2022 Wholesale Electricity Market Electricity Statement of Opportunities

June 2022

A report for the Wholesale Electricity Market

Important notice

Purpose

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This publication is generally based on information available to AEMO as at 1 June 2022 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	17/06/2022	Initial release.

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Executive summary

The Wholesale Electricity Market (WEM) *Electricity Statement of Opportunities* (ESOO), published annually, presents AEMO's 10-year Long Term Projected Assessment of System Adequacy (PASA) for the South West Interconnected System (SWIS) in Western Australia (WA).

This WEM ESOO reports peak demand and operational consumption forecasts across a range of weather and demand growth scenarios for the 2022-23 to 2031-32 Capacity Years[1] and supply-demand balance projections in the SWIS over the 10-year outlook period.

The WEM ESOO is one of the key aspects of the Reserve Capacity Mechanism (RCM), which ensures enough capacity is available to meet the Planning Criterion for the SWIS. The Planning Criterion ensures there is sufficient capacity in the SWIS to meet the forecast 10% probability of exceedance (POE)[2] peak demand plus a reserve margin, and limits expected unserved energy to 0.002% of annual energy consumption (including transmission losses) for each Capacity Year of the 10-year outlook period.

The RCM, operated by AEMO, is unique to the WEM. It is designed to ensure there is sufficient capacity to meet peak demand two years ahead. Reflecting the dynamic nature of forecasts, the RCM operates on a four-year rolling Reserve Capacity Cycle.

Each year, Reserve Capacity is procured two years before the obligations take effect; AEMO assesses and assigns Capacity Credits to generation (thermal and renewable), energy storage, and Demand Side Management capacity to meet the Reserve Capacity Requirement (RCR) for Year 3 of the relevant Reserve Capacity Cycle. This means the 2022 WEM ESOO is used to determine the RCR for 2024-25. The RCR is based on the 10% POE peak demand forecast under the expected demand growth scenario.

Market Participants must make their capacity available to the market for dispatch in the relevant Capacity Year and may pay capacity refunds if they fail to do so.

AEMO applied the *Progressive Change* scenario, developed by AEMO and described in the 2*021 Inputs, Assumptions and Scenarios Report* (IASR)[3], as the expected demand growth scenario in this WEM ESOO, so this scenario was used to determine the RCR. *Progressive Change* reflects moderate growth in the economy and a future energy system based on current State and Federal Government environmental and energy policies, including transitioning Australia's economy to net zero greenhouse gas emissions by 2050.

The SWIS supply-demand projections in this ESOO were modelled before the recent announcement by the WA Government[4] that it intends to retire Synergy's remaining coal-fired power stations and invest in new wind generation and energy storage capacity during the 10-year outlook period. The announcement is not expected to affect 2024-25 for which the RCR is set. AEMO welcomes this early advice from the WA Government regarding

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[1] A Capacity Year commences at the start of the Trading Day commencing on 1 October and ends on the end of the Trading Day ending on 1 October of the following calendar year. A Trading Day is a period of 24 hours commencing at 08.00. All references to years in the Executive Summary are Capacity Years unless otherwise specified.

[2] POE means the likelihood of a value being exceeded. A 10% POE peak demand forecast is expected to be met or exceeded, on average, one year in 10, and reflects more extreme weather conditions than a 50% POE forecast.

[3] See December 2012 update, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[4] Department of the Premier and Cabinet, Media statements, June 2022. See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/06/State-owned-coal-power-stations-to-be-retired-by-2030.aspx.

future capacity changes in the SWIS, and will consider the implications of these changes in future WEM ESOO updates.

Key findings

- **The 10% POE peak demand is forecast to grow at an average annual rate of 0.9% over the outlook period.** This is higher than the average annual peak demand growth of 0.2% forecast in the 2021 WEM ESOO, with the increase primarily driven by forecast stronger growth in demand from large industrial loads (LILs), residential customers, and uptake of electric vehicles (EVs).
- **Operational consumption is forecast to decline at an average annual rate of 0.3% over the 10-year outlook period,** compared to the forecast decline of 0.8% in the 2021 WEM ESOO.
- Based on the 10% POE peak demand forecast, **the RCR has been determined as 4,526 megawatts (MW) for 2024-25**.
- **Sufficient capacity is projected to be available to meet forecast peak demand until 2024-25**, assuming no capacity changes compared to 2023-24 other than the planned retirement of Muja C unit 6 (193 MW) in October 2024[5].
- **Capacity shortfalls are projected from 2025-26, assuming no new capacity becomes committed**. The projected shortfall is driven by the combined impacts of the forecast growth in peak demand and lower capacity following the retirement of Muja C unit 6.
- **Sustained uptake of distributed photovoltaic (DPV) generation is expected to continue**. DPV is forecast to grow at an average annual rate of 7.0% (238 MW per year), to reach an estimated 4,716 MW of installed capacity by the end of the 10-year outlook period.
- **A new record for minimum demand** of 765 MW was set on 14 November 2021. If left unconstrained, minimum demand is forecast to fall as low as 11 MW by 2026-27 due to continued growth in DPV installations. **Mitigation actions are either in place or being investigated by AEMO to prevent minimum operational demand causing instability in the power system**. These actions support the WA Government's Energy Transformation Strategy (ETS)[6] to enable the transition to more renewables, and greater decentralisation through higher distributed energy resources (DER).

Peak demand and operational consumption forecasts

AEMO forecasts 10% POE peak demand to increase at an average annual rate of 0.9% over the outlook period, from 4,042 MW in 2022-23 to 4,389 MW in 2031-32 (see Table 1). This is higher than the average annual growth rate of 0.2% presented in the 2021 WEM ESOO, largely driven by stronger forecast growth in peak demand from LILs, residential customers, and uptake of EVs.

[5] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/08/Muja-Power-Station-in-Collie-to-be-scaled-back-from-2022.aspx.

[6] Further information about the ETS can be found at https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.

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

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	5-year average annual growth	2031-32	10-year average annual growth
10% POE	4,042	4,055	4,078	4,106	4,157	0.7%	4,389	0.9%
50% POE	3,781	3,790	3,821	3,855	3,899	0.8%	4,141	1.0%
90% POE	3,533	3,551	3,575	3,619	3,666	0.9%	3,894	1.1%

Table 2 shows operational consumption forecasts for the low, expected, and high demand growth scenarios, which mainly reflect different assumptions about economic growth, DER uptake, energy efficiency improvements, new LILs, and growth in the number of residential connections.

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

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	5-year average annual growth	2031-32	10-year average annual growth
Low	14,986	14,562	14,048	13,663	13,618	-2.4%	13,169	-1.4%
Expected	16,545	16,206	15,893	15,759	15,763	-1.2%	16,151	-0.3%
High	17,601	17,175	16,836	16,722	16,799	-1.2%	18,880	0.8%

Annual operational consumption is forecast to decline in the first half of the outlook period and slightly increase in the second half. This results in an overall decrease of 0.3% per year on average in the operational consumption forecast, but with consumption decreasing at a slower rate than forecast in the 2021 WEM ESOO (0.8%). The slight rise in the second half of the outlook period is due to a forecast increase in LIL consumption and energy use by EVs, compensating for the projected fall in business mass market (BMM) and residential consumption.

The operational consumption and peak demand forecasts continue to follow opposite trends, and diverge at a greater pace than the forecasts in the 2021 WEM ESOO. This is largely attributed to continued DPV uptake having contrasting impacts on the overall consumption and peak demand profiles in the WEM.

Reserve Capacity Requirement and pricing

The Reserve Capacity Target (RCT) determined for 2024-25 is 4,526 MW, which sets the RCR[7] for the 2022 Reserve Capacity Cycle. Table 3 shows the RCT set by the expected 10% POE peak demand requirement of the Planning Criterion for each Capacity Year of the 2022 Long Term PASA Study Horizon. For 2023-24, the Reserve Capacity Price (RCP) is $105,949 per MW, with an RCP of $118,599 per MW for Transitional Facilities[8]. The RCPs for all Facilities for 2024-25 will be determined once Capacity Credits have been assigned for the 2022 Reserve Capacity Cycle.

[7] 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. While the RCT is updated in each Long Term PASA study, once the RCR is determined for a specific Reserve Capacity Cycle, it remains unchanged.

[8] RCPs for the 2021 Reserve Capacity Cycle can be found at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price. Transitional Facilities are facilities (other than Demand Side Programmes) that were assigned Capacity Credits for the 2018 Reserve Capacity Cycle.

Table 3 Reserve Capacity Targets (MW)

Capacity Year	10% POE peak demand	Intermittent loads[A]	Reserve margin[B]	Load following[C]	Total
2022-23[D]	4,042	3	335	110	4,490
2023-24[D]	4,055	3	335	110	4,503
2024-25	**4,078**	**3**	**335**	**110**	**4,526**
2025-26	4,106	3	335	110	4,554
2026-27	4,157	3	335	110	4,605
2027-28	4,194	3	335	110	4,642
2028-29	4,227	3	335	110	4,675
2029-30	4,275	3	335	110	4,723
2030-31	4,322	3	335	110	4,770
2030-32	4,389	3	335	110	4,837

A. 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.
B. Calculated as the greater of (1) 7.6% of the sum of the 10% POE forecast peak demand plus the Intermittent Load allowance; and (2) the maximum sent-out capacity of the largest generating unit (NewGen Kwinana, 334.8 MW, calculated on a sent-out basis at 41°C).
C. Since the 2021 WEM ESOO, the Economic Regulation Authority (ERA) has approved the Load Following Service requirements for the 2021-22 financial year as 110 MW between 05:30 and 20:30 and 65 MW between 20:30 and 05:30 (see https://www.erawa.com.au/cproot/22038/2/202122-Ancillary-Service-audit-and-approval-report.PDF). AEMO considers the Load Following Service requirement of 110 MW in calculating the RCTs to cover peak demand periods, and assumes no change to this requirement over the outlook period. From October 2023, this requirement may change with the implementation of a five-minute Dispatch Interval and the new Essential System Services framework as part of the introduction of security-constrained economic dispatch in the WEM.
D. Figures have been updated to reflect the current forecasts. However, the RCR of 4,421 MW and 4,396 MW set in the 2020 WEM ESOO for the 2020 Reserve Capacity Cycle (2022-23) and the 2021 WEM ESOO for the 2021 Reserve Capacity Cycle respectively do not change.
C. The capacity values of 2024-25 and remaining years are forecasts, assuming the quantity of Capacity Credits assigned for 2023-24 remained unchanged other than the retirement of Muja C unit 6 from 2024-25.

Trends in observed demand extremes and impact of DPV

The 2021-22 summer was the hottest summer on record across the Greater Perth region[9]. During last summer, 82 Trading Intervals recorded temperatures above 40°C, compared to 25 in the 2020-21 summer. The hot weather contributed to peak demand being the second highest annual peak on record.

The 2021-22 summer peak demand was 3,984 MW and occurred during the Trading Interval commencing at 18:00 on 19 January 2022. This peak was primarily driven by high temperatures and occurred on the second day of six consecutive days with maximum daily temperatures exceeding 41°C, as seen in Figure 1. On this peak demand day, DPV generation was estimated to have reduced peak demand by 9.3% (409 MW).

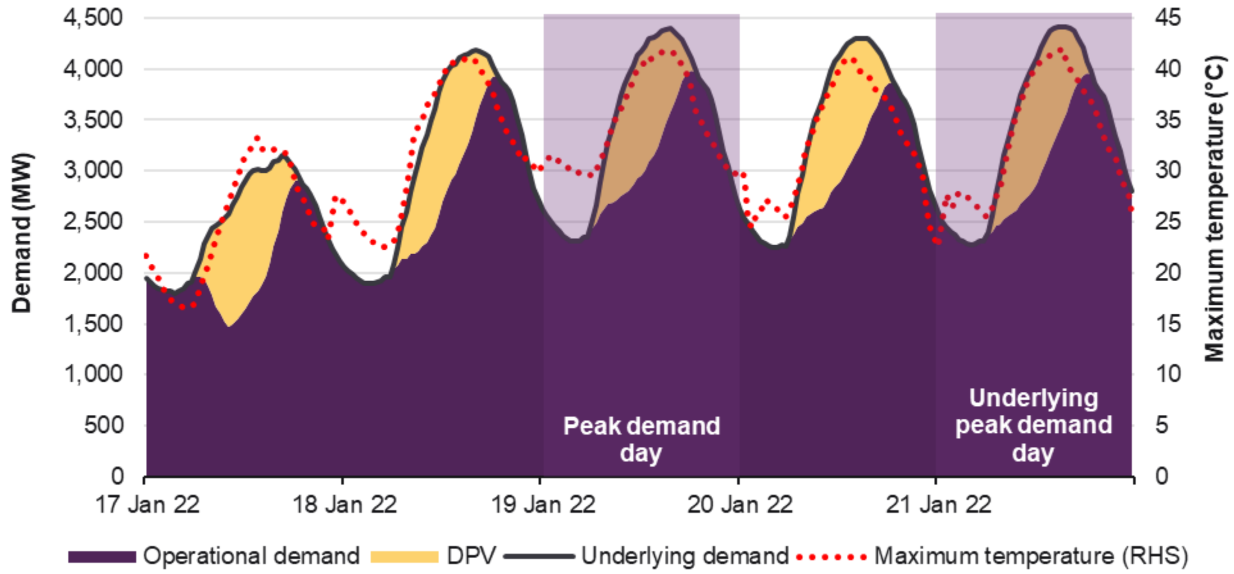
The peak in underlying demand of 4,411 MW occurred two days later, on 21 January 2022[10]. This was on the fourth day of the six consecutive days with maximum daily temperatures exceeding 41°C (see Figure 1). This is the highest underlying peak demand on record.

AEMO forecasts DPV growth in the SWIS to continue, from 2,042 MW in March 2022 to 4,716 MW by the end of the outlook period. Despite the uptake of DPV being forecast to more than double, the impact of DPV generation on peak demand is projected to reduce, as high demand periods are forecast to occur in the early evening.

[9] See http://www.bom.gov.au/climate/current/season/wa/perth.shtml.

[10] DPV generation is estimated to have reduced peak demand by 10.4% (459 MW) on 21 January 2022.

Figure 1 Demand and temperature profiles for a five-day period covering the peak demand day (19 January 2022) and underlying peak demand day (21 January 2022)



Source: AEMO, Bureau of Meteorology, Clean Energy Regulator (CER) and Solcast.

However, the role of DPV in reducing operational minimum demand is directly proportional to the growth in installed capacity. The WEM minimum demand record has been broken five times since the 2021 WEM ESOO was published. The most recent record minimum demand of 765 MW was observed on 14 November 2021 during the Trading Interval commencing at 11:30, during which DPV generation was approximately 1,253 MW.

Unconstrained minimum operational demand is forecast to continue to fall rapidly from the current record of 765 MW to only 11 MW by 2026-27 (see Table 4) due to sustained uptake of DPV. Mitigation actions are either in place or being investigated by AEMO to prevent minimum operational demand causing instability in the power system. These mitigations complement the activities underway as part of the WA Government's ETS to enable the transition to low-emissions and greater decentralisation through higher DER in WA.

Table 4 Unconstrained minimum demand forecasts for different weather scenarios, expected demand growth (MW)

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	5-year average annual growth
10% POE	587	416	262	140	40	-48.9%
50% POE	546	375	231	108	11	-62.1%
90% POE	502	333	184	54	-37	N/A[A]

A. Due to a negative demand value for 2026-27, the 5-year average annual growth rate cannot be calculated.

The energy transition and forecast supply-demand balance in the SWIS

This WEM ESOO has considered the ongoing and accelerating transition of the SWIS to low-emissions energy and greater decentralisation through higher DER, which are key enablers of the transition to net zero greenhouse gas emissions in the WA economy.

The 2021 WEM ESOO forecast that sufficient capacity would be available to meet 10% POE peak demand for the entire outlook period. The change in the long-term capacity outlook in the 2022 WEM ESOO is largely a result of higher peak demand forecasts in this report.

Table 5 presents the forecast supply-demand balance over the outlook period:

- Excess capacity is forecast to decrease from 331 MW (7.5%) in 2023-24 to 8 MW (0.2%) in 2024-25.
- From 2025-26, 10% POE peak demand is expected to exceed available capacity, assuming no further capacity changes beyond the retirement of Muja C unit 6 (193 MW) in October 2024.
- The capacity shortfall is forecast to increase to 303 MW (6.3%) by 2031-32.

Table 5 Reserve Capacity supply-demand balance, 2022-23 to 2031-32

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
RCR/RCT[A] (MW)	4,421	4,396	4,526	4,554	4,605	4,642	4,675	4,723	4,770	4,837
Capacity (MW)	4,807[B]	4,727[B]	4,534[C]	4,534	4,534	4,534	4,534	4,534	4,534	4,534
Excess capacity (MW)	386	331	8	-21	-72	-108	-142	-190	-237	-303
Excess capacity (%)	8.7	7.5	0.2	-0.5	-1.6	-2.3	-3.0	-4.0	-5.0	-6.3

A. The quantities reported for 2022-23, 2023-24, and 2024-25 are the RCR, while the remaining Capacity Years are the RCT.
B. The 2022-23 and 2023-24 available capacity values are the total quantities of Capacity Credits assigned.
C. The capacity values of 2024-25 and remaining years are forecasts, assuming the quantity of Capacity Credits assigned for 2023-24 remained unchanged other than the retirement of Muja C unit 6 from 2024-25.

With a very small surplus forecast for 2024-25 and projected capacity shortfalls in future years, there is an opportunity for new capacity to participate in the RCM to ensure these forecast capacity shortfalls do not eventuate. AEMO is currently collating the submissions received as part of the Request for Expressions of Interest process[11] for the 2022 Reserve Capacity Cycle, a summary of which will be published by 30 June 2022.

The supply-demand balance in the SWIS may vary from the forecasts in this 2022 WEM ESOO as the power system continues its accelerated transition – potential changes in peak demand forecasts, the supply mix, and the RCM are discussed below.

AEMO will continue to monitor supply and demand changes in the SWIS, the outcomes of the RCM Review, and provide updated forecasts in future WEM ESOOs. Stage 2 of the WA Government's ETS commenced in July 2021 and includes the implementation of reforms developed in Stage 1, as well as new initiatives to maintain power system security and reliability as the power system transitions to more renewables and greater decentralisation.

AEMO also looks forward to supporting the Coordinator of Energy in the development of the next Whole of System Plan (WOSP) for the SWIS, which is expected to explore a range of scenarios for the development of the SWIS over the coming 20 years, including to help achieve the WA Government's goal of net zero by 2050 for the WA economy.

Changes in peak demand forecasts

Economic, technological, and public policy are key drivers of changes in peak demand forecasts. The use of the *Progressive Change* scenario for the 2022 WEM ESOO differs from the approach AEMO has taken for the April 2022 update to the 2021 National Electricity Market (NEM) ESOO and 2022 *Integrated System Plan*, in which

[11] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/expressions-of-interest.

AEMO now considers *Step Change* to be the most likely scenario. The *Step Change* scenario has a focus on a more rapid adoption of energy efficiency, DER, and digital energy, and step increases in global energy policy ambition to constrain global warming to less than 2°C.

Currently, AEMO does not have sufficient information about the pace of electrification in the SWIS to support the use of the *Step Change* scenario for the WEM ESOO. However, this is likely to change as initiatives under the WA Climate Policy are further developed and the impact of recent WA Government announcements supporting the uptake of EVs take effect, and as more information about the future electrification plans of SWIS customers become known.

AEMO has also modelled the *Slow Change* (low) and *Strong Electrification* (high) scenarios in this WEM ESOO to consider future demand in the SWIS with a slower, or more rapid, energy transition. The high scenario forecasts provide an indication of the potential additional demand growth, and scale of additional investment in new capacity that may be required, as a result of more rapid electrification in the SWIS.

Changes in the supply mix

The entry of new capacity in the WEM, or decisions by Market Participants to withdraw existing capacity from service, will continue to change the supply mix in the SWIS. Variable renewable generation technologies such as wind and solar have become the least-cost forms of new electricity and are forecast to continue to grow. Older coal-fired power stations are being retired, and new firm capacity and storage will be required to support renewables and maintain a secure and reliable electricity supply in the SWIS, such as the recent announcement by the WA Government regarding the retirement of Synergy's remaining coal-fired power stations and investments in new wind and energy storage capacity.

Changes to the RCM

As part of the ongoing ETS work program, in late 2021 the Coordinator of Energy commenced the RCM Review[12], which is the most significant review of the RCM since the establishment of the WEM. AEMO is supporting the review, which seeks to ensure the RCM continues to provide the required level of reliability as demand and supply in the SWIS change. Changes resulting from this review may influence capacity investment or retirements, or affect the way in which the RCR is determined or capacity is certified in future Reserve Capacity Cycles (see Chapter 8 for more information on the RCM Review).

Working together to deliver solutions

Maintaining power system security and reliability as the SWIS undergoes a once-in-a-lifetime transition is an ongoing challenge, which has been articulated within the WA Government's ETS. AEMO, Energy Policy WA, and Western Power are working together to identify solutions to alleviate the operational issues expected to arise from changes in the way electricity is supplied and used in the SWIS.

[12] The Coordinator of Energy is undertaking a review of the RCM under clause 2.2D.1 of the WEM Rules. See https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group.

Additional developments that have occurred since the 2021 WEM ESOO include:

- The Network Access Quantity (NAQ) framework[13] has been established in the WEM Rules and takes effect from the 2022 Reserve Capacity Cycle. The NAQ aims to encourage the installation of new capacity in the least congested parts of the network.
- Significant progress has been made on the implementation of the new security constrained economic dispatch (SCED) arrangements for the WEM, which are scheduled to commence on 1 October 2023[14].
- Significant progress has also been made on the implementation of the DER Roadmap[15], which provides a plan for the better integration of DER in the SWIS. This has included the launch of a virtual power plant pilot, Project Symphony[16], which co-ordinates DER assets across several suburbs to manage the supply--demand balance at a local level.
- The EV Action Plan[17] has been published and activities outlined in the plan are underway. The EV Action plan provides for EV integration balanced with maintaining power system security.
- Emergency Solar Management (ESM)[18] arrangements have been established, providing for the energy from DPV systems to be curtailed, as a last resort, in emergency situations.

[13] See https://www.wa.gov.au/system/files/2022-04/WRIG%20Slides%20-%20Meeting%203%20%20-%20AEMO%20-%20NAQ%20WEMP%20Development%20-%20March%202022.pdf.

[14] Information on AEMO's WEM Reform Program is available at https://aemo.com.au/en/initiatives/major-programs/wem-reform-program.

[15] See https://www.wa.gov.au/system/files/2020-04/DER_Roadmap.pdf.

[16] See https://www.wa.gov.au/government/announcements/project-symphony-paving-the-way-our-brighter-energy-future.

[17] The EV Action Plan was published on 17 August 2021. See https://www.wa.gov.au/government/publications/electric-vehicle-action-plan-preparing-was-electricity-system-evs.

[18] ESM came into effect from 14 February 2022. Further information can be found at https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

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- This WEM ESOO uses many terms that have meanings defined in the Wholesale Electricity Market Rules (WEM Rules) and Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021. The WEM 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 3 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 in this Executive Summary 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. The peak demand forecast model has been based on the Perth Metro weather station (station identification number 9225). All historical temperature references in this WEM ESOO relate to the Perth Airport weather station (station identification number 9021).
- Trading Interval HH:MM means Trading Interval commencing at HH:MM.

1 Year in review – Reserve Capacity Mechanism

This chapter presents a summary of key outcomes and events associated with the Reserve Capacity Mechanism (RCM) in the Wholesale Electricity Market (WEM) in Western Australia (WA) since the publication of the 2021 WEM *Electricity Statement of Opportunities* (ESOO)[19].

July 2021

- The responsibility for determining the Benchmark Reserve Capacity Price (BRCP) was transferred from AEMO to the Economic Regulation Authority (ERA)[20].
- The responsibility for conducting periodic reviews of the Planning Criterion was transferred from the ERA to the Coordinator of Energy[21].

September 2021

- AEMO received 31 Expressions of Interest (EOI) for the 2021 Reserve Capacity Cycle[22] in September 2021 to offer additional potential Reserve Capacity of 300.846 megawatts (MW)[23]. Of the 25 valid EOIs received, one new Facility and one Facility upgrade were assigned Capacity Credits, contributing 46.658 MW of new Reserve Capacity for 2023-24[24]. For more information on Facilities assigned Capacity Credits for 2023-24, see Chapter 2.

October 2021

- Following announcements by BP regarding the conversion of the Kwinana Refinery into an import terminal[25], Synergy notified AEMO of its intention to retire the Kwinana Cogeneration Facility (PPP_KCP_EG1)[26]. PPP_KCP_EG1 was deregistered on 11 March 2022 and had previously been assigned 80.4 MW of Capacity Credits for 2021-22 and 2022-23.

[19] The 2021 WEM ESOO was published on 17 June 2021. See https://www.aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2021/2021-wholesale-electricity-market-electricity-statement-of-opportunities.pdf.

[20] Clause 4.16.1 of the WEM Rules.

[21] Clause 4.5.15 of the WEM Rules.

[22] Excluding duplicate EOI submissions.

[23] See https://www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2021/2021-expressions-of-interest-summary-report.pdf.

[24] All references to years in this WEM ESOO are Capacity Years unless otherwise specified.

[25] See https://www.bp.com/en_au/australia/home/media/press-releases/kwinana.html.

[26] Scheduled Generator; commenced operation 1 July 2003 with maximum capacity of 116 MW. See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/notifications-of-facility-retirements.

November 2021

- The Coordinator of Energy commenced a review of the RCM[27], which incorporates the review of the Planning Criterion and other RCM aspects[28]. A final information paper, including any potential revisions to the RCM, is expected to be published in December 2022.
- On 14 November 2021, minimum operational demand[29] of 765 MW was observed, which was a 20% decrease on the previous record of 954 MW set on 14 March 2021. According to AEMO's Quarterly Energy Dynamics report[30], approximately 78% of generation was from renewable resources during the minimum operational demand Trading Interval. This set a new minimum demand record for the South West Interconnected System (SWIS) since market start in 2006. Growth in distributed photovoltaics (DPV)[31] in the SWIS continues to reduce minimum operational demand during the day. For more information on the most recent minimum demand record and forecast minimum demand, see Chapter 5. Work is underway to address the challenges associated with decreasing minimum demand, and is discussed in Chapter 8.

December 2021

- The ERA determined the BRCP as $165,700 per MW for the 2022 Reserve Capacity Cycle (2024-25). This is a 9.2% increase over the BRCP determined for the 2021 Reserve Capacity Cycle. The increase is mostly a result of higher capital and labour costs[32].

January 2022

- AEMO published the 2022 Request for Expressions of Interest to invite existing and potential Market Participants to submit an EOI for the 2022 Reserve Capacity Cycle[33]. This was the first EOI process where each respondent was required to state whether its new Facility or Facility upgrade was to be classified as a Network Augmentation Funding Facility (NAFF)[34] in its Certified Reserve Capacity (CRC) application[35]. NAFF classifications are an element of the Network Access Quantity (NAQ) framework, which commences in the 2022 Reserve Capacity Cycle. For more information on the NAQ framework, see Chapter 8.
- On 19 January 2022, peak operational demand[36] for the 2021-22 summer period was 3,984 MW during the 18:00-18:30 Trading Interval. This was the second-highest annual operational demand recorded in the SWIS[37], an outcome of high temperature conditions and power demand from air-conditioning.

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[27] Under clause 2.2D.1(h) of the WEM Rules. See https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group.

[28] See https://www.wa.gov.au/system/files/2021-11/RCM-Review-2021-Scope-of-works.PDF.

[29] Refer to Chapter 3 for key definitions of operational demand and underlying demand.

[30] See https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf.

[31] DPV includes rooftop PV.

[32] See https://www.erawa.com.au/cproot/22355/2/-BRCP.2022---Notice---Publication-of-final-determination.pdf.

[33] It is mandatory for existing and potential Market Participants with new Facilities and Facility upgrades intending to apply for CRC to submit an EOI.

[34] A NAFF is a Facility that is an Energy Producing System for which the relevant Market Participant has committed to funding Network Augmentation Works which are expected to be in service by 1 October of Year 3 of the relevant Reserve Capacity Cycle – see clause 4.10A.2 of the WEM Rules.

[35] See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/eoi/2022/2022-request-for-expressions-of-interest.pdf.

[36] Underlying demand is measured as operational demand adjusted to remove the impact of behind-the-meter PV output.

[37] It is 26 MW below the 4,004 MW record during the 17:30-18:00 Trading Interval on 8 February 2016.

- On 21 January 2022, peak underlying demand reached a new record of 4,411 MW during the 15:30-16:00 Trading Interval. Information on the most recent peak operational and underlying demand record and forecast peak operational demand is presented in Chapter 5.

February 2022

- AEMO deferred key events in Year 1 of the 2022 Reserve Capacity Cycle. The deferrals aimed to allow AEMO and stakeholders time to resolve complexities related to implementation of the NAQ framework under a security-constrained market design[38].

April 2022

- A total of 4,726.572 MW of Capacity Credits were assigned to meet the Reserve Capacity Requirement (RCR) of 4,396 MW for the 2021 Reserve Capacity Cycle in relation to 2023-24, representing a 7.5% excess capacity level[39]. For details on the RCR for the 2022 Reserve Capacity Cycle, and the forecast supply-demand balance for the outlook period, see Chapter 7.
- The Reserve Capacity Price (RCP) for the 2021 Reserve Capacity Cycle (2023-24) was calculated to be $105,949.27/MW/year for non-Transitional Facilities and $118,599.19/MW/year for Transitional Facilities[40]. This represents a 24% increase to the RCP for non-Transitional Facilities and a 2.8% increase in RCP for Transitional Facilities compared to the 2020 Reserve Capacity Cycle. The increase in RCP for non-Transitional Facilities reflects a lower level of Reserve Capacity excess compared to the previous Reserve Capacity Cycle. For more information on the RCP, see Chapter 2.
- Landfill Gas and Power Pty Ltd notified AEMO that it intends to retire Kalamunda Diesel Facility (KALAMUNDA_SG)[41]. KALAMUNDA_SG is assigned 1.3 MW of Capacity Credits for 2021-22 and no Capacity Credits for 2022-23. The expected closure date is 1 July 2022.

May 2022

- The EOI window for the 2022 Reserve Capacity Cycle closed on 9 May 2022. The 2022 EOI summary report is scheduled to be published by the end of June 2022.

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[38] See https://aemo.com.au/consultations/current-and-closed-consultations/deferral-of-the-2022-reserve-capacity-cycle-timetable.

[39] See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/assignment/2022/capacity-credits-assigned-for-the-2023-24-capacity-year.pdf.

[40] Transitional Facilities include facilities (other than Demand Side Programmes) that were assigned Capacity Credits for the 2018 Reserve Capacity Cycle. See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price.

[41] Scheduled Generator; commenced operation 13 July 2008 with maximum capacity of 1.3 MW. See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/notifications-of-facility-retirements.

2 Changes in supply

This chapter discusses changes in the capacities of Facilities that are allocated Capacity Credits for 2023-24, as well as changes to the RCPs that Facilities are paid for their Capacity Credits.

This chapter refers to RCM Facility Classes specified in clause 1.45.6A of the Wholesale Electricity Market Rules (WEM Rules)[42]. For the 2022 and 2023 Reserve Capacity Cycles, a Market Participant who intends to apply for CRC for an existing or a new Facility will need to apply to AEMO to seek an assignment of that Facility to an RCM Facility Class in accordance with section 1.45 of the WEM Rules[43].

2.1 Introduction

The RCM operated by AEMO is unique to the WEM and is designed to ensure there is sufficient capacity to meet peak demand two years ahead. To achieve this, AEMO operates the RCM to assess and assigns Capacity Credits[44] to Facilities that are capable of providing Reserve Capacity to meet the RCR.

Market Participants seeking assignment of Capacity Credits must first apply for CRC[45]. Market Participants holding CRC must submit a bilateral trade declaration detailing what quantity of CRC they wish to trade bilaterally, and how many will not be made available to the market. Following AEMO's acceptance of a bilateral trade declaration, a Market Participant's Facility will be assigned Capacity Credits if it meets the prioritisation criteria in the WEM Rules. AEMO will then calculate an administered RCP to determine payment for each Capacity Credit assigned[46]. Market Participants must make this capacity available to the market for dispatch for the relevant Capacity Year and may pay capacity refunds if they fail to do so.

The WA Government's ETS has introduced changes to the RCM to provide a framework for integrating storage resources in the RCM and assigning Capacity Credits under a model of constrained network access. From the 2021 Reserve Capacity Cycle, AEMO started to assess CRC at a component[47] level and apply the Linearly Derating Capacity (LDC) methodology to certify Electric Storage Resources (ESR). From the 2022 Reserve Capacity Cycle, the NAQ Model[48] will be applied to assign Capacity Credits considering the network constraints

[42] Amending Rules to the registration framework have been gazetted as part of the Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021 to introduce a new registration taxonomy into the WEM. The commencement date has not yet been specified for the amended registration rules. Section 1.45 of the WEM Rules specifies transitional provisions that apply the new registration taxonomy to Market Participants participating in the RCM for the 2021, 2022 and 2023 Reserve Capacity Cycles.

[43] A new Facility or an existing Facility with an upgrade intending to apply for CRC is required to submit an EOI, in order for AEMO to determine the indicative Facility Class and FTT. AEMO's determination of the indicative Facility Class and FTT becomes the Facility's final RCM Facility Class.

[44] Capacity Credits are a notional unit of Reserve Capacity. Each Capacity Credit is equivalent to 1 MW of Reserve Capacity. Capacity Credits can be traded via AEMO at the Reserve Capacity Price or can be traded bilaterally.

[45] The CRC process if a technical review of the capability of the Facility and determines the maximum quantity of Capacity Credits which can be allocated to each Facility.

[46] Capacity Credits are funded via the assignment of an Individual Reserve Capacity Requirement (IRCR) to Market Customers based on their contributions to peak system demand.

[47] An Electric Storage Resource, Intermittent Generating System, or a Non-Intermittent Generating System that forms part of a Facility, other than a Demand Side Programme. See https://aemo.com.au/-/media/files/electricity/wem/procedures/certification-of-reserve-capacity-for-the-2021-reserve-capacity-cycle.pdf.

