,734	2.9%	6,296	4.4%
50% POE	3,847	4,002	4,078	4,164	4,338	4,485	3.1%	6,030	4.6%
90% POE	3,606	3,735	3,809	3,897	4,053	4,201	3.1%	5,718	4.7%

Note: 2022-23 is the base year (year 0) and 2032-33 is the final year (year 10) for the average annual growth rate calculation.

Table 2 Operational consumption forecasts for different demand growth scenarios (gigawatt hours (GWh))

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	5-year average annual growth	2032-33	10-year average annual growth
Low	16,878	16,969	17,128	17,506	18,541	18,962	2.4%	24,910	4.0%
Expected	17,615	18,010	18,237	18,607	19,509	20,375	3.0%	30,306	5.6%
High	18,318	18,984	20,816	26,510	33,127	38,676	16.1%	58,884	12.4%

Note: 2022-23 is the base year (year 0) and 2032-33 is the final year (year 10) for the average annual growth rate calculation.

In addition to these industrial drivers, continued growth is anticipated in both the residential and business sectors, including the forecast strong adoption of EVs, influenced by Federal and WA Government policies. In the residential sector, forecast growth is largely driven by updated appliance uptake projection[10] and the resulting increase in cooling loads.

These developments, coupled with conventional drivers of growth in population and economy, have propelled forecast demand growth. Projected growth is partially offset by forecast energy savings resulting from improved energy efficiency measures and ongoing consumer investments in distributed solar photovoltaic (PV) systems.

Consideration of a broader range of capacity supply risks to ensure sufficient reserve margin to maintain system reliability and security

The SWIS is undergoing a significant transition towards a lower emissions energy system. Fuel supply challenges and prolonged unplanned Facility outages have led to the unavailability of coal and gas capacity. These factors contribute to a broader range of supply-demand risks in capacity, impacting power system security and reliability. Continued growth in wind and solar generation, including large-scale wind and solar Facilities as well as rooftop PV systems, also present challenges to system operation as the supply of electricity becomes increasingly weather-dependent.

In January 2023, the WEM Rules were amended as part of the WA Government's Energy Transformation Strategy[11], which incorporates several critical reforms to the RCM, to reflect the needs of the SWIS through the energy transition. These amendments enable AEMO to take account of the broader range of supply risks in

[10] This 2023 WEM ESOO is based on appliance projections from the 2021 Residential Energy Baseline Study: Australia and New Zealand, which was published in May 2022, replacing the 2015 Residential Baseline Study used in previous years. See https://www.energyrating.gov.au/news-and-stories/2021-residential-energy-baseline-study-australia-and-new-zealand.

[11] For more information, see https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.

setting the RCT, including consideration of risks associated with an aging thermal generation fleet and rapidly shifting operational conditions as a larger proportion of capacity is delivered by intermittent generation.

As part of its determination of the appropriate contingency size, AEMO analysed NIGS outage records during Hot Season from the past five years and identified that, at this stage of the energy transition in the SWIS, the largest contingency is likely to be related to the risk of multiple generating units being unavailable due to forced outages. Forced outages for the NIGS fleet have increased, exceeding 1.3 gigawatts (GW) in December 2022. A similar level of outages was also experienced during June 2023.

The increasing risks of generation unavailability have informed AEMO's determination for the RCT, inclusive of a risk margin equivalent to the three largest generation units.

AEMO also modified the estimation of the minimum Regulation Raise requirement under the future Essential System Services framework to better account for the impacts of increasing penetration of intermittent generation in the power system.

Combined, these changes have increased the reserve margin considered in the RCT determination over the outlook period, compared to the methodology used in previous WEM ESOOs.

As the energy transition continues, AEMO will continue to evaluate the evolving risks associated with potential supply disruptions to the SWIS, including the minimum requirements for Regulation services. Future WEM ESOOs will incorporate updates to the determination of the largest risk and Regulation requirements to ensure an adequate reserve margin is incorporated into the RCTs to maintain power system security and reliability. By regularly reassessing and adapting to the changing risk and technology mix landscape, AEMO aims to ensure the resilience and reliability of the power system as it navigates the challenges posed by the energy transition.

Staged reductions in the existing capacity supply as the coal-fired generation phases out

Staged reductions in existing supply capacity are expected, due to the anticipated retirement of an estimated total of 1,366 MW[12] of coal-fired generation capacity by 2030-31.

The reductions in existing capacity arise from the planned retirement of coal-fired generation. The 2023 WEM ESOO forecasts include the phased closure of Synergy's Collie and Muja D Power Stations by 2030, as announced by the WA Government[13], which results in a decrease in available capacity for supplying the SWIS of 193 MW from 2024-25[14] and further 317 MW and 422 MW from 2027-28 and 2029-30, respectively.

Accounting for recent challenges in coal supply, mounting economic pressures posed by alternative energy sources, escalating fuel and operating costs, and increasing demand for sustainable energy, AEMO's modelling assumes that the Bluewaters Power Station will exit the WEM from 2030-31. This assumption reduces forecast available capacity by an additional 434 MW, further signalling the need for investment in new generation.

[12] This includes the retirement of Muja C unit 6 (193 MW) from 2023-24, Collie Power Station (317.2 MW) from 2027-28, Muja D Power Station (422 MW) from 2029-30, and Bluewater Power Station (434 MW) from 2030-31.

[13] WA 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. The 2022 WEM ESOO was unable to consider these capacity withdrawals in the supply-demand balance forecasts due to the timing of this announcement.

[14] The 2022 WEM ESOO supply-demand balance accounted for the planned retirement of Muja Unit 6 and as such, this did not contribute to an additional supply gap in 2024-25.

The Reserve Capacity Requirement

The RCT determined for the 2025-26 Capacity Year is 5,543 MW, which sets the RCR for the 2023 Reserve Capacity Cycle. Table 3 shows the RCT set by the expected 10% POE peak demand requirement, revised contingency component, Intermittent Loads allowance component, and Regulation Raise component of the Planning Criterion for each Capacity Year of the 2023 Long Term PASA Study Horizon.

Table 3 Reserve Capacity Targets (MW)

Capacity Year	10% POE peak demand	Intermittent Loads	Contingency component of the reserve margin	Regulation Raise	Total
2023-24	4,253	8	983	120	5,364
2024-25	4,315	8	976	131	5,430
2025-26	4,418	8	976	141	5,543
2026-27	4,580	8	976	153	5,716
2027-28	4,734	7	898	167	5,806
2028-29	4,976	7	898	180	6,061
2029-30	5,325	6	898	192	6,422
2030-31	5,713	6	898	204	6,821
2031-32	6,021	6	898	215	7,140
2032-33	6,296	5	898	225	7,425

Forecast supply-demand balance of capacity requires new capacity investment in the WEM

The forecast supply-demand balance indicates the significant investment needed in additional generation, energy storage, and DSM capacity to supply the SWIS and meet the WEM reliability standards across the entire outlook period, as presented in Figure 1.

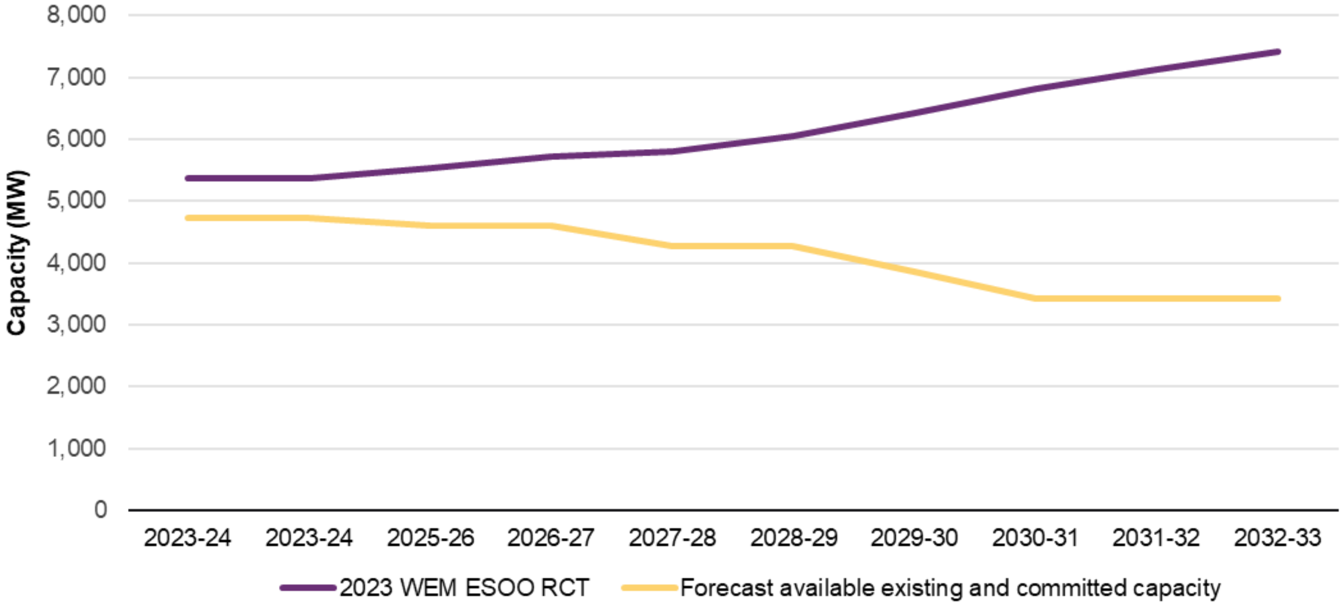
This 2023 WEM ESOO forecasts the RCT to grow at an average annual rate of 3.7% over the outlook period, in comparison to the expected 0.8% annual growth rate in the 2022 WEM ESOO.

For 2023-24, the forecast RCT is 5,364 MW, marking a 968 MW increase compared to the forecast RCR in the 2021 WEM ESOO[15]. In 2024-25, the forecast RCT grows to 5,430 MW, a 904 MW increase from the RCR forecast in the 2022 WEM ESOO.

The RCT determined for 2025-26 is 5,543 MW, setting the RCR for the 2023 Reserve Capacity Cycle. It is 1,017 MW higher than the RCR set for 2024-25 (4,526 MW) and 989 MW higher than the RCT forecast for 2025-26 in the 2022 WEM ESOO. By 2032-33, the RCT is anticipated to reach 7,425 MW.

[15] At https://www.aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2021/2021-wholesale-electricity-market-electricity-statement-of-opportunities.pdf.

Figure 1 Reserve Capacity forecast supply-demand balance, expected demand growth scenario, 2023-24 to 2032-33 (MW)



Note: the capacity supply for 2023-24 and 2024-25 are based on the quantity of Capacity Credits assigned for the two Capacity Years, respectively. The capacity supply for 2025-26 to 2032-33 represents the estimated CRC that could be potentially available based on existing and committed supply capacity only.

Considering existing and committed capacity supply, AEMO projects additional capacity is required to meet forecast demand. This assessment forecasts a need for additional capacity from the start of the outlook period in 2023-24, rising to 945 MW in 2025-26, and to around 4,000 MW by 2032-33. This is a significant shift compared to the 2022 WEM ESOO outlook, where the additional capacity requirement was expected to begin in 2025-26 and reach 303 MW by 2031-32.

This shift in the capacity supply-demand balance reflects the anticipated strong growth in demand, the inclusion of larger contingency sizes and minimum Regulation requirements in the RCT calculation, and the expected decrease in capacity supply as a result of anticipated coal-fired generation retirements, as discussed above.

Near-term need for additional capacity procurement to manage reliability risks for 2023-24 and 2024-25

The significant near-term capacity needs identified in this report may not be fully mitigated through the RCM, or have not been mitigated for Capacity Years with assigned Capacity Credits, which has necessitated AEMO seeking additional services through the following frameworks:

- **Supplementary Reserve Capacity (SRC)** – a contractual framework which allows AEMO, within six months of the start of the relevant Capacity Year, to procure services to mitigate forecast capacity shortfalls.
- **Non-Co-optimised Essential System Services (NCESS)** – a contractual framework which allows AEMO, where a procurement is triggered by the Coordinator of Energy, to procure services to mitigate power system security or power system reliability risks.

Table 4 provides an overview of the capacity investment gap associated with 2023-24 to 2027-28 Capacity Years, with the actions AEMO has undertaken to mitigate identified shortfalls.

Table 4 Supply-demand balance for the expect scenario, 2021 to 2025 Reserve Capacity Cycle (MW)

Capacity Year	2023-24	2024-25	2025-26	2026-27	2027-28
Reserve Capacity Cycle (WEM ESOO)	2021	2022	2023	2024	2025
Cycle Status	Capacity assigned	Capacity assigned	Capacity assignment over coming months	Not commenced	Not commenced
RCT	5,364	5,430	5,543	5,716	5,806
Capacity	4,727	4,596	4,598	4,598	4,281
Capacity investment gap	638	833	945	1,118	1,525
Additional Services	SRC procurement underway	NCESS procurement underway SRC considered in 2024, if required	None identified at this stage	None identified at this stage	None identified at this stage

AEMO triggered the SRC mechanism for 2022-23[16] to secure up to 174 MW to address the capacity shortfall identified for the 2022-23 summer. A total of 96.1 MW of SRC was ultimately contracted, and this capacity was activated on two occasions to help meet peak demand over the 2022-23 summer, at a total cost of $3.85 million.

AEMO is seeking to mitigate supply risks in 2023-24 through the SRC procurement process[17] initiated in early August 2023 for up to 326 MW of capacity over the 2023-24 Hot Season. It is important to note that the quantity of SRC AEMO is seeking to procure is lower than the reliability gap identified in this report. This is due to the methodology used to quantify required reserves for each process, which reflects nearer-term forecasts and updates of expected operating conditions, including unplanned outages and project delays. The WEM Rules require AEMO to use the most recent published Long Term PASA forecasts and methodologies, and any other information AEMO considers relevant in determining the SRC requirement.

To address emerging reliability challenges in the SWIS for 2024-25, in December 2022 AEMO triggered the procurement of NCESS for minimum and peak demand services. This procurement aims to secure up to 830 MW of peak demand NCESS for 2024-25 and 2025-26 (2024-26 Peak Demand NCESS)[18]. AEMO is in the process of finalising contracts with successful participants in this tender process. The amount of procured peak demand NCESS capacity, combined with the Capacity Credits assignment for 2024-25, will determine the additional capacity required to address the forecast reliability gap for 2024-25. This requirement may be adjusted based on the 2024 WEM ESOO forecasts, with the SRC process available to procure additional capacity for 2024-25 if required.

The anticipated procurement of SRC for 2023-24 and possibly 2024-25, alongside the peak demand NCESS procurement for 2024-26, highlights the immediate requirement for investment in capacity in the WEM. Capacity projects with shorter lead times, such as DSM capacity and distributed energy resources (DER) aggregation, hold significant potential to participate in these additional capacity procurement processes.

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

[17] See https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/supplementary-reserve-capacity/src-2022-23-presentation-04082023.pdf.

[18] Energy Policy WA, *Coordinator of Energy Determination: AEMO Non-co-optimised Essential System Service Trigger Submission*, 2022, at https://www.wa.gov.au/system/files/2022-12/Coordinator%20of%20Energy%20Determination%20-%20Reliability%20Service%20-%20f2.pdf.

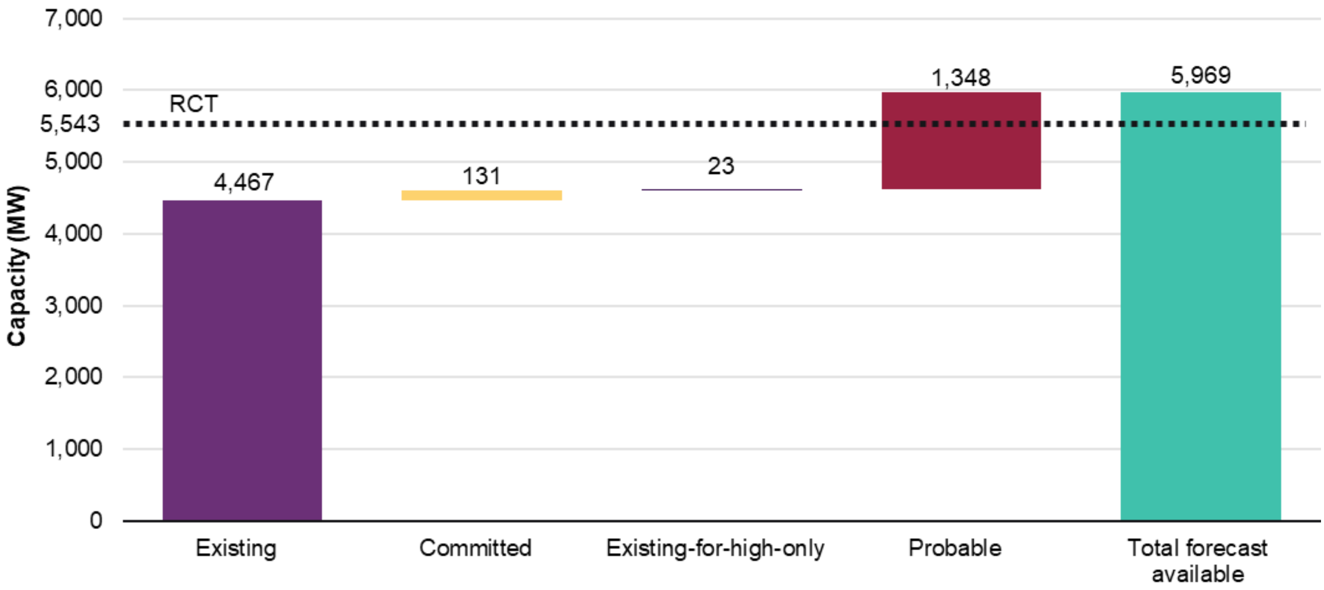
Committed capacity is not yet sufficient to offset generator retirements and forecast increases in demand for 2025-26

AEMO estimates that a total of 4,598 MW of capacity is expected to be available to meet the RCR of 5,543 MW for the 2023 Reserve Capacity Cycle related to 2025-26. This includes 4,467 MW of existing capacity and 131 MW of committed capacity. An additional 945 MW of capacity is therefore needed to meet the RCR for 2025-26. The 2024-26 Peak Demand NCESS is likely to contribute significantly to this requirement but is not considered committed until contracts are finalised and relevant contractual conditions precedent are achieved.

In addition to the projects that have already been committed, there are several other generation and storage projects in various stages of development. These range from proposed to probable projects that may happen but do not yet meet all the criteria to be considered by AEMO as committed.

AEMO has analysed the development status of new projects obtained from the 2022 and 2023 Expressions of Interest (EOI)[19] provided as part of the RCM, the 2023 Long Term PASA formal information requests, and the 2024-26 Peak Demand NCESS process. This analysis considers factors such as network access, project financing status, and environmental approvals. Based on this analysis, a total of 1,348 MW of new projects in the pipeline that meet AEMO's evaluation criteria are considered probable capacity[20] for supplying capacity in 2025-26, including the 2024-26 Peak Demand NCESS capacity announced or under contract negotiation with AEMO (see Figure 2).

Figure 2 Forecast Reserve Capacity status for 2025-26



Note: The Existing-for-high-only capacity is included in the high demand growth scenario only for the capacity supply forecasts. It is associated with Registered Facilities that did not receive Capacity Credits for 2024-25 but received Capacity Credits for 2022-23 or 2023-24.

[19] See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2023/2023-expressions-of-interest-summary-report.pdf.

[20] Probable capacity is considered only in the high demand growth scenario for the capacity supply forecasts. It is associated with new projects that are candidates for registration but have not received Capacity Credits for 2024-25 and includes the 2024-26 Peak Demand NCESS capacity under contract negotiation with AEMO.

The pipeline of probable projects expected to supply 2025-26 includes 60 MW of wind generation, 34 MW of solar generation capacity, 1,077 MW of battery energy storage system capacity, 120 MW of DSM capacity, and 57 MW of peaking capacity operated with gas or diesel fuels[21].

If these projects are completed as planned, they could fulfill the additional capacity needed to meet the RCR for 2025-26, thereby addressing reliability challenges and supporting the ongoing energy transition.

Strong capacity investment signals and planned transmission expansion are expected to improve the long-term reliability outlook

In the longer term, AEMO forecasts a significant opportunity for investment in WA, with capacity needed to meet growing demand and ensure a reliable and secure power system. Based on existing and committed capacity, an additional 1,118 MW of capacity is projected to be required by 2026-27, increasing to 4,000 MW by 2032-33. The need for capacity investment was similarly reflected in the SWIS Demand Assessment, which identified the need for significant investment in firmed renewables across the next 20-years.

Information collected by AEMO from a range of sources indicates there is already a substantial pipeline of wind and solar generation, battery storage, gas or diesel peaking generation and DSM that may be developed over coming years in response to this opportunity. Further opportunities also exist for additional capacity projects to contribute to future SWIS reliability needs.

Investment in the capacity of the electricity network will also be required to enable this new capacity to be delivered to customers. AEMO projects that network constraints will impact the electricity sent out to meet demand in the SWIS sub-regions, particularly beyond 2025-26. These constraints align with those outlined in the SWIS Demand Assessment, which outlines network augmentation options to be implemented in stages to address network transfer capability requirement over the next 20 years.

Proactive, collaborative action is required and is progressing

In summary, the forecast reliability gap highlights both the urgency and significance of the capacity investment opportunity in the SWIS. Timely development of new capacity and network augmentations will be required over the coming decade to meet growing demand in the SWIS and replace coal-fired generation as it is retired. By proactively addressing barriers and facilitating the progression of these projects, AEMO and other agencies can contribute to a more reliable power system.

The Energy Transformation Strategy being progressed by the WA Government aims to facilitate the shift towards low emissions and distributed energy sources. AEMO is working in collaboration with Energy Policy WA, Western Power and SWIS stakeholders as part of this ongoing effort geared towards establishing a modern electricity system and market that ensures ongoing power system security and reliability to meet customer needs during the accelerated energy transition in the SWIS.

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

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Notes

- This WEM ESOO uses many terms that have meanings defined in the Wholesale Electricity Market Rules (WEM Rules) and Wholesale Electricity Market Amendment (Tranche 6A Amendments) Rules 2023. The WEM Rules meanings are adopted unless otherwise specified. Terms which are defined in the WEM Rules are capitalised. Other terms are defined throughout the report and in the Glossary.
- All data in this WEM ESOO is based on Capacity Years unless otherwise specified. A Capacity Year commences in Trading Interval 08:00 on 1 October and ends in Trading Interval 07:30 on 1 October of the following calendar year.
- Consumption/demand is operational consumption/demand unless otherwise specified in this WEM ESOO. A definition of operational consumption and demand can be found in Chapter 1 and in the Glossary.
- This WEM ESOO provides low, expected, and high demand growth scenarios based on different levels of economic growth as defined in clause 4.5.10 of the WEM Rules. Unless otherwise indicated, demand forecasts are based on the expected demand growth scenario.
- All temperature data is sourced from the Bureau of Meteorology at a half-hourly resolution and is based on the maximum temperature recorded in that Trading Interval.
- HH:MM Trading Interval means Trading Interval commencing at HH:MM.
- This WEM ESOO provides forecasts for the10-year outlook period that refers to the period 2022-23 to 2032-33. The first half of the outlook period refers to the period 2022-23 to 2027-28, and the second half refers to the period 2027-28 to 2032-33.
- The compound annual growth rate was used to calculate the average annual growth rate. AEMO refined the calculation by using the first outlook year (year 1) minus one year (year 0) as the base year instead of year 1 to calculate the 10-year average annual growth rate. 2022-23 and 2027-28 were used as year 0 to calculate the five-year average annual growth rates for the first half and second half of the outlook period, respectively.

1 Introduction

1.1 Purpose and scope

The Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) presents the results of AEMO's annual Long Term Projected Assessment of System Adequacy (PASA) for the South West Interconnected System (SWIS) in Western Australia (WA) over a 10-year horizon. Its primary purpose is to identify the investment in capacity from generation, storage, and demand-side management (DSM) needed to ensure a secure and reliable electricity supply for the SWIS over the coming ten years.

The WEM ESOO plays a critical role in the Reserve Capacity Mechanism (RCM), which aims to ensure adequate capacity in each Capacity Year to meet the Planning Criterion for the SWIS. The Planning Criterion ensures there is sufficient capacity in the SWIS to meet peak demand forecasts plus a reserve margin, and limit expected unserved energy (EUE) to less than 0.002% of the annual forecast demand[22].

To support the objective of the RCM, the WEM ESOO:

- Determines the Reserve Capacity Target (RCT) for each Capacity Year in the 10-year horizon and projects the supply-demand balance of capacity. The 2023 WEM ESOO covers the outlook period from the 2023-24 to 2032-33 Capacity Years[23].
- Sets the RCT as the Reserve Capacity Requirement (RCR) for the relevant Reserve Capacity Cycle, enabling the procurement of Capacity Credits. The 2023 WEM ESOO designates the RCT determined for 2025-26 as the RCR for the 2023 Reserve Capacity Cycle.
- Identifies necessary investments to maintain Power System Reliability[24].

As part of the Long Term PASA study, the WEM ESOO develops and presents forecasts for electricity consumption and peak demand across a range of weather and demand growth scenarios. These forecasts are vital inputs for assessing the power system reliability and forecasting the supply-demand balance over the outlook period, accounting for the anticipated available capacity supply and network capabilities.

To manage the risk of under-procurement or changes to available capacity, the RCM includes the Supplementary Reserve Capacity (SRC) mechanism. This mechanism allows AEMO to procure additional capacity based on the latest WEM ESOO forecasts and other information AEMO considers relevant, within six months before the start of a Capacity Year. Additionally, at AEMO's request, the Coordinator of Energy (Coordinator) may trigger the Non-Co-optimised Essential System Services (NCESS) procurement to acquire additional capacity or other services, where required to maintain power system security and reliability.

[22] Clause 4.5.9 of the WEM Rules, the Planning Criterion. Limb A refers to peak demand forecast plus a reserve margin and limb B refers capacity needed to limit EUE to less than 0.002% of the annual forecast demand.

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

[24] As defined under the WEM Rules, this refers to the ability of the SWIS to deliver energy within reliability standards while consistently and efficiently supplying energy to meet demand, and while maintaining Power System Adequacy and Power System Security. This involves ensuring that all demand for electricity is met, allowing for scheduled or unscheduled equipment outages, and withstanding sudden disturbances such as equipment failures.

In this 2023 WEM ESOO:

- Chapter 1 introduces important definitions and scenarios that underpin the accelerating shift towards decarbonisation presented by the energy transition.
- Chapter 2 presents supporting forecasts and key drivers for electricity consumption and demand, incorporating for the first time the impact of electrification from the non-transportation sector and electricity consumption for hydrogen production.
- Chapter 3 focuses on consumption forecasts and Chapter 4 presents peak and minimum demand forecasts, revealing a robust growth trajectory throughout the outlook period.
- Chapter 5 provides a summary of the Reserve Capacity forecasts used for the reliability assessment, assumptions regarding capacity classifications, changes in assigned Capacity Credits for 2024-25, and the pipeline of future projects.
- Chapter 6 offers detailed insights into the outcomes of the reliability assessment, including RCT determinations and the supply-demand balance outlook. This chapter highlights opportunities for investment in capacity to maintain system reliability, as well as transmission network constraints and augmentation works.

1.2 Key definitions

AEMO uses various parameters and components to develop electricity consumption and demand forecasts. Table 5 presents several of the key definitions used in this process. As much as possible, AEMO uses the same definitions in developing the consumption and demand forecasts for ESOOs in both the WEM and the National Electricity Market (NEM), while also considering WEM-specific definitions where applicable.

Table 5 also includes several key definitions that have been applied for the reliability assessment.

Table 5 Definitions for key terms used in the 2023 WEM ESOO

Term	Definition
Distributed energy resources terms	
Distributed energy resources (DER)	DER includes distributed photovoltaics (DPV), distributed battery storage, and electric vehicles (EVs).
Distributed energy storage systems (DESS)	DESS are small distributed behind-the-meter battery storage systems installed for residential, commercial, and large commercial customers, that do not hold Capacity Credits in the WEM.
Distributed photovoltaics (DPV)	DPV is used to capture both rooftop PV and PV non-scheduled generation (PVNSG); see below for definitions.
Electric vehicle (EV)	EVs are electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.
PV non-scheduled generation (PVNSG)	Defined as non-scheduled photovoltaic generators larger than 100 kilowatts (kW) but smaller than 10 megawatts (MW) that do not hold Capacity Credits in the WEM.
Rooftop photovoltaics (PV)	Defined as photovoltaics installed on a residential building (less than 15 kW) or business premises (less than 100 kW).
Virtual power plant (VPP)[A]	An aggregation or grouping of DER that is actively controlled and coordinated via an Orchestration System[B] by an operator. VPPs can operate in a coordinated manner to provide services to other parties (such as the wholesale market and/or network).

Term	Definition
Consumption and demand terms	
Consumption	The amount of power used over a period of time, conventionally reported as megawatt hours (MWh), gigawatt hours (GWh), or terawatt hours (TWh), depending on the magnitude of power consumed. It is reported on a "sent-out" basis (excluding electricity used by a generator[C]) unless otherwise stated.
Demand	Demand is defined as the amount of power consumed at any time. Peak and minimum demand is measured in megawatts (MW) and averaged over a 30-minute period. It is reported on a "sent-out" basis (excluding electricity used by a generator) unless otherwise stated (see below for definitions of demand specifications).
Delivered consumption (or demand)	Electricity consumption (or demand) that is supplied to electricity users from the grid. It excludes the part of their consumption (or demand) that is met by behind-the-meter (typically rooftop PV) generation.
Operational consumption[D] (or demand)[E]	• Electricity consumption (or demand) that is met by sent-out electricity supply of all market registered energy producing units[F]. It includes losses incurred from the transmission and distribution of electricity and electricity consumption (or demand) of EVs but excludes electricity consumption (or demand) met by DPV generation. • Operational consumption includes energy efficiency losses of distributed battery storage operation. • Operational demand includes impacts of distributed battery storage discharging (reducing operational demand) and charging (increasing operational demand). • Peak and minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of market-based solutions that might increase or reduce operational demand (including storage, coordinated EV charging and demand response). Only non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained peak and minimum operational demand forecasts.
Market underlying consumption (or demand)	The total amount of electricity consumption (or demand) in the market, which includes electricity delivered to meet the consumption (or demand) of residential and business customers (including the impact of distributed battery storage operation), network losses, and DPV generation.
End-user underlying consumption (or demand)	The total amount of electricity consumption (or demand) by electricity users from their power points (excluding network losses), regardless of whether it is supplied from the grid or by behind-the-meter (typically rooftop PV) generation.
Other consumption and demand forecasting terms	
Business sector	Business sector includes industrial and commercial users. This sector is subcategorised further to include large industrial loads (LILs) and business mass market (BMM); see below for definitions.
Business mass market (BMM)	BMM covers those business loads that are not included in the LIL sector.
Large industrial load (LIL)	LILs are users that consume, or are forecast to consume, at least 10 MW for a minimum of 10% of the time (around 875 hours a year) or at least 50 GWh per year. LILs include existing and new LILs.
Committed and prospective LIL	New LILs are segmented into committed and prospective LILs based on AEMO's evaluation criteria, including final investment decision (FID), environmental approval, network access status, and decarbonisation (see Section 2.7 and Appendix A2 for further information). Committed LILs are included in both expected and high scenarios, while prospective LILs are only included in the high demand growth scenario.
Residential sector	Residential sector includes non-contestable[H] residential customers (supplied by Synergy) only.
Probability of exceedance (POE)	A measure of the likelihood of a value being met or exceeded. For example, a 10% POE maximum demand forecast is expected to be met or exceeded, on average, one year in 10, while a 90% POE maximum demand forecast is expected to be met or exceeded nine years in 10.
Reliability assessment terms	
Anticipated Installed Capacity (AIC)	The anticipated quantity of Reserve Capacity available from existing, committed, or probable capacity; see below for definitions.
Committed capacity	Capacity provided by new projects that are candidates for registration and have been assigned Capacity Credits for 2024-25 or scored 80% or higher in the new project status evaluation as outlined in Chapter 5 of this WEM ESOO. Committed capacity is included in both expected and high scenarios for the capacity supply forecasts.

Term	Definition
Existing capacity	Capacity provided by Registered Facilities that have been assigned Capacity Credits for 2022-23, 2023-24, or 2024-25. Existing capacity is included in the low, expected, and high scenarios for the capacity supply forecasts.
Expected Unserved Energy (EUE)	A normalised metric, which does not have a unit. It represents the estimated percentage of forecast electricity operational consumption for a Capacity Year which cannot be met by all AIC in that Capacity Year.
Probable capacity	Capacity comprised of new projects that: • are a candidate for registration and have submitted a valid Expression of Interest for the 2023 Reserve Capacity Cycle (2023 EOI)[I], • are contracted or expected to be contracted for the 2024-26 Peak Demand NCESS, or • have scored 50% or more but less than 80% in the new project status evaluation. Probable capacity is included only in the high scenario for the capacity supply forecasts.

A. As defined in AEMO's VPP Visibility Guideline (p8), at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/wa_wem_consultation_documents/2022/proposed-design-for-a-visibility-framework/vpp-visibility-guideline.pdf.
B. Orchestration System means, without limitation, the technologies, technology platform(s), algorithms, process and systems used to coordinate the Injection and Withdrawal of energy from the DER within an Aggregation of DER. See AEMO's VPP Visibility Guideline.
C. This may be called 'auxiliary load', 'parasitic load', or 'self-load', and refers to energy generated for use within power stations.
D. 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.
E. 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.
F. Includes market generators and utility-scale energy storage systems.
G. Historical market underlying consumption (or demand) calculation does not consider impacts of distributed battery storage. Due to the current relatively low uptake of distributed battery storage in the SWIS, its impact on historical underlying demand is negligible.
H. A non-contestable customer is a customer that uses less than 50 MWh of electricity per year and is connected to Western Power's distribution network.
I. The information that a 2023 EOI must include to be deemed valid is outlined in clause 4.4.1 of the WEM Rules.

1.3 Scenarios

The WEM Rules require the WEM ESOO to use three demand growth scenarios: low, expected, and high. AEMO has selected three scenarios from the 2023 Draft *Inputs Assumptions and Scenarios Report* (IASR)[25] scenarios to align with these requirements. These selections consider the policy commitments of the Federal Government and WA Government at the time of the development of this WEM ESOO.

The 2023 WEM ESOO scenarios build on the scenarios in the 2022 WEM ESOO[26] and reflect AEMO's latest assumptions relating to economic, political, technological innovation, and climatic factors that influence the energy transition.

Relative to 2022, the 2023 WEM ESOO scenarios are underpinned by the following changes:

- Increased emissions reduction targets.
- An inclusion of business and residential electrification.
- An emerging role for a green hydrogen industry.

Australia's federal, state and territory governments are actively supporting the energy transition and related emissions reduction initiatives. One of the most significant federal policies has been the commitment to reducing emissions by 43% by 2030, and a net zero target by 2050. In WA, the state government will introduce climate

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

[26] AEMO, 2022 Wholesale Electricity Market Electricity Statement of Opportunities, 2022 at https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf.

change legislation this year to reduce government emissions by 80% below the 2020 level by 2030, and to meet net zero by 2050[27].

The scenarios in the 2023 WEM ESOO are[28]:

- **Low scenario** (*Progressive Change*) – this scenario explores the challenges of achieving Australia's Paris Agreement commitment of a 43% emissions reduction compared to 2005 levels by 2030 in a more challenging economic environment. While ongoing energy sector investments are required by national and state policies, industrial loads face increased risks due to economic constraints and high energy costs on a global scale. The slower pace of change in this scenario is primarily due to higher technology costs and supply chain challenges compared to other scenarios. Nonetheless, substantial investments in decarbonisation are still anticipated, as a result, the transition in this scenario is expected to be faster than the low scenario presented in the 2022 WEM ESOO.
- **Expected scenario** (*Step Change*) – this scenario is centred around achieving a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. It highlights the importance of active consumer participation and significant investments in clean energy resources to drive the decarbonisation of Australia's economy. Notably, compared to the 2022 WEM ESOO, this scenario forecasts a substantial increase in electrification across both the business and residential sectors, which is a new inclusion in this WEM ESOO. Additionally, the scenario takes into consideration the growing interest in developing hydrogen production capabilities to meet emerging domestic and international energy demands.
- **High scenario** (*Green Energy Exports*) – this scenario reflects very strong decarbonisation efforts both domestically and globally to limit temperature increase to 1.5°C. This leads to a rapid transformation of Australia's energy sectors and a strong emphasis on electrification. With increased domestic and international economic growth, there is a global demand for green energy. The scenario benefits from higher domestic and international economic growth, driving a global demand for green energy. Enhanced settings for technological development, supply chain management, social acceptance, and domestic and international cooperation enable substantial growth in green energy exports, including the export of green hydrogen through ammonia and energy-intensive manufacturing utilising hydrogen, such as green steel production.

