2019 Electricity Statement of Opportunities

June 2019

A report for the Wholesale Electricity Market

Important notice

PURPOSE

AEMO publishes the Wholesale Electricity Market Electricity Statement of Opportunities under clause 4.5.11 of the Wholesale Electricity Market Rules.

This publication has been prepared by AEMO using information available in May 2019. Information made available after this date may have been included in this publication where practical.

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VERSION CONTROL

Version	Release date	Changes
1	14/6/2019	Initial release
2	18/6/2019	Correction to measurement (MW to GWh), Table 2, page 5

Executive summary

This Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) presents AEMO's Long Term Projected Assessment of System Adequacy (PASA) for the South West interconnected system (SWIS) in Western Australia (WA). It reports AEMO's peak demand and operational consumption[1] forecasts across a range of weather and demand growth scenarios for the 10-year Long Term PASA Study Horizon for the 2019-20 to 2028-29 Capacity Years[2]. The WEM ESOO is one of the key aspects of the Reserve Capacity Mechanism (RCM), which ensures enough capacity is available to meet reliability targets set under the Long Term PASA study for the SWIS. The WEM ESOO report highlights the 10% probability of exceedance (POE)[3] peak demand forecast under the expected demand growth scenario[4], which is used to determine the Reserve Capacity Requirement (RCR)[5] for the 2021-22 Capacity Year.

Key findings

Long Term PASA ensures there is sufficient capacity in the SWIS to meet the forecast 10% POE peak demand plus a reserve margin, and to limit projected unserved energy to 0.002% of annual energy consumption for each Capacity Year of a 10-year forecast period.

- Based on the 10% POE peak demand forecast, the RCR has been determined as 4,482 megawatts (MW) for the 2021-22 Capacity Year.
- The 10% POE peak demand is forecast to grow slowly at an average annual rate of 0.4% over the outlook period. This is slightly lower than the 0.6% growth rate projected in the 2018 WEM ESOO.
- Assuming no changes in installed or committed capacity, there is expected to be sufficient capacity to meet forecast demand over the outlook period.
- For the first time, operational consumption is forecast to fall at an average annual rate of 0.4%, in comparison to 0.9% growth reported in the 2018 WEM ESOO.
- Both peak demand and operational consumption growth are expected to be subdued due to the continued uptake of behind the meter photovoltaic (PV) capacity[6], as well as ongoing energy efficiency improvements. This PV capacity is forecast to grow at an average annual rate of 7.6% (122 MW per year), with higher uptake expected in the early years of the outlook period, to reach an estimated 2,500 MW installed by 2028-29.
- The Demand Side Management (DSM) Reserve Capacity Price (RCP) for the 2019-20 Capacity Year is $16,990 per MW[7].

[1] Operational consumption refers to electricity supplied from the transmission grid over a period.

[2] A Capacity Year commences in the Trading Interval starting at 8:00 AM on 1 October and ends in the Trading Interval ending at 8:00 AM on 1 October of the following calendar year. All data in this WEM ESOO is based on Capacity Years unless otherwise specified.

[3] POE means the likelihood a peak demand forecast will be met or exceeded. A 10% POE peak demand forecast is expected to be exceeded, on average, only one year in 10, while 50% and 90% POE peak demand forecasts are expected to be exceeded, on average, five years in 10 and nine years in 10 respectively. A 10% POE forecast assumes more extreme weather and is more conservative than 50% and 90% POE forecasts for capacity planning.

[4] This 2019 WEM ESOO provides low, expected, and high demand growth scenarios based on different levels of economic growth. Unless otherwise indicated, demand growth forecasts in this executive summary are based on the expected demand growth scenario.

[5] The RCR is AEMO's determination of the total amount of generation or DSM capacity required in the SWIS to satisfy the Planning Criterion for a specific Reserve Capacity Cycle.

[6] Behind the meter PV capacity includes both residential and commercial rooftop PV that is less than 100 kilowatts (kW) and commercial PV systems ranging between 100 kW and 30 MW.

[7] This DSM RCP for the 2019-20 Capacity Year is based on the forecast Expected DSM Dispatch Quantity and is published in accordance with clause 4.5.13(i) of the WEM Rules. The RCP paid to generators for the 2019-20 and 2020-21 Capacity Years is $126,683/MW and $114,134/MW respectively; see https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price.

Reserve Capacity Requirement

The RCR for the 2021-22 Capacity Year is 4,482 MW[8].

Excess capacity has increased from 4.9% for the 2019-20 Capacity Year to 8.4% for the 2020-21 Capacity Year. This has largely been due to new large-scale renewable generation with an estimated nameplate capacity of around 400 MW[9] that was assigned Capacity Credits for the 2020-21 Capacity Year.

Assuming there are no changes to the current level of installed and committed capacity, based on forecast demand excess capacity is forecast to increase to 484 MW (10.8%) for the 2021-22 Capacity Year. By the end of the outlook period, excess capacity is forecast to fall to 407 MW (8.9%) due to peak demand growth.

The RCP for the 2021-22 Capacity Year will be determined once Capacity Credits have been assigned for the 2019 Reserve Capacity Cycle[10].

DSM Reserve Capacity Price

For the 2019-20 Capacity Year, the DSM RCP is $16,990 per MW[11].

The DSM RCP for the 2020-21 Capacity Year will be published in the 2020 WEM ESOO, three months before the price takes effect, in line with the WEM Rules.

Peak demand and operational consumption forecasts

The accuracy of peak demand forecasts directly affects the accuracy of the RCR, which is based on the 10% POE peak demand forecast. If peak demand forecasts are inaccurate there is a risk of setting an inappropriate RCR and RCP.

Since the RCP reflects the economic value of capacity, an inappropriately high or low RCP risks sending misleading price signals to the market. AEMO recognises the significant changes underway in the WEM (such as distributed energy resources (DER)[12] uptake), which are causing variability and uncertainty in peak demand. In response, AEMO is continuing to enhance its forecasting systems to monitor and analyse the impact of these changes.

AEMO forecasts the 10% POE peak demand to increase at an average annual rate of 0.4% over the 10-year outlook period, as presented in Table 1. These forecasts are lower than the peak demand forecasts published in the 2018 WEM ESOO, with the variance between the two forecasts at 118 MW in the 2021-22 Capacity Year.

Key drivers for lower forecasts include methodology improvements (particularly around the effect of behind the meter PV on peak demand), as well as revised economic and population growth forecasts. These reductions in the peak demand forecasts are partially offset by three new block loads in the expected case, which contribute to an additional 84 MW by 2021. Further details on these changes can be found in Chapter 3.

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8 Calculated as the 10% POE peak demand forecast, plus a reserve margin and maintaining the Minimum Frequency Keeping Capacity requirements (as defined in clause 3.10.1(a) of the WEM Rules). The reserve margin is calculated as the greater of (1) 7.6% of the 10% POE peak demand (including transmission losses) and allowing for Intermittent Loads and (2) the maximum capacity of the largest generating unit in the SWIS.

9 Including Alinta's Yandin Wind Farm (214.2 MW nameplate capacity; 40.932 MW Capacity Credits for the 2020-21 Capacity Year) and Bright Energy Investments' Warradarge Wind Farm (183.6 MW nameplate capacity; 36.124 MW Capacity Credits for the 2020-21 Capacity Year).

10 Timing for the events in the 2019 Reserve Capacity Cycle can be found in the 2019 Reserve Capacity timetable at http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Reserve-capacity-timetable.

11 All DSM information required by the WEM Rules is provided in Chapter 6 of this WEM ESOO.

12 DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter.

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

Scenario	2019-20 (MW)	2020-21 (MW)	2021-22 (MW)	2022-23 (MW)	2023-24 (MW)	5-year average annual growth	2028-29 (MW)	10-year average annual growth
10% POE	4,007	4,063	4,075	4,074	4,078	0.4%	4,152	0.4%
50% POE	3,758	3,813	3,819	3,822	3,826	0.5%	3,897	0.4%
90% POE	3,536	3,589	3,597	3,597	3,606	0.5%	3,672	0.4%

Source: ACIL Allen with AEMO input.

Operational consumption forecasts in gigawatt hours (GWh) for the high, expected, and low growth scenarios are shown in Table 2. These forecasts reflect different economic, population and electric vehicles growth scenarios[13]. Chapter 3 contains further information about the DER forecasts.

Table 2 Operational consumption forecasts[A] for different economic growth scenarios

Scenario	2019-20 (GWh)	2020-21 (GWh)	2021-22 (GWh)	2022-23 (GWh)	2023-24 (GWh)	5-year average annual growth	2028-29 (GWh)	10-year average annual growth
High	18,225	18,302	18,179	18,059	17,952	-0.4%	18,112	-0.1%
Expected	18,221	18,289	18,151	18,008	17,864	-0.5%	17,543	-0.4%
Low	18,191	18,004	17,832	17,679	17,521	-0.9%	17,024	-0.7%

A. Operational consumption forecasts are by financial year.
Source: ACIL Allen with AEMO input.

In the expected growth scenario, operational consumption is forecast to decline at an average annual rate of 0.5% over the next five years and 0.4% over the entire outlook period. This is in contrast to the 2018 WEM ESOO, which forecast operational consumption to grow at an average annual rate of 0.9% over the outlook period. The revision is largely associated with higher behind the meter PV forecasts, combined with falling residential consumption which is partly due to energy efficiency improvements. Chapter 5 contains analysis of the trends in operational consumption.

Trends in SWIS peak demand

Peak demand has previously averaged close to 3,700 MW (except for the all-time peak demand in 2015-16) over the past seven years, as shown in Table 3. This year's peak demand represents a significant decrease from previous years and was the lowest summer peak observed in the SWIS since 2006.

The unusually low 2018-19 peak demand indicates the increasing impact of behind the meter PV as well as the impact of the timing of very hot days (with maximum temperatures over 40°C[14]) on peak demand.

[13] For behind the meter PV, expected case forecasts have been applied to all three demand growth scenarios. This is because behind the meter PV uptake has been observed to be strongly driven by the payback period and customers' technology adoption preferences, rather than general macroeconomic drivers like GSP growth. Behind the meter battery storage is assumed to have no effect on operational consumption due to its small efficiency losses.

[14] BOM 2019, *About the climate extremes analyses: Extreme climate indices used.* Available at http://www.bom.gov.au/climate/change/about/extremes.shtml.

Table 3 Comparison of peak demand days, 2011-12 to 2018-19 Capacity Years

Capacity Year	Date	Trading Interval commencing	Peak demand (MW)	Daily maximum temperature[A] (°C)	Time of temperature peak	Rank of day[B]	Maximum temperature in Trading Interval (°C)
2018-19	7 February 2019	17:30	3,256	35.8	15:00	21	33.5
2017-18	13 March 2018	17:30	3,616	38.5	14:00	2	36.2
2016-17	21 December 2016	17:00	3,543	42.8	14:30	2	38
2015-16	8 February 2016	17:30	4,004	42.6	15:00	3	41
2014-15	5 January 2015	15:30	3,744	44.2	13:30	1	41.1
2013-14	20 January 2014	17:30	3,702	38.7	15:00	7	36.9
2012-13	12 February 2013	16:30	3,739	41.1	13:00	2	36
2011-12	25 January 2012	16:30	3,860	40.0	15:00	7	39.1

A. Measured at the Perth Airport weather station (station identification number 9021).
B. A rank of 1 indicates that it was the hottest day in the Capacity Year, and a rank of 2 indicates that it was the second hottest day in the Capacity Year.
Source: AEMO and Bureau of Meteorology (BOM).

It is expected that long term temperature trends are likely to continue to have significant impacts on peak demand. As ongoing evidence from BOM suggests continued changes in Australia's climate conditions[15], AEMO will continue to monitor the effects of climate on peak demand.

Impact of behind the meter PV systems

AEMO estimates the demand that would have occurred if there was no generation from behind the meter PV ("underlying demand"[16]). Underlying demand is then analysed to examine the effect of behind the meter PV on peak demand. Historically, underlying peak demand generally occurs on the same day as peak demand. Since 2006, which marks the commencement of the energy market, 2018-19 is the second time[17] that underlying peak demand occurred on a day that was different to the peak demand day.

Underlying peak demand is estimated as 3,555 MW at 14:00 on 20 January 2019[18], 9.2% higher than the observed peak demand of 3,256 MW at 17:30 on 7 February 2019, as shown in Figure 1. In 2018-19, the peak demand reduction due to rooftop PV (106 MW) output was outweighed by the reduction in peak demand due to the shift in peak demand time (193 MW). Although behind the meter PV generation dropped off slightly earlier on 7 February 2019 than it did on 20 January 2019, the underlying peak demand time was the crucial factor that determined the observed peak demand.

The most recent summer peak demand (for the 2018-19 Capacity Year) was equal to the most recent winter peak demand (in winter 2018), the first time this has happened since energy market commencement in 2006.

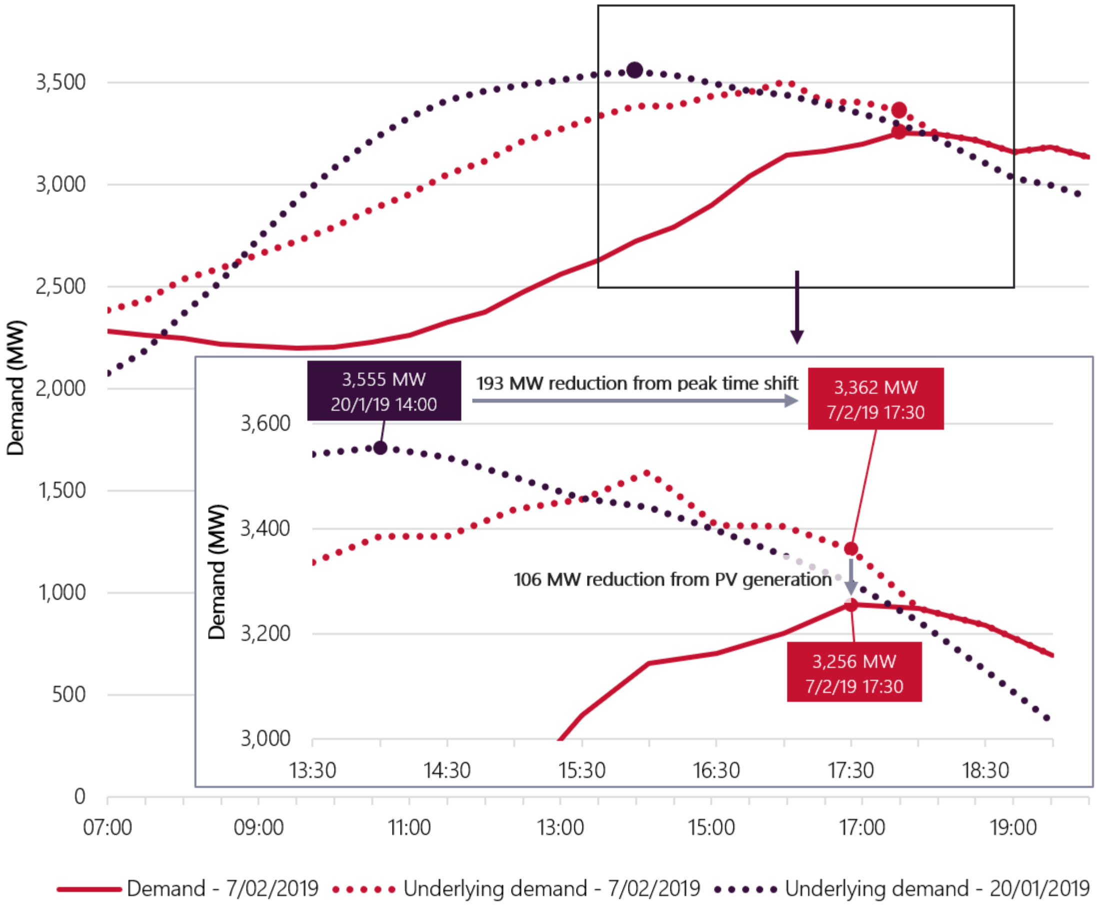
[15] BOM 2018, *State of the Climate 2018*, Australian Government. Available at http://www.bom.gov.au/state-of-the-climate/State-of-the-Climate-2018.pdf.

[16] Underlying demand refers to all electricity consumed on site and can be provided by localised generation from behind the meter PV, battery storage, and embedded generators, or by the electricity grid.

[17] The first time was 2013-14.

[18] 20 January 2019 was the hottest day of the 2018-19 Capacity Year.

Figure 1 **Underlying and observed demand on underlying and observed peak demand days**



The continued growth of behind the meter PV installations has affected the level and timing of peak demand over the last eight years. Actual peak demand for each year in the past eight years is compared with the estimated underlying peak demand in Table 4.