[48] Has the meaning given in the Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020, see https://www.wa.gov.au/system/files/2021-05/Wholesale-Electricity-Market-Amendment-Tranches-2-and-3-Amendments-Rules-2020%20%281%29.pdf.

and a prioritisation order in receiving network access during peak demand periods. Further information about the NAQ Model is provided in Chapter 8 of this WEM ESOO.

2.2 Changes in the certification process

AEMO employs four certification methodologies to assess and assign CRC.

Facilities can participate in the RCM using several components, wherein each component can be a different Facility Technology Type (FTT)[49] as assigned by AEMO. All Facilities have at least one component, except for Demand Side Programmes (DSP) which do not have components. AEMO applies four certification methodologies to assess and assign CRC at a component level, if it is part of a Scheduled Facility or Semi-Scheduled Facility; or at a Facility level if it is a Non-Scheduled Facility or DSP.

Table 6 outlines a high-level description of each certification methodology and examples of capacity to be assessed by each methodology. Chapter 4 of the WEM Rules and the Certification of Reserve Capacity for the 2022 and 2023 Reserve Capacity Cycles WEM Procedure (2022 and 2023 CRC WEM Procedure)[50] contain complete information on the certification methodologies[51].

Table 6 Certification methodologies and examples

Certification methodology	Description of methodology	Facility Technology Type (Component)	RCM Facility Class	Technology type
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.	A Non-Intermittent Generating System	A Scheduled Facility or a Semi-Scheduled Facility	Coal-fired steam turbine, gas-fired turbine, distillate fuelled engine.
Relevant Level Methodology (RLM)	Considers the performance of the Facility during periods with the lowest level of excess capacity over demand. These periods are more likely to occur when demand in the SWIS is the highest.	An Intermittent Generating System	A Scheduled Facility or a Semi-Scheduled Facility	Photovoltaics, wind turbine, landfill gas-powered turbine.
Linearly Derating Capacity (LDC)	Allocates capacity based the ability of an ESR to sustain output over a given period.	An ESR	A Scheduled Facility or a Semi-Scheduled Facility	Battery, hydro-powered generator, hydrogen-fuelled reciprocating engine or electrolyser.
Relevant Demand	The benchmark consumption level by which the demand from the load or aggregated loads can be curtailed.	One or multiple Loads	A DSP	Large single load or an aggregation of multiple smaller loads.

49 Has the meaning given in the Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021, see https://www.wa.gov.au/system/files/2021-12/Wholesale-Electricity-Market-Amendment-Tranche-5-Amendments-Rules-2021.pdf.

50 A procedure for the relevant Reserve Capacity Cycle can be accessed at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

51 The WEM Rules and the 2022 and 2023 CRC WEM Procedure prevail over this WEM ESOO to the extent of any inconsistency.

2.3 Changes in Capacity Credits for 2023-24

2.3.1 Key updates

There was limited movement in the number of Market Participants (from 35 to 34) and Facilities (67 to 65) participating in the RCM between 2022-23 and 2023-24. The total number of assigned Capacity Credits fell from 4,807.2 MW to 4,726.6 MW, a decline of 1.7%. compared to 2022-23.

Key changes in relation to Facilities assigned Capacity Credits between 2022-23 and 2023-24 are:

- New entry – the Synergy Kwinana Big Battery (KWINANA_ESR1) with 100 MW/ 200 megawatt hours (MWh) of capacity was assigned 46.3 MW for 2023-24. This is the first standalone ESR Facility to be assigned Capacity Credits in the WEM.
- Retirements – the Kwinana Cogeneration Facility supplying the former BP refinery in Kwinana (PPP_KCP_EG1) was deregistered on 11 March 2022 and was assigned 80.4 MW for 2022-23. This represents the single largest reduction in Capacity Credits for 2023-24, but was partially offset by the entrance of KWINANA_ESR1.
- Existing Facilities **–** changes in Capacity Credit assignments between 2022-23 and 2023-24 included:
  - The Synergy Muja D unit 7 (MUJA_G7) was assigned 207.2 MW of Capacity Credits, a reduction of 3.8 MW from the Capacity Credits assigned for 2022-23.
  - The Phoenix Kwinana Waste-to-Energy Facility (PHOENIX_KWINANA_WTE_G1) was assigned 33.9 MW Capacity Credits, a 0.9 MW increase from the 2022-23 assignment.
  - The Wesfarmers Kleenheat Gas DSP Facility (PREMPWR_DSP_02) was assigned 21.8 MW Capacity Credits, a 2.2 MW reduction from the 2022-23 assignment.
  - The Southern Cross Power Station (STHRNCRS_EG) was not assigned any Capacity Credits for 2023-24 after being assigned 21 MW of Capacity Credits for 2022-23.
  - Despite upgrades to Collgar Wind Farm (INVESTEC_COLLGAR_WF1), the total quantity of Capacity Credits assigned to this Facility reduced by 2.1 MW on 2022-23 due to a lower Relevant Level value.

In general, the total quantity of Relevant Level values calculated for Semi-Scheduled Facilities and Non-Scheduled Facilities for 2023-24 fell by 20.3 MW, largely due to the continued trend of declining Relevant Level values[52] for solar and wind Facilities.

2.3.2 Capacity Credits by certification methodology

The nominal value and proportion of Capacity Credits certified using each of the ‘Capability at 41°C’, RLM, and Relevant Demand certification methodologies fell in 2023-24 compared to 2022-23 (Table 7). The LDC was used for the first time to assign 46.3 MW of Capacity Credits (1%) to an ESR which is a sole component of a Scheduled Facility.

Most Capacity Credits are assigned to Non-Intermittent Generating Systems using the ‘Capability at 41°C’ methodology – that is, traditional thermal generation Facilities. In 2023-24, 93.5% of Capacity Credits were

[52] The increasing penetration of DPV generation in the SWIS is resulting in periods of highest demand shifting to later in the day, and occurring more in the winter months when, on average, wind farms’ and solar farms’ output is lower.

assigned to Non-Intermittent Generating Systems, a marginal decrease from 2022-23 where Facilities certified under the 'Capability at 41°C' methodology received 94.1% of Capacity Credits allocated.

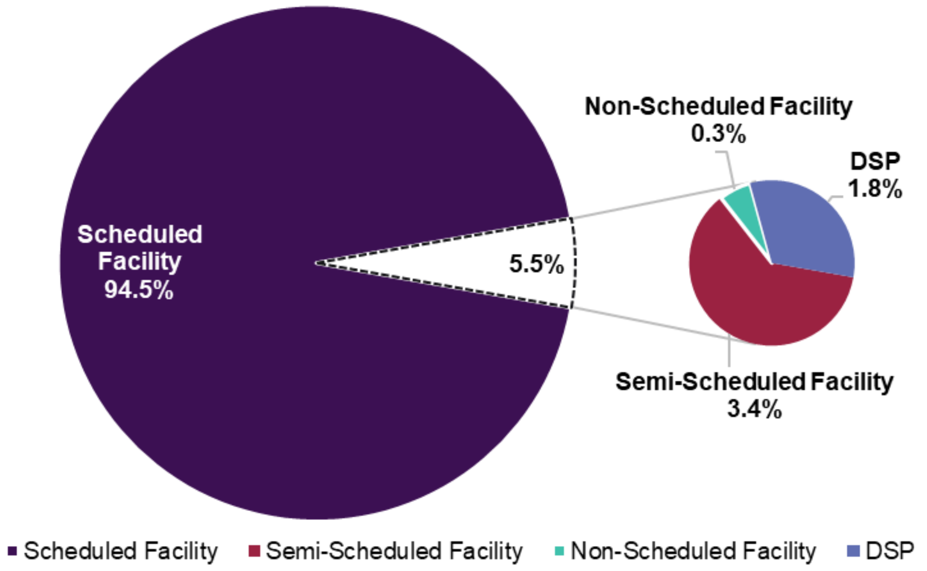
Table 7 Capacity Credits by certification methodology

Certification methodology	2022-23 MW	2022-23 %	2023-24 MW	2023-24 %
Capability at 41°C	4,523.1	94.1	4,418.7	93.5
RLM	198.1	4.1	177.8	3.8
LDC	0	0	46.3	1
Relevant Demand	86	1.8	83.8	1.8
Total	**4,807.2**	**100**	**4,726.6**	**100**

2.3.3 Capacity Credits by RCM Facility Class

In 2023-24, Scheduled Facilities were allocated 94.5% of Capacity Credits, whereas Non-Scheduled Facilities comprised only 0.3% of Capacity Credit allocations (Figure 2).

Figure 2 Capacity Credit allocation shares by Facility type, 2023-24



Non-Scheduled Facilities (less than 10 MW) are not obliged and/or able to respond to dispatch instructions. Semi-Scheduled Facilities and DSPs have varying capabilities and availabilities during peak periods. By contrast, Scheduled Facilities are obliged to, and able to respond to dispatch instructions and are typically active during peak periods.

2.3.4 Capacity Credits by fuel type

In 2023-24, the maximum capacity[53] of 26 Facilities with renewable energy sources was 1,249.7 MW or 21.1% of the generating fleet (Figure 3). Facilities with renewable energy sources were assigned 236.8 MW of Capacity Credits, accounting for 5% of total Capacity Credits assigned. Facilities with non-renewable energy sources

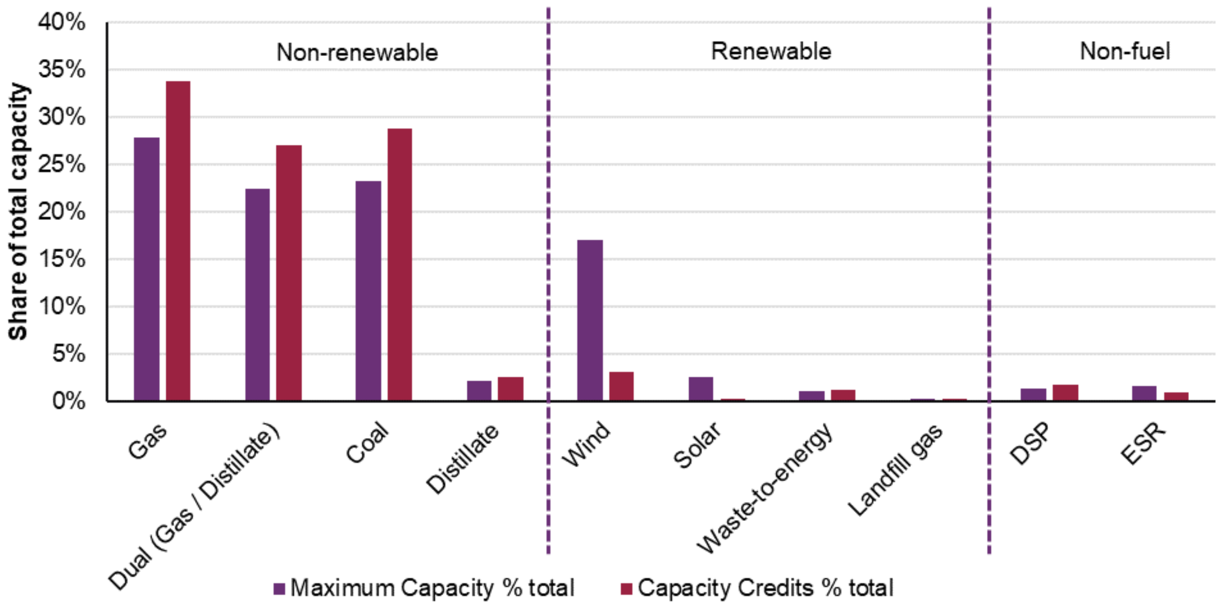
[53] Maximum capacity data is based on the net sent-out generation or installed capacity and can be found on AEMO's Market Data website, at http://data.wa.aemo.com.au/#facilities.

receive a relatively large share of Capacity Credits. Gas Facilities receive 33.8% of Capacity Credit allocations, despite only accounting for 27.9% of the fleet.

The methodology for allocating Capacity Credits to different Facility types is being considered as part of the RCM Review. For further information on the RCM Review, see Chapter 8.

In 2023-24, the Capacity Credit capacity factors[54] for Facilities with renewable energy sources is 19%, substantially lower than the capacity factor of 97.4% for Facilities with non-renewable energy sources. As shown in Table 8, Facilities with renewable energy sources can expect to have lower capacity factors due to their intermittent nature. These Facilities will be able to take advantage of emerging battery technologies by adding ESR components, or other forms of firming capacity, to their Facilities, potentially increasing and provide greater certainty to their capacity factors.

Figure 3 Proportions of Capacity Credits and maximum capacity by fuel type, 2023-24[A,B,C]



A. Due to the nature of DSPs, the maximum capacity of DSP here has been defined as the contracted quantity. This accommodation has been made for percentage calculation and graphical purposes.
B. Figures may not align to other published totals due to filters applied in the methodology.
C. Wind includes the wind and solar hybrid Facilities, and solar includes the solar and Electric Energy Storage hybrid Facility.

[54] Capacity Credit capacity factor is defined as the ratio of Capacity Credit to maximum capacity, for the purposes of this WEM ESOO.

Table 8 Capacity Credits and capacity factors by energy source, 2023-24

Fuel type	Maximum capacity (MW)	Capacity Credits Assigned	Capacity Credit capacity factor
Gas	1647.1	1597.8	97.0%
Dual (Gas / Distillate)	1326.0	1277.9	96.4%
Coal	1371.1	1362.4	99.4%
Distillate	132.2	121.6	92.0%
Wind[A]	1010.8	150.0	14.8%
Solar[A]	150.8	14.9	9.9%
Waste-to-energy	65.0	59.0	90.8%
Landfill gas	21.6	12.9	59.8%
DSP[B]	85.0	83.8	98.6%
ESR	100.0	46.3	46.3%

A. Wind includes the wind and solar hybrid Facilities, and solar includes the solar and Electric Energy Storage hybrid Facility.
B. Due to the nature of DSPs, the maximum capacity of DSP here has been defined as the contracted quantity. This accommodation has been made for percentage calculation and graphical purposes.

2.4 Reserve Capacity Price (RCP)

The RCP is the price paid for Capacity Credits procured centrally through AEMO, and is calculated annually using the formula stipulated in the WEM Rules. When the RCP formula is calculated to determine RCP at various excess capacity values, this creates an RCP curve (see Figure 4).

Historically, the RCP curve was relatively flat, which may have led to a tendency to over-procure Reserve Capacity[55] in the WEM by not sending a clear enough signal of the value of additional capacity during times of excess. Amendments to steepen the curve (and introduce DSM RCP[56]) came into effect for 2017-18. The RCP regime was further amended in 2020 (applicable from 2021-22) to remove the DSM RCP and modify the RCP formula to make the RCP more responsive to changes in excess capacity[57]. The current RCP curve based on the BRCP for 2023-24 is shown in Figure 4.

2.4.1 Factors influencing the RCP

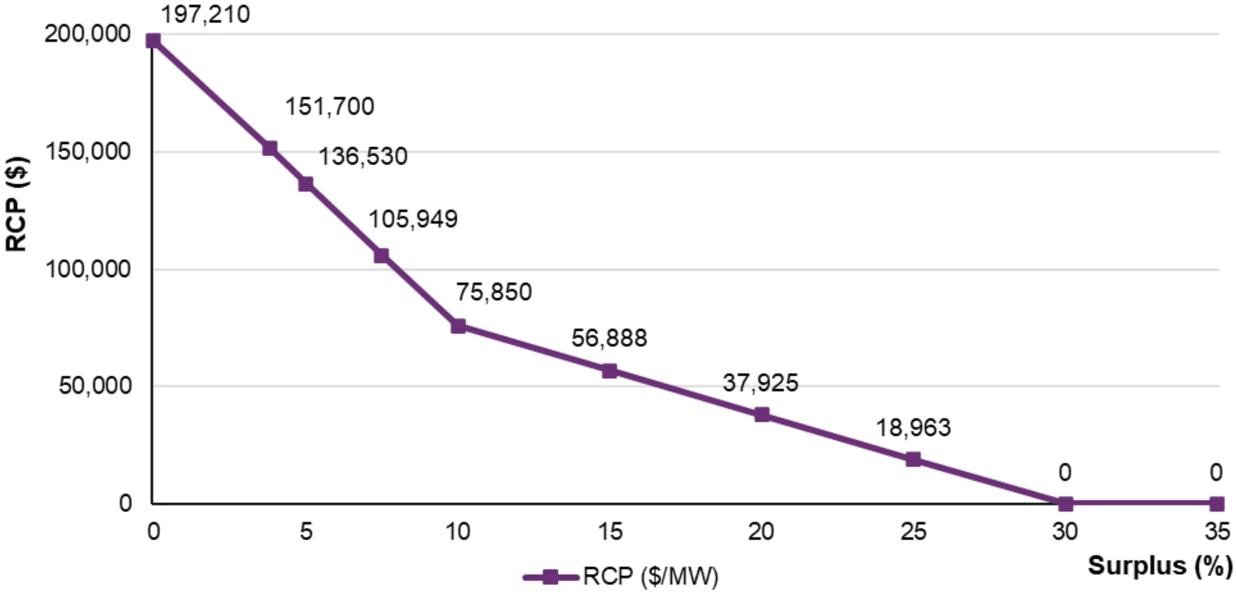
The current RCP formula is intended to provide an effective price signal, reflecting the level of excess capacity in the market. Under the current formula, the RCP is determined by adjusting the BRCP based on the level of excess capacity. Figure 4 shows an example of the resulting RCP at various excess capacity levels based on the 2023-24 BRCP. For full details of the calculations used to determine the RCP, refer to clause 4.29.1 of the WEM Rules.

[55] For example, over 20% of excess capacity was procured in the 2016-17 at an estimated cost of $116 million to consumers. For further details on the RCP formula review, see https://www.wa.gov.au/system/files/2019-08/Final-Recommendations-Report-Improving-Reserve-Capacity-pricing-signals_0.pdf.

[56] DSM RCP was removed from 2012-22 onward, such that DSPs receive the same RCP as other Facilities. For further detail on RCP changes, see https://www.wa.gov.au/system/files/2021-11/RCM-Review-2021-Scope-of-works.PDF. Note that the DSM RCP is referred to as DSP RCP in this source.

[57] For further detail on RCP, including RCP for Transitional or Fixed Price Facilities, see https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price.

Figure 4 2023-24 RCP curve (2023-24 BRCP = $151,700/MW)A,B,C



A. The pricing methodology uses three parameters including (a) a price cap where in periods of a capacity shortfall, the RCP cannot exceed 1.3 times the BRCP; (b) an absolute zero point where if excess capacity exceeds 30%, the RCP will fall to zero; and (c) the economic point where excess capacity exceeds 10%, the RCP will fall to 50% of the BRCP.
B. RCP is equal to BRCP ($151,700) when excess capacity is equal to 3.75%.
C. There was 7.5% excess capacity for the 2023-24 Capacity Year.

Historical factors influencing excess capacity

Excess capacity varies annually and is driven by changes in the RCR in a given Reserve Capacity Cycle, and the amount of Capacity Credits procured. The RCR is affected by changes to peak demand forecasts, which have historically been impacted by factors such as changes in economic growth expectations, changes to forecasting models, and changes to the Planning Criterion.

The procurement of Capacity Credits has historically been impacted by:

- Changes in the method for assigning CRC to Intermittent Generating Systems (introduction of the RLM) [58].
- Introduction of DSM RCP that came into effect in 2017-18[59], and removal from 2021-22, to align with a revised RCP formula[60].
- Changes to the Relevant Demand methodology[61].
- More recently, the retirement of Synergy's four coal-fired units of the Muja AB facility and removal of other generating units from the RCM[62].

[58] The increasing penetration of DPV generation in the SWIS is resulting in periods of highest demand shifting to later in the day, and occurring more in the winter months when, on average, wind farms' and solar farms' output is lower. See Table 6.

[59] See 2017 WEM ESOO, at https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

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

[61] See https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2017/2017-electricity-statement-of-opportunities-for-the-wem.pdf.

[62] See 2017 WEM ESOO and 2018 WEM ESOO, at https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

Historical factors influencing the BRCP

The BRCP continues to provide the basis for the pricing methodology and is calculated in accordance with the WEM Procedure: Benchmark Reserve Capacity Price, which is administered by the ERA, and which was updated in 2013 (by the Independent Market Operator) and 2020[63]. While the BRCP has remained reasonably stable, two significant changes to the BRCP calculated were:

- A 45% increase in the BRCP from 2011-12 to 2012-13. This was predominantly driven by a spike in transmission connection costs (350% higher than previous estimates).
- A 32% decrease in BRCP from 2013-14 to 2014-15. This was driven by a reduction in the weighted average cost of capital due to uncertainty stemming from the global financial crisis in 2011 (the 2014-15 BRCP was determined in 2012), reduced transmission costs from a methodology change in Western Power calculations, and the inclusion of inlet cooling as a component of the reference technology used to determine the BRCP (both the costs and efficiency gains)[64].

The BRCP regime is being reviewed as part of the scope of the RCM Review. For further information on the RCM Review, see Chapter 8.

[63] See https://www.erawa.com.au/electricity/wholesale-electricity-market/market-procedures.

[64] See https://aemo.com.au/-/media/archive/docs/default-source/reserve-capacity/imo-final-report-max-reserve-capacity-price-2014-15cb08d52a9766f6a0.pdf.

3 Demand and consumption forecasting approach

This chapter presents key definitions, a description of the forecasting scenarios, a summary of the demand and consumption forecast methodology, and information about supporting forecasts.

AEMO forecasts are based on various definitions describing specific characteristics of the parameter that is presented. Several of these key definitions are included in Table 9. Where practical, AEMO aligns the definitions used to develop the electricity consumption and demand forecasts for both the National Electricity Market (NEM) ESOO and the WEM ESOO, while noting WEM-specific definitions.

Table 9 Definitions for key demand and consumption terms used in the 2022 WEM ESOO

Term	Definition
Distributed energy resources terms	
Distributed energy resources (DER)	DER includes distributed PV, distributed battery storage, and electric vehicles (see below for definition)
Rooftop photovoltaic (PV)	Defined as a system comprising one or more photovoltaic panels, installed on a residential building (less than 15 kilowatts [kW]) or business premises (less than 100 kW) to convert sunlight into electricity.
PV non-scheduled generation (PVNSG)	Defined as non-scheduled photovoltaic generators larger than 100 kW but smaller than 10 MW that do not hold Capacity Credits in the WEM.
Distributed PV (DPV)	DPV includes both rooftop PV and PVNSG.
Distributed battery storage	Defined as behind-the-meter battery storage systems installed for residential, commercial, and large commercial that do not hold Capacity Credits in the WEM.
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.
Demand and energy consumption terms	
Consumption	The amount of power used over a period of time, conventionally reported as megawatt hours (MWh) or gigawatt hours (GWh) depending on the magnitude of power consumed. It is reported on a "sent-out" basis (excluding electricity used by a generator[A]) 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).
Operational consumption[B] (or demand)[C]	Electricity consumption (or demand) that is met by sent-out electricity supply of all market registered energy producing units[D]. 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 (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.
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, if it is supplied from the grid or by behind-the-meter (typically rooftop PV) generation.

Term	Definition
Delivered consumption (or demand)	Electricity consumption (or demand) that is supplied to electricity users from the grid. It therefore excludes the part of their consumption (or demand) that is met by behind-the-meter (typically rooftop PV) generation.
Market underlying consumption (or demand)[E]	The total amount of electricity consumption (or demand) in the market, which includes consumption (or demand) delivered to the residential and business customers (include the impact of distributed battery storage operation), network losses, and DPV generation.
Other forecasting terms	
Residential sector	Includes residential customers (supplied by Synergy) only.
Business sector	Includes industrial and commercial users. This sector is subcategorised further to include the 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 at least 10% of the time (around 875 hours a year).
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.

A. This may be called 'auxiliary load', 'parasitic load', or 'self-load' referring to energy generated for use within power stations.
B. 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.
C. 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.
D. Includes market generators and utility-scale energy storage systems.
E. 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.

3.1 Scenarios

In line with the WEM Rules, the operational peak demand and consumption forecasts for this WEM ESOO were developed using low, expected and high demand growth scenarios for the 10-year outlook period from 2022-23 to 2031-32[65].

The *2021 Inputs, Assumptions and Scenarios Report* (IASR)[66] details how AEMO uses WEM ESOO's scenarios to model the future of the NEM forecasting and planning publications. When reading this WEM ESOO forecasts and planning documents, it is important to understand the modelling inputs and assumptions. This WEM ESOO used a selection of scenarios, assumptions, and supporting forecasts from AEMO's IASR published in July 2021.

A series of stakeholder consultative forums were held to refine the assumptions and inputs of the 2021 IASR to inform AEMO's forecasting and planning publications. The updates considered new data as it became available during the process, as well as evolution of government policy settings.

A more comprehensive consultation to develop the next IASR[67] will commence later in 2022, with a draft 2023 IASR due for publication in December 2022. AEMO encourages WEM stakeholders to participate in these

[65] As required under clause 4.5.10(a) of the WEM Rules.

[66] See report at https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf and addendum at https://aemo.com.au/-/media/files/major-publications/isp/2022/addendum-to-the-2021-inputs-assumptions-and-scenarios-report.pdf.

[67] See Section 1.4 of the Draft 2022 *Forecasting Assumptions Update* for further information, at https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/draft-2022-forecasting-assumptions-update.pdf.

consultation sessions to develop the 2023 IASR, the outcomes of which will inform the modelling and forecasts in future WEM ESOOs[68].

Table 10 outlines the evolution of the 2021 IASR scenarios and the selection and mapping of the IASR scenarios to the 2021 and 2022 WEM ESOOs.

Table 10 Evolution of scenarios in the 2021 IASR and scenario mapping for the 2022 WEM ESOO (highlighted in purple) and 2021 WEM ESOO (highlighted in yellow)[A]

Economic growth and population outlook	2021 IASR draft scenario taxonomy[B, C] (March 2021)	2021 IASR final scenario taxonomy[D] (July 2021)	2021 IASR updated scenario taxonomy[E] (December 2021)
Low	*Slow Growth*	Renamed to *Slow Change*	**Unchanged – *Slow Change***
Moderate	*Current Trajectory*	Renamed to *Steady Progress*	Removed
Moderate	*2050 Net Zero*	Renamed to *Net Zero 2050*	**Renamed to Progressive Change**
Moderate	*Sustainable Growth*	Renamed to *Step Change*	Unchanged – *Step Change*
High	*Rapid Decarbonisation*[F]	Renamed to *Strong Electrification*	**Unchanged – *Strong Electrification***
High	*Export Superpower*	Renamed to *Hydrogen Superpower*	Renamed to *Hydrogen Export*

A. AEMO incorporated varying levels of carbon offsetting activities, such as carbon sequestration, within the scenario narratives and in the carbon budgets that apply in the net zero emission future.
B. Released in Draft 2021 IASR Submissions Webinar: https://aemo.com.au/-/media/images/videos/2021/draft-iasr-submissions-webinar.mp4.
C. The 2021 IASR draft scenario names were applied by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) (https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2021/CSIRO-DER-Forecast-Report) and Green Energy Market (GEM) (https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf) in developing the 2021 WEM ESOO DER; see Section 3.3.1 of this chapter for further information.
D. Published in the 2021 IASR which includes five core scenarios and five sensitivity scenarios. See Section 2 of the 2021 IASR report: https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf.
E. Published in the Draft 2022 *Forecasting Assumptions Update*: https://aemo.com.au/-/media/files/major-publications/isp/2022/iasr/draft-2022-forecasting-assumptions-update.pdf.
F. *Rapid Decarbonisation* is a sensitivity scenario based on *Export Superpower*, in which the economy is more heavily based on electrification (hydrogen uptake is limited) to achieve the same economy-wide emission reductions. See https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-iasr-consultation-summary-report.pdf.

The scenarios developed in the 2021 IASR considered:

- Key demand drivers that include economic and population growth.
- Technological improvements such as DER uptake and energy efficiency improvement.
- Climatic assumptions about mean temperature.
- Public policy assumptions.

The WEM ESOO requires the three scenarios of low, expected and high demand growth to be used. AEMO has selected three scenarios from the updated 2021 IASR scenarios that mirror these as closely as possible, taking into consideration the WA State Government's and Federal Government's existing policy commitments at the time of the development of this WEM ESOO:

- *Slow Change*: this scenario includes lower assumed forecast economic growth than the historical trend, reflects slower technology advancement, and slower progress than any other scenario on decarbonisation.
- *Progressive Change*: this scenario reflects moderate growth in the economy and a future energy system based on the current WA State Government's and Federal Governments' environmental and energy policies, including transitioning Australia's economy to a net zero level of emissions by 2050.

[68] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

- *Strong Electrification*: this scenario features strong economic activity, high levels of electrification and energy efficiency investments, and strong economy-wide decarbonisation objectives to achieve economy-wide net zero emissions by early 2040s.

Compared to the 2021 WEM ESOO, the scenario mapping remained unchanged for the low and high demand growth scenarios. The *Current Trajectory* scenario did not have an explicit decarbonisation objective beyond 2030. It was removed from the updated 2021 IASR scenarios list, given Australia's commitment to net zero emissions by 2050. Therefore, the expected demand growth scenario has changed from the *Current Trajectory* scenario to the *Progressive Change* scenario for this WEM ESOO.

The use of the *Progressive Change* scenario for this WEM ESOO differs from the approach AEMO has taken for the April 2022 update to the NEM ESOO and *Integrated System Plan*, in which AEMO now considers the *Step Change* scenario to be the most likely scenario. The *Step Change* scenario has a focus on a more rapid adoption of energy efficiency, DER, digital energy and step increases in global energy policy ambition to constrain global warming to less than 2°C. It aims to exceed 26-28% carbon emission reduction by 2030 and achieve an economy-wide net zero emission before 2050 in Australia.

Currently, AEMO does not have sufficient information about the pace of electrification in the SWIS to support the use of the *Step Change* scenario for this WEM ESOO. However, this is likely to change as the initiatives under the WA Climate Policy[69] are further developed and the impact of recent announcements supporting the uptake of EVs take effect, and as more information about the future electrification plans of SWIS customers become known.

Table 11 consolidates key demand drivers, changes in DER uptake, and emissions reduction targets to apply for each of the demand growth scenarios considered for this WEM ESOO (see Section 3.3 for more information on the supporting forecasts).

Table 11 2022 WEM ESOO scenario settings

2022 WEM ESOO scenario	Low	Expected	High
2021 IASR scenario mapping	*Slow Change*	*Progressive Change*	*Strong Electrification*
Economic and population growth forecasts	Low	Expected	High
Prospective LIL forecast	Low	Expected	High
Residential connections	Low	Expected	High
Energy efficiency	Low	Expected	High
DPV	Low	Expected	High
Distributed battery storage	Low	Expected	High
EV	Low	Expected	High
Decarbonisation target[A]	26-28% reduction by 2030 No explicit decarbonisation target beyond 2030	26-28% reduction by 2030 Economy-wide net zero target by 2050	Exceed 26-28% reduction by 2030 Economy-wide net zero by early 2040s

A. While the implications of the long-term carbon emission reduction policy were considered in shaping the forecasts, the forecasts are limited to the 10-year outlook period for this WEM ESOO.

[69] See https://www.wa.gov.au/service/environment/environment-information-services/western-australian-climate-change-policy.

3.2 Demand and consumption forecasts methodology

AEMO developed operational demand and consumption forecasts for this WEM ESOO[70] that are consistent with the forecasting methodologies outlined in the *2021 Electricity Demand Forecasting Methodology Information Paper* (Methodology Information Paper)[71] published in September 2021. Where practical, AEMO aligns methods used to develop the electricity consumption and demand forecasts for both the NEM and the WEM. A summary of the forecast methodologies for this WEM ESOO is provided in Appendix A1.

AEMO will continue to evolve its forecasting methodology to reflect market developments, emerging trends, and stakeholder feedback[72].

3.3 Supporting forecasts

AEMO engages specialist external consultants to develop supporting forecasts to provide inputs to the in-house demand and consumption forecasts, including forecasts for DER, economic growth outlook (gross state product [GSP]), population and energy efficiency.

To align forecast methodology development with the development cycle of the 2023 IASR, AEMO has changed the timing for developing new supporting forecasts, with a more focused approach to review and update inputs in the second half of this year, ahead of a formal consultation process with stakeholders that will commence in December 2022 for the 2023 IASR.

For this WEM ESOO, AEMO continued to apply the supporting forecasts from the 2021 IASR used in the 2021 WEM ESOO, rebased to reflect current actuals, where practical.

More information on the consultant forecasts for DER, GSP, population and energy efficiency are in the sections below. AEMO updated other supporting forecasts including the residential electricity connection and prospective LIL forecasts.

Appendix A2 details the supporting forecasts' methodologies.

3.3.1 DER forecasts

AEMO commissioned two external consultants, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Green Energy Market (GEM), to develop the 2021 WEM ESOO DER forecasts as part of the 2021 IASR. The separate forecasting models developed by these consultants provided AEMO with a broader spectrum of expected DPV and battery storage uptake to consider across the forecast scenarios.

Table 12 summarises the approach applied to develop the 2022 WEM ESOO DER forecasts by rebasing the 2021 WEM ESOO DER forecasts and making changes to the mapping of DER scenarios for this WEM ESOO development[73].

[70] Prior to 2020, AEMO engaged consultants to develop annual peak demand and operational consumption forecasts for WEM ESOOs.

[71] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/electricity-demand-forecasting-methodology.pdf.

[72] AEMO recently initiated a consultation for forecasting assumptions update for ESOO. At https://aemo.com.au/consultations/current-and-closed-consultations/2022-consultation-on-forecasting-assumptions-update.

[73] Low, expected, and high demand growth scenarios are named slow growth, net zero, and rapid decarbonisation respectively in CSIRO's and GEM's reports. In addition to the scenarios, CSIRO and GEM developed forecasts for current trajectory, sustainable growth, and export superpower scenarios. These scenarios were not used in this 2022 WEM ESOO.

Compared to the 2021 WEM ESOO DER forecasts, the 2022 WEM ESOO DER forecasts:

- Replaced the average of CSIRO and GEM *Current Trajectory* forecast with the average of CSIRO and GEM *Net Zero 2050* forecast for the expected DPV and distributed battery storage uptake scenario.
- Replaced the GEM *Slow Growth* forecast with the CSIRO *Slow Growth* forecast for the low DPV and distributed battery storage uptake scenario.
- Replaced the CSIRO *Current Trajectory* forecast with the rebased CSIRO *Net Zero 2050* forecast for the expected EV uptake forecast.