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

A complete description of the scenarios, including narratives and key parameters is presented in the 2023 IASR.

Table 6 provides a summary of scenario assumptions for the 2023 WEM ESOO, highlighting changes compared to the 2022 WEM ESOO.

[27] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2023/01/McGowan-Government-to-introduce-climate-change-legislation.aspx.

[28] The corresponding scenarios from the 2023 IASR are noted in italics.

Table 6 Scenario and assumption variations, 2023 WEM ESOO compared to 2022 WEM ESOO

Demand growth scenario	Low		Expected		High	
WEM ESOO	2023	2022	2023	2022	2023	2022
Scenario name	*Progressive Change*	*Slow Change*	*Step Change*	*Progressive Change*	*Green Energy Exports*	*Strong Electrification*
Australian economic and demographic drivers	Lower	Lower	Moderate	Moderate	High (partly driven by green energy)	Higher
Energy efficiency	Lower	Lower	High	Moderate	Higher	Higher
DER uptake (batteries, PV and EVs)	Lower	Lower	High	Moderate	Higher	Higher
Storage aggregation and coordination such as VPPs	Lower	N/A	High	N/A	Higher	N/A
Electrification (other than transportation sector)	Lower	N/A	High	N/A	Higher	N/A
Uptake of coordinated EV charging[A]	Moderate	Slower	Faster	Moderate	Faster	Faster
Hydrogen use/ hydrogen blending in gas distribution network[B]	Low production for domestic use, with no export hydrogen. Up to 10% blending in gas network.	N/A	Medium-Low production for domestic use, with minimal export hydrogen. Up to 10% blending in gas network.	N/A	High production for domestic and export use. Up to 10% blending in gas network until 2030, with potential for higher blending thereafter.	N/A
National decarbonisation target	At least 43% emissions reduction by 2030	26-28% reduction by 2030	At least 43% emissions reduction by 2030.	26-28% reduction by 2030	At least 43% emissions reduction by 2030.	26-28% reduction by 2030
	Net zero by 2050	No target beyond 2030	Net zero by 2050.	Net-zero by 2050	Net-zero by 2050.	Net-zero by early 2040s
Supply chain barriers	More challenging	N/A	Moderate	N/A	Less challenging	N/A

A. This refers to charging optimised towards system conditions, where charging happens at time of low system demand.
B. Hydrogen blending of the gas network will need to accommodate the technical requirements of transmission and distribution pipelines, as well as the capabilities of connected gas appliances. Higher blends than ~10% may require appliance change and/or switches to dedicated hydrogen transmission pipelines.

In 2022, while the *Step Change* scenario in the 2021 IASR was generally regarded as the most likely scenario and used as such in other AEMO planning, the *Progressive Change* scenario from the IASR was applied as the expected scenario in the 2022 WEM ESOO. At that time, AEMO did not have sufficient information about the pace of electrification in the SWIS to support the use of the *Step Change* scenario as the expected scenario for the SWIS. AEMO now has updated electrification information for the SWIS which confirms the appropriateness of *Step Change* being applied as the expected scenario in 2023 WEM ESOO, and this incorporates an uplift in demand forecast compared to last year's forecast.

1.4 Consumption and demand forecast methodology

The approaches used in forecasting operational demand and consumption are largely in line with the methodologies outlined in AEMO's *Forecasting Approach – Electricity Demand Forecasting Methodology* paper (Methodology Paper), expected to be published in August 2023[29].

This section provides a brief summary of the consumption and demand forecasting approach, highlighting key differences in the drivers and methodologies compared to the 2022 WEM ESOO.

Where practical, AEMO has aligned methods used to develop electricity consumption and demand forecasts for both the NEM and the WEM.

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

1.4.1 Consumption forecasts

AEMO developed electricity consumption forecasts for three demand growth scenarios: low, expected, and high. These forecasts were based on projected consumption in the business sector, residential sector, and electric vehicle (EV) charging.

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

For the **residential consumption** forecast, AEMO applied a growth model based on historical residential connections and monthly consumption data. The forecast was then adjusted by considering the impact of various external consumption drivers, including the rate of fuel switching and the uptake of energy efficiency measures[30].

The electricity consumption required for **hydrogen production** was based on the 2022 multi-sectoral modelling developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and ClimateWorks Centre (CWC)[31].

Forecasts for the **electricity consumption needed to charge EVs** were based on CSIRO's 2022 EV projections, which considered EV uptake numbers, charging profiles, and the percentage split across charge profiles during EV charging.

The total operational consumption forecasts were calculated by aggregating the underlying consumption of the business and residential sectors, along with EV consumption forecasts, adjusting for factors such as distributed photovoltaic (DPV) generation, distributed energy storage systems (DESS), losses, and distribution and transmission network losses.

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[29] The Methodology Paper is scheduled to be published by the end of August 2023, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines. The 2022 Methodology Paper is available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf?la=en.

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

[31] CSIRO and CWC, Multi-sector energy modelling 2022:methodology and results, Final report 2022, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

1.4.2 Demand forecasts

For the demand forecasts, AEMO considered both:

- structural drivers, which are not influenced by weather or seasonal effects (these are captured through the scenarios), and
- random drivers that affect outcome at the time when peak demand and minimum demand occur[32].

Summer and winter peak demands are heavily dependent on cooling and heating loads, respectively, in response to extreme temperature conditions. In addition, LILs and hydrogen loads may reduce their production during peak demand periods to reduce their exposure to Reserve Capacity costs and high electricity prices.

To capture the range of possible demand outcomes from the random drivers, AEMO applied a Generalised Extreme Value (GEV) model[33] to capture and understand the distribution of extreme events in the summer and winter seasons. This resulted in a distribution of possible peak demand outcomes.

Peak and minimum demand forecasts represent uncontrolled or unconstrained demand[34], without considering market-based or non-market-based interventions that may reduce system load during peak and minimum demand periods. As such, the forecast does not account for:

- Demand side participation procured through the RCM.
- Any unserved energy as a result of directed load shedding or significant network outages.
- Any coordinated, customer-controlled behind-the-meter battery and EV charging (through Virtual Power Plants (VPPs)). The timing of VPP charging is anticipated to materially influence the scale of grid demand; increased charging during daytime periods when DPV generation is available, rather than during peak demand in the evening, would both reduce peak demand and increase minimum demand.

1.4.3 Changes in the forecasting approach and drivers

The 2023 WEM ESOO consumption and demand forecasts incorporated new and updated drivers (see Chapter 2 for further information) and applied refined modelling approaches, including:

- Incorporation of emerging drivers – the 2023 WEM ESOO forecasts considered electricity usage from hydrogen production, electrification, and EV uptake[35] in both the business and residential sectors. These additions were informed by the 2022 multi-sectoral modelling and were projected to have a growing impact on the forecasts over the outlook period. These updates align with stronger carbon emission reduction targets aimed at tackling climate change. The forecasts assumed 90% curtailment of hydrogen load during peak demand, based on industry feedback. AEMO will continuously monitor industry trends and stakeholder feedback to refine this assumption for future WEM ESOO forecasts.
- Improved new LIL information – Western Power provided detailed information on new LIL connections for the 10-year outlook period. AEMO adjusted the evaluation criteria for selection of committed and prospective LILs,

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

[33] The GEV model is fitted using monthly operational minima and maxima as a function of PV capacity, PV non-scheduled generation (PVNSG) capacity, customer connections (National Metering Identifiers (NMIs)), calendar effect variables and average weather.

[34] The unconstrained demand forecasts help identify the potential system needs for, and value of, these solutions such as demand side participation.

[35] This included electrification and EV uptake from both residential and business sectors.

taking into consideration Western Power's input, industrial decarbonisation, and global demand for critical minerals required for the energy transition. Load factor assumptions by industry type were also refined.

- Refreshed forecast for distributed energy resources (DER) – DER forecasts have been updated, with components rebased where possible. This included an increase in EV charging during peak demand periods due to stronger forecasts for EV uptake, despite adjustments made to charge profiles to reflect lower demand during peak for convenience charging[36].
- Updated appliances uptake data[37] and energy efficiency savings forecasts – the 2023 WEM ESOO forecasts incorporated updated data on the uptake of appliances, and energy efficiency savings forecasts have been revised to reflect slower improvements in residential energy efficiency.
- Improved classification of historical consumption data – AEMO recalibrated the residential data provided by Synergy and improved allocation of historical consumption between the residential and BMM sectors to better align with AEMO's definitions of delivered consumption. The adjustments resulted in a more accurate representation of the starting point for residential and BMM consumption forecasts.
- Retraining the GEV model – the GEV model was trained using a complete set of 2022 data. This raised the starting point for peak demand forecasts[38], and fine-tuned the model to better forecast the impact of DPV growth on minimum demand.

1.5 Reliability assessment methodology

AEMO engaged Ernst & Young (EY) to conduct the 2023 reliability assessment. The assessment was performed based on the 2023 WEM ESOO electricity consumption and demand forecasts for the 10-year Long Term PASA Study Horizon (2023-24 to 2032-33), to:

- Assess the extent to which the anticipated installed capacity of the energy producing systems and DSM capacity can satisfy both limbs of the Planning Criterion, identifying any capacity shortfalls.
- Determine whether the RCTs are set by limb A or limb B of the Planning Criterion and quantify the RCTs (in megawatts (MW)).
- Determine the requirements for the capacities of Availability Classes 1 and 2[39] to fulfill the RCTs for 2024-25 and 2025-26, respectively.

[36] In the 2022 EV projections, CSIRO revised the peak charging demand for the convenience charging profile to around 0.4 kilowatts (kW), in comparison to be almost 1.2 kW presented in the 2021 EV projections. See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf.

[37] This 2023 WEM ESOO is based on appliance projections from the 2021 Residential Energy Baseline Study: Australia and New Zealand, which was published in May 2022, replacing the 2015 Residential Baseline Study used in previous years. See https://www.energyrating.gov.au/news-and-stories/2021-residential-energy-baseline-study-australia-and-new-zealand.

[38] The data consists of both temperature and underlying demand data. "Full 2022 data" means data from the entire year of 2022, which covers the 2021-22 summer. The peak demand forecasts are increased as a result of a relatively higher peak demand observed in the 2021-22 summer.

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

- Create a demand duration curve of the forecast minimum capacity requirements (Availability Curves)[40] for 2024-25 and 2025-26, based on the 10% probability of exceedance (POE) peak demand forecast under the expected scenario and the RCT determination.

EY applied time sequential dispatch modelling to carry out the reliability assessment. The assessment considered network constraints, Facility outages, renewable resource variability, and weather-driven demand patterns, conducting iterations to evaluate unserved energy events.

Further information about the reliability assessment methodology is in Appendix A3 of this WEM ESOO and EY's 2023 reliability assessment report[41].

[40] The Availability Curve (defined in clause 4.5.10(e) of the WEM Rules) shows how demand changes over a Capacity Year, with demand on the vertical axis and time on the horizontal axis. It can be used to determine the number of hours when the capacity requirement exceeds a given level of demand and includes a capacity margin to indicate total expected capacity required.

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

2 Consumption and demand forecasting inputs

Each year, AEMO updates its 10-year projections of energy consumption and peak demand for the three WEM scenarios and presents them in the WEM ESOO. These updates are based on stakeholder consultation and various model inputs.

For the 2023 WEM ESOO, AEMO aligned the low, expected, and high scenarios with the *Progressive Change*, *Step Change*, and *Green Energy Exports* scenarios developed as part of the 2023 IASR, respectively. The 2023 IASR scenarios built on the 2021 IASR scenarios (used for developing the 2022 WEM ESOO) and reflect the collective insights of AEMO and stakeholders. AEMO ensures that the scenarios maintain relevance by updating them to reflect the changing landscape of social, technological, and political factors[42]. Notably, the 2023 IASR scenarios include Australia's increased commitment to meeting net zero emissions by 2050.

AEMO provided external consultants with scenario assumptions to develop key inputs for the 2023 WEM ESOO consumption and demand forecasts, and consulted with stakeholders on the forecasting inputs via Forecasting Reference Group (FRG) meetings, including:

- **State-based macroeconomic projection** (see Sections 2.1 and Section 2.2) – accounting for economic drivers such as inflation, population, and investments that impact demand, supply, and energy prices. This resulted in two forecast outcomes for WA:
  - State economic performance and demographic projections.
  - Influence of global commodity prices, trade, and industrial composition at the state level.
- **State-based forecasts of DER uptake** (see Section 2.3) – incorporating post-pandemic spending behaviour, investment opportunities, and global supply chain constraints. This resulted in two key forecast outcomes for the SWIS:
  - Uptake of DPV and DESS for the business and residential sectors.
  - Uptake of EVs, EV charging consumption and profiles, EV sales, and fleet share.
- **State-based energy efficiency forecast** (see Section 2.4) – accounting for the impact of policy-led sectoral energy efficiency savings on energy use. This produced two key forecast outcomes for the SWIS:
  - Estimation of energy efficiency savings.
  - Energy efficiency improvement in industrial, commercial, and residential sectors.
- **Whole-of-economy multi-sectoral modelling** (see Sections 2.5 and 2.6) – the modelling outcome informed the pace and breadth of the energy transformation in the SWIS. This ensured consistent emissions abatement outcomes, aligned with the scenario narratives, the World Energy Outlook[43] scenarios, and Representative Concentration Pathways[44]. The key forecast inputs included:

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[42] For example, the *Slow Change* scenario from the 2021 IASR described a potential world with low social and political appetite for decarbonisation. Following Australia's commitment to a 43% emissions reduction target by 2030, planning for a *Slow Change* is no longer consistent with the policy settings.

[43] See IEA, *World Energy Outlook 2022*, at https://www.iea.org/reports/world-energy-outlook-2022.

[44] See https://www.ipcc-data.org/guidelines/pages/glossary/glossary_r.

- Electrification through fuel-switching for industrial, commercial, and residential sectors.
- Electricity required for the forecast magnitude of renewable hydrogen production for domestic use and export purposes.

- Additionally, AEMO undertook a **detailed survey of existing LILs and assessment of new LILs** in the SWIS (see Section 2.7). This resulted in two forecast inputs:
  - Scale of new LILs, especially an improved view of the long term projects in the pipeline informed by Western Power's assessment of project connections.
  - Scale of existing LILs, identified and categorised based on an extensive list of National Metering Identifiers (NMIs).

These inputs served as key drivers for the demand and consumption forecasts, and are categorised as existing and emerging drivers in this WEM ESOO:

- **Existing drivers** – traditionally influential factors include economic and population growth, DPV and DESS uptake, energy efficiency savings, LILs, and consumer preference.
- **Emerging drivers** – recently recognised drivers expected to gain importance include EV uptake, electrification in the business and residential sectors[45], and renewable hydrogen production.

Two of these emerging drivers – electrification in business and residential sectors and renewable hydrogen production – are included in this WEM ESOO for the first time, to align with more ambitious Australian Federal Government and WA Government policies and market development. Emerging drivers, along with strong growth in new LIL projects, are projected to dominate long-term consumption and demand forecasts, surpassing existing drivers (see Chapters 3 and 4 for details).

2.1 Economic and population growth outlook

AEMO engaged Oxford Economics Australia[46] to provide forecasts for WA gross state product (GSP) and population[47]. Oxford Economics Australia applied a suite of models including the Oxford Global Economic Model, the Global Industry Model, and the Australian Regional Model to develop the economic forecasts for Australia at the state and national level.

Economic growth refers to the expansion of a nation's capacity to produce goods and services. The current and expected future level of economic growth affects investment and spending in an economy and influences how consumers, businesses, and governments allocate their resources.

Economic growth expectations for WA (see Figure 3) are varied across the scenarios:

- The high scenario includes higher economic growth both domestically and internationally with strong policy coordination.
- The expected scenario includes moderate economic growth combined with strong policy coordination.

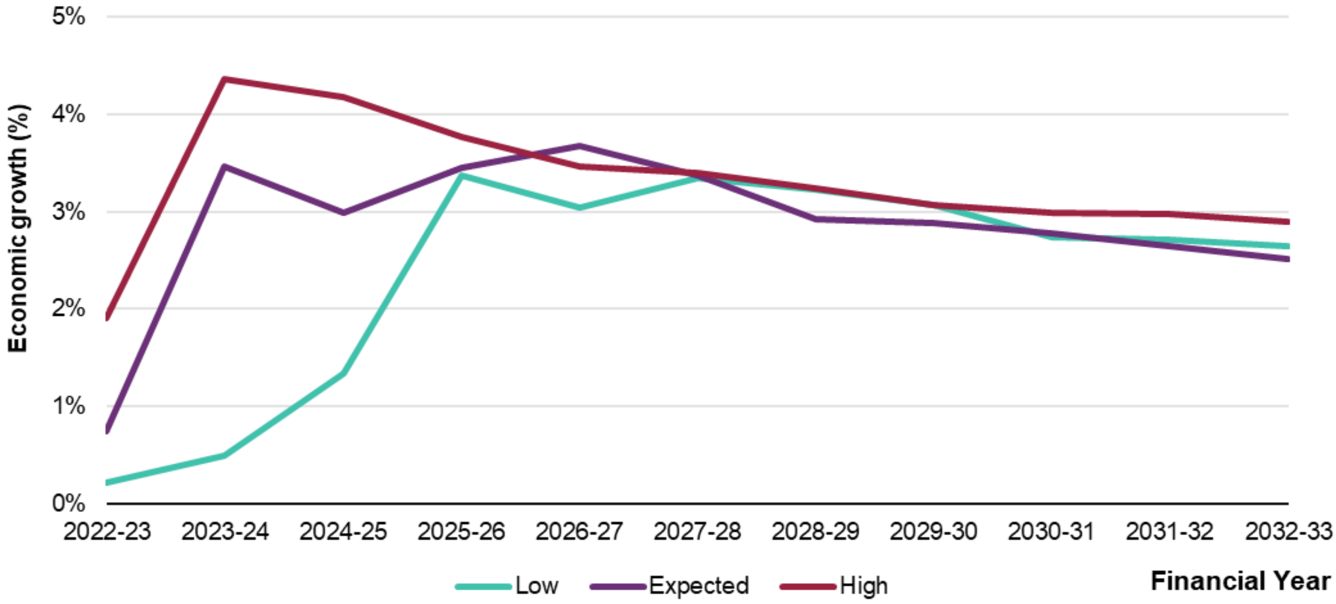
[45] It refers to the electrification for non-transportation related activities in the business and residential sectors. Transportation-related electrification is reflected in the EV uptake forecasts.

[46] BIS Oxford Economics was rebranded as Oxford Economics Australia in May 2023.

[47] See Oxford Economics Australia, Macroeconomic Projections Report, 2022, at https://aemo.com.au/media/files/stakeholder consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf.

- The low scenario features slower economic growth and lesser policy coordination (but includes the actions needed to meet current policy commitments).

Figure 3 Forecast WA economic growth under three scenarios, 2022-23 to 2032-33 financial years

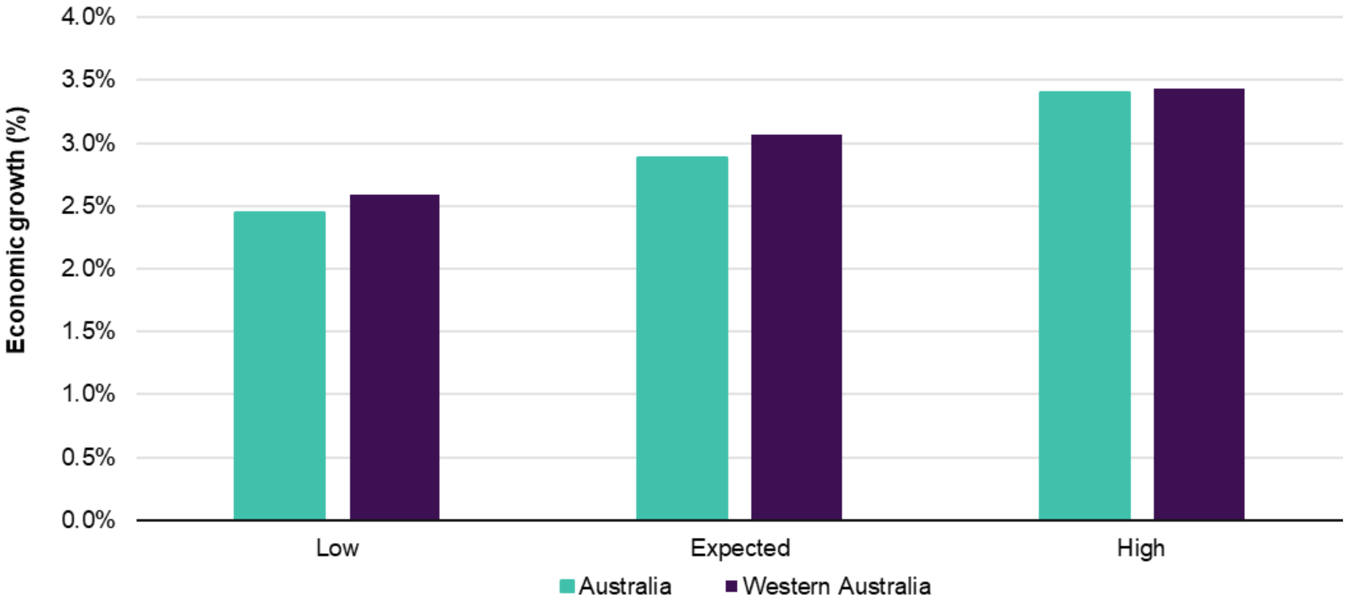


Source: Oxford Economics Australia.

Across all scenarios, growth in WA is expected to outpace growth at the national level. AEMO notes that WA's relatively high economic growth rate (see Figure 4) can facilitate the state's energy transition, especially when coupled with policy commitment to decarbonise the state's economy. Higher economic growth is expected to increase government revenues and help stimulate investment and spending in the state and may lead to higher population growth. Coordination of investment and spending via government policy is expected to increase the pace of the energy transition. Across all scenarios, economic growth recovers from the low growth period experienced due to COVID-19, regressing towards an average long-term growth rate[48].

[48] The average long-term growth rate is decreasing over time due to structural changes in the economy, such as an ageing population and subdued investment added and productivity growth.

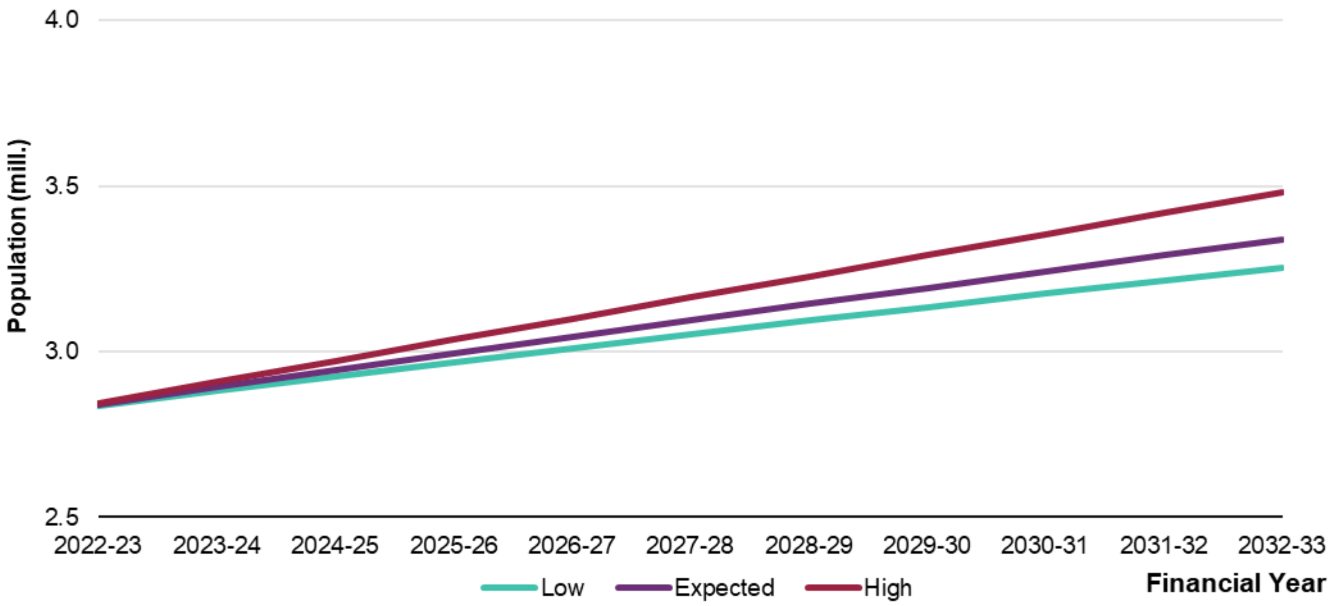
Figure 4 Forecast WA and national 10-year economic average annual growth rate under three scenarios, 2022-23 to 2032-33 financial years



Source: Oxford Economics Australia.

Population growth influences economic growth (see Figure 5). An increase in the population level simultaneously increases the labour supply, which facilitates greater production of goods and services, and increases their demand within an economy. Simultaneously, economic growth attracts individuals seeking better opportunities, resulting in population movements that further contribute to economic growth.

Figure 5 Forecast WA population growth under three scenarios, 2022-23 to 2032-33 financial years



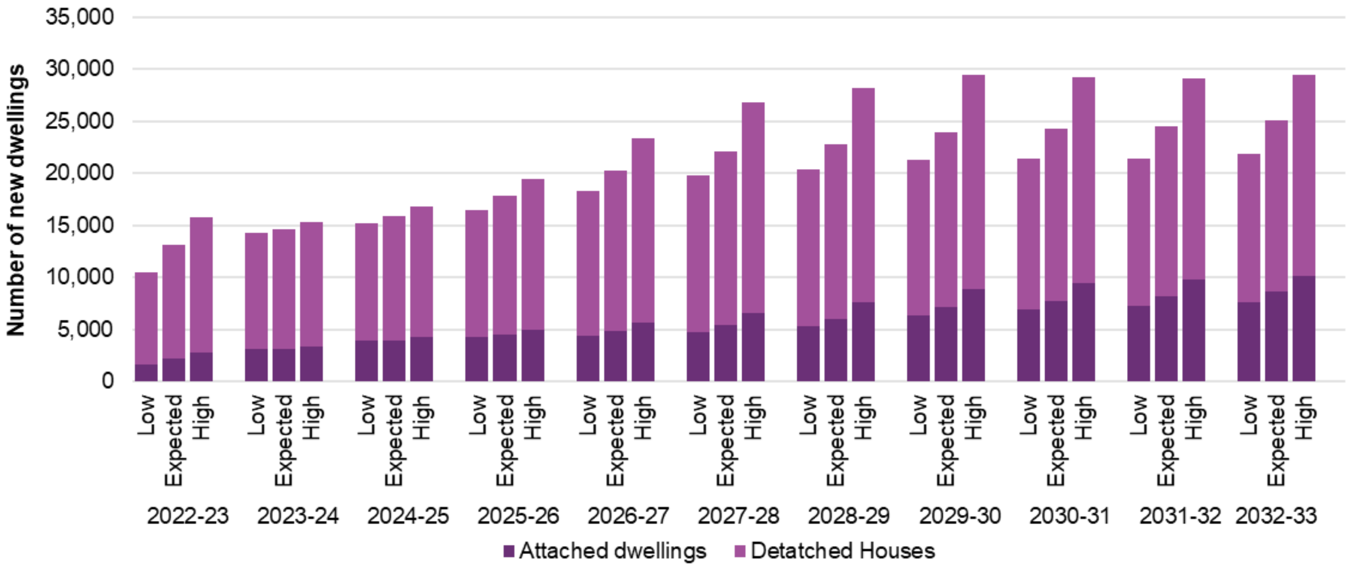
Source: Oxford Economics Australia.

2.2 Residential electricity connection forecasts

AEMO's forecast of increased residential electricity consumption is mostly driven by growth in electricity connections. Strong economic and population growth will contribute to a corresponding increase in the number of residential household constructions that require electricity connections.

AEMO's SWIS connections model used the updated population forecasts (see Section 2.1) in conjunction with historical residential connections numbers provided by Synergy to forecast the number of residential connections. On average, from 2022-23 to 2032-33, the forecasts show that the SWIS can expect over 20,000 additional residential connections per annum (see Figure 6).

Figure 6 Forecast SWIS new residential connections under three scenarios, 2022-23 to 2032-33



Source: AEMO and Oxford Economics Australia.

In the expected scenario from 2022-23 to 2032-33, on average approximately 72% of all new connections are forecast to be connections to detached houses. Over the same period, the annual proportion of new connections for attached dwellings[49] is projected to increase from 17% in 2022-23 to 34% in 2032-33, indicating a growing trend towards urban infill.

As the total number of detached houses is forecast to grow, the future nominal hosting capacity for DER in the SWIS, including DPV and DESS, is expected to increase. However, attached dwellings are less suitable for hosting DER resources than detached houses. As the proportion of the population living in attached dwellings increases, the capacity to host DER resources relative to the population will likely decrease over time.

[49] Attached dwellings are residential housing units that share structural components (such as a floor, wall, or ceiling) with other housing units. Examples of attached dwellings include townhouses and apartments.

2.3 DER forecasts

AEMO commissioned two external consultants, CSIRO[50] and Green Energy Markets (GEM)[51], to develop the 2023 WEM ESOO DPV and distributed DESS uptake forecasts. Both consultants used the same underlying assumptions and scenario narratives but employed separate forecasting models. This provided AEMO with greater confidence in the expected DPV and DESS uptake than a single forecast of this key forecast component to be considered across the three scenarios. CSIRO also provided EV uptake projections and EV daily charging patterns[52].

Table 7 presents the scenario mapping of the two consultants' forecasts for the 2023 WEM ESOO DER forecasts.

Table 7 CSIRO and GEM scenario mapping for the 2023 WEM ESOO DER forecasts

	High	Expected	Low
EV forecasts mapping	CSIRO	CSIRO	CSIRO
PV forecasts mapping	GEM	Average of CSIRO and GEM	CSIRO
PVNSG forecasts mapping	GEM	GEM	CSIRO
DESS and VPP forecasts mapping	Average of CSIRO and GEM	Average of CSIRO and GEM	CSIRO

The consultant forecasts were selected based on the best match with the scenario narratives, retention of appropriate forecast relativities between scenarios, and suitability in capturing dispersion between the trajectories to reflect the uncertainty inherent in long-term forecasts.

CSIRO's outlook was more closely aligned with the lower starting assumptions of the low scenario, while the elevated outlook seen in GEM's forecasts best represented the ambitious assumptions of the high scenario. AEMO considers that averaging PV, DESS, and VPP forecasts for the expected scenario provides a balanced view of outlooks.

2.3.1 EV uptake

The replacement of internal combustion engine vehicles with battery electric vehicles and plug-in hybrid electric vehicles is a considerable driver of electrification. Consumers' transport needs and charging patterns will significantly shape future daily demand profiles and constitute a large increase in electricity consumption.

The 2023 WEM ESOO forecasts an increased uptake of EVs in the SWIS relative to the forecasts of the 2022 WEM ESOO (see Figure 7). This is primarily attributed to an increase in federal and state government policies supporting EV uptake, including EV sales targets, subsidies for EV purchases[53], and build-out of public fact-

[50] CSIRO, Small-scale Solar PV and Battery Projections Report 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf.

[51] GEM, Final Projections for DER - Solar PV and Stationary Energy Battery Systems 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf.

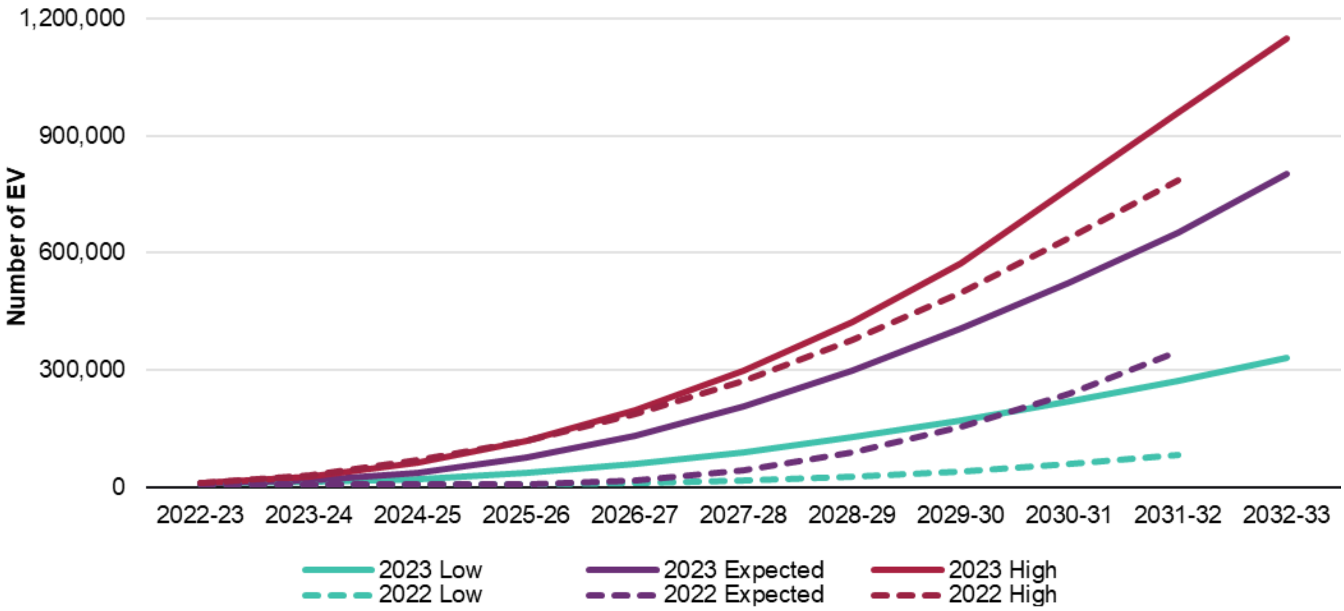
[52] CSIRO, Electric Vehicle Projections 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf.

[53] Improved data from the Electric Vehicle Council and Federal Chamber of Automotive Industries has provided clearer insight into EV sales in Australia. The data reveals that states offering subsidies have experienced the strongest growth in EV sales. Please refer to CSIRO's Electric Vehicle Projections 2022 report for further information.

charger networks. The relative increase in the uptake of EVs is further supported by stronger climate policy settings in the 2023 WEM ESOO scenarios. More detail is available in CSIRO's EV report.

By 2032-33, the EV fleet share is projected to make up approximately 30%[54] of all cars, commercial vehicles, buses, and trucks. In terms of electricity consumption, EVs are forecast to consume 2.6 terawatt hours (TWh) and 4.1 TWh of electricity per annum under the expected and high scenarios, respectively.

Figure 7 EV number projections under three demand scenarios from 2022 and 2023 WEM ESOOs, 2022-23 to 2032-33



Note: comparison with 2022 forecasts presented because there have been notable changes.
Source: CSIRO and AEMO.

Electric commercial vehicles and electric buses and trucks are projected to grow as a proportion of the EV fleet over the outlook period (see Figure 8).

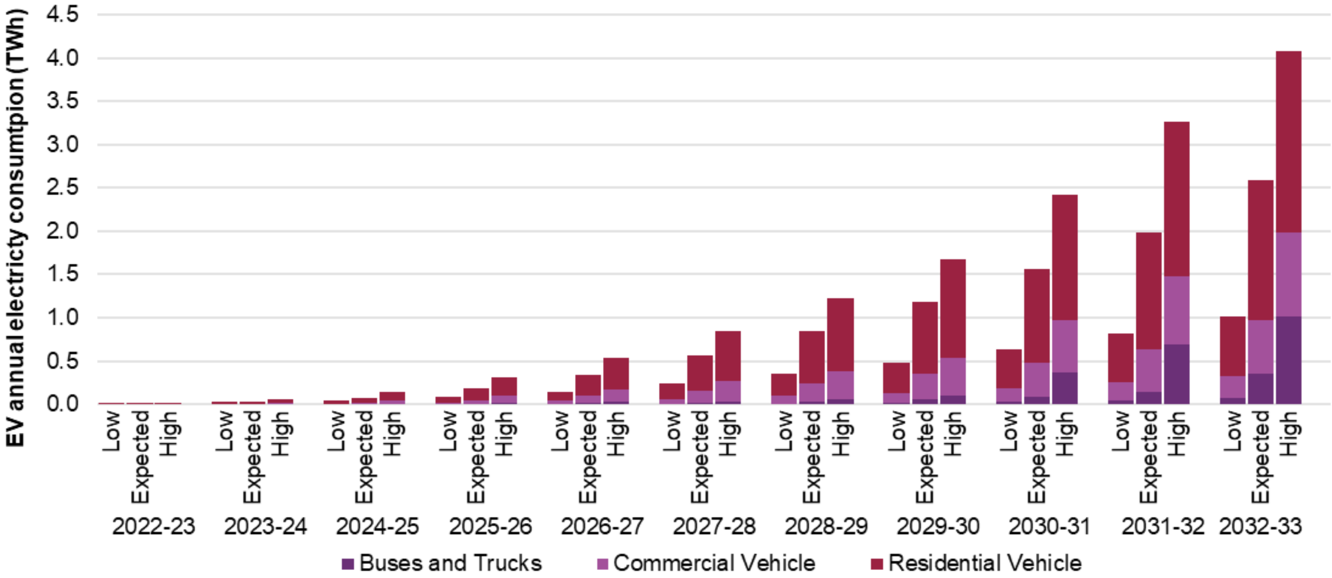
Under the expected scenario, between 2022-23 and 2032-33, the forecast annual electricity consumption for commercial vehicles is expected to rise from 0.5 gigawatt hours (GWh) to 628.6 GWh, representing 2.6% and 24.3% of total annual EV electricity consumption, respectively. For buses and trucks, under the expected scenario, between 2022-23 and 2032-33, the forecast annual electricity consumption is expected to rise from approximately 0.6 MWh to 346.8 GWh, representing under 0.1% and 13.4% of total EV electricity consumption, respectively.