Table 4 **Effect of behind the meter PV on peak demand, 2011-12 to 2018-19**

Capacity Year	Month	Trading Interval commencing	Peak demand (MW)	Estimated underlying peak demand (MW)	Estimated underlying peak Trading Interval	Reduction in peak demand from PV generation (MW)	Reduction in peak demand from peak time shift (MW)
2018-19	Jan/Feb[A]	17:30	3,256	3,555	14:00	106	193
2017-18	Mar	17:30	3,616	3,727	16:30	12	99
2016-17	Dec	17:00	3,543	3,767	15:00	153	71
2015-16	Feb	17:30	4,004	4,147	16:30	63	81
2014-15	Jan	15:30	3,744	3,902	14:30	136	22
2013-14	Jan[A]	17:30	3,702	3,767	16:30	46	19
2012-13	Feb	16:30	3,739	3,806	14:00	55	12
2011-12	Jan	16:30	3,860	3,931	15:30	42	29

A. Underlying peak demand occurred on a different day in the same Capacity Year.

AEMO expects the strong growth of behind the meter PV capacity in the SWIS to continue, with an expected 2,500 MW of total installed capacity by the end of the outlook period. Technological, commercial, and regulatory factors, as well as increasing environmental awareness, continue to drive this strong uptake.

Response to Individual Reserve Capacity Requirement

The Individual Reserve Capacity Requirement (IRCR) financially incentivises Market Customers to reduce consumption during peak demand periods and consequently reduce their exposure to capacity payments.

The highest IRCR response to date occurred on 7 February 2019 when 59 customers reduced consumption, resulting in total load reduction of 82 MW. IRCR response in early February has been high historically as customers expect peak demand will occur in this period. The peak demand days in the 2018-19 Capacity Year have been easier for Market Customers to predict, as they occurred in late January to early March, resulting in high IRCR response rates. In the 2018-19 Hot Season, 190 unique customers responded in at least three Trading Intervals, indicating that the IRCR mechanism continues to encourage electricity users to reduce demand at peak times.

Other market changes in the WEM

There are several changes currently occurring in the WEM that may impact the RCM, including:

- The Generator Interim Access (GIA) arrangement[19], developed as a short-term solution to network congestion, is fully subscribed at just under 900 MW after receiving strong interest from project developers.
- Amendments to Reserve Capacity pricing arrangements have been proposed[20] to ensure that the RCP reflects the economic value of capacity.
- The DER Roadmap (to be developed by mid-2020), which forms part of the WA Government's Energy Transformation Strategy[21], will consider ways to mitigate the system security and market issues associated with strong uptake of DER technologies.
- A Whole of System Plan, which aims to consolidate many aspects of power system planning, is being developed by the WA Government (supported by AEMO and Western Power).

[19] 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 Energy Transformation Strategy), and the GIA tool will be decommissioned. There is currently concern that the GIA arrangement will limit the entry of some renewable facilities that may have otherwise connected prior to 2022 if the GIA arrangement had no capacity restriction.

[20] For further information, see https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Improving-Reserve-Capacity-pricing-signals/.

[21] For further information, see https://www.treasury.wa.gov.au/Treasury/News/Energy_Transformation_Strategy/.

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1. Introduction

The Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) is an annual publication which presents AEMO's Long Term Projected Assessment of System Adequacy (Long Term PASA) for the South West interconnected system (SWIS) in Western Australia (WA).

The WEM ESOO presents peak demand and operational consumption forecasts over a 10-year Long Term PASA Study Horizon. The Long Term PASA ensures there is sufficient capacity in the SWIS to meet the forecast peak demand plus a reserve margin.

The Reserve Capacity Mechanism (RCM) is a market-oriented mechanism that aims to ensure that a minimum level of generation and Demand Side Management (DSM) capacity is available in the SWIS to meet forecast electricity peak demand, and to limit expected energy shortfalls[22] to 0.002% of annual energy consumption for each Capacity Year of a 10-year forecast period[23]. The Long Term PASA in the 2019 WEM ESOO considers the 2019-20 to 2028-29 Capacity Years[24].

The development of the WEM ESOO is integral to the operation of the RCM in the WEM and may be used by Market Participants when making strategic, planning, investment, and other decisions relating to the issues and opportunities presented.

A key deliverable from the 2019 Long Term PASA is the determination of the Reserve Capacity Requirement (RCR) for the 2019 Reserve Capacity Cycle. The RCR is the quantity of generation and DSM capacity required under the RCM for the 2021-22 Capacity Year.

The 2019 WEM ESOO also includes information about:

- A summary of relevant government policies and initiatives.
- Relevant WEM Rules and methodologies under review.
- Emerging trends in Reserve Capacity requirements and pricing.
- Current and future issues relating to the operation of the SWIS.
- A summary of electricity infrastructure development plans for the SWIS.

[22] The expected energy shortfall is the expected unserved energy, which refers to a forecast by AEMO of the aggregate amount in megawatt hours by which the electricity demand is projected to exceed supply.

[23] The Planning Criterion, which sets the level of capacity to be procured through the RCM, is defined in clause 4.5.9 of the WEM Rules.

[24] A Capacity Year commences in the Trading Interval starting at 8:00 AM on 1 October and ends in the Trading Interval ending at 8:00 AM on 1 October of the following calendar year. All data in this WEM ESOO is based on Capacity Years unless otherwise specified.

2. Changes in generation capacity

This chapter examines the diversity of existing Facilities participating in the WEM based on Market Participant, fuel type, and Facility characteristics[25].

2.1 Capacity diversity

This chapter focuses on generation capacity associated with Facilities in the WEM that have been allocated Capacity Credits via the RCM[26].

2.1.1 Changes to Capacity Credit assignments

For the 2020-21 Capacity Year, 65 registered Facilities have been assigned 4,965.551 megawatts (MW) of Capacity Credits. This compares to 62 Facilities holding 4,887.970 MW of Capacity Credits for the 2019-20 Capacity Year and 50 Facilities holding 3,531.1 MW of Capacity Credits at capacity market start in 2005.

In the 2018 Reserve Capacity Cycle for the 2020-21 Capacity Year, new capacity was assigned Capacity Credits as follows:

- Two Non-Scheduled Generator (NSG) Facilities were assigned Capacity Credits:
  - Yandin Wind Farm (40.932 MW).
  - Warradarge Wind Farm (36.124 MW).
- Two upgrades to existing NSG Facilities were assigned Capacity Credits:
  - Greenough River Solar Farm extended its solar generation capacity, resulting in an additional 8.580 MW of Capacity Credits.
  - Badgingarra Wind Farm installed solar generation capacity and received an additional 5.904 MW of Capacity Credits.

2.1.2 Capacity Credits by fuel type

Figure 2 summarises the market share of Capacity Credits by fuel type within the WEM. It shows a significant decrease in DSM Capacity Credits following the 2016-17 Capacity Year, likely due to the introduction of a revised formula for calculating the DSM Reserve Capacity Price (RCP) for Demand Side Programmes (DSPs) which resulted in a lower price[27]. Consequently, DSM Capacity Credits declined by nearly 500 MW between the 2016-17 and 2020-21 Capacity Years.

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[25] More information on existing generation and DSM capacity can be found in the 2019 Request for Expressions of Interest, published January 2019 and available at https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Expressions-of-interest.

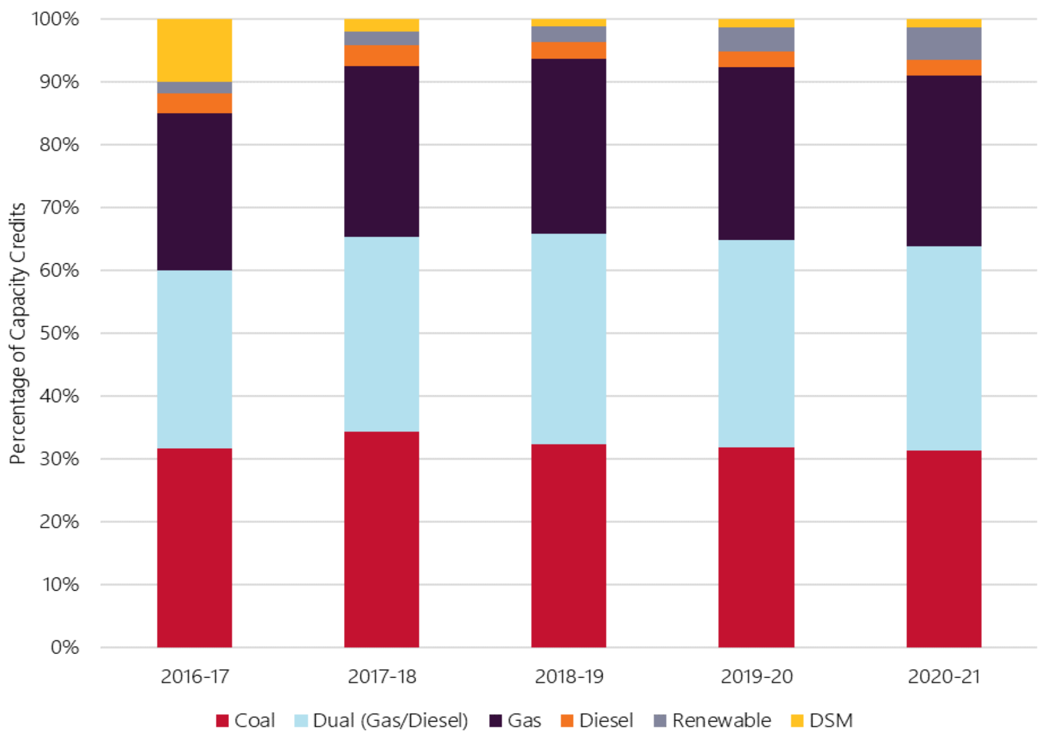
[26] Behind the meter photovoltaic (PV) does not receive Capacity Credits. For further information about behind the meter PV, refer to Chapter 3 and Chapter 4.

[27] Refer to the Government Gazette No.89 'Electricity Industry (Commencement of Electricity Industry (Wholesale Electricity) Market Amendment Regulations) Order 2016', Perth, 31 May 2016.

Key changes in Capacity Credits assigned between the 2019-20 and 2020-21 Capacity Years are:

- An increase of 38% in the share of capacity assigned to renewables (increasing from 3.8% of total Capacity Credits assigned for the 2019-20 Capacity Year to 5.2% of total Capacity Credits assigned for the 2020-21 Capacity Year).
- A decrease of 1.5% in total capacity share for coal, gas, diesel, and dual-fuel Facilities (decreasing from 94.9% of total Capacity Credits assigned for the 2019-20 Capacity Year to 93.5% of total Capacity Credits assigned for the 2020-21 Capacity Year).

Figure 2 Proportion of Capacity Credits by fuel type, 2016-17 to 2020-21 Capacity Years



2.2 Certified Facilities

The 65 Facilities that have been assigned a total of 4,965.551 MW of Capacity Credits for the 2020-21 Capacity Year are operated by a total of 31 Market Participants, and comprise:

- 39 Scheduled Generators.
- 24 NSGs.
- 2 DSP Facilities.

2.2.1 Facility types

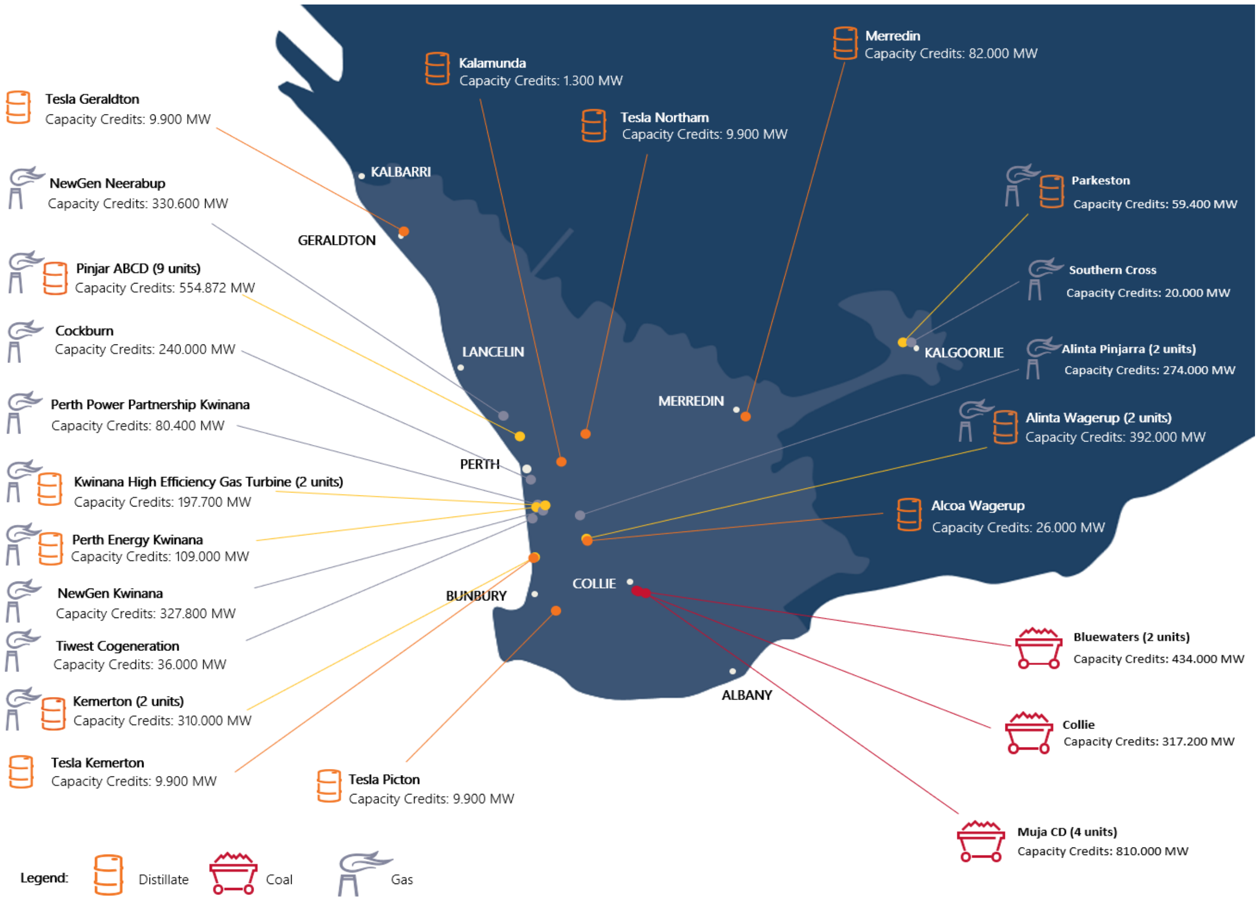
Scheduled Generators

The locations and Capacity Credit assignments for Scheduled Generators certified for the 2020-21 Capacity Year are shown in Figure 3.

Between the 2019-20 and 2020-21 Capacity Years, there have been no significant changes to the Scheduled Generation fleet, with assigned Capacity Credits increasing by 3.372 MW from a total of 4,638.5 MW to

4,641.872 MW[28]. Muja CD remains the largest power station, with four units[29] accounting for 16.3% of Capacity Credits assigned for the 2020-21 Capacity Year.

Figure 3 Scheduled Generator map for the SWIS, 2020-21



Non-Scheduled Generators

NSGs are typically assigned a lower level of Capacity Credits relative to their nameplate capacity, to reflect their contribution during peak demand periods, in comparison to Scheduled Generators which are assigned Capacity Credits based on their maximum generation capacity at 41°C[30]. The Capacity Credit assignment, nameplate capacity, and location of each Non-Scheduled Generator certified for the 2020-21 Capacity Year is shown in Figure 4.

Despite the quantity of Capacity Credits assigned to existing NSG Facilities decreasing[31], the quantity of Capacity Credits assigned to new and existing NSGs has increased overall by 74.209 MW (or 40%) between the 2019-20 and 2020-21 Capacity Years, from 183.470 MW to 257.679 MW. This increase is due to two:

- Facility upgrades – Badgingarra Wind Farm and Greenough River Solar Farm – totalling 14.484 MW of capacity.

[28] The 3.372 MW increase in assigned Capacity Credits is a result of improved operational efficiencies/output from existing Scheduled Generators.

[29] Muja CD comprises Muja units G5, G6, G7, and G8, with 195, 193, 211, and 211 MW of Capacity Credits in the 2020-21 Capacity Year, respectively.