Table 12 Developing the 2022 WEM ESOO DER forecast[A]

DER	Updating approach	Low	Expected	High
DPV	Rebased the 2021 WEM DPV forecasts by shifting the consultants' forecasts to match current installations as of March 2022[B]	CSIRO *Slow Growth*	Average of CSIRO and GEM *Net Zero 2050*	CSIRO *Rapid Decarbonisation*
Distributed battery storage	Not rebased due to lack of reliable data source for current installations	CSIRO *Slow Growth*	Average of CSIRO and GEM *Net Zero 2050*	CSIRO *Rapid Decarbonisation*
EV	Rebased the 2021 WEM DPV forecasts by shifting the consultant's forecast to match with actual vehicle count as of December 2021[C]	CSIRO *Slow Growth*	CSIRO *Net Zero 2050*	CSIRO *Rapid Decarbonisation*

A. The CSIRO and GEM developed the 2021 WEM DER forecasts using the scenario names released in Draft 2021 IASR webinar. See Table 10 for details.
B. Estimated based on the Clean Energy Regulator (CER) numbers with minor adjustments by AEMO combined with AEMO estimates of PVNSG installations.
C. EV actual uptakes as estimated by the Electric Vehicle Council (EVC) to December 2021, known to be approximate only, but considered by the EVC to be a reasonable estimate.

3.3.2 GSP and population forecasts

AEMO engaged BIS Oxford Economics (BIS Oxford) to provide forecasts for WA GSP and population[74]. AEMO rebased the WA GSP using actuals published by Australia Bureau of Statistics (ABS) and continued to apply the 2021 projected annual growth rates from 2022 onwards.

While keeping the population growth projection unchanged for this WEM ESOO, AEMO forecast the residential connections by using updated Synergy residential connections, together with BIS Oxford's dwelling construction forecasts for this WEM ESOO.

3.3.3 Energy efficiency forecasts

AEMO commissioned Strategy. Policy. Research. Pty Ltd (SPR)[75] to provide energy efficiency forecasts for the 2021 WEM ESOO. For this WEM ESOO, AEMO rebased the forecasts relative to the 2021-22 base year, to remove future energy savings from activities occurring prior to and in 2021-22. For the residential forecast, this entailed netting off the 2021-22 value from each year of the forecasting period. For the business forecast, AEMO used estimated actual energy savings from SPR to calculate an historical trend of energy savings and project this trend in the forecasting period. The trend was then netted off from the forecast for each year of the outlook period, leaving only energy savings from activities projected to occur after the 2021-22 base year.

[74] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf.

[75] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/strategy-policy-research---energy-efficiency-forecasts-2021.pdf.

4 Distributed energy trends and forecasts

WA has one of the highest levels of installed DPV capacity in the world. During daylight hours, with clear sky conditions, DPV is the largest single generator in the SWIS. As of March 2022, the SWIS had 2,042 MW of DPV capacity installed. Approximately 357 MW of DPV capacity was installed in 2020-21, a slight increase compared to the previous Capacity Year.

Distributed battery storage capacity continues to increase, reaching a total installed capacity of 14.8 MWh as of March 2022. Distributed battery storage is forecast to reach an installed capacity of 2.5 gigawatt hours (GWh) in 2031-32.

The EV uptake is forecast to increase across the outlook period, with more than 340,000 EVs projected to be on the road in the SWIS in 2031-32.

4.1 DPV and battery storage trends

4.1.1 Installed capacity

DPV uptake continues with an additional 357 MW of DPV capacity estimated to have been installed in 2020-21 (see Figure 5). The total installed DPV capacity, which includes rooftop PV and PV non-scheduled generation (PVNSG) in the SWIS, reached 2,042 MW[76] as of March 2022. This represents a capacity greater than the sum of capacities of the six largest generators[77] in the SWIS. As of March 2022, over 340,000 systems[78] have been installed[79] and there is ongoing growth in DPV installations across WA dwellings.

A total of 1.9 MWh of battery capacity was installed in the SWIS in 2020-21, a notable drop from the quantity of capacity (6.8 MWh) installed in 2019-20. Nevertheless, the additional 1.3 MWh of battery capacity estimated to have been installed between the start of 2021-22 and the end of March 2022 suggests there will be a greater uptake in 2021-22.

Figure 6 shows the monthly DPV installation and distributed battery storage between the start of 2020-21 and February 2022. The average monthly installation rate of DPV is estimated to be 28.3 MW. A notable drop is observed for January and February 2022, with monthly installations of no more than 23 MW. Battery storage is estimated to have an average monthly installation rate of 0.17 MWh, with peak installations occurring in November 2021 with more than 0.35 MWh installed. As of March 2022, total residential battery storage capacity exceeded 14.8 MWh, a 27.6% increase from October 2020.

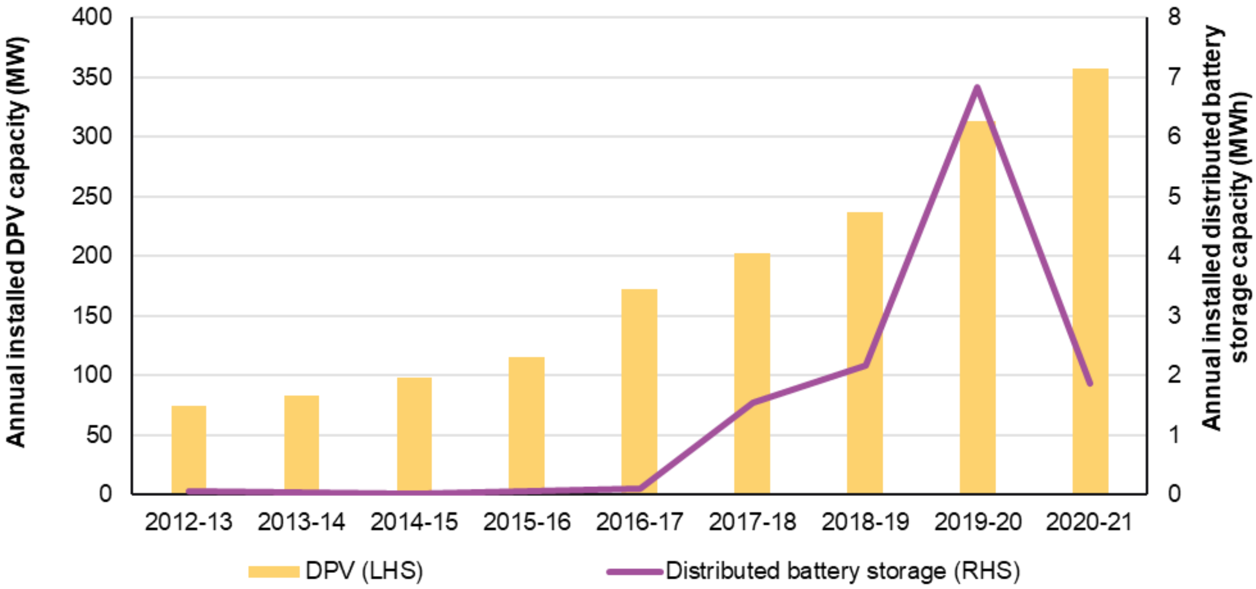
[76] DPV installations as at March 2022 based on CER data with minor adjustments by AEMO.

[77] Refer to Table 36 in Appendix A10.

[78] Data is as of April 2022 sourced from WA DER Register.

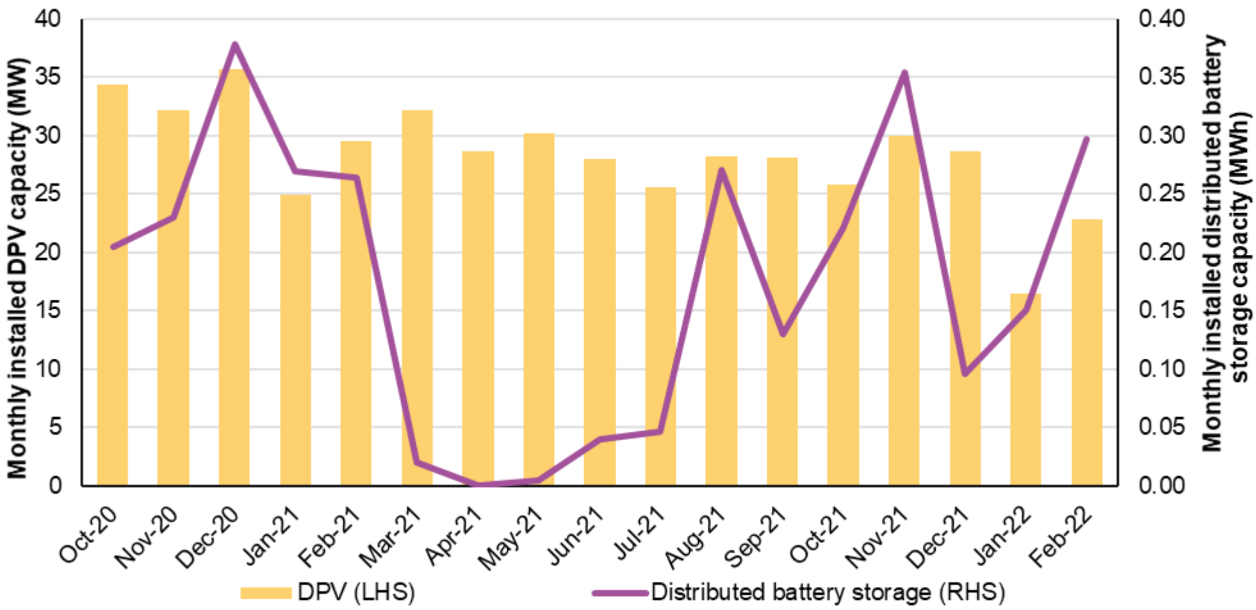
[79] Includes installations larger than 100 kW that are not registered as Facilities in the SWIS.

Figure 5 Annual installed capacity of DPV and battery storage, 2012-13 to 2020-21[A]



A. DPV data from the CER, with minor adjustments by AEMO. Battery storage installation data as of April 2022, WA DER Register, at https://aemo.com.au/energy-systems/electricity/der-register/data-der/data-dashboard.

Figure 6 Monthly installed capacity of DPV and battery storage, October 2020 to February 2022[A,B]

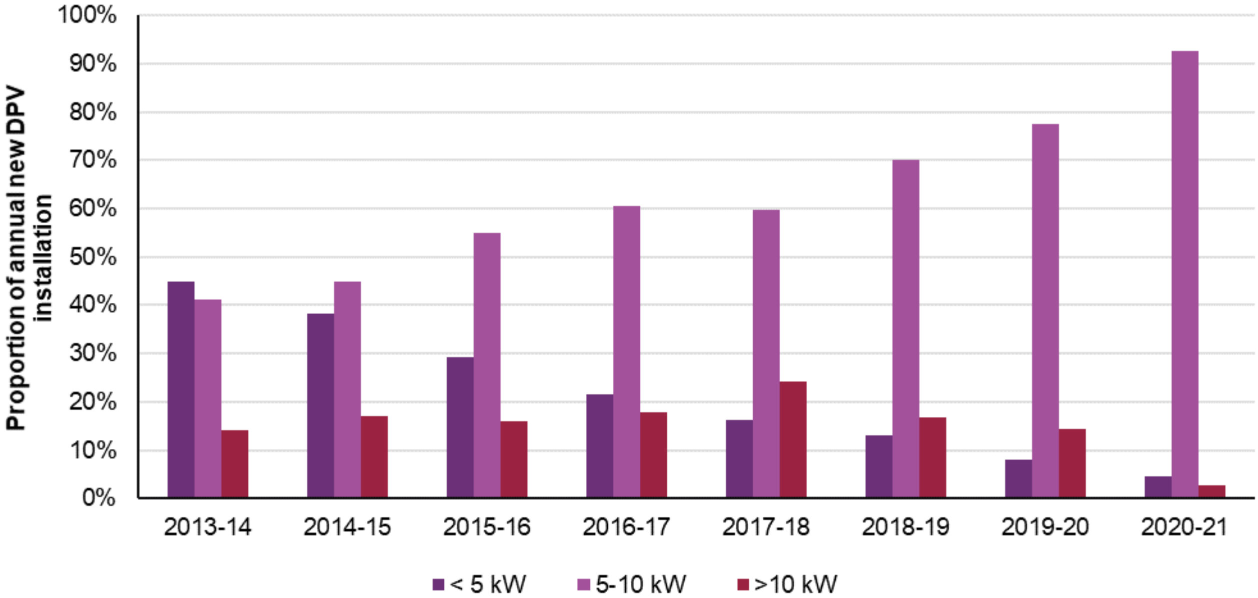


A. DPV data from the CER, with minor adjustments by AEMO. Battery storage installation data as of April 2022, WA DER Register.
B. Energy is a measure of power over time, so the quantity of stored energy is measured in MWh.

4.1.2 Installed DER system size

It is evident that the size of the DPV systems installed over the past eight years has changed, from systems with a capacity of less than 5 kilowatts (kW), to systems with a capacity between 5 kW and 10 kW. Figure 7 details the share of new DPV installations by system size and Capacity Year from 2013-14 onwards in the SWIS. DPV systems smaller than 5 kW dominated in 2013-14 but have since been displaced by systems sized between 5 kW and 10 kW. In 2020-21, 92.6% of the total number of DPV systems installed were sized between 5 kW and 10 kW.

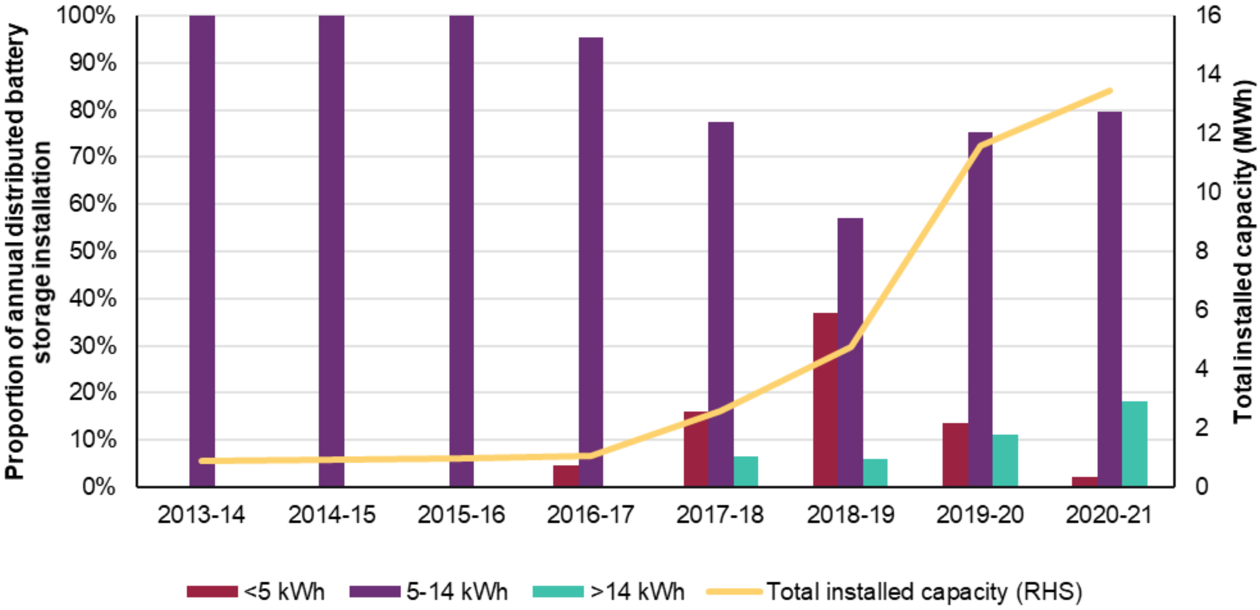
Figure 7 Proportion of annual new DPV installation by system size, 2013-14 to 2020-21[A]



A. Data as of April 2022, WA DER Register.

Battery storage systems installed in the SWIS are typically sized between 5 kilowatt hours (kWh) and 14 kWh, a size range representing 79.5% of the total number of battery installations that occurred in 2020-21. Figure 8 shows that the proportion of smaller sized battery storage installations (less than 5 kW) has decreased from 36.9% of installations during 2018-19 to 1.1% of battery installation during 2020-21, while installations of battery storage systems with a storage capacity greater than 14 kWh have increased from 6.4% of total installations during 2017-18 to 18.4% of total installations in 2020-21.

Figure 8 Proportion of annual distributed battery storage installation by system size, 2013-14 to 2020-21[A]



A. Data as of April 2022, WA DER Register.

4.2 DER forecasts

The 2022 WEM ESOO DER forecasts were developed by rebasing the 2021 WEM ESOO DER forecasts developed by CSIRO[80] and GEM[81] and making changes to the mapping of DER scenarios. AEMO rebased the DPV to match current installations as of March 2022 and EV forecasts to match with the actual vehicle count as of December 2021[82], while no change has been made to the distributed battery storage forecast[83].

Further details on the DER scenario mapping and rebase methodology are available in Section 3.3.1 of this WEM ESOO. A summary of the DER forecast methodologies is provided in Appendix A2.4. Further information on the methodology and assumptions for the DER forecasts are provided in the CSIRO and GEM reports.

4.2.1 DPV forecasts

Installed capacity forecasts

The rebased DPV installed capacity forecasts for the low, expected, and high demand growth scenarios are presented in Figure 9. Total DPV installed capacity is forecast to grow:

- In the low demand growth scenario at an average annual rate of 5.6% (178 MW), to reach 4,143 MW in 2031-32, up from 2,542 MW in 2022-23.
- In the expected demand growth scenario at an average annual rate of 7.0% (238 MW), to reach 4,716 MW in 2031-32, up from 2,575 MW in 2022-23
- In the high demand growth scenario at an average annual rate of 7.8 % (308 MW), to reach 5,658 MW in 2031-32, up from 2,883 MW in 2022-23.

Overall, the DPV installed capacity is forecast to grow more slowly for the low and high demand growth scenarios than in the 2021 WEM ESOO, largely influenced by lower growth in DPV uptake in 2021-22 than was forecast in the 2021 WEM ESOO. This has lowered the starting point of the rebased DPV forecasts for the three scenarios from 2022-23. AEMO attributes the slower DPV uptake in 2021-22 to factors such as steeper panel prices, COVID-19 disruptions, and the global supply chain crunch[84].

DPV installed capacity is forecast to grow at a similar average annual growth rate in the expected demand growth scenario in this WEM ESOO, similar to the 2021 WEM ESOO forecast, despite the lowered starting point for the rebasing. This is largely due to a change in the DER scenario mapping. The expected demand growth scenario has changed from the *Current Trajectory* scenario in the 2021 WEM ESOO to the *Progressive Change* scenario for this WEM ESOO[85]. A stronger growth forecast for the *Progressive Change* scenario has largely offset the lower rebasing point for the DPV uptake forecast under the expected demand growth scenario.

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[80] CSIRO developed the 2021 DPV, battery storage, and EV forecasts, Small-Scale Solar and Battery Projections 2021. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf; CSIRO, 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.

[81] GEM developed the 2021 DPV and battery storage forecasts. 2021 GEM DER report. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf.

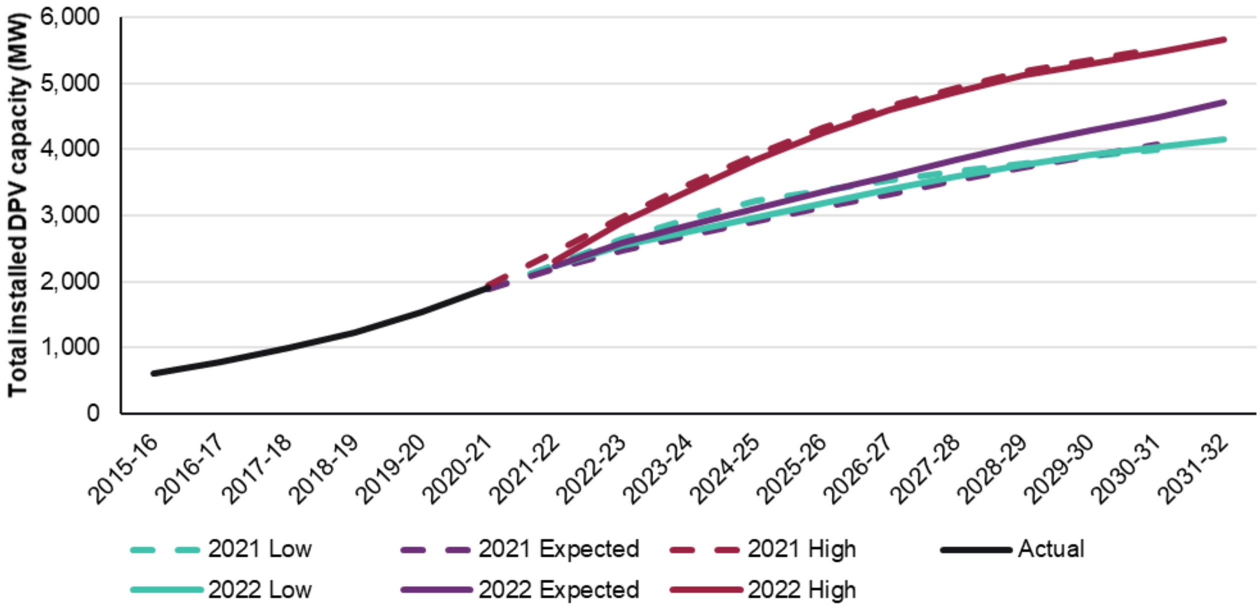
[82] EV uptake data for 2021 as estimated by the Electric Vehicle Council (EVC), known to be approximate only, but considered by the EVC to be a reasonable estimate.

[83] The distributed battery storage forecast was not rebased due to lack of reliable data source for current installations.

[84] See https://www.afr.com/companies/energy/rooftop-solar-growth-expected-to-slow-in-2022-20220218-p59xrw.

[85] See Chapter 3 of this WEM ESOO for further information.

Figure 9 Total DPV installed capacity forecasts under three demand growth scenarios compared to actuals, 2015-16 to 2031-32[A,B]



A. The total installed DPV capacity represents the sum of rooftop PV and PVNSG installed capacity.
B. The DPV installed capacity for 2021-22 was based on the actual data as of March 2021 and AEMO's forecast for the period April to September 2022.
Source: CSIRO and GEM.

4.2.2 Distributed battery storage forecasts

The main driver for customers to install battery storage is to store excess DPV generation and maximise financial returns from DPV generation. The installed distributed battery storage capacity forecasts for the low, expected, and high demand growth scenarios are shown in Figure 10.

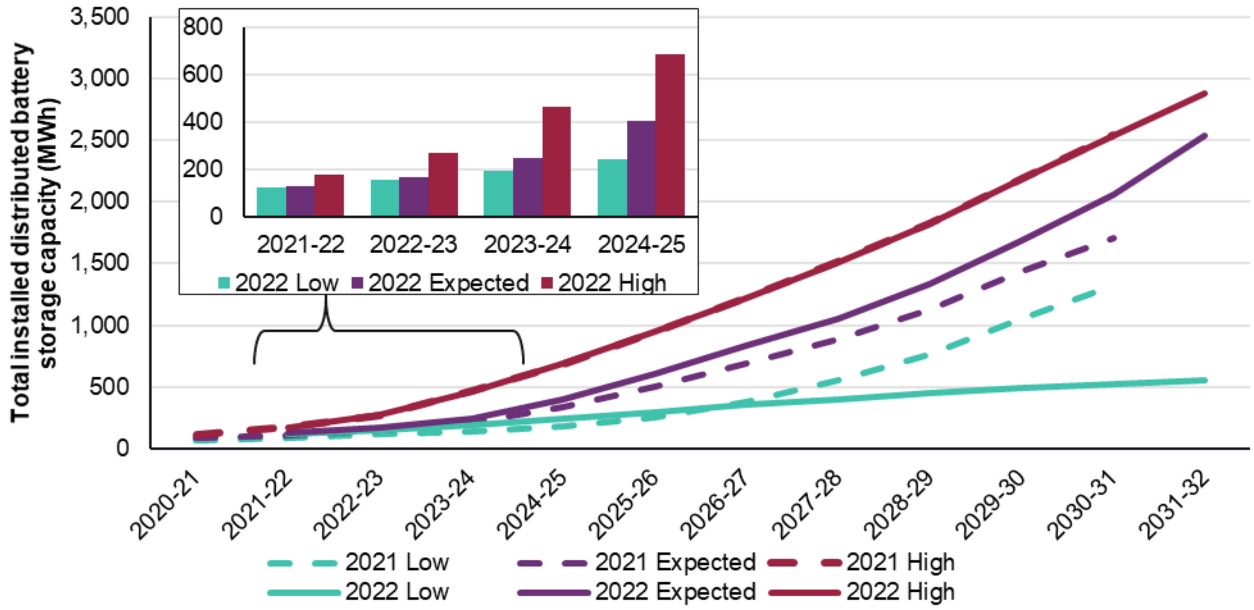
The distributed battery storage installed capacity is forecast to grow:

- In the low demand growth scenario at an average annual rate of 15.4%, to reach 558 MWh in 2031-32, up from 153 MWh in 2022-23.
- In the expected demand growth scenario at an average annual rate of 35.3%, to reach 2,541 MWh in 2031-32, up from 167 MWh forecast in 2022-23.
- In the high demand growth scenario at an average annual rate of 30.0%, to reach 2,874 MWh in 2031-32, up from 271 MWh in 2022-23.

Overall, the forecast installed distributed battery storage capacity is higher in the low and expected scenario in this WEM ESOO compared to the 2021 WEM ESOO forecast over the outlook period, due to the changes in the scenario mapping (see Chapter 3 for further information). The forecast for the high demand growth scenario remains unchanged in this WEM ESOO compared to the 2021 WEM ESOO forecast.

The consumption forecast for this WEM ESOO considered the efficiency losses of batteries charging and discharging when developing the consumption forecasts. Round-trip efficiencies were assumed as 85% and 90% for the battery storage forecasts developed by CSIRO and GEM, respectively.

Figure 10 Total installed distributed battery storage capacity under three demand growth scenarios, 2021-22 to 2031-32[A,B]



A. Cumulative installed capacity forecasts account for degradation of battery performance over time. Data includes degradation of distributed battery storage capacity.
B. Inset plot only displays 2022 WEM ESOO forecasts.
Source: CSIRO and GEM.

CSIRO developed the daily charge and discharge profile for distributed batteries. The profiles were based on historical solar irradiance, assuming batteries primarily charge from excess DPV generation. AEMO modelled the contribution of batteries to peak demand by including batteries as a dependent variable in the half-hourly modelling of weather conditions, seasonal effects, and random volatility, in a similar manner to DPV.

The demand forecasts consider operation of distributed batteries under a combination of flat and time-of-use tariffs[86] and applied a battery operating strategy to minimise household/commercial business bills without any concern for whether the aggregate outcome is also optimised for the electricity system.

Battery discharge profiles applied for the demand forecasts for this WEM ESOO remain unchanged from the 2021 WEM ESOO[87].

4.2.3 EV uptake forecasts

The rebased forecasts for EV uptake include battery EVs (BEVs) and plug-in hybrid EVs (PHEVs). For each type, the projected EV uptake for vehicle classes includes residential, light commercial, and heavy commercial such as buses and trucks.

Consistent with the 2021 WEM ESOO EV uptake forecasts, the rebased projections for EV uptake for this WEM ESOO continue to assume a slow start, due to limited public charging infrastructure, and the narrow range of models currently available, and the higher cost relative to vehicles with internal combustion engines (ICE).

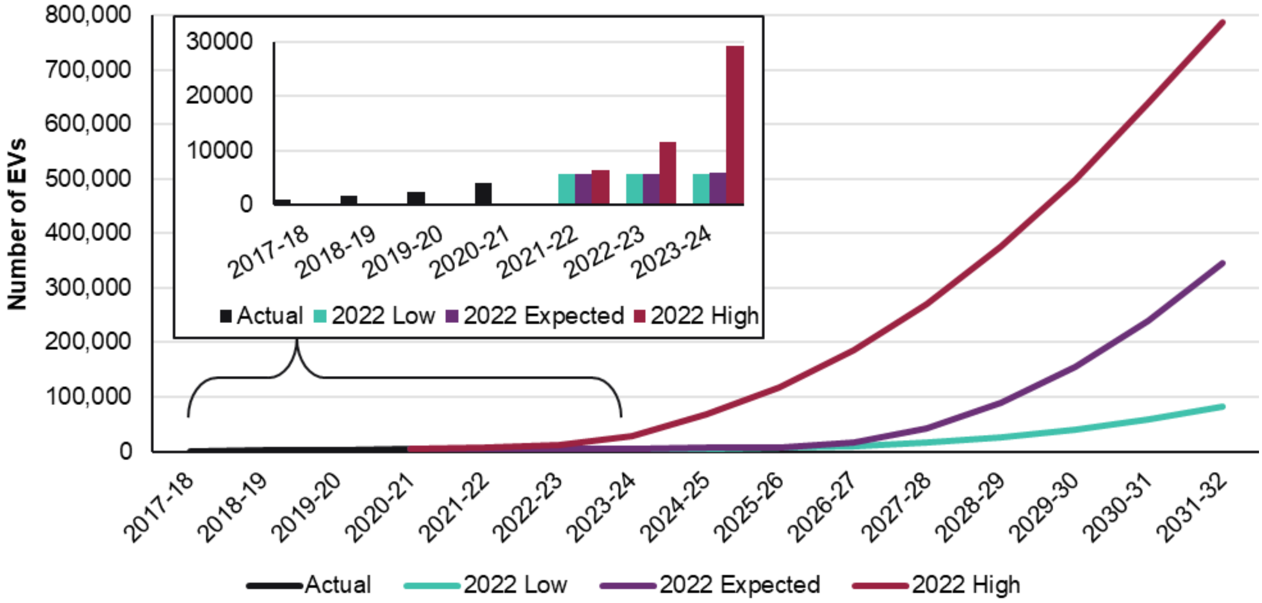
[86] Time-of-use tariffs can provide cost-reflective pricing signals that reflect the costs to service the peak.
[87] See Section 4.2.2 of the 2021 WEM ESOO for further information.

EV number forecasts

Figure 11 shows the rebased forecasts of EV numbers in the SWIS for the low, expected, and high demand growth scenarios. In summary:

- In the low demand growth scenario, EV numbers are forecast to grow at an average annual rate of 34.7%, to reach 81,566 in 2031-32, up from 5,572 in 2022-23.
- In the expected demand growth scenario, EV numbers are forecast to grow at an average annual rate of 57.8%, to reach 346,781 in 2031-32, up from 5,704 in 2022-23.
- In the high demand growth scenario, EV numbers are forecast to grow at an average annual rate of 59.7%, to reach 787,244 in 2031-32, up from 11,645 in 2022-23.

Figure 11 Number of EVs in SWIS under three demand growth scenarios compared to actuals,2017-18 to 2031-32[A,B]



A. Includes BEVs and PHEVs. BEVs only have electric motors (that are solely battery-powered), while PHEVs have both petrol engines and electric motors. Both BEVs and PHEVs can recharge their batteries at a power outlet.
B. Inset plot only displays the 2022 WEM ESOO forecasts.
Source: EVC (uptake data for 2021 as estimated by the EVC, known to be approximate only, but considered by the EVC to be a reasonable estimate), AEMO, and CSIRO.

The range in forecast EV uptake across the low, expected, and high scenarios is driven by similar assumptions as outlined in Section 4.2.3 of the 2021 WEM ESOO, including[88]:

- Economic drivers, including timing of cost parity of short-range EV with ICE for the low demand growth scenario in 2035, for the expected demand growth scenario in 2030, and for the high demand growth scenario in 2025.
- Infrastructure drivers, including the level of growth in apartment share of dwellings.
- Business models, covering aspects such as the level of affordable public charging availability.
- EV policy settings, including timing of ICEs becoming unavailable and timing of achieving 100% EV sales of new car sales.

[88] See the 2021 CSIRO EV Report for further information: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf.

On 10 May 2022, the WA Government announced[89] the Clean Energy Car Fund, including $3,500 rebates on the purchase of EV and hydrogen vehicles, and a commitment to increase EV charging infrastructure. As noted with DPV, government policies can have a significant influence on technology uptake.

AEMO notes that while the WA Government announcement is relevant in enabling the transition to more zero emissions vehicles, it may not have a rapid impact on the EV uptake in the near term. As such, AEMO has not updated its EV forecasts for this ESOO, but will continue to monitor developments in this area in future ESOOs.

EV charging profiles applied for the demand forecasts for this WEM ESOO remain unchanged from the 2021 WEM ESOO, including convenience charging, fast charging or highway charging, day charging and night charging (see Section 4.2.3 of the 2021 WEM ESOO for further information).

As EV uptake increases, effective management of the impact of EVs on peak demand will require a more detailed understanding of consumer driving and charging behaviour, how controlled charging incentives may affect that behaviour, and opportunities for consumers to participate in demand response management or provide grid services. AEMO will continue to monitor trends in EV uptake and charging patterns. Assumptions regarding EV impact on peak demand will be updated in future WEM ESOOs as the market penetration level changes.

[89] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/05/WAs-climate-action-efforts-accelerate-with-60-million-dollar-EV-package.aspx.

5 Demand trends and forecasts

The 2021-22 operational peak demand (3,984 MW) was the second-highest annual peak since the WEM commenced in 2006. This was driven by two consecutive days with maximum ambient temperatures above 41°C and high overnight temperatures. Peak demand is forecast to increase at an average annual rate of 0.9% over the 10-year outlook period in the expected demand growth scenario.

Minimum demand records continue to be reset, with five new demand lows occurring since the 2021 WEM ESOO. This trend is driven by ongoing growth in DPV generation.

5.1 Demand trends

5.1.1 Peak demand

The 2021-22 summer operational peak demand[90] of 3,984 MW occurred in the Trading Interval commencing at 18:00 on 19 January 2022. It is the second highest annual peak demand since the WEM commenced in 2006.

The underlying peak demand[91] of 4,411 MW occurred two days later, on 21 January 2022. This is the highest underlying peak demand on record. It is the third time operational and underlying peak demand Trading Intervals have not occurred on the same day since 2006[92].

Key observations in the 2021-22 summer operational and underlying peak demand compared to the 2020-21 summer (see Table 13 and Figure 12) include:

- The peak was 195 MW (5%) higher than 2020-21, as a result of a higher underlying peak demand during the day, primarily driven by higher overnight temperatures up to 33.3°C.
- The underlying peak demand was 241 MW (6%) higher than 2020-21, resulting from four consecutive days in a row with daily maximum temperatures exceeding 41°C.