The 2023 WEM ESOO forecast of 2.6 TWh electricity consumption per annum for EVs by 2032-33 is approximately 50% higher than the forecast in the 2022 WEM ESOO, in the expected scenario[55].

[54] The EV fleet share is forecast to reach more than 60% by 2039-40. For detailed forecasts, see Appendix Table B.2, CSIRO's Electric Vehicle Projections 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf.

[55] The 2022 WEM ESOO expected scenario maps to the CSIRO's *Net Zero 2050* scenario in CSIRO's Electric Vehicle Projections 2021. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf.

Figure 8 Forecast EV consumption by vehicle type under three scenarios, 2022-23 to 2032-33 (TWh)



Source: CSIRO and AEMO.

The EV model considered various charging profiles of EVs over the course of a day. The EV charging profiles were developed by CSIRO by using real world data on charging behaviour[56] and reflecting factors including vehicle usage behaviour and time-of-use tariffs. The charge profiles considered were[57,58]:

- Convenience – vehicle charging occurs when it is most convenient for the user, including in the evenings.
- Night – vehicle charging occurs predominantly overnight.
- Day – vehicle charging occurs predominantly during the day.
- Fast/highway – vehicle charging occurs on roads with fast chargers.

The EV model developed by the CSIRO considered a range of federal and state government strategies and policies. Fast charging profiles were readjusted to a flatter daily peak, based on public smart meter charging data. Time-of-use and convenience charging behaviour were updated, with higher weekend charging and a lower evening peak for convenience profiles. It was assumed that a higher percentage of businesses and commercial fleets might use fast/highway charging compared to residential vehicles, and appropriate adjustment was made to smart day charging to reflect that.

Stakeholder feedback suggested that AEMO should increase the proportion of evening charging to align with observed consumer preference. The forecasts incorporated this by accounting for a higher share for residential smart night charging in the WEM.

The impact of EV uptake on underlying consumption and demand forecasts is described in Chapters 3 and 4 of this WEM ESOO.

[56] The publication of reports describing the outcome of EV charging trials in Australia has given CSIRO the opportunity to significantly revise its charging profiles in its 2022 EV projections, including the Origin Energy EV smart charging trial, Energex, and Ergon Energy Network 2022 EV smart charge (Queensland) insights.

[57] Note that a charging profile is a description of the shape of the charging behaviour and does not exclude charging at other times. For example, the *Night* charge profile also includes daytime charging.

[58] Further information on vehicle charging profiles can be found in section 4.10 of CSIRO's Electric Vehicle Projections 2022. See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf.

A portion of EVs may be considered VPPs, wherein their charging and discharging are coordinated to achieve a more centralised operational objective, with a varying proportion by scenario. This portion of EV operation is incorporated into the reliability modelling, which considers the charging patterns throughout each day in the modelled year. During this process, charging periods are strategically selected to coincide with the periods of lowest demand, filling in the deepest troughs in demand. Charging is reduced at times when demand is higher. For further information on the EV VPP operation, see EY's 2023 reliability assessment report[59].

2.3.2 Distributed PV uptake

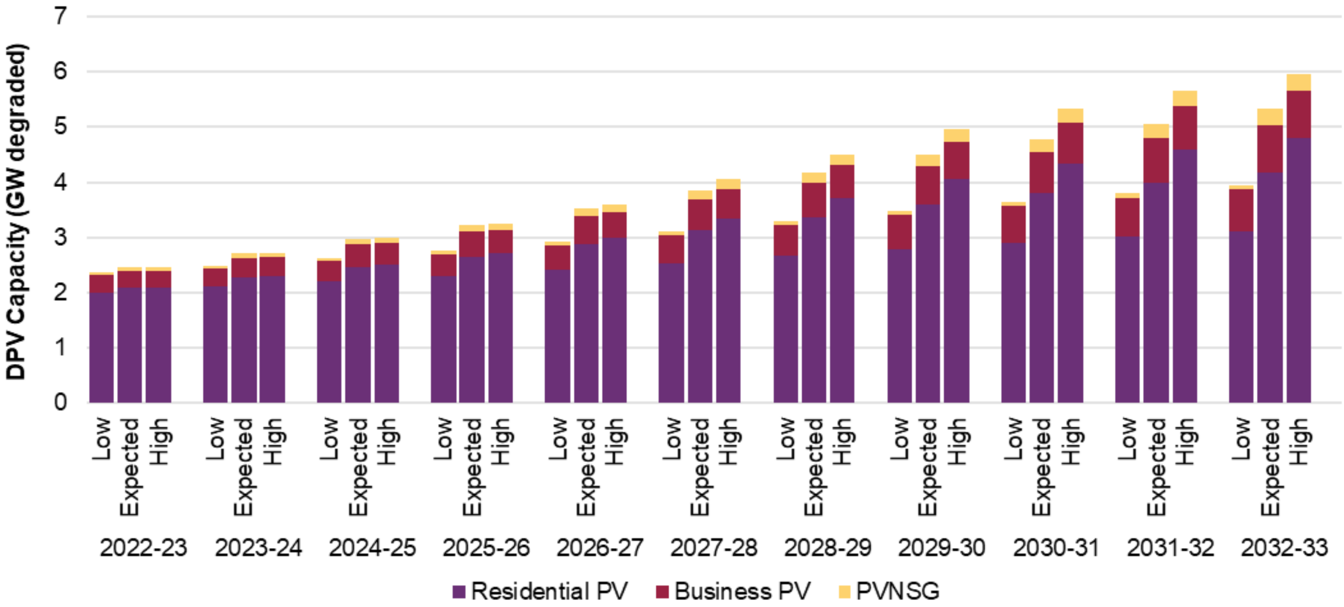
DPV installations continue to be popular in WA and their installed capacity is expected to grow significantly over the outlook period across all three scenarios (see Figure 9). Under the expected scenario, between 2022-23 and 2032-33, PV capacity installed on residential and business rooftops in the SWIS is forecast to grow from 2.4 GW to over 5 GW and PVNSG capacity is expected to increase from 54 MW to 289 MW (see Table 8).

Table 8 Forecast installed DPV capacity (MW degraded) and average annual growth rate in the SWIS under the expected scenario

	Residential PV	Business PV	PVNSG	Total
2022-23	2,084	316	53	**2,453**
2023-24	2,275	362	72	**2,709**
2032-33	4,189	848	289	**5,325**
10-year average annual growth	7.2%	10.4%	18.4%	**8.1%**

Source: CSIRO, GEM, and AEMO.

Figure 9 Total installed DPV capacity under three scenarios, 2022-23 to 2032-33 (GW degraded)



Note: forecast DPV values are inclusive of expected degradation of solar panel output over time. CSIRO applied a degradation rate of 0.5% per annum and GEM applied a degradation rate of 0.7% per annum.
Source: CSIRO, GEM, and AEMO.

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

DPV forecasts reflect a slowdown influenced by post-pandemic spending habits and supply chain constraints[60]. Installation of DPV capacity is supported to 2030 by the Small-scale Renewable Energy Scheme (SRES), which provides Small-scale Technology Certificates (STC) to consumers installing DPV systems, a subsidy provided under the national Renewable Energy Target. After the STC scheme ends, installation of DPV capacity is forecast to be relatively slower, but long-term uptake of DPV installation is forecast to continue over the outlook period, driven by forecast reductions in the cost of PV systems, population growth, and the relatively short payback period for DPV investments.

The three scenarios represent a range of DPV penetration, with continued growth of PV installations through to 2032-33. Owner-occupied houses (a prime candidate for PV installation) currently have around 39% PV uptake in the SWIS[61], which increases to between 60-65% by 2032-33 depending on the scenario. Some detached dwellings will be impeded by shading or ownership considerations (rental premises may be less likely to invest in PV systems without alternative financial models), and the forecasts recognise the increasing opportunity for PV installations occurs on other dwelling types, such as townhouses, terraces and, to a lesser extent, apartments.

2.3.3 DESS uptake

Distributed residential and commercial battery systems have the potential to change the future demand profiles, particularly maximum and minimum daily demand. Over time it is expected that aggregation and orchestration of DER via VPPs will influence DESS demand profiles. The extent of this impact depends on factors including:

- The energy storage capacity and charge/discharge power of the battery system installed.
- The capacity of any PV system or controlled load installed at the same premises, and the volume and timing of energy consumption of the household or business.
- The development and implementation of arrangements that enable VPPs to access returns for the provision of services (to the WEM and/or network for example).
- Customer-driven requirements may also impact DESS demand profiles, including the configuration of DESS system and/or optimisation objectives if operating autonomously and/or technical aspects such as energy to power ratio and round-trip efficiency.

For DESS VPPs, a certain percentage of the total installed DESS capacity is reserved and captured in the reliability modelling. In this operation type, DESS operation is optimised to reduce overall system costs while functioning as a controllable form of grid-scale battery storage. For further information on the EV VPP operation, see EY's 2023 reliability assessment report[62].

The capacity of DESS in the SWIS is expected to increase over the outlook period, but there remains substantial uncertainty about the uptake level, with some differences across the scenarios as shown in Figure 10. Battery energy storage forecasts are sensitive to improvements in technology costs, as well as the rate of customer adoption. Further, it is widely anticipated that VPPs of some form will be necessary to manage the large volumes of energy resources forecast by 2032-33. However, the timing and structure if these VPPs will depend on policy work underway under the WA Government's DER Roadmap[63].

[60] Five-year annual DPV capacity growth rate – 2017-18 to 2022-23, 19.9%; 2022-23 to 2027-28, 9.4%.

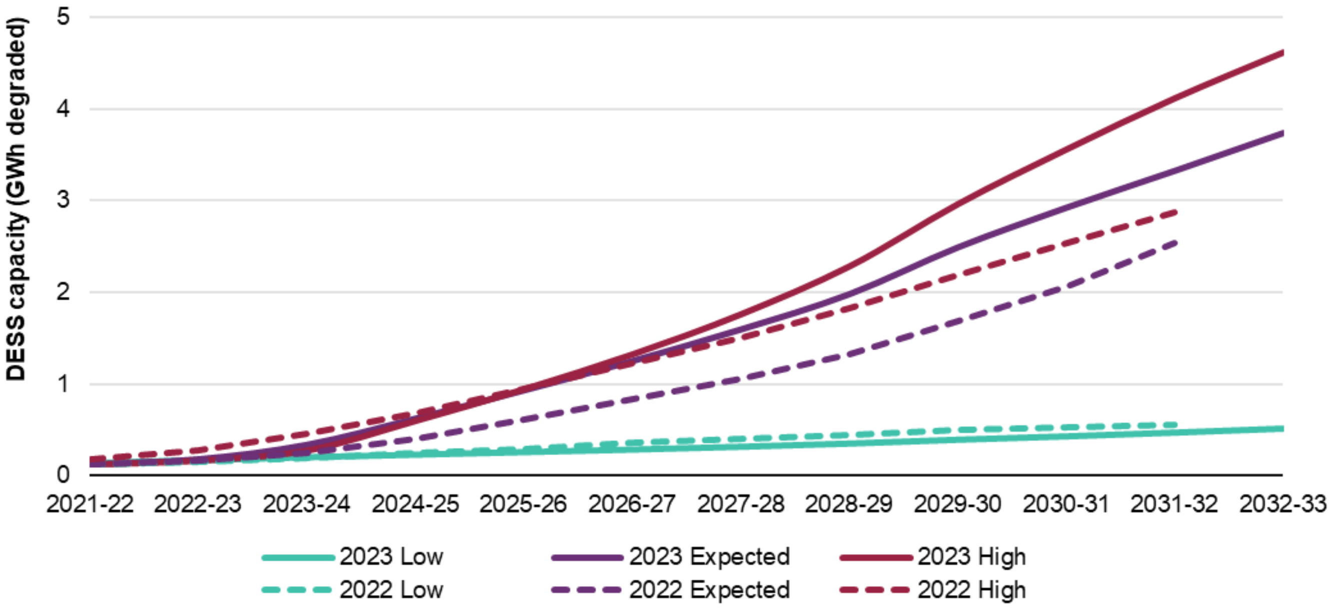
[61] Australian PV Institute developed percentage of dwellings with a PV system by State/Territory, see https://pv-map.apvi.org.au/historical.

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

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

In the expected scenario, by 2032-33, the installed DESS energy capacity is forecast to exceed 3.7 GWh (degraded)[64], while in the low scenario it is forecast to be approximately 0.5 GWh. With a typical DESS storage duration of two hours, this corresponds to an installed power capacity of over 1.8 GW for the expected and high scenarios, and less than 0.3 GW for the low scenario. The 2023 WEM ESOO DESS installation forecasts are driven by increases in DPV installations, compared to the 2022 WEM ESOO. DESS shifts DPV generation to later in the day when electricity is more valuable. At high levels of DPV generation, DPV export (feed-in) prices will be lower and DPV will be more likely to be curtailed, incentivising the installation of DESS capacity.

Figure 10 Forecast installed DESS capacity in the SWIS under three scenarios from 2022 and 2023 WEM ESOOs, 2022-23 to 2032-33 (GWh degraded)



Note: comparison with 2022 forecasts presented because there have been notable changes.
Source: CSIRO, GEM, and AEMO.

2.4 Energy efficiency savings are forecast to grow across the scenarios throughout the outlook period

AEMO commissioned external consultant Strategy.Policy.Research. (SPR) to develop the 2023 WEM ESOO energy efficiency savings forecasts[65]. The forecasts reflect the potential role of energy efficiency by considering effects on energy savings attributable to the quality and quantity of investment in new technologies, buildings, and processes, uptake of appliance and equipment in business and residential sectors, and fuel-switching[66]. The forecasts accounted for varying levels of policy ambition coupled with demand drivers (such as population, building stock growth, and building stock type), to align with the scenario narratives.

[64] Forecast DESS values are inclusive of expected degradation of storage over time. CSIRO applied a degradation rate of 1.6% per annum and GEM applied a degradation rate of 4% per annum.

[65] Energy efficiency relates to how much energy is consumed to perform a task whereby policy seeks to improve this efficiency. For detail, see https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/2023-energy-efficiency-forecasts-final-report.pdf.

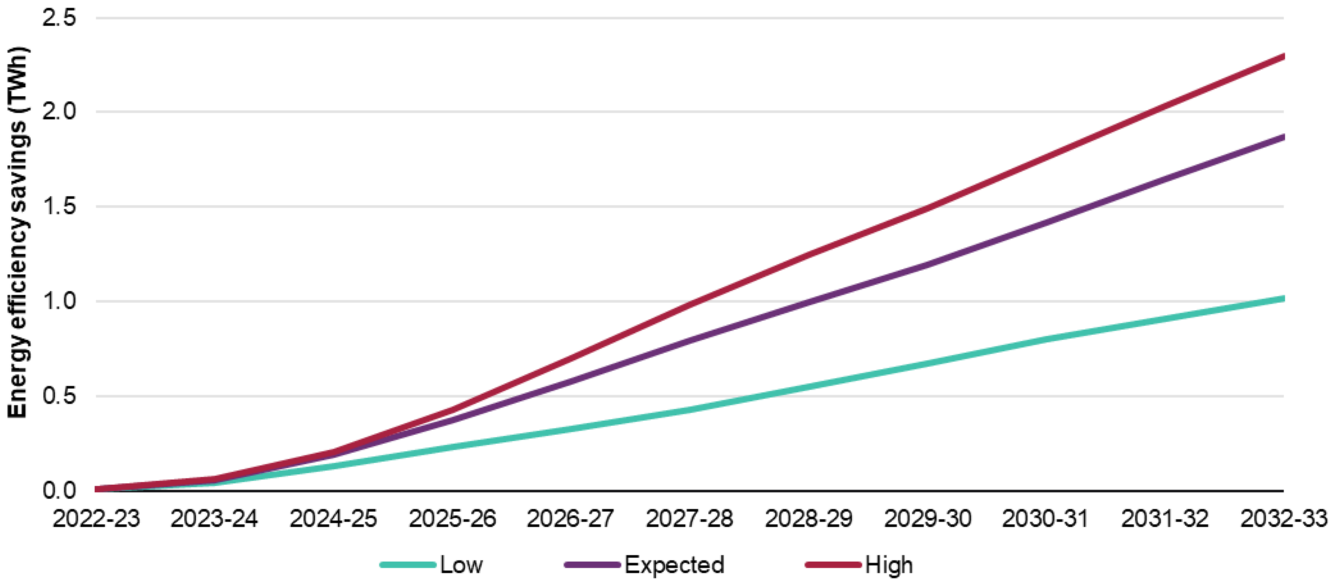
[66] Fuel-switching under energy efficiency improvement is only considered to the extent that incremental impacts on the fuel mix are attributable to efficiency policy measures.

The energy efficiency forecasts considered these government measures aimed at lowering energy consumption:

- Building energy performance requirements contained in the Building Code of Australia 2010 and the National Construction Code (NCC) 2019 and NCC 2022.
- The Greenhouse and Energy Minimum Standards program of mandatory product labelling requirements and/or minimum energy performance standards for different classes of appliances and equipment.
- Building rating and disclosure schemes for existing commercial offices, including the Commercial Building Disclosure (CBD) and the National Australian Built Environment Rating System (NABERS) Energy for Offices.
- Hypothetical introduction of new universal mandatory disclosure and minimum energy performance standards, for existing residential and non-residential building classes, excluding the share of buildings already rated under NABERS or CBD.
- A hypothetical industrial assessment program modelled on the former Energy Efficiency Opportunities program.

Figure 11 shows the total energy efficiency savings forecast for the BMM and residential sectors. Energy efficiency savings for LILs are included within their survey responses and are therefore captured in the LIL forecast results (in Section 2.7). By 2032-33, energy efficiency savings in the BMM and residential sectors together are forecast to reach 1.0 TWh, 1.9 TWh, and 2.3 TWh in the low, expected, and high scenarios, respectively. The share of savings from energy efficiency improvements is higher in the residential sector than in BMM in the short term but is lower in the medium to long term, reflecting the flow of investments, policy ambitions and demand drivers.

Figure 11 Forecast total energy efficiency savings in the BMM and residential sectors, under three scenarios, 2022-23 to 2032-33 (TWh)



Source: SPR and AEMO.

2.5 Electrification is forecast to grow strongly, dominated by industrial fuel-switching opportunities

AEMO commissioned external consultants, CSIRO and CWC, to develop the 2022 multi-sectoral modelling[67] that included the SWIS electrification forecasts[68]. AEMO recognises that decarbonisation of the Australian economy requires fuel-switching- towards low and no emissions alternatives. AEMO included the potential electrification of future loads (including the transport sector) alongside existing loads in the 2023 WEM ESOO forecasts. The key factors considered were:

- **A range of electrification outcomes** – residential and commercial building sectors' electrification of space heating, cooking, and water heating appliances (from gas or liquefied petroleum gas), electrification of the transport sector, and electrification in the business sector.
- **Cost efficiency of electrification** – the cost-efficiency of electrification relies on various factors, including appliance replacement expense, electricity infrastructure capabilities and costs, and the accessibility of alternative low-emission fuels like hydrogen and biomethane.

Figure 12 shows the electrification forecasts for all sectors in the SWIS, excluding EVs[69].

In all three scenarios, electrification is forecast to grow significantly from current levels, with business electrification projected to be significantly higher than residential electrification. This finding suggests that electrification stands as one of the most cost-effective emissions reduction strategies across all scenarios, alongside other strategies such as energy efficiency improvements and renewable energy adoption.

By 2032-33, electricity consumption for electrification of residential and business sectors together is forecast to reach 5.7 TWh, 7.1 TWh, and 12.2 TWh, respectively, in the low, expected, and high scenarios. Throughout the outlook period, electrification in the SWIS is dominated by electrification in the business sector.

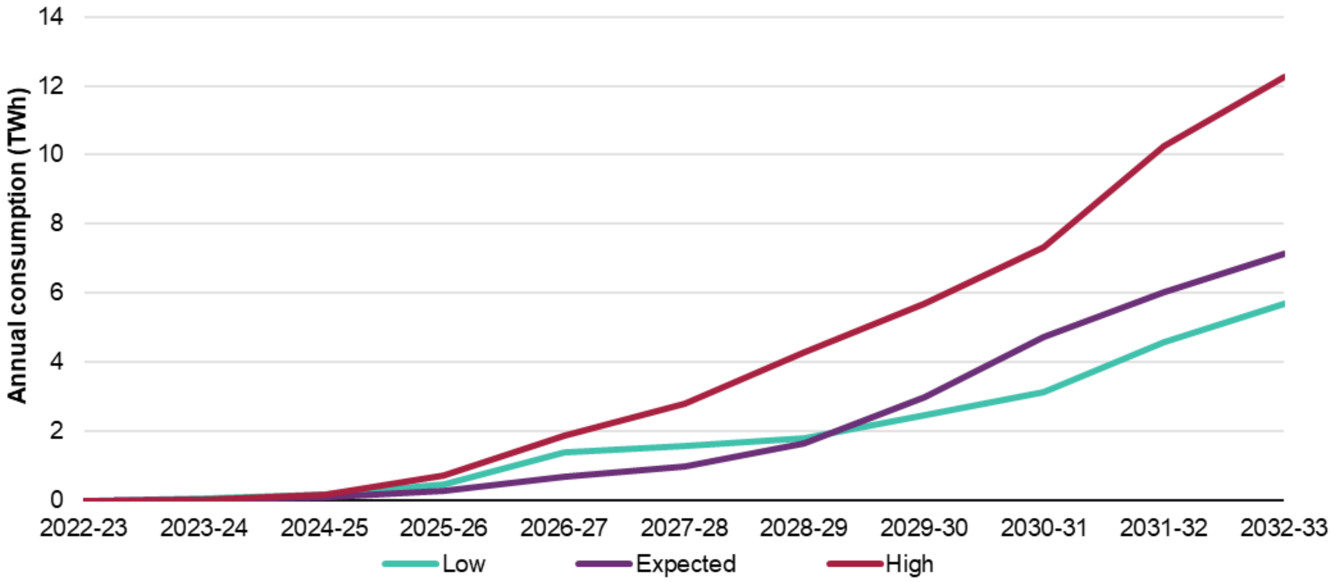
In the short to medium term, electrification in the low scenario surpasses the expected scenario. This is because in the low scenario, electrification is projected to play a greater role in reducing carbon emissions compared to the other scenarios, whereas the other scenarios are forecast to rely more on alternative approaches, such as improving energy efficiency and switching to low-emission fuels like hydrogen and biomethane.

[67] CSIRO and CWC, Multi-sector energy modelling 2022: methodology and results, Final report 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

[68] Electrification includes any process that involves fuel-switching to electricity, such as replacing a gas hot water system with a heat pump, electrified heating and cooling of air.

[69] Forecast EV uptake is presented in Section 2.1.3.

Figure 12 Forecast total annual electricity consumption from business and residential electrification (excluding EVs) under three scenarios, 2022-23 to 2032-33 (TWh)



Note: the highest annual business and residential electricity consumption from electrification is forecast in the low scenario for 2023-24 and 2024-25. See the 2023 WEM ESOO Data Register for futher information.
Source: CSIRO and CWC.

2.6 Forecast growth in hydrogen production is highly uncertain, and will be influenced by opportunities for export

CSIRO and CWC's 2022 multi-sectoral modelling[70] included electricity consumption forecasts for hydrogen production within the SWIS. Significant hydrogen production announcements have been made in WA, as evidenced by CSIRO's HyResource listing of projects[71], but only four small-scale projects are currently in operation.

AEMO's forecasts predominantly consider electricity consumption arising from electrolysers producing hydrogen from renewable sources – often referred to as 'green hydrogen'. AEMO's hydrogen assumptions vary by scenario because the trajectory of capital cost reductions and uptake timing is highly uncertain. The assumed hydrogen production for domestic use (including the transport sector) and export is informed by the outcomes of the multi-sectoral modelling. The key factors considered were:

- **Hydrogen for domestic purposes** – hydrogen supports uptake in the industry and transport sectors while competing with electrification and biomethane. It has the strongest uptake in the high scenario, due to a high assumed learning rate and maturing export market to drive down costs.
  - Gas distribution networks are expected to provide a delivery means for blended hydrogen, with up to 10% blending share in the low and expected scenarios. The high scenario allows a greater proportional blend in the long term, reflecting the opportunity for more significant changes in the use of gas and renewable gases by consumers, after 2030.

[70] CSIRO and CWC, Multi-sector energy modelling 2022:methodology and results, Final report 2022, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

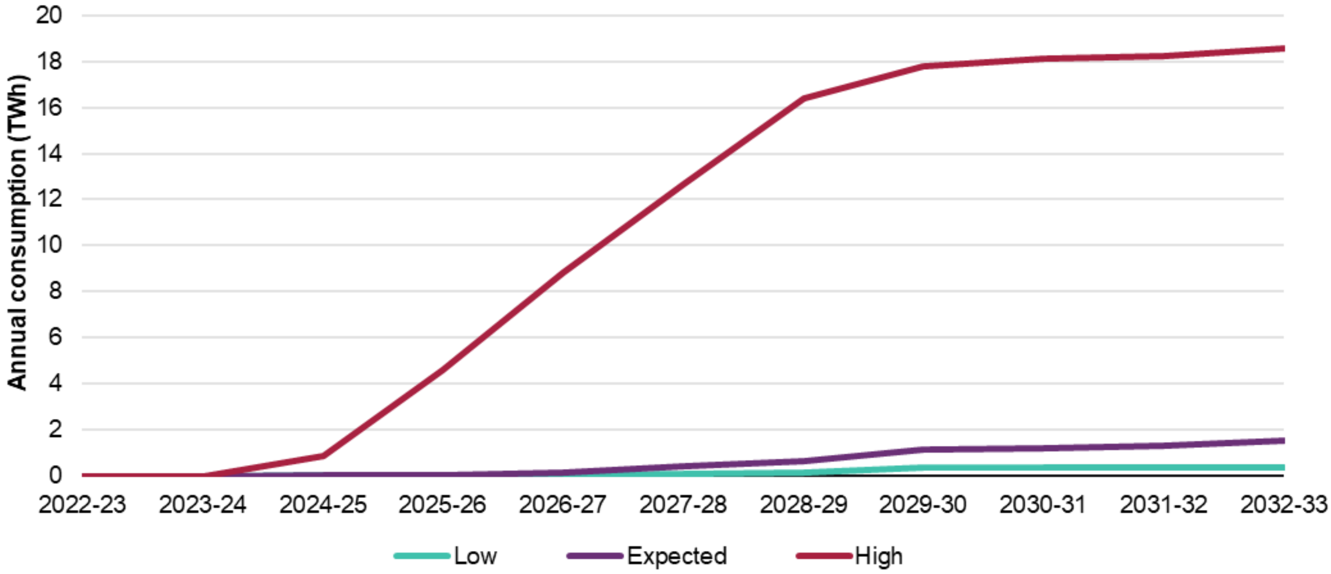
[71] See https://research.csiro.au/hyresource/projects/facilities/.

- **Hydrogen for export purpose** – WA has strong potential to export green hydrogen, attributed to its high-quality renewable energy potential and a history as a reliable international energy and resource supplier.

Figure 13 shows forecast total annual consumption in the SWIS for hydrogen production, for both domestic use and export purposes.

By 2032-33, electricity consumption for hydrogen production is forecast to reach 0.4 TWh, 1.5 TWh, and 18.5 TWh, respectively, for the low, expected, and high scenarios. In the low and expected scenarios, uptake of hydrogen production in the short to medium term is largely attributed to the domestic use of hydrogen to complement existing gas use, whereas hydrogen export opportunities have a larger influence affecting long-term growth in the high scenario.

Figure 13 Forecast total electricity consumption for hydrogen production in SWIS under three scenarios, 2022-23 to 2032-33 (TWh)



Source: CSIRO and CWC.

2.7 Large industrial loads

LILs are users that consume or are forecast to consume at least 10 MW for a minimum of 10% of the time each year (around 875 hours a year), or at least 50 GWh per year. LILs consumed approximately 30% of all operational consumption in the SWIS in the current Capacity Year.

For existing LILs, AEMO carries out surveys to gain an understanding of their anticipated future consumption and demand forecasts in addition to any planned expansions or closures. AEMO's surveys seek to identify any future electrification or energy efficiency upgrades that are planned for the facility.

For new LILs, AEMO undertook market research to identify prospective projects under development and assess the project development statuses. AEMO has also liaised closely with Western Power to forecast the growth of new LILs over the 10-year outlook period. Western Power has provided detailed prospective connection information, including the 10-year forward looking load connection list, ranging from conceptual through to constructed projects.

AEMO took into consideration stakeholder feedback that highlighted a potential for underestimating new LILs in the medium to long term. Reflecting this feedback, AEMO has revised the criteria for assessing WEM LILs. A carbon reduction criterion has been used to replace the Environmental Protection Authority (EPA) approval criterion for projects expected to come online in four or more years' time, because developers may not apply for EPA approval for projects this far in the future. The carbon reduction criterion is based on the long-term government policy of decarbonisation – it applies to projects which either reduce carbon emissions or are part of the energy transition (such as lithium mining).

These changes had no impact on committed projects in the expected scenario, but increased prospective projects in the high scenario.

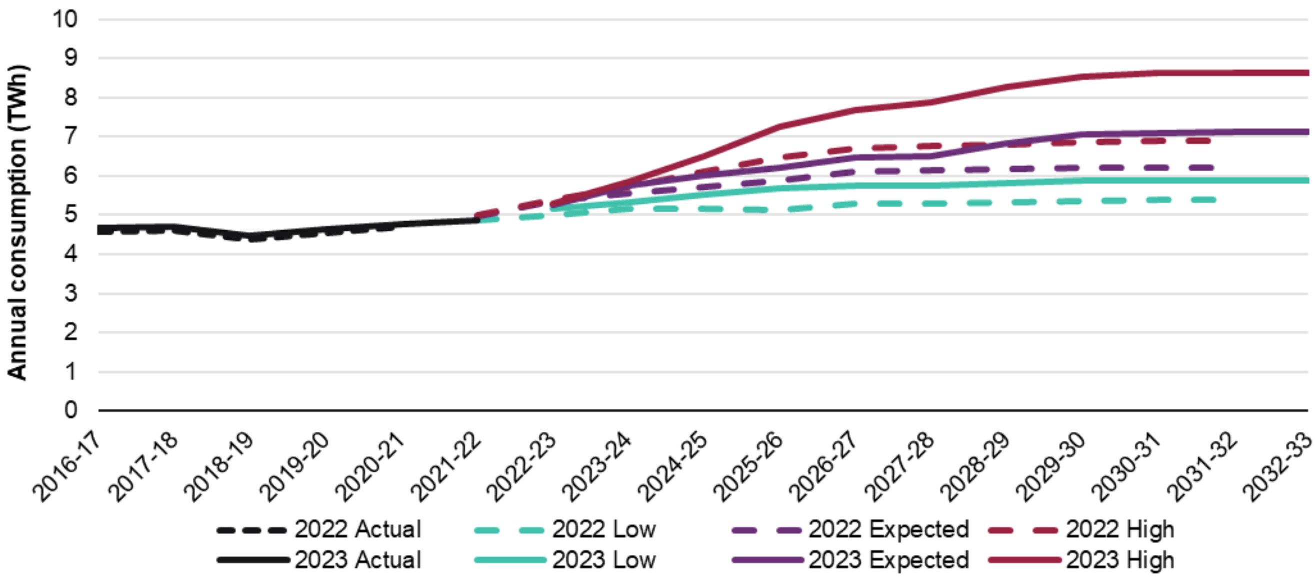
The change of methodology and more detailed information from Western Power has led to an increased LIL forecast relative to the 2022 WEM ESOO, with additional projects added later in the outlook period.

For more details on LIL methodology, refer to Appendix A2.

Figure 14 compares existing and new LIL consumption forecasts for the low, expected, and high scenarios from the 2022 and 2023 WEM ESOOs, and shows actual LIL consumption from 2016-17 to 2021-22. LIL consumption shown here does not include electricity consumption from hydrogen projections and electrification of LILs[72].

The consumption from existing and new LILs, in total, is forecast to grow throughout the outlook period and reach 5.9 TWh, 7.1 TWh, and 8.6 TWh, respectively in the low, expected, and high scenarios by 2032-33[73]. Compared to the 2022 WEM ESOO, this year's WEM ESOO projects LILs to grow between 1.5% and 25.3% faster, largely driven by the growth in new LILs.

Figure 14 Actual and forecast LILs under three scenarios from 2022 and 2023 WEM ESOOs, 2016-17 to 2032-33 (TWh)



Note: comparison with 2022 forecasts presented because there have been notable changes.

[72] For discussion on electricity consumption associated with LIL electrification and in the hydrogen sector, see Sections 2.1.6 and 2.17, respectively.

[73] In addition, a facility that substantially increased its consumption was reclassified from BMM (as per 2022 WEM ESOO) to a LIL in the 2023 WEM ESOO. This reclassification provided a moderate uplift of the historical LILs actual data in 2023 WEM ESOO, but does not impact the overall total load in the SWIS (as the BMM load category has a commensurate reduction).

3 Consumption trends and forecasts

Operational consumption is forecast to increase at an average annual rate of 5.6% over the 10-year outlook period in the expected demand growth scenario. This is a significant change from the 2022 WEM ESOO, and is attributed largely to the projected increase in business electrification and to forecast contributions from uptake of EVs.

In this chapter:

- Market underlying consumption includes business underlying consumption, residential underlying consumption, and transmission and distribution network losses[74]. Both business and residential underlying consumption can be met by battery storage and DPV generation:
  - For business underlying consumption, the sectoral components are LIL and BMM underlying consumption, business EV uptake[75], hydrogen production, the impact of climate change on increasing temperatures, business electrification[76], and energy efficiency savings[77].
  - For residential underlying consumption, the sectoral components are residential base forecast consumption[78], appliance uptake, residential EV uptake[79], residential electrification[80], the impact of climate change on increasing temperatures, and energy efficiency savings.
- Operational consumption, which excludes electricity consumption met by DPV generation and includes all network losses, is met by sent-out electricity supply from market registered energy producing units.
- Underlying consumption refers to market underlying consumption unless otherwise specified.

3.1 The updated consumption forecasting approach and drivers result in greater forecast consumption than in the 2022 WEM ESOO

Overall, underlying consumption is forecast to increase across all three scenarios throughout the outlook period. This growth accounts for a range of existing and emerging drivers reflecting recent policy settings towards Australia's commitment to a 43% emission reduction by 2030, and using the updated consumption forecast approach described in Chapter 1. By 2032-33:

- In the low scenario, underlying consumption is forecast to be one-and-a-half times 2022-23 levels.

[74] Throughout the 2023 WEM ESOO outlook period, transmission and distribution network losses are projected to account for an average 6.9% per annum share of underlying consumption.

[75] Business underlying consumption is presented as a total and excludes the impact of business EV in Section 3.4.1.

[76] 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.

[77] Energy efficiency is the desire to consume less energy to perform a given task. Insulating a building to reduce the amount of energy required to cool it is an example of an energy efficiency measure. The impact of energy efficiency has been factored into the calculations of sectoral delivered consumption.

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

[79] Residential underlying consumption is presented as a total and excludes the impact of residential EV in Section 3.4.2.

[80] 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.

- In the expected scenario, underlying consumption is forecast to be almost twice 2022-23 levels.
- In the high scenario, which projects expansion of a green hydrogen sector, underlying consumption is forecast to be more than triple 2022-23 levels.