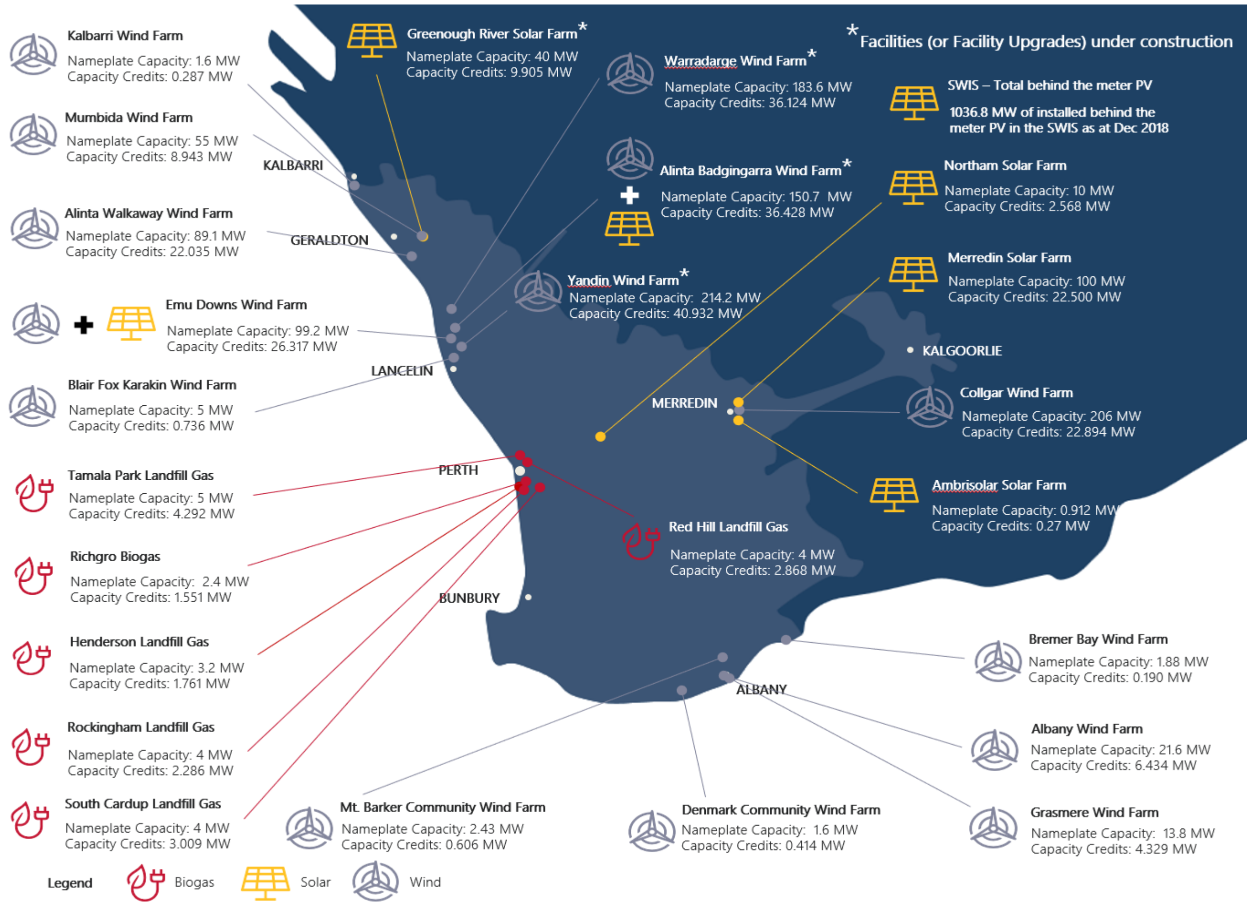
[30] The estimated contribution of NSG Facilities during peak periods is determined using the Relevant Level Methodology as detailed in Appendix 9 of the WEM Rules. Available at https://www.erawa.com.au/rule-change-panel/wholesale-electricity-market-rules. Scheduled Generators usually receive a quantity of Capacity Credits close to their nameplate capacity.

[31] Capacity Credits assigned to many existing Facilities have decreased due to decreasing Relevant Levels (the MW quantity determined by AEMO in accordance with the Relevant Level Methodology specified in Appendix 9 of the WEM Rules).

- New Facilities – Warradarge Wind Farm and Yandin Wind Farm – totalling 77.056 MW of capacity.

NSG capacity is comprised of 78% wind, 16% solar, and 6% biogas. The assignment of Capacity Credits for wind and biogas Facilities tends to be relatively consistent each year. In contrast, individual solar Facilities are demonstrating trends of lower Capacity Credit assignment. This is caused by increased behind the meter photovoltaic (PV) penetration reducing the level of demand from the SWIS during the day, consequently shifting peak demand intervals to evening periods when solar irradiance is minimal[32]. Section 4.1.4 contains further information relating to peak demand intervals shifting to evening periods.

Figure 4 Non-Scheduled Generators map for the SWIS, 2020-21



2.2.2 Facility size and characteristics

Classification of Capacity Credits

The Capacity Credits assigned to a Facility indicate the level of capacity that is expected to be available during peak demand periods. This is independent of the total energy generation each year, which is affected by factors including operating cost per megawatt hour, age, system demand, classification, and scheduled outages.

Newer generators are generally more fuel-efficient and can operate for longer periods without an outage, so have a higher energy output. Facilities that provide baseload generation, such as coal-fired generators, are designed to operate continuously and have high start-up costs. Consequently, it may be more economically

32 The generation profiles of large-scale and behind the meter PV are correlated, and a decline in behind the meter PV generation in the evening corresponds to a subsequent increase in observed demand from the grid. As a result, peak demand periods are typically occurring after the decline in behind the meter PV generation, where large-scale PV demonstrates a similarly low output, leading to a reduced Relevant Level.

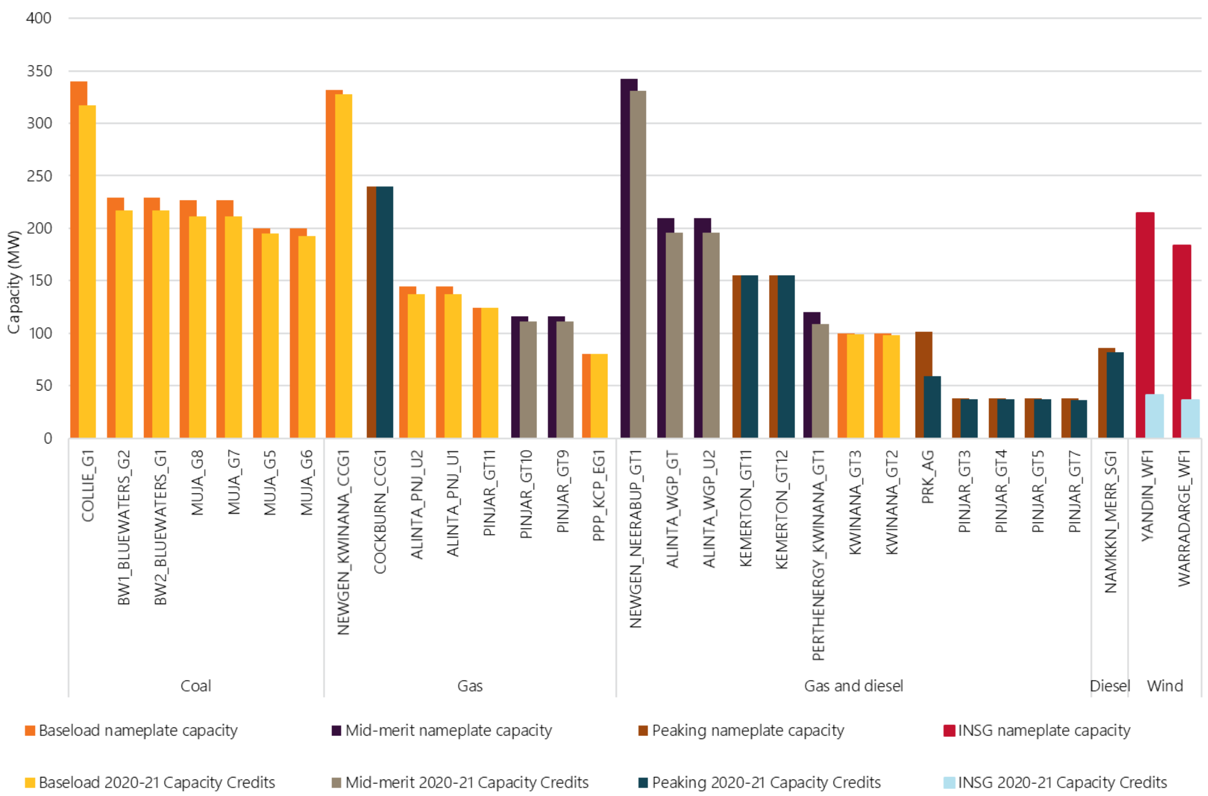
viable for these Facilities to continue to operate at lower demand times when wholesale electricity prices are low or even negative due to high levels of generation from NSG.

AEMO defines the classification of baseload, mid-merit, peaking, and NSG Facilities as follows[33]:

- **Baseload capacity** relates to Scheduled Generators that operate more than 70% of the time.
- **Mid-merit capacity** relates to Scheduled Generators that operate between 10% and 70% of the time.
- **Peaking capacity** relates to Scheduled Generators that operate less than 10% of the time.
- **NSG capacity** relates to Facilities that cannot be scheduled because the level of output is dependent on factors beyond the control of the operator.

The nameplate capacities, Capacity Credit assignments, and classifications of Facilities that have received Capacity Credits in the 2020-21 Capacity Year are shown in Figure 5.

Figure 5 Facility Capacity Credits and operating classification (Facilities receiving more than 35 MW of Capacity Credits)[A,B]



A. Facilities smaller than 35 MW have been excluded for better presentation of the information.
B. The difference between nameplate capacity and Capacity Credits for Scheduled Generators relates to the measurement at 41°C being slightly lower than nameplate capacity. For NSGs, the difference is accounted for by the Relevant Level calculation.

In summary, for the 2020-21 Capacity Year:

- The 12 largest Facilities by Capacity Credits have been classified as either baseload or mid-merit, and hold 57% of the total assigned Capacity Credits.
- 53% of assigned Capacity Credits have been classified as baseload, 21% as mid-merit, and 19% as peaking. The remaining Capacity Credits have been assigned to NSG and DSM Facilities.

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[33] The classification of baseload, mid-merit, and peaking Facilities is based on the percentage of Trading Intervals in the 2017-18 Capacity Year that the Facility operated, adjusted for full outages. A full outage has been defined as a Trading Interval where a Facility has gone on an outage equal to its Capacity Credit allocation during the 2017-18 Capacity Year.

- 100% of coal, 65% of gas, and 12% of dual-fuel Capacity Credits have been classified as baseload, totalling 2,627.1 MW.
- 17% of gas and 52% of dual-fuel Capacity Credits have been classified as mid-merit, totalling 1,053.6 MW.
- 18% of gas, 100% of diesel and 36% of dual-fuel Capacity Credits have been classified as peaking, totalling 941.172 MW.

For comparison, the behind the meter PV fleet (which does not receive Capacity Credits) had an installed capacity of approximately 1,036.8 MW as of December 2018, which is larger than Muja CD at 854 MW.

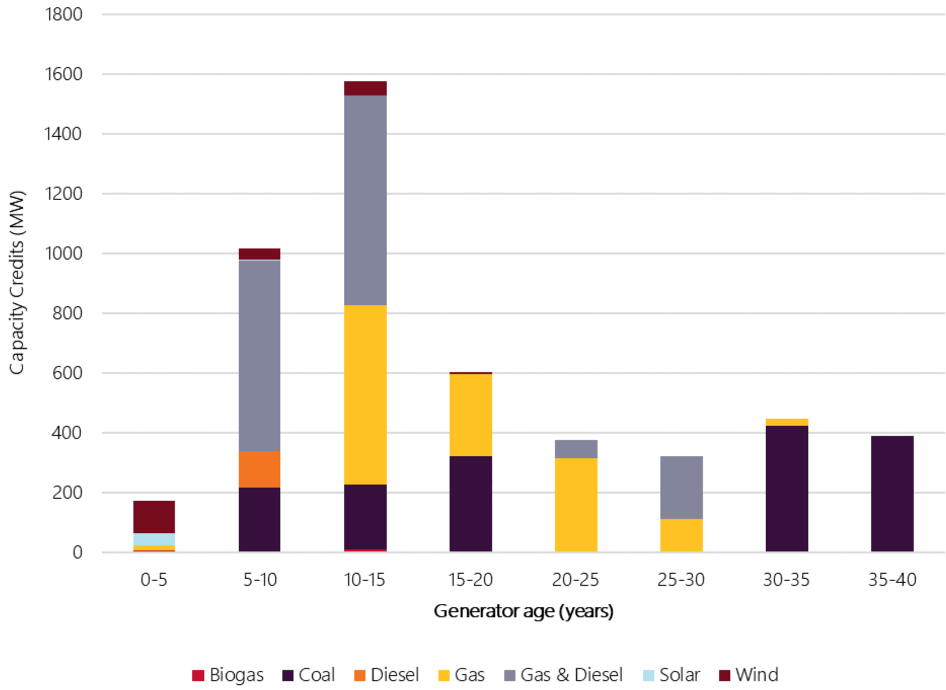
Facility age

Capacity Credits assigned for the 2020-21 Capacity Year are summarised in Figure 6, by fuel type and age of the generation mix participating in the RCM. Wind and solar are the most common fuel type installed over the past five years, despite receiving a significantly lower level of Capacity Credits than those assigned to Scheduled Generators. This is likely due to the additional sources of revenue streams available through Large-scale Generation Certificates under the Renewable Energy Target[34], and the relatively lower cost of operation compared to Scheduled Generators.

Other aspects relating to generator age and Capacity Credits include:

- At 34-39 years old, the Muja CD coal Facilities are the oldest generation in the SWIS and received a total of 810 MW of Capacity Credits in the 2020-21 Capacity Year.
- 97% of large-scale solar capacity has been installed in the past five years or is currently under construction.

Figure 6 Capacity Credits in the SWIS by fuel type and generator age, for the 2020-21 Capacity Year



[34] For further information, see http://www.environment.gov.au/climate-change/government/renewable-energy-target-scheme.

3. Forecast methodology and assumptions

This chapter describes the methodology and assumptions used to undertake the 2019 Long Term PASA study for the 2019-20 to 2028-29 Capacity Years to meet the Planning Criterion outlined in the WEM Rules. It includes a summary of methodologies for peak demand and operational consumption[35] forecasts and the expected energy shortfall (unserved energy) assessment. It presents inputs into the peak demand and operational consumption forecasts, including:

- Distributed energy resources technologies[36] uptake (behind the meter PV and battery storage, and electric vehicles [EVs]).
- Economic growth.
- Population growth.
- New block loads.

3.1 The Planning Criterion

The Planning Criterion that AEMO uses in the Long Term PASA study is outlined in clause 4.5.9 of the WEM Rules[37]. The Planning Criterion includes two parts to ensure that there is sufficient available capacity in each Capacity Year during the 2019 Long Term PASA Study Horizon[38] to:

- Meet the highest demand in a half-hour Trading Interval (part (a) of the Planning Criterion), assessed using the expected 10% probability of exceedance (POE[39]) peak demand forecasts presented in Chapter 4.
- Ensure adequate levels of energy can be supplied throughout the year (part (b) of the Planning Criterion), assessed by conducting reliability analysis to forecast the expected unserved energy (EUE) based on the peak demand and operational consumption forecasts presented in Chapters 4 and 5.

In line with past trends, the 2019 Long Term PASA study determined that the peak demand-based capacity requirement in part (a) set the Reserve Capacity Target (RCT)[40] for each Capacity Year from the 2019-20 to

[35] Operational consumption refers to electricity supplied from the transmission grid over a period.

[36] DER technologies refers to small-scale embedded technologies that either produce electricity, store electricity, or manage consumption, and reside within the distribution system, including resources that sit behind the customer meter.

[37] The Planning Criterion applies to the provision of generation and DSM capability – see clause 4.5.10 of the WEM Rules.

[38] The 2019 Long Term PASA Study Horizon is the 10-year period commencing on 1 October 2019 (1 October in Year 1 of the 2019 Reserve Capacity Cycle).

[39] POE means the likelihood a peak demand forecast will be met or exceeded. A 10% POE peak demand forecast is expected to be exceeded, on average, only one year in 10, while 50% and 90% POE peak demand forecasts are expected to be exceeded, on average, five years in 10 and nine years in 10 respectively. A 10% POE forecast assumes more extreme weather and is more conservative than 50% and 90% POE forecasts for capacity planning.