Perth experienced the hottest summer on record in 2021-22[93] and the number of Trading Intervals with temperatures above 40°C increased to 82 from 25 in the previous summer. This resulted in the extremes observed in both the operational and underlying peak demand, as well as a higher average operational and underlying demand over the 2021-22 summer period[94]. The increase is driven largely by higher demand for cooling from the residential sector.

[90] The peak demand is identified as the highest operational demand calculated for a Capacity Year (see Chapter 3 for the definition of operational demand).

[91] 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.

[92] The first time was in 2013-14, and the second in 2018-19. See https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2019/2019-WEM-ESOO-report.pdf.

[93] See http://www.bom.gov.au/climate/current/season/wa/perth.shtml.

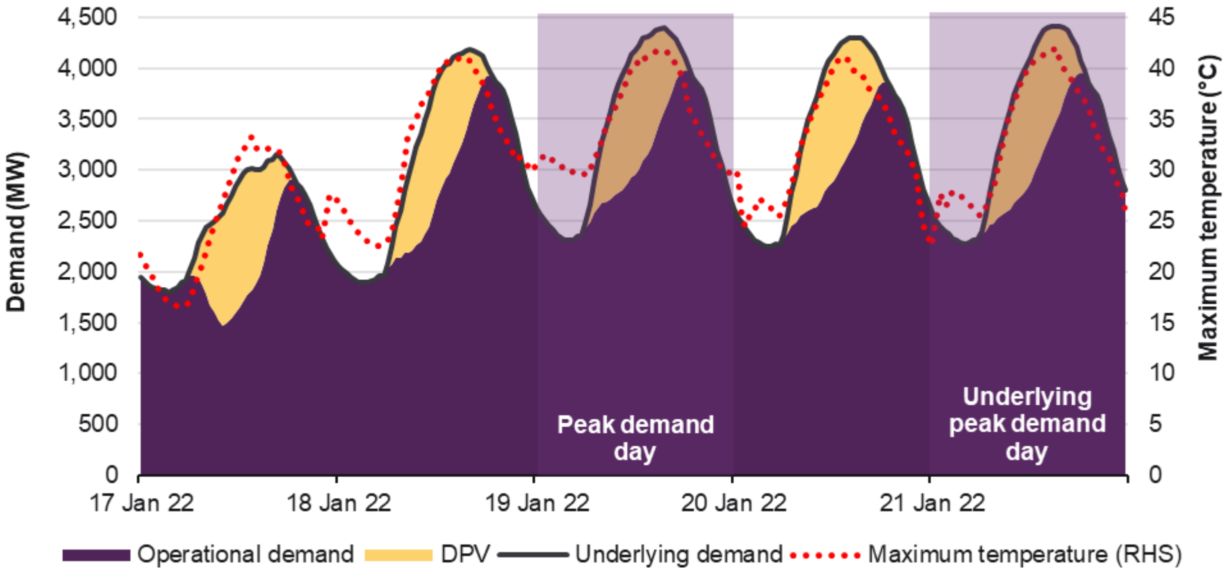
[94] For the 2021-22 summer, the average operational demand is 2,133 MW and the average underlying demand is 2,541 MW. They are 1.4% and 4.9% higher, respectively, than the previous summer.

Table 13 Comparison of annual peak demand days (19 January 2022 and 8 January 2021) and underlying peak demand days (21 January 2022 and 8 January 2021)A

Event	Date	Daily maximum operational demand		Daily maximum underlying demand		Temperature (°C)			Peak demand reduction from PV[D] (MW)	Peak demand reduction from peak time shift (MW)
		Trading Interval	MW	Trading Interval	MW	Daily maximum	Moving average[B]	Overnight minimum[C]		
2021-22 peak demand	19 January 2022	18:00	3,984	15:30	4,393	41.8	38.7	29.7	122	287
2021-22 underlying peak demand	21 January 2022	18:00	3,953	15:30	4,411	42.0	41.7	22.6	124	335
2020-21 Operational and underlying peak demand	8 January 2021	18:00	3,789	14:00	4,170	41.5	38.8	21.9	81	300

A. Based on data as of 31 March 2022.
B. Calculated based on a three-day moving average of maximum temperatures.
C. Minimum temperature recorded between 20:00 to 4:30 Trading Intervals.
D. The difference between the peak demand and the daily maximum underlying demand.
Sources: AEMO, Bureau of Meteorology (BOM), CER, and Solcast.

Figure 12 Demand and temperature profiles for a five day period covering the peak demand day (19 January 2022) and underlying peak demand day (21 January 2022)



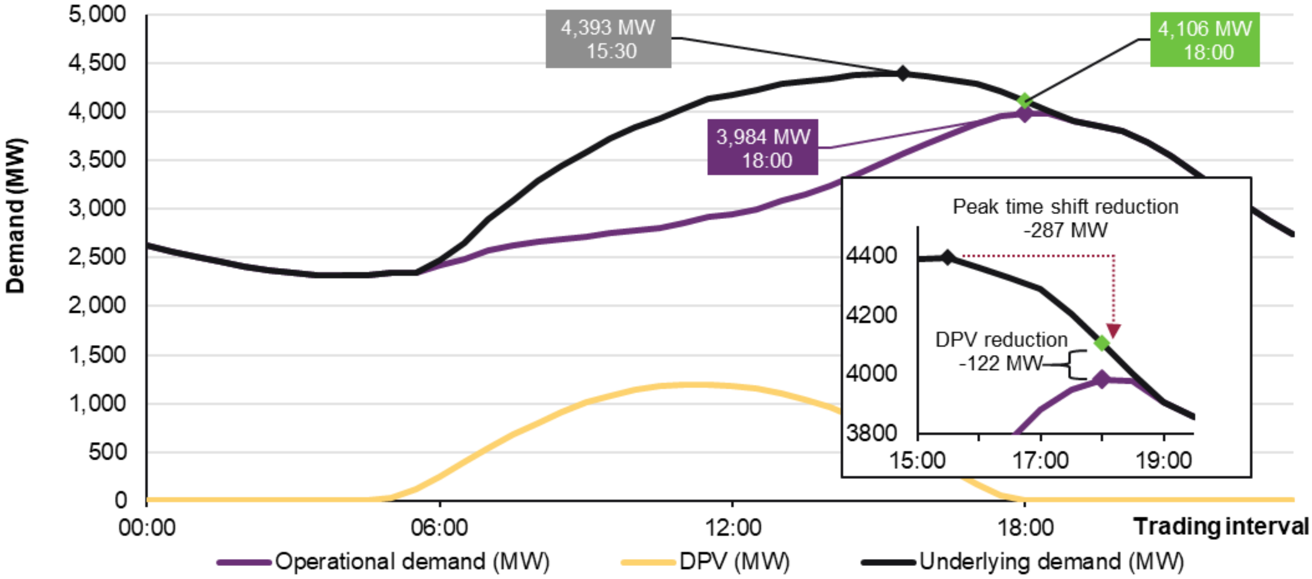
Source: AEMO, BOM, CER and Solcast.

Figure 13 compares the operational and underlying demand profiles on the observed peak demand day (19 January 2022):

- Daily maximum underlying demand is estimated to be 4,393 MW occurred in the Trading Interval commencing at 15:30, two and half hours before the occurrence of the operational peak. The timing of the underlying peak demand followed the hottest time of the day of 42°C at 15:30.

- The difference between the maximum underlying and operational demand is approximately 409 MW. Of this difference, 287 MW was caused by DPV generation reducing operational demand during Trading Intervals that followed underlying peak demand (peak demand time-shift effect) and 122 MW was caused by DPV generation reducing operational demand at the Trading Interval of peak demand (direct DPV reduction).

Figure 13 Operational and underlying demand profiles on the observed peak demand day, 19 January 2022



Source: AEMO, BOM, and Solcast.

Seasonal trends and winter peak demand

A peak demand record was observed during the most recent winter season, when a peak demand of 3,537 MW was recorded on 22 June 2021 in the Trading Interval 18:00. This was 2.8% higher than the previous year's winter peak (3,441 MW), setting a new winter peak record since the start of the WEM.

Winter operational peak demand and underlying peak demand are typically identical, because winter peak demand usually occurs at night when there is no effect from DPV generation. The higher winter peak demand in the most recent winter may be attributed to wetter-than-usual winter weather[95], leading to increased demand for heating, compared to the dry and warmer than average winter in 2020[96].

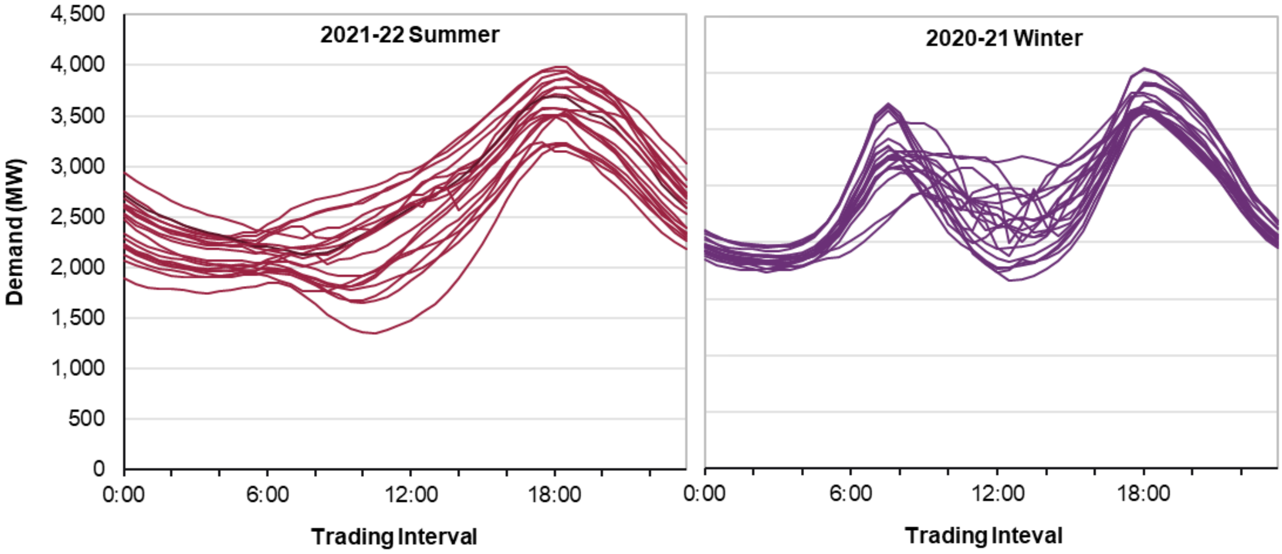
Figure 14 presents a comparison of the hourly variations in demand on the top 20 demand days for the most recent summer and winter seasons. The daily load profiles in the SWIS are typically bimodal[97] with the exception of higher demand days in the summer.

[95] See http://www.bom.gov.au/climate/current/annual/wa/perth.shtml.

[96] See http://www.bom.gov.au/climate/current/season/wa/archive/202008.perth.shtml.

[97] A bimodal distribution appears as a single distribution with two peaks.

Figure 14 Comparison of intraday profiles of top 20 demand days for 2021-22 summer and 2020-21 winter[A]



A. Based on the top 20 peak demand days for the summer for 2021-22 and winter season for 2020-21
Source: AEMO, BOM and Solcast.

5.1.2 Minimum demand

Minimum demand record

Minimum demand events frequently occur around noon time on non-working days in the shoulder season, particularly from September to November, when clear skies are coupled with mild temperatures. Table 14 summarises the five new minimum demand records observed since the 2021 WEM ESOO was published. The current minimum demand record of 765 MW was set during 2021-22, occurring on 14 November 2021.

Minimum demand records continue to be driven by the strong uptake of DPV[98], with increasing contribution of DPV generation to meet underlying demand during the minimum demand Trading Intervals.

Table 14 Minimum demand records since the 2021 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 generation (%)
5 September 2021	12:30	Sunday	871	21.8	1,188	58
23 October 2021	12:30	Sunday	862	25.9	1,225	59
7 November 2021	12:30	Sunday	834	26.3	1,253	60
13 November 2021	12:00	Saturday	821	30.3	1,276	61
14 November 2021	11:30	Sunday	765	32.2	1,253	62

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

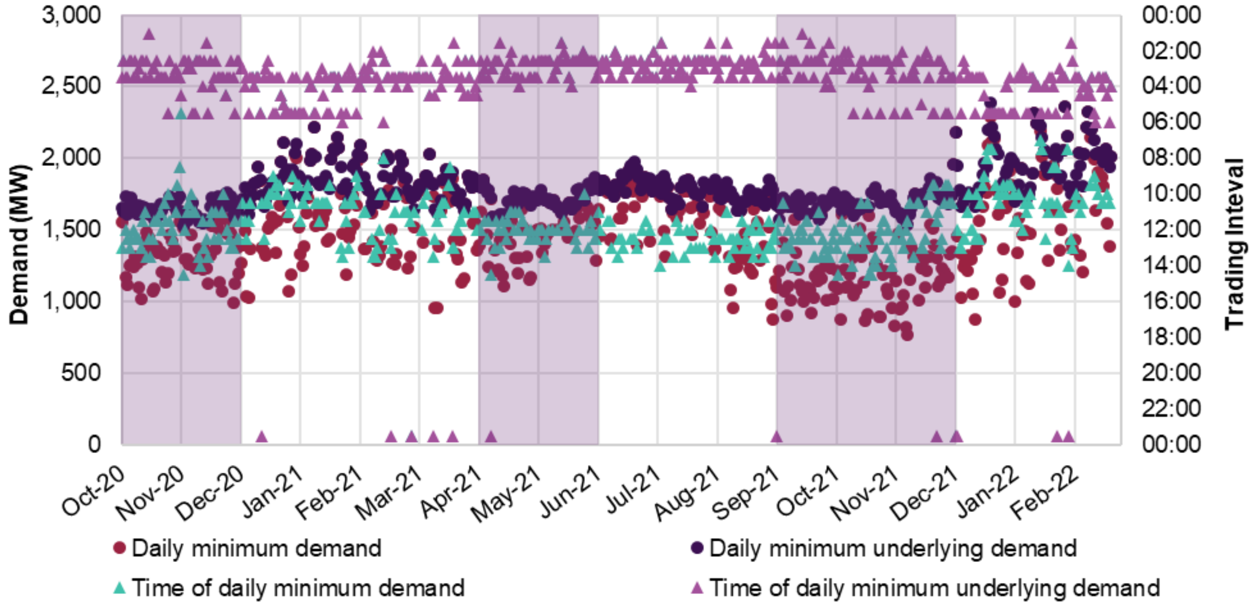
Daily minimum demand

Figure 15 compares the daily operational and underlying minimum demand since the start of 2020-21:

[98] See Chapter 4 for the DPV uptake forecast.

- The variance between daily operational and underlying minimum demand ranged by more than 900 MW, with the difference most pronounced during spring (September to November) when the temperatures were mild.
- From October 2021 to February 2022, DPV was estimated to have reduced minimum demand during daytime hours[99] by 773 MW on average. During this period, the average underlying and operational demand were at 2,736 MW and 1,801 MW, respectively. The greatest reduction in the minimum demand by Trading Interval was 1,333 MW, observed at 12:00 on 9 January 2022 when the underlying demand was 2,333 MW and operational demand was 1,000 MW.
- Daily minimum demand typically occurred around mid-day or varied by one or two hours among the shoulder season (11:30 to 13:00), winter (11:30 to 12:30), and summer (9:30 to 11:00).
- Daily minimum demand was observed to occur more frequently during daytime hours, increasing from 64% of the time in 2019-20 to 75% in 2020-21.

Figure 15 Daily operational and underlying minimum demand, 2020-21 to 2021-22[A]



A. Shaded regions highlight months of shoulder season.
Source: AEMO, CER and Solcast.

5.2 Demand forecasts

5.2.1 Annual peak demand forecasts

Summer peak demand forecasts

Figure 16 shows the 10% POE peak demand forecasts under the low, expected and high demand growth scenarios from 2021 and 2022 WEM ESOOs, together with the actuals from 2015-16 to 2021-22. For the 2022 WEM ESOO forecast scenarios:

[99] In this WEM ESOO, daytime hours means Trading Intervals 08:00 to 16:30.

- In the low demand growth scenario, peak demand is forecast to remain stable over the outlook period[100], as growth in demand from LILs and EVs is offset by the DPV generation and energy discharged from battery storage during peak periods.
- In the expected demand growth scenario, peak demand is forecast to increase at an average annual rate of 0.9%. Forecast growth in demand for the first half of the outlook period is largely driven by increased LIL demand. The long-term trend increases from 2026-27 are due to growth in forecast demand from residential customers and EVs, partially offset by energy discharged from battery storage during peak.
- In the high demand growth scenario, peak demand is forecast to increase at an average annual rate of 2.1%, largely driven by strong growth in the uptake of EVs, residential customer, and LIL demand, despite increased energy discharge from battery storage at the time of peak.

Figure 16 10% POE peak demand forecasts under three demand growth scenarios compared to actuals, 2015-16 to 2021-22

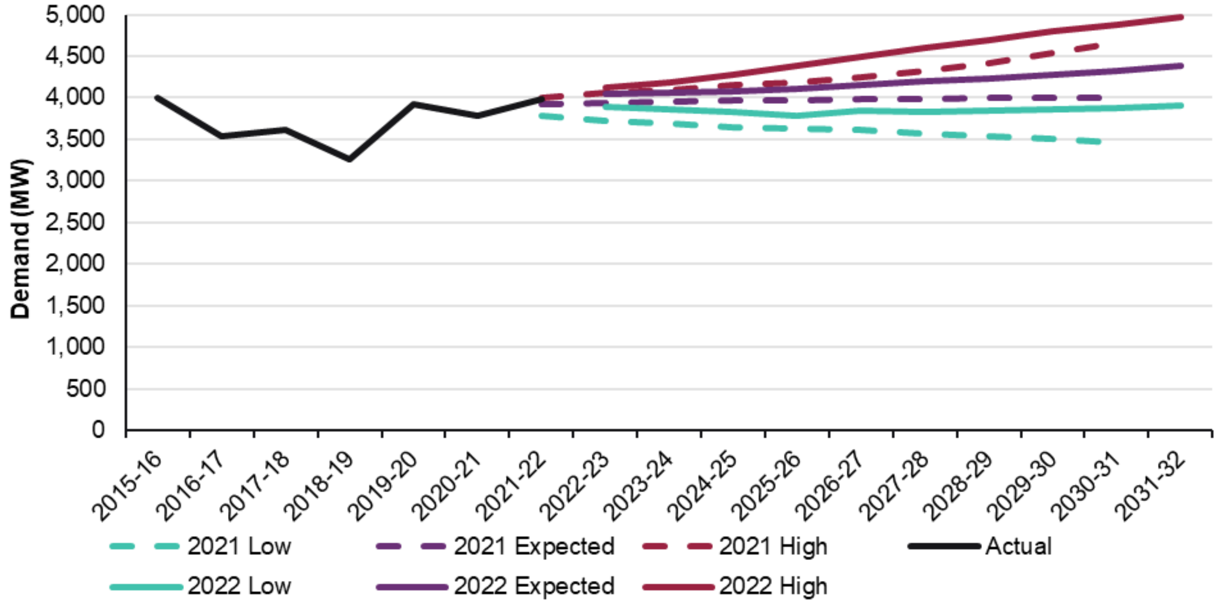


Figure 16 also shows that the 10% POE peak demand forecasts presented in this WEM ESOO for the three demand growth scenarios are higher than the forecasts in the 2021 WEM ESOO. The forecast 10% POE peak demand is 322 MW higher for 2030-31 in this WEM ESOO than in the 2021 WEM ESOO, where the 2030-31 peak demand was forecast to be 4,000 MW. The higher peak demand forecasts in this WEM ESOO are mostly driven by stronger growth in residential load and LILs, coming from growth in household connections and LIL activities. The high 2021-22 summer peak demand[101] also raised the starting point of the demand forecasts[102].

For the projected DER impact on the peak demand forecast across the outlook period in this WEM ESOO:

- DPV – in the expected demand growth scenario, the peak demand reduction from DPV is expected to reduce further over the outlook period[103] compared to the 2021 WEM ESOO. This is despite the installed capacity of

[100] It has an average annual growth rate less than 0.1% over the outlook period.

[101] The 2021-22 summer peak demand is 195 MW higher than 2020-21. See Section 5.1.1 for further information.

[102] See Appendix A2 for further information.

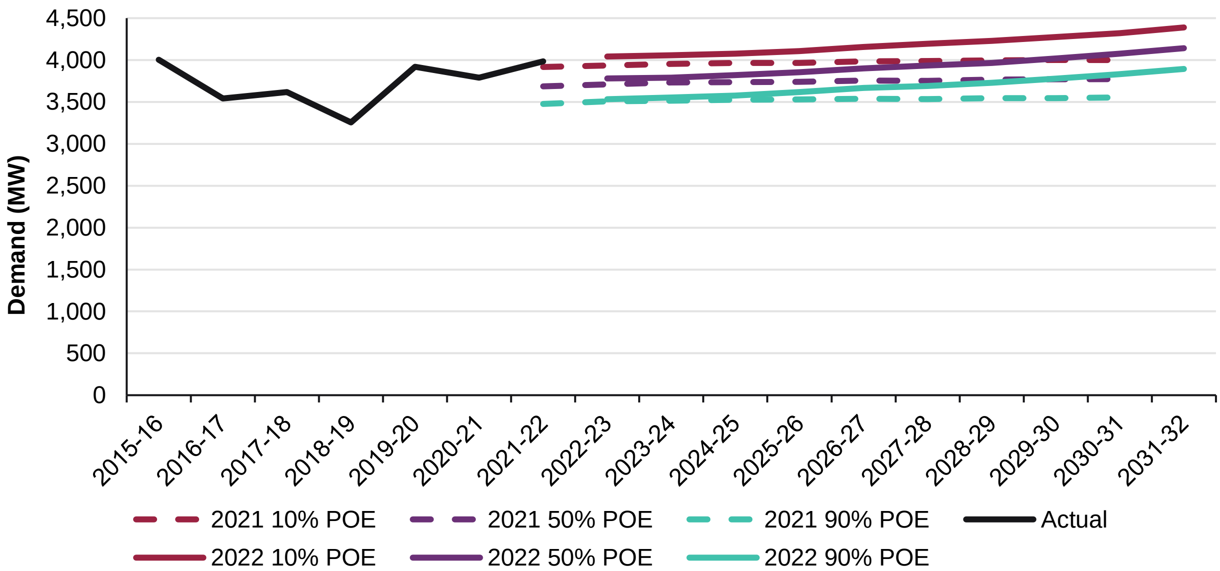
[103] In 2021-22, the DPV capacity factor at the time of peak demand (18:00 to 18:30, 19 January 2022) is estimated to be 6.1%. Peak demand is forecast to be most likely to occur in the Trading Interval 18:30 for 2031-32 under the expected demand growth scenario. The average capacity factor of DPV during the Trading Interval 18:30 for January over the period 2012 to 2021 is 1.5%.

DPV being forecast to more than double[104]. In the high demand growth scenario, peak reduction from DPV generation[105] is forecast to decline faster than the expected demand growth scenario as peak demand is forecast to shift closer to sunset earlier in the outlook period, when solar irradiance is minimal.

- Distributed battery storage – in all demand growth scenarios, battery storage is forecast to reduce peak demand, by discharging after sunset (for customers on flat tariffs) or due to high price signals (for customers on time-of-use tariffs). Distributed energy discharge from battery storage has a greater reduction in peak towards the end of the outlook period due to increasing market penetration. See Chapter 4 for more details.
- EVs – in all demand growth scenarios, EV charging is forecast to increase peak demand. Residential EVs are forecast to be the greatest contributor to peak demand by having a greater share of EVs with the convenience charging profile (which features charging after returning home from work and through the peak periods). EV charging is forecast to increase peak demand, to a greater extent, from the second half of the outlook period under the expected and high demand growth scenarios[106].

Figure 17 shows actual peak demand for the period 2015-16 to 2021-22 and the 10%, 50%, and 90% POE peak demand forecasts for the outlook period under the expected demand growth scenario. All three forecasts show stable growth across the outlook period, with an average annual growth rate between 0.9% and 1.1%.

Figure 17 10%, 50%, and 90% POE peak demand forecasts under the expected demand growth scenario compared to actuals, 2015-16 to 2031-32



The spread among the 10%, 50%, and 90% POE peak demand forecasts remains largely consistent over the outlook period under the expected demand growth scenario.

[104] Under the expected demand growth scenario, the DPV installation is forecast to grow in the SWIS from 2,042 MW to 4,716 MW by 2031-32 in this WEM ESOO.

[105] Under the high demand growth scenario, the DPV installation is forecast to grow in the SWIS from 2,042 MW to 5,658 MW by 2031-32 in this WEM ESOO.

[106] AEMO has incorporated four fixed charging profiles to reflect changing patterns of consumers (see Chapter 4). Over time, it is expected that EV charging will eventually change to mirror the generation profile of low-cost variable renewable energy sources. To account for this, AEMO has modelled three dynamic charging behaviours. Although the proportion of EVs on the convenience charging profile is projected to reduce over time, for the three demand growth scenarios, more than 65% of EVs were assumed to be on the convenience charging profile by 2031-32.

On average, the 50% POE peak demand forecasts are 256 MW lower than the 10% POE peak demand forecasts and 242 MW higher than the 90% POE forecasts.

Winter peak demand forecasts

Winter peak demand is expected to remain lower by an average of 9.4% than summer peak demand throughout the outlook period. This is consistent with historical observations in the SWIS, where annual peak demands are driven by the increased electricity use for cooling during hot weather. In summary, for the 10% POE forecasts (see Appendix A6 for the full set of winter peak demand forecasts):

- In the low demand growth scenario, winter peak demand is projected to stay relatively flat over the outlook period with an average annual growth rate of 0.1%[107], a result of increasing demand from LILs and EV charging being largely offset by a reduction in demand from the residential sector and battery charging.
- In the expected demand growth scenario, winter peak demand is projected to increase at an average annual rate of 1.1% over the outlook period, reaching 4,000 MW in 2031-32, a result of increasing demand from EV charging, LILs, and the residential sector, which is not fully offset by an increase in energy discharge from battery storage during these peak demand periods.
- In the high demand growth scenario, winter peak demand is projected to grow at an average annual rate of 2.2%, reaching 4,504 MW in 2031-32, largely as a result of higher forecasts for EV charging and the residential sector compared to the expected and low demand growth scenarios, despite an increase in energy discharge from battery storage during these peak demand periods.

Peak demand forecast accuracy

The peak demand event was 67 MW higher than the 10% POE demand forecast in the 2021 WEM ESOO for summer 2021-22, and would be just above a forecast 5% POE peak demand, primarily driven by the extreme temperatures for the 2021-22 summer and the number of heatwave events. More heatwaves increase the likelihood of extreme maximum demand. The 67 MW variance is largely attributed to:

- Weather effects – maximum temperature on the day (41.8°C) was towards the higher end of the forecast distribution for daily maximum demand (38°C to 42°C).
- DPV – increased cooling load is partly offset by the high DPV generation (122 MW), which is estimated to be towards the higher end of the forecast distribution for a peak demand event (39 MW to 131 MW).

The peak demand occurred during the 18:00-18:30 Trading Interval, in the middle of the forecast distribution for peak demand timing (between the Trading Interval commencing 17:30 and the Trading Interval commencing 18:30 on a weekday).

5.2.2 Timing of peak demand and Electric Storage Resource Obligation Intervals (ESROI) for 2024-25

The ESROI are a set of eight contiguous Trading Intervals[108] during which an ESR is obligated to be available if participating in the RCM. AEMO must determine the ESROI in accordance with clause 4.11.3A of the WEM Rules for 2024-25[109]. Table 15 shows the Peak Demand Periods determined for the winter, summer, and shoulder

[107] It is forecast to change from 3,520 MW in 2022-23 to 3,548 MW in 2031-32.

[108] Electric Storage Resource Obligation Duration has the same meaning as defined in the WEM Rules.

[109] AEMO may prepare a forecast of the ESROI for the period of 2025-26 to 2031-32 to be published after the 2022 WEM ESOO publication.

season in 2024-25. In determining the Peak Demand Periods, AEMO analysed the timing when peak demand is likely to occur[110] for each season for the 10% POE and 50% POE[111] peak demand forecasts under the expected demand growth scenario[112].

Based on the analysis of the Peak Demand Periods[113], AEMO has determined the ESROI are Trading Intervals 16:30 to 20:00 for 2024-25[114], covering all Peak Demand Periods of the three seasons. As the ESROI require eight contiguous Trading Intervals, the ESROI are set by adding one or two Trading Intervals to either side of the Peak Demand Period. AEMO considers the ESROI spanning from Trading Intervals commencing 16:30 to 20:00 would provide sufficient coverage for the Peak Demand Periods of all seasons, and therefore considers it unnecessary to vary the ESROI seasonally.

Table 15 Trading Intervals in which peak demand is likely to occur during the expected demand growth scenario considering 10% and 50% POE Peak Demand and Peak Demand Period for 2024-25

POE	Summer	Winter	Shoulder
50%	17:30 to 19:30	18:00 to 19:00	18:00 to 19:30
10%	17:30 to 19:00	18:00 to 19:30	17:30 to 18:30
Peak Demand Period	17:30 to 19:30	18:00 to 19:30	17:30 to 19:30

In determining the ESROI, AEMO has also considered the operational requirements of the SWIS. It was identified that the determined ESROI conforms well for Medium Term Projected Assessment of System Adequacy (PASA), as ESR would be available during high demand periods. The ESROI are not operationally relevant for Short Term PASA, as it is performed on blocks of 6-hour periods of the day (as specified in the WEM Rules) that are not lined up to capture the natural peak times of the day.

5.2.3 Minimum demand forecasts

Minimum demand forecasts are presented for a five-year outlook period from 2022-23 to 2026-27. They represent uncontrolled or unconstrained demand, free of market-based solutions that might increase operational demand, including energy storage, coordinated EV charging, and demand side response in periods of low demand[115].

Current operational challenges associated with decreasing minimum demand conditions in the SWIS have been articulated in the WA Government's ETS. AEMO, Energy Policy WA (EPWA), and Western Power are working together to explore solutions to alleviate the operational issues expected to arise from decreasing minimum demand, in addition to the work carried out for Emergency Solar Management (ESM) (see Chapter 8 for more information).

All annual minimum demand events are forecast to occur in the shoulder season, driven by the combination of high DPV generation and lower underlying demand due to milder temperatures. While DPV generation's impact on peak demand is expected to fall, as high demand periods are forecast to occur in the evening, the role of DPV

[110] A minimum of 10% probability threshold is applied to define the Trading Intervals in which peak demand is likely to occur. Results have been provided for the 10% and 50% POE.

[111] A probability density function will be used to determine the period during which peak demand is likely to occur (a set of Trading Intervals defined as the Peak Demand Period). See https://www.wa.gov.au/system/files/2021-04/Meeting%203%2C%202021%20-%20Slides%20-%20ESROI%20WEM%20Procedure.pdf.

[112] See Appendix A1.1 for AEMO's peak demand forecast methodologies.

[113] The forecast shift of peak demand periods towards an early evening is shown in the Peak Demand Period.

[114] These Trading Intervals are the same as the ESROI determined for 2023-24. See https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2021/2021-esroi-analysis.pdf.

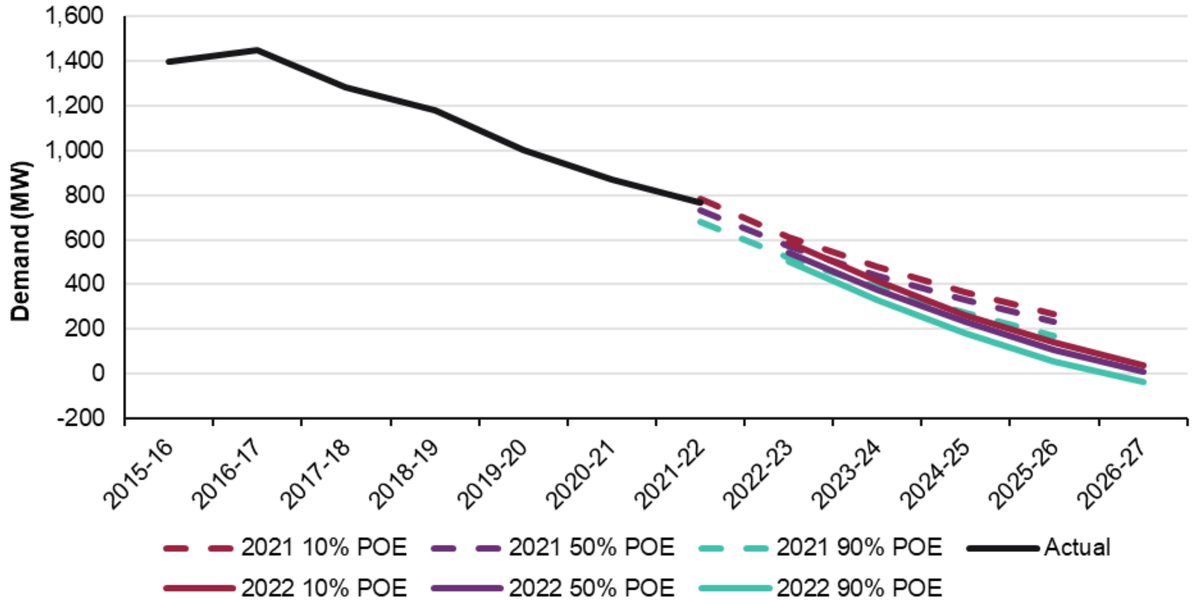
[115] Only non-coordinated, consumer-controlled battery and EV charging is considered in the unconstrained minimum demand forecasts.

generation in reducing operational minimum demand is directly proportional to the growth in installed capacity (see Section 5.1.2).

Annual minimum demand forecasts

Figure 18 shows the 10%, 50%, and 90% POE minimum demand forecasts under the expected demand growth scenario for the period 2022-23 to 2026-27, with actual minimum demand from 2015-16 to 2021-22. The 50% POE minimum demand is forecast to decline rapidly from 546 MW in 2022-23 to 11 MW in 2026-27, at an average annual reduction rate of 62.1%. This is driven by the continued uptake of DPV[116], partially offset by the demand growth in LILs, EV charging, and energy discharge from distributed battery storage.