Using the updated forecasting approach, across the scenarios, there is an upward trend in:

- Business underlying consumption, due to the impact of electrification, partially offset by energy efficiency savings.
- Residential underlying consumption, driven by new connections and appliance uptake growth, partially offset by energy efficiency savings.
- Sectoral growth, also driven by the electrification of the transport sector, as EV uptake and charging behaviours of light and heavy vehicles impact electricity consumption (see Section 3.4)

In comparison, the 2022 WEM ESOO projected more moderate growth in all three demand growth scenarios. This forecast reflected a slower pace in EV uptake and a lack of the impact of business and residential electrification as well as consumption from hydrogen production.

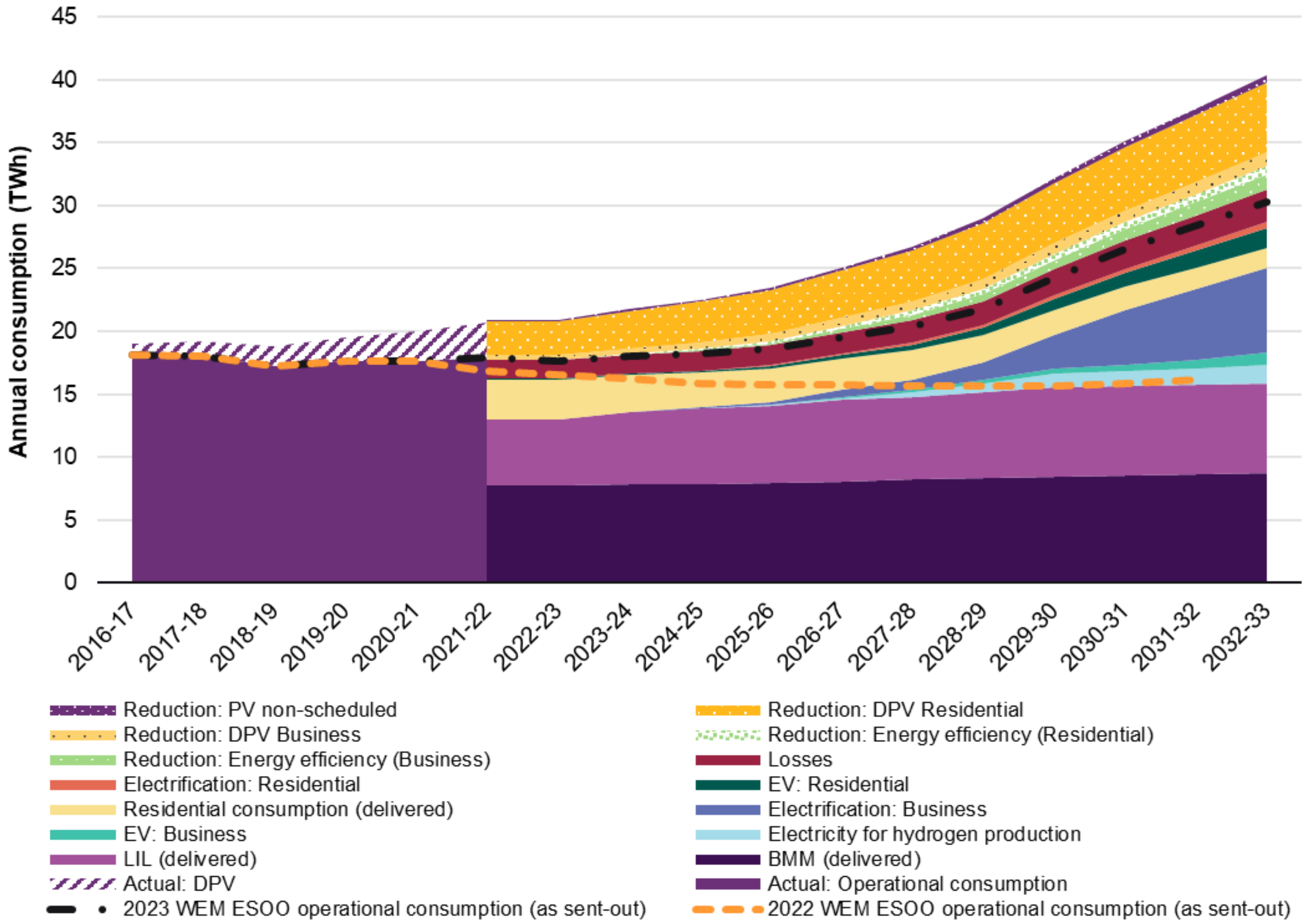
3.2 Forecast growth is primarily influenced by existing drivers in the short to medium term, and by emerging drivers in the long term

Figure 15 shows historical underlying consumption and a breakdown of the 2023 WEM ESOO forecast into various sectoral components under the expected scenario over the outlook period. It also shows operational consumption forecast[81], and compares the overall 2022 and 2023 WEM ESOO operational consumption forecasts (orange and black dashed lines respectively) under this scenario.

DPV generation is forecast to offset nearly one-fifth of underlying consumption on average in the expected scenario that would have otherwise been included in operational consumption.

[81] Figure 15 presents forecasts of operational consumption net of sectoral components that decrease it (that is, supply from distributed resources and reductions from energy efficiency).

Figure 15 Actual and breakdown of forecast annual consumption, by sectoral components, under expected scenario, 2016-17 to 2032-33 (TWh)A,B,C



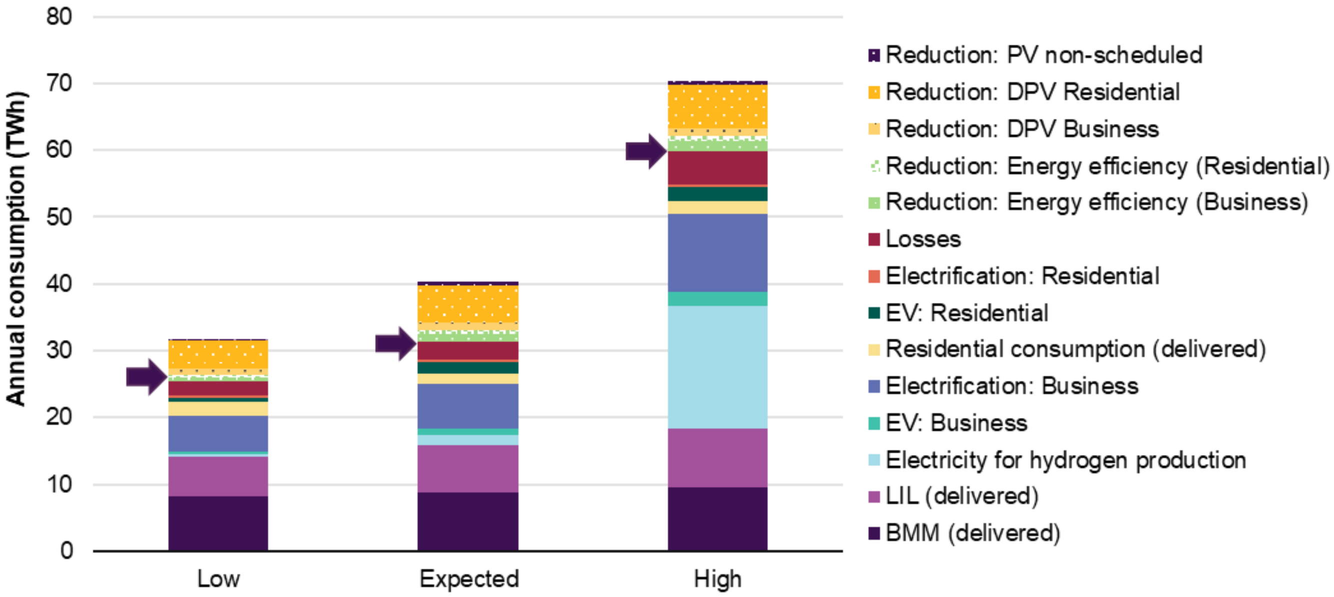
A. Components that contribute to operational consumption are in solid colours while those reducing operational consumption are in shaded patterns.
B. The impact of PVNSG on total consumption is small, so its contribution to the business and residential sectors is not presented separately.
C. Battery storage and climate change impacts are negligible compared to other components and are therefore not shown separately. The impacts of these are included in the calculations of 2023 WEM ESOO operational consumption.

Figure 16 shows the forecast impact of each sectoral component on underlying consumption at the end of the outlook period (in 2032-33), and the level of operational consumption. It shows that:

- Business delivered consumption is forecast to be almost three times greater in the high scenario compared to the low scenario.
- Business and residential electrification is projected to be more than two times greater in the high scenario than the low scenario.
- Business and residential EV consumption is projected to be four times greater in the high scenario than the low scenario.

The only sectoral component forecast to be lower in the high scenario than in the low scenario is residential delivered consumption, because a higher proportion of residential underlying consumption is projected to be met by DPV and saved with greater adoption of energy efficient choices.

Figure 16 Breakdown of annual consumption forecasts under three scenarios in 2032-33 (TWh)[A,B]



A. Sectoral components that contribute to operational consumption are drawn in solid colours while those reducing operational consumption are drawn in dotted patterns. The level of forecast operational consumption is indicated with an arrow.
B. The operational consumption forecast model includes consumption from battery storage and climate change.

In summary, operational consumption in 2032-33 is forecast to reach:

- 24.9 TWh and 30.3 TWh in the **low** and **expected scenarios**, respectively. In both scenarios, BMM is projected to contribute around 30%, while LIL and total electrification are projected to each contribute less than 25%.
- 58.9 TWh in the **high scenario**, with the hydrogen sector contributing more than 30%, while LIL and total electrification contribute less than 20% and 25%, respectively.

3.3 Operational consumption is forecast to grow, heavily influenced by business sector electrification and hydrogen production

Figure 17 compares operational consumption forecasts for the low, expected, and high scenarios from the 2022 and 2023 WEM ESOOs, and shows actual operational consumption from 2016-17 to 2021-22.

Operational consumption increased by 279.4 GWh (1.6%), while underlying consumption supplied by DPV generation grew by 492.1 GWh (21.4%) in 2021-22 compared to the previous Capacity Year.

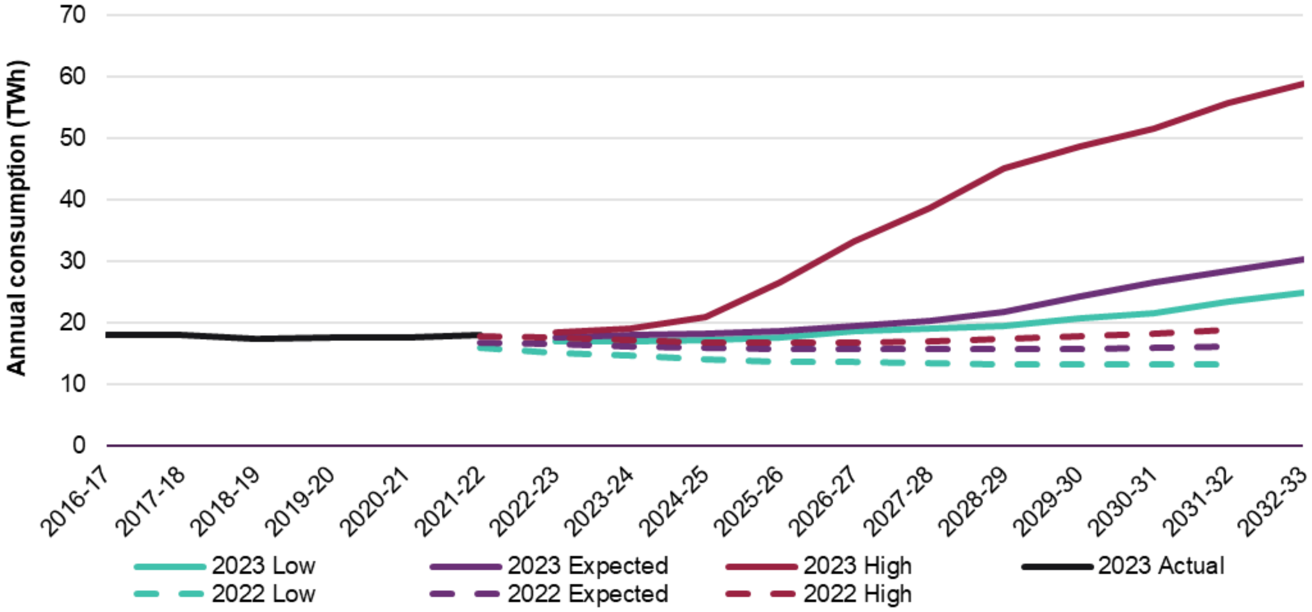
Operational consumption is forecast to grow annually throughout the outlook period across all three scenarios, driven by growth in business delivered consumption more than offsetting the decrease in residential delivered consumption.

Between 2022-23 and 2032-33, operational consumption is forecast to increase by at least 8.0 TWh and up to 40.6 TWh, depending on the scenario. In summary, the average annual growth rate for operational consumption over this outlook period:

- In the low scenario is 4.0%, adding 8.0 TWh. Growth is slower in the first half of the outlook period, driven by LIL and slower electrification, and faster in the second half, due to projected faster growth of electrification, EV uptake and BMM.

- In the expected scenario is 5.6%, adding 12.7 TWh. Similar to the low scenario, the first half forecasts slower growth, attributed to LIL and slower electrification, while the second half forecasts faster growth, due to a projected stronger growth of electrification and EV uptake, complemented by consumption in the hydrogen sector.
- In high scenario is 12.4%, with a tripling of current consumption levels, adding 40.6 TWh. Significant growth is forecast in the first half, driven by robust growth in hydrogen production, electrification, and LIL. Growth is much slower in the second half of the outlook period, with significantly slower growth in electricity consumption for hydrogen production, despite electrification and EV uptake each being more than three times larger than in the first half.

Figure 17 Actual and forecast operational consumption under three scenarios from 2022 and 2023 WEM ESOO scenarios, 2016-17 to 2032-33 (TWh)



Compared to the 2022 WEM ESOO, operational consumption is forecast to be higher for the entire outlook period across all three demand growth scenarios, by at least 0.7 TWh and up to 36.7 TWh[82]. The higher forecasts in the 2023 WEM ESOO are attributed to a range of emerging drivers and updated existing drivers.

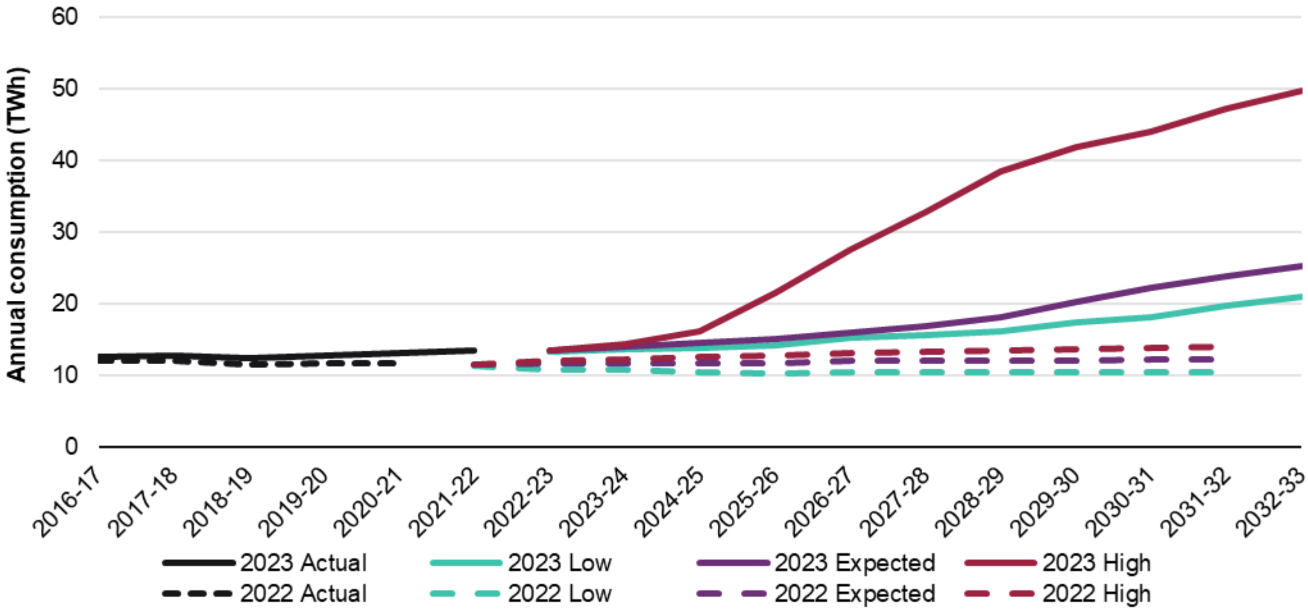
3.4 Sectoral consumption: business consumption growth is forecast to outpace residential consumption growth

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

Figure 18 presents forecasts for business underlying consumption for the low, expected, and high scenarios, compared with the 2022 WEM ESOO scenarios, and with the actuals from 2016-17 to 2021-22.

[82] The 2022 WEM ESOO forecast the operational consumption to decline at an average annual rate of 0.4%, calculated using 2021-22 (year 0) as the base year. This is slightly higher than the rate of decline (0.3%) reported in the 2022 WEM ESOO, where the base year was 2022-23 (year 1).

Figure 18 Actual and forecast business underlying consumption under three scenarios from 2022 and 2023 WEM ESOOs, 2016-17 to 2032-33 (TWh)[A,B]



A. AEMO revised BMM historical consumption data upward in the 2023 WEM ESOO due to improved segmentation of residential and business actuals. See Section 1.4.3 for further information.
B. Business underlying consumption shown here excludes the impact of business EVs, which is discussed separately later in this section.

Without the impact of business EVs, between 2022-23 and 2032-33, business underlying consumption is forecast to increase throughout the outlook period, adding at least 7.6 TWh to up to 36.2 TWh. In summary, it is forecast to increase[83]:

- From 13.3 TWh to 20.9 TWh (on average growing 4.6% annually) in the **low scenario**, largely driven by electrification and BMM.
- From 13.4 TWh to 25.2 TWh (on average growing 6.5% annually) in the **expected scenario**, largely driven by the growth in electrification, LIL, BMM and consumption in hydrogen sector.
- From 13.4 TWh to 49.7 TWh (on average 14.0% annual growth) in the **high scenario**, largely driven by consumption in hydrogen sector and electrification.

Compared to the 2022 WEM ESOO, business underlying consumption is forecast to be at least 1.5 TWh and up to 33.4 TWh higher between 2022-23 and 2032-33, depending on the scenario. AEMO has improved the segmentation of residential and business actuals in the 2023 WEM ESOO. This has resulted in BMM historical consumption data being revised upward and correspondingly residential has been rebalanced downward[84], reflecting the corresponding sectors' forecasts in the short and medium terms. The consideration of hydrogen sector, electrification, and growth in the new LIL connections[85] in this year's ESOO resulted in higher business sector consumption in the long term.

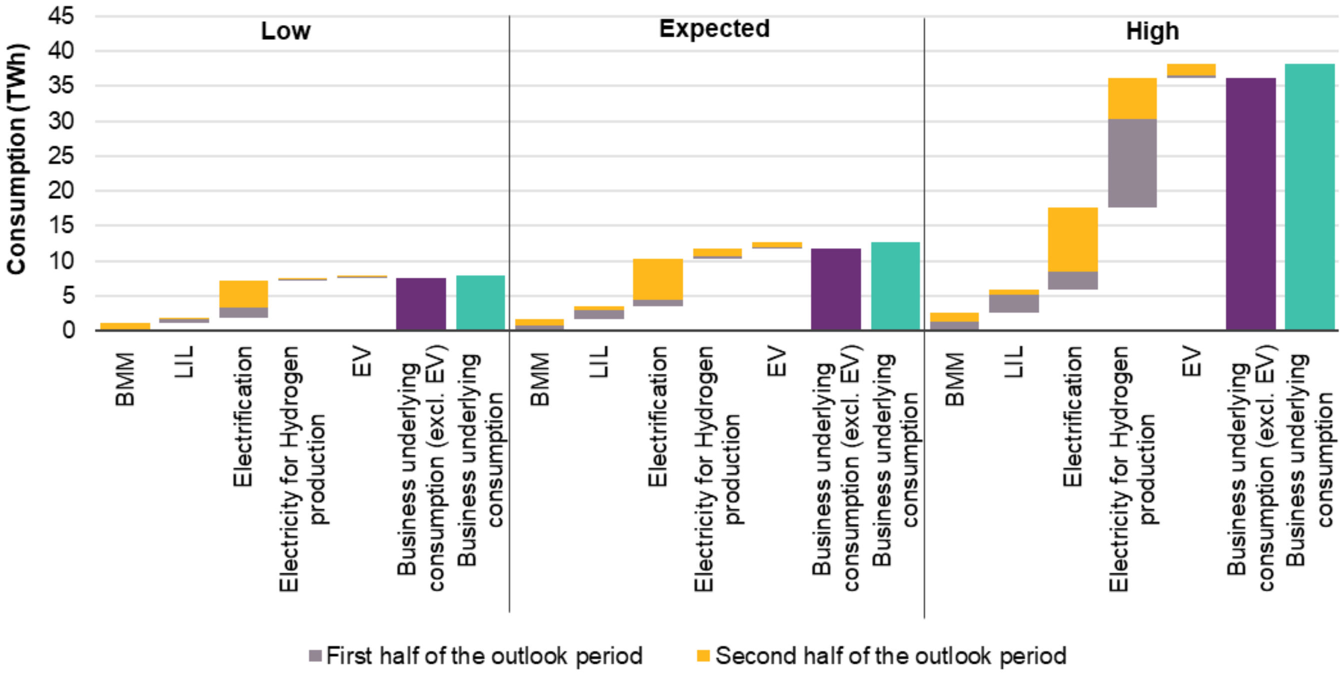
[83] The slight difference in the starting points for business underlying consumption forecasts across scenarios is because 2022-23 is not yet complete at the time of developing the 2023 WEM ESOO forecasts, and is thus considered an estimate inclusive of scenarios spread to a range of possible outcomes.

[84] Compared to the 2022 WEM ESOO actuals, the 2023 WEM ESOO residential actuals are lower, on average by 1.0 TWh annually, between 2016-17 and 2020-21.

[85] The growth in new LILs is largely driven by increased demand in critical minerals for energy transition.

Figure 19 shows the influence of sectoral components in driving the 2023 WEM ESOO business underlying consumption forecast between 2022-23 and 2032-33.

Figure 19 Business underlying consumption growth forecasts under three scenarios by components for the first half (2022-23 to 2027-28) and second half (2027-28 to 2032-33) of the outlook period (TWh)



Note: totals of sectoral components are presented excluding and including sectoral EVs to reflect the forecast methodology. The impacts of energy efficiency, climate change, and price are factored into the total underlying business consumption and not shown separately, because their influence is relatively small.

In summary, the business sector forecasts over the 10-year outlook period show:

- **BMM** – BMM is forecast to add 1.1 TWh, 1.7 TWh, and 2.5 TWh to underlying sectoral consumption in the low, expected, and high scenarios, respectively. The strength of economic indicators outpaces the effects of energy efficiency savings and price impacts in the first half of the outlook period, resulting in stronger growth across both expected and high scenarios compared to the second half of the outlook. However, the influence of these trends is reversed in the low scenario.
- **LIL** – LILs are forecast to grow and add 0.7 TWh, 1.8 TWh, and 3.4 TWh in the low, expected, and high scenarios, respectively. The higher growth forecast in the first half of the outlook period is due to a higher volume of new LILs meeting AEMO's criterion for inclusion in the first half of the outlook period[86]. Among new LIL projects that are anticipated to come online at different times throughout the outlook period, lithium production and processing is a key contributor. Other contributors include critical minerals, mining, and processing such as rare earths, magnesium, and rail projects.
- **Hydrogen sector** – electricity usage in this sector (including ammonia processing for hydrogen export and green steel) is forecast to add 0.4 TWh, 1.5 TWh, and 18.5 TWh, respectively, in the low, expected, and high scenarios. Across the scenarios, the growth is slower in the second half of the outlook period than in the first

[86] AEMO's assessment criteria for new LILs are discussed in Appendix A2.2.

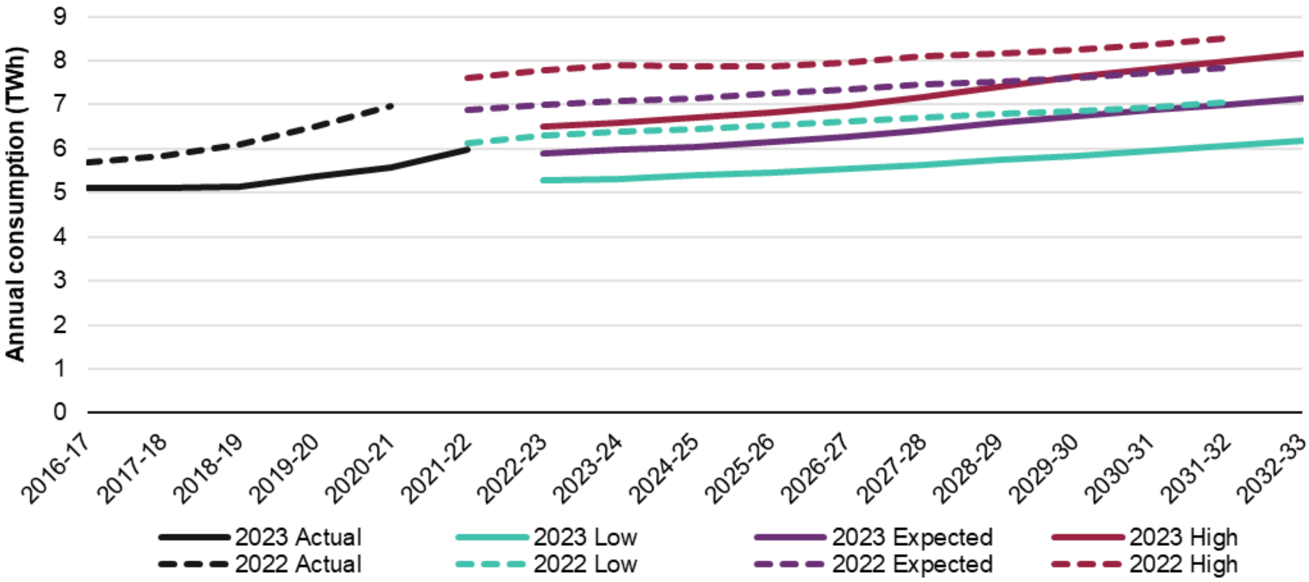
half, attributed to the gradual transition of electricity sourced to operate electrolysers from the SWIS to onsite renewable generation[87].

- **Electrification (excluding EVs)** – business sector electrification is forecast to add 5.4 TWh, 6.7 TWh, and 11.8 TWh in the low, expected, and high scenarios, respectively. Alumina refineries are forecast to be the largest contributor to the growth of business electrification, which is significantly higher than projected residential electrification.
- **EVs –** EV uptake is forecast to add around 0.3 TWh, 1.0 TWh, and 2.0 TWh in the low, expected, and high scenarios, respectively. The forecast assumes an inflection in sales for commercial vehicles in 2025-26 to 2026-27 (for battery EVs), and early 2030s (for fuel cell EVs), due to the anticipated availability of suitable vehicles at competitive prices. This contributes to a higher scale of electricity consumption in the later years of the outlook period across all scenarios.

3.4.2 Continued growth in residential underlying consumption is largely driven by growing connections and residential EV uptake

Figure 20 presents forecasts for residential underlying consumption, for the low, expected, and high demand growth scenarios from the 2022 and 2023 WEM ESOOs, with actuals from 2016-17 to 2021-22.

Figure 20 Actual and forecast residential underlying consumption under three scenarios from 2022 and 2023 WEM ESOOs, 2016-17 to 2032-33[A,B]



A. AEMO revised residential historical consumption data downward in the 2023 WEM ESOO due to improved segmentation of residential and business actuals. See Section 1.4.3. for further information.
B. Residential underlying consumption shown here excludes the impact of residential EVs, which is discussed separately later in this section.

Without the impact of residential EVs, between 2022-23 and 2032-33, residential underlying consumption is forecast to increase throughout the outlook period, adding at least 0.9 TWh to up to 1.7 TWh, depending on the scenario.

[87] Hydrogen production facilities are anticipated to further optimise project economics as they become larger and increase their energy requirements. Energy costs are likely to be mitigated by investing in behind-the-meter generation like wind and solar farms. This assumption is consistent with AEMO's ongoing discussions with proponents considering developing hydrogen production projects.

In summary, residential underlying consumption is forecast to grow[88]:

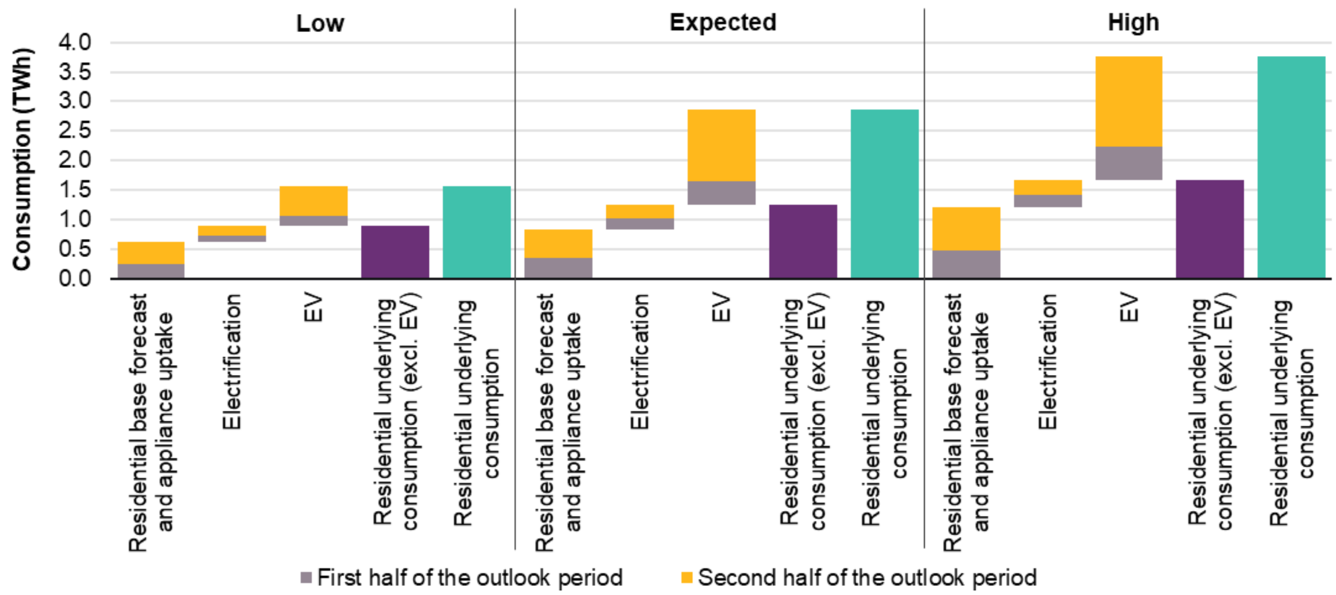
- From 5.3 TWh to 6.2 TWh (on average 1.6% annually) in the **low scenario**, attributed to slow forecast growth in residential connections.
- From 5.9 TWh to 7.1 TWh (on average 2.0% annually) in the **expected scenario**, attributed to a faster growth in residential connections and electrification offset by greater energy efficiency savings than in the low scenario.
- From 6.5 TWh to 8.2 TWh (on average 2.3% annually) in the **high scenario**, with fastest growth in residential connections.

Despite the forecast growth in residential underlying consumption, residential delivered consumption is forecast to decline in all three demand growth scenarios throughout the outlook period (average annual decrease of 2.6%, 6.8%, and 7.2%, respectively in the low, expected, and high scenarios) as more underlying consumption is being met by residential DPV generation.

Compared to the 2022 WEM ESOO, residential underlying consumption is forecast to be 6.0% to 16.7% lower throughout the outlook period and represents a smaller proportion of overall consumption due to recalibration of the residential-BMM split.

Figure 21 shows the influence of sectoral components in driving forecast residential underlying consumption between 2022-23 and 2032-33 in the 2023 WEM ESOO. Across all three scenarios, while forecast growth in the number of residential connections contributes to residential underlying consumption growth, it is partially offset by sectoral energy efficiency savings.

Figure 21 Residential underlying consumption growth forecasts by component for the first half (2022-23 to 2027-28) and second half (2027-28 to 2032-33) of the outlook period (TWh)[A,B]



A. Totals of sectoral components are presented excluding and including sectoral EVs to reflect the forecast methodology.
B. The residential base forecast and appliance uptake component shown here includes the impact of energy efficiency, climate change, and price on residential underlying consumption; these are not shown separately because their contribution is relatively small.

[88] The slight difference in the starting points for residential underlying consumption forecasts across scenarios is because 2022-23 is not yet complete at the time of developing the 2023 WEM ESOO forecasts and is thus considered an estimate inclusive of scenarios spread to a range of possible outcomes.

In summary:

- **Residential base forecast and appliance uptake –** this component includes the combined impact of residential base forecast, appliance uptake, energy efficiency, climate change, and price, that is forecast to add 0.6 TWh, 0.8 TWh, and 1.2 TWh in the low, expected, and high scenarios, respectively.
- **Electrification (excluding EVs)** – residential sector electrification is forecast to add approximately 0.3 TWh, 0.4 TWh, and 0.5 TWh in the low, expected, and high scenarios, respectively.
- **EVs –** residential EV uptake is forecast to add approximately 0.7 TWh, 1.6 TWh, and 2.1 TWh in the low, expected, and high scenarios, respectively. Forecast assumption on an inflection in EV sales, as mentioned in business EV, contributes to a larger scale of electricity consumption in the later years of the outlook period, across the scenarios.

4 Demand forecasts

Peak demand is forecast to increase at an average annual rate of 4.4% over the 10-year outlook period in the expected scenario. This is a significant increase relative to the 2022 WEM ESOO (0.9%) and is largely attributed to forecast electrification and an increase in cooling load.

Minimum demand (at 50% POE) is forecast in the expected scenario to decrease for the first five years at an average annual rate of 13.4%, a much lower rate of decline than forecast in the 2022 WEM ESOO (56.7%), and reverse to an upward trend after 2027-28 as growth in demand is projected to exceed the growth in DPV generation at the time of minimum demand.

4.1 Peak demand forecast increased with updated demand forecasting approach

The 2023 WEM ESOO forecasts significantly higher peak demands under all three scenarios compared to the 2022 WEM ESOO, driven by the introduction of emerging drivers such as electrification and hydrogen loads, and an increase in demand from existing drivers such as cooling and increase in LILs, including an updated forecasting approach. See Chapter 1 for further information on the updated forecasting approach and Chapter 2 on the drivers for demand forecasts.

The key drivers for the forecasts differ across the three scenarios and over the outlook period:

- In the first half of the outlook period, electrification is forecast to be the dominant driver in all three scenarios. Increases in cooling load are a significant secondary contributing driver under the expected scenario, while the secondary drivers are an increase in LILs under the low scenario, and increases in cooling load and hydrogen production under the high scenario.
- In the second half of the outlook period, electrification is projected to remain the most important driver across all three scenarios. The second largest contributor is increase in cooling load for the low scenario, and growth in EVs and increased cooling load for both expected and high scenarios.

Forecast demand under each demand growth scenario is in Appendix A5.

4.1.1 Significant growth in summer peak demand is primarily driven by electrification

Figure 22 shows the 10% POE peak demand forecasts under the low, expected, and high scenarios from the 2022 and 2023 WEM ESOOs, with actuals from 2016-17 to 2022-23.

The 2022-23 summer operational peak demand of 3,683 MW, which occurred in the 16:00 Trading Interval on 2 March 2023, was 301 MW lower than the 2021-22 summer peak demand due to mild summer weather conditions[89]. Further analysis of the 2022-23 summer peak demand is presented in Appendix A1.1.

Over the outlook period 2023-24 to 2032-33, the 2023 WEM ESOO forecasts are as follows:

- In the **low scenario**, peak demand is increasing at an average annual rate of 3.3%. The increase is much steeper in the second half of the outlook period. Electrification dominates as the primary driver across the entire outlook horizon, with increase in LILs and in cooling load as the secondary drivers for the first and second half of the outlook period, respectively.
- In the **expected scenario**, peak demand is increasing at an average annual rate of 4.4%. Similar to the low scenario, the rate of increase is notably higher in the second half of the outlook period. Both electrification and increase in cooling load have similar contribution as the dominant drivers in the first half of the outlook period. In the second half of the outlook period, only electrification remains as the dominant driver but is supplemented by both growth from EV uptake and increase in cooling load as the secondary drivers.
- In the **high scenario**, peak demand is increasing at an average annual rate of 6.8%. Electrification is the dominant driver across the entire outlook horizon, and the most important secondary driver is hydrogen and increase in cooling load for the first half of the outlook period and both growth from EV uptake and increase in cooling load for the second half.