[40] The RCT is AEMO's estimate of the total amount of generation and/or DSM capacity required in the SWIS to satisfy the Planning Criterion for a Capacity Year under an "expected demand growth" scenario – see clause 4.5.10(b)(i) of the WEM Rules.

2028-29 Capacity Years. The RCT determined for the 2021-22 Capacity Year sets the RCR for the 2019 Reserve Capacity Cycle. Detailed information about the forecast RCT is provided in Chapter 6.

Section 3.2 summarises the methodologies used to assess both elements of the Planning Criterion in the 2019 Long Term PASA study.

3.2 Forecast methodology

3.2.1 Overview

The general forecasting methodology[41] undertaken by AEMO's consultants to provide the key forecasting inputs for this 2019 WEM ESOO is consistent with that used for ESOOs in the National Electricity Market (NEM)[42], where practical. The demand forecasts are based on similar parameters, such as weather, number of connections and economic growth. The same consultants were used to provide the economic and DER forecasts for both the WEM and NEM as inputs to the ESOO forecasts.

AEMO engaged:

- Deloitte Access Economics (DAE) to develop economic and population growth forecasts (see Sections 3.4.1 and 3.4.2)[43].
- Commonwealth Scientific and Industrial Research Organisation (CSIRO) to develop DER forecasts (see Section 3.3)[44].
- ACIL Allen to develop the peak demand and operational consumption forecasts for the 2019 WEM ESOO (see Sections 3.2.2 and 3.2.3)[45].
- Robinson Bowmaker Paul (RBP) to carry out reliability forecasts, including EUE (see Section 3.2.4)[46].

ACIL Allen adopted a similar approach to forecasting as in previous years, with improvements made to the assumptions associated with the impact of behind the meter PV, batteries, EV, and block loads.

The peak demand forecasts developed by ACIL Allen were based on:

- Three weather scenarios: 10% POE, 50% POE, and 90% POE.
- Low, expected, and high demand growth scenarios, which reflect different economic and population scenarios, different levels of new block loads (of at least 20 MW in size), and different levels of EV uptake.

ACIL Allen applied three forecasts of demand growth (low, expected, and high) for each of the three weather scenarios, for a total of nine peak demand forecasts. A total of three operational consumption forecasts were developed, under low, expected, and high demand growth scenarios.

Using a similar methodology as in the 2018 WEM ESOO, the expected scenario for behind the meter PV uptake was applied across the three demand growth scenarios. This approach continues to be adopted because behind the meter PV uptake has been observed to be strongly driven by the payback period (calculated based on factors such as installation cost, electricity prices and customer load sizes) and

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[41] This section discusses the methodology used to prepare summer peak demand forecasts. For details about the winter forecasts, see ACIL Allen's report.

[42] Major differences in the detailed requirements of the approach include timing of studies, specific WEM rule requirements for the RCM which are different to the NEM (e.g. reliability planning criteria), and treatment of network constraints in the WEM.

[43] DAE 2019. Long term economic scenario forecasts. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Long-term-economic-scenario-forecasts---Deloitte-Access-Economics.pdf.

[44] CSIRO 2019. Projections for small scale embedded energy technologies. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Projections-for-Small-Scale-Embedded-Technologies-Report-by-CSIRO.pdf.

[45] ACIL Allen 2019. Peak demand and energy forecasts for the South West interconnected system. Available at: http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[46] RBP 2019. 2019 assessment of system reliability, development of Availability Curves, and DSM Dispatch Quantity forecasts for the South West interconnected system. Available at: http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

customers' technology adoption preferences, rather than general macroeconomic drivers like GSP growth[47]. As current observed trends suggest behind the meter battery uptake is likely to follow the same pattern, the expected scenario for battery uptake was similarly applied across the three demand growth scenarios in this 2019 WEM ESOO.

A summary of the key assumptions behind each demand growth scenario is presented in Table 5.

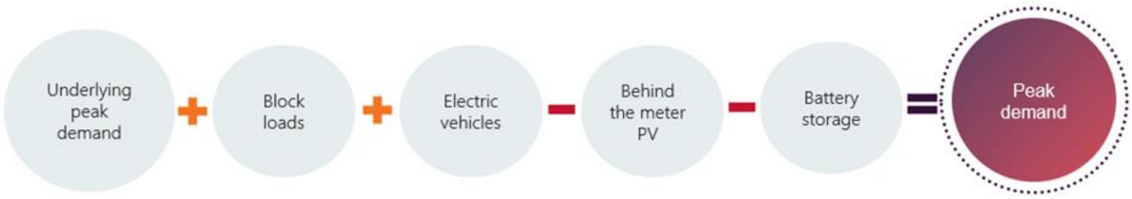
Table 5 Key assumptions for low, expected, and high demand growth scenarios

	Expected	Low	High
Economic growth forecast **Developed by DAE – see Section 3.4.1**	Expected	Low	High
Population forecast **Developed by DAE – see Section 3.4.2**	Expected	Low	High
Forecast block loads **Determined by AEMO in consultation with stakeholders – see Section 3.4.3**	Expected	Low	High
Weather conditions **Based on Perth Airport weather station records sourced from BOM**	10% POE, 50% POE, and 90% POE peak demand forecasts were produced for each scenario.		
DER forecasts **Developed by CSIRO – see Section 3.3**			
Behind the meter PV	Expected		
Batteries	Expected		
EVs	Expected	Low	High

3.2.2 Peak demand forecasts

ACIL Allen applied an econometric approach to forecasting peak demand in the SWIS by establishing a statistical relationship between historical peak demand and key drivers including weather and economic factors. Separate models were used for the summer and winter periods. The peak demand forecasts were developed by applying the adjustments to the underlying peak demand forecasts to account for the impact of existing and potential new block loads, EVs, behind the meter PV and battery storage, as shown in Figure 7.

Figure 7 Components of peak demand forecasts



[47] See the CSIRO report.

Improvements in the underlying peak demand forecasting model for the 2019 WEM ESOO study include:

- Accounting for the contribution of block loads as discrete increases in peak demand by excluding existing block loads from the historical data used to estimate the underlying peak demand regression model. New and existing block loads were then added back on as post-model adjustments.
- Better accounting for the peak demand reduction caused by behind the meter PV shifting the peak demand time to later in the day. Historical underlying demand figures in the Trading Interval starting at 17:30[48] (when peaks are assumed to continue to occur during the outlook period, reflecting recent history[49]) were used to develop the underlying peak demand regression model, rather than the underlying peak demand values at the times of historically observed peaks.
- Accounting for EVs' contribution to peak demand as post-model adjustments based on charging profiles developed by CSIRO.

These improvements resulted in lower peak demand forecasts and average annual peak demand growth rates over the outlook period, compared to the model applied in the 2018 WEM ESOO[50].

Economic, demographic, and weather parameters[51] were identified as other factors affecting peak demand and energy consumption. Forecasts for the economic and demographic parameters are in Section 3.4.

3.2.3 Operational consumption forecasts

ACIL Allen used econometric models to develop its operational consumption forecasts. The underlying residential and non-residential (including commercial and industrial) energy consumption regression models were developed separately. Post-model adjustments were applied to both underlying forecasts to account for the impact of behind the meter PV and EVs[52]. The non-residential underlying forecasts were further adjusted by accounting for consumption of existing and potential new block loads.

Synergy supplied historical residential connections[53] and consumption by tariff to AEMO for the development of the underlying residential energy consumption forecasts.

Heating degree days (HDD) and cooling degree days (CDD) were applied in the underlying modelling to measure the impact of average temperature conditions on energy consumption. HDD and CDD are used to determine the amount of energy required for heating and cooling respectively. The number of HDD and CDD in a given year was calculated as the sum of the difference between average daily temperature and the cooling and heating benchmark temperature respectively. The cooling benchmark temperature is 26°C and 24°C for the residential and the non-residential sectors respectively, when customers are assumed to turn on air-conditioning. The heating benchmark temperature is 18°C for both sectors.

3.2.4 Reliability assessment

The reliability assessment was undertaken with the aim of limiting EUE to no more than 0.002% of annual expected operational consumption for each Capacity Year of the 2019 Long Term PASA Study Horizon. RBP carried out the assessment in three phases and applied a combination of time sequential capacity availability simulation and Monte Carlo analysis.

- Phase 1: Develop forecast load duration curves (LDCs).

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48 Previous WEM ESOO reports used the actual underlying daily peak demand, which historically has occurred before 17:00.

49 AEMO's analysis indicates that continued uptake of behind the meter PV is likely to shift the peak demand interval later in the day (see Section 3.3.1).

50 See Section 5.5 of ACIL Allen's report for more detailed information.

51 Daily maximum and minimum temperature data for the Perth Airport weather station was collected from the BOM from 1 January 1987. See Section 5.4 of ACIL Allen's report for more detailed information.

52 The net effect of battery storage on operational consumption is assumed to be zero, since batteries simply store energy (kilowatt hours [kWh]) to be used at a later time, and efficiency losses are small.

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

- Five distinct forecast LDCs were developed based on each of the five most recent historical load profiles (the 2012-13 to 2017-18 Capacity Years). This provided a greater level of variation in load chronology compared to using an averaged LDC to develop the forecast LDCs as in previous WEM ESOOs.
- For each Capacity Year of the Long Term PASA Study Horizon, the historical load profile was scaled to match the 50% POE peak demand and expected energy forecasts. This produced five different forecast LDCs for each Capacity Year based on each of the five historical reference years used[54].

- Phase 2: Run simulation to calculate the average EUE.
  - The EUE simulation was run five times for each Capacity Year using each of the five forecast LDCs developed in Phase 1. This resulted in five EUE estimates for each Capacity Year over the Long Term PASA Study Horizon. For each EUE simulation:
    - Time sequential capacity availability simulation was used to compare the total available capacity to the corresponding load in an hour. This considered planned outages, intermittent generation, an application of the network constraints to Constrained Access Facilities[55], and randomly sampled forced outages. EUE occurs whenever the total available capacity is less than the load in an hour.
    - The Monte Carlo analysis was applied to run the EUE simulation over many iterations with probabilistically simulated forced outages. The EUE was calculated as the average of the total estimates of unserved energy of the Monte Carlo runs.
  - The average EUE for a given Capacity Year was calculated as the average of the five EUE estimates.
- Phase 3: Determine the amount of Reserve Capacity required to limit the EUE to 0.002% of the annual expected operational consumption forecast.
  - The average EUE was calculated as a percentage of the annual expected energy forecast for a given Capacity Year.
  - If the percentage of EUE is greater than 0.002%, the RCT is incrementally increased to reassess the average EUE until the EUE is less than or equal to 0.002%. The RCT will be then set by part (b) of the Planning Criterion.

For the 2019 Long Term PASA study, EUE remained less than 0.002% in every Capacity Year of the Long Term PASA Study Horizon. The RCT was hence set by part (a) of the Planning Criterion for each of the 10 relevant Capacity Years.

3.3 DER forecasts

AEMO commissioned CSIRO to develop DER forecasts of behind the meter PV and battery storage for residential and commercial sectors, and EV for passenger vehicles, light commercial vehicles, trucks, and buses[56]. These forecasts were applied as post-model adjustments to the underlying peak demand and energy consumption forecasts.

The DER forecasts were developed for Australia across three growth scenarios: low, expected, and high[57]. The WA forecasts are specific to the postcodes covered by the SWIS. All three growth scenario forecasts have been provided in this section and the 2019 WEM ESOO data register for stakeholders to use in their analysis if desired.

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54 The forecast LDC based on the 50% POE peak and expected energy demand represents an expected scenario for the reliability assessment in accordance with clause 4.5.9(b) of the WEM Rules.

55 As defined in chapter 11 of the WEM Rules. Constrained Access Facilities include Facilities that are under the Generator Interim Access arrangement.

56 The CSIRO DER forecasts included the installation numbers and capacity of behind the meter PV, battery storage and EV, and charge and discharge profiles of battery storage and EV. All assumptions and forecasts for DER reported in this section refer to gross quantities.

57 Low, expected, and high scenarios are named differently in the CSIRO’s report as slow change, neutral and fast change scenarios respectively. In addition to these scenarios, CSIRO produced forecasts for low and high DER scenarios. The additional DER scenarios are discussed in more detail in CSIRO’s report.

Table 6 shows the high-level assumptions applied to develop the DER forecasts under each scenario. Detailed information, including assumptions for the low and high DER scenarios, is published in CSIRO's methodology and results report.

Table 6 DER forecast – main assumptions

Demand settings	Expected	Low[A]	High[A]
Economic growth and population outlook	Expected	Weak	Strong
Residential PV – up to 10 kW **Small-scale and large-scale commercial PV (10 kW to 30 MW)** **Battery storage installed capacity**	Expected	Proportionally fewer installations than the expected scenario.	Proportionally more installations than the expected scenario.
Battery cost trajectories	Expected	Relatively weaker cost reductions than the expected scenario.	Relatively stronger cost reductions than the expected scenario.
EV uptake	Expected	Weak	Strong, with EVs more rapidly reaching cost parity with internal combustion engines.
EV charging times	Expected	Slower adoption of consumer energy management opportunities, leading to less controllable charging times.	Greater adoption of consumer energy management opportunities, leading to more controllable charging times.
Emissions reduction trajectories	• 26% reduction below 2005 levels by 2030, with achievement linked to large scale renewable investments and earlier coal retirements. • No direct carbon pricing mechanism.	Same as the expected scenario.	• 45% reduction below 2005 levels by 2030, with achievement linked to large scale renewable investments and earlier coal retirements[B]. • No direct carbon pricing mechanism. • Further policies to encourage DER uptake.
Tariff arrangements	No significant change to existing/proposed tariff arrangements.	Same as the expected scenario.	Development of a prosumer future, with customers embracing digital trends to benefit from new tariff arrangements to lower costs.

A. The high and low scenarios for PV and batteries have been provided and discussed in this report for stakeholders to use in their own analysis if desired.
B. An emission reduction level considered by several independent organisations' studies and used to provide a range of emissions reduction trajectories for the analysis.
Source: CSIRO and AEMO.

Except for large-scale behind the meter commercial PV forecasts, defined as installations larger than 100 kilowatts (kW), all forecasts were developed by CSIRO based on a consumer technology adoption curve projection methodology, which considers both financial (payback periods calculation) and non-financial aspects of a consumer's purchase decision and accounts for:

- Early adopters who invest even when payback periods are beyond the life of the technology.
- Main stream adopters who invest when payback periods are within a reasonable range.

- Late followers who do not invest even when the payback period is very short, because they may be constrained by infrastructure or personal preferences.

Investment decisions for large-scale behind the meter commercial PV systems (above 100 kW) were determined solely by financial factors, with investment being made if the project met a required rate of return threshold. CSIRO's analysis modelled three different size ranges for these large-scale commercial PV projects: 100 kW to 1 MW, 1 MW to 10 MW, and 10 MW to 30 MW.

An overview of the methodology, assumptions, and inputs used to develop these forecasts is presented in the following sections.

3.3.1 Behind the meter PV uptake outlook

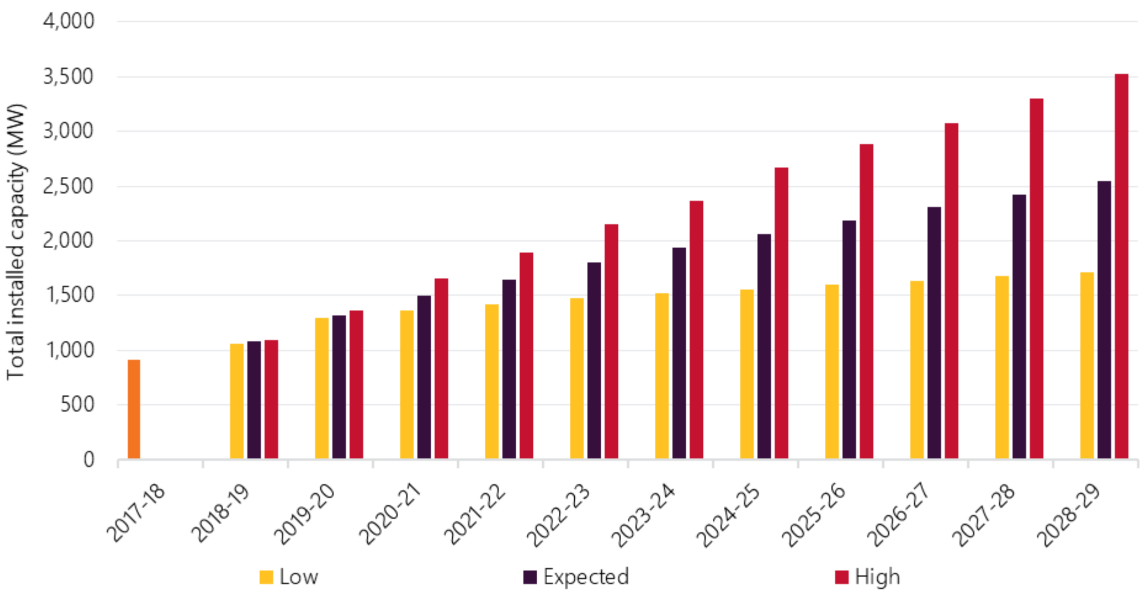
CSIRO developed behind the meter PV monthly installed capacity forecasts over the 2018-19 to 2028-29 financial years for residential (<10 kW) and commercial (10 kW to 30 MW) PV installations. AEMO, in consultation with ACIL Allen, developed monthly solar capacity factor traces[58]. These traces, together with the behind the meter PV capacity forecasts, were used to derive behind the meter PV's contribution to reducing peak demand and operational consumption.