Figure 18 Minimum demand and 10%, 50%, and 90% POE minimum demand forecasts under the expected demand growth scenario compared to actuals, 2015-16 to 2026-27[A]



A. Actual minimum demand for 2021-22 is a year-to-date value, based on data as of 31 March 2022.

The minimum demand forecasts in this WEM ESOO for the expected demand growth scenario are lower than the forecasts in the 2021 WEM ESOO, largely due to reducing operational demand from higher DPV generation.

Timing of minimum demand

Operational minimum demand events continue to occur through the shoulder season around the months of September to November, strongly influenced by DPV generation. Minimum demand in the expected demand growth scenario is forecast to be most likely to occur from the Trading Interval commencing 11:30 to the Trading Interval commencing 12:30 across the outlook period[117], corresponding to the solar noon[118] when DPV generation is at its peak (on a clear-sky day). This period is consistent with the new minimum demand records set since the 2021 WEM ESOO (see Section 5.1.2).

[116] In the expected demand growth scenario, installed DPV capacity is forecast to increase from 2,574 MW to 3,598 MW between 2022-23 and 2026-27 (see Chapter 4 for further information).

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

[118] Solar noon time is dependent on 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/.

6 Consumption trends and forecasts

Annual operational consumption in 2020-21 increased by 31 GWh (0.2%), while consumption being met by DPV generation grew by 414 GWh (22.0%), compared to the previous Capacity Year. Annual operational consumption is forecast to decline at an average annual rate of 0.3% in the expected demand growth scenario, primarily due to a projected decline in residential and BMM consumption. Consumption is forecast to be lower than the forecast in the 2021 WEM ESOO, because this WEM ESOO projects lower BMM consumption and more underlying consumption being met by DPV[119] during the outlook period.

In this chapter:

- Consumption means operational consumption in all sections, except sections 6.1.2, 6.1.3, and 6.2.3, which specifically discuss end-user underlying, market underlying, delivered and operational consumption.
- Underlying consumption refers to end-user underlying consumption unless otherwise specified.
- The first half of the outlook period refers to the period 2022-23 to 2026-27, and the second half refers to 2027-28 to 2031-32.

6.1 Historical consumption trends

6.1.1 Consumption by sector

Figure 19 shows consumption between 2013-14 and 2020-21 for three sectors – BMM, residential, and LIL consumption. In summary, consumption over this period:

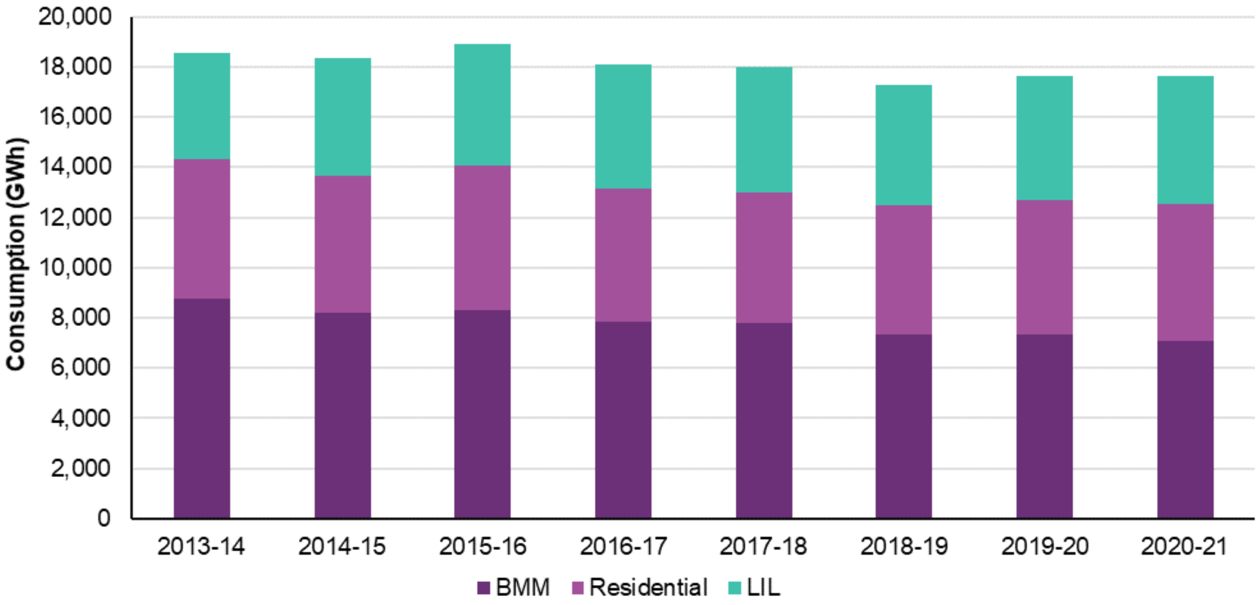
- Increased at an average annual rate of 0.9% between 2013-14 to 2015-16, due to growth in LILs (average annual rate of 7.1%).
- Declined at an average annual rate of 1.7% between 2015-16 and 2019-20, largely due to falling BMM and residential consumption as a result of growth in DPV generation and energy efficiency improvements.
- Increased at an annual rate of 0.2% between 2019-20 and 2020-21, due to an increase in residential and LIL consumption (annual rate of 2.2% and 3.4%, respectively), partially offset by falling BMM consumption (annual decline rate of 3.4%).

Throughout the period, the residential sector's contribution to total consumption remained steady between 30% and 31%, while the BMM share declined from 47% to 40%, and LILs' share increased from 23% to 29%. LIL consumption grew every year except 2018-19, when a heavy storm caused significant maintenance outages at large mines. The strongest growth in LIL consumption was observed between 2013-14 to 2014-15, at 11.9%[120].

[119] Since underlying consumption equals the sum of delivered consumption and DPV, an increase in DPV would decrease delivered consumption, assuming underlying consumption remains constant.

[120] This value is different from the average annual growth rate reported in the 2021 WEM ESOO (13.6%), due to a subsequent reclassification of some National Metering Identifiers (NMIs) from BMM to LIL.

Figure 19 Annual consumption by sector, 2013-14 to 2020-21

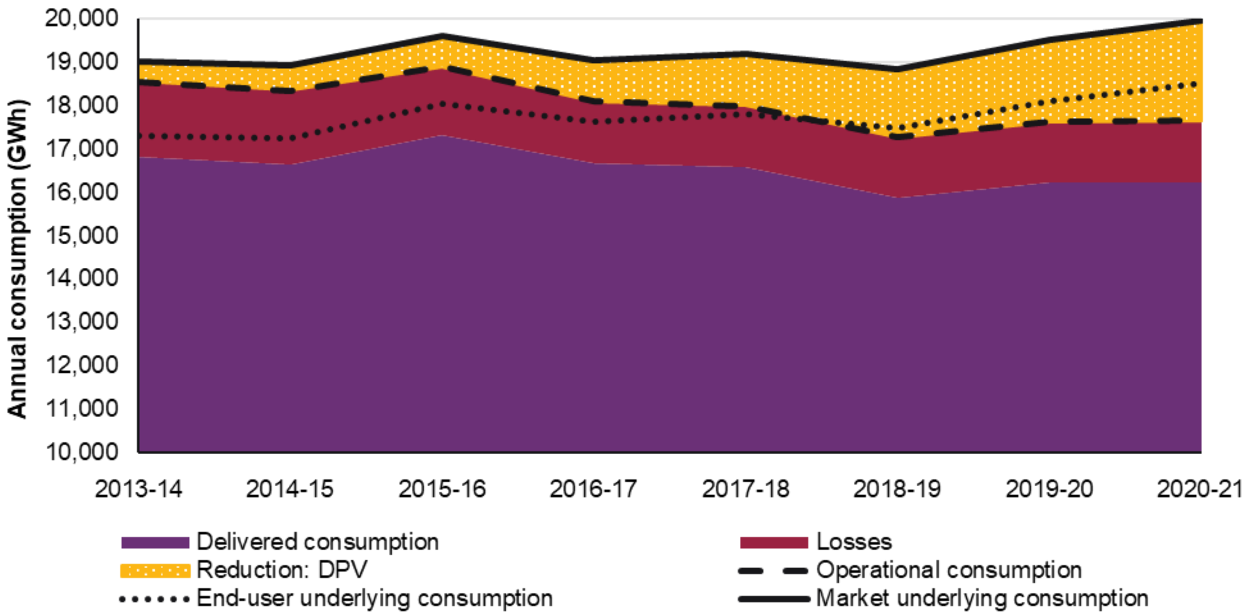


Source: AEMO and Synergy.

6.1.2 Consumption breakdown

A breakdown of delivered consumption, underlying consumption met by DPV generation, and an estimate of network losses is shown in Figure 20.

Figure 20 Annual consumption breakdown (by component), 2013-14 to 2020-21[A,B]



A. Components that contribute to operational consumption are drawn in solid colours while those components reducing consumption are shown in shaded patterns.
B. Market underlying consumption includes network losses, while end-user underlying consumption excludes it.
Source: AEMO, CER, and Solcast.

From 2013-14 to 2020-21, underlying consumption increased at an average annual rate of 1.0%, while delivered consumption decreased at an average annual rate of 0.5%. The reduction in delivered consumption is due to underlying consumption increasingly being met by DPV generation, which increased by 388.8% from 470 GWh to 2,298 GWh between 2013-14 and 2020-21.

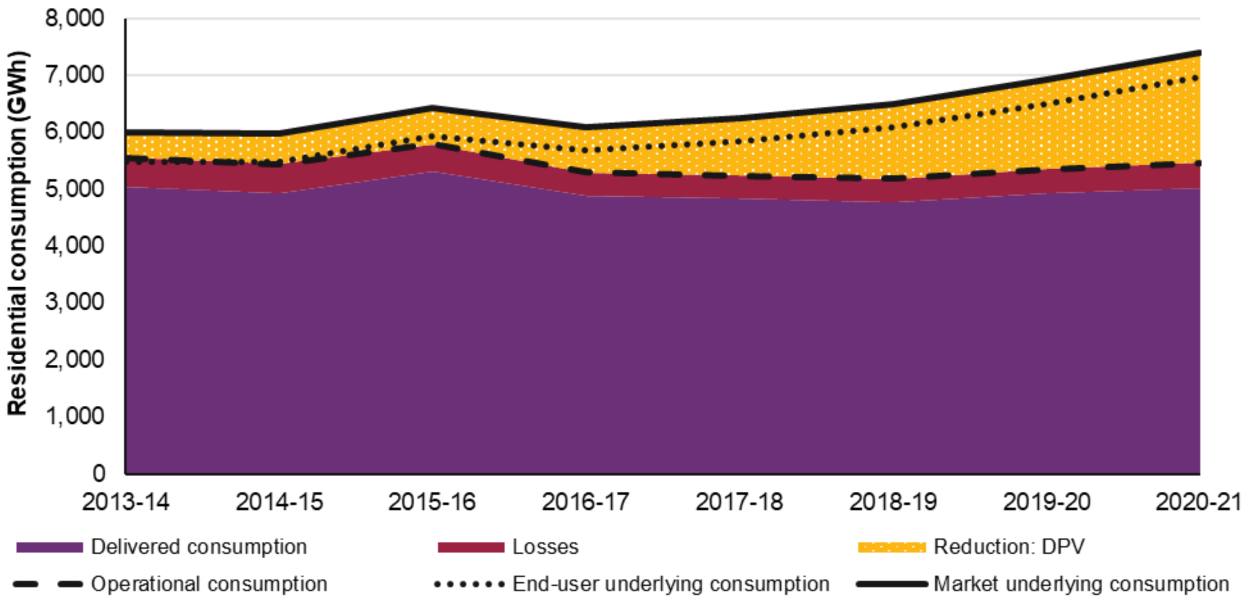
6.1.3 Residential consumption breakdown

The breakdown of residential operational consumption into delivered residential consumption, underlying residential consumption met by DPV, and an estimate of network losses is shown in Figure 21. In general, the overall rise in residential consumption met by DPV drove the increasing need for energy storage mechanisms, control and visibility that contributed to the improvements in the energy efficiency of this sector.

In summary:

- Between 2013-14 and 2018-19, delivered residential consumption declined at an average annual rate of 1.1%, while underlying residential consumption increased at an average annual rate of 2.1%. This gap is driven by the significant growth in underlying consumption being met by DPV.
- From 2018-19, both delivered and underlying residential consumption increased at average annual growth rates of 2.7% and 6.9%, respectively, while consumption being met by DPV generation grew at an average annual rate of 20.9%.
- The share of underlying residential consumption that is met by DPV has more than tripled, growing from 7.9% in 2013-14 to 27.8% in 2020-21.

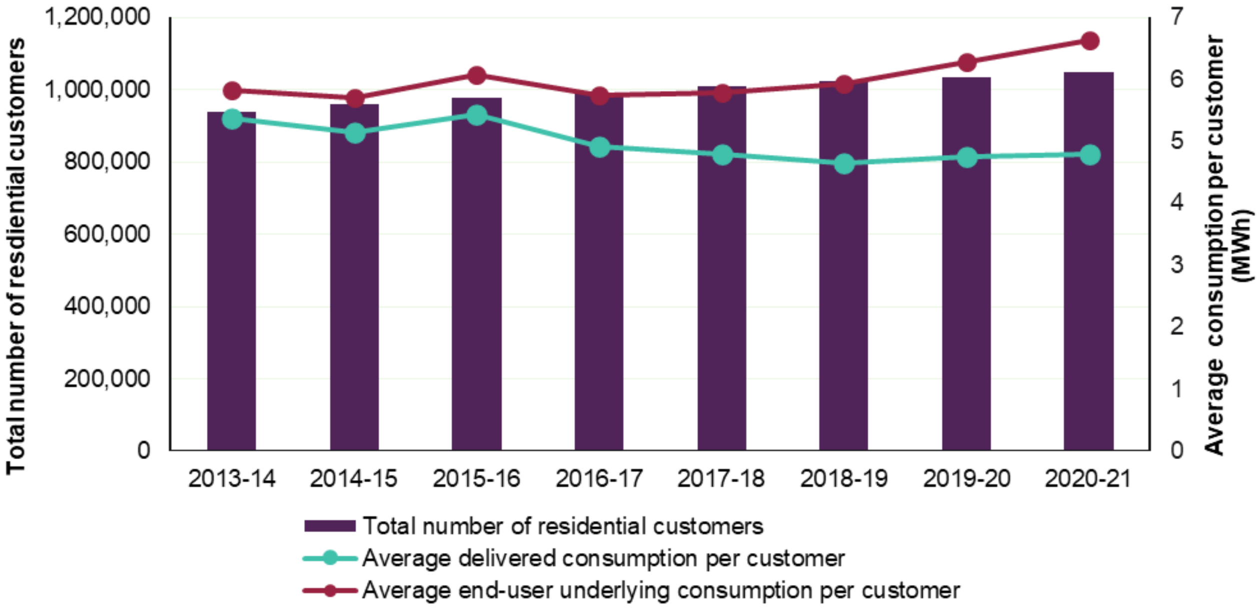
Figure 21 Annual residential consumption breakdown (by component), 2013-14 to 2020-21[A,B]



A. Components that contribute to residential consumption are drawn in solid colours while the component reducing it is drawn in shaded pattern.
B. Market underlying consumption includes network losses, while end-user underlying consumption excludes it.
Source: AEMO, Solcast and Synergy.

Between 2013-14 and 2020-21, underlying residential consumption per customer increased at an average annual rate of 1.9% (see Figure 22). For the same period, delivered residential consumption per customer declined at an average annual rate of 1.6%, most likely attributed to the underlying consumption increasingly being met by DPV, ongoing improvements in the efficiency of residential appliances, and the growth in residential customers (average annual rate of 1.6%).

Figure 22 Average annual consumption per residential customer, 2013-14 to 2020-21



Source: AEMO calculations based on data provided by Synergy.

6.2 Consumption forecasts

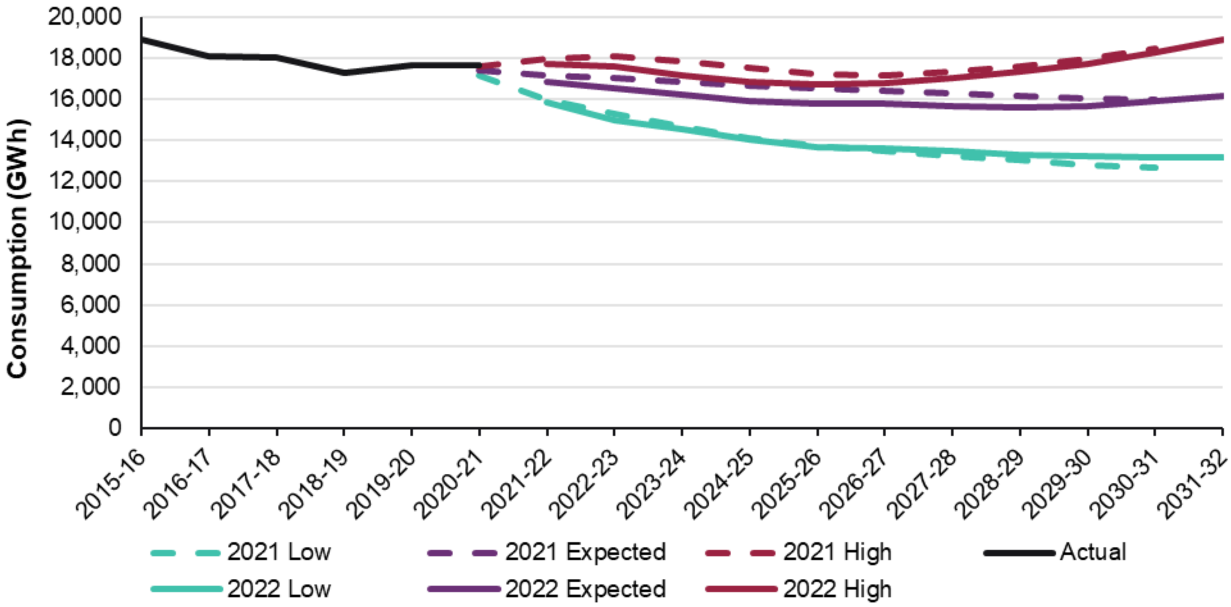
6.2.1 Total annual consumption forecasts

Figure 23 compares consumption forecasts for the low, expected, and high demand growth scenarios for the 2021 and 2022 WEM ESOOs, with the actuals from 2015-16 to 2020-21. In summary, over the outlook period:

- In the low demand growth scenario, consumption is forecast to decline at an average annual rate of 1.4%. Forecast strong declines in BMM and residential consumption contribute to a faster rate of decline in the first half of the outlook period (2.4% average annual rate) compared to the second half of the outlook period (0.5% average annual rate).
- In the expected demand growth scenario, consumption is forecast to decrease at an average annual rate of 0.3%. Declining consumption in the first half of the outlook period (1.2% average annual rate) is forecast to be partially offset by growth in the second half (0.7% average annual rate), attributed to a projected increase in LIL consumption.
- In the high demand growth scenario, consumption is forecast to increase at an average annual rate of 0.8%. Declining consumption in the first half of the outlook period due to significant forecast growth in DPV uptake (average annual rate of 1.2%) is projected to be offset by growth in the second half due to higher BMM and residential consumption (average annual rate of 2.6%).

Compared to the 2021 WEM ESOO, the consumption forecast is lower for the entire outlook period across all three scenarios, with the exception of the last few years (2026-27 to 2030-31) in the low demand growth scenario. In this scenario, the last few years' BMM and LIL consumption is forecast to offset the underlying consumption met by DPV generation.

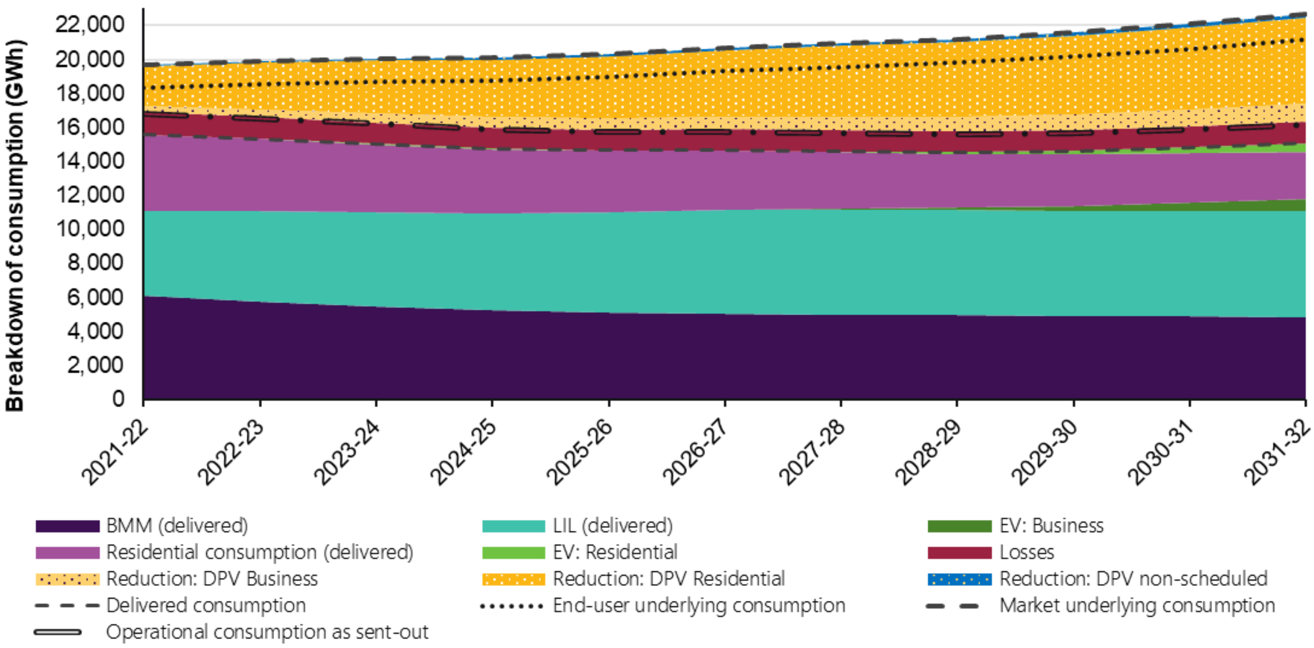
Figure 23 Consumption forecasts under three demand growth scenarios from 2021 and 2022 WEM ESOOs compared to actuals, 2015-16 to 2031-32



6.2.2 Consumption breakdown

Figure 24 breaks down forecast consumption into various sectoral components (including losses) under the expected demand growth scenario over the outlook period.

Figure 24 Breakdown of annual consumption forecasts under expected demand growth scenario, 2021-22 to 2031-32[A,B,C]



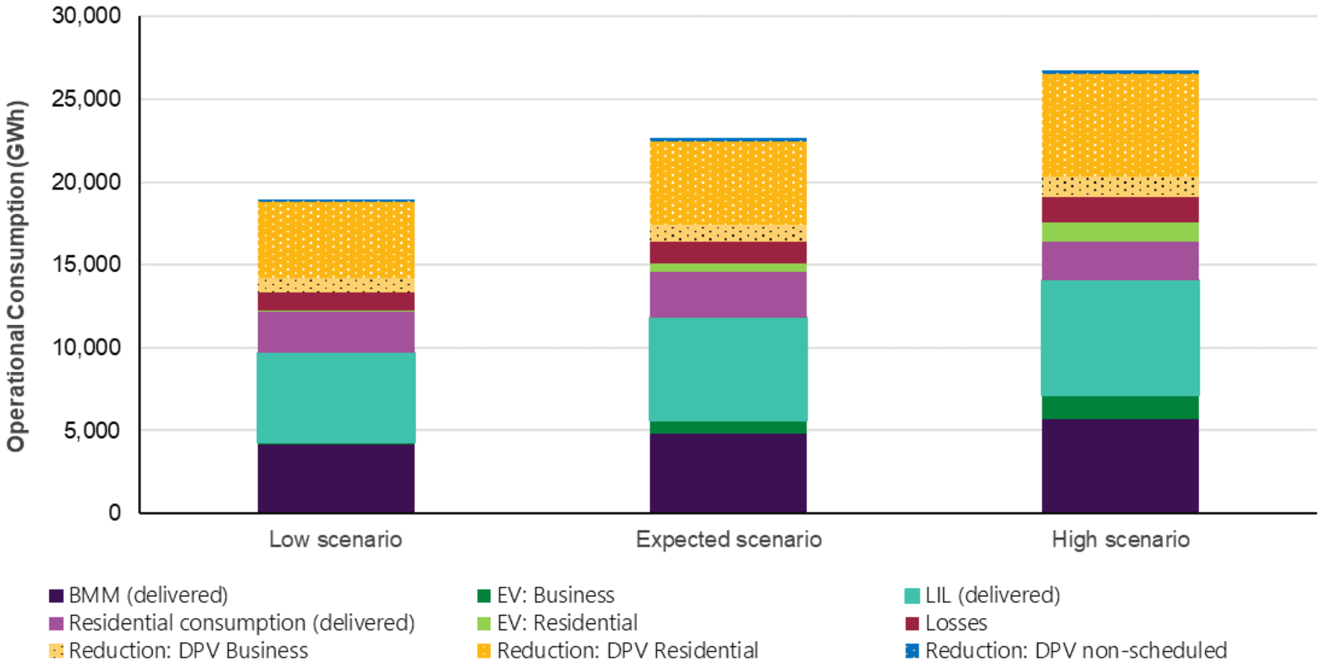
A. The operational consumption forecast model includes consumption from battery storage.
B. Sectoral components that contribute to operational consumption are drawn in solid colours while those reducing operational consumption drawn in shaded patterns.
C. Market underlying consumption forecast includes network losses, while end-user underlying consumption forecast excludes it.

The sectoral components for business consumption are BMM, LIL, business EV uptake, and consumption met by business rooftop PV. The sectoral components for the residential sector are delivered consumption, residential EV uptake and consumption met by residential rooftop PV. Both business and residential consumption can be met by non-scheduled PV[121]. In summary:

- Underlying consumption is forecast to grow throughout the entire outlook period but at a higher rate in the second half (average annual rate of 1.0% and 2.0% for the first and second half, respectively). This is largely attributed to the significant EV uptake in the second half of the outlook period.
- Despite the growth in underlying consumption, there is a decline in delivered consumption as the underlying consumption is increasingly being met by DPV generation. Delivered consumption is forecast to decline over the first half (average annual rate of 1.1%) and increase over the second half (average annual rate of 0.8%) of the outlook period. The rise in delivered consumption over the second half is mostly attributed to an increase in LIL delivered consumption that partially offsets the fall in BMM delivered consumption. The residential delivered consumption is forecast to decline over the entire outlook period.

Figure 25 captures the relative forecast impact of each sectoral component in 2031-32.

Figure 25 Breakdown of annual operational consumption forecasts under three demand growth scenarios in 2031-32[A]



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

In summary, in the high demand growth scenario, forecast business consumption is more than 30% higher than the low scenario, while projected EV consumption is more than 10 times greater. The only sectoral component forecast to be lower in the high demand growth scenario compared to the two other scenarios is residential delivered consumption, as a higher proportion of residential underlying consumption is projected to be met by DPV.

[121] The impact of non-scheduled PV on total consumption is small, so its contribution to the business and residential sectors is not presented.

7 Reliability assessment outcomes

This chapter presents the Reserve Capacity Target (RCT)[122] determined for each Capacity Year of the 2022 Long Term PASA Study Horizon (2022-23 to 2031-32). The RCT for 2024-25 is 4,526 MW, which sets the Reserve Capacity Requirement (RCR)[123] for the 2022 Reserve Capacity Cycle. Excess capacity[124] is projected to decline from 331 MW (7.5%) in 2023-24 to 8 MW (0.2%) in 2024-25, assuming no further capacity changes beyond the retirement of Muja C unit 6 (193 MW) in October 2024.

7.1 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. However, the marginal cost of capacity increases as the difference between available capacity and peak demand increases, while the marginal benefit to reliability declines. Therefore, setting a reliability standard requires a trade-off between the economic effects of involuntary load shedding and the cost of acquiring capacity that will only be required during peak periods[125].

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 requirements below:

- The 10% POE peak demand forecast under the expected demand growth scenario plus allowances for Intermittent Loads[126], frequency control[127], and a reserve margin[128] ("defined scenario").

[122] 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.

[123] 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.

[124] Excess capacity is calculated as: (Available capacity - RCR or RCT)/(RCR or RCT). For 2022-23 and 2023-24, available capacity is the total quantity of Capacity Credits assigned, for 2024-25 to 2031-32, available capacity is the forecast quantity of Reserve Capacity.

[125] The value of customer reliability (VCR) and the cost of supply are two factors to consider in setting the level of the reliability standard. The VCR represents the value customers place on having reliable supply and avoiding most types of reliability events. VCRs seek to reflect the value different types of customers place on a reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour ($/kWh) of unserved energy. Generally, the more conservative the reliability standard, the higher the cost for consumers.

[126] 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.

[127] Additional capacity required to provide Minimum Frequency Keeping Capacity and ensure that load following ancillary service (LFAS) is maintained.

[128] The reserve margin accounts for both the annual variability of peak demand in the SWIS and the failure of the largest generating unit.

- Limit expected unserved energy (EUE) to 0.002%[129] of annual forecast expected energy consumption.

Since the RCM commenced in 2005, the defined scenario has set the RCT because it has exceeded the capacity required to satisfy the EUE component of the Planning Criterion.

A review of the RCM is underway to ensure that the RCM continues to provide system reliability at optimal consumer costs, in light of the changes anticipated to future system demand profiles and supply sources. It is currently exploring potential changes to the Planning Criterion (see Chapter 8 for further information).

AEMO engaged Robinson Bowmaker Paul (RBP) to conduct the 2022 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 2021 WEM ESOO are presented in Appendix A3. Further information about the methodology can be found in RBP's report[130].

7.2 The Reserve Capacity Target

7.2.1 Defined scenario

Table 16 shows the RCT, set by the expected 10% POE peak demand requirement of the Planning Criterion (defined scenario), for each Capacity Year of the 2022 Long Term PASA Study Horizon.

Table 16 Reserve Capacity Targets (MW)[A]

Capacity Year	10% POE peak demand	Intermittent Loads[B]	Reserve margin[C]	Load following[D]	Total
2022-23[E]	4,042	3	335	110	4,490
2023-24[E]	4,055	3	335	110	4,503
2024-25	**4,078**	**3**	**335**	**110**	**4,526**
2025-26	4,106	3	335	110	4,554
2026-27	4,157	3	335	110	4,605
2027-28	4,194	3	335	110	4,642
2028-29	4,227	3	335	110	4,675
2029-30	4,275	3	335	110	4,723
2030-31	4,322	3	335	110	4,770
2031-32	4,389	3	335	110	4,837

A. All figures have been rounded to the nearest MW.
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.
C. Calculated as the greater of 7.6% of the sum of the 10% POE forecast peak demand plus the Intermittent Load allowance and the maximum sent-out capacity (measured at 41°C) of the largest generating unit in accordance with clause 4.5.9(a) of the WEM Rules. To set the RCT, AEMO considers NewGen Kwinana (NEWGEN_KWINANA_CCG1, assigned 334.8 MW of Capacity Credits for 2022-23 and 2023-24) to be the largest generating unit.
D. Since the 2021 WEM ESOO, the ERA has approved AEMO's proposed LFAS requirements for the 2021-22 financial year (110 MW between 05:30 and 20:30 and 65 MW between 20:30 and 05:30) (see https://www.erawa.com.au/cproot/22038/2/202122-Ancillary-Service-audit-and-approval-report.PDF). AEMO considers the load following requirement of 110 MW in calculating the RCTs to cover peak demand periods and assumes no change to this requirement over the outlook period. From October 2023, this requirement may change with the implementation of a five-minute Dispatch Interval and the new Essential System Services framework as part of the introduction of security constrained economic dispatch (SCED) constraints in the WEM.
E. Figures have been updated to reflect the current forecasts. However, the RCR of 4,421 MW set in the 2020 WEM ESOO for the 2020 Reserve Capacity Cycle (2022-23) and the RCR of 4,396 MW set in the 2021 WEM ESOO for the 2021 Reserve Capacity Cycle do not change (2023-24).

[129] 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.

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

The RCT determined for 2024-25 is 4,526 MW, which sets the RCR for the 2022 Reserve Capacity Cycle. It is 130 MW higher than the RCR set for 2023-24 (4,396 MW) and 117 MW higher than the RCT forecast for 2024-25 (4,409 MW) in the 2021 WEM ESOO. This is largely due to higher 10% POE peak demand forecasts as a result of stronger growth in residential load and LILs, combined with the influence of the high demand over the 2021-22 summer (see Chapter 5 for further information), with a small amount (5 MW) contributed by higher LFAS requirements.

7.2.2 Unserved energy assessment

The unserved energy assessment concluded that the RCT set by the defined scenario is sufficient to limit EUE to below 0.002% of annual forecast energy consumption for each Capacity Year in the 2022 Long Term PASA Study Horizon. The assessment forecasts unserved energy occurring in all months each year except for April, May, and November, largely consistent with the findings of the 2021 reliability assessment. Unserved energy is forecast to occur between 17:00 and 20:00, coinciding with peak demand periods throughout the year.

Forecast unserved energy is most likely to occur in summer when demand is high, or winter when the majority of planned outages are scheduled. When demand and planned outages are high, forced outages or network curtailments can cause shortfalls of capacity and, hence, unserved energy.

Forecast unserved energy for each Capacity Year in the 2022 Long Term PASA Study Horizon is broadly similar to the 2021 WEM ESOO. The largest difference occurs in 2029-30 – in the 2021 reliability assessment, high forecast planned outages reported by Market Participants in response to the information request under clause 4.5.3 of the WEM Rules coincided with high forecast winter peak demand, leading to relatively high unserved energy. Market Participants have revised their expected planned outages for 2029-30 for the 2022 reliability assessment, resulting in lower EUE in that year.

Over the 2022 Long Term PASA Study Horizon, binding network constraints contribute to between 7% and 100% of unserved energy. Notwithstanding the binding constraints, the level of EUE is well below the 0.002% threshold in the scenario modelled.

The full results of the EUE assessments are provided in Appendix A4.

7.3 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 DSPs and standalone ESR[131].

The minimum Availability Class 1 capacity requirement and the capacity associated with Availability Class 2 for 2023-24 and 2024-25 are shown in Table 17. For the 2022 Reserve Capacity Cycle, the Availability Class 1 capacity requirement (3,891 MW) outlined in Table 17 for 2024-25 sets the minimum amount of generation capacity that is required to be procured via the RCM to avoid a generation capacity shortfall. Additional Availability

[131] 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.