Figure 22 Actual and forecast 10% POE peak demand forecasts under three scenarios from 2022 and 2023 WEM ESOOs, 2016-17 to 2032-33 (MW)

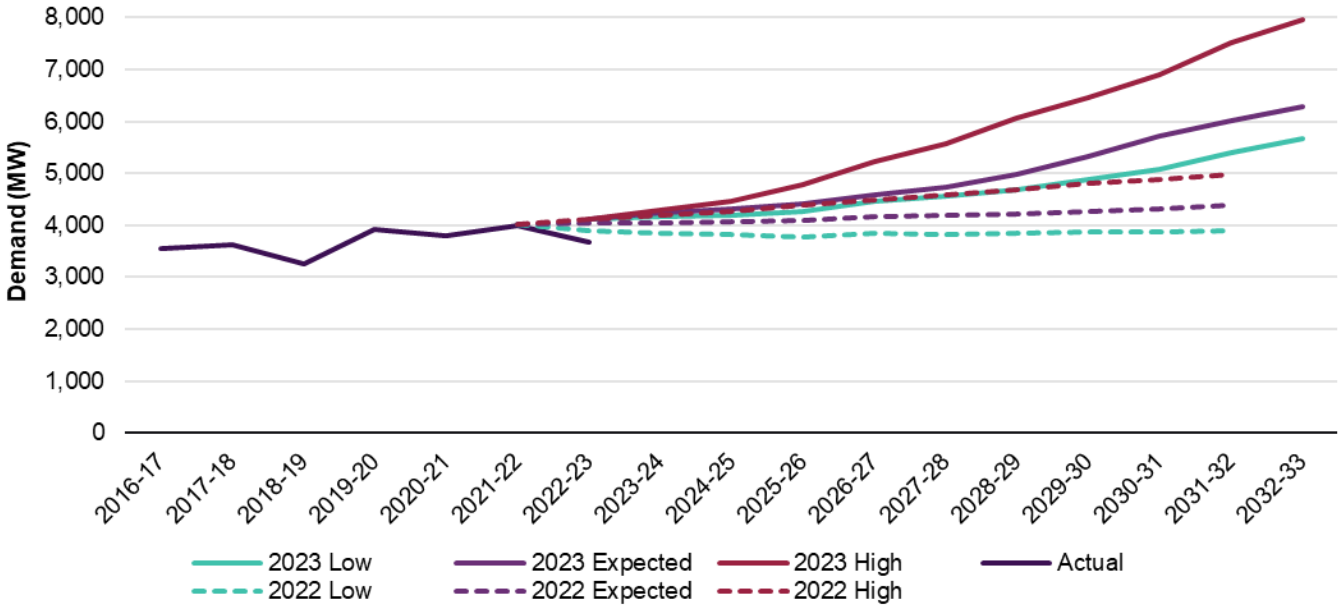


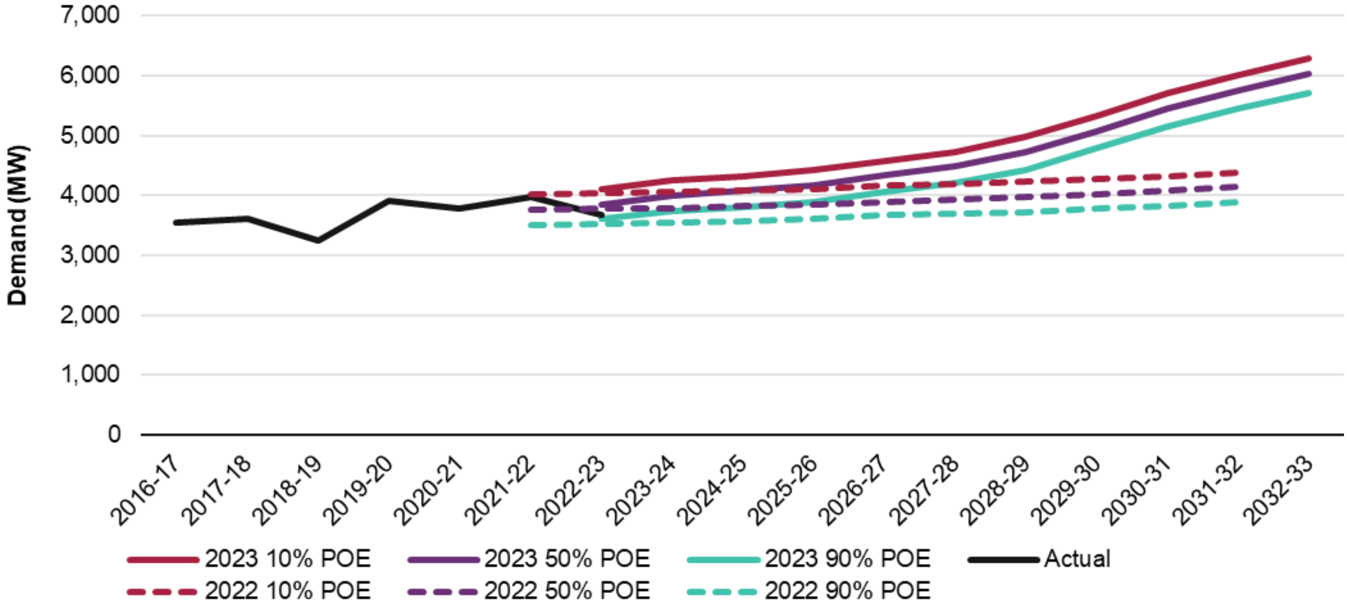
Figure 23 also highlights that the 10% POE peak demand forecasts in this 2023 WEM ESOO are significantly higher (between 37% and 51% higher in 2031-32 across the three scenarios) compared to those in the 2022 WEM ESOO. The increased peak demand forecasts are primarily driven by projected growth in electrification and cooling load. An emerging driver – hydrogen load – is also a notable contributing factor under

[89] Perth Metro's daily maximum temperatures ranged from 22.9 to 39.5 °C this summer, which was the fourth summer without a single 40°C day, following summers 2017-18, 2001-02, and 1998-99. See http://www.bom.gov.au/climate/current/season/wa/archive/202302.perth.

the high scenario. EV load was the dominant driver in the 2022 WEM ESOO forecasts, but its percentage contribution is reduced in this WEM ESOO after electrification and hydrogen assumptions were introduced and projected EV charging profiles were revised.

Figure 23 shows the 10%, 50%, and 90% POE peak demand forecasts[90] for the outlook period under the expected scenario. All three forecasts show growth across the outlook period, with average annual growth rates between 4.4% and 4.7%, compared to steady annual growth rates between 0.9% and 1.0% in the 2022 WEM ESOO forecasts[91]. The spread between the 10%, 50%, and 90% POE peak demand forecasts remains largely consistent over the outlook period under the expected scenario[92].

Figure 23 Actual and 10%, 50%, and 90% POE peak demand forecasts, expected scenario, 2016-17 to 2032-33 (MW)



4.1.2 Strong growth in winter peak demand is driven by forecast increases in heating load, electrification, and hydrogen production

Winter peak demand is forecast to remain lower than summer peak demand by an average of 11.8% throughout the outlook period for the expected scenario. This is in line with historical trends, but there can be significant variations year on year, for example if one is a mild season and the other is extreme.

In winter 2022, a record peak demand of 3,615 MW was observed in 18:30 Trading Interval on 9 August 2022 and was only 1.8% lower than the most recent summer peak demand (summer 2022-23 was a relatively mild summer). This record was reset by the observed peak demand of 3,652 MW[93], which occurred during the 18:00 Trading Interval on 26 June 2023 (for more details, refer to Appendix 1.2).

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

[91] The growth rates for the 2022 WEM ESOO have been recalculated following the adjustment of the base year to its calculation.

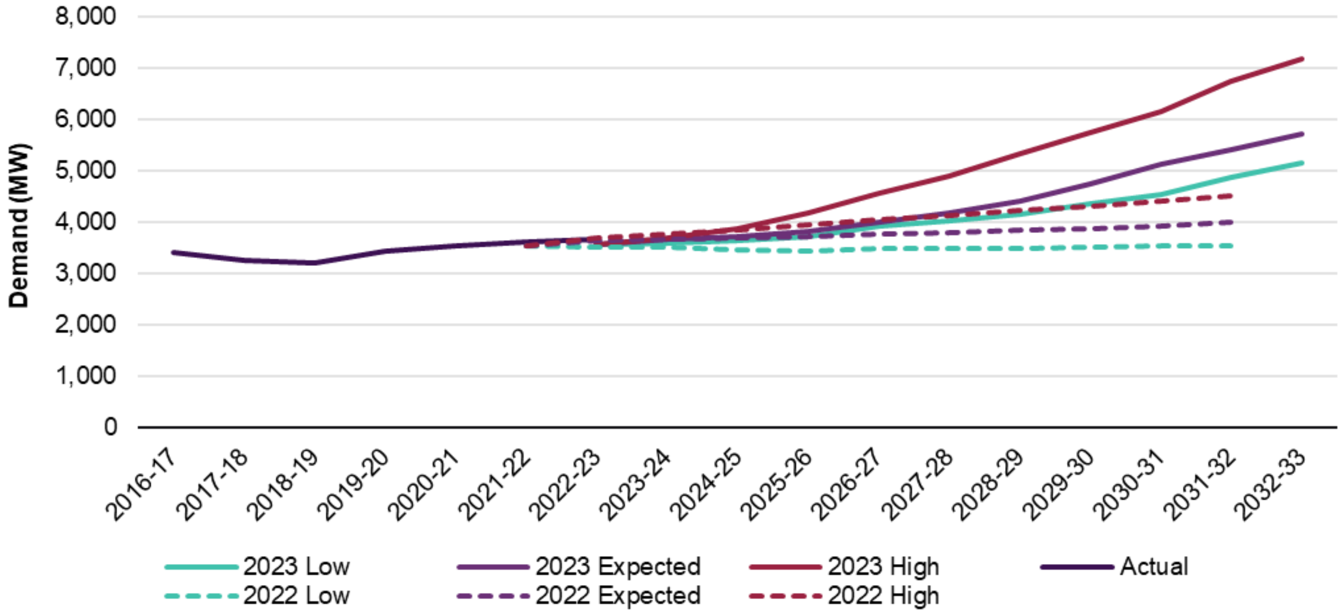
[92] On average, the 50% POE peak demand forecasts are 254 MW lower than the 10% POE peak demand forecasts and 286 MW higher than the 90% POE peak demand forecasts.

[93] Note that this estimate is based on operational demand data while the 2022 winter peak demand of 3,615 MW is derived using Total Sent Out Generation (TSOG) data.

Figure 24 shows the 10% POE winter peak demand forecasts under the low, expected, and high scenarios from the 2022 and 2023 WEM ESOOs, with actuals from 2016-17 to 2022-23. In summary:

- In the **low scenario**, winter peak demand is projected to increase over the outlook period at an average annual growth rate of 3.8%, largely as a result of electrification. Secondary drivers are increases in both LILs and heating load in the first half of the outlook period, and mostly heating load in the second half.
- In the **expected scenario**, winter peak is projected to increase at an average annual of 4.9%. Electrification and increases in LILs and heating loads play notable roles in the first half of the outlook period. While electrification remains a dominant driver in the second half, it is supplemented by growth in EV uptake and increase in heating load.
- In the **high scenario**, winter peak demand is projected to grow at an average annual rate of 7.3%, largely due to increasing electrification. Other contributing factors are increases in LILs and hydrogen load in the first half of the outlook period, and growth from EV uptake and increase in heating load over the second half.

Figure 24 Actual and forecast 10% POE peak winter demand forecasts under three scenarios from 2022 and 2023 WEM ESOOs, 2016-17 to 2032-33 (MW)



4.2 The variance between actual and forecast peak demand in summer 2022-23 is due to time of peak demand, weather effects and DPV

The peak demand of 3,683 MW occurred during the 16:00 Trading Interval on 2 March 2023 and was 359 MW lower than the 10% POE demand forecast for summer 2022-23 in the 2022 WEM ESOO, and just below the 70% POE event.

The major factors that contributed to the 359 MW variance were:

- **Time of peak demand** – peak demand occurred during the 16:00 Trading Interval due to a weather front arriving in the afternoon. This initially caused a drop in DPV generation[94], increasing operational demand,

[94] DPV generation dropped from 571 MW in the 15:00 Trading Interval to 171 MW in the 16:00 Trading Interval.

before a cool change caused demand to drop off. The timing was earlier than the forecast distribution for peak demand timing in the 2022 WEM ESOO 10% POE forecasts (which was the period between the start of 17:00 Trading Interval and end of 20:00 Trading Interval for 2022-23).

- **Weather effects** – the maximum temperature on the day (36.9°C) was below the lower end of the forecast distribution for daily maximum temperature (37.8-41.2°C).
- **DPV** – estimated DPV generation (171 MW) at the time of the peak was above the forecast distribution for a peak demand event (9.46 MW to 123.28 MW), due to the time of the peak being earlier than typical for a summer peak. Higher DPV generation offsets demand, contributing to a lower outcome overall.

4.3 Electric Storage Resource Obligation Intervals (ESROIs) remained unchanged

The ESROIs are a set of eight contiguous Trading Intervals during which an Electric Storage Resource (ESR) has an obligation to be available if participating in the RCM. AEMO must determine the ESROIs in accordance with clause 4.11.3A of the WEM Rules for 2025-26.

AEMO analysed the timing when peak demand is likely to occur[95] for the 10% POE and 50% POE peak demand forecasts under the expected scenario, and identified the period between the start of 17:30 Trading Interval and end of 19:00 Trading Interval as the Peak Demand Periods[96]. Table 9 shows the Peak Demand Periods determined for 2025-26. The ESROIs are then determined by adding two Trading Intervals to each side, that is, the start and the end, of the Peak Demand Period to achieve a total of eight contiguous Trading Intervals. The ESROIs are determined as the period between the start of the 16:30 Trading Interval and end of the 20:00 Trading Interval for 2025-26[97].

Table 9 Trading Intervals in which peak demand is likely to occur for 50% POE and 10% POE peak demand forecasts and Peak Demand Period for 2025-26, expected scenario

POE	Trading Intervals
50%	17:30 to 19:00
10%	17:30 to 19:00
Peak Demand Period	17:30 to 19:00

AEMO has also examined whether the determined ESROIs meet the operational requirements of the SWIS for Medium Term PASA. With the quantity of ESRs anticipated to come online by 2025-26[98], it is expected that a more refined set of ESROIs will be required to take seasonality into consideration. This means that using a constant set of ESROIs throughout the year may not be appropriate for future WEM ESOOs and further analysis is required.

[95] Trading Intervals in which peak demand is likely to occur is determined as any Trading Intervals in which at least 10% of the individual simulations result in the occurrence of peak demand.

[96] Peak Demand Periods covers all Trading Intervals in which peak demand is likely to occur for both 10% and 50% POE peak demand forecast.

[97] These Trading Intervals are the same as the ESROIs determined for 2024-25. See Section 5.2.2 in the 2022 WEM ESOO, at https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf.

[98] Based on information from public announcement and 2024-26 Peak Demand NCESS.

The appropriateness of ESROIs will be considered operationally under the Short Term PASA starting from the New WEM Commencement Day, 1 October 2023. AEMO will assess the ESROIs for each coming seven days at 30-minute Trading Intervals as part of the Short Term PASA as per clause 6.3.1 of the WEM Rules. If a constant set of ESROIs is employed by default throughout the year, AEMO may be more likely to modify them in Short Term PASA timeframes.

4.4 Forecast decline in minimum demand up to 2027-28 followed by uptrend in later years

Minimum demand conditions in the SWIS continue to be a challenge as DPV uptake continues to grow. The current minimum operational demand record of 633 MW[99] was set in the 12:30 Trading Interval on 16 October 2022.

AEMO has identified material risks[100] that, in the absence of a targeted response[101], may prevent the secure and reliable operation of the SWIS under minimum demand operation conditions for 2023-24. AEMO analysed the risks and submitted a request to the Coordinator in April 2023 to trigger an NCESS[102] procurement for a minimum demand service[103]. The Coordinator has determined[104] the NCESS procurement for an expected utilisation of up to 125 MW of Minimum Demand Service during 2023-24.

Figure 25 shows the forecasts for 10%, 50%, and 90% POE minimum demand under the expected scenario for the period 2023-24 to 2032-33, and actual minimum demand from 2016-17 to 2021-22. Seasonal minimum forecasts are provided in Appendix A7. In summary:

- The 50% POE minimum demand is forecast to decline rapidly at a rate of 13.4%, from 683 MW in 2022-23 to 332 MW in 2027-28, then to increase to 814 MW by 2032-23.
- The forecast is higher compared to the 2022 WEM ESOO forecast, which had an average annual reduction rate of 56.7% for 50% POE.

These updated forecasts have informed AEMO's assessment of Power System Security at minimum demand.

AEMO has determined that the range of minimum demand levels under which the system can be securely managed will require a minimum demand service[105] to avoid the risk of AEMO intervention.

[99] The minimum operational demand of 633 MW is derived using TSOG data which is non-loss adjusted.

[100] The factors contributing to the risks include forecast operational demand falling below the AEMO's forecast Power System Security threshold, lack of load participation during system minimum demand events, and lack of alternatives to existing emergency mechanisms such as emergency solar management (ESM).

[101] Targeted response refers to any planned mechanism that AEMO may trigger when minimum demand falls below a level which is identified as critical. An example is the ESM in Western Australia. See https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

[102] NCESS is a framework developed as part of the WA Government's Energy Transformation Strategy (ETS) work streams. See Government of WA, A Framework for Non-Co-optimised Essential System Services, 2021, at https://www.wa.gov.au/system/files/2021-05/Information-Paper-Non-Cooptimised-Essential-System-Services.pdf.

[103] See AEMO, Non-Co-optimised Essential System Services Trigger Submission, 2023, at https://www.wa.gov.au/system/files/2023-04/NCESS-Trigger-Submission-Low-Load-redacted.pdf.

[104] See https://www.wa.gov.au/system/files/2023-04/Coordinator%20of%20Energy%20Determination%20-%20Minimum%20Demand%20Service%20%28April%202023%29.pdf.

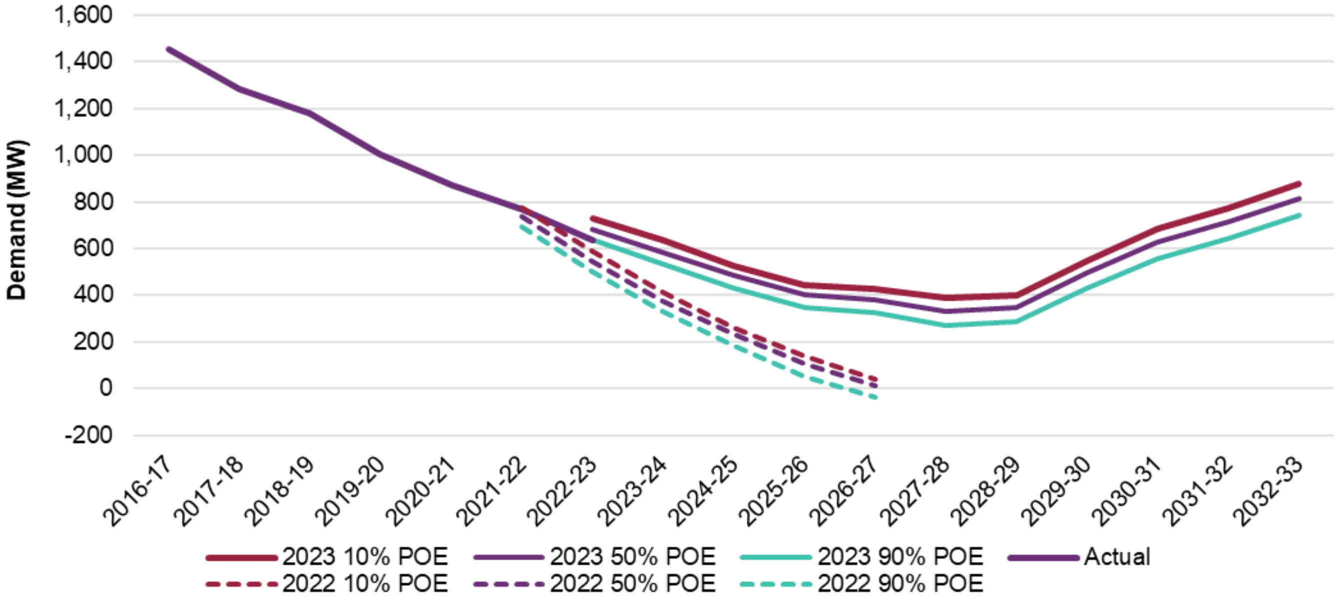
[105] To reflect updated forecasts in this WEM ESOO AEMO revised the quantity of Minimum Demand Service to procure through NCESS to 114 MW.

Under the **expected scenario**, minimum demand is forecast to decrease in the early years, driven by the continued uptake of DPV[106] but offset slightly by load increase due to LILs. In the later years, electrification and EV charging also contribute to the uplift in demand, exceeding the impact of growth in DPV thus resulting in an uptrend.

Minimum demand events continue to occur typically on mild weekend days, where demand is lower, through the shoulder season, mostly in the months of September to November, and are strongly correlated with peak DPV generation.

Minimum demand in the expected scenario is forecast to occur during the period between the start of 11:30 Trading Interval and end of 13:30 Trading Interval across the outlook period[107]. This covers the solar noon[108] when DPV generation is at its peak. This is consistent with the timing of the new minimum demand records set since the 2022 WEM ESOO (refer to Appendix 1.3).

Figure 25 Actual and 10%, 50%, and 90% minimum demand forecasts, expected scenario, 2016-17 to 2032-33[A,B]



A. Minimum forecasts are presented in seasonal years.
B. Actual minimum demand for 2023-24 is a year-to-date value, based on data until 31 March 2023.

[106] In the expected scenario, installed DPV capacity is forecast to increase from 2,453 MW to 3,853 MW between 2022-23 and 2027-28 (see Chapter 2 for more information).

[107] A minimum of 10% probability threshold is applied to define the Trading Intervals in which minimum demand is likely occur.

[108] Solar noon time is dependent on the longitude and date and occurs when the sun is at its highest point in the sky. Solar noon for Perth varies across the year between 12:00 to 12:30, as calculated at https://gml.noaa.gov/grad/solcalc/.

5 Supply forecasts

This chapter presents the capacity supply forecasts for each Capacity Year within the 2023 Long Term PASA Study Horizon (2023-24 to 2032-33). The forecast amount of available Reserve Capacity is a key input in the 2023 reliability assessment and projecting the capacity supply-demand balance outlook.

5.1 Capacity classification

The capacity supply forecasts consider both existing capacity and new projects in the development pipeline. This includes generation, energy storage, and DSM capacity. Capacity, for the purposes of the RCM, means Certified Reserve Capacity (CRC), which is usually less than the nameplate capacity of a Facility. The methodology for assessing and assigning CRC and Capacity Credits is generally based on the Facility Technology Type[109]:

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

These forecasts project the anticipated Reserve Capacity available for each Capacity Year within the outlook period, from 2023-24 to 2032-33. This information serves as a key input into the 2023 reliability assessment and capacity supply-demand balance outlook projection.

To determine the capacity supply forecast, various new projects are considered alongside upgrades to existing Facilities. AEMO assessed the development status of new projects obtained from the 2022 and 2023 Expressions of Interest (EOI)[110] provided as part of the RCM, the 2023 Long Term PASA formal information requests, and the procurement of the peak demand service NCESS for 2024-25 and 2025-26[111] (2024-26 Peak Demand NCESS).

AEMO evaluated these new projects[112] based on each project's final investment decision (FID) progress, the likelihood of the project connecting to the SWIS based on information sourced from Western Power, and the project's state of progress through environmental approval stages.

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

[110] See 2023 Expressions of Interest summary report, 2023, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2023/2023-expressions-of-interest-summary-report.pdf.

[111] See Energy Policy WA, Coordinator of Energy Determination: AEMO Non-co-optimised Essential System Service Trigger Submission, 2023, at https://www.wa.gov.au/system/files/2023-04/Coordinator-of-Energy-Determination-Minimum-Demand-Service-28Apri2023.pdf.

[112] New projects that received Capacity Credits for 2024-25, are in 2024-26 Peak Demand NCESS, or submitted a 2023 EOI and are a candidate for registration are not tested using the three criteria assessment.

The outcome of this project status evaluation informed the classification of projects into the following capacity categories[113] (for further details on the evaluation methodology, refer to Appendix 3.5):

- **Existing** capacity – associated with Registered Facilities that have been assigned Capacity Credits for 2022-23, 2023-24, or 2024-25.
- **Committed** capacity – includes new projects that are candidates for registration and have been assigned Capacity Credits for 2024-25 or scored 80% or higher in the new project status evaluation.
- **Probable** capacity – comprises new projects that:
  - Are a candidate for registration and have submitted a valid 2023 EOI[114].
  - Are contracted or expected to be contracted for the 2024-26 Peak Demand NCESS.
  - Have scored 50% or more but less than 80% in the new project status evaluation.
- **Proposed** capacity – includes all new projects that have been proposed but have not met the criteria to be in the existing, committed, or probable capacity categories.

Table 10 summarises which capacity categories are included in each scenario for the capacity supply forecasts. Existing capacity is included in each of the low, expected, and high scenarios, except for the existing-for-high-only capacity, which is only included in the high scenario. The existing-for-high-only capacity is associated with Registered Facilities that did not receive Capacity Credits for 2024-25 but received Capacity Credits for 2022-23 or 2023-24. This capacity may seek Capacity Credits in future cycles. Committed capacity is included in both the expected and high, while probable capacity is considered only in the high scenario. Proposed capacity is not included in any scenario.

Retiring capacity is included until its scheduled or assumed retirement dates applicable to each scenario (for more information, see Section 5.2.2).

The available Reserve Capacity for the initial two Capacity Years, 2023-24 and 2024-25, is determined by the assigned Capacity Credits for each respective year. For the subsequent Capacity Years from 2025-26 to 2032-33, the potential amount of available Reserve Capacity is estimated based on the anticipated CRC evaluated for each technology type.

Table 10 Scenario inclusion for different capacity classifications and retirement cases

Scenario	Existing capacity	Committed capacity	Probable capacity	Proposed capacity	Coal Generator Retirement case
Low	Yes	No	No	No	Low
Expected	Yes	Yes	No	No	Expected
High	Yes	Yes	Yes	No	High

Note: existing-for-high-only capacity is only included in the high scenario from 2025-26 onwards.

113 Due to new information being available after the reliability modelling commencement, there may be some small discrepancies between the achieved score and subsequent classification of some capacity projects. This chapter uses the latest available information, for each capacity project in the three criteria assessment.

114 Valid EOI as defined in clause 4.4.1 of the WEM Rules.

5.2 Changes to existing and committed capacity

5.2.1 Changes in Capacity Credits for 2024-25

For 2024-25, 38 Market Participants (up from 34 in 2023-24) operating 69 Facilities (up from 65 in 2023-24) were assigned a total of 4,596.4 MW of Capacity Credits. The 130 MW of new committed capacity does not fully offset the retirement of Muja C unit 6 (193 MW), resulting in a 2.8% decline in Capacity Credits compared to 2023-24 (4,726.6 MW). The Reserve Capacity Price has been determined to be $194,783.54/MW for new Facilities for 2024-25.

Key changes in 2024-25 compared to 2023-24 include:

- New entries – a total of 130 MW of new committed capacity has been assigned Capacity Credits for 2024-25, including:
  - The Western Power and Power Research and Development Walpole Mini-Pumped Hydro Project (PRDSO_WALPOLE_HG1) with 1.5 MW/30 MWh of capacity[115] was assigned 1.5 MW of Capacity Credits for 2024-25. This is the first pumped hydro storage to be assigned Capacity Credits in the WEM.
  - The East Rockingham Waste to Energy Project (ERRRF_WTE_G1) with 28.6 MW of capacity was assigned 25.1 MW of Capacity Credits for 2024-25[116]. This Facility was assigned Capacity Credits for 2022-23 and 2023-24 but Commercial Operation has been delayed, and it is now expected to begin operations in the first half of 2023-24.
  - The Phoenix Energy Kwinana Waste to Energy Project (PHOENIX_KWINANA_WTE_G1) with 38 MW of capacity was assigned 33.9 MW of Capacity Credits for 2024-25[117]. This Facility was also assigned Capacity Credits for 2022-23 and 2023-24 but Commercial Operation has been delayed.
  - The Flat Rocks Wind Farm Project Stage 1 (FLATROCKS_WF1) with 73.9 MW of capacity[118] was assigned 20.4 MW of Capacity Credits for 2024-25.
  - The Cunderdin Solar Farm Project (SBSOLAR1_CUNDERDIN_PV1) with a total of 100 MW of capacity was assigned 48.7 MW of Capacity Credits for 2024-25, with 44.8 MW assigned to the ESR component and 3.8 MW assigned to the PV component[119].
- Retirements – Muja C unit 6 is scheduled to retire on 1 October 2024 and was assigned 193 MW of capacity for 2023-24. This represents the single largest reduction in Capacity Credits for 2024-25, but is partially offset by the entrance of new committed capacity.
- Existing Facilities – changes to Capacity Credit assignments from 2023-24 to 2024-25 included:
  - The Alcoa Wagerup Facility (ALCOA_WGP) was assigned 16 MW of Capacity Credits for 2024-25, a decrease of 10 MW.

[115] For more information on the Walpole Mini-Pumped Hydro Project, see https://www.westernpower.com.au/our-energy-evolution/projects-and-trials/walpole-mini-pumped-hydro/.

[116] East Rockingham's Waste to Energy Project is not a Registered Facility. For more information on East Rockingham's Waste to Energy Project, see https://erwte.com.au/.

[117] Phoenix Energy's Kwinana Waste-to-Energy Project is not a Registered Facility. For more information on Phoenix Energy's Kwinana Waste-to-Energy Project, see https://www.phoenixenergy.com.au/projects/.

[118] For more information on Flat Rocks Wind Farm Project Stage 1, see https://www.enelgreenpower.com/our-projects/in-development/flat-rocks-wind-project.

[119] For more information on Sun Brilliance's Cunderdin solar farm, see https://www.globalpower-generation.com/projects/projects-in-australia.

- The Synergy Muja D unit 7 (MUJA_G7) was assigned 211 MW of Capacity Credits for 2024-25, an increase of 3.8 MW.
- The NewGen Kwinana Facility (NEWGEN_KWINANA_CCG1) was assigned 327.8 MW of Capacity Credits for 2024-25, a reduction of 7 MW.
- The Wesfarmers Kleenheat Gas DSP Facility (PREMPWR_DSP_02) was assigned 23 MW Capacity Credits for 2024-25, an increase of 1.2 MW.
- The Synergy Kwinana battery (KWINANA_ESR1) was assigned 45.3 MW of Capacity Credits for 2024-25, a 1 MW reduction.
- The Perth Energy South Cardup Facility (SOUTH_CARDUP) was not assigned Capacity Credits for 2024-25, after being assigned 1.8 MW of Capacity Credits for 2023-24.
- The Tesla Geraldton Facility (TESLA_GERALDTON_G1) was assigned 9.999 MW of Capacity Credits for 2024-25 due to a 0.099 MW upgrade.
- The Tesla Kemerton Facility (TESLA_KEMERTON_G1) was assigned 9.999 MW of Capacity Credits for 2024-25 due to a 0.099 MW upgrade.
- The Tesla Picton Facility (TESLA_PICTON_G1) was assigned 9.999 MW of Capacity Credits for 2024-25 due to a 0.099 MW upgrade.

The Capacity Credits assigned for Semi-Scheduled and Non-Scheduled Facilities for 2024-25 increased by a total of 3.9 MW from 2023-24.

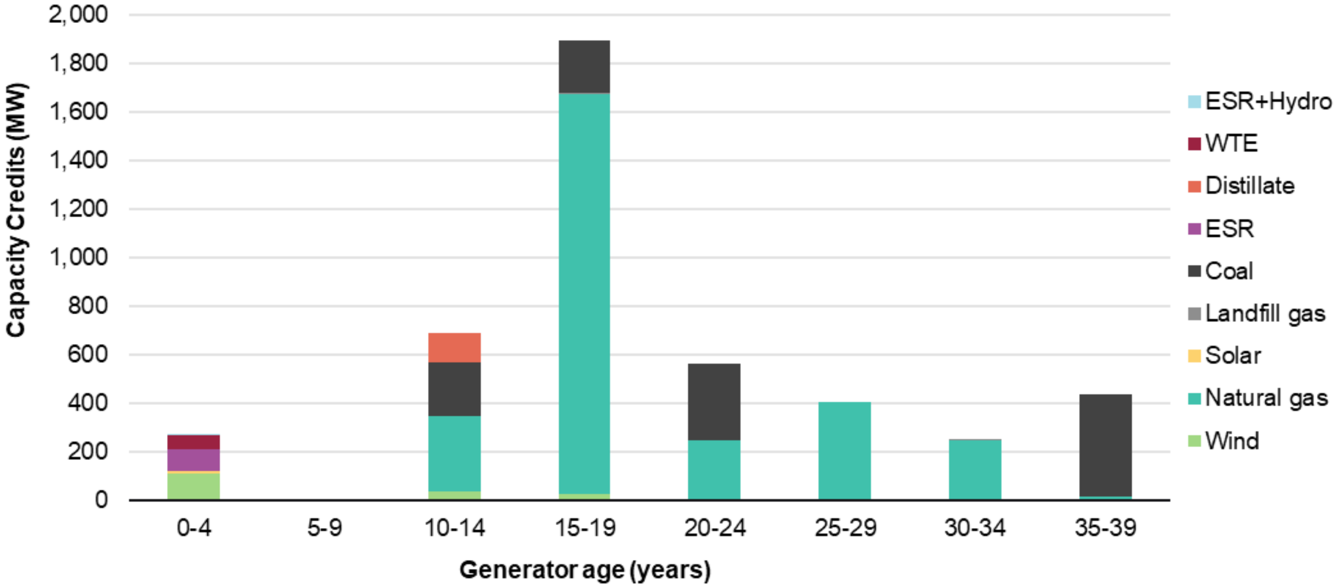
5.2.2 Facility age

Capacity Credits assigned for 2024-25 are summarised in Figure 26, by fuel type and age of the associated Facility participating in the RCM. Of all Facilities less than five years old, energy storage, waste to energy, wind, solar and pumped hydro constitute 99.9% of the Capacity Credits assigned in 2024-25 (the remaining 0.1% being associated with upgrades to distillate-fuelled Facilities). Among these, wind and energy storage provide the majority (73.5%).

Other observations relating to generator age and Capacity Credits are:

- The Muja D coal and the Alcoa Wagerup Facilities have been in operation for 37-38 years, are the oldest generators in the SWIS, and were assigned a total of 438 MW Capacity Credits in 2024-25.
- Facilities operating for 30-39 years make up 15.5% of the Capacity Credits assigned in 2024-25.
- All battery, waste-to-energy and hydro based Facilities have been installed in the last year or are currently under construction.

Figure 26 Capacity Credits in the SWIS for 2024-25 by fuel type and generator age



Note: generator age of 0-4 years includes committed capacity that has been assigned Capacity Credits for 2024-25. Facility ages are as of July 2023.

5.2.3 Facility retirements

Consistent with the WA Government's plan to retire state-owned coal generators by 2030[120], AEMO expects the phase-out of coal generation in the SWIS by 2030-31. This will lead to a reduction of 1,366 MW of Capacity Credits supply for the SWIS, the majority of this being state-owned generators set to retire by 2030.

Based on announcements made by the WA Government, and supporting advice provided by Market Participants, the following generators have been modelled to retire within the 10-year ESOO outlook period:

- Collie Power Station with 317.2 MW of Capacity Credits assigned for 2024-25 (modelled as retiring 1 October 2027).
- Muja C unit 6 with 193 MW of Capacity Credits assigned for 2023-24 (modelled as retiring 1 October 2024).
- Muja D unit 7 and 8 with 211 MW and 211 MW of Capacity Credits assigned for 2024-25, respectively (retiring 1 October 2029).

Considering the operational and commercial pressures on coal-fired generation in the SWIS, such as recent interruptions to coal sourced from within WA, the relatively lower operational cost of intermittent generators, increasing demand for electricity sourced from renewable energy generation, increasing variability in supply and demand due to the growth in variable renewables including rooftop PV, and government policies to transition to net zero, AEMO has assumed the retirement of the Bluewater units with the following retirement dates:

- Low scenario: 1 October 2030.
- Expected scenario: 1 October 2030.
- High scenario: 1 October 2025.

[120] See WA 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.

The retirement of Bluewaters is assumed for modelling purposes only. This assumption is made wholly by AEMO and does not reflect any formal decision made by the operators of the Facility to retire the generation plant.