The expected growth scenario for behind the meter PV uptake was applied across the low, expected, and high peak demand and energy forecasts. Behind the meter PV uptake forecasts under all scenarios are presented in the 2019 WEM ESOO data register[59] so that users of this report may undertake their own analysis using alternative DER uptake scenarios.

Installed capacity forecasts and assumptions

Figure 8 shows the forecast total uptake of behind the meter PV in the SWIS under the low, expected and high growth scenarios.

Figure 8 Forecast installed behind the meter PV system capacity, 2018-19 to 2028-29 financial years



Source: CSIRO.

[58] Solar capacity factor traces are a measure of the average percentage output relative to installed capacity of solar panels for each half-hour Trading Interval.

[59] Available at: http://aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

Under the expected growth scenario, installed behind the meter PV capacity is forecast to grow at an average annual rate of 7.6% (122 MW per year) to reach 2,546 MW by June 2029 from 1,081 MW in June 2019[60]. Under the low and high growth scenarios, total behind the meter PV installed capacity in the SWIS was forecast to grow at an average annual rate of 3.2% and 11.1% and reach 1,716 MW and 3,524 MW by June 2029 respectively.

While the 10-year average annual growth rate in the expected growth scenario remains relatively similar to expected growth in the 2018 WEM ESOO forecast, this year's low and high growth scenario forecasts demonstrated a greater range. This is due to a change in forecast methodology and assumptions. Total forecast installed capacity under the expected growth scenario is higher than the forecast presented in the 2018 WEM ESOO partly due to the inclusion of the uptake of commercial behind the meter PV systems (larger than 100 kW).

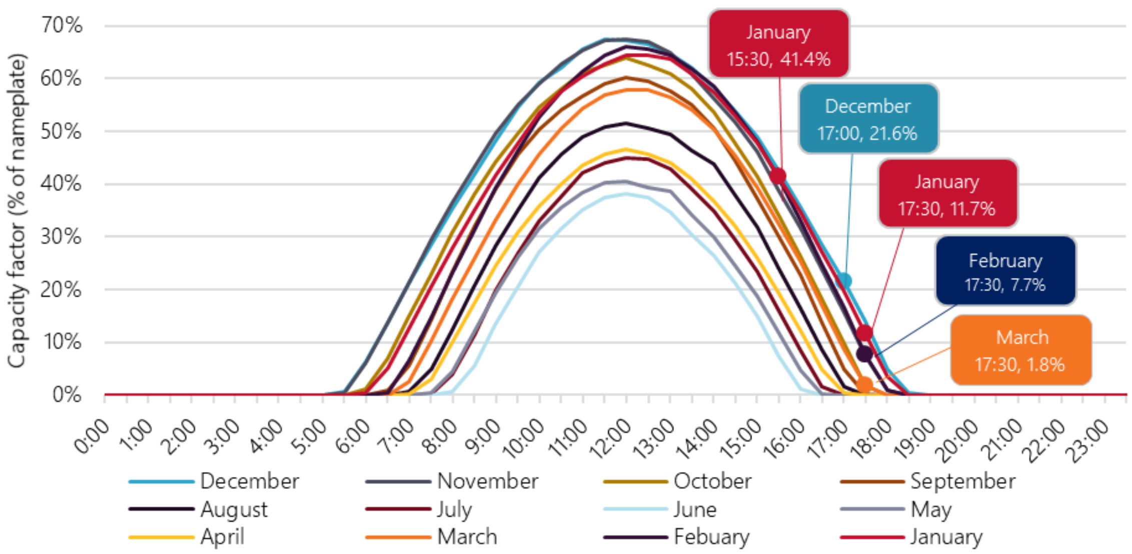
Overall, the behind the meter PV capacity forecasts for all growth scenarios have stronger average annual growth rates over the first five years of the outlook period (2019-20 to 2023-24) than the second half of the outlook period (2024-25 to 2028-29). This projected slower growth over the period 2024-25 to 2028-29 is mainly attributed to higher market saturation levels.

Continued increases in behind the meter PV penetration will continue to assist in reducing summer peak demand and carbon emissions. One of the key challenges being addressed by AEMO is the rapid uptake of behind the meter PV (this is discussed further in Chapter 7).

Historical and averaged daily capacity factor traces

The methodology for developing behind the meter PV capacity factors in the SWIS was aligned with the approach taken in the 2018 WEM ESOO[61], updated for an additional year of solar irradiance data. The historical solar capacity factor traces for the period from June 2011 to February 2019 were averaged by month to develop an average daily capacity factor trace for each month, as shown in Figure 9.

Figure 9 Solar capacity factor traces, averaged by month, for behind the meter PV in the SWIS[A,B]



A. All capacity factor values are half-hourly averages and all times are half-hour interval start times (e.g. the average capacity factor in January between 15:30 and 16:00 is 41.4%).
B. The coloured boxes indicate the months and Trading Intervals of historical peak demand over the last five Capacity Years. For further information on peak demand Trading Intervals, please refer to Chapter 4.

60 This value deviates from the Clean Energy Regulator's (CER's) small-scale PV installed capacity numbers, due to the inclusion of a degradation factor to account for the gradual reduction in generation capacity from PV systems as they age. CSIRO also applied a degradation factor to the behind the meter PV installation forecast (for more detailed information, see Section 5.1 of the CSIRO report). Degradation factors are a new inclusion in the 2019 WEM ESOO DER forecasts.

61 See Chapter 3.3.4 of the 2018 WEM ESOO for further information on the development of these capacity factor traces.

Solar traces were based on actual data so they implicitly incorporate variations in both the physical alignment of panels and solar irradiance. The average yearly capacity factor calculated from the traces for the 2012 to 2018 calendar years is 15.8%.

Impact on peak demand

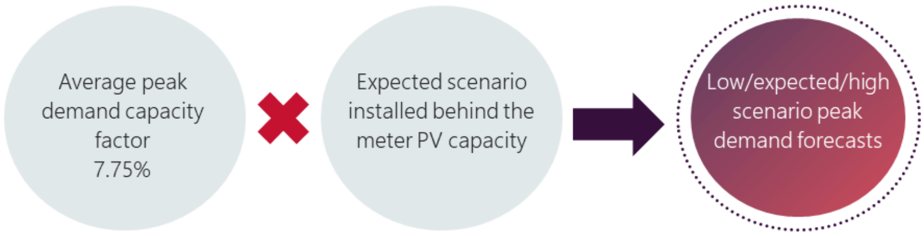
Behind the meter PV reduces peak demand by shifting the peak to a later Trading Interval in the day and displacing demand from the SWIS.

AEMO calculated the expected reduction effect of behind the meter PV on peak demand in the Trading Interval starting at 17:30[62] using the following steps:

- Identify the average capacity factor for behind the meter PV over the 17:30 to 18:00 period in February (the assumed peak time) from the monthly average solar trace. The result was a capacity factor of 7.75%.
- Multiply this capacity factor by the expected scenario behind the meter PV capacity forecast to obtain the expected peak demand reduction from behind the meter PV, as shown in Figure 10.

The calculated expected peak demand reduction from behind the meter PV was applied as a post-model adjustment to the low, expected, and high peak demand scenarios, as illustrated in Figure 11[63].

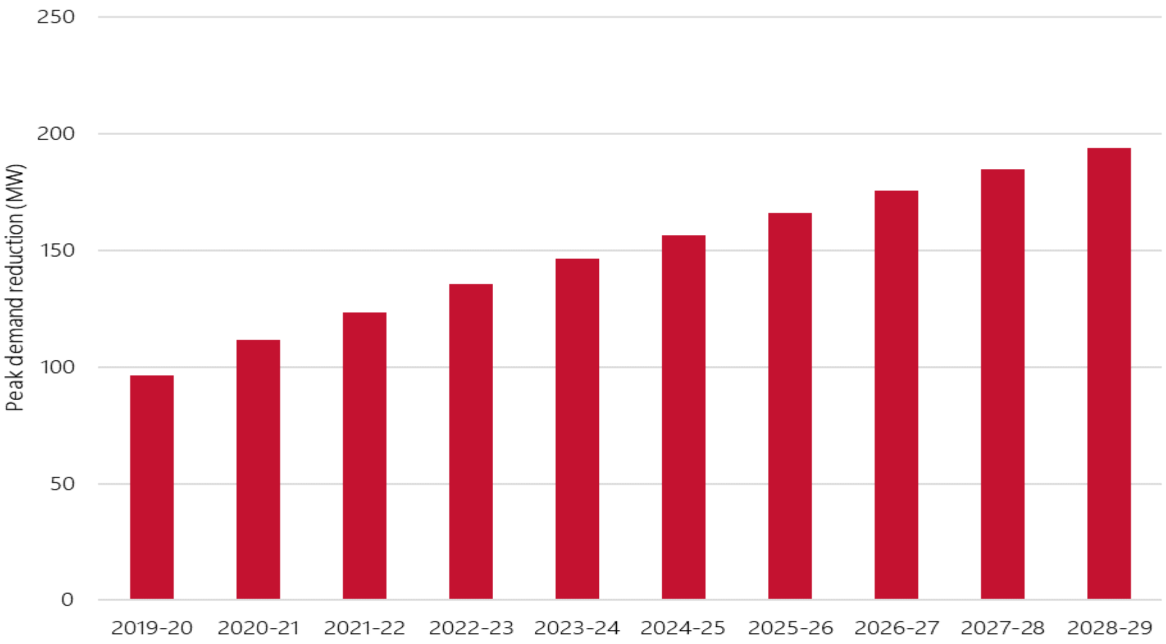
Figure 10 Methodology for the low, expected, and high scenario peak demand reduction from behind the meter PV



[62] A similar approach was used for batteries (Section 3.3.2) and EVs (Section 3.3.3).

[63] Due to changes to the assumed peak demand timing, the solar irradiance variation adjustment applied in the 2018 WEM ESOO to consider the peak demand reduction effect of behind the meter PV was not required.

Figure 11 **Forecast peak demand reduction from behind the meter PV systems (summer), 2019-20 to 2028-29[A]**



A. Calculated based on behind the meter PV uptake forecasts in February under the expected growth scenario and a peak demand Trading Interval starting at 17:30.
Source: ACIL Allen, based on AEMO and CSIRO data.

AEMO has analysed the effect of the continued penetration of behind the meter PV on average peak demand timing in the SWIS.

Underlying demand[64] on the peak demand day was averaged across five annual peaks from the 2013-14 to 2017-18 Capacity Years. Various levels of behind the meter PV penetration and average PV generation capacity factors in February were then applied to this underlying demand curve to estimate the effect of high levels of behind the meter PV penetration, as shown in Figure 12.

In the future, once behind the meter PV penetration crosses a certain threshold, peak demand could occur later in the day, in the Trading Interval starting at 18:00 on average[65]. As industrial and commercial loads start reducing consumption after 17:00, a 18:00 peak demand Trading Interval could mean further reductions in future peak demand forecasts[66]. AEMO will continue to monitor the timing of peak demand.

Batteries may also influence the timing of peak demand in the future; however, without incentives to discharge around peak times in a controlled fashion, such as in a virtual power plant (VPP), this influence is expected to be relatively small[67].

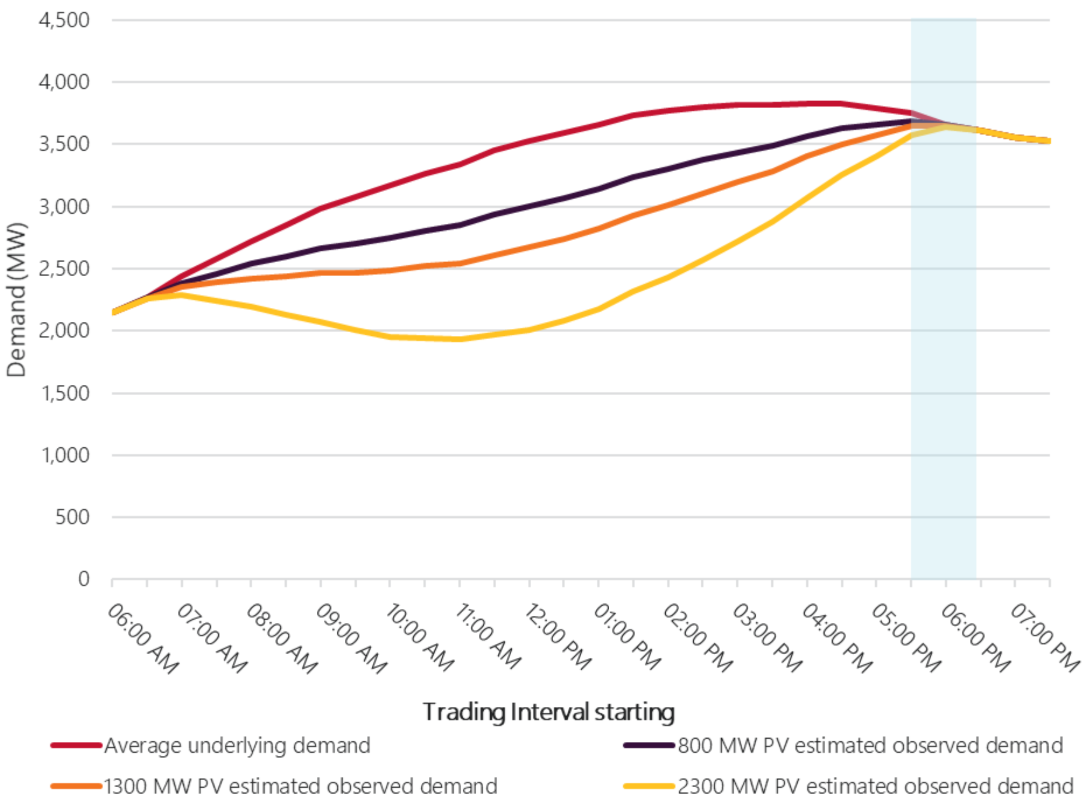
[64] Underlying demand refers to all electricity consumed on site and can be provided by localised generation from behind the meter PV, battery storage, and embedded generators, or by the electricity grid. Differences between observed and underlying demand are examined further in Chapter 4.

[65] The exact timing of the future peak demand interval will vary depending on whether peak demand events occur earlier or later in summer. In December, behind the meter PV has higher capacity factors in the evening, which could see the peak shift half an hour later than this. Conversely, lower capacity factors in March would likely limit peak demand to half an hour earlier.

[66] For the 2019 WEM ESOO, AEMO has used a 17:30 peak demand Trading Interval to remain in line with historical peak demand observations

[67] Based on analysis previously conducted by AEMO. For further information refer to the *Battery peak demand modelling* presentation in the February 2019 WA Electricity Consultative Forum meeting pack, at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/WA_Meetings/WAECF/2019/WAE-CF-18-Meeting-Pack.zip.

Figure 12 **Forecast influence on average peak demand timing of various levels of behind the meter PV penetration**



Effect on operational consumption

To estimate the future reduction in operational consumption due to behind the meter PV, the expected behind the meter PV uptake forecast was applied across the low, expected, and high operational consumption forecasts. This approach has been used for consistency with the approach applied for behind the meter PV's effect on underlying peak demand.