Class 1 capacity can be used to fulfil the capacity requirement associated with Availability Class 2 (635 MW) to meet the RCR.

Table 17 Availability Classes (MW)

	2023-24[A]	2024-25
Minimum capacity required to be provided from Availability Class 1	3,566	3,891
Capacity associated with Availability Class 2	937	635
RCT	4,503	4,526

A. These figures reflect the current forecasts. The RCR of 4,396 MW determined in the 2021 WEM ESOO for 2023-24 remains unchanged. This comprised capacity requirements of 3,496 MW of Availability Class 1 and 900 MW of Availability Class 2, which also remain unchanged. The 4,727 MW of Capacity Credits assigned for 2023-24 is sufficient to meet the RCT.
Source: AEMO and RBP.

The Availability Class requirements for 2023-24 are similar to the 2021 WEM ESOO, which specified a minimum Availability Class 1 requirement of 3,496 MW and capacity associated with Availability Class 2 of 900 MW based on a RCR of 4,396 MW.

For 2024-25, the Availability Class 1 requirement has increased to 3,891 MW, mainly due to higher forecast EUE compared to 2023-24, which is largely driven by the retirement of Muja C unit 6 in 2024-25. The retirement reduces the amount of controllable generation capacity available by 4.4%, and results in a corresponding increase in intermittent generation, which has variable output depending on weather conditions. The increased share of intermittent generation combined with planned outages and curtailment of North Country wind farms result in higher levels of modelled unserved energy.

7.4 Availability Curves

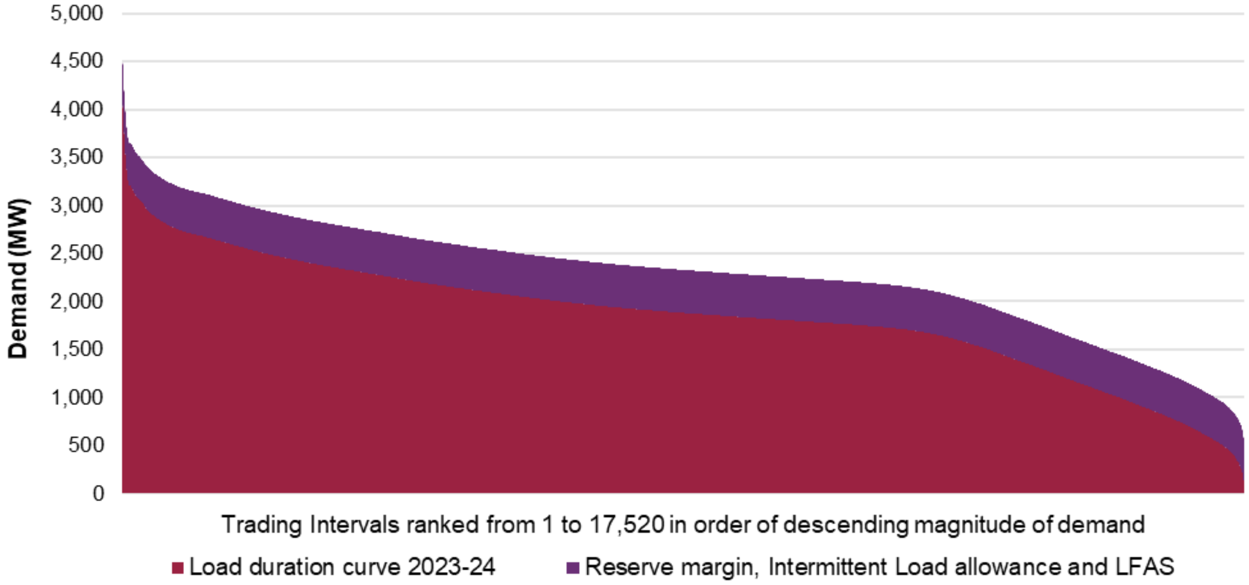
The Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirement for each Trading Interval over a Capacity Year[132]. The minimum capacity requirement for each Trading Interval is calculated as the sum of the forecast demand for that Trading Interval, reserve margin, and allowances for Intermittent Loads and LFAS.

The Availability Curves[133] for 2023-24 and 2024-25, as required under clause 4.5.13(f) of the WEM Rules, are shown in Figure 26 and Figure 27.

[132] 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.

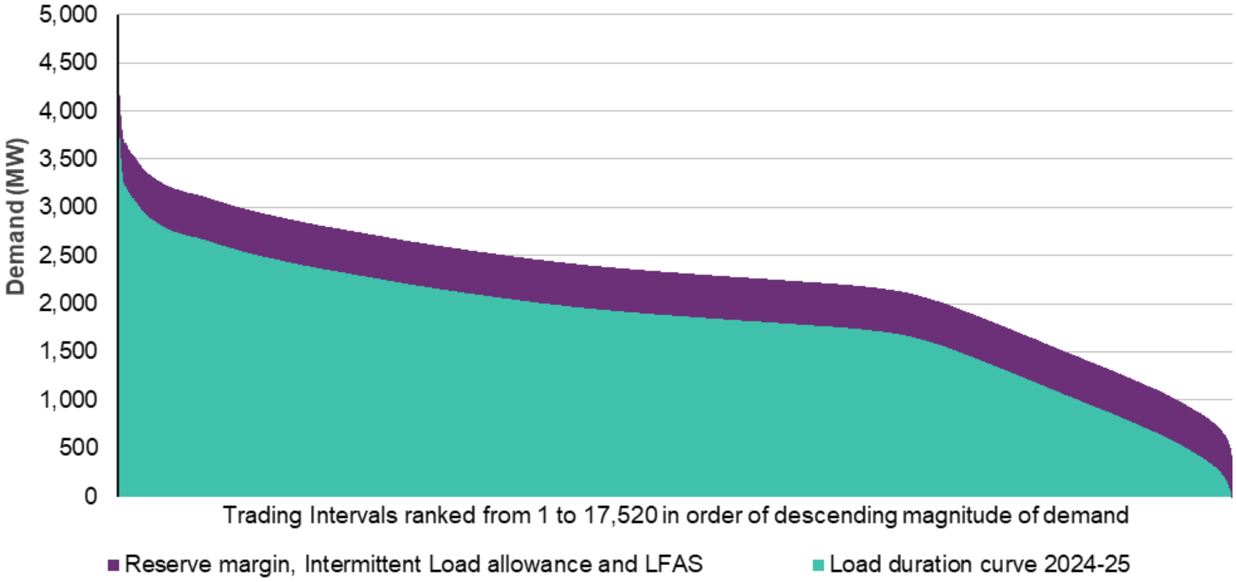
[133] The Availability Curves are determined using the 10% POE forecasts for the first 24 hours and the 50% POE forecasts for the remaining 8,736 hours of each year. This approach assumes that the difference in load duration curves is most evident in the first 24 hours.

Figure 26 Availability Curve, 2023-24



Source: RBP.

Figure 27 Availability Curve, 2024-25



Source: RBP.

7.5 Supply-demand balance

To forecast the capacity supply-demand balance over the 2022 Long Term PASA Study Horizon under the expected scenario, AEMO has assumed that:

- There are no capacity retirements other than Muja C unit 5 on 1 October 2022 and Muja C unit 6 on 1 October 2024[134]. On 14 June 2022, the WA Government announced[135] the planned retirement of Synergy's remaining coal-fired power stations and investment in new wind generation and energy storage, over the period to 2030. These changes have not been included in forecasts of the supply-demand balance in this WEM ESOO and are discussed further below.
- While the EOI process identifies potential new capacity that may enter the SWIS for the relevant Capacity Year, no new committed capacity[136] commences operation over the Long Term PASA Study Horizon, except new Facilities that were assigned Capacity Credits for 2022-23 and 2023-24[137].
- No probable projects[138] are developed over the Long Term PASA Study Horizon.
- The total amount of generation capacity assigned Capacity Credits is 4,721 MW for 2022-23, 4,643 MW for 2023-24, and 4,450 MW for each Capacity Year in the remainder of the Long Term PASA Study Horizon.
- The total number of Capacity Credits assigned to DSM capacity is 86 MW in 2022-23, 83.8 MW in 2023-24 and 83.8 MW for the remainder of the Long Term PASA Study Horizon.
- The total number of Capacity Credits assigned to ESR capacity is 46.25 MW in 2023-24 and 46.25 MW[139] for the remainder of the Long Term PASA Study Horizon.

In Table 18, the RCT is compared to the expected level of capacity in each Capacity Year of the 2022 Long Term PASA Study Horizon. The expected level of capacity declines in 2023-24 with the retirement of the Kwinana Cogeneration Facility and Muja C unit 5 and again in 2024-25 with the retirement of Muja C unit 6. If the shortfalls were to eventuate, the RCP would equal the BRCP multiplied by 1.3 from 2025-26, indicating that new capacity is required.

Table 19 provides a more detailed capacity outlook for 2022-23 to 2024-25. Excess capacity is projected to decrease from 331 MW (7.5%) to 8 MW (0.2%) between 2023-24 and 2024-25 due to the planned retirement of Muja C unit 6 in October 2024, which is only partially offset by entry of Synergy's Kwinana Big Battery (46.25 MW) in 2023-24.

[134] The Kwinana Cogeneration Facility (80.4 MW) retired in December 2021, and the Kalamunda Diesel Facility (1.3 MW) will retire in July 2022.

[135] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/06/State-owned-coal-power-stations-to-be-retired-by-2030.aspx

[136] Committed capacity for a Capacity Year refers to new generation, DSM, or energy storage capacity that is yet to enter service but has received Capacity Credits for a previous Reserve Capacity Cycle as outlined in step 2.10.3 of the WEM Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion at https://www.aemo.com.au/-/media/files/electricity/wem/procedures/2017/undertaking-the-long-term-pasa-and-conducting-a-review-of-the-planning-criterion.pdf.

[137] For 2022-23, includes East Rockingham waste-to-energy (25.134 MW) and an upgrade to the Ambrisolar Facility (0.719 MW). For 2023-24, includes the Kwinana battery (46.25 MW) and an upgrade to Collgar wind farm (0.408 MW).

[138] Probable projects refer to Facilities that have not already received Capacity Credits for a previous Reserve Capacity Cycle but have been granted CRC for the current Reserve Capacity Cycle, as outlined in paragraph 2.10.4 of the WEM Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion.

[139] Does not consider battery degradation, which is factored into the LDC calculation used to assign CRC.

Table 18 Forecast capacity supply-demand balance, 2022-23 to 2031-32

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
RCR/RCT[A] (MW)	4,421	4,396	4,526	4,554	4,605	4,642	4,675	4,723	4,770	4,837
Capacity (MW)	4,807[B]	4,727[B]	4,534[C]	4,534	4,534	4,534	4,534	4,534	4,534	4,534
Excess capacity (MW)	386	331	8	-21	-72	-108	-142	-190	-237	-303
Excess capacity (%)	8.7	7.5	0.2	-0.5	-1.6	-2.3	-3.0	-4.0	-5.0	-6.3

A. The quantities reported for 2022-23, 2023-24, and 2024-25 are the RCR, while the remaining Capacity Years are the RCT.
B. The 2022-23 and 2023-24 available capacity values are the total quantities of Capacity Credits assigned.
C. The capacity values for 2024-25 and remaining years are forecasts, assuming the quantity of Capacity Credits assigned for 2023-24 remain unchanged other than the retirement of Muja C unit 6 from 2024-25. This estimate does not consider the EOI received for the 2022 Reserve Capacity Cycle, which will be published in a summary report by the end of June 2022.

Table 19 Capacity outlook in the SWIS, 2022-23 to 2024-25 (MW)[A]

Capacity category	2022-23	2023-24	2024-25[B]
Energy producing capacity	**4,721**	**4,643**	**4,550**
• Existing[C]	4,695[D]	4,596	4,550
• Committed[E]	26	47	0
DSM capacity	**86**	**84**	**84**
• Existing[C]	86	84	84
• Committed[E]	0	0	0
Total capacity	4,807	4,727	4,534
RCR	4,421	4,396	4,526
Excess capacity	386 (8.7%)	331 (7.5%)	8 (0.2%)

A. All capacity values are in terms of Capacity Credits, rounded to the nearest integer. Values for 2022-23 and 2023-24 are Capacity Credits assigned for the 2020 and 2021 Reserve Capacity Cycles, respectively.
B. All Facilities are assumed to receive the same quantity of Capacity Credits in 2024-25 as in 2023-24 other than the planned retirement of Muja C unit 6 in 2024-25.
C. Refers to existing Energy Producing Systems or DSM which has held Capacity Credits for a previous Reserve Capacity Cycle.
D. Comprises solely generation capacity.
E. Refers to new Energy Producing Systems or DSM that holds Capacity Credits for the relevant Capacity Year but have not held Capacity Credits for a previous Reserve Capacity Cycle.

7.5.1 Potential changes to the supply-demand balance

As noted above, the WA Government recently announced plans to retire Synergy's remaining coal-fired generators, namely the Collie Power Station (317.2 MW Capacity Credits) and Muja D Power Station (418.2 MW of Capacity Credits), by 2030. Indicative retirement dates of 1 October 2027 and 1 October 2029, respectively, are proposed. The Minister also announced the intention to invest in around 810 MW of new wind generation and 1,100 MW/4,400 MWh of energy storage capacity to contribute to meeting Synergy and the Water Corporation's energy needs over the period to 2030.

The proposed retirement dates do not require additional capacity to be provided in 2024-25, for which this WEM ESOO sets the RCR. AEMO welcomes the early advice from the WA Government about these proposed changes, which reflect and support the ongoing energy transition and decarbonisation of the SWIS, and will consider them further in future WEM ESOO updates.

The supply-demand balance in the SWIS may vary from the 2022 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 recent announcement by the WA Government.
- Changes to the RCM resulting from the RCM Review, which may influence capacity changes or affect the way in which the RCR is determined, or capacity is certified in future Reserve Capacity Cycles (see Chapter 8 for more information on the RCM Review).

The different demand scenarios (high, expected and low) considered by AEMO capture some of this potential variability in the future supply-demand balance. While not yet certain enough to include in the forecasts, AEMO is aware that there is considerable potential for peak demand to grow more strongly over the outlook period than previously anticipated, as electrification of transport and other sectors gathers pace and proposals for new, large energy-consuming projects progress.

The supply-demand balance for different forecast capacity scenarios is presented in Appendix A3.4 and the full set of peak demand forecasts is presented in Chapter 5.

7.5.2 Other related information

The Request for EOI window for the 2022 Reserve Capacity Cycle opened on 10 January 2022 and closed on 9 May 2022[140]. AEMO invited EOIs from project proponents with new Energy Producing Systems[141] and DSM capacity who are seeking CRC and Capacity Credits for 2024-25. A project proponent must submit an EOI to be eligible to seek CRC under section 4.8 of the WEM Rules for any new capacity, which includes an upgrade of a Facility.

The 2022 EOI Summary Report will be published on 30 June 2022 and will be available on AEMO's website[142].

The NAQ process for the 2022 Reserve Capacity Cycle[143] will determine network limitations that can be used to determine the optimal location for new generation to alleviate capacity shortfall. AEMO will publish this information once the NAQ process for the 2022 Reserve Capacity Cycle is completed in June 2023, and will use this information to prepare the 2023 WEM ESOO (see Section 8.4 for information about network access for generators and connecting new loads).

[140] The 2022 Reserve Capacity timetable can be found at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/timetable/2022-reserve-capacity-cycle-timetable.pdf.

[141] The Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020 include amending rules with respect to Energy Producing Systems. An Energy Producing System is defined as: "Set of one or more electricity producing resources or devices such as generation systems or Electric Storage Resources". This definition currently has legal effect under the transitional rule specified in clause 1.36C.6 of the WEM Rules.

[142] At https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Expressions-of-interest.

[143] See https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/timetable/2022-reserve-capacity-cycle-timetable.pdf.

8 Market development and challenges

This chapter highlights some developments, opportunities, and challenges in the WEM that are relevant to the Reserve Capacity Mechanism, including:

- WA's Energy Transformation Strategy initiatives.
- Other WEM reviews and rule changes.
- Maintaining power system security and reliability.
- Infrastructure developments in the SWIS.

8.1 WA Energy Transformation Strategy

The ETS is the WA Government's plan to enable the transition to a future power system characterised by low-emissions and distributed energy sources – providing, secure, reliable and affordable energy to support the decarbonisation of the broader economy.

Stage 1 of the ETS[144] commenced in 2019 and concluded in May 2021. This stage included these work streams:

1. Foundation Regulatory Frameworks, to establish a security-constrained economic dispatch and new Essential System Services (ESS) framework for the SWIS, which AEMO is now implementing as part of the WEM Reform Program.
2. Whole of System Planning, to establish and develop the first Whole of System Plan (WOSP) to guide investment in energy generation, network and storage in the SWIS over the next 20 years.
3. DER, including development of the DER Roadmap and commencement of actions set out in the DER Roadmap.

Stage 2 of the ETS launched in July 2021. It includes:

- Future initiatives until 2025 to enable the transition to low-emissions energy and DER in the SWIS[145].
- The implementation of reforms developed under Stage 1 as follows:
  - Delivery of the DER Roadmap activities by 2024 (see Section 8.1.3), including development of an Electric Vehicle Action Plan (EV Action Plan), which is discussed in Section 8.1.4.
  - New network connections, ESS and Western Power's network access arrangements.
  - Preparing for new market start in October 2023.
- The RCM Review and proposed legislative reforms referred to as 'Project Eagle', discussed in sections 8.1.5 and 8.1.6 respectively.
- The development of the next WOSP and work focused on maintaining a secure and reliable power system as the energy transition progresses (discussed in sections 8.1.7 and 8.3).

[144] See https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.

[145] See https://www.wa.gov.au/government/announcements/western-australias-energy-transformation-strategy-moves-its-next-stage.

8.1.1 WEM Reform

The 2021 WEM ESOO summarised the key amendments to the WEM Rules and the Electricity Networks Access Code 2004 that were made to support the delivery of the Foundation Regulatory Frameworks stream of the ETS[146]. AEMO is implementing these changes in its ongoing WEM Reform Program[147], with commencement of the new Security Constrained Economic Dispatch (SCED) market scheduled for 1 October 2023.

The ETS has implemented wide-ranging reforms in the RCM to support the adoption of a constrained network access model and the participation of ESR[148]. Changes to the RCM are being implemented in a phased approach across both the 2021 and 2022 Reserve Capacity Cycles. Information about the NAQ framework is provided in Section 8.1.2.

8.1.2 Network Access Quantity framework

As part of the WEM Reform Program, new or existing Facilities providing capacity will be assessed in a constrained access environment, guided by the NAQ framework. Under this framework, AEMO will consider the forecast effects of congestion on a Facility's ability to provide capacity during peak Trading Intervals before assigning Capacity Credits.

The NAQ framework is unique to the WEM and will be implemented from the 2022 Reserve Capacity Cycle. The mechanism aims to provide investment certainty for capacity providers who contribute to the reliability of the system, by establishing a prioritisation order for the assignment of NAQ to Facilities. NAQ will be assigned to existing Facilities ahead of new Facilities, with new Facilities receiving NAQ up to the residual capacity of the network.

AEMO is currently developing relevant WEM Procedures to document the NAQ assignment methodology, NAQ model and the Facility Dispatch Scenarios[149]. The WEM Reform Implementation Group website has more information[150].

8.1.3 Distributed Energy Resources Roadmap progress

The DER Roadmap[151] is a five-year plan with a set of actions to facilitate the integration of all forms of DER in the SWIS, including solar panels, battery storage, EVs, and customer appliances, coordinated via active energy management systems. There has been significant progress made under the DER Roadmap over the last year[152]:

- From 18 December 2021, all new and upgraded DPV installations are required to comply with the revised inverter standard (AS/NZS 4777.2:2020). The revised standard ensures DPV is better able to 'ride through' system disturbances, helping to manage system security.
- AEMO has developed and implemented revised dynamic modelling tools and approaches to improve understanding of system behaviour during disturbances, now incorporating dynamic models of DER and load

[146]See https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-rules.

[147] See https://www.aemo.com.au/initiatives/major-programs/wem-reform-program.

[148] Energy Policy WA published an information paper in May 2021 on changes to support the implementation of constrained access and facilitate ESR participation in the RCM. See https://www.wa.gov.au/government/publications/reserve-capacity-mechanism-changes-support-the-implementation-of-constrained-access-and-facilitate-storage-participation.

[149] See https://www.wa.gov.au/system/files/2022-04/WRIG%20Slides%20-%20Meeting%203%20%20-%20AEMO%20-%20NAQ%20WEMP%20Development%20-%20March%202022.pdf.

[150] See https://www.wa.gov.au/government/document-collections/wem-reform-implementation-group-wrig.

[151] See https://www.brighterenergyfuture.wa.gov.au/distributed-energy-resources.

[152] See https://www.wa.gov.au/system/files/2022-06/Distributed-Energy-Resources-Roadmap_second-year-update-WEB.pdf.

and accounting for the effects of high levels of DER in the management of contingency events on the power system.

- AEMO continues to work with Western Power on updates to improve the operation of the SWIS Under Frequency Load Shedding (UFLS) scheme, to ensure this last-resort protection scheme operates effectively to maintain system security with high levels of DPV.
- System Restart arrangements have been reviewed and work is commencing to better understand the roles that DER can play in the restart process.
- Project Symphony has progressed through detailed planning, with build and integration well underway:
  - This pilot uses cloud-based technology to co-ordinate assets such as solar panels, air conditioning units, and EVs alongside community batteries to create a virtual power plant (VPP).
  - Focusing on homes and businesses in Harrisdale, Piara Waters, and Forrestdale (where over 50% of homes have installed DPV), Project Symphony will orchestrate over 800 DER assets to test their capability to provide services to the WEM and network.
  - The project seeks to uncover how DER assets can be effectively deployed to maintain system security and better utilise DPV generation and other devices to provide valuable capabilities to the power system.
  - The Project Symphony pilot is currently underway and is expected to be completed by the end of 2023[153].
- EPWA has progressed its consideration of the DER Orchestration Roles and Responsibilities during 2021 and early 2022, to provide investment and policy guidance to all SWIS and WEM stakeholders. From this, work is underway to understand the legislative and market changes required to enable DER participation in the WEM.
- EPWA published the *DER Roadmap Two-Year Progress Report* on 2 June 2022[154]. The two-year progress report highlights achievements over the previous year, and key activities to be progressed over the coming year.

8.1.4 Electric Vehicle Action Plan

The EV Action Plan[155] was introduced in August 2021, delivering on action 16 in the DER Roadmap and also addressing requirements of the State EV Strategy[156].

The EV Action Plan aims to minimise risks and maximise benefits to electricity supplies in WA as EVs are adopted at higher levels. EVs present a unique challenge compared with other DER, due to their mobile nature and potentially unpredictable charging patterns which are based on owners' behaviours. Key aspects of the EV Action Plan include:

- Developing EV uptake scenarios for inclusion in the WOSP and the WEM ESOO.
- Improving connection requirements for and visibility of EVs in the power system.
- Developing and implementing the ability to aggregate and control EVs within the power system.

[153] See https://www.synergy.net.au/Our-energy/For-tomorrow/Project-Symphony.
[154] See https://www.wa.gov.au/government/publications/distributed-energy-resources-roadmap-two-year-progress-report.
[155] See https://www.wa.gov.au/system/files/2021-08/EPWA-EVActionPlan_18Aug2021e.pdf.
[156] See https://www.wa.gov.au/service/environment/environment-information-services/electric-vehicle-strategy.

- Developing an electricity tariff specifically for EV users or other measures to encourage charging at times when the power system and network can best accommodate it.

These focal areas will support the integration of EVs while maintaining power system security. The ability to shift EV charging to off-peak periods, through either pricing incentives or control mechanisms, will allow greater utilisation of DPV generation during the day while reducing demand pressure and costs in the peak evening period. In time, the potential for bidirectional charging may enable EVs to be operated much like a stationary battery, charging during periods of high DPV output and discharging for use during peak demand periods – either vehicle-to-home or vehicle-to-grid.

In May 2022, the WA Government announced a new EV package[157], providing rebates on EV purchases and further investment in the EV charging network. These expansions include providing grants to support installation costs, trials of EV charging stations at train stations, and the addition of eight new charging stations to extend the EV highway eastward to South Australia[158].

8.1.5 RCM Review

The Coordinator of Energy is undertaking an RCM Review and has established an associated working group[159]. The RCM Review includes the Coordinator of Energy's first review of the Planning Criterion and methodology used to forecast peak demand for the WEM ESOO.

The RCM Review[160] was initiated to ensure the RCM continues to deliver reliable power supplies for customers in the SWIS, in light of the transition to renewable generation and supporting technologies (such as energy storage) as well as changing future system demand profiles, at an optimal cost for consumers. It represents the most significant review of the RCM since its establishment in 2004, and will be completed in three stages:

- Assess the requirements for the capacity needed to achieve the purpose of the RCM, in the context of the recent and anticipated transformation of the SWIS and WEM, including consideration of the current Planning Criterion, the approach to assessing the contribution to reliability provided by various energy technologies, and the methodology for determining the BRCP.
- In light of the outcomes of Stage 1, consider the implications for outage management, the capacity refund method, Reserve Capacity Testing requirements, and the allocation of capacity costs to customers via the Individual Reserve Capacity Requirement.
- Develop a detailed design for amendments to the RCM and consider transitional issues.

The RCM Review is proposed to be progressed throughout 2022 and will aim to submit a Rule Change Proposal for consideration by the Coordinator of Energy in February 2023. Updates on the RCM Review can be found on the Market Advisory Committee website[161].

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157 See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/05/WAs-climate-action-efforts-accelerate-with-60-million-dollar-EV-package.aspx.

158 See https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/08/WA-accelerates-towards-longest-EV-fast-charging-network.aspx and https://www.synergy.net.au/Our-energy/For-tomorrow/EV-Highway.

159 See https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group.

160 See https://www.wa.gov.au/system/files/2022-04/WRIG%20Slides%20-%20Meeting%203%20%20-%20Main%20Slide%20Deck%20-%20March%202022.pdf.

161 See https://www.wa.gov.au/government/document-collections/market-advisory-committee-meetings-held-between-january-2022-and-december-2022.

8.1.6 Project Eagle

In late 2021, EPWA commenced consultation on a package of changes to WA's energy legislation to support the energy transition. This includes a number of proposals relevant to the WEM, including:

- Developing an overarching legislative objective, incorporating the concepts of security, reliability, affordability and environmental sustainability in electricity supplies for the long-term interests of electricity consumers.
- Enabling an end-to-end power system security and reliability framework, as proposed by the Energy Transformation Taskforce during Stage 1 of the ETS[162], reflecting the current roles of Western Power and AEMO as network an system operator, respectively, and addressing gaps and overlaps that have emerged over time as roles have changed and the energy transition has gathered pace.
- Simplifying the governance of the various codes and rules made under WA's energy legislation and addressing gaps in the scope of these instruments.

8.1.7 Whole of System Plan 2023

Section 4.5A of the WEM Rules requires the Coordinator of Energy to develop a WOSP for the SWIS at least once every five years. EPWA, with the support of Western Power and AEMO, is commencing the development of the next WOSP for the SWIS (WOSP 2023). Stakeholder engagement on WOSP 2023 is expected to commence in mid-2022, with completion of the WOSP scheduled for late 2023.

WOSP 2023 will consider the least-cost mix of generation, network and storage investment required in the SWIS across a range of demand scenarios over the coming 20-year period. The purposes of the WOSP are outlined in clause 4.5A.5 of the WEM Rules.

The WOSP 2023 will consider the WA Government's ambition for net zero greenhouse gas emissions by 2050, which has been announced since the development of the last WOSP.

In parallel to the development of the WOSP, EPWA will lead electricity emissions modelling as part of the development of Sectoral Emissions Reduction Strategies (SERS) by the WA Government[163]. The SERS are intended to provide emissions reduction pathways for WA with tangible actions for reducing emissions consistent with the WA Government's target of net zero emissions by 2050, recognising the importance of significant action this decade to reduce emissions. Together, WOSP 2023 and electricity SERS will be important in guiding the energy transition and the role of the SWIS in supporting the decarbonisation of the WA economy more broadly.

8.2 WEM Reviews and Rule Changes

Various calculations and processes in the RCM are periodically reviewed to ensure they remain fit-for-purpose. Three WEM reviews[164] that were historically progressed by the ERA have been transferred to the Coordinator of

[162] See https://www.wa.gov.au/system/files/2021-04/Power%20System%20Security%20and%20Reliability%20Standards%20Framework_0.pdf.

[163] See https://www.wa.gov.au/service/environment/environment-information-services/sectoral-emissions-reduction-strategies.

[164] See clause 3.15.1A and 4.5.15 of the WEM Rules.

Energy – the reviews of the Planning Criterion and SWIS peak demand forecasting process, and the review of ESS Standards[165].

Most of the methodology reviews have been temporarily suspended while EPWA completes the RCM Review[166] (see Section 8.1.5). The ERA's website[167] has more information about methodology reviews.

Four Rule Change Proposals[168] are under development that were reported in the 2021 WEM ESOO and may affect the RCM. These are currently on hold pending the outcomes from the RCM Review.

8.3 Maintaining power system security and reliability

The 2021 WEM ESOO[169] presented the current and emerging challenges for the operators of the SWIS. AEMO published the *Renewable Energy Integration – SWIS Update Report* in September 2021[170] which confirmed these challenges have become more common due to higher renewable energy penetration[171]. While power system security has improved as a result of the actions taken since the publication of AEMO's March 2019 *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS* report[172], the following operational challenges continue:

- Low operational load conditions (and consequently low system load[173]) are a permanent feature of the SWIS.
- The increasing uptake of DPV is resulting in lower operational demand, leading to:
  - More synchronous generating units (typically coal and gas generators) being decommitted, and in the case of the Synergy coal-fired generation fleet, progressively retired. These synchronous generators may need to be constrained-on in future as they naturally provide services such as inertia, frequency control[174], system strength, ramping management, and voltage control to keep the power system secure. They also play an important role in contributing to reliability, which in future will need to be met by other types of firm generation, including storage, and is an issue currently being considered as part of the RCM Review.

[165] Formerly referred to as ancillary services review in clause 3.15.1 of the WEM Rules. The WEM Amending Rules transfer the responsibility from the ERA to the Energy Coordinator as per WEM Amendment (Governance) Rules 2021. See https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-rules.

[166] Includes Benchmark Reserve Capacity Price, Energy Price Limits, Reserve Capacity Price Factors, the Relevant Level Methodology, Planning Criterion. See https://www.wa.gov.au/system/files/2021-11/RCM-Review-2021-Scope-of-works.PDF.

[167] See https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews.

[168] See https://www.wa.gov.au/organisation/energy-policy-wa/wem-rule-change-proposals.

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

[170] See https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf.

[171] All-time record of 78.6% renewable energy penetration was set in Q3 2021 on 7 September 2021 during the 1200 hrs Trade Interval.

[172] See https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/system-operations/integrating-utility-scale-renewables-and-distributed-energy-resources-in-the-swis.

[173] System load is operational load plus generator auxiliary loads (loads required to operate the generators such as mills, fans, and pumps for coal generators). Depending on the combination of generators online, and the intervals over which load is measured, the difference between operational (or 'market') demand and system load is approximately 200 MW, where system load is the higher value. However, under conditions of low operational and system load, the MW difference may be much lower.

[174] The Coordinator of Energy has approved AEMO's submission to trigger the Non-Co-optimised ESS (NCESS) procurement process for Fast Frequency Response on 28 April 2022. See https://www.wa.gov.au/government/announcements/coordinators-determination-aemos-ncess-submission.

  - A reduced quantity of load available for UFLS[175], which is the last line of defence against frequency collapse in response to non-credible contingencies.
- Highly variable operational demand over very short time periods due to fast-moving cloudbanks that quickly reduce DPV generation, as observed on[176]:
  - 11 March 2022 when demand increased by 468 MW within 30 minutes.
  - 26 March 2022 when demand[177] increased by 800 MW between 10:38 and 12:16 and then decreased by 720 MW between 12:30 and 13:26.
- Managing increasing synchronous generator outage durations, particularly during high operational demand intervals when demand swings rapidly between peaks and troughs[178].
- The power system has experienced lower levels of inertia since 2019 as a function of the changing ratio of inverter-based resource to synchronous generation[179] in the SWIS. With the staged retirement[180] of Muja C (unit 5 of 195 MW in 2022 and unit 6 of 193 MW in 2024) occurring alongside increasing DPV and utility-scale wind and solar farm installations, non-synchronous generation is expected to exceed synchronous generation by 2023-24.

The current record for minimum operational demand is 765 MW[181], which was set on 14 November 2021. As noted in Chapter 5, the record for minimum operational demand has been broken five times in 2021-22, and the minimum will continue to decrease over time. While power system security has improved over the past two years, successfully managing declining operational demand will be an ongoing challenge. While dispatch options including ESS are in place to maintain power system security (operational demand between approximately 600 MW and 700 MW), operational demand below 600 MW presents a heightened power security threat which AEMO analysis indicates could occur before 2024[182].

AEMO, Western Power, and EPWA have commenced a program of work for immediate and longer-term remedial action through the DER Roadmap Actions and the ETS Stage 2 to address the impacts of low operational demand and related issues arising from the continued uptake of variable renewables, inverter-based technologies and DER.

This program of work includes the Low Demand Project, established by EPWA in partnership with AEMO and Western Power. The Project aims to assess, understand, and quantify emerging risks to power system security on

[175] UFLS schemes are the "safety net" that arrests a severe frequency decline following large contingency events, such as the simultaneous loss of multiple generating units. It involves the automatic disconnection of customer loads to rapidly correct the supply/demand balance and arrest the frequency decline, to maintain the SWIS within the allowed operating frequency band.

[176] See https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed. The report uses non- loss adjusted sent-out SCADA data.

[177] Operational demand measurement at a given point in time. For further information, see Quarterly Energy Dynamics Report at https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

[178] The WA Electricity Consultative Forum (WAECF) held on 2 March 2022 presented case studies of peak load events during the Hot Season in 2021-22. See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/wa-electricity-consultative-forum-waecf.

[179] Synchronous generation have historically provided services to the SWIS such as inertia (which improves ability to maintain frequency stability), system strength (to help maintain voltage stability), and ramping capability (to meet rapid changes in real-time supply-demand balance).