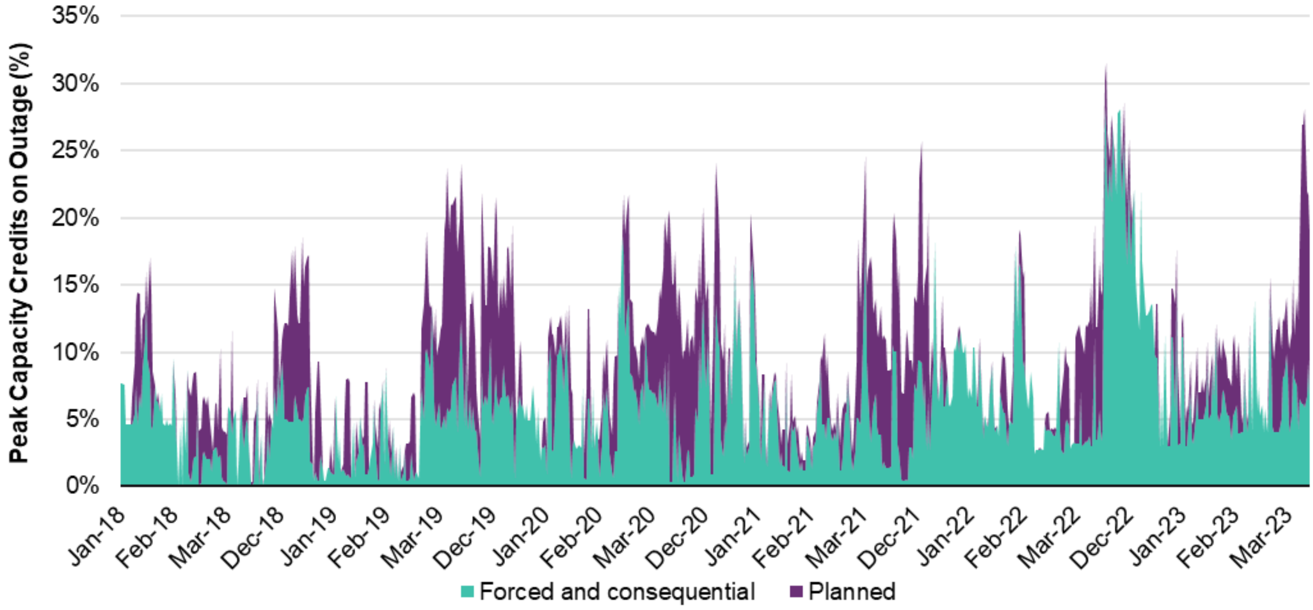
5.2.4 Facility outage and availability

Peak interval total outages (planned, forced and consequential[121]) of NIGS as a percentage of assigned Capacity Credits for each day for the 2018-19 to 2022-23 Hot Season are illustrated in Figure 27. This assesses the peak interval total outage size[122] of NIGS for each day during periods where peak demand can be expected.

Peak forced and consequential outage sizes of NIGS have seen a significant increase during the latest Hot Season[123]. In December 2022 the peak interval total outage size was 1,514 MW (1,273 MW of forced and consequential), which represented 32% of the Capacity Credits assigned for 2022-23. A high level of outages also occurred in recent months, peaking in June 2023 at 1,333 MW (1,188 MW of this was forced), which represents 28% of the Capacity Credits assigned in 2022-23.

Planned outages are generally avoided over hot periods when demand is expected to be highest.

Figure 27 Daily peak percentage of Capacity Credits on outage during Hot Season for 2018-19 to 2022-23



Note: peak Capacity Credits on outage is calculated as the daily peak total outage over the total assigned Capacity Credits for the relevant Capacity Year.

Figure 28 shows the 20 NIGS with the highest level of forced outages and their maximum assigned Capacity Credits over the 36 months ending in June 2023. The key observations are:

- Pinjar unit 10 has been on forced outage for the entirety of 2022-23 due to mechanoelectrical issues.
- Collie and Muja power stations faced coal supply issues that resulted in significantly higher levels of forced outages for 2022.

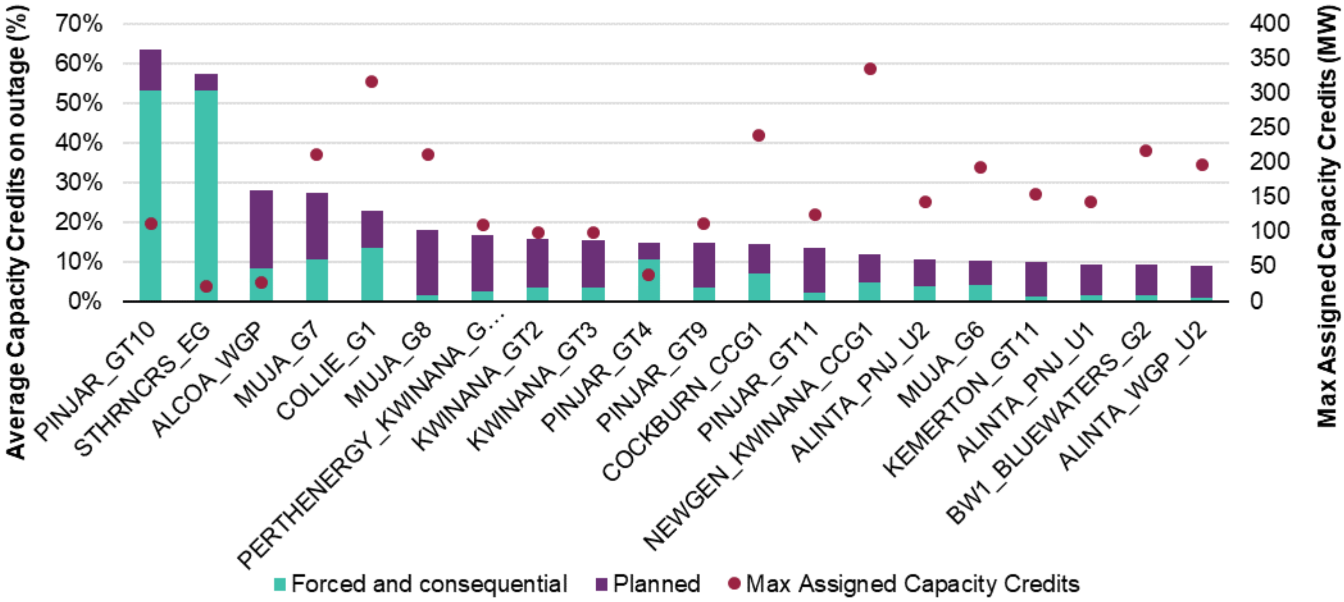
[121] A consequential outage is an outage defined in clause 3.21.1 of the WEM Rules. In summary, it is an outage unrelated to and not caused by the generator, but by another generator's forced outage or a Network Operator's planned outage.

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

[123] Hot Season as defined by the WEM rules: the period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April.

- Combined outage rates for Muja CD (units 6, 7, and 8) were in a range of 10% to 27%.
- Pinjar unit 10, Southern Cross Power Station, Collie Power Station, and Muja D unit 7 had the highest forced and consequential outage rates, at 53.3%, 53.2%, 13.5% and 10.4% respectively.

Figure 28 Capacity Credits on outage[A] and maximum Capacity Credits assigned[B] by Facility for 36 months up to the end of June 2023[C]



A. Capacity Credit on outage is calculated as the sum of outage in MW during the period over the assigned Capacity Credit multiplied by the total number of Trading Interval for that period.
B. Maximum Capacity Credits assigned is the largest amount of Capacity Credits assigned to a given Facility among each Capacity Year in the 36-month period (2019-20 to 2022-23).
C. Retired Facilities have not been included (KALAMUNDA_SG and MUJA_G5).

5.3 Pipeline of future projects

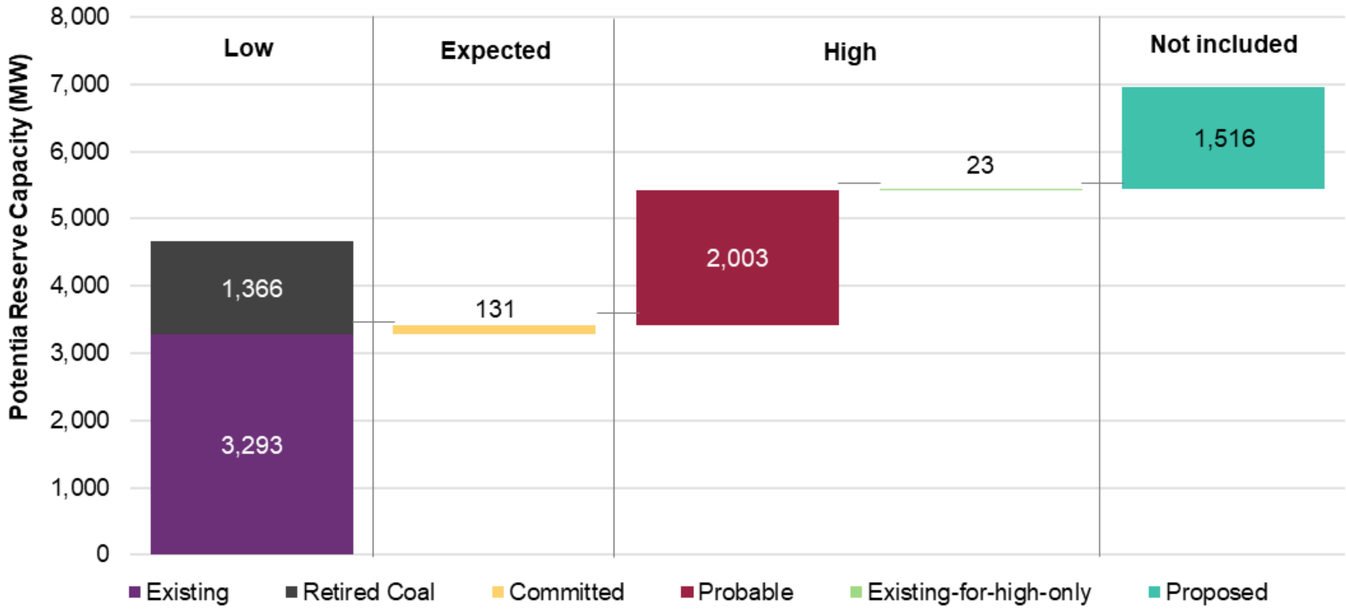
AEMO has identified 3,650 MW of new capacity with the potential to connect to the SWIS by 2030. This large pipeline of projects has been classified by capacity category as described in Section 5.1 and Appendix 3.5. Figure 29 shows the total Reserve Capacity forecast for each capacity category alongside the retiring capacity.

From the possible maximum of 3,650 MW of new capacity:

- 131 MW[124] is committed capacity which would offset just 10% of the capacity projected to be lost by 2030 from the retirement of coal generation.
- 2,003 MW is probable capacity which would offset all retirements and increase Reserve Capacity in the SWIS by 760 MW from 2030-31.
- 1,516 MW is proposed capacity that did not meet AEMO's criteria for inclusion in the committed or probable capacity.

[124] Note that the committed capacity of 131 MW is higher than the total new entries of 130 MW for 2024-25, as there is an addition of 1.6 MW starting from 2025-26 to the committed capacity, coming from projects that have scored 80% or higher in the new project status evaluation.

Figure 29 Total size of existing Facilities and new projects split by capacity catagory after all retirements are considered (from 2030-31 onwards) (MW)



There are 46 projects considered as probable capacity which are assumed to achieve Commercial Operation during 2024-25, 2025-26, 2026-27 and 2029-30. The Commercial Operation dates have been advised by the project proponent or estimated by AEMO using information made available by the proponent and the Network Operator. Probable projects include those expected to enter through NCESS procurement for the 2024-26 Peak Demand NCESS.

Of the estimated 2,003 MW of probable projects assumed to be available by 2032-33:

- 82 MW are wind generation.
- 45 MW are solar generation.
- 120 MW are DSM capacity.
- 177 MW are Non-Intermittent Generating Systems (distillate and gas).
- 1,579 MW are battery energy storage systems[125].

Of the 46 projects considered, 23 are standalone batteries (of which 14 are less than 1 MW of capacity) and five projects have a battery component included. Standalone batteries and battery components are expected to make up 79% of the total probable capacity.

5.3.1 Probable projects

There are multiple new capacity projects that have been announced that are not included in the committed capacity. These announced projects have been assessed by AEMO and have been included as probable capacity. The capacities used by AEMO for these projects may differ from the public information relating to these projects outlined below.

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

Large (>100 MW) storage projects that have been announced include:

- Synergy's Collie Battery with 500 MW/2000 MWh of nameplate capacity[126].
- Neoen's Muchea Battery with 200 MW/400 MWh of nameplate capacity[127].
- Synergy's Kwinana Battery 2 with 200 MW/800 MWh of nameplate capacity[128].
- Neoen's Collie Battery with 200 MW/800 MWh of nameplate capacity[129].

Other notable projects that have been announced include:

- Moonies Hill New Energy's Flat Rocks Wind Farm stage 2 with 100 MW of nameplate capacity[130].
- Synergy's Kings Rocks Wind Farm with 150 MW of nameplate capacity[131].
- Bristol Springs Project Stage 1 Solar Farm with 114 MW of nameplate capacity[132].

5.4 Scenario observations

By 2025-26, the expected scenario anticipates an additional 131 MW of Reserve Capacity on top of the existing capacity. Figure 30 shows the anticipated Reserve Capacity split by generator type for the expected scenario over the outlook period.

The key observations for the expected scenario are:

- The retirement of coal-fired generation is driving significant reductions in the Reserve Capacity across the outlook period.
- The new Reserve Capacity that comes from committed projects starting in 2024-25 does not completely cover the loss of capacity from the retirement of Muja C unit 6.
- The small increase in 2025-26 can be accredited to new Reserve Capacity from projects that scored high enough in the new project status evaluation to be included in the committed capacity.
- The Phoenix Energy Kwinana and East Rockingham Waste-to-Energy Projects have been modelled starting from 2023-24, which has the highest anticipated Reserve Capacity of 4,726.6 MW.

126 See https://www.mediastatements.wa.gov.au/Pages/McGowan/2023/05/WAs-first-big-battery-ready-with-bigger-battery-on-the-way.aspx.

127 See https://mucheabattery.com.au/.

128 See https://www.synergy.net.au/Our-energy/SynergyRED/Large-Scale-Battery-Energy-Storage-Systems/Kwinana-Battery-Energy-Storage-System-2.

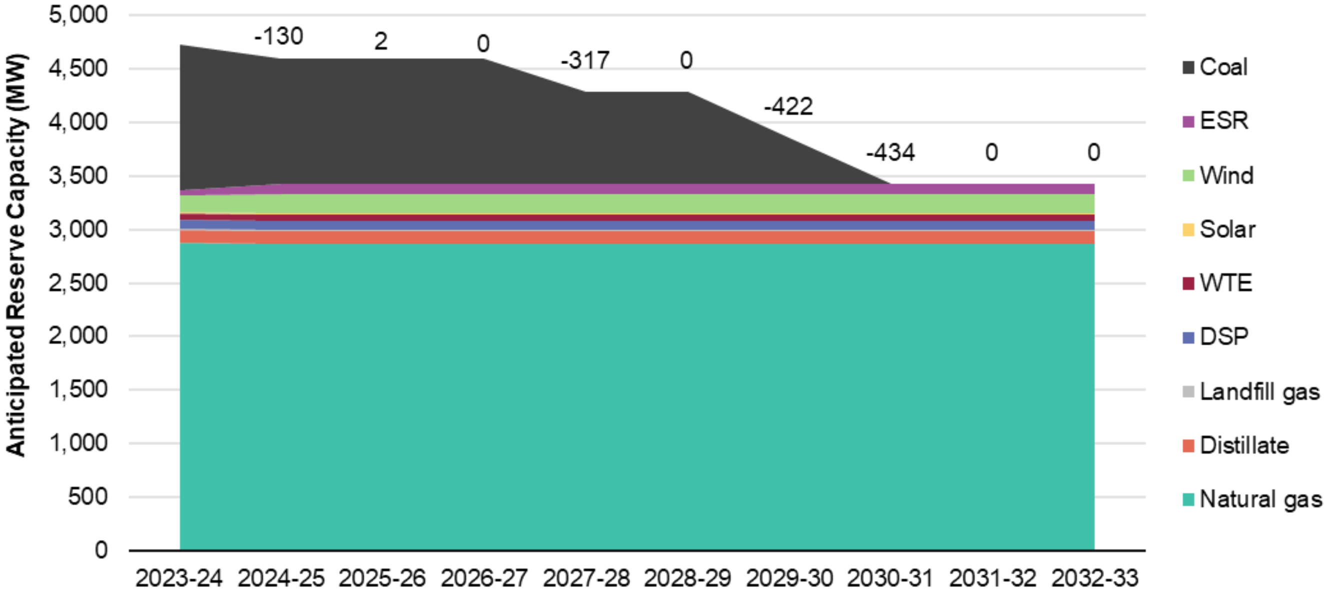
129 See https://colliebattery.com.au/.

130 See https://mhenergy.com.au/portfolio/.

131 See https://www.synergy.net.au/Our-energy/SynergyRED/King-Rocks-Wind-Farm.

132 See https://frontierhe.com/bristol-springs-project/.

Figure 30 Forecast Reserve Capacity split by generation type, expected scenario, 2023-24 to 2032-33 (MW)



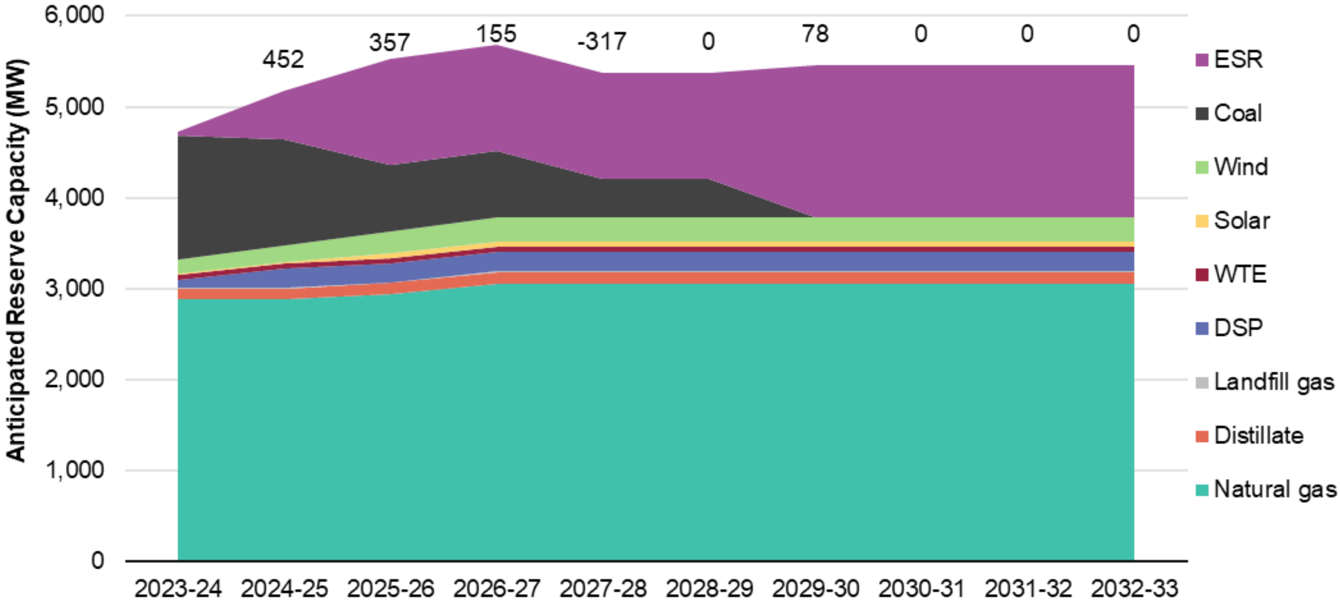
Note: the ESR grouping includes the battery components of wind and solar projects, standalone batteries, and pumped hydro.

By 2029-30, the high scenario anticipates an additional 2,157 MW of Reserve Capacity on top of the existing capacity. This includes 23 MW of existing-for-high-only capacity starting in 2025-26, 131 MW of committed capacity and 2,003 MW of probable capacity.

Figure 31 shows the anticipated Reserve Capacity split for generator type in the high scenario over the outlook period. The key observations for the high scenario are:

- New Reserve Capacity in the high scenario fully offsets retirements of coal generation and provides a net increase in capacity of 760 MW.
- Reserve Capacity reductions associated with coal retirements are offset by new entry in all years apart from 2027-28 where capacity reductions resulting from the retirement of the Collie Power Station (317 MW) exceeds forecast new entry in that capacity year.
- The growth in anticipated Reserve Capacity from 2024-25 to 2025-26 can largely be attributed to the additional capacity from the 2024-26 Peak Demand NCESS projects.
- Due to the earlier estimated retirement of the Bluewaters in the high scenario, batteries overtake coal as the second largest technology type capacity in the SWIS by 2025-26.
- The highest anticipated Reserve Capacity is 5,690 MW in 2026-27.

Figure 31 Forecast Reserve Capacity split by generation type, high scenario, 2023-24 to 2032-33 (MW)



Note: the ESR grouping includes the battery components of wind and solar projects, standalone batteries and pumped hydro.

6 Reliability assessment outcomes

This chapter presents the RCT[133] determined for each Capacity Year of the 2023 Long Term PASA Study Horizon (2023-24 to 2032-33). The RCT for 2025-26 is 5,543 MW, which sets the RCR[134] for the 2023 Reserve Capacity Cycle. The capacity investment gap[135] is projected to increase from 638 MW (11.9%) in 2023-24 to 945 MW (17.1%) in 2025-26, due to increases in demand forecasts, contingency reserve and regulation raise used in the RCT calculation and the retirement of some coal-fired generation.

6.1 Planning Criterion

Reliability standards are used in power systems to ensure the risk of failing to meet demand falls within acceptable limits. Involuntary load shedding caused by insufficient capacity can be costly to the economy and community, especially when there are frequent long-duration supply disruptions.

Globally, different reliability standards are used in power systems depending on the specific reliability risks, which vary according to the system's size, demand profiles, generator characteristics and outages, and level of interconnection. In the WEM, the reliability standard is called the Planning Criterion and is defined in clause 4.5.9 of the WEM Rules.

AEMO uses the Planning Criterion to set the RCT for each Capacity Year in the Long Term PASA Study Horizon. The Planning Criterion requires sufficient capacity to be available in the SWIS in each Capacity Year to meet both of the limbs below:

- The 10% POE peak demand forecast under the expected scenario plus allowances for Intermittent Loads[136], Regulation Raise[137] and a reserve margin[138] (limb A).

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

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

[135] The capacity investment gap percentage is calculated as: (RCR or RCT – available capacity)/(RCR or RCT). For 2023-24 and 2024-25, available capacity is the total quantity of Capacity Credits; for 2025-26 to 2032-33, available capacity is the forecast quantity of Reserve Capacity under the expected demand growth scenario, comprising existing and committed capacity.

[136] An Intermittent Load is a load that is normally fully served by embedded generation. It only requires electricity from the network when its embedded generator is not fully operational. It must reasonably be expected to have net energy consumption for not more than 4,320 Trading Intervals in any Capacity Year (approximately 25% of time), as specified in clause 2.30B.2 of the WEM Rules.

[137] Additional capacity required to provide Minimum Frequency Keeping Capacity and ensure that minimum Regulation Raise requirement is maintained. The transition from LFAS to Frequency Control Essential System Services (FCESS) Regulation will occur on 1 October 2023, with the launch of the new WEM. The Long Term PASA FCESS Regulation formula has been used for all Capacity Years in the RCT calculation. This formula includes estimations of how the growing volume of Variable Renewable Energy (VRE) generation will affect the amount of forecast error and subsequently the required amount of Minimum Frequency Keeping Capacity.

[138] The reserve margin accounts for both the annual variability of peak demand in the SWIS and the size of the largest contingency relating to loss of supply that could be expected at the time of peak demand, which may relate to outages of either generation or network assets.

- Limit EUE to 0.002%[139] of annual forecast expected energy consumption (limb B).

Since the RCM commenced in 2005, limb A has set the RCT because it has exceeded the capacity required to satisfy the EUE component of the Planning Criterion. The 2023 assessment has remained consistent with this observation, with limb A setting the RCT for all Capacity Years in the Long Term PASA Study Horizon.

AEMO engaged EY to conduct the 2023 reliability assessment, including the EUE assessment and determination of the Availability Class capacity requirements and Availability Curves. A summary of the assessment methodology, and changes to the methodology relative to the 2022 WEM ESOO, are presented in Appendix A3. Further information about the methodology can be found in EY's 2023 reliability assessment report[140].

6.1.1 Changes to the Planning Criterion since the 2022 WEM ESOO

The Planning Criterion in clause 4.5.9 of the WEM Rules was amended on 1 January 2023, as part of the Tranche 6 WEM Amending Rules, to implement one of the outcomes of the RCM Review being undertaken by the Coordinator[141]. Specifically, this change amended the reserve margin portion of limb A, replacing:

- the maximum capacity, measured at 41°C, of the largest generating unit; with
- the size, in MW, of the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand.

The reserve margin is then determined as the greater of the largest contingency relating to loss of supply and 7.6% of the forecast peak demand, including transmission losses and allowing for Intermittent Loads.

This amendment maintained the principle that the SWIS should be able to withstand the largest risk forecast at times of high demand, and acknowledges that the largest risk may in fact be greater than a single generating unit[142]. This methodology change more effectively reflects the broader reliability risks in the SWIS, as the energy transition continues.

6.1.2 Selection of the largest contingency relating to loss of supply and Regulation Raise

The SWIS is undergoing a significant transition towards a lower emissions energy system. Emerging persistent fuel issues and prolonged unplanned Facility outages have led to the unavailability of coal and gas capacity. These factors contribute to a broader range of supply-demand risks in capacity, impacting power system security and reliability.

AEMO has taken into account this evolving landscape when determining the size of the largest contingency related to loss of supply, as outlined in clause 4.5.9(a)(ii) of the WEM Rules. For the 2023 WEM ESOO, the assessment considered risks beyond a single generator contingency. Factors such as fuel supply disruptions, project delays, the volume and frequency of outages (forced and planned) especially during tight operational conditions, and failures of network elements were considered to determine the size of contingencies. This

139 A normalised metric, which does not have a unit. It represents the estimated percentage of forecast electricity consumption for a Capacity Year which cannot be met by the anticipated capacity of all Energy Producing Systems and DSM Facilities in that Capacity Year.

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

141 Details of the RCM Review are available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review.

142 Energy Policy WA, *Reserve Capacity Mechanism Review, Stage 1 Consultation Paper*, 2022, page XI, at https://www.wa.gov.au/system/files/2022-08/EPWA-Reserve-Capacity-Mechanism-review-consultation-paper.pdf.

methodology aligns with rule changes introduced in the Tranche 6 WEM Amending Rules and more accurately reflects the broader reliability risks in the SWIS during the ongoing energy transition.

As part of its determination of the appropriate risks at peak demand, AEMO analysed Facility outage records of NIGS during Hot Seasons from the last five years and identified that the largest risk relates to the forced outage of multiple generating units (Outage rates are further discussed in Chapter 5). It was found that:

- The total capacity of the three largest generating units was sufficient to cover historic forced outage levels in all analysed Hot Season months besides December 2022, which had 16 days (or 595 Trading Intervals) where over 1 GW of forced outages occurred for one or more Trading Intervals[143] and a peak total forced outage of 1,355 MW was recorded on 1 December 2022.
- If December 2022 was excluded from the analysis, reserves equivalent to the two largest generating units were insufficient to cover all forced outage levels, with 19 days (189 Trading Intervals)[144] exceeding reserves.
- This analysis informed AEMO's determination that the three largest generating units should set the size of risk for this component of the reserve margin[145], with AEMO considering December 2022 as an extreme case caused by ongoing fuel supply issues. This change has resulted in an increase in the reserve margin of between 568 MW and 648 MW[146] across the forecast horizon.

AEMO also modified the estimation of the minimum Regulation Raise requirement under the future Essential System Services framework to better account for the impacts of increasing penetration of intermittent generation in the power system. Combined, these changes have increased the reserve margin considered in the RCT determination over the outlook period from the methodology used in previous WEM ESOOs.

Future WEM ESOOs will incorporate updates to the determination of the largest risk and Regulation Raise requirements to ensure an adequate reserve margin is incorporated into the RCTs to maintain power system security and reliability. By regularly reassessing and adapting to the changing risk and technology mix landscape, AEMO aims to ensure the resilience and reliability of the power system as it navigates the challenges posed by the energy transition.

6.1.3 Future changes to the Planning Criterion

Further changes to the Planning Criterion have been considered as part of the RCM Review. AEMO anticipates that some or all of these changes are likely to be enacted in time for the 2024 WEM ESOO and may affect the projected reliability assessment outcomes.

The following changes have been confirmed as outcomes of Stage 1 of the RCM Review[147]:

- Updating the calculation of the reserve margin in clause 4.5.9(a)(i) of the WEM Rules by replacing the hard-coded proportion of 7.6% of the forecast peak demand with an AEMO-determined proportion of the generation fleet expected to be unavailable at system peak (as discussed in Section 6.6.1 above).

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143 Days and Trading Intervals are not necessarily consecutive and are reflective of the total over the specified period.

144 Including December 2022, the capacity of the two largest generating units was insufficient to cover the forced outage levels recorded from 42 days (944 Trading Intervals).

145 The contingency component of the reserve margin refers to the total size, in MW, of the largest contingency relating to loss of supply expected at the time of forecast peak demand, as per clause 4.5.9.(a) of the WEM Rules.

146 The increase in the reserve margin is reduced from 648 MW to 568 MW after the retirement of Collie Power Station.

147 Energy Policy WA, *Reserve Capacity Mechanism Review, Information Paper (Stage 1) and Consultation Paper (Stage 2)*, 2023, sections 2.1 and 2.2.2, at https://www.wa.gov.au/system/files/202305/epwa-reserve-capacity-mechanism-review-information-and-consultation-paper.pdf.

- The addition of a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the Capacity Year.

In addition, on 2 August 2023, a further amendment to the Planning Criterion was confirmed[148] as part of Stage 2 of the RCM Review, to update the EUE limit in clause 4.5.9(b) of the WEM Rules from 0.002% to 0.0002% of annual energy consumption. The date for implementation of this change is under consideration.

Development of draft rule changes to give effect to these changes is underway, along with consideration of the timeframes for implementation.

6.2 The Reserve Capacity Target

6.2.1 Limb A of the Planning Criterion

Table 11 shows the RCT, set by the expected 10% POE peak demand requirement of the Planning Criterion (limb A), for each Capacity Year of the 2023 Long Term PASA Study Horizon.

Table 11 Reserve Capacity Targets (MW)[A]

Capacity Year	10% POE peak demand	Intermittent Loads[B]	Contingency component of the reserve margin[C]	Regulation Raise[D]	Total
2023-24[E]	4,253	8	983	120	**5,364**
2024-25[E]	4,315	8	976	131	**5,430**
2025-26	4,418	8	976	141	**5,543**
2026-27	4,580	8	976	153	**5,716**
2027-28	4,734	7	898	167	**5,806**
2028-29	4,976	7	898	180	**6,061**
2029-30	5,325	6	898	192	**6,422**
2030-31	5,713	6	898	204	**6,821**
2031-32	6,021	6	898	215	**7,140**
2032-33	6,296	5	898	225	**7,425**

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. An estimate of the capacity required to cover the forecast cumulative needs of Intermittent Loads, which are excluded from the 10% POE expected peak demand forecast. Determined in accordance with clause 4.5.2A of the WEM rules.
C. Calculated as the greater of 7.6% of the 10% POE forecast peak demand and the size, in MW, of the largest contingency relating to loss of supply expected at the time of forecast peak demand in accordance with clause 4.5.9(a) of the WEM Rules. To set the RCT, AEMO has considered the largest contingency to be the loss of the three largest generating units. NewGen Kwinana (NEWGEN_KWINANA_CCG1, assigned 334.8 MW of Capacity Credits for 2023-24 and 327.8 MW of Capacity Credits for 2024-25) is the largest generating unit in 2023-24 then the second largest in 2024-25, NewGen Neerabup (NEWGEN_NEERABUP_GT1, assigned 330.6 MW of Capacity Credits for 2023-24 and 2024-25) is the second largest generating unit in 2023-24 and the largest in 2024-25 and Collie Power Station (COLLIE_G1, assigned 317.2 MW of Capacity Credits for 2023-24 and 2024-25) is the third largest generating unit up until its retirement in October 2027, after which Cockburn Power Station (COCKBURN_CGG, assigned 240 MW of Capacity Credits for 2023-24 and 2024-25) will be the third largest generating unit.
D. As part of the new WEM launching on 1 October 2023, the Frequency Control Essential System Services (FCESS) Regulation service will be used to ensure frequency is maintained within the Normal Operating Frequency Band. This new process incorporates the previously used Load Following Ancillary Service (LFAS) value of 110 MW and also plans around the variability that comes with new wind, DPV and solar generation.
E. Figures have been updated to reflect the 2023 WEM ESOO forecasts. However, the RCR of 4,396 MW set in the 2021 WEM ESOO for the 2021 Reserve Capacity Cycle (2023-24) and the RCR of 4,526 MW set in the 2022 WEM ESOO for the 2022 Reserve Capacity Cycle (2024-25) do not change.

The RCT determined for 2025-26 is 5,543 MW, which sets the RCR for the 2023 Reserve Capacity Cycle. It is 1,017 MW higher than the RCR set for 2024-25 (4,526 MW) and 989 MW higher than the RCT forecast for

[148] Energy Policy WA, *Reserve Capacity Mechanism Review: Information Paper (Stage 2)*, 2023, at https://www.wa.gov.au/system/files/2023-08/reserve_capacity_mechanism_review_-_information_paper_stage_2.pdf.

2025-26 (4,554 MW) in the 2022 WEM ESOO. This is largely due to higher 10% POE peak demand forecasts as a result of electrification and increase in cooling loads, combined with the higher reserve margin due to the largest risk being determined as the total capacity of the three largest generating units, and higher Regulation Raise requirement to account for the impacts of increasing penetration of intermittent generation in the power system.

6.2.2 Unserved energy assessment

The unserved energy assessment concluded that the RCT set by limb A of the Planning Criterion is sufficient to limit EUE to below 0.002% of annual forecast energy consumption for each Capacity Year in the 2023 Long Term PASA Study Horizon.

The assessment forecasts unserved energy to occur most frequently during Hot Season in earlier years, and winter in later years. Modelled unserved energy occurred mostly between 17:30 and 20:30 in earlier years and 17:00 and 23:30 in later years. Forecast unserved energy is most likely to occur in summer and winter when demand is high, with winter months also exhibiting lower solar generation. When demand and planned outages are high, forced outages or network curtailments can cause shortfalls of capacity and, hence, unserved energy.

The modelling considered planned outages, random unplanned outages via Monte Carlo simulation, and weather data over 12 reference years, to estimate unserved energy. Unserved energy occurred in the model in all months for most years, and across all Trading Intervals in later years.

While limb A continues to set the RCT, forecast unserved energy also exceeds the 0.002% requirement for all years in the outlook period. The full results of the EUE assessments are provided in Appendix A4.

6.3 Availability Classes

CRC is allocated to two classes based on capacity availability:

- Availability Class 1 relates to scheduled and intermittent generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages.
- Availability Class 2 relates to capacity that is not expected to be available for dispatch for all Trading Intervals and includes DSP and standalone ESR[149].

The minimum Availability Class 1 capacity requirement and the capacity associated with Availability Class 2 for 2024-25 and 2025-26 are shown in Table 12.

For the 2023 Reserve Capacity Cycle, the Availability Class 1 capacity requirement (4,510 MW) for 2025-26 sets the minimum amount of Availability Class 1 capacity that is required to be procured via the RCM to avoid a generation capacity shortfall. Additional Availability Class 1 capacity can be used to fulfil the capacity requirement associated with Availability Class 2 (1,033 MW) to meet the RCR.

The Availability Class requirements for 2024-25 are higher than the value in the 2022 WEM ESOO, consistent with the increased RCT for 2024-25 in this 2023 WEM ESOO.

[149] DSM capacity is required to satisfy the minimum availability requirements as specified in clause 4.10.1(f) of the WEM Rules, including being available to provide capacity for at least 200 hours in a Capacity Year to participate in the RCM. ESR capacity is required to be available for the Electric Storage Resource Obligation Intervals.