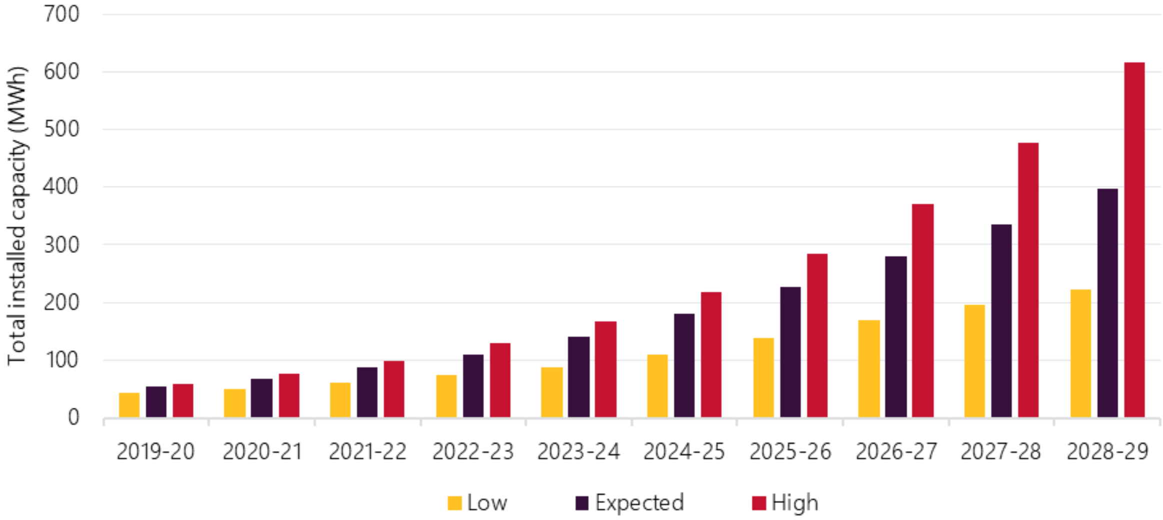
The effect on operational consumption was forecast by multiplying the expected behind the meter PV system installation forecasts by the average behind the meter PV capacity factor from the solar traces. The forecast reduction in operational consumption from behind the meter PV is 3,432 gigawatt hours (GWh) by the end of the forecast period (the 2028-29 financial year), or 20% of total underlying forecast energy consumption

3.3.2 Behind the meter battery storage forecasts

The behind the meter battery storage forecasts assumed that each residential battery storage installation was paired with a PV system to minimise electricity imported from the grid. Commercial battery storage installations were assumed to be motivated by customers' incentive to reduce Individual Reserve Capacity Requirements (IRCR) (see Chapter 4 for more information about the IRCR). The high-level assumptions used to forecast battery storage installed capacity are outlined in Table 6.

The battery installed capacity forecasts for the low, expected, and high growth scenarios are shown in Figure 13. Under the expected growth scenario, the installed capacity of battery systems in the SWIS is projected to increase at an annual average growth rate of 24.9% from 54 megawatt hours (MWh) in June 2020 to 398 MWh in June 2029. The high growth rate is primarily attributed to the expected reduction in the cost of battery systems over the forecast period.

Figure 13 **Forecast installed capacity of battery storage systems (behind the meter), 2019-20 to 2028-29 financial years**



Source: CSIRO.

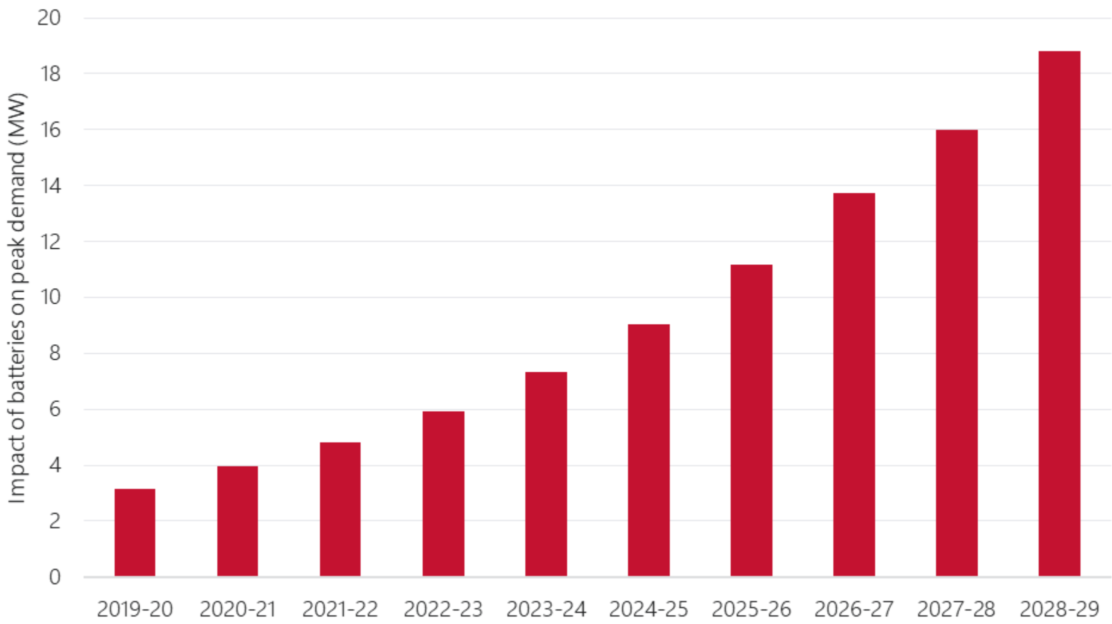
Impact on peak demand

The impact of batteries on peak demand depends on how the unit is operated. CSIRO developed battery discharge profiles for residential and commercial customers. The contribution of batteries to peak demand was calculated based on the following assumptions:

- Charge and discharge rates remain within the technical constraints of currently available battery storage technology.
- Battery systems are only used to time-shift the consumption of generation from behind the meter PV systems, with no charging from the grid.
- Customers are not incentivised to participate in any centrally coordinated schemes.

The impact of battery storage on peak demand was calculated as the expected residential and commercial battery storage installed capacity forecasts multiplied by the residential and commercial battery discharge profiles respectively. The discharge profiles applied were the February average discharge profiles in the Trading Interval commencing at 17:30. The subsequent peak demand reduction from battery storage was applied across the low, expected, and high peak demand forecasts, as shown in Figure 14.

Figure 14 Peak demand reduction from battery storage, 2019-20 to 2028-29[A]



A. Relatively small peak demand reduction from battery storage compared to installed capacity due to behind the meter PV offsetting some of need for batteries at the Trading Interval starting 17:30.
Source: ACIL Allen, based on data from CSIRO.

Based on Clean Energy Regulator (CER) data, as of May 2019 there were fewer than 1,000 distributed battery installations in WA[68]. This number only counts batteries installed alongside a new behind the meter PV installation, and is based on voluntary reporting, so it is likely to be lower than the actual number.

Impact on operational consumption

In this 2019 WEM ESOO, it has been assumed that behind the meter battery storage will have a negligible impact on operational consumption over the forecast period because behind the meter battery storage simply stores energy to use later and has relatively small efficiency losses[69], particularly for the first five years of the outlook period.

AEMO continues to monitor trends in battery uptake and usage. The forecast methodology for the effect of behind the meter batteries on operational consumption will be updated as further units are installed and will be included in future WEM ESOOs.

3.3.3 Electric vehicle assumptions

CSIRO developed the EV forecasts based on a consumer technology adoption curve projection methodology in a similar manner as the behind the meter PV (<100 kW) and battery storage forecasts. The high-level assumptions used to forecast EV uptake are outlined in Table 6. The low, expected and high EV forecasts have been applied to the low, expected, and high peak demand and operational consumption forecasts respectively.

[68] CER, *State data for battery installations with small-scale systems*. Accessed 20 May 2019. Available at http://www.cleanenergyregulator.gov.au/DocumentAssets/Pages/State-data-for-battery-installations-with-small-scale-systems.aspx. CSIRO sourced estimated actuals from Sunwiz for the DER forecasts.

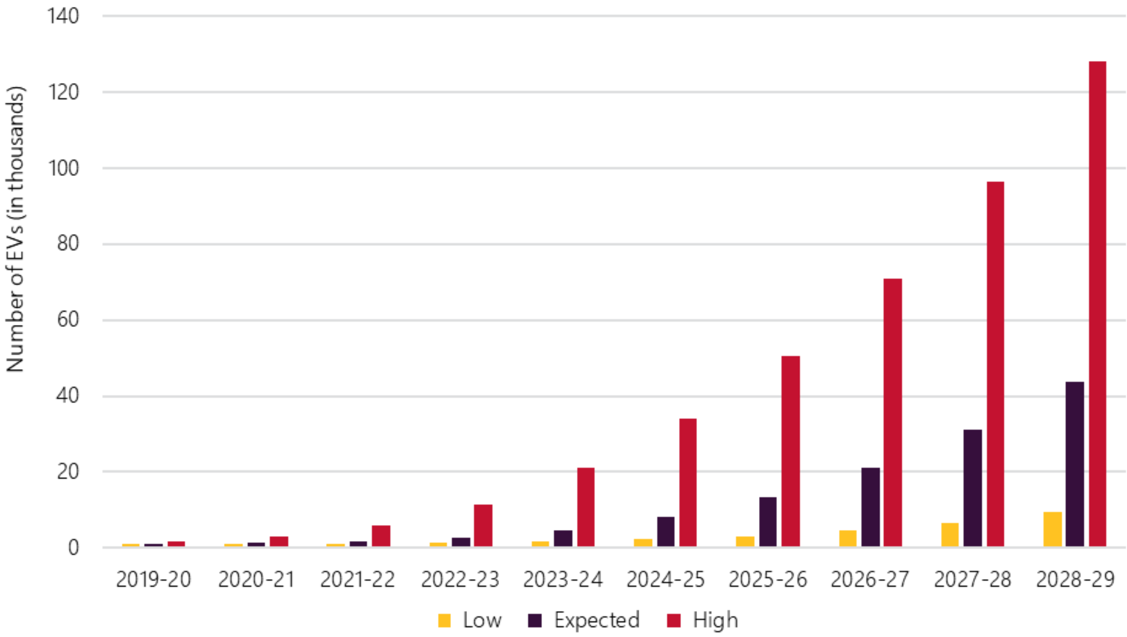
[69] Depending on the technology type of battery storage system, the typical round-trip efficiency of energy storage in batteries can be in the range between 70% and 95%.

EV uptake forecasts

Forecast EV numbers in the SWIS are shown in Figure 15. Projections for EV uptake assume a slow start, due to limited infrastructure, the narrow range of models currently available, and the cost relative to vehicles with internal combustion engines. The range between the high and low growth forecasts is relatively wide due to:

- Different cost projections, including the time to reach cost parity with internal combustion engine vehicles.
- Uncertainty regarding decisions on industry and emissions reduction policies.
- Differences in assumptions regarding infrastructure limitations and new business models.

Figure 15 Projected number of EVs, 2019-20 to 2028-29 financial years



Source: CSIRO.

EV impact on peak demand

The impact of EVs on peak demand depends on the number of EVs charging at peak demand times and was calculated as the projected number of EVs multiplied by the specific charge profile for the EV class. The charge profiles applied were the February average charge profile in the Trading Interval commencing at 17:30.

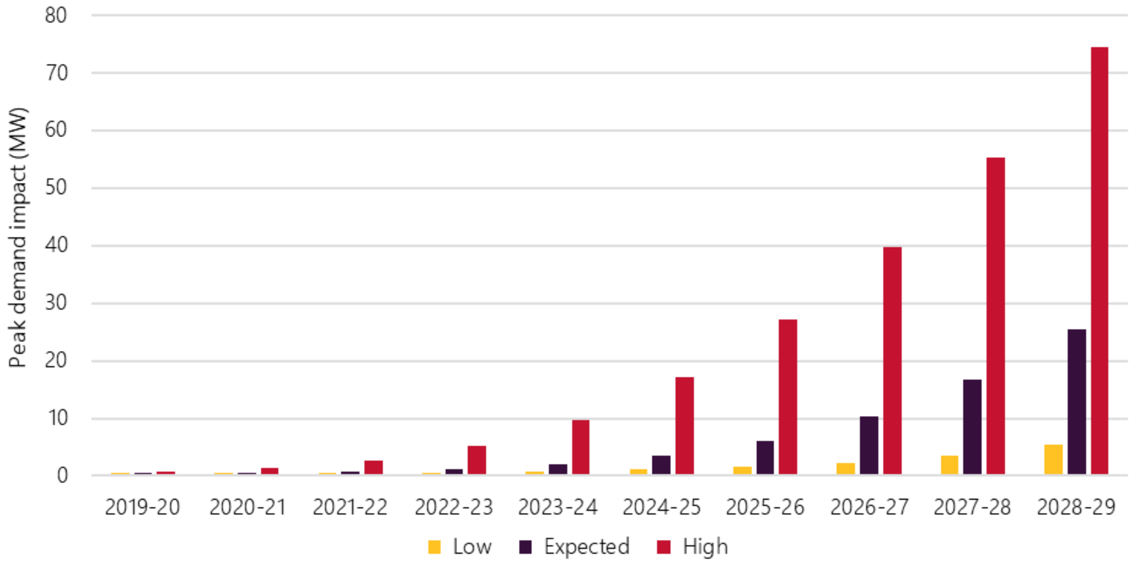
CSIRO developed four types of charge profiles for each of the EV classes[70] – convenience, day, night, and fast/highway charging. Development of these charge profiles considers:

- Expected behaviours based on assumptions including tariff, solar aligned charging, and other incentives:
  - Convenience charging – EVs being charged as soon as drivers get home, including peak hours charging.
  - Day and night charging – smart charging during off-peak hours.
  - Fast/highway charging – EVs on roads during the day when immediate charging is required.
- Charging habits associated with the class of EV, such as trucks charging at different times relative to a passenger vehicle.

[70] The classes of EVs considered in the 2019 WEM ESOO were plug-in hybrid EV and EV in passenger, light commercial, truck, and bus classes.

Figure 16 shows the potential impact of EVs on peak demand over the outlook period. Under the expected growth scenario, EVs are forecast to add 25 MW to peak demand by 2028-29. Under the low and high growth scenarios, EVs are forecast to increase peak demand by 5 MW and 74 MW respectively by 2028-29.

Figure 16 Forecast EV impact on peak demand under an uncoordinated charging regime, 2019-20 to 2028-29



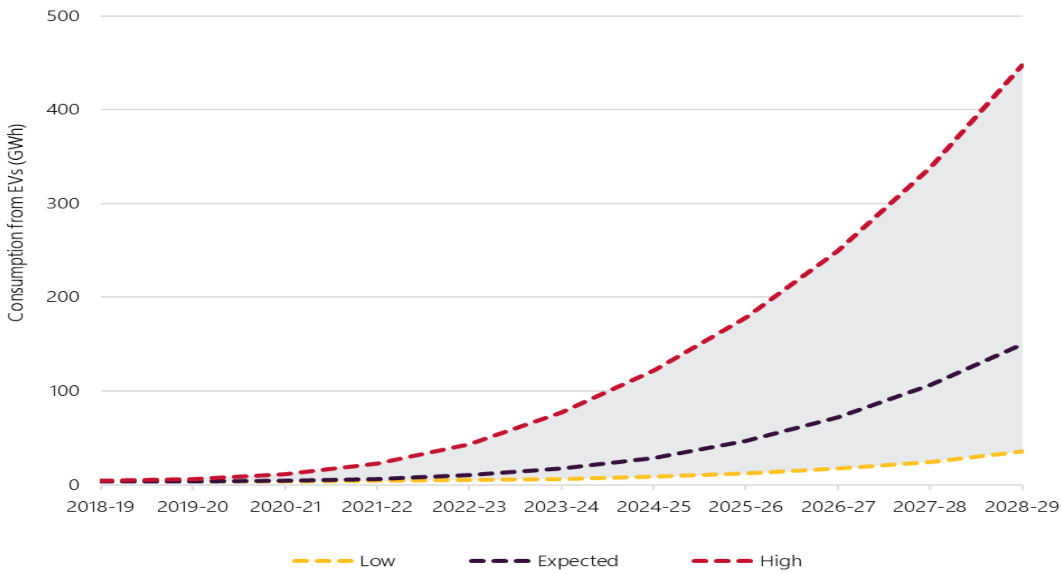
Source: CSIRO.

As EV uptake increases, effective management of the impact of EVs on peak demand will require a 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 about EV impact on peak demand will be updated in future WEM ESOOs as the market penetration level changes.

EV impact on operational consumption

The forecast effect of EVs on operational consumption in the SWIS is shown in Figure 17.

Figure 17 EV contribution to operational consumption, 2019-20 to 2028-29 financial years



Source: CSIRO.

Under the expected growth scenario, EV energy consumption is forecast to be 150 GWh by the end of the 2028-29 financial year, accounting for approximately 0.9% of total operational consumption. Under the low and high growth scenarios, EV energy consumption is forecast to reach 36 GWh (0.2%) and 447 GWh (2.5%) by the 2028-29 financial year respectively.