[180] Kwinana Cogeneration Plant (80.4 MW) and Kalamunda Power Station (1.3 MW) have also been retired. See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/notifications-of-facility-retirements.

[181] The 761 MW value reported in the Quarterly Energy Dynamics – Q4 2021 Report is based on non-loss adjusted sent-out SCADA data while this publication uses non-loss adjusted sent-out generation.

[182] See https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf.

the SWIS during periods of low operational demand. Based on the outcomes of the Project, appropriate responses, frameworks, and mechanisms will be developed.

8.3.1 Emergency Solar Management

One of AEMO's recommendations from the *Renewable Energy Integration – SWIS Update Report* was to develop the capability to curtail or reduce the output of new DPV installations. The WA Government responded to the recommendation and implemented Emergency Solar Management (ESM)[183], which has been developed through collaboration between EPWA, AEMO, Synergy, and Western Power.

This new ESM[184] capability applies to rooftop PV systems which are installed or upgraded from 14 February 2022 and have an inverter size of 5 kW or less. During an extreme low load event, AEMO will first undertake a range of actions to manage the power system (such as reducing large-scale generation, procuring additional energy services, and coordinating with Western Power on network configuration). If these actions are insufficient to maintain system security, AEMO will direct Western Power to take action to maintain a minimum demand threshold. Only when all other options have been exhausted, as a last resort AEMO will have the ability to request curtailment of electricity from managed DPV generators[185].

ESM capability will reduce the risk of power loss for consumers during these infrequent and rare emergency events, and customers with managed DPV will continue to receive power from the grid if ESM is exercised. The implementation of ESM is expected to allow more renewables to be installed overall, while providing a last-resort option for managing power system security in a SWIS characterised by high levels of DPV.

8.4 Infrastructure developments in the SWIS

As initiatives under the ETS continue to be developed and implemented, Western Power remains responsible for the management and operation of its network infrastructure in the SWIS.

In accordance with clause 4.5.10 of the WEM Rules, this section highlights how infrastructure developments proceed in the SWIS and how consumers and Market Participants currently access the SWIS to connect generation or load.

8.4.1 Western Power's Applications and Queuing Policy

Western Power's Applications and Queuing Policy (AQP) sets out how connection applications and access offers are managed. It is designed to manage applications in an orderly, transparent, and fair manner, especially where network capacity is scarce. The AQP underpins and regulates the connection process, which progresses customers along a pathway consisting of several milestones, leading to an Access Offer for connection to the Western Power network.

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[183] See https://www.wa.gov.au/government/announcements/low-load-response-discussion-paper-released-managing-risks-power-system-security.

[184] See https://www.wa.gov.au/organisation/energy-policy-wa/emergency-solar-management.

[185] For details on how AEMO, Western Power and Synergy respond to extreme low load events, see https://www.wa.gov.au/system/files/2022-03/Distributed-Energy-Resources-DER-Stakeholder-Update-Feb-2022.pdf and the WAECF meeting papers (2 March 2022) at: https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/wa-electricity-consultative-forum-waecf.

As part of the implementation of constrained network access for generation in the SWIS, a transitional AQP is in place and is set out in Appendix 2A of the Electricity Networks Access Code 2004 (Access Code)[186]. This transitional AQP will remain in place until an updated AQP is approved by the ERA as part of Western Power's fifth access arrangement process, which is currently underway[187].

8.4.2 Network access for generators

Several areas in the network have very limited network capacity[188] to support new generator connections without significant network augmentation. As a result of amendments to the Access Code in 2020 and 2021, new connections to the Western Power network are now made on the basis of the constrained network access model being implemented through the ETS.

Western Power's Annual Planning Report (APR) 2020[189] describes the network configuration and provides an indication of network capacity to support new load and generation connections.

The Generator Interim Access (GIA) solution, launched in July 2018, continues to provide interim constrained access connection for a limited number of renewable generators to facilitate further connections to the SWIS prior to SCED go-live on 1 October 2023[190].

Renewable generation capacity totalling approximately 630 MW has been connected via the GIA since 2019, including Yandin Wind Farm (211.7 MW), Warradarge Wind Farm (180 MW), and Merredin Solar Farm (100 MW).

Based on operational experience and after undertaking a review of GIA, including engaging with the industry on its use and impacts, Western Power is working with key stakeholders, including AEMO, on prudent improvements to GIA prior to the deployment of SCED in October 2023.

8.4.3 Connecting new loads

Where Western Power identifies a network limitation affecting the connection of a new block load, or in response to growth in overall demand by reference service customers, the Access Code contemplates network augmentation as well as "alternative options" to address network needs.

Alternative options are alternatives to part or all of a major augmentation or new facilities' investment, including standalone power systems, storage works, demand-side management, and generation solutions (such as distributed generation), either instead of or in combination with network augmentation.

Similarly, the WEM Rules make provision for Non-Co-optimised Essential System Services (NCESS) to procure generation to meet demand instead of or in combination with network augmentation where it is prudent and efficient.

Proponents who have installed (or are planning to install) generation or storage capacity or DSM capacity capable of providing network support are encouraged to contact Western Power to discuss these opportunities.

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186 See https://www.wa.gov.au/system/files/2021-07/ENAC-consolidated-version-30July2021.pdf.

187 See https://www.erawa.com.au/AA5.

188 See https://www.wa.gov.au/system/files/2019-08/Modelling-the-impacts-of-constrained-network-access-EY-report_0.pdf.

189 See https://www.westernpower.com.au/media/4768/annual-planning-report-2020-20210211v2.pdf.

190 SCED is a process designed to meet electricity demand at the lowest cost, given the operational limitations of the generation fleet and transmission system. For more information about the development of SCED for the WEM, see https://www.wa.gov.au/sites/Home | Western Australian Government (www.wa.gov.au)default/files/2019-08/Information-Paper-Energy-scheduling-and-dispatch-paper.pdf.

Western Power published the inaugural Network Opportunity Map (NOM) in October 2021 (and will update the NOM annually). The NOM will highlight opportunities for third parties to deliver services to Western Power in the assessment of options to address network needs. In October 2022, Western Power will also publish the Transmission System Plan document which will include a set of investment options for developing the transmission system over the planning horizon.

Western Power continues to work with large mining customers, local government, and other stakeholders to facilitate their energy needs, and is in the process of developing revised transmission network strategies. Key activities include:

- Installing additional 330/132 kilovolt (kV) transformer capacity at Kemerton to address asset issues and provide future growth opportunities for the region, as well as providing reference capacity to existing and new industrial loads supplied from Kemerton. The new transformer is expected to be commissioned in mid-2022. Further details of the work being undertaken by Western Power can be found in its APR 2020[191].
- Several projects in the Eastern Goldfields region to increase network capacity in the area and facilitate providing supply to regional mining loads has been completed, including the replacement of static volt-ampere reactive (VAR) compensators[192] at West Kalgoorlie terminal, installing a third 220/132 kV transformer at West Kalgoorlie terminal, and additional static synchronous compensators.

Western Power has recently completed the implementation of the Eastern Goldfields Load Permissive Scheme which releases available network capacity within the Eastern Goldfields region. This scheme is designed to facilitate the connection of new load through a non-reference service.

8.5 Other industry trends and developments

The WA Government has committed to working with all sectors of the economy to achieve net zero greenhouse gas emissions by 2050 in the WA Climate Change Policy[193]. This policy is part of a suite of strategies underpins strategies such as the ETS, Renewable Hydrogen Strategy (and Renewable Hydrogen Roadmap[194]), the Future Battery Industry Strategy[195], the EV Strategy[196] and the SERS[197]. A number of initiatives and funds[198,199, 200] have also been established to incentivise research and development into emissions reduction technologies such as standalone power stations, local battery and wind turbine manufacturing, and adoption of EVs.

Hydrogen production from renewable energy (renewable hydrogen) is an emerging low-emissions technology that has gained momentum[201] since the publication of the 2021 WEM ESOO. Hydrogen production and consumption

[191] See https://www.westernpower.com.au/media/4768/annual-planning-report-2020-20210211v2.pdf

[192] A VAR compensator is a set of electrical devices for providing fast-acting reactive power on high-voltage electricity transmission networks.

[193] See https://www.wa.gov.au/service/environment/environment-information-services/western-australian-climate-change-policy.

[194] See https://www.wa.gov.au/organisation/department-of-jobs-tourism-science-and-innovation/the-western-australian-renewable-hydrogen-industry.

[195] See https://www.wa.gov.au/organisation/department-of-jobs-tourism-science-and-innovation/western-australias-future-battery-industry.

[196] The WA Government announced a $60 million Clean Energy Car Fund in May 2022 offering rebates to encourage consumers to purchase and electric or hydrogen cell vehicle, coupled with the longest electric highway with charging infrastructure aims to reduce carbon emissions.

[197] See https://www.wa.gov.au/service/environment/environment-information-services/sectoral-emissions-reduction-strategies.

[198] See https://www.wa.gov.au/service/environment/environment-information-services/clean-energy-future-fund.

[199] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/04/Clean-energy-projects-to-lower-emissions-and-create-jobs.aspx.

[200] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2021/09/750-million-dollar-Climate-Action-Fund-to-drive-WAs-low-carbon-future.aspx.

[201] See announcements on the WA Government media statements website, at https://www.mediastatements.wa.gov.au/Pages/Default.aspx.

may impact the SWIS by increasing load, providing an energy storage medium and providing a mechanism to export renewable energy overseas.

The WA Government has announced it will be investigating a renewable hydrogen target that will require retailers in the SWIS to procure a certain percentage of electricity from renewable hydrogen projects[202]. The renewable hydrogen target aims to support emerging hydrogen projects, improve grid stability and maximise the integration of renewable energy in the SWIS.

AEMO is monitoring a number of projects that have been publicly announced but are still in the research and development or feasibility stages. As these projects progress to final investment decision, AEMO will include them in forecast modelling in future WEM ESOOs.

[202] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/05/Renewable-hydrogen-target-to-be-investigated-for-Western-Australia.aspx.

A1. Forecast methodology and assumptions

This appendix summarises the methodologies for demand and consumption forecasts, focusing on the WEM-specific features.

A1.1 Demand forecasts

For the demand forecast under each of the low, expected and high demand growth scenarios, AEMO modelled structural drivers (population, economic growth, electricity price, technology adoption) as well as uncertainties that are due to random effects including weather conditions (primarily temperature[203]), seasonal effects, and random stochastic volatility. These uncertainties were modelled using a probability distribution where peak demand forecasts were expressed as three POE values from the probability distribution for each scenario, including:

- A 10% POE value is expected to be exceeded, on average, one year in 10, reflecting hot weather conditions.
- A 50% POE value is expected to be exceeded, on average, one year in two, reflecting average weather conditions.
- A 90% POE value is expected to be exceeded, on average, nine years in 10, reflecting mild weather conditions.

AEMO developed three models for the demand forecasts:

- A maximum Generalised Extreme Value (GEV) model.
- A minimum GEV model.
- A half-hourly model.

The GEV model focuses on capturing and understanding the distribution of extreme values. The half-hourly model is more reliant on weather, which is used to simulate half-hourly demand and model the impact of DER. AEMO applied the GEV model to estimate the minimum and peak demand in the summer of 2021-22, the base year of the forecast[204]. This estimate was used to benchmark the peak demand forecasts (developed by the half-hourly model) for the base year and to rebase the half-hourly model, if required. AEMO then applied the half-hourly model to forecast demand growth to 2031-32.

A1.1.1 Generalised Extreme Value model (GEV)

The GEV model was fitted by applying weekly, fortnightly, or monthly operational maximums as a function of DPV capacity (MW), customer connections, calendar effects, and weather. The GEV models were applied to simulate peak demand for each week, fortnight, or month, then this was aggregated to the seasonal peak demand

[203] In this WEM ESOO, the peak demand forecast model has been based on the Perth Metro weather station (station identification number 9225). All historical temperature references in this WEM ESOO relate to the Perth Airport weather station (station identification number 9021).

[204] Actual demand data for the 2021-22 summer was available at time of forecasting, however, the base year was re-estimated by the GEV model to establish a probability distribution of operational peak demand to calculate the POE operational peak demand values.

(summer, winter, and shoulder). The peak demand forecasts developed by the GEV were used for the base year, and the half-hourly model then forecast the year-on-year change in demand, accounting for shifts in time-of-day for peak demand.

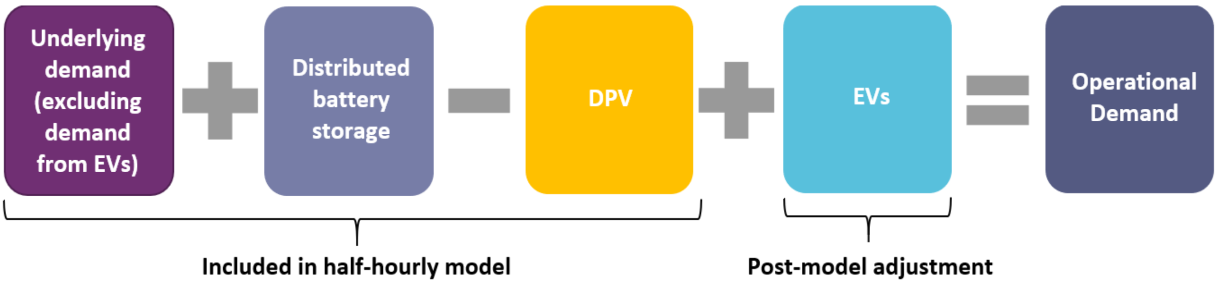
A1.1.2 Half-hourly forecasting model

AEMO developed a half-hourly regression model for the peak demand forecasts for the 2022 WEM ESOO. This model forecasts half-hourly demand by simulating the relationship between underlying demand[205] and key explanatory variables (including weather effects) and calendar effects (such as public holidays, the day of the week, and the month).

The forecasting process split forecast demand for each half-hour into heating load, cooling load, and base load elements[206], then increased half-hourly heating load, cooling load, and base load by annual or seasonal growth indices. The indices were derived from projections on structural drivers including economic conditions (such as electricity price and GSP growth) and demographic conditions (such as connections growth).

Underlying demand forecasts (excluding demand from LILs and EVs), along with forecasts of uptake of DPV and battery storage, were then modelled on a half-hourly basis to capture variation in these components due to weather effects. The corresponding demand value was then adjusted to reflect the impact of the modelled DPV and battery storage components. This result was adjusted post-modelling by the impact of EV operation. The operational demand forecasts accounted for the impact of generation of DPV and operation of distributed battery storage and EVs on underlying demand (see Figure 28).

Figure 28 Adjustment process for half-hourly modelled demand[A]



A. The impact of distributed battery storage in this context is either positive (increasing demand due to charging) or negative (decreasing demand due to discharging).

For each year of the outlook period, the half-hourly model was run for 5,000 simulated weather years. From the 5,000 simulated annual peak demand values, AEMO then extracted the 10% POE, 50% POE, and 90% POE peak values and associated peak timing.

The WEM minimum/peak demand forecast process is integrated into the NEM simulation process, leveraging the climate change modelling developed in collaboration with BOM and CSIRO (discussed in Appendix A2.3 of the Methodology Information Paper). Further information about the peak demand forecasts applying the GEV model and the half-hourly model is provided in Chapter 5 of the Methodology Information Paper.

205 Note that the underlying demand component does not include LIL.

206 Heating/cooling load is defined as temperature dependent consumption (for example, electricity used for heating/cooling). Load that is independent of temperature (such as electricity used in cooking) is called base load or non-heating load.

A1.1.3 Minimum demand forecasts

The methodology applied for minimum demand forecasts is similar to that applied for the peak demand forecasts; AEMO applied a minimum GEV model and a half-hourly model. Key differences in the methodology applied are:

- Minimum demand forecasts produced by the half-hourly model were re-based using results from the minimum GEV model. This was done because the GEV model was seen to be comparatively more accurate at modelling minimum demand levels than the half-hourly model.
- Minimum demand forecasts are presented for a five-year outlook period, from 2022-23 to 2026-27.

A1.2 Operational consumption forecasts

AEMO developed the annual operational consumption forecasts for the low, expected, and high demand growth scenarios. These forecasts were segmented into two broad customer sectors, business and residential.

A1.2.1 Business consumption forecasts

In forecasting business consumption, AEMO modelled non-residential EVs and LILs separately from BMM, based on the observation that they have historically been subject to different underlying energy consumption drivers.

A1.2.2 Large industrial load forecasts

LILs are defined as loads which use more than 10 MW for at least 10% of the year and were identified based on their demand 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.

For existing LILs, AEMO adopted a survey-based approach to forecast electricity consumption, which was supplemented by obtaining additional information through interviews. The survey collected information on forecast electricity consumption (MWh) and maximum demand (MW) for each demand growth scenario.

AEMO engaged with industry stakeholders including Western Power and customers to identify new LILs and the appropriate demand growth scenario. AEMO developed demand and energy consumption forecasts for new LILs based on their contracted maximum demand, adjusted by diversity factors[207]. Forecasts of these new LILs are detailed in Chapter 6.

For more information on the LIL forecasting process, see Section 2.2.1 of the Methodology Information Paper.

A1.2.3 BMM underlying consumption forecast

BMM consumption forecasts[208] were developed using short-term and long-term models. The short-term model was used to forecast consumption in the base year (2021-22 financial year[209]), accounting for weather-sensitive loads. The long-term model grew the short-term forecasts from the base year by applying GSP as an economic driver.

[207] Diversity factors are weightings applied to a new LIL's contracted maximum demand to account for different consumption level during the load's operation.

[208] This covers any distribution-connected loads excluded from the LIL category.

[209] The base year forecast is then converted to the 2021-22 Capacity Year.

The short-term model applied a linear regression model to forecast the BMM underlying consumption by considering heating degree days (HDD)[210] and cooling degree days (CDD)[211]. A heating benchmark temperature of 16°C and a cooling benchmark temperature of 21°C were used to calculate HDD and CDD. The short-term model predicted the weather-normalised starting year forecast in the absence of behavioural changes to economic drivers. This provided a starting point (to reflect current consumption patterns) that considered intra-year seasonality, holiday, and weather variations.

Based on the coefficients estimated in the short-term model, the heating load, cooling load, and base load segments were then estimated for the long-term model. The long-term model also applied a linear regression model based on the energy intensity (defined as GSP divided by BMM energy usage on an annual basis) to determine the long-term relationship which was carried through the forecast horizon with the high and low demand growth scenarios having an approximate 5% variation by 2032 with respect to the expected demand growth scenario.

For each forecast year:

- The heating/cooling load for each forecast period was estimated by applying the short-term model's heating/cooling load coefficients to the GSP.
- The base load for each forecast period was estimated by applying the BMM base load coefficient to the GSP and price projections.

A climate change index was applied by adjusting the heating and cooling load forecasts, where average temperature was adjusted by an increase of 0.03°C per year.

The short-term and long-term models were then combined to produce a regional consumption forecast. The process for combining the two methods was a weighted average. The first year of the forecast applied a weighting of 100% to the trend-based forecast, dropping to 80% in year two, 60% in year three, and to 0% by year six, with the remainder from the long-term model.

A1.2.4 Residential underlying consumption forecasts

AEMO applied a "growth" model to develop 10-year annual residential electricity consumption forecasts based on historical residential connections[212] and monthly consumption data that was supplied by Synergy.

The residential operational consumption forecast was generated by applying the following steps:

1. The monthly average underlying consumption per residential connection was calculated for a five-year period (2016-17 to 2020-21 financial years). The five-year period was chosen to capture the most recent residential consumption patterns and seasonality. A 95% confidence interval was included, providing dispersion between the low and the high demand growth scenario.
2. A regression model was applied to the monthly data for the five-year period from step 1, using average monthly underlying consumption per connection, CDD, and HDD (with benchmarks at 21°C and 16°C

[210] HDD is the number of degrees that a day's average temperature is *below* a critical temperature. It is used to account for deviation in weather from 'standard' weather conditions.

[211] CDD is the number of degrees that a day's average temperature is *above* a critical temperature. It is used to account for deviation in weather from 'standard' weather conditions.

[212] In the SWIS, Synergy supplies electricity to non-contestable customers whose annual electricity consumption is less than 50 MWh. See https://www.erawa.com.au/gas/switched-on-energy-consumers-guide/can-i-choose-my-retailer.

respectively). The monthly average underlying consumption per connection was split between base load, cooling load, and heating load elements based on the estimated coefficients of CDD and HDD[213].

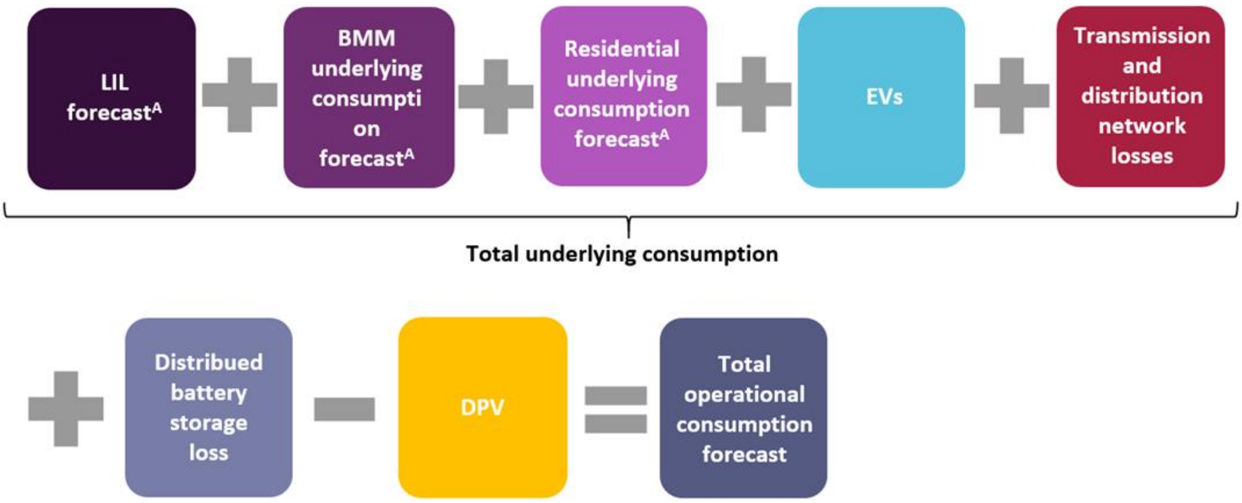
3. The average annual base load, heating load, and cooling load at a per-connection level were estimated on projected annual CDD and HDD under 'standard' weather conditions.
4. The forecast was then adjusted by considering the impact of other modelled consumption drivers, including electric appliance uptake, energy efficiency savings, changes in retail prices, climate change impacts, gas-to-electricity switching, and the DPV rebound effect[214].
5. The forecasts were then scaled up with the connection growth forecast to project future base, heating, and cooling consumption over the forecast period[215].
6. The forecast of residential underlying consumption was estimated as the sum of base, heating, and cooling load as well as the consumption from EVs.

For more information on residential consumption forecasts, see Chapter 3 of the Methodology Information Paper.

A1.2.5 Total operational consumption forecasts

The total underlying consumption forecasts are the aggregate of the LILs forecasts, the BMM underlying consumption forecasts (excluding consumption from EVs), and residential underlying consumption forecasts (excluding consumption from EVs). The total business operational consumption forecasts were developed by applying the adjustments to the total underlying consumption forecasts to account for impacts of electricity consumption of EVs, generation of DPV, and distributed battery storage system losses, as shown in Figure 29[216].

Figure 29 Adjustment process for operational consumption forecasts[A]



A. Excluding network losses and consumption from EVs.

For more information on operational consumption forecasts, see Chapter 2 of the Methodology Information Paper.

[213] The coefficients represented the sensitivities of residential loads per connection to cool and warm weather respectively.

[214] The PV rebound effect refers to the notion that households with installed DPV are likely to increase consumption due to increase consumption due to lower electricity bills.

[215] The connection forecast methodology has refined with a split of residential and non-residential connections. Only the residential connections were used.

[216] The impact of battery storage on consumption is assumed to be negligible, aside from minor efficiency losses, and therefore not included.

A2. Supporting forecasts

A2.1 Economic growth outlook and population

AEMO engaged BIS Oxford to provide forecasts for WA GSP and population[217]. BIS Oxford applied a suite of models including Oxford Global Economic Model (GEM), the Global Industry Model, and the Australian Regional Model to develop the economic forecasts for Australia for each Australian state:

- At the international level, countries are linked through trade (imports and exports), financial variables (the United States Federal Reserve rates and exchange rates), and commodity prices.
- At the country level, the model is Keynesian in the short run, with output driven by shifts in the demand. In the long run, the model is neo-classical and gross domestic product is determined by the economy's supply side potential (labour supply, capital stock, and productivity).
- At the state level, the model is built on an industry basis to incorporate state characteristics, including state-specific short run cycles, particularly around investment activity in mining and construction sectors.

BIS Oxford considers the impact of climate change through three channels:

- Global temperature impact on depreciation of capital stock and production potential.
- Investment in energy efficiency improvements leading to productivity gains.
- Increased renewable penetration and pace of electrification, which has an effect on global demand for transitional emissions-intensive materials (coal, oil, and gas).

BIS Oxford's low, expected, and high projections for GSP are presented in Table 20. These projections were applied to the low, expected, and high demand growth scenarios respectively. The economic forecasts for this WEM ESOO were rebased[218] using the forecast from the previous year, whilst population forecasts remained the same (due to a lack of data required to rebase). Economic growth in WA is expected to growth with an average annual rate of approximately 2.8% over the outlook period. WA's GSP growth rate is projected to exceed the national average[219].

Table 20 WA GSP (%) annual growth forecasts for different economic growth scenarios, 2022-23 to 2031-32 financial years[A]

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Low	0.4	1.9	3.3	3.7	3.5	3.4	3.0	2.7	2.7	2.7
Expected	3.2	3.4	3.5	3.3	3.1	3.0	3.0	2.9	2.8	2.6
High	2.6	3.3	2.7	3.3	3.4	3.4	3.2	2.8	2.8	2.8

A. BIS Oxford's 2021 Macroeconomic Projections Report adopts the 2021 IASR draft scenario taxonomy (see Table 10 for more information).
Source: BIS Oxford.

[217] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf.

[218] Rebasing included shifting the projection to match the actuals from 2021 data published by ABS, and trend (annual percentage change) applied from 2022 onwards. See https://www.abs.gov.au/statistics/economy/national-accounts/australian-system-national-accounts/latest-release.

[219] For national GSP, see https://www.treasury.act.gov.au/__data/assets/pdf_file/0010/399979/GSP.pdf.

The low demand growth scenario is characterised by lower population growth, slower pace of technological progress, and weaker investment growth (particularly in mining) compared to the expected demand growth scenario. The high demand growth scenario is characterised by strong decarbonisation objectives and moderate economic and population growth relative to the expected demand growth scenario.

See BIS Oxford's report for more information on the methodology and assumptions for the WA GSP forecasts.

A2.2 Residential electricity connection forecasts

AEMO developed the residential connections forecast under low, expected, and high demand growth scenarios for the SWIS. The forecast annual growth rates for the three connections growth scenarios are outlined in Table 21 below.

The forecast was developed by using historical SWIS residential connection point growth rates, together with BIS Oxford's dwelling construction forecasts. The short-term trend was blended (over a period of five years) with BIS Oxford's long-term forecast. Forecast new builds from BIS Oxford was split by building class and combined with the ABS dwelling statistics[220] to forecast residential connections in each scenario.

Table 21 Forecast residential connections growth (%) scenarios, 2022-23 to 2031-32 financial years

Scenario	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Low	1.3	1.4	1.5	1.5	1.6	1.7	1.8	1.9	1.8	1.7
Expected	1.4	1.5	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.0
High	1.4	1.7	2.0	2.1	2.1	2.0	1.9	2.0	2.1	2.1

A2.3 Prospective large industrial loads

AEMO engaged with a range of stakeholders, including Western Power, in deciding which prospective and committed LILs to include in the 2022 WEM ESOO. All new LIL projects were evaluated on a graded scale according to:

- The project's current state of progress through environmental approval stages.
- 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 final investment decision (FID) and/or the project has commenced construction.

The 2022 WEM ESOO incorporated a methodological improvement by applying a different set of weightings for LILs that are expected to come online within the next 12 months, reducing the weight applied to the Western Power's assessment as connection is highly likely if other criteria are satisfied. The graded scale was then used to classify projects based on their likelihood of progressing and ultimately connecting to the SWIS.

Five projects were identified as new LILs and were included in the demand and operational consumption forecasts for the 2022 WEM ESOO. These include mineral processing plants and a major public infrastructure

[220] Dwelling Structure by Dwelling Type (SA2+) from ABS 2016 Census, see http://stat.data.abs.gov.au/Index.aspx.

development. Three of the prospective LILs from the 2021 WEM ESOO have come online and have been included in this WEM ESOO's operational consumption and demand forecasts.

The evaluation process yielded annual consumption and demand forecast (Table 22) for the three grades of LILs:

- A LIL graded as highly likely to connect to the SWIS was included in the low, expected, and high demand growth scenarios.
- A LIL graded as moderately likely to connect to the SWIS was included in the expected and high demand growth scenarios.
- A LIL graded as even chances to connect to the SWIS was included only in the high demand growth scenario.
- While LILs were modelled explicitly in the operational consumption forecasts, their impact on maximum demand is indirect, and are therefore indicative only.

Table 22 Prospective LIL forecast outcome

Growth scenario	LIL grade	Estimated electricity consumption to add relative to 2020-21 (GWh)	Estimated demand to add to peak demand relative to 2020-21 (MW)
Low	**Highly likely to connect to the SWIS**	409	65
Expected	**Moderately likely to connect to the SWIS**	561	87
High	**Even chances to connect to the SWIS**	912	137

A2.4 DER forecasts

AEMO commissioned two external consultants to develop DER forecasts:

- Commonwealth Scientific and Industrial Research Organisation (CSIRO): developed DPV, battery storage, and EV[221] uptake forecasts.
- Green Energy Market's (GEM's): developed forecasts considering DPV and battery storage[222].

DPV and EV forecasts from the 2021 WEM ESOO have been rebased by aligning all scenarios to start from actuals at the end of March 2022. This in effect is simply a shift up or down of the forecast projections for each scenario such that the initial point matches with actuals.

The 2022 WEM ESOO adopts some revision to the DER forecast scenario mapping to better align with the NEM ESOO. This includes linking the low scenario to CSIRO's Slow Growth forecast and transitioning to the *Net Zero 2050* scenario for the expected demand growth scenario, where the 2021 WEM ESOO adopted the *Current Trajectory* scenario[223]. For more information, see Section 3.3.1.

[221] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf and https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf.

[222] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf.

[223] The expected demand growth scenario applies the average of both CSIRO and GEM's forecasts in 2021 and 2022 WEM ESOOs.

A2.4.1 CSIRO forecasting methodologies

The CSIRO forecasts aim to develop robust methodologies over both short-term and long-term periods. The CSIRO examines DPV, battery storage, and EV uptake over several market segments (residential, small commercial, and large commercial) over various time horizons. Differing methodologies and time horizons are employed as the predictive value of a given method is not equal over various time horizons. Numerous assumptions regarding technology cost, policy drivers, infrastructure, and consumer preferences are considered and varied the CSIRO scenarios[224].

Long-term model

The CSIRO long-term methodology reflects a theoretical model approach known as the consumer technology adoption model. Theoretical models perform best in the long run but often overlook short-term variations caused by imperfect information and unforeseen events. The CSIRO model is a mixed approach wherein payback periods are calculated and then augmented by non-price factors. The payback model considers existing and new electricity load, technology cost, and electricity tariffs. Non-price factors include the age, educational attainment, and discretional income of the consumer, and the type and ownership of building.

Short-term model

The CSIRO short-term methodology is a linear regression model based on actual data and does not incorporate an underlying theory of drivers. Extrapolations are most effective when modelling short-term time horizons. Extrapolating trends over the long run yields poor results due to the failure to account for underlying drivers. The CSIRO trend model is based upon two years of actuals, with dummy variables assigned to account for trends in monthly sales.

A2.4.2 GEM forecasting methodology

GEM's forecast methodologies develop several models: a payback model which assesses the financial attractiveness of investments into DPV and battery systems, a model of customer load profiles, and a linear regression model used in forecasting residential and commercial demand. Results are segmented into various size brackets (residential, small commercial, and large commercial[225]). GEM applies numerous assumptions across scenarios which align to those developed by AEMO and the CSIRO. GEM's methods are generally based on the assumption that previous installation levels and payback periods can be used to determine future installations. Financial assumptions considered are differences in technology cost reductions, wholesale generation costs, policy support, and network charges. The finance-centric approach is moderated with considerations for market saturation, the rate of new dwelling construction, and expected replacement cycles for systems[226].

[224] For a full discussion of the methodologies and assumptions employed by CSIRO, see https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2021/CSIRO-DER-Forecast-Report and https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf.

[225] Small power stations (1MW to 30 MW) are also considered, however are in front of the meter and do not constitute DER.

[226] For a full discussion of the methodologies and assumptions employed by GEM, see https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf.

The payback model

The payback model evaluates revenues and costs to determine the payback period. Financial incentives from government policy support are accounted for as an upfront deduction to the capital cost of the project. Revenues are determined by assessing reductions in demand, grid exports, tariffs, and grid imports (when DPV is insufficient to charge the battery).

The load profile model

Load profiles are determined for residential customers, and small and large commercial customers:

- Residential load profiles are based upon actual data from the Ausgrid Smart Grid, Smart City[227] trial wherein 300 residential customers who were separately metered from their solar generation. Separated metering allowed for the independent analysis of the DPV system.
- Commercial load profiles were based upon the load for the Dandenong substation[228], which primarily services non-residential customers. Substation loads were scaled to be representative of small commercial customers likely to claim small-scale technology credits, and large commercial customers likely to claim Large-Scale Generation Certificates.

Demand models

GEM forecasts commercial[229] and residential demand using a linear relationship based on four factors: (1) relative financial attractiveness, (2) relative level of saturation (using a scaling factor to incorporate a discount rate), (3) relative customer awareness, and (4) relative solar industry competitiveness and marketing. Scalars (3) and (4) are highly subjective but have been shown to have a clear impact on the level of demand.

[227] This dataset is available from Ausgrid's website here: https://www.ausgrid.com.au/Industry/Our-Research/Data-to-share/Solar-home-electricity-data.

[228] A single substation was chosen for simplicity; however, results were validated against other load servicing substations.