Table 12 Availability Classes (MW)

	2024-25[A]	2025-26
Minimum capacity required to be provided from Availability Class 1	4,430	4,510
Capacity associated with Availability Class 2[B]	1,000	1,033
RCT	5,430	5,543

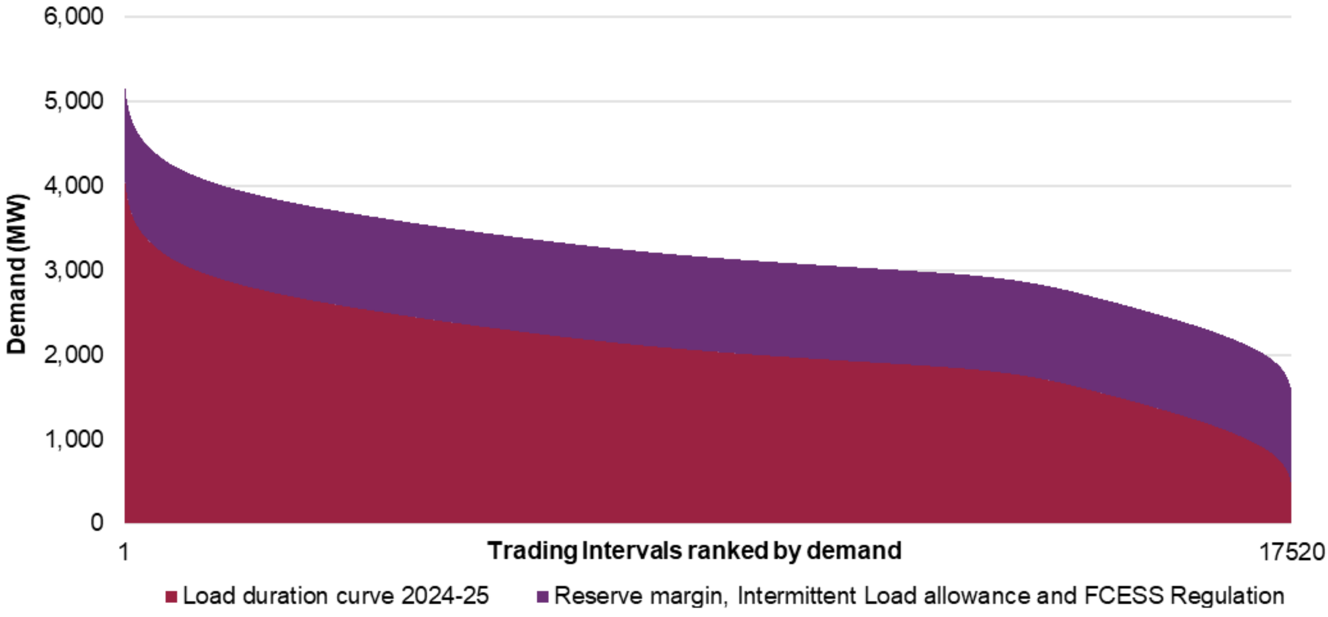
A. These figures reflect the forecasts in this 2023 WEM ESOO. The RCR of 4,526 MW determined in the 2022 WEM ESOO for 2024-25 remains unchanged.
B. Capacity associated with Availability Class 2 does not need to be provided by Availability Class 2 capacity. It is capacity that may be provided from either Availability Class 1 or Availability Class 2.
Source: AEMO and EY.

6.4 Availability Curves

The Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirement for each Trading Interval over a Capacity Year[150]. The minimum capacity requirement for each Trading Interval is calculated as the sum of the forecast demand for that Trading Interval, reserve margin, and allowances for Intermittent Loads and Regulation Raise.

The Availability Curves[151] for 2024-25 and 2025-26, as required under clause 4.5.13(f) of the WEM Rules, are shown in Figure 32 and Figure 33

Figure 32 Availability Curve, 2024-25 (MW)

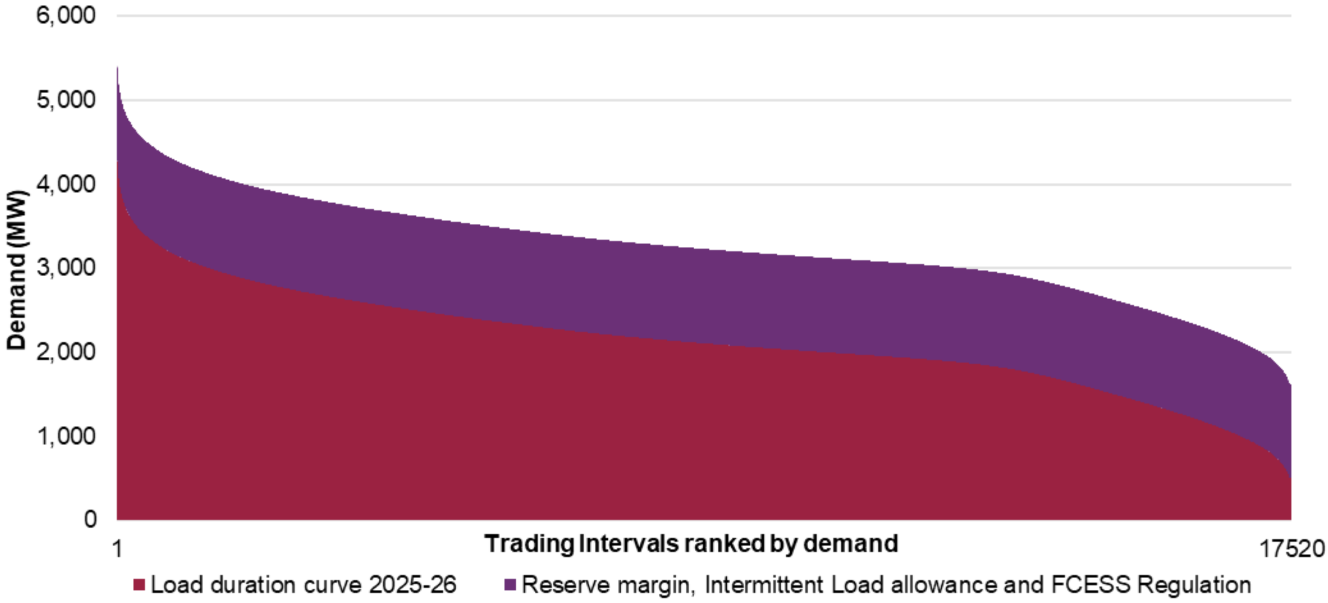


Source: EY.

[150] The Availability Curve (defined in clause 4.5.10(e) of the WEM Rules) shows how demand changes over a Capacity Year, with demand on the vertical axis and time on the horizontal axis. It can be used to determine the number of hours when the capacity requirement exceeds a given level of demand and includes a capacity margin to indicate total expected capacity required.

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

Figure 33 Availability Curve, 2025-26 (MW)



Source: EY.

6.5 Opportunity for investment

6.5.1 Supply-demand balance

In Table 13, the RCT is compared to the expected level of capacity in each Capacity Year of the 2023 Long Term PASA Study Horizon. This comparison indicates that additional capacity to supply the SWIS is projected to be necessary to satisfy the Planning Criterion for each year. The requirement for additional capacity across the Long Term PASA Study Horizon has grown relative to the 2022 WEM ESOO, due to the combined effect of higher demand forecasts and RCTs, and a reduction in forecast capacity.

Table 13 Forecast capacity supply-demand balance for expected scenario, 2023-24 to 2032-33[A]

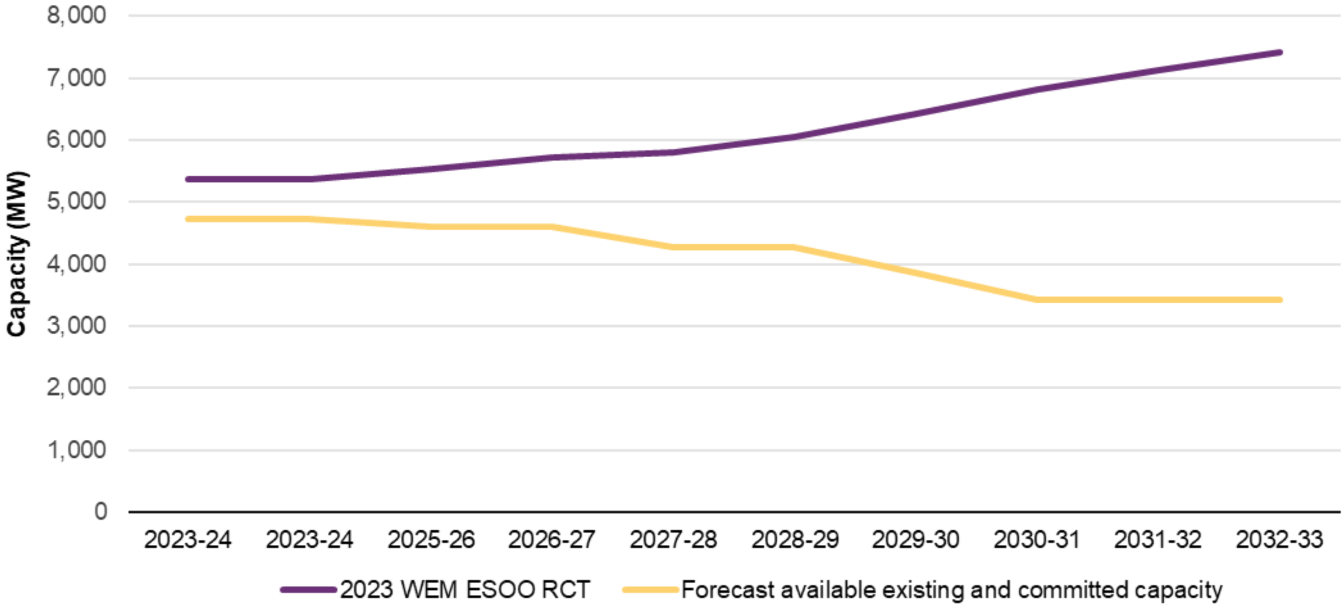
	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
RCT[B] (MW)	5,364	5430	5,543	5716	5,806	6061	6,422	6821	7,140	7425
Capacity (MW)	4,727[C]	4,596[C]	4,598[D]	4598	4,281	4281	3,859	3425	3,425	3425
Capacity investment gap (MW)	638[E]	833[E]	945	1118	1,525	1781	2,563	3396	3,715	4000
Capacity investment gap (%)	11.9[F]	15.3[F]	17	19.6	26	29.4	40	49.8	52	53.9

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. The quantities reported are the RCTs. The RCRs for 2023-24, 2024-25 and 2025-26 are 4,396, 4,526 and 5,543 MW respectively.
C. The 2023-24 and 2024-25 available capacity values are the total quantities of Capacity Credits assigned.
D. The capacity values for 2025-26 and remaining years represent the forecast quantity of Reserve Capacity under the expected demand growth scenario, comprising existing and committed capacity are forecasts, as described in Chapter 5.
E. Based on the RCRs for 2023-24 and 2024-25, the available capacity figures represent a capacity surplus of 331 MW and 70 MW, respectively.
F. Based on the RCRs for 2023-24 and 2024-25, the available capacity figures represent a capacity surplus of 7.5% and 1.6%, respectively.

Based on the RCRs for 2023-24 and 2024-25, the available capacity figures represent a capacity surplus of 7.5% and 1.6%, respectively. Where additional capacity is forecast to be required, the Reserve Capacity Price (RCP) will equal the maximum price of Benchmark Reserve Capacity Price (BRCP) multiplied by 1.3 from 2025-26, providing a strong signal that new capacity is required. The BRCP for 2025-26 was determined in December 2022 by Economic Regulation Authority (ERA) as $193,400[152].

The forecast supply-demand balance indicates strong investment opportunities for capacity providers (generation, energy storage, and DSM capacity) to supply the SWIS and meet the WEM reliability standards across the entire outlook period, as presented in Figure 34.

Figure 34 Reserve Capacity forecast supply-demand balance for expected demand scenario, 2023-24 to 2032-33 (MW)



This 2023 WEM ESOO forecasts the RCT to grow at an average annual rate of 3.7% over the outlook period, in comparison to the expected 0.8% annual growth rate in the 2022 WEM ESOO.

AEMO is seeking to mitigate supply risks in the 2023-24 Capacity Year through a Supplementary Reserve Capacity (SRC) procurement process[153] initiated in early August 2023 for up to 326 MW of capacity over the 2023-24 Hot Season. It is important to note that the quantity of SRC AEMO is seeking to procure is lower than the reliability gap identified in this report. This is due to the methodology used to quantify required reserves for each process, which closer to the start of the relevant Capacity Year may be reduced to reflect current operating conditions and near-term forecasts. The WEM Rules require AEMO to use the most recent published Long Term PASA forecasts and methodologies, and any other information AEMO considers relevant in determining the SRC requirement.

The 326 MW of SRC quantity considers supply risks reflective of current operational experience relating to unplanned facility outages, delay of projects coming online, and any other risks not captured under the contingency size used in the reliability studies for the 2022 WEM ESOO.

This leads to a smaller reliability gap than identified by the methodology used to set a Reserve Capacity Requirement two years ahead. To address emerging reliability challenges in the SWIS for 2024-25, in December

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[152] See https://www.erawa.com.au/cproot/23061/2/Notice---Benchmark-Reserve-Capacity-Price-2025-26---Publication-of-Final-determination.pdf.

[153] See https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/supplementary-reserve-capacity/src-2022-23-presentation-04082023.pdf.

2022 AEMO triggered the procurement of NCESS for minimum and peak demand services. This procurement aims to secure up to 830 MW of peak demand NCESS for 2024-25 and 2025-26 (2024-26 Peak Demand NCESS)[154]. AEMO is in the process of finalising contracts with successful participants in this tender process. The amount of procured peak demand NCESS capacity, combined with the Capacity Credits assignment for the 2024-25, will determine the additional capacity required to address the forecast reliability gap for 2024-25. This requirement may be adjusted based on the 2024 WEM ESOO forecasts, with the SRC process available to procure additional capacity for 2024-25 if required.

AEMO anticipates that the outlook for long-term reliability beyond 2025-26 will improve relative to the projections above, due to strong capacity investment signals and planned transmission expansion, demonstrating a commitment to achieve a sustainable energy future and maintain power system security and reliability.

Nevertheless, these supply-demand balance projections underscore the urgency in advancing generation, storage, and transmission projects to bolster reliability and support the rapid energy transition. The findings emphasise the need for additional capacity investment, expedited progress of probable projects, and the sustained investment in transmission infrastructure envisioned in the SWIS Demand Assessment[155] to enhance the overall reliability outlook and pave the way for a robust and resilient power system capable of meeting future demand and facilitating the transition to a cleaner and more sustainable energy future.

Potential changes to the supply-demand balance

The supply-demand balance in the SWIS may vary from the 2023 WEM ESOO forecasts during the 10-year outlook period due to:

- Changes in peak demand forecasts, which are affected by economic, technological, and public policy drivers.
- Entry of new capacity in the WEM, or decisions by Market Participants to withdraw existing capacity from service, such as the announcements by the WA Government in 2022 relating to coal generator retirement.
- Changes to the RCM resulting from the RCM Review, which may improve capacity investment signals and affect the way in which the RCR is determined, or capacity is certified in future Reserve Capacity Cycles[156].
- Changes to Network Access Quantity (NAQ) framework[157] outcomes due to introduction of new facilities and/or network augmentation.

The different demand scenarios (high, expected, and low) considered by AEMO capture some of this potential variability in the future supply-demand balance. The forecasts in this 2023 ESOO include considerable growth of the peak demand over the outlook period relative to the forecasts in the 2022 WEM ESOO. The drivers for this growth are presented in Chapter 2.

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

[155] See Government of WA, SWIS Demand Assessment 2023 to 2042 A future ready grid, 2023 at https://www.wa.gov.au/system/files/2023-05/swisda_report.pdf.

[156] Review outcomes from the RCM Review, for which WEM Rules amendments are under development, include the introduction of a new flexible capacity product, the replacement of Availability Classes with Capability Classes, an amended Relevant Level Method for valuation of intermittent generators, and an update to the EUE requirement to 0.002%. For further information, see Energy Policy WA, *Reserve Capacity Mechanism Review, Information Paper (Stage 1) and Reserve Capacity Mechanism Review, Information Paper (Stage 2)*, at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review?utm_medium=email&utm_campaign=Reserve-Capacity-Mechanism-Review-Information-Paper-Stage-2&utm_content=Reserve+Capacity+Mechanism+Review&utm_source=epwanews.mailer.dmirs.wa.gov.au#reserve-capacity-mechanism-review-information-paper-stage-2.

[157] Details on the NAQ framework can be found at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/network-access-quantities.

The supply-demand balance for low and high forecast scenarios is presented in Appendix A3.4 and the full set of peak demand forecasts is presented in Chapter 4.

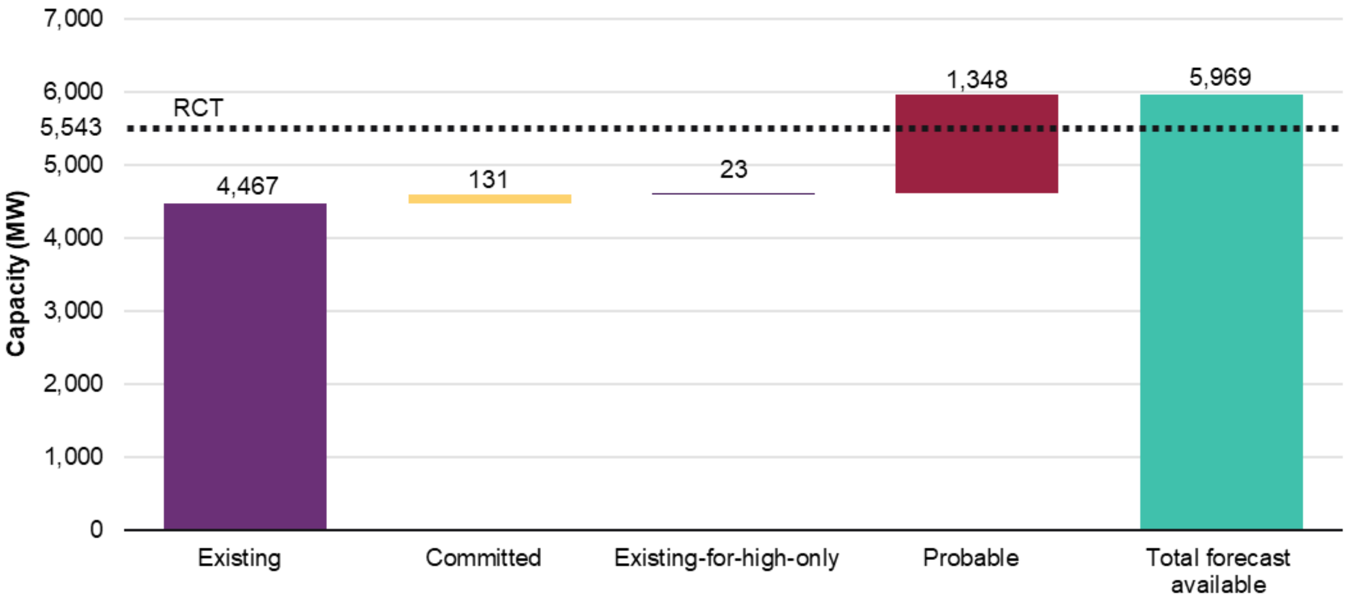
6.5.2 Capacity investment opportunities and pipeline progression

AEMO estimates that a total of 4,598 MW of capacity is expected to be available to meet the RCR of 5,543 MW for the 2023 Reserve Capacity Cycle related to 2025-26. This includes 4,467 MW of existing capacity and 131 MW of committed capacity. An additional 945 MW of capacity is therefore needed to meet the RCR for 2025-26. The NCESS for Reliability in 2024-25 is likely to contribute to but not fully meet this requirement and is not considered committed until contracts are finalised and relevant contractual conditions precedent are achieved.

In addition to the projects that have already been committed, there are several future generation and storage projects in various stages of development. These range from proposed to probable projects that may happen but do not meet all of AEMO's criteria to be considered committed.

As discussed in Chapter 5, a total of 1,348 MW of new projects in the pipeline satisfy AEMO's evaluation criteria to be considered probable capacity[158] for supplying capacity in 2025-26, including the 2024-26 Peak Demand NCESS capacity under contract negotiation with AEMO (see Figure 35).

Figure 35 Forecast Reserve Capacity status for 2025-26 (MW)



Note: the existing-for-high-only capacity is included in the capacity supply forecasts for only the high demand growth scenario. It is associated with Registered Facilities that did not receive Capacity Credits for 2024-25 but received Capacity Credits for 2022-23 or 2023-24.

[158] Probable capacity is considered only in the high demand growth scenario for the capacity supply forecasts. It is associated with new projects that are candidates for registration but have not received Capacity Credits for 2024-25. These projects have scored at least 50% but less than 80% in the new project status evaluation. Additionally, probable capacity includes the 2024-26 Peak Demand NCESS capacity under contract negotiation with AEMO.

The pipeline of probable projects expected to supply 2025-26 includes 60 MW of wind generation capacity, 34 MW of solar generation capacity, 1,077 MW of battery energy storage system capacity, 120 MW of DSM capacity, and 57 MW of peaking capacity operated with gas or diesel fuels[159].

If these projects are completed as planned, they could provide the additional capacity needed to meet the RCR for 2025-26, thereby addressing reliability challenges and supporting the ongoing energy transition.

In the longer term, AEMO forecasts a significant increase in capacity being needed to meet growing demand and ensure a reliable and secure power system. This emphasises opportunities for market investment to meet customer needs, and the potential risks if investment falls short.

Based on existing and committed capacity, an additional 1,118 MW of capacity is projected to be required by 2026-27, increasing to 4,000 MW by 2032-33. This further highlights the pressing need for proactive capacity investment measures.

To address this challenge, AEMO has identified 1,503 MW of probable projects that can be progressed to provide capacity for the SWIS in 2026-27, with an estimated 2,003 MW of probable projects available in 2032-33. Furthermore, an additional 1,516 MW of new projects have been identified by AEMO as proposed capacity[160] to meet demand by 2032-33.

AEMO recognises that much of the new capacity classified as probable is capacity from battery energy storage systems, which may contribute differently to reliability than other forms of capacity. AEMO will investigate further refinement to its reliability assessment methodology for the 2024 WEM ESOO to consider the impact that different technologies in the project pipeline will have in meeting the Planning Criterion.

6.5.3 Transmission investment opportunities and network augmentations

Network Constraints identified from the reliability modelling

The ESOO reliability model includes a Constraint Set that represents the limitations[161] of the network[162] and allows the model to consider the impact of network congestion on EUE. The constraints used in this model have been formulated based on information provided by the Network Operator[163] and consider existing and committed network projects in the outlook period.

It is noted that the Constraint Set does not consider augmentations committed after the ESOO reliability modelling commenced, such as the 2022 RCM Limit Advice (published 28 July 2023), or the 2023 Transmission System Plan. The constraints also do not consider likely but uncommitted augmentations associated with the SWIS Demand Assessment. These augmentations are likely to reduce network congestion and associated EUE and will be considered in future ESOOs when updated network information is available to AEMO. Network changes and augmentation works are discussed later in this section.

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

[160] Proposed capacity is not considered in the capacity supply forecasts for the low, expected, and high demand growth scenarios. It is associated with the new projects identified by AEMO, but did not meet the new project status evaluation to be classified as committed or probable capacity.

[161] Only thermal limitations were included in this Constraint Set. The Non-Thermal Limit Advice provided by the Network Operator was not relevant to the determination of EUE.

[162] The system is configured as an “N-0” system, which has no planned or forced network outages at times of peak demand. Constraints are formulated to protect against single credible contingencies, also known as “N-1” events.

[163] Information provided by the Network Operator includes but is not limited to impedances, ratings, protecting schemes, typical configurations, and load allocation.

The reliability modelling identified multiple constraints that may restrict available capacity or lead to EUE. The results indicate areas of the SWIS where increased transfer capability or additional supply capacity may be of benefit. These include (but are not limited to)[164] the constraints presented in Table 14.

Table 14 Constraints identified in the reliability modelling

Restricted sub-regions	Augmentation options
Kwinana	Increased transmission capacity out of Kwinana and Mason Road.
Rockingham/Mandurah	Increased transmission capacity into Rockingham / Waikiki / Mandurah. New capacity at Rockingham / Waikiki / Mandurah.
Eastern Goldfields and East Country	Increased transmission capacity and redundancy along 220 kilovolts (kV) link between Muja and West Kalgoorlie, and between Merredin and Northam.
North Metro/North Country	Increased transmission capacity and redundancy between Northern Terminal and Three Springs. New capacity providers in Metro North, south of Joondalup.
Geraldton	Increased transmission capacity south out of Mungarra.
Greater Southern	Increased transmission capacity between Kojanup and Albany.

Network Access Quantity

The NAQ framework was applied for the first time in the 2022 Reserve Capacity Cycle to assign Capacity Credits. All facilities were assigned NAQ equal to assigned CRC.

It is noted that the network limits used in the final 2022 NAQ calculation[165] are different to those used in the 2023 WEM ESOO modelling, as updated network information was made available after the commencement of reliability modelling.

It is further noted that network limits that cause infrequent constraint (for example, <5% of dispatch scenarios) do not typically impact the assigned NAQ[166]. Table 15 shows binding network limitations identified by the NAQ model.

Table 15 Network limitations identified to bind in at least one dispatch scenario of the NAQ model

Potentially limited network element	Relevant contingency
Southern Terminal (ST) T2 **Northern Terminal (NT)-East Perth (EP)/Belmont (BEL) 81**	Southern Terminal (ST) T1
Northern Terminal (NT) T1	Northern Terminal (NT) T2
Southern Terminal (ST)-Cannington Terminal (CT) 81	Kenwick Link (KNL) T1
Eastern Goldfields Voltage Stability	West Kalgoorlie (WKT) T1
Kwinana (KW)-Kwinana Desalination Plant (KDP)/Mason Road (MSR) 81	Kwinana (KW)-Mason Road (MSR) 81

Network changes and augmentation works

Committed network changes and augmentations identified by Western Power were used in the reliability model and Constraint Set.

[164] The modelling did not undertake a market benefit assessment of options listed. The options discussed here are based on a high-level review of constraint outcomes.

[165] Final RCM Constraint equations are available at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/system-operations/congestion-information-resource/constraints-library.

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

Network changes and augmentations that are not committed, but may impact network constraints in future, include but are not limited to:

- Changes associated with uncommitted generation connections.
- Augmentations described in the SWIS Demand Assessment.
- Augmentations identified in the Final 2022 RCM Limit Advice.
- Augmentations included in the 2023 Transmission System Plan.

Where uncommitted generators are included in reliability modelling, this is based on information provided by the Network Operator where available, and otherwise by a theoretical direct connection to the nearest substation. Detailed design may change the connection arrangement and impact the results.

The SWIS Demand Assessment identified an additional 4,000 km of new transmission lines and approximately 50 GW of new renewable electricity and storage infrastructure to support increased demand over the next 20 years. The WA Government has committed funding to the initial planning stage of these network investments, but the projects themselves are not yet fully scoped or committed and have therefore not been directly considered as part of this report. The investments include two stages:

- Stage 1 augmentation works provide options to be progressed by the mid-2020s. This involves augmentations between the South-West and South-East nodes and the Neerabup and Metro North nodes.
- Stage 2 augmentation works provides options to be progressed by the early-mid 2030s. This involves augmentations along most major corridors in the SWIS.

The Final 2022 RCM Limit Advice includes some recently committed network changes and augmentations, which were uncommitted at the time of reliability modelling and hence were not considered as part of this report. These augmentations included:

- Line upgrades out of Kwinana and into the South-West.
- Special Protection Schemes to improve network capability in some scenarios around South-West and North Metro regions.

The draft 2023 Transmission System Plan also included additional information regarding potential network changes and augmentations not committed at the time of reliability modelling. These augmentations will be reviewed as part of future WEM ESOOs.

A1. Historical demand

A1.1 Low summer peak demand due to mild summer

The 2022-23 summer operational peak demand[167] of 3,683 MW occurred in the 16:00 Trading Interval on 2 March 2023. The underlying peak demand[168] of 4,140 MW occurred in the 15:00 Trading Interval on 30 January 2023.

Key observations from the 2022-23 summer operational and underlying peak demand compared to the 2021-22 summer include (see Figure 36 and Table 16):

- Peak operational demand was 301 MW (8%) lower than 2021-22, due to the unusually mild summer. The peak demand day was mostly cloudy[169], which shifted the time of occurrence of the peak demand earlier[170] than seen in the previous years[171]. The maximum temperature was persistently above 36.5°C during the three days up to the peak demand day, and the overnight minimum temperature was 18.5°C.
- On the peak demand day, the difference between the maximum underlying and operational demand was approximately 446 MW. The underlying demand peaked in the 14:00 Trading Interval, two hours before operational demand peak. Of this difference, 275 MW was caused by DPV generation reducing operational demand during Trading Intervals that followed underlying peak demand (peak demand time-shift effect), and 171 MW[172] was caused by DPV generation reducing operational demand at the Trading Interval of peak demand (direct DPV reduction).
- The underlying peak demand was 271 MW (6%) lower than in 2021-22. The daily maximum and minimum overnight temperatures were 36.2°C and 20.5°C, respectively.

The 2022-23 summer contrasted strongly with the previous summer[173], with no Trading Intervals exceeding 40°C, compared to 82 trading intervals in 2021-22). This resulted in moderate operational and underlying peak demand, driven by lower demand for cooling from the residential sector.

[167] The peak demand is identified as the highest operational demand calculated for a Capacity Year (see Chapter 1 for the definition of operational demand).

[168] Underlying demand is calculated as the sum of operational demand and an estimate of DPV generation and impacts of distributed battery storage. Historical underlying demand calculation does not consider impacts of distributed battery storage. Due to the current relatively low uptake of distributed battery storage in the SWIS, its impact on historical underlying demand is negligible.

[169] See http://www.bom.gov.au/climate/dwo/202303/html/IDCJDW6111.202303.shtml.

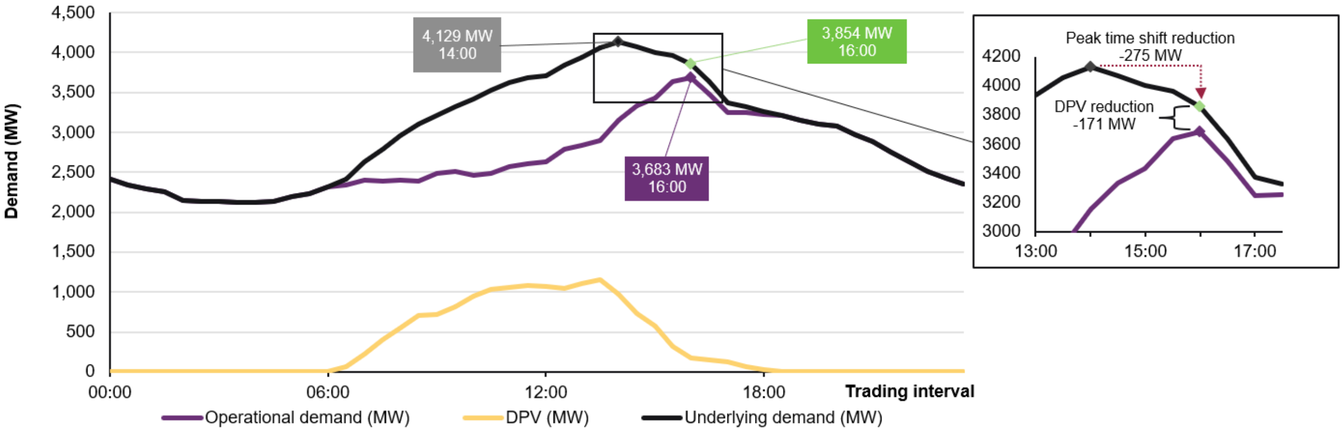
[170] Underlying demand equals the sum of operational demand and DPV reduction. Assuming the underlying demand is the same but DPV is reduced due to cloudiness, operational demand would be higher even during daylight hours.

[171] The last time the summer operational peak demand occurred at or before 16:00 was 2014-15.

[172] This direction DPV reduction is lowest among all 16:00 Trading Intervals in the 2022-23 summer.

[173] In 2021-22, 82 Trading Intervals had temperature above 40 °C.

Figure 36 Operational and underlying demand profiles on the observed peak demand day, 2 March 2023



Source: AEMO, Bureau of Meteorology, and Solcast.

Table 16 Comparison of annual peak demand days (2 March 2023 and 19 January 2022) and underlying peak demand days (30 January 2023 and 21 January 2022)[A]

Event	Date	Daily maximum operational demand		Daily maximum underlying demand		Temperature (°C)			Peak demand reduction	
		Trading Interval	MW	Trading Interval	MW	Daily maximum	Moving average[B]	Overnight minimum[C]	Peak demand reduction from peak time shift (MW)	Peak demand reduction from PV[D] (MW)
2022-23 peak demand	2 March 2023	**16:00**	**3,683**	14:00	4,128	36.9	36.7	18.5	171	275
2021-22 peak demand	19 January 2022	**18:00**	**3,984**	15:30	4,393	41.8	38.7	29.7	122	287
2022-23 underlying peak demand	30 January 2023	18:30	3,580	**15:00**	**4,140**	34.3	36.2	20.5	14	546
2021-22 underlying peak demand	21 January 2022	18:00	3,953	**15:30**	**4,411**	42.0	41.7	22.6	124	335

A. Based on the data as of 31 March 2023.
B. Calculated based on a three-day moving average of daily maximum temperatures.
C. Minimum temperature recorded between 20:00 and 4:30 Trading Intervals.
D. The difference between the peak demand and the daily maximum underlying demand.
Source: AEMO, Bureau of Meteorology, Clean Energy Regulator (CER), and Solcast.

A1.2 Record high winter peak demand due to a consistently cold and wet day

The 2022 winter peak demand of 3,615 MW occurred in the 18:30 Trading Interval on 9 August 2023. This was 2% higher than the previous year's winter peak (3,587 MW) and was a record high for winter peak demand since the start of the WEM. The winter underlying peak demand was identical to the winter operational peak demand as it occurred in the evening, meaning there was no effect from DPV generation. The peak demand of 3,615 MW on

9 August was an outlier for the 2022 winter[174], and was driven by the low maximum temperature of 10.7°C[175] for the entire day, heavy rainfall[176], and a lack of sunshine for two consecutive days[177].

A1.3 Record minimum demand as over 70% of underlying demand was met by DPV

Minimum operational demand events frequently occur around noon on non-working days in the shoulder seasons, particularly from September to November, when clear skies are coupled with mild temperatures. Table 17 summarises the four new minimum operational demand record days observed since the 2022 WEM ESOO was published. The current minimum operational demand record of 633 MW was set on 16 October 2022.

Minimum demand records are driven by the continued uptake of DPV[178], increasing the contribution of DPV generation to meeting the underlying demand. The percentage of underlying demand met by DPV exceeded 70% for the first time when the latest minimum demand record was set.

Table 17 Minimum demand records since 2022 WEM ESOO[A]

Date	Trading Interval commencing	Day of the week	Minimum demand (MW)	Daily maximum temperature (°C)	Demand reduction from DPV[B] (MW)	Percentage of underlying demand met by DPV (%)
11 September 2022	12:30	Sunday	749	23.8	1,362	65
08 October 2022	12:30	Saturday	712	22.4	1,475	67
15 October 2022	12:30	Saturday	686	21.4	1,442	68
16 October 2022	12:00	Sunday	633	20.6	1,486	70

A. Based on data as of 31 March 2022.
B. Demand reduction from DPV generation at the time of minimum demand was recorded.

174 No other day of the 2022 winter had demand exceeding 3,350 MW.

175 This is the lowest daily maximum temperature for the entire 2022 winter season.

176 On 9 August 2022, rainfall of 25.8 mm was recorded, the highest for the entire 2022 winter season. See http://www.bom.gov.au/climate/dwo/202208/html/IDCJDW6111.202208.shtml.

177 See http://www.bom.gov.au/climate/dwo/202208/html/IDCJDW6111.202208.shtml.

178 See Chapter 2 for the DPV uptake forecast.

A2. Forecast methodology and assumptions for Large Industrial Loads

This appendix summarises the methodologies for the LILs forecasts, focusing on the WEM-specific features.

LILs are users that consume or are forecast to consume at least 10 MW for a minimum of 10% of the time each year (around 875 hours a year), or at least 50 GWh per year based on demand and consumption over the previous Capacity Year. This definition captures the most energy-intensive transmission and distribution connected- consumers in the SWIS, including mining and mineral processing loads.

A2.1 Existing LILs

For existing LILs forecasts, AEMO carried out surveys to collect information on their anticipated consumption (MWh) and maximum demand (MW) over the outlook period for each demand growth scenario. AEMO's surveys also sought to identify any future electrification or energy efficiency upgrades. The surveys were supplemented by obtaining additional information through interviews as required.