3.4 Supporting forecasts

AEMO engaged DAE to provide forecasts for WA gross state product (GSP) and the WA population forecasts. AEMO developed the new block load forecasts in consultation with industry stakeholders.

The following sections provide an overview of these supporting forecasts and assumptions.

3.4.1 Economic outlook

DAE developed low, expected, and high projections for WA GSP, as presented in Table 7.

Table 7 WA GSP forecasts, 2019-20 to 2023-24 financial years

Scenario	2019-20 (%)	2020-21 (%)	2021-22 (%)	2022-23 (%)	2023-24 (%)	Average annual 10-year growth (%)
High	2.7	3.6	3.8	3.9	3.7	4.1
Expected	2.3	3.1	3.3	3.5	3.3	3.6
Low	1.7	2.5	2.8	3.0	2.8	3.0

Source: DAE.

The GSP forecasts were provided to ACIL Allen to use in the peak demand and operational consumption forecasts. These GSP forecasts were underpinned by various assumptions on:

- Population growth.
- Labour force participation.
- Real household disposable income.
- Industrial production.
- Service sector activity.
- Trends of the Australian dollar to United States dollar exchange rates.

For the first three years, the forecasts of the GSP growth rates are lower than the forecasts in the 2018 WEM ESOO. The lower underlying population forecasts over this period was the main driver of these differences. In the long term, the WA economy is expected to experience faster growth rates due to higher mining production activity resulting from higher iron ore prices and LNG production.

3.4.2 Population growth

While population growth is correlated with peak demand and energy consumption growth, the impact of population growth is offset by behind the meter PV and energy efficiency improvements (see Chapter 5 for further information). WA population growth rates were used as a proxy for SWIS population growth. DAE developed the WA population forecasts based on the Australian Bureau of Statistics' (ABS) population projection released in November 2018[71]. The forecasts for WA population growth are outlined in Table 8.

[71] The ABS Population projections considered the 2016 Census of Population and Housing. ABS Cat. No 3220.0, Population Projections, Australia, 2017 (base) – 2066. Available at https://www.abs.gov.au/AUSSTATS/abs@.nsf/mf/3222.0.

Table 8 WA population growth, 2019-20 to 2023-24 financial year

Scenario	2019-20 (%)	2020-21 (%)	2021-22 (%)	2022-23 (%)	2023-24 (%)	Average annual 10-year growth (%)
High	1.2	1.3	1.5	1.6	1.7	1.8
Expected	1.1	1.2	1.3	1.4	1.5	1.5
Low	1.0	1.1	1.2	1.2	1.2	1.2

Source: DAE, based on ABS population projections.

While WA's population is expected to continue to grow, the growth rates are lower than the 2018 WEM ESOO forecasts. The updated projections consider the 2016 Census of Population and Housing and assessed WA population growth based on historical demographic trends and recently updated assumptions of future fertility, mortality, overseas and internal migration levels.

WA's estimated population at 30 June 2017 of 2.57 million is projected to increase to 2.64 million in 2019-20 and is forecast to grow at an average of 1.5% per annum in the expected growth scenario over the outlook period to reach 3.02 million by 30 June 2029.

3.4.3 Block loads

Block loads are temperature-insensitive large loads (of at least 20 MW in size) that are expected to operate almost continuously and at a relatively stable level. AEMO developed the demand and operational consumption forecasts for existing and potential new block loads and provided the forecasts to ACIL Allen for use in the post-model adjustments to the underlying peak demand and energy consumption forecasts.

AEMO engaged with external industry stakeholders, including Western Power, in its decision making process of new block loads' inclusion in this 2019 WEM ESOO. Demand and energy consumption values of new block loads were based on the new block loads' contracted maximum demand, adjusted using diversity factors[72]. Applying diversity factors was an improvement to the new block load forecasts from previous WEM ESOOs.

Three new block loads with multiple development stages were included in the low, expected, and high peak demand and operational consumption forecasts in this 2019 WEM ESOO[73]. The new block loads were one expansion to an existing mine site and two new mineral processing plants. In summary:

- Low demand growth scenario includes only stage one development of each block load, which is forecast to increase demand by 40.5 MW by 2020.
- Expected growth scenario includes all development stages of each block load, with a corresponding 84 MW increase in demand by 2020.
- In addition to the three block loads included in the expected growth scenario, an additional block load of 24 MW was added to the high growth scenario, for a total 108 MW increase in demand.

The new block loads' annual contribution to operational consumption under the low, expected, and high growth scenarios were estimated to be approximately 261 GWh, 567 GWh, and 735 GWh, respectively.

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

[73] These three new block loads include the block loads considered in the expected and high growth scenario forecasts in the 2018 WEM ESOO.

4. Historical and forecast peak demand

The 10% POE peak demand is forecast to grow slowly at a 10-year average annual rate of 0.4%, slightly lower than the forecasts published in the 2018 WEM ESOO. Key drivers for lower forecasts include methodology improvements (particularly around the treatment of block loads and the effect of behind the meter PV on peak demand) and revised economic and population growth forecasts.

4.1 Historical peak demand

4.1.1 Summer 2018-19 peak demand

The 2018-19 summer peak demand of 3,256 MW was observed in the 17:30 to 18:00 Trading Interval on 7 February 2019. The following sections investigate the reasons behind this unusually low peak demand:

- Section 4.1.2 considers the 2018-19 peak demand in the context of previously observed trends.
- Section 4.1.3 examines the IRCR response during the peak demand Trading Interval.
- Section 4.1.4 evaluates the differences between observed and underlying demand.

Temperature data reported in this chapter is measured at the Perth Airport weather station (station identification number 9021), unless otherwise specified.

4.1.2 Summer peak demand: 2018-19 versus historical

Over the past eight years, peak demand has been around 3,600 MW to 3,700 MW (with the exception of 2015-16 which observed an all-time peak), as shown in Table 9.

For the 2018-19 Capacity Year:

- Peak demand was the lowest summer peak observed in the SWIS since energy market start in 2006 and represents a significant decrease from previous years.
- For the second time since 2006, underlying peak demand occurred on a day that was different to the peak demand day.
- The peak demand day occurred on the twenty-first hottest day in the Capacity Year, the first time since market start that peak demand occurred outside of the ten hottest summer days.
- The maximum temperature of the peak demand day was the lowest since 2006.

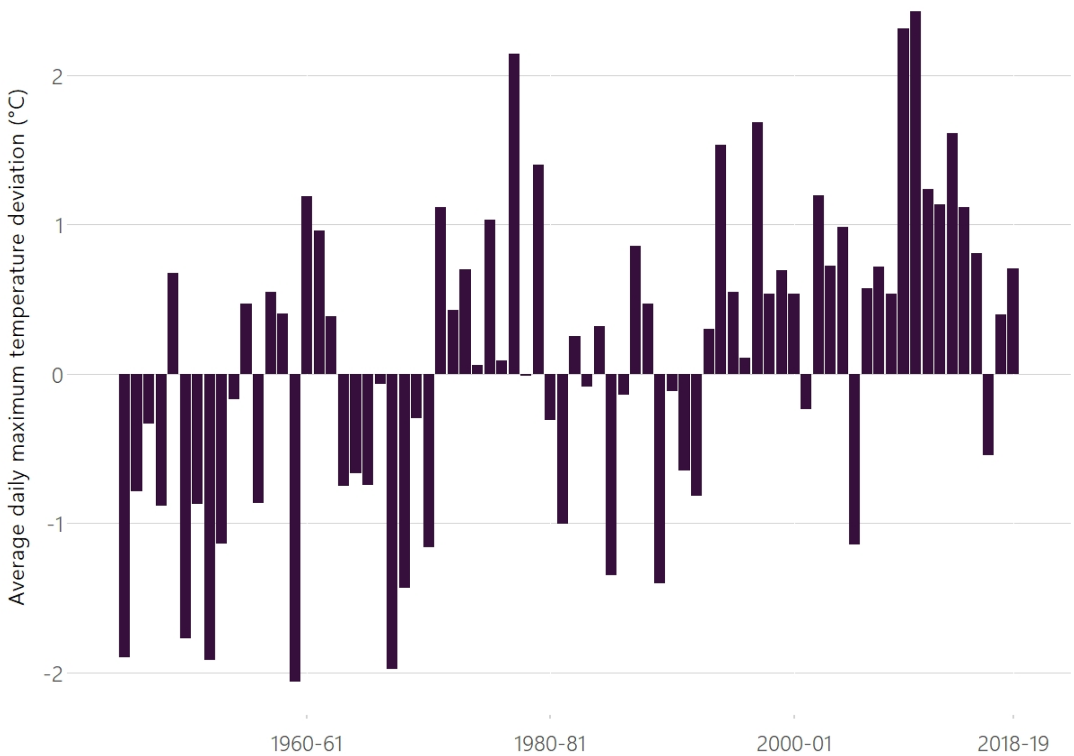
Table 9 Comparison of peak demand days, 2011-12 to 2018-19 Capacity Years

Capacity Year	Date	Trading Interval commencing	Peak demand (MW)	Daily maximum temperature (°C)	Time of temperature peak	Rank of day[A]	Maximum temperature in Trading Interval (°C)
2018-19	7 February 2019	17:30	3,256	35.8	15:00	21	33.5
2017-18	13 March 2018	17:30	3,616	38.5	14:00	2	36.2
2016-17	21 December 2016	17:00	3,543	42.8	14:30	2	38.0
2015-16	8 February 2016	17:30	4,004	42.6	15:00	3	41.0
2014-15	5 January 2015	15:30	3,744	44.2	13:30	1	41.1
2013-14	20 January 2014	17:30	3,702	38.7	15:00	7	36.9
2012-13	12 February 2013	16:30	3,739	41.1	13:00	2	36.0
2011-12	25 January 2012	16:30	3,860	40.0	15:00	7	39.1

A. A rank of 1 indicates it was the hottest day in the Capacity Year, 2 indicates the second hottest day in the Capacity Year, and so on.
Source: AEMO and BOM.

Year-on-year variations in weather have a significant influence on peak demand values. Figure 18 compares average daily maximum temperatures in the Hot Season[74] of each financial year against the 30-year (1961-90) average.

Figure 18 Average daily maximum temperature deviations (°C)[A], December to March in each financial year



A. Deviations from 30.5˚C, the 30-year average temperature from 1961 to 1990.
Source: AEMO and BOM.

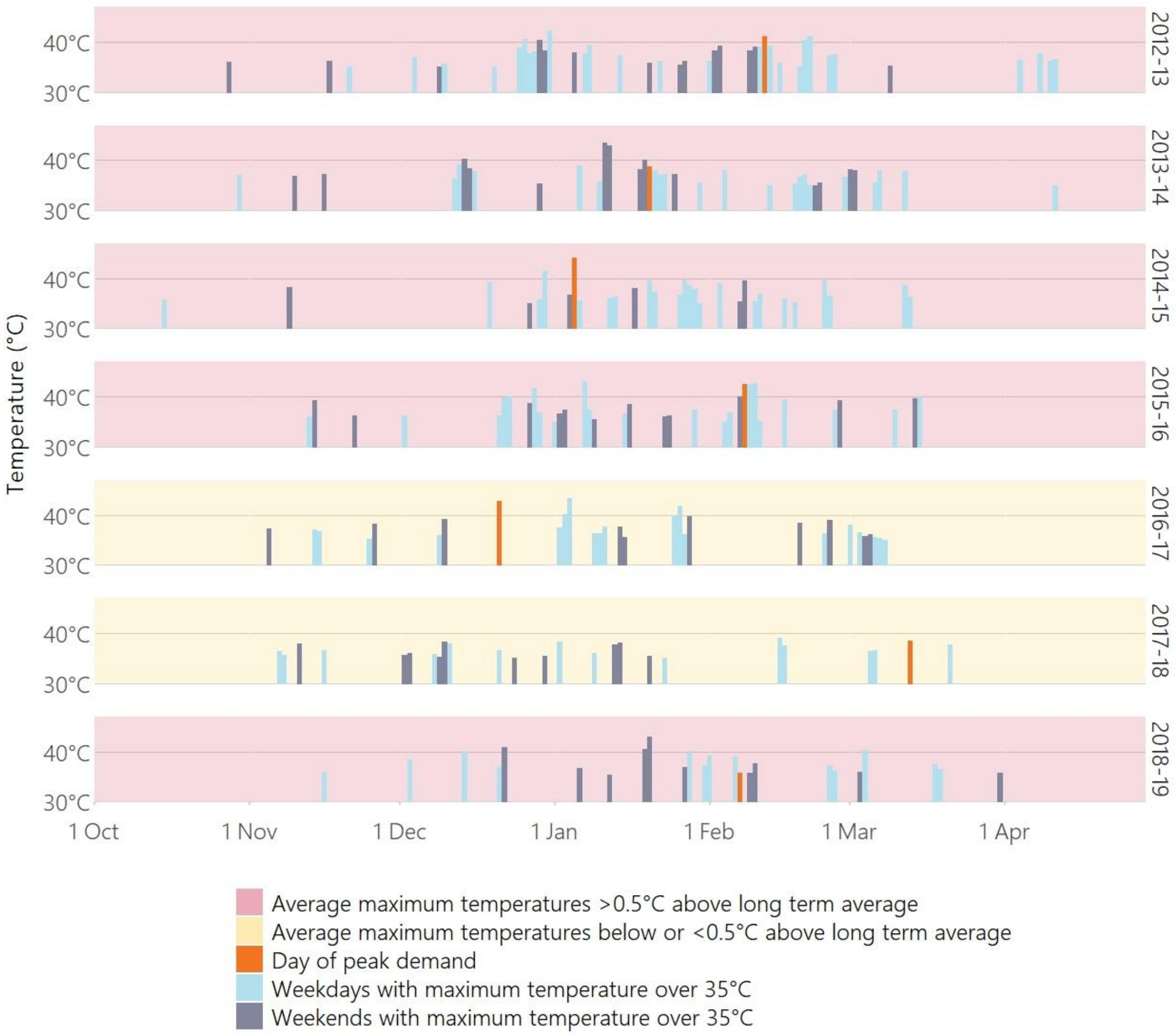
[74] The period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on the following 1 April, as defined in Chapter 11 of the WEM Rules.

The long-term temperature trend shows an overall increase in average daily maximum temperatures since 1945, with a period of particularly hot years between 2009-10 and 2015-16. This is correlated with relatively high peak demand levels (averaging 3,800 MW) and a record peak demand in the 2015-16 Capacity Year.

The 2018-19 peak demand of 3,256 MW is 287 MW lower than 2016-17 peak demand and 360 MW lower than 2017-18 peak demand. This is an interesting outcome given 2018-19 was warmer compared to the previous two Capacity Years, as shown in Figure 18.

The pattern of hot days in the 2018-19 Capacity Year had a significant impact on the unusually low peak demand. Figure 19 shows the occurrence and temperature of hot days[75] since the 2012-13 Capacity Year and identifies the peak demand day in each year.

Figure 19 Occurrence and temperature of hot days (over 35°C), 2012-13 to 2018-19 Capacity Years



Source: AEMO and BOM.

In summary, the following patterns are observed in Figure 19:

- In the period between 2012-13 and 2015-16, average maximum temperatures across the Hot Season were more than 0.5°C warmer than the historical 30-year average shown in Figure 18. Peak demand in this period occurred following a series of consecutive hot days. In most cases, peak demand occurred within the top three hottest days in the year. The only exception is the 2013-14 Capacity Year, when the peak

[75] Days with maximum temperature greater than 35°C. Bureau of Meteorology 2019, *About the climate extremes analyses: Extreme climate indices used.* Available at http://www.bom.gov.au/climate/change/about/extremes.shtml.

demand day occurred on the seventh hottest day in the year, but on the third of a series of days with temperatures above 35°C.

- In 2016-17 and 2017-18, average maximum temperatures across the Hot Season were slightly cooler than in the years preceding them. In both years, the peak demand day occurred on an isolated hot day that was the second hottest day of the year.
- In 2018-19, the average maximum temperature was 0.7°C warmer than the historical 30-year average. However, the peak demand day (7 February 2019) was unusually low and did not follow either historical pattern (2012-13 to 2015-16 and 2016-17 to 2017-18). The following factors likely contributed to the recent low summer peak demand in comparison to the previous six years:
  - Periods of consecutive hot days did not last more than two days.
  - The top three hottest days occurred on weekends, which generally have lower electricity demand and are therefore less likely to be peak demand days.