[229] Additional weight is given to financial attractiveness when forecasting commercial demand.

A3. Reliability assessment methodology

This appendix provides a summary of the reliability methodology used to assess EUE, the Availability Class requirements, and Availability Curves for the 2022 Long Term PASA study. While the methodology has not changed since the 2021 reliability assessment, updated data has been used to construct the load profiles used in the modelling.

In this appendix, historical reference years refer to 2016-17 to 2020-21.

A detailed description of the methodology and assumptions can be found in RBP's report[230].

A3.1 Expected unserved energy assessment

The EUE assessment aims to limit EUE to no more than 0.002% of annual expected operational consumption for each Capacity Year in the 2022 Long Term PASA Study Horizon[231]. RBP carried out the assessment in three phases and applied a combination of time sequential capacity availability simulation and Monte Carlo analysis as follows:

- **Phase 1**: Undertake hourly load forecasting to develop five sets of hourly operational load forecasts for each Capacity Year in the Long Term PASA Study Horizon. This method was previously used in the 2021 EUE assessment.
  - Underlying historical load profiles were created for each of five historical reference years by adding historical behind-the-meter PV generation to operational demand.
  - The underlying load profiles for each reference year were scaled to the underlying 50% POE peak demand and energy consumption forecasts for each Capacity Year to develop hourly underlying load forecasts[232].
  - Five sets of hourly DPV generation and battery storage charge/discharge contribution were forecast for each Capacity Year[233].
  - Preliminary operational load hourly forecasts were created by aggregating the forecast hourly DPV and battery storage contribution and the forecast hourly underlying load profiles[234], and adjusting for network losses.
  - The five preliminary operational load profiles were then scaled to the operational 50% POE peak demand and energy consumption forecasts to produce five hourly operational load forecasts for each Capacity Year under the expected scenario.

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

[231] In accordance with the second component of the Planning Criterion outlined in clause 4.5.9(b) of the WEM Rules.

[232] This creates five sets of hourly underlying load forecasts for each Capacity Year based on each of the five historical reference years' underlying load profiles' chronology and shapes.

[233] Each set of forecasts was based on the hourly DPV capacity factor traces and battery storage charge/discharge profiles from each historical reference year and the installed DPV and battery storage capacity forecasts for the relevant Capacity Year in the outlook period.

[234] Forecast hourly DPV generation was netted off the forecast hourly underlying load profiles. Forecast hourly battery contribution was subtracted from (when discharging) or added to (when charging) the forecast hourly underlying load profiles.

- **Phase 2**: Run the simulation to calculate the EUE using the hourly operational load forecasts developed in Phase 1.
  - Time sequential capacity availability simulation was used to compare the total available capacity to the corresponding load in an hour.
  - The simulation assesses the capacity gap (available capacity minus load) for every hour of each Capacity Year sequentially, given a specific capacity mix, load profile, network constraints[235], Planned Outage schedules, and randomly sampled Forced Outages.
  - Monte Carlo analysis was used to run the simulation with 50 Forced Outage iterations for each of the five forecast operational load profiles to generate a probability distribution of unserved energy. In total, 250 iterations were carried out for each Capacity Year.
  - 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 the 250 iterations.
- **Phase 3**: Determine the amount of Reserve Capacity required to limit the EUE to 0.002% of the annual expected operational consumption forecast.
  - The EUE was calculated as a percentage of the annual expected operational consumption forecast for a given Capacity Year. If the percentage of unserved energy forecast for a given Capacity Year is less than or equal to 0.002% then the simulation is stopped and the RCT will be set by the first component of the Planning Criterion.
  - If the percentage of EUE is more than 0.002%, the capacity requirement calculated based on part (a) of the Planning Criterion is incrementally increased to reassess the EUE until EUE is less than or equal to 0.002%. The RCT will then be set by part (b) of the Planning Criterion.

A3.2 Minimum capacity requirements (Availability Classes)

RBP determined the minimum quantity of capacity required to be provided by Availability Class 1 for the 2023-24 and 2024-25 Capacity Years (the second and third years of the Long Term PASA Study Horizon) by simulating unserved energy as follows:

1. The load forecasts were developed using a similar load forecasting approach as described in Phase 1 under Section A3.1, but with the following differences:
   - Historical sent-out generation for the five historical reference years was used to develop an average underlying load shape. This was then applied to 2020-21 load chronology and scaled to the underlying 50% POE peak demand and energy consumption forecasts to produce a single forecast underlying load profile.
   - Historical hourly DPV capacity factor traces and battery capacity charge/discharge profiles from the five historical reference years were used to develop an average historical DPV capacity factor trace and battery capacity charge/discharge profile.

[235] The 2022 reliability study has considered the network constraints that apply to Constrained Access Facilities under the GIA arrangement for the 2022-23 Capacity Year and full constrained network access from 1 October 2023.

  - A single operational load profile was forecast by aggregating the hourly underlying load forecasts and the hourly DPV and battery storage contributions. This operational load profile was then adjusted for network losses and scaled to meet the operational 50% POE peak demand and energy consumption forecasts.

2. Availability Class 2 capacity is modelled in greater detail to account for the availability constraints of DSM[236] and ESR capacity. In summary:
   - For 2022-23 , Availability Class 2 capacity is comprised solely of DSM capacity, as no stand-alone ESR capacity holds Capacity Credits for 2022-23.
   - For 2023-24 and onward, Availability Class 2 capacity includes both standalone ESR and DSM capacity.
     - ESR was dispatched first to reduce demand, with availability restricted to the period between 16:30 and 20:30.
     - DSM capacity was then dispatched optimally to reduce residual peak demand, subject to availability and scheduling constraints.
3. A reserve requirement was modelled to represent the criteria for evaluating Outage Plans (the Ready Reserve Standard and Ancillary Service Requirements under clause 3.18.11 of the WEM Rules).
4. Forced Outages were removed from the model to avoid double-counting, since the reserve requirement already accounts for Forced Outages.
5. The model was iterated to reallocate the quantity of capacity between Availability Class 1 and 2 (capped at the RCT) until the 0.002% EUE limit was violated.

The quantity of energy producing capacity where the EUE equals 0.002% of the expected operational consumption sets the minimum Availability Class 1 requirement. The Availability Class 2 requirement is calculated by subtracting the Availability Class 1 requirement from the RCT.

A3.3 Availability Curves

For the 2022 WEM ESOO, the Availability Curves were determined for 2023-24 and 2024-25 (the second and third Capacity Years in the Long Term PASA Study Horizon). RBP determined the Availability Curves by:

- Using the operational load profiles for 2023-24 and 2024-25 developed in Phase 1 of the EUE assessment but with the following differences:
  - Load for the first 24 hours is based on the 10% POE peak demand forecast under the expected demand growth scenario, as required under clause 4.10.5(e)(i) of the WEM Rules.
  - Load for the remaining hours (25 to 8,760) is based on a 50% POE peak demand forecast under the expected demand growth scenario.
  - Applying a smoothing function to the first 72 hours of the estimated load duration curve.
- Adding the reserve margin and allowances for Intermittent Loads and LFAS to the forecast load duration curve as required under clause 4.5.10(e)(ii) of the WEM Rules.

[236] Excluding Interruptible Load used to provide Spinning Reserve.

This approach assumes that the difference between a 10% POE and a 50% POE peak year would only be evident in the first 24 hours of the load duration curve. Consequently, the forecast minimum capacity requirements for the twenty-fourth hour onwards are expected to match the load profile with a 50% POE peak demand forecast under the expected demand growth scenario.

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

To forecast the capacity supply-demand balance over the 2022 Long Term PASA Study Horizon under the low and high capacity scenarios, AEMO has forecast additional capacity supply models and compared them with the RCT determined in this WEM ESOO.

The low scenario assumes no new facilities are brought online and includes the recent WA Government's announcement of the retirement of Collie Power Station and Muja D Power Station[237].

Table 23 Supply-demand balance for the low capacity scenario, 2022-23 to 2031-32

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
RCR/RCT[A] (MW)	4,421	4,396	4,526	4,554	4,605	4,642	4,675	4,723	4,770	4,837
Capacity (MW)	4,807[B]	4,727[B]	4,534[C]	4,534	4,534	4,216[D]	4,216	3,798[E]	3,798	3,798
Excess capacity (MW)	386	331	8	-21	-72	-425	-459	-925	-972	-1,039
Excess capacity (%)	8.7	7.5	0.2	-0.5	-1.6	-9.2	-9.8	-19.6	-20.4	-21.5

A. The quantities reported for 2022-23, 2023-24, and 2024-25 are the RCR, while the remaining Capacity Years are the RCT.
B. The 2022-23 and 2023-24 available capacity values are the total quantities of Capacity Credits assigned.
C. The capacity values for 2024-25 and remaining years are forecasts, assuming the quantity of Capacity Credits assigned for 2023-24 remain unchanged other than the retirement of Muja C unit 6 from 2024-25. This estimate does not consider the Expressions of Interest received for the 2022 Reserve Capacity Cycle, which will be published in a summary report by the end of June 2022.
D. Assumed Collie Power Station is scheduled for retirement in October 2027.
E. Assumed Muja D Power Station is scheduled for retirement in October 2029.

The high capacity scenario includes prospective facilities (see Appendix A3.5) that may be brought online during the Long Term PASA Study Horizon. It also includes Western Power's community batteries. It does not include the proposed closure of Collie Power Station in October 2027 and Muja D Power Station in October 2029.

[237] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/06/State-owned-coal-power-stations-to-be-retired-by-2030.aspx.

Table 24 Supply-demand balance for the high capacity scenario, 2022-23 to 2031-32

	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
RCR/RCT[A] (MW)	4,421	4,396	4,526	4,554	4,605	4,642	4,675	4,723	4,770	4,837
Capacity (MW)	4,807[B]	4,727[B]	4,650[C]	4,650	4,650	4,650	4,650	4,650	4,650	4,650
Excess capacity (MW)	386	331	124	96	45	8	-25	-73	-120	-187
Excess capacity (%)	8.7	7.5	2.7	2.1	1.0	0.2	-0.5	-1.5	-2.5	-3.9

A. The quantities reported for 2022-23, 2023-24, and 2024-25 are the RCR, while the remaining Capacity Years are the RCT.
B. The 2022-23 and 2023-24 available capacity values are the total quantities of Capacity Credits assigned.
C. The capacity values for 2024-25 and remaining years are forecasts, assuming the quantity of Capacity Credits assigned for 2023-24 remain unchanged other than the retirement of Muja C unit 6 from 2024-25. This estimate does not consider the Expressions of Interest received for the 2022 Reserve Capacity Cycle, which will be published in a summary report by the end of June 2022.

A3.4.1 Selection criteria for prospective facilities

Prospective facilities can be at various stages of progress. The facilities can be planned, in the approvals phase, or in the construction phase. Some of those in the construction phase may already have been awarded Capacity Credits in previous cycles, especially if they are close to completion.

Three tests were used to rank the prospective facilities:

1. **Environmental Protection Authority (EPA) approval** – for a project to proceed, the operator needs to receive environmental approval from WA's EPA. EPA approval is in five stages, with the fifth stage being the ministerial statement to approve the project. AEMO allocated 100% once a project has reached Stage 5 (Approval) with 20%, 40%, 60%, and 80% allocated to stages 1 to 4 respectively. A second method of approval is where an existing facility is to be modified (for example, by the addition of a battery). In this case, the approval is just an amendment to the existing ministerial statement, it is either 0% or 100%, depending on whether the approval has been published.
2. **Western Power connection approval** – connection status is obtained by AEMO directly from the operator. 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, and have assigned 50% if it is an addition (for example, a battery) to an existing generating facility that is already connected.
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.

These factors were then weighted to give an overall percentage for each prospective facility. AEMO included facilities that achieved a weighted score of at least 25% in the high scenario figures.

A4. Expected unserved energy results

Table 25 Expected unserved energy results, 2022-23 to 2031-32

Capacity Year	Operational consumption (MWh)	0.002% of operational consumption (MWh)	EUE (MWh)	EUE (%)
2022-23	16,545,290	347	4.623	0.00003
2023-24	16,205,860	343	0.000	0.00000
2024-25	15,892,830	339	1.418	0.00001
2025-26	15,758,820	337	0.152	0.00001
2026-27	15,762,650	334	1.800	0.00001
2027-28	15,681,750	332	1.857	0.00001
2028-29	15,615,460	329	0.298	0.00001
2029-30	15,680,140	328	0.876	0.00001
2030-31	15,871,200	329	2.116	0.00001
2031-32	16,151,240	334	0.708	0.00001

Source: AEMO and RBP.

A5. Summer peak demand forecasts

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

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,888	3,631	3,399
2023-24	3,859	3,620	3,388
2024-25	3,824	3,581	3,352
2025-26	3,782	3,548	3,323
2026-27	3,839	3,591	3,363
2027-28	3,834	3,594	3,366
2028-29	3,846	3,605	3,383
2029-30	3,864	3,622	3,407
2030-31	3,877	3,644	3,423
2031-32	3,901	3,661	3,437
Average growth	0.0%	0.1%	0.1%

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

Capacity Year	10% POE	50% POE	90% POE
2022-23	4,042	3,781	3,533
2023-24	4,055	3,790	3,551
2024-25	4,078	3,821	3,575
2025-26	4,106	3,855	3,619
2026-27	4,157	3,899	3,666
2027-28	4,194	3,934	3,692
2028-29	4,227	3,967	3,727
2029-30	4,275	4,018	3,777
2030-31	4,322	4,075	3,833
2031-32	4,389	4,141	3,894
Average growth	0.9%	1.0%	1.1%

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

Capacity Year	10% POE	50% POE	90% POE
2022-23	4,121	3,856	3,606
2023-24	4,182	3,919	3,680
2024-25	4,278	4,021	3,764
2025-26	4,389	4,121	3,872
2026-27	4,500	4,225	3,972
2027-28	4,594	4,327	4,067
2028-29	4,697	4,427	4,165
2029-30	4,798	4,525	4,264
2030-31	4,885	4,616	4,360
2031-32	4,978	4,709	4,443
Average growth	2.1%	2.2%	2.3%

A6. Winter peak demand forecasts

Table 29 Winter peak demand forecasts under the low demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,520	3,359	3,215
2023-24	3,502	3,358	3,214
2024-25	3,457	3,316	3,178
2025-26	3,434	3,295	3,157
2026-27	3,476	3,339	3,200
2027-28	3,491	3,352	3,209
2028-29	3,497	3,362	3,224
2029-30	3,513	3,375	3,240
2030-31	3,534	3,396	3,262
2031-32	3,548	3,415	3,279
Average growth	0.1%	0.2%	0.2%

Table 30 Winter peak demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,631	3,476	3,331
2023-24	3,654	3,506	3,358
2024-25	3,680	3,526	3,385
2025-26	3,721	3,565	3,422
2026-27	3,774	3,620	3,474
2027-28	3,801	3,651	3,503
2028-29	3,836	3,683	3,540
2029-30	3,880	3,722	3,578
2030-31	3,933	3,780	3,634
2031-32	4,000	3,840	3,696
Average growth	1.1%	1.1%	1.2%

Table 31 Winter peak demand forecasts under the high demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	3,693	3,536	3,389
2023-24	3,767	3,605	3,454
2024-25	3,854	3,691	3,547
2025-26	3,960	3,794	3,643
2026-27	4,052	3,894	3,743
2027-28	4,138	3,982	3,828
2028-29	4,223	4,067	3,918
2029-30	4,320	4,154	4,007
2030-31	4,409	4,243	4,094
2031-32	4,504	4,338	4,187
Average growth	2.2%	2.3%	2.4%

A7. Minimum demand forecasts

Table 32 Minimum demand forecasts under the expected demand growth scenario (MW)

Capacity Year	10% POE	50% POE	90% POE
2022-23	587	546	502
2023-24	416	375	333
2024-25	262	231	184
2025-26	140	108	54
2026-27	40	11	-37
Average growth	-48.9%	-62.1%	N/A

A8. Operational consumption forecasts

Table 33 Operational consumption forecasts (GWh)

Capacity Year	Low	Expected	High
2022-23	14,986	16,545	17,601
2023-24	14,562	16,206	17,175
2024-25	14,048	15,893	16,836
2025-26	13,663	15,759	16,722
2026-27	13,618	15,763	16,799
2027-28	13,449	15,682	17,044
2028-29	13,288	15,615	17,301
2029-30	13,211	15,680	17,729
2030-31	13,180	15,871	18,276
2031-32	13,169	16,151	18,880
Average growth	-1.4%	-0.3%	0.8%

A9. Energy producing systems

Table 34 Scheduled Generators, 2020-21[A]

Market Participant	Facility	Classification[B]	Energy Generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%)[C]
Alcoa of Australia Limited	ALCOA_WGP	Baseload	33.210	0.19%	26.000	0.54%
Alinta Sales Pty Ltd	ALINTA_PNJ_U1	Baseload	695.089	3.95%	137.000	2.86%
	ALINTA_PNJ_U2	Baseload	730.554	4.15%	137.000	2.86%
	ALINTA_WGP_GT	Mid-merit	115.463	0.66%	196.000	4.10%
	ALINTA_WGP_U2	Peaking	76.497	0.43%	196.000	4.10%
Bluewaters Power 1 Pty Ltd	BW1_BLUEWATERS_G2	Baseload	1506.946	8.56%	217.000	4.53%
Bluewaters Power 2 Pty Ltd	BW2_BLUEWATERS_G1	Baseload	1488.519	8.45%	217.000	4.53%
Goldfields Power Pty Ltd	PRK_AG	Mid-merit	45.643	0.26%	59.400	1.24%
Landfill Gas and Power Pty Ltd	KALAMUNDA_SG	Peaking	0.003	0.00%	1.300	0.03%
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	Mid-merit	178.316	1.01%	330.600	6.91%
NewGen Power Kwinana Pty Ltd	NEWGEN_KWINANA_CCG1	Baseload	1960.840	11.13%	327.800	6.85%
Southern Cross Energy	STHRNCRS_EG	Baseload	97.621	0.55%	20.000	0.42%
Synergy	COCKBURN_CCG1	Mid-merit	189.699	1.08%	240.000	5.01%
	COLLIE_G1	Mid-merit	895.844	5.09%	317.200	6.63%
	KEMERTON_GT11	Peaking	71.210	0.40%	155.000	3.24%
	KEMERTON_GT12	Peaking	65.643	0.37%	155.000	3.24%
	KWINANA_GT2	Baseload	310.146	1.76%	98.500	2.06%
	KWINANA_GT3	Baseload	321.453	1.82%	99.200	2.07%
	MUJA_G5	Mid-merit	729.668	4.14%	195.000	4.07%
	MUJA_G6	Baseload	791.069	4.49%	193.000	4.03%
	MUJA_G7	Baseload	946.383	5.37%	211.000	4.41%

Market Participant	Facility	Classification[B]	Energy Generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%)[C]
	MUJA_G8	Baseload	1173.706	6.66%	211.000	4.41%
	MUNGARRA_GT1[D]	N/A	16.713	0.09%	0.000	0.00%
	MUNGARRA_GT3[D]	N/A	14.242	0.08%	0.000	0.00%
	PINJAR_GT1	Peaking	3.311	0.02%	31.072	0.65%
	PINJAR_GT10	Mid-merit	147.457	0.84%	111.000	2.32%
	PINJAR_GT11	Mid-merit	226.794	1.29%	124.000	2.59%
	PINJAR_GT2	Peaking	1.782	0.01%	30.300	0.63%
	PINJAR_GT3	Peaking	1.894	0.01%	37.000	0.77%
	PINJAR_GT4	Peaking	1.858	0.01%	37.000	0.77%
	PINJAR_GT5	Peaking	1.735	0.01%	37.000	0.77%
	PINJAR_GT7	Peaking	3.339	0.02%	36.500	0.76%
	PINJAR_GT9	Mid-merit	138.859	0.79%	111.000	2.32%
	PPP_KCP_EG1	Baseload	557.792	3.17%	80.400	1.68%
	WEST_KALGOORLIE_GT2[D]	N/A	2.614	0.01%	0.000	0.00%
	WEST_KALGOORLIE_GT3[D]	N/A	1.596	0.01%	0.000	0.00%
Tesla Geraldton Pty Ltd	TESLA_GERALDTON_G1	Peaking	0.155	0.00%	9.900	0.21%
Tronox Management Pty Ltd	TIWEST_COG1	Baseload	245.444	1.39%	36.000	0.75%
Western Energy Pty Ltd	PERTHENERGY_KWINANA_GT1	Peaking	21.227	0.12%	109.000	2.28%

A. Only Facilities with net sent-out generation in 2020-21 have been included.
B. AEMO classifies Scheduled Generators as: Baseload capacity (operates more than 70% of the time), Mid-merit capacity (operates between 10% and 70% of the time), or Peaking capacity (operates less than 10% of the time).
C. The Capacity Credits share (%) is calculated from a total of 4,786.3 MW of Capacity Credits assigned to Scheduled Generators and Intermittent Non-Scheduled Generators for 2020-21. A total of 4,965.551 MW of Capacity Credits were assigned for the 2020-21 Capacity Year, including 66.000 MW of Capacity Credits assigned to DSPs.
D. Registered Facilities with net sent-out generation that did not participate in the RCM for 2020-21.

Table 35 Non-Scheduled Generators, 2020-21[A]

Market Participant	Facility	Energy Source	Maximum Capacity (MW)	Energy Generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%)[B]
Alinta Sales Pty Ltd	ALINTA_WWF	Wind	89.100	297.436	1.69%	22.035	0.46%
	BADGINGARRA_WF1	Wind	130.000	515.334	2.93%	36.428	0.76%
	YANDIN_WF1	Wind	211.680	678.542	3.85%	40.932	0.86%
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1	Wind	180.000	606.483	3.44%	36.124	0.75%
Blair Fox Pty Ltd AFT The Blair Fox Trust	BLAIRFOX_BEROSRD_WF1[C]	Wind	9.252	12.329	0.07%	0.000	0.00%
	BLAIRFOX_KARAKIN_WF1	Wind	5.000	4.031	0.02%	0.736	0.02%
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	Wind	218.500	667.764	3.79%	22.894	0.48%
Delorean Energy Retail	BIOGAS01[C]	Landfill Gas	2.000	4.627	0.03%	0.000	0.00%
Denmark Community Windfarm Ltd	DCWL_DENMARK_WF1	Wind	1.440	5.592	0.03%	0.414	0.01%
EDWF Manager Pty Ltd	EDWFMAN_WF1	Wind	80.000	292.342	1.66%	26.317	0.55%
Landfill Gas and Power Pty Ltd	RED_HILL	Landfill Gas	3.640	20.556	0.12%	2.868	0.06%
	TAMALA_PARK	Landfill Gas	4.800	30.918	0.18%	4.292	0.09%
Merredin Solar Farm Nominee Pty Ltd	MERSOLAR_PV1	Solar	100.000	225.775	1.28%	22.500	0.47%
Metro Power Company Pty ltd	AMBRISOLAR_PV1	Solar	0.960	1.999	0.01%	0.270	0.01%
Mt. Barker Power Company Pty Ltd	SKYFRM_MTBARKER_WF1	Wind	2.430	7.060	0.04%	0.606	0.01%
Mumbida Wind Farm Pty Ltd	MWF_MUMBIDA_WF1	Wind	55.000	185.536	1.05%	8.943	0.19%
Northam Solar Project Partnership	NORTHAM_SF_PV1	Solar	9.800	20.560	0.12%	2.568	0.05%
Perth Energy Pty Ltd	ROCKINGHAM	Landfill Gas	4.000	10.187	0.06%	2.286	0.05%
	SOUTH_CARDUP	Landfill Gas	4.158	17.042	0.10%	3.009	0.06%
SRV AGWF Pty Ltd as trustee for AGWF Trust	ALBANY_WF1	Wind	21.600	56.925	0.32%	6.434	0.13%
	GRASMERE_WF1	Wind	13.800	42.065	0.24%	4.329	0.09%
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	Solar	40.000	84.809	0.48%	9.905	0.21%
Synergy	BREMER_BAY_WF1	Wind	0.600	1.780	0.01%	0.190	0.00%

Market Participant	Facility	Energy Source	Maximum Capacity (MW)	Energy Generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%)[B]
	KALBARRI_WF1	Wind	1.600	1.473	0.01%	0.287	0.01%
Waste Gas Resources Pty Ltd	HENDERSON_RENEWABLE_IG1	Landfill Gas	3.000	12.745	0.07%	1.761	0.04%

A. Only Facilities with net sent-out generation in 2020-21 have been included.
B. The Capacity Credits share (%) is calculated from a total of 4,786.3 MW of Capacity Credits assigned to Scheduled Generators and Intermittent Non-Scheduled Generators for 2020-21. A total of 4,965.551 MW of Capacity Credits were assigned for 2020-21, including 66.000 MW of Capacity Credits assigned to DSPs.
C. Facilities with net sent-out generation that that did not participate in the RCM for 2020-21.

A10. Facility capacities

Table 36 Capacities of Registered Facilities

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Maximum Capacity (MW)
Alcoa of Australia Limited	ALCOA_WGP	26.000	26.000
Alinta Sales Pty Ltd	ALINTA_PNJ_U1	142.450	143.000
	ALINTA_PNJ_U2	142.450	143.000
	ALINTA_WGP_GT	196.000	196.000
	ALINTA_WGP_U2	196.000	196.000
	ALINTA_WWF	14.278	89.100
	BADGINGARRA_WF1	25.543	130.000
	YANDIN_WF1	34.109	211.680
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1	25.324	180.000
Blair Fox Pty Ltd AFT The Blair Fox Trust	BLAIRFOX_BEROSRD_WF1	0.000	9.252
	BLAIRFOX_KARAKIN_WF1	0.331	5.000
Bluewaters Power 1 Pty Ltd	BW1_BLUEWATERS_G2	217.000	217.000
Bluewaters Power 2 Pty Ltd	BW2_BLUEWATERS_G1	217.000	217.000
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	19.758	218.500
Delorean Energy Retail	BIOGAS01	0.602	2.000
Denmark Community Windfarm Ltd	DCWL_DENMARK_WF1	0.405	1.440
EDWF Manager Pty Ltd	EDWFMAN_WF1	12.877	80.000
Goldfields Power Pty Ltd	PRK_AG	59.748	68.000
Landfill Gas and Power Pty Ltd	RED_HILL	2.753	3.640
	TAMALA_PARK	4.265	4.800
Merredin Energy	NAMKKN_MERR_SG1	82.000	92.600
Merredin Solar Farm Nominee Pty Ltd	MERSOLAR_PV1	8.507	100.000

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Maximum Capacity (MW)
Metro Power Company Pty ltd	AMBRISOLAR_PV1	0.867	0.960
Mt. Barker Power Company Pty Ltd	SKYFRM_MTBARKER_WF1	0.625	2.430
Mumbida Wind Farm Pty Ltd	MWF_MUMBIDA_WF1	7.337	55.000
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600	342.000
NewGen Power Kwinana Pty Ltd	NEWGEN_KWINANA_CCG1	334.800	335.000
Northam Solar Project Partnership	NORTHAM_SF_PV1	1.010	9.800
Perth Energy Pty Ltd	ROCKINGHAM	1.964	4.000
	SOUTH_CARDUP	1.750	4.158
SRV AGWF Pty Ltd as trustee for AGWF Trust	ALBANY_WF1	5.389	21.600
	GRASMERE_WF1	3.662	13.800
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	4.499	40.000
Synergy	BREMER_BAY_WF1	0.167	0.600
	COCKBURN_CCG1	240.000	249.700
	COLLIE_G1	317.200	318.300
	KALBARRI_WF1	0.203	1.600
	KEMERTON_GT11	155.000	154.700
	KEMERTON_GT12	155.000	154.700
	KWINANA_GT2	98.500	103.200
	KWINANA_GT3	99.200	103.200
	MUJA_G6	193.000	193.600
	MUJA_G7	207.155	212.600
	MUJA_G8	211.000	212.600
	PINJAR_GT1	31.000	38.500
	PINJAR_GT10	110.500	118.150

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Maximum Capacity (MW)
	PINJAR_GT11	124.000	130.000
	PINJAR_GT2	30.500	38.500
	PINJAR_GT3	37.000	39.300
	PINJAR_GT4	37.000	39.300
	PINJAR_GT5	37.000	39.300
	PINJAR_GT7	37.000	39.300
	PINJAR_GT9	111.000	118.150
Tesla Corporation Management Pty Ltd	TESLA_PICTON_G1	9.900	9.900
Tesla Geraldton Pty Ltd	TESLA_GERALDTON_G1	9.900	9.900
Tesla Kemerton Pty Ltd	TESLA_KEMERTON_G1	9.900	9.900
Tesla Northam Pty Ltd	TESLA_NORTHAM_G1	9.900	9.900
Tronox Management Pty Ltd	TIWEST_COG1	36.000	42.100
Waste Gas Resources Pty Ltd	HENDERSON_RENEWABLE_IG1	1.578	3.000
Western Energy Pty Ltd	PERTHENERGY_KWINANA_GT1	109.000	116.000

A. The maximum capacity of ALCOA_WGP is 16.000 MW for 2021-22, as shown in the WEM market data website.

Table 37 Capacities of committed and probable Facilities

Market Participant	Facility	Capacity Credits 2023-24 (MW)	Maximum Capacity (MW)
East Rockingham RRF Project	ERRRF_WTE_G1	25.134	29.000
Kwinana WTE Project Co	PHOENIX_KWINANA_WTE_G1	33.909	36.000
Synergy	KWINANA_ESR1	46.250	100.000

Table 38 Demand Side Management capability and availability[A]

Market Participant	DSP Name	Capacity Credits 2023-24 (MW)	Maximum MW available to provide Reserve Capacity
Bluewaters Power 1 Pty Ltd	GRIFFINP_DSP_01	20.000	20.000
Wesfarmers Kleenheat Gas Pty Ltd	PREMPWR_DSP_02	21.773	24.000
Synergy	SYNERGY_DSP_04	42.000	42.000

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

Glossary

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

Term	Definition
baseload capacity	Facilities that operate more than 70% of the time.
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.
capacity factor	The ratio of Capacity Credits to maximum capacity.
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.
contracted quantity	The Reserve Capacity expected to be made available by a DSP Facility via load curtailment.
cooling degree day	The number of degrees that a day's average temperature is above a critical temperature. It is used to account for deviation in weather from ‘standard’ weather conditions.
daytime hours	Trading Intervals commencing 08:00 to 16:30.
defined scenario	The 10% POE peak demand forecast under the expected demand growth scenario plus allowances for Intermittent Loads, frequency control, and a reserve margin.
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.
generator interim access	The GIA arrangement was developed to facilitate new generation connections on a constrained basis. It is not scalable and was intended as an interim solution. Generators connected under the GIA arrangement will be migrated to the new security-constrained dispatch engine as part of the implementation of constrained access (to be delivered under the WA Government’s ETS), and the GIA tool will be decommissioned.
heating degree day	The number of degrees that a day's average temperature is below a critical temperature. It is used to account for deviation in weather from ‘standard’ weather conditions.

Term	Definition
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.
mid-merit capacity	Facilities that operate between 10% and 70% of the time.
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. • 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	2022-23 to 2031-32, inclusive.
peak demand	The highest amount of demand consumed at any one time. Peak demand refers to operational peak demand unless otherwise stated.
peaking capacity	Facilities that operate less than 10% of the time.
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 Intermediate Season as defined in the WEM Rules.
summer	The Hot Season as defined in the WEM Rules.
synchronous generation	Synchronous generators are directly connected to the power system and rotate in synchronism with grid frequency. Thermal (coal, gas) and hydro (water) driven power turbines are typically synchronous generators.
under frequency load shedding	An emergency frequency control scheme that involves the controlled disconnection of load to correct a large supply-demand imbalance.
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.
value of customer reliability	The value customers place on having reliable electricity supply and avoiding most types of reliability events.
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.
weighted average cost of capital	A calculation of a company's cost of capital in which each component of capital, debt, and equity, is proportionately weighted. Weighted average cost of capital is used in calculating BRCP.

Term	Definition
winter	The Cold Season as defined in the WEM Rules.

Measures and abbreviations

Units of measure

Abbreviation	Unit of measure
GW	Gigawatt
GWh	Gigawatt hour
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour
VAR	volt-ampere reactive
W	Watt

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
AQP	Applications and Queuing Policy
BEV	Battery electric vehicle
BIS Oxford	BIS Oxford Economics
BMM	Business mass market
BOM	Bureau of Meteorology
BRCP	Benchmark Reserve Capacity Price
CDD	Cooling degree day
CER	Clean Energy Regulator
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEBS	Distribution Energy Buy Back Scheme
DER	Distributed energy resources
DPV	Distributed photovoltaics
DSM	Demand Side Management
DSP	Demand Side Programme
DSS	Dispatch Support Service

Abbreviation	Expanded name
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
ESS	Essential System Service
ETS	Energy Transformation Strategy
EUE	Expected unserved energy
EV	Electric vehicle
EVC	Electric Vehicle Council
FID	Final Investment Decision
FTT	Facility Technology Type
GEM	Green Energy Market
GEV	Generalised extreme value
GIA	Generator Interim Access
GSP	Gross state product
HDD	Heating degree day
IASR	Inputs, Assumptions and Scenarios report
ICE	Internal combustion engine
INSG	Intermittent Non-Scheduled Generator
IRCR	Individual Reserve Capacity Requirement
LDC	Linearly Derating Capacity
LFAS	Load following ancillary service
LIL	Large industrial load
NAFF	Network Augmentation Funding Facility
NAQ	Network Access Quantity
NCS	Network Control Services
NEM	National Electricity Market
NMI	National Metering Identifiers
NOM	Network Opportunity Map
PASA	Projected Assessment of System Adequacy
PHEV	Plug-in hybrid electric vehicle
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generator
RBP	Robinson Bowmaker Paul
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement

Abbreviation	Expanded name
RCT	Reserve Capacity Target
RLM	Relevant Level Methodology
SCED	Security Constrained Economic Dispatch
SERS	Sectoral Emissions Reduction Strategies
SWIS	South West Interconnected System
TSOG	Total Sent Out Generation
UFLS	Under frequency load shedding
VCR	Value of customer reliability
VDRT	Voltage disturbance ride-through
VPP	Virtual power plant
WA	Western Australia
WACC	Weighted average cost of capital
WAECF	Western Australian Electricity Consultative Forum
WEM	Wholesale Electricity Market
WOSP	Whole of System Plan