A2.2 New LILs

For the new LILs forecasts, AEMO undertook market research and engaged with a range of stakeholders, including Western Power, in deciding which prospective and committed LILs to include in the 2023 WEM ESOO. Input from Western Power's queue of active connection projects played a notable role in the development of the new LILs forecasts.

AEMO has improved the new LIL forecasts for the 2023 WEM ESOO by incorporating decarbonisation considerations into the project evaluation methodology. The methodology now accounts for both long-term government decarbonisation policy targets and the fact that operators apply for EPA approvals three to four years in advance of their expected FID for the project in question.

Following these improvements, AEMO has limited the consideration of the EPA approval status criterion to projects that are expected to come online within four years, and added a decarbonisation criterion.

For all new LIL projects, two scoring systems were applied:

- For projects that are expected to come online within the next four years.
- For projects expected to start more than four years ahead.

The new LIL projects were evaluated on a graded scale using weighting summarised in Table 18 according to:

- Western Power's assessment on the likelihood of the project connecting to the SWIS.
- Whether the project proponent has publicly announced that it has taken a positive FID and/or the project has commenced construction.

- Whether the project is a carbon reduction project. This captures projects that are part of the energy transition. Examples include projects that involve hydrogen production or extraction and processing of critical minerals such as lithium, cobalt, and rare earth elements. The purpose of adding this criterion is to give weight to those projects that will be favoured by government and corporate policy to decarbonise, as well as those that stand to benefit from the global energy transition.
- The project's current state of progress through environmental approval stages. The stages are scored from 0% for "no application submitted" through to 100% for "Stage 5 (approved)". For projects that are expected online within four years, the system gives a weight to EPA approval, which is needed for a project to progress. No weight is given for EPA application for projects expected online more than four years ahead.

Table 18 Weighting for evaluation criteria for LIL projects

Criteria	Projects expected online within four years	Projects expected online more than four years ahead
Western Power active stage	30.0%	33.3%
Status of EPA approval	30.0%	-
Likelihood of FID	30.0%	33.3%
Is this a carbon reduction project?	10.0%	33.3%

A3. Reliability assessment methodology

This appendix provides a summary of the reliability assessment methodology used to assess capacity investment gaps, forecast the RCT, determine the Availability Class Capacity Credit balance, and develop Availability Curves for the 2023 Long Term PASA study.

The reliability assessment was undertaken by EY and includes additional considerations from the methodology employed in the 2022 reliability assessment. Some key changes include:

- An increase in the simulation temporal resolution to half-hourly time-sequential modelling for each study year.
- Simulation of the co-optimised energy and ESS markets.
- An increased number of historical weather reference years[179].
- An increase in the number of Monte Carlo iterations to simulate randomly occurring forced outages.

In this appendix, historical weather reference years refer to 2010-11 to 2021-22.

A detailed description of the methodology and assumptions can be found in EY's 2023 reliability assessment report[180].

A3.1 Expected unserved energy assessment

The EUE assessment determines the amount of Reserve Capacity required to limit EUE to no more than 0.002% of annual expected operational consumption for each Capacity Year in the 2023 Long Term PASA Study Horizon. EY carried out the assessment using an in-house electricity market dispatch model and a set of inputs and assumptions agreed with AEMO.

The EUE assessment included three phases and applied a combination of time-sequential capacity availability and dispatch simulation, co-optimised energy and ESS market dispatch simulation and Monte Carlo analysis as follows:

- **Phase 1** – model set up with agreed demand and supply parameters, including the details of Anticipated Installed Capacity (AIC) of WEM Facilities for each forecast year, and AEMO's annual peak demand (MW) and annual energy consumption (MWh) forecasts for each demand scenario (low, expected, high). With the demand forecasts, this phase involved translating AEMO's annual energy and demand inputs into half-hourly data series for each historical weather reference year (12 in this instance) to obtain half-hourly demand data for future modelled Capacity Years.
  - The approach to developing half-hourly demand inputs for dispatch modelling is based on splitting the operational demand into components that can be modelled separately, where each has an influence on changing the shape of the demand profile. These components include:
    - Behind-the-meter rooftop PV and PVNSG, collectively referred to as DPV.

[179] EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and interspatial patterns in electricity demand, wind energy and solar energy on the weather resources and consumption behaviour in one or more historical years (referred to as reference years).

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

        - EVs.
        - DESS (which have a positive or negative impact on demand at different times due to charging or discharging respectively).
        - LILs, electrolyser loads for hydrogen production, and electrification loads.
    - The remaining demand profile is termed ‘fixed shape consumption’ (FSC), which is driven by residential and business energy use behaviour patterns in response to the weather from half-hour to half-hour.
    - Using a range of approaches, EY produced a set of half-hourly, time sequential demand data for each of the above-mentioned components, which together result in the operational demand sent out (OPSO) that the dispatch model is run to meet in each modelled half-hour interval. As a final step in the process the underlying peak demand was scaled such that on average across all the modelled reference years (12 in this instance) the operational peak outcome was aligned with AEMO’s forecasts for each demand scenario and modelled year.
- **Phase 2** – run the simulations to calculate EUE using the half-hourly operational demand forecasts developed in Phase 1 and Facilities and their parameters as also agreed in Phase 1.
    - Co-optimised, time sequential dispatch modelling of energy and Essential System Service markets was used to determine whether available capacity can be fully dispatched to meet corresponding demand for each given half-hourly interval.
    - The simulation assesses the capacity gap (demand minus dispatched capacity) for every half-hour of each Capacity Year sequentially, given a specific capacity mix, demand profile, network constraints, Essential System Service requirements, planned outage schedules, generator and storage forced outages, ramp rate limitations, storage modelling, renewable resource variability.
    - A large number of Monte Carlo iterations captured the impact of random forced generator outages, combined with multiple weather reference years.
    - Each iteration yielded an estimate of unserved energy. For each Capacity Year, the EUE was calculated as the average of the total estimates of unserved energy from all iterations for a given Capacity Year.
- **Phase 3** – determine the amount of Reserve Capacity required to limit the EUE to 0.002% of the annual expected operational consumption forecast, which represents limb B of the Planning Criterion.
    - The EUE was calculated by dividing the modelled annual EUE volumes (MWh) by forecast annual operational energy consumption (MWh).
    - If the percentage of EUE for a given Capacity Year was less than 0.002%, then existing coal or gas units would be removed from the AIC until removing another coal or gas unit resulted in EUE above 0.002%.
    - If the percentage of EUE was more than 0.002%, the AIC would be incrementally increased by adding a new generic open-cycle gas turbine (OCGT) unit and remodelling until EUE was less than or equal to 0.002%.
    - To satisfy both limbs of the Planning Criterion, the RCT is set as the greater of the capacity requirement calculated based on limb A[181] and the amount of Capacity Credits, after adding generic OCGT, required to limit EUE to less than 0.002% (limb B).

[181] The 10% POE peak demand forecast under the expected scenario plus allowances for frequency control and a reserve margin.

A3.2 Minimum capacity requirements (Availability Classes)

EY determined the minimum quantity of capacity required to be provided by Availability Class 1 for the 2024-25 and 2025-26 Capacity Years (the second and third years of the Long Term PASA Study Horizon) by finding the maximum amount of Availability Class 2 capacity before the modelled annual EUE % breaches the 0.002% standard. The maximum amount of capacity within Availability Class 2 was determined by the following steps:

1. Use the results of the RCT determination to derive the AIC which will be used in dispatch modelling for Availability Classes determination. The approach used to derive AIC will depend on whether the RCT was set by limb A or limb B of the Planning Criterion. If the RCT was set by limb B, the Capacity Credits and AIC will be known. The approach below thus only applies to a case when the RCT has been set by limb A (and there was a capacity investment gap or surplus).

   The magnitude of Capacity Credits is equalised with the RCT determined for a relevant Capacity Year, and the AIC is adjusted respectively. This is done by adding OCGT units or removing existing coal or gas units and their associated Capacity Credits (depending on whether there is a Capacity Credit / forecast Reserve Capacity shortfall or surplus respectively relative to the RCT) and will produce AIC and associated Capacity Credits.

2. Run the reliability model to dispatch AIC across all demand intervals for the 10% POE expected scenario for a relevant Capacity Year. Then analyse the modelling results and observe the modelled annual EUE % over an average of the reference years and Monte Carlo simulations.
3. Informed by the results of Step 2 above, determine the amount of capacity to be removed from Availability Class 1 and to be simultaneously added to Availability Class 2 capacity (DSP or standalone ESR) to obtain Revised AIC.
4. Run the reliability model to dispatch the Revised AIC across all demand intervals for the 10% POE expected scenario (average of reference years) for the required Capacity Years (2024-25 and 2025-26). Then analyse the modelling results and observe the annual EUE % and reiterate (if needed) until the modelled annual EUE % just breaches the 0.002% standard.

The minimum amount of Availability Class 1 capacity can be determined by taking the difference between the RCT and the maximum amount of Availability Class 2 capacity derived from the process described above in Step 1 to Step 4.

A3.3 Availability Curves

For the 2023 WEM ESOO, the Availability Curves were determined for 2024-25 and 2025-26 (the second and third Capacity Years in the Long Term PASA Study Horizon). Availability Curves were determined by:

- Summing the following two items for each interval of a Capacity Year:
  - (a) The forecast demand for the 10% POE expected demand scenario.
  - (b) A constant margin applicable to all demand intervals in a Capacity Year being the difference between the RCT and the forecast peak demand for the 10% POE expected demand scenario.

If RCT was set by limb A of the Planning Criterion, item (b) of the Availability Curve is equal to the sum of:

- the Intermittent Load allowance,

- the reserve margin, and
- the Regulation Raise allowance.

However, if the RCT were to be set by limb B of the Planning Criterion, item (b) is derived as the difference between:

- The RCT (as set by limb B) and
- The forecast 10% POE expected peak interval demand, that is, the annual maximum value of item (a).

Based on the above, for each of the 2024-25 and 2025-26 Capacity Years modelled, EY developed an Availability Curve as follows:

- Rank demand intervals for the 10% POE expected scenario (average of reference years) in order of descending magnitude of demand.
- Increase each demand data point by adding a constant margin (item (b) above) being the difference between:
  - The value of the RCT and
  - The value of the forecast 10% POE expected peak demand.

A3.4 Supply-demand balance under low and high scenarios

To forecast the capacity supply-demand balance over the 2023 Long Term PASA Study Horizon under the low and high scenarios, AEMO has:

1. Forecast the RCT for the low and high scenarios by using the 10% POE peak demand forecasts, Intermittent Loads, Contingency component of the reserve margin and load following for the respective scenarios.
2. Forecast the amount of available Reserve Capacity for the low and high scenarios.
3. Compared these capacity supply models with their respective RCT.

Table 19 presents the forecast supply-demand balance over the outlook period for the low scenario. The low scenario assumes that no new Facilities (committed or probable) are brought online and includes the retirements outlined in Section 5.2.3.

Table 19 Supply-demand balance for the low scenario, 2023-24 to 2032-33[A]

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
RCT[B] (MW)	5,275	5,296	5,376	5,569	5,606	5,732	5,934	6,142	6,466	6,754
Capacity (MW)	4,668[C]	4,467[C]	4,467[D]	4,467	4,149	4,149	3,727	3,293	3,293	3,293
Capacity investment gap (MW)	608[E]	829[E]	910[E]	1,102	1,456	1,582	2,206	2,848	3,173	3,460
Capacity investment gap (%)	11.5[F]	15.7[F]	16.9[F]	19.8	26.0	27.6	37.2	46.4	49.1	51.2

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. The quantities reported are the RCTs. The RCRs for 2023-24, 2024-25 and 2025-26 are 4,396 MW, 4,526 MW and 5,543 MW respectively.
C. The 2023-24 and 2024-25 available capacity values are the total quantities of Capacity Credits assigned for existing capacity.
D. The capacity values for 2025-26 and remaining years represent the forecast quantity of Reserve Capacity under the low demand growth scenario, comprising of existing capacity.
E. Based on the RCRs for 2023-24, 2024-25 and 2025-26, the available capacity figures represent a capacity investment gap of -272 MW, 59 MW and 1,077 MW, respectively.
F. Based on the RCRs for 2023-24 and 2024-25, the available capacity figures represent a capacity investment gap of -6.2%, 1.3% and 19.4%, respectively.

Table 20 presents the forecast supply-demand balance over the outlook period for the high scenario. The high scenario includes existing, committed, and probable capacity (see Appendix A9) that may be brought online during the Long Term PASA Study Horizon. The retirements used for the high scenario are outlined in Section 5.2.3.

Table 20 Supply-demand balance for the high scenario, 2023-24 to 2032-33[A]

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
RCT[B] (MW)	5,398	5,577	5,917	6,370	6,677	7,169	7,595	8,038	8,676	9,134
Capacity (MW)	4,727[C]	5,178[C]	5,535[D]	5,690	5,373	5,373	5,451	5,451	5,451	5,451
Capacity investment gap (MW)	671[E]	398[E]	382[E]	680	1,304	1,796	2,144	2,587	3,226	3,683
Capacity investment gap (%)	12.4[F]	7.1[F]	6.5[F]	10.7	19.5	25.1	28.2	32.2	37.2	40.3

A. All figures have been rounded to the nearest MW. Consequently, totals may have a 1 MW difference due to rounding.
B. The quantities reported are the RCTs. The RCRs for 2023-24, 2024-25 and 2025-26 are 4,396, 4,526 and 5,543 MW respectively.
C. The 2023-24 and 2024-25 available capacity values are the total quantities of Capacity Credits assigned for existing capacity.
D. The capacity values for 2025-26 and remaining years represent the forecast quantity of Reserve Capacity under the low demand growth scenario, comprising of existing capacity.
E. Based on the RCRs for 2023-24, 2024-25 and 2025-26, the available capacity figures represent a capacity investment gap of -331 MW, -652 MW and 8 MW, respectively.
F. Based on the RCRs for 2023-24, 2024-25 and 2025-26, the available capacity figures represent a capacity investment gap of -12.4%, -7.1% and 0.2%, respectively.

A3.5 New project status evaluation

New projects that received Capacity Credits for 2024-25 are considered as committed capacity. New projects that submitted a valid 2023 EOI and are candidate for registration, or are in 2024-26 Peak Demand NCESS project list are considered as probable capacity. These projects are not tested using the new project status evaluation. All other projects are assessed based on their project score in the new project status evaluation. The projects can be planned, in the approvals phase, or in the construction phase.

Three tests were used to rank the new projects:

1. **EPA approval** – for a project to proceed, the proponent needs to receive environmental approval from WA's EPA. AEMO allocated 0% for a facility that has not yet applied for approval, 50% for a submitted application that has not yet been granted, and 100% for a granted application.
2. **Western Power connection approval** – connection status is obtained by AEMO directly from Western Power. AEMO allocated 0% for a Facility that has not yet submitted an application, 50% for a submitted application that has not yet been granted, and 100% for a granted application.
3. **FID by proponent** – a FID is taken by a proponent once all internal studies and planning has been completed, the environmental approvals are in place, and the commercial work (for example, fuel and sales agreements) has been finalised. AEMO allocated 0% for a facility that has not taken an FID and 100% for a facility that has.

These factors were then weighted using the weighting outlined in Table 21 to give an overall percentage each new project.

The thresholds for classifying assessed projects are:

- Committed capacity: project score >= 80%.
- Probable capacity: project score >= 50%.
- Proposed capacity: project score < 50%.

Table 21 New project status evaluation methodology

Criteria	Weighting	Options	Score (%)
EPA	0.33	Granted	100
		Applied	50
		Not Applied	0
Western Power Access	0.33	Granted	100
		Applied	50
		Not Applied	0
FID	0.33	Yes	100
		No	0

A4. Expected unserved energy results

Table 22 Expected unserved energy results under expected scenario, 2023-24 to 2032-33

Capacity Year	Operational consumption (MWh)	0.002% of operational consumption (MWh)	EUE (MWh)	EUE (%)
2023-24	18,010,219	360	1,214	0.00674%
2024-25	18,237,201	365	2,519	0.01381%
2025-26	18,607,085	372	3,184	0.01711%
2026-27	19,509,007	390	6,019	0.03085%
2027-28	20,375,377	408	36,135	0.17734%
2028-29	21,825,432	437	94,104	0.43116%
2029-30	24,250,785	485	620,739	2.55966%
2030-31	26,482,030	530	2,830,594	10.68873%
2031-32	28,367,749	567	4,069,492	14.34549%
2032-33	30,305,884	606	5,268,259	17.38362%

Source: AEMO and EY.

A5. Summer peak demand forecasts

Table 23 Summer peak demand forecasts under the low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	4,112	3,847	3,606
2023-24	4,169	3,952	3,698
2024-25	4,191	3,965	3,713
2025-26	4,267	4,039	3,788
2026-27	4,453	4,234	3,967
2027-28	4,560	4,338	4,061
2028-29	4,679	4,446	4,176
2029-30	4,874	4,654	4,383
2030-31	5,076	4,844	4,554
2031-32	5,394	5,160	4,872
2032-33	5,676	5,436	5,139
Average growth	3.3%	3.5%	3.6%

Table 24 Summer peak demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	4,112	3,847	3,606
2023-24	4,253	4,002	3,735
2024-25	4,315	4,078	3,809
2025-26	4,418	4,164	3,897
2026-27	4,580	4,338	4,053
2027-28	4,734	4,485	4,201
2028-29	4,976	4,716	4,433
2029-30	5,325	5,073	4,780
2030-31	5,713	5,456	5,155
2031-32	6,021	5,747	5,450
2032-33	6,296	6,030	5,718
Average growth	4.4%	4.6%	4.7%

Table 25 Summer peak demand forecasts under the high demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	4,112	3,847	3,606
2023-24	4,286	4,049	3,773
2024-25	4,461	4,225	3,928
2025-26	4,789	4,545	4,240
2026-27	5,227	4,967	4,668
2027-28	5,584	5,317	4,989
2028-29	6,058	5,781	5,459
2029-30	6,467	6,194	5,852
2030-31	6,895	6,594	6,243
2031-32	7,520	7,202	6,846
2032-33	7,967	7,656	7,299
Average growth	6.8%	7.1%	7.3%

A6. Winter peak demand forecasts

Table 26 Winter peak demand forecasts under the low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,557	3,395	3,255
2023-24	3,589	3,427	3,287
2024-25	3,632	3,465	3,330
2025-26	3,716	3,550	3,413
2026-27	3,916	3,750	3,604
2027-28	4,030	3,857	3,709
2028-29	4,148	3,972	3,823
2029-30	4,352	4,166	4,013
2030-31	4,544	4,351	4,203
2031-32	4,864	4,678	4,526
2032-33	5,150	4,954	4,793
Average growth	3.8%	3.9%	3.9%

Table 27 Winter peak demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,557	3,395	3,255
2023-24	3,655	3,483	3,336
2024-25	3,727	3,553	3,409
2025-26	3,832	3,658	3,513
2026-27	3,999	3,826	3,681
2027-28	4,171	3,987	3,837
2028-29	4,412	4,225	4,065
2029-30	4,755	4,557	4,392
2030-31	5,141	4,929	4,771
2031-32	5,423	5,235	5,068
2032-33	5,712	5,512	5,351
Average growth	4.9%	5.0%	5.1%

Table 28 Winter peak demand forecasts under the high demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,557	3,395	3,255
2023-24	3,691	3,526	3,382
2024-25	3,863	3,685	3,543
2025-26	4,172	3,997	3,847
2026-27	4,565	4,389	4,225
2027-28	4,906	4,715	4,552
2028-29	5,344	5,149	4,990
2029-30	5,740	5,531	5,353
2030-31	6,152	5,926	5,749
2031-32	6,733	6,515	6,337
2032-33	7,174	6,950	6,761
Average growth	7.3%	7.4%	7.6%

A7. Minimum demand forecasts

Table 29 Minimum demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	730	683	637
2023-24	636	586	537
2024-25	525	483	430
2025-26	445	405	348
2026-27	428	382	325
2027-28	388	332	273
2028-29	399	346	289
2029-30	548	496	431
2030-31	683	628	554
2031-32	774	718	643
2032-33	877	814	743
Average growth (five-year)	-11.9%	-13.4%	-15.6%
Average growth (10-year)	1.9%	1.8%	1.6%

A8. Operational consumption forecasts

Table 30 Operational consumption forecasts (GWh)

Capacity Year	Low	Expected	High
2022-23	16,878	17,615	18,318
2023-24	16,969	18,010	18,984
2024-25	17,128	18,237	20,816
2025-26	17,506	18,607	26,510
2026-27	18,541	19,509	33,127
2027-28	18,962	20,375	38,676
2028-29	19,465	21,825	44,987
2029-30	20,690	24,251	48,639
2030-31	21,585	26,482	51,438
2031-32	23,389	28,368	55,579
2032-33	24,910	30,306	58,884
Average growth	4.0%	5.6%	12.4%

A9. Facility and Demand Side Management capacities

A9.1 Capacities of existing capacity

The potential amount of available Reserve Capacity for the period 2025-26 to 2032-33 is estimated to be the same as the Capacity Credits assigned in 2024-25. Should the Facility be due to retire, the available Reserve Capacity for that Facility will revert to zero from retirement until the end of the outlook period.

Table 31 Capacities of Existing Facilities

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Capacity Credits 2024-25 (MW)	Retirement Date	Maximum Capacity (MW)
Alcoa of Australia Limited	ALCOA_WGP	26	16.000		16.000
Alinta Sales Pty Ltd	ALINTA_PNJ_U1	142.450	142.450		143.000
	ALINTA_PNJ_U2	142.450	142.450		143.000
	ALINTA_WGP_GT	196.000	196.000		196.000
	ALINTA_WGP_U2	196.000	196.000		196.000
	ALINTA_WWF	14.278	15.121		89.100
	BADGINGARRA_WF1	25.543	25.066		130.000
	YANDIN_WF1	34.109	33.388		211.680
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1	25.324	29.788		180.000
Blair Fox Pty Ltd AFT The Blair Fox Trust	BLAIRFOX_KARAKIN_WF1	0.331	0.309		5.000
Bluewaters Power 1 Pty Ltd	BW1_BLUEWATERS_G2	217.000	217.000	01/10/2030	217.000
Bluewaters Power 2 Pty Ltd	BW2_BLUEWATERS_G1	217.000	217.000	01/10/2030	217.000
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	19.758	25.162		218.500
Delorean Energy Retail	BIOGAS01	0.602	0.414		2.000
Denmark Community Windfarm Ltd	DCWL_DENMARK_WF1	0.405	0.492		1.440
EDWF Manager Pty Ltd	EDWFMAN_WF1	12.877	11.404		80.000
Goldfields Power Pty Ltd	PRK_AG	59.748	59.748		68.000
Landfill Gas and Power Pty Ltd	RED_HILL	2.753	2.603		3.640
	TAMALA_PARK	4.265	4.018		4.800
Merredin Energy	NAMKKN_MERR_SG1	82.000	82.000		82.000
Merredin Solar Farm Nominee Pty Ltd	MERSOLAR_PV1	8.507	7.062		100.000
Metro Power Company Pty ltd	AMBRISOLAR_PV1	0.867	0.918		0.960
Mt. Barker Power Company Pty Ltd	SKYFRM_MTBARKER_WF1	0.625	0.748		2.430

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Capacity Credits 2024-25 (MW)	Retirement Date	Maximum Capacity (MW)
Mumbida Wind Farm Pty Ltd	MWF_MUMBIDA_WF1	7.337	7.909		55.000
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600	330.600		342.000
NewGen Power Kwinana Pty Ltd	NEWGEN_KWINANA_CCG1	334.800	327.800		335.000
Northam Solar Project Partnership	NORTHAM_SF_PV1	1.010	0.821		9.800
Perth Energy Pty Ltd	ROCKINGHAM	1.964	1.447		4.000
	SOUTH_CARDUP	1.750	0		4.158
SRV AGWF Pty Ltd as trustee for AGWF Trust	ALBANY_WF1	5.389	6.195		21.600
	GRASMERE_WF1	3.662	4.220		13.800
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	4.499	3.810		40.000
Synergy	BREMER_BAY_WF1	0.167	0.201		0.600
	COCKBURN_CCG1	240.000	240.000		249.700
	COLLIE_G1	317.200	317.200	01/10/2027	318.300
	KALBARRI_WF1	0.203	0.155		1.600
	KEMERTON_GT11	155.000	155.000		154.700
	KEMERTON_GT12	155.000	155.000		154.700
	KWINANA_ESR1	46.250	45.250		100.000
	KWINANA_GT2	98.500	98.500		103.200
	KWINANA_GT3	99.200	99.200		103.200
	MUJA_G6	193.000	0	01/10/2024	193.600
	MUJA_G7	207.155	211.000	01/10/2029	212.600
	MUJA_G8	211.000	211.000	01/10/2029	212.600
	PINJAR_GT1	31.000	31.000		38.500
	PINJAR_GT10	110.500	110.500		118.150
	PINJAR_GT11	124.000	124.000		130.000
	PINJAR_GT2	30.500	30.500		38.500
	PINJAR_GT3	37.000	37.000		39.300
	PINJAR_GT4	37.000	37.000		39.300
	PINJAR_GT5	37.000	37.000		39.300
	PINJAR_GT7	37.000	37.000		39.300
	PINJAR_GT9	111.000	111.000		118.150
Tesla Corporation Management Pty Ltd	TESLA_PICTON_G1	9.900	9.900		9.900
Tesla Geraldton Pty Ltd	TESLA_GERALDTON_G1	9.900	9.900		9.900
Tesla Kemerton Pty Ltd	TESLA_KEMERTON_G1	9.900	9.900		9.900
Tesla Northam Pty Ltd	TESLA_NORTHAM_G1	9.900	9.900		9.900
Tronox Management Pty Ltd	TIWEST_COG1	36.000	36.000		42.100

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Capacity Credits 2024-25 (MW)	Retirement Date	Maximum Capacity (MW)
Waste Gas Resources Pty Ltd	HENDERSON_RENEWABLE_IG1	1.578	1.501		3.000
Western Energy Pty Ltd	PERTHENERGY_KWINANA_GT1	109.000	109.000		109.000

Note: Retirement date for Bluewaters is estimated by AEMO and does not reflect any decision by Bluewaters. For further information see Section 5.2.3

Table 32 Demand Side Management capability and availability

Market Participant	DSP Name	Capacity Credits 2023-24 (MW)	Capacity Credits 2024-25 (MW)	Maximum MW available to provide Reserve Capacity
Bluewaters Power 1 Pty Ltd	GRIFFIN_DSP_01	20.000	20.000	20.000
Synergy	SYNERGY_DSP_04	42.000	42.000	42.000
Wesfarmers Kleenheat Gas Pty Ltd	PREMPWR_DSP_02	21.773	23.000	24.000

Note: DSPs must be available to provide at least 200 hours of Reserve Capacity during a Capacity Year, for no less than 12 hours per Business Day between 08:00 and 20:00.

A9.2 Capacities of committed capacity

The potential amount of available Reserve Capacity for the period 2025-26 to 2032-33 is estimated to be the same as the Capacity Credits assigned in 2024-25. East Rockingham's and Phoenix Kwinana's Waste-to-Energy projects were assigned Capacity Credits for 2023-24 but have not commenced Commercial Operation due to delays. Notwithstanding these delays, they have been modelled starting in 2023-24. All other committed projects are modelled starting in 2024-25 unless specified otherwise.

Table 33 Capacities of committed projects[A]

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Capacity Credits 2024-25 (MW)	Maximum Capacity (MW)
Cunderdin Development Pty Ltd	SBSOLAR1_CUNDERDIN_PV1	0	48.677	100
East Rockingham RRF Project	ERRRF_WTE_G1	25.134	25.134	28.600
Kwinana WTE Project Co	PHOENIX_KWINANA_WTE_G1	33.909	33.909	38.000
Moonies Hill Energy	FLATROCKS_WF1	0	20.358	73.900
PRD SWIS OPS PTY LTD	PRDSO_WALPOLE_HG1	0	1.500	1.500
Tesla Corporation Management Pty Ltd[B]	TESLA_PICTON_G1	0	0.099	0.099
Tesla Geraldton Pty Ltd[B]	TESLA_GERALDTON_G1	0	0.099	0.099
Tesla Kemerton Pty Ltd[B]	TESLA_KEMERTON_G1	0	0.099	0.099

A. Projects that are included in the committed capacity due to scoring 80% or higher in the new project status evaluation have a combined anticipated Reserve Capacity and Maximum Capacity of 1.6 MW and 3 MW, respectively. These projects are modelled starting in 2025-26.
B. These projects are upgrades to existing Facilities that will be added to the existing capacities from 2024-25 onwards. The Maximum Capacity and total Capacity Credits from 2024-25 and onwards is 9.999 MW for all these facilities.

A9.3 Capacities of probable capacity

Table 34 Capacities of probable Facilities by Generator Type

	Capacity Credits (MW)					Maximum Capacity (MW)				
Generator Type	2024-25	2025-26	2026-28	2029-30	2030-33	2024-25	2025-26	2026-28	2029-30	2030-33
Wind Generation[A]	0	60.0	81.6	81.6	81.6	0	300.0	411.7	411.7	411.7
Battery[B]	441.7	1,076.8	1,079.3	1,579.3	1,579.3	446.7	1,085.6	1,090.5	1,590.5	1,590.5
Gas Generation	20.0	57.4	167.2	167.2	167.2	20.0	57.4	173.4	173.4	173.4
Solar Farm	0	33.8	45.2	45.2	45.2	0	277.5	391.5	391.5	391.5
Distillate Generation	0	0	10.0	10.0	10.0	0	0	10.0	10.0	10.0
Demand Side Providers	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0

A. Wind Generation grouping includes wind and solar hybrids.
B. Battery grouping includes standalone batteries and the battery components of projects.

Glossary, measures, and abbreviations

Glossary

This document uses many terms that have meanings defined in the WEM Rules. The WEM meanings are adopted unless otherwise specified.

Term	Definition
business mass market	Covers those business loads that are not included in the LIL sector.
business sector	Includes industrial and commercial users. This sector is subcategorised further to include LIL and BMM.
capability at 41°C	Sent out capacity calculated at air temperature of 41°C. This accounts for efficiency loss at high temperatures, which are typical during peak demand periods.
component	An ESR, an Intermittent Generating System, or a Non-Intermittent Generating System that forms part of a Facility, other than a DSP.
consumption	The amount of power used over a period of time, conventionally reported as MWh or GWh depending on the magnitude of power consumed. It is reported on a “sent-out” basis (excluding electricity used by a generator) unless otherwise stated.
daytime hours	Trading Intervals commencing 08:00 to 16:30.
delivered consumption (demand)	Electricity consumption (demand) that is supplied to electricity users from the grid (excluding network losses). It therefore excludes the part of their consumption (demand) that is met by behind-the-meter (typically rooftop PV) generation.
demand	The amount of power consumed at any time. Peak and minimum demand is measured in MW and averaged over a 30-minute period. It is reported on a “sent-out” basis (excluding electricity used by a generator) unless otherwise stated
distributed battery storage	Behind-the-meter battery storage systems installed for residential, commercial, and large commercial, that do not hold Capacity Credits in the WEM.
distributed energy resource	Includes distributed PV, distributed battery storage, and EVs.
distributed photovoltaics	Includes both rooftop PV and PVNSG.
electric vehicle	Electric-powered vehicles, ranging from small residential vehicles such as motor bikes or cars, to large commercial trucks and buses.
end-user underlying consumption (demand)	The total amount of electricity consumption (demand) by electricity users from their power points (excluding network losses), regardless of if it is supplied from the grid or by behind-the-meter (typically rooftop PV) generation.
expected unserved energy	A normalised metric, which does not have a unit. It represents the estimated percentage of forecast electricity consumption for a Capacity Year which cannot be met by the anticipated capacity of all Energy Producing Systems and DSM facilities in that Capacity Year.
expression/s of interest	An annual call out for expressions of interest from new generation or DSM Facilities that may seek CRC and Capacity Credits for the relevant Capacity Year.
installed capacity	The generating capacity (in MW) of a single or multiple generating units.
large industrial loads	Users that consume, or are forecast to consume, at least 10 MW for at least 10% of the time (around 875 hours a year).
load shedding	The controlled reduction of electricity supply to parts of the power system servicing homes and businesses to protect system security and mitigate damage to infrastructure.
market underlying consumption (demand)	The total amount of electricity consumption (demand) in the market, which includes consumption (demand) delivered to the residential and business customers (including the impact of distributed battery storage operation), network losses, and DPV generation.
maximum capacity	The net sent-out generation or installed capacity of a Facility, as detailed on AEMO’s Market Data website.
operational consumption (demand)	• Electricity consumption (demand) that is met by sent -out electricity supply of all market-registered energy-producing systems. It includes losses incurred from the transmission and distribution of electricity and electricity consumption (demand) of EVs but excludes electricity consumption (demand) met by DPV generation.

Term	Definition
	• Operational consumption includes energy efficiency losses of distributed battery storage operation. • Operational demand includes impacts of distributed battery storage discharging (that reduces operational demand) and charging (that increases operational demand). • Peak and minimum operational demand forecast represents uncontrolled or unconstrained demand, free of market-based solutions that might increase or reduce operational demand (including storage, coordinated EV charging and demand response). Only non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained peak and minimum operational demand forecasts.
outlook period	2023-24 to 2032-33, inclusive.
peak demand	The highest amount of demand consumed at any one time. Peak demand refers to operational peak demand unless otherwise stated.
photovoltaics	Systems to convert sunlight into electricity.
photovoltaic non-scheduled generator	Non-scheduled PV generators larger than 100 kW but smaller than 10 MW that do not hold Capacity Credits in the WEM. These form part of DPV.
probability of exceedance	A measure of the likelihood of a value being met or exceeded. For example, a 10% POE maximum demand forecast is expected to be met or exceeded, on average, one year in 10, while a 90% POE maximum demand forecast is expected to be met or exceeded nine years in 10.
reliability standard	The Planning Criterion defined in clause 4.5.9 of the WEM Rules.
residential sector	Includes residential customers (supplied by Synergy) only.
rooftop photovoltaics	Systems comprising of one or more photovoltaic panels, installed on a residential building (less than 15 [kW]) or business premises (less than 100 kW) to convert sunlight into electricity.
shoulder season	The period including Trading Months of April, May, August, and September.
summer	The Hot Season as defined in the WEM Rules.
underlying demand	The sum of operational demand and an estimate of DPV generation and impacts of distributed battery storage. Historical underlying demand calculation does not consider impacts of distributed battery storage. Due to the current relatively low uptake of distributed battery storage in the SWIS, its impact on historical underlying demand is negligible.
virtual power plant	An aggregation of resources (such as decentralised generation, storage, and controllable loads) coordinated to deliver services for power system operations and electricity markets.
winter	The period including all Trading Months from June to August.

Units of measure

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

Abbreviations

Abbreviation	Expanded name
AIC	Anticipated Installed Capacity
AEMO	Australian Energy Market Operator
BMM	Business mass market
BRCP	Benchmark Reserve Capacity Price

Abbreviation	Expanded name
CBD	Commercial Building Disclosure
CER	Clean Energy Regulator
Coordinator	Coordinator of Energy
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CWC	ClimateWorks Centre
DER	Distributed energy resources
DESS	Distributed energy storage systems
DPV	Distributed photovoltaics
DSM	Demand Side Management
DSP	Demand Side Programme
EOI	Expressions of Interest
EPA	Environmental Protection Authority
EPWA	Energy Policy Western Australia
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resources
ESROI	Electric Storage Resource Obligation Intervals
ETS	Energy Transformation Strategy
EUE	Expected unserved energy
EV	Electric vehicle
EY	Ernest & Young
FCESS	Frequency Control Essential System Services
FID	Final Investment Decision
FRG	Forecasting Reference Group
FSC	Fixed shape consumption
GEM	Green Energy Market
GEV	Generalised extreme value
GSP	Gross state product
IASR	Inputs, Assumptions and Scenarios report
IGS	Intermittent Generating Systems
LDC	Linearly Derating Capacity
LFAS	Load following ancillary service
LIL	Large industrial load
NABER	National Australian Built Environment Rating System
NAQ	Network Access Quantity
NCC	National Construction Code
NCESS	Non-Co-optimised Essential System Services
NEM	National Electricity Market
NIGS	Non-Intermittent Generating Systems
NMI	National Metering Identifiers

Abbreviation	Expanded name
OCGT	open-cycle gas turbines
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generator
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
RLM	Relevant Level Methodology
SPR	Strategy.Policy.Research.
SRC	Supplementary Reserve Capacity
SRES	small-scale renewable energy scheme
STC	small-scale technology certificates
SWIS	South West Interconnected System
TSOG	Total Sent Out Generation
VPP	Virtual power plant
WA	Western Australia
WEM	Wholesale Electricity Market

A10. List of tables and figures

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