The occurrence of peak demand on the twenty-first hottest day of the Capacity Year is unusual, and additional analysis was conducted to identify the factors leading to high demand on 7 February 2019. Historical observation has shown that peak demand usually occurs on a working day when there:

- Are high temperatures on the days preceding the peak demand day.
- Is high humidity and high temperature.

Table 10 shows the eight hottest weekdays[76] in Capacity Year 2018-19 alongside factors that typically affect peak demand. The 7 February 2019 peak demand meets only one of the above factors, having the highest temperature on the day preceding one of the hottest eight working days in 2018-19 (bolded in Table 10).

Table 10 Weather and generation conditions on the eight hottest weekdays in the 2018-19 Capacity Year

	1/02	6/02	18/03	31/01	25/02	19/03	26/02	7/02 (Peak demand day)
Max temperature	39.2	38.9	37.4	37.3	37.3	36.5	36.1	35.8
Rank of working day[A]	1	2	3	4	5	6	7	8
Peak demand on the day (MW)	2,981	3,112	2,983	2,992	3,110	2,972	3,061	3,256
Temperature on the day before (°C)	37.3	34.6	34	33.2	30.9	37.4	37.3	**38.9**
Temperature at 17:30 (°C)	31.6	34	30	33.9	33.7	27.8	32.1	33.5
Relative humidity[B] (%) at 15:00	29	32	41	20	26	58	36	30
Wind speed[B] (km/h) at 15:00	20	19	11	11	9	15	17	19
Day of the week	Fri	Wed	Mon	Thurs	Mon	Tues	Tues	Thurs

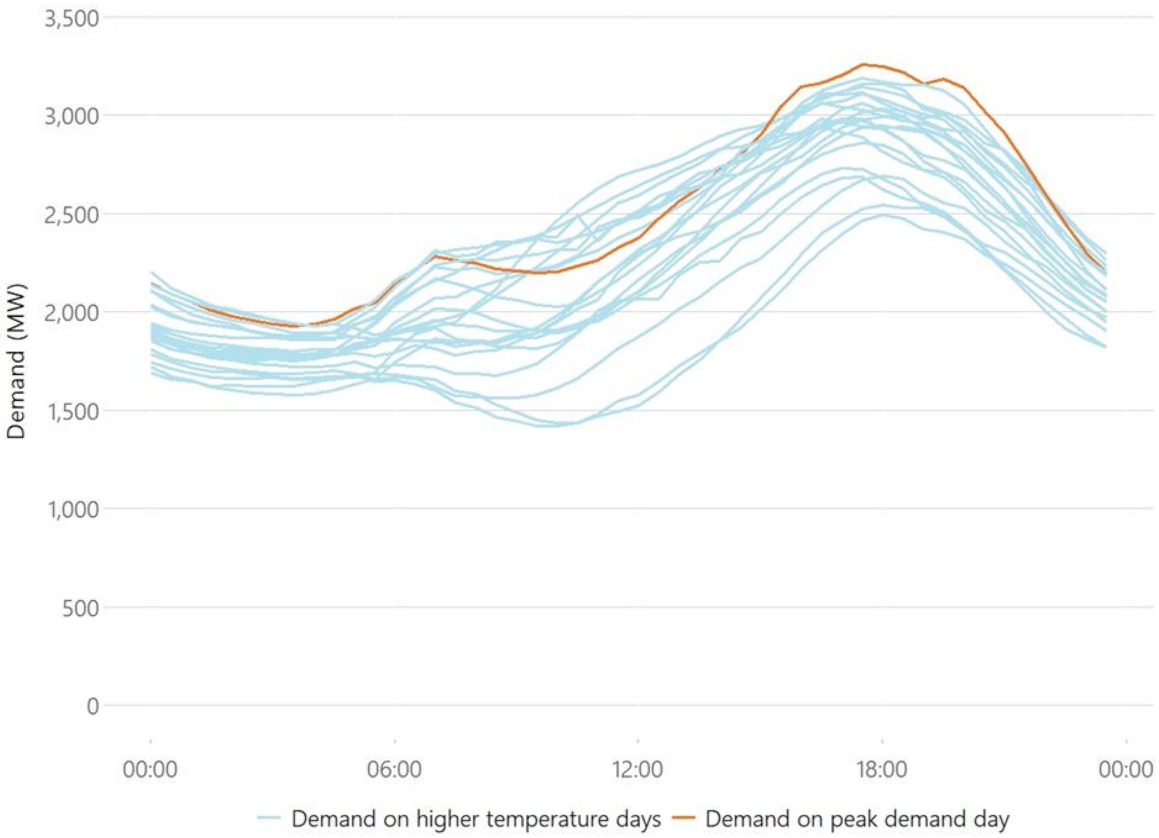
A. A rank of 1 indicates the hottest working day in the Capacity Year, a rank of 2 the second hottest working day in the Capacity Year, and so on.
B. Relative humidity and wind observations are measured at the Perth Metro weather station (station identification number 9225), and can be found at http://www.bom.gov.au/climate/dwo/IDCJDW6111.latest.shtml.

[76] Weekends and public holidays have been removed as they are typically lower load days.

Figure 20 shows the load profile of the peak demand day in relation to the demand profiles of the 20 hottest days in the 2018-19 Capacity Year, and illustrates that demand on 7 February 2019:

- Remained relatively high through the night and early hours of the morning, likely due to high temperatures on the preceding day, with a morning peak at 07:00.
- Decreased through the daylight hours as generation from behind the meter PV increased[77].
- Increased in the evening to levels that were higher than the evening peak on any other day. This occurred not only in the peak demand Trading Interval, but also in the intervals surrounding it. The Trading Intervals commencing 17:00 to 18:30 on 7 February 2019 recorded the top four highest demands for the entire Capacity Year.

Figure 20 Demand profiles on the 21 hottest days in the 2018-19 Capacity Year



The conditions and circumstances behind this year's unusually low peak demand highlight the increasing challenge of forecasting peak demand:

- Several key factors that have historically coincided with peak demand periods were not observed this year.
- The key factors themselves are subject to change – while temperature is one of the key factors affecting the timing and level of peak demand, the long-term effect of temperature on peak demand is uncertain. This is particularly the case because data from BOM suggests continued changes in Australia's climate conditions[78].

While meteorologists and climate experts are best placed to forecast future temperature trends, AEMO will continue to monitor and report the effects of climate on peak demand in future WEM ESOOs.

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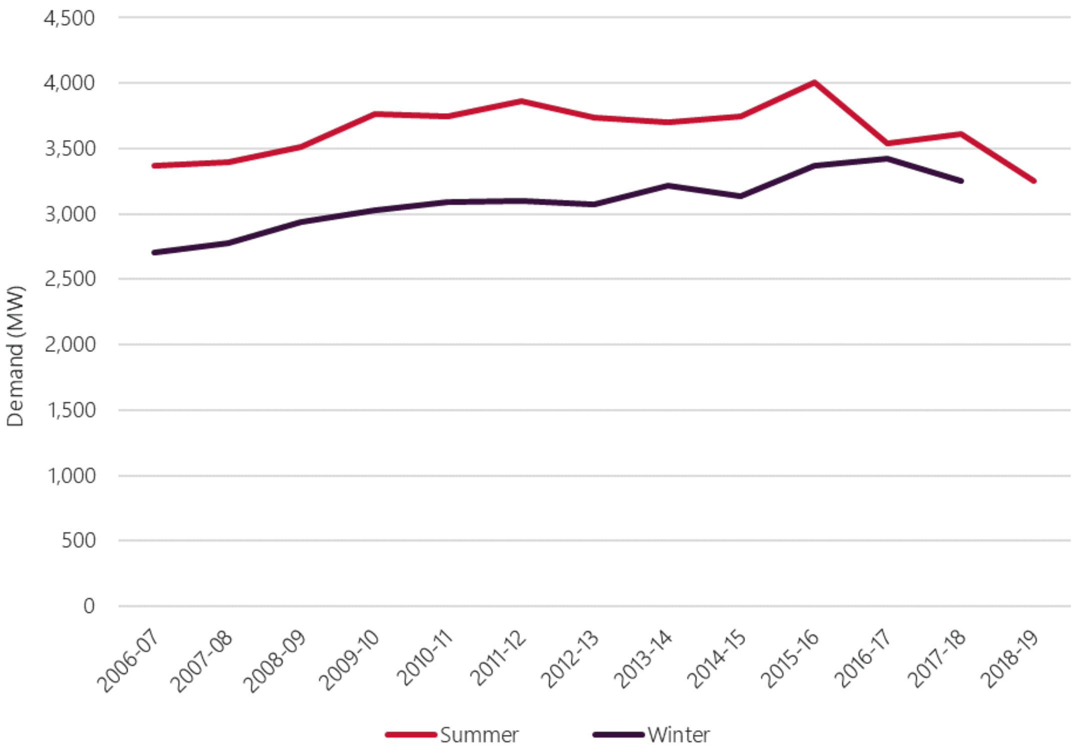
[77] Behind the meter PV generation on 7 February 2019 is discussed further in Section 4.1.4.

[78] BOM 2018, *State of the Climate 2018*, Australian Government, at http://www.bom.gov.au/state-of-the-climate/State-of-the-Climate-2018.pdf.

Seasonal trends

Summer and winter peak demand have shown different growth trends over the past 10 years, as shown in Figure 21, with winter peak demand trending upward and summer peak demand trending downward.

Figure 21 Summer and winter peak demand[A], Capacity Year 2006-07 to 2018-19[B] Capacity Years



A. Summer includes the Hot Season as defined in the WEM Rules, and winter includes June to August.
B. At the time of publication, values for winter 2019 were not available.

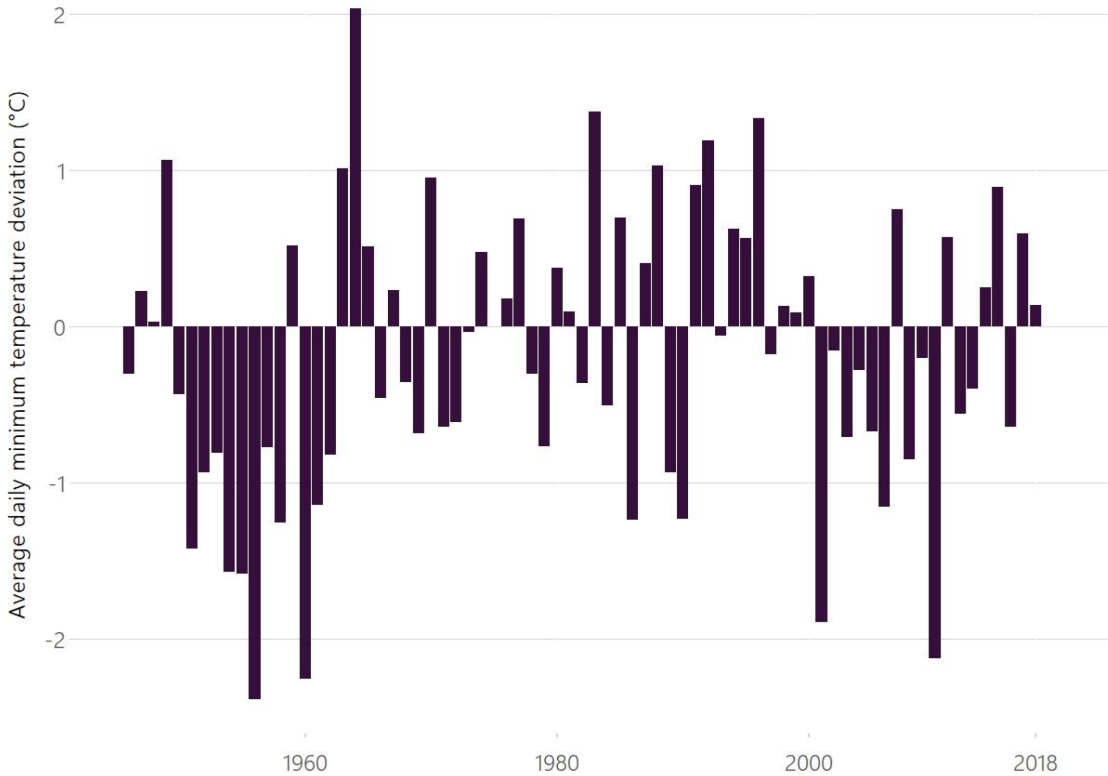
For the 2017-18 Capacity Year, winter peak demand (3,256 MW) equalled the 2018-19 summer peak demand and occurred in the Trading Interval commencing at 18:30 on 9 August 2018. This is the first time this has occurred since energy market start in 2006.

Figure 22 compares average daily minimum temperatures in winter for each Capacity Year against the 30-year (1961-90) average, illustrating that the winter of 2018 was slightly warmer than the long-term average. The latest winter peak demand is close to the five-year[79] winter peak historical average of 3,242 MW. The fact that the recent summer and winter peak demand were equal reflects an unusually low summer peak demand, rather than a colder winter.

The winter peak has always occurred after sunset, when behind the meter PV generation is zero. In contrast, summer peak demand generally occurs when there is sufficient sunlight for behind the meter PV generation to reduce demand from the SWIS. The narrowing difference between summer and winter peak demand is indicative of the increasing effect of behind the meter PV.

[79] From the 2012-13 to 2016-17 Capacity Years.

Figure 22 **Average daily minimum temperature deviations (˚C)^A, winter in each calendar year**



A. Deviations from 8.5˚C, the 30-year average temperature from 1961 to 1990.
Source: AEMO and BOM.

4.1.3 Individual Reserve Capacity Requirement response

The RCM is funded through the IRCR mechanism, which requires AEMO to assign an IRCR to each Market Customer based on the peak demand usage from its customer base in the previous Hot Season[80].

Specifically, the IRCR is a quantity (in MW) determined based on the median consumption of each metered load in a Market Customer's portfolio during the 12 system peak Trading Intervals from the previous Hot Season. The IRCR is used to allocate the cost of Capacity Credits acquired through the RCM to Market Customers. As a result, the IRCR financially incentivises Market Customers to reduce their consumption during peak demand periods, and consequently reduces their exposure to capacity charges.

The estimated reduction in peak demand associated with IRCR response since 2012 is shown in Table 11.

There is no clear trend in the IRCR responses over the past eight years, with demand reductions varying from 41 MW to 82 MW and the number of customers responding between 20 and 59. The IRCR response on 7 February 2019 in the Trading Interval commencing 17:30 is the highest to date at 82 MW. This relatively high response corresponded to a predictable peak demand, which occurred in February following a hot day[81].

In the 2018-19 Hot Season, 190 unique customers responded in at least three Trading Intervals, indicating that the IRCR mechanism is working as expected by encouraging electricity users to reduce demand at peak times. Out of those unique customers, only 15 responded in at least eight out of the 12 IRCR Trading Intervals, demonstrating that the prediction of all IRCR intervals is challenging, or there are other factors which affect a customer's ability to reduce demand.

[80] See clauses 4.28.7 and 4.28.11 and Appendix 5 of the WEM Rules.

[81] The maximum daily temperature on 6 February 2019, one day before the peak demand day, was 38.9°C.

Table 11 IRCR response on summer peak demand days, 2012 to 2019

Date	Daily peak demand (MW)	Time of peak demand	Estimated IRCR reduction (MW)	Number of customers responding
7 February 2019	3,256	17:30	82	59
13 March 2018	3,616	17:30	41	36
21 December 2016	3,543	17:00	50	52
8 February 2016	4,004	17:30	77	57
5 January 2015	3,744	15:30	42	20
20 January 2014	3,702	17:30	50	44
12 February 2013	3,732	16:30	65	59
25 January 2012	3,857	16:30	50	59

4.1.4 Underlying peak demand

AEMO estimates the demand that would have occurred if there was no generation from behind the meter PV ("underlying demand"[82]). Underlying demand is then analysed to examine the effect of behind the meter PV on peak demand. Historically, underlying peak demand generally occurs on the same day as peak demand. Since 2006, which marks the commencement of the energy market, 2018-19 is the second time[83] that underlying peak demand occurred on a day that was different to the peak demand day.

Underlying peak demand is estimated as 3,555 MW at 14:00 on 20 January 2019[84], 9.2% higher than the observed peak demand of 3,256 MW at 17:30 on 7 February 2019, as shown in Figure 23.

In 2018-19, the peak demand reduction due to rooftop PV (106 MW) output was outweighed by the reduction in peak demand due to the shift in peak demand time (193 MW). Although behind the meter PV generation dropped off slightly earlier on 7 February 2019 than it did on 20 January 2019, the underlying peak demand time was the crucial factor that determined the observed peak demand.

[82] Underlying demand refers to all electricity consumed on site and can be provided by localised generation from behind the meter PV, battery storage, and embedded generators, or by the electricity grid.

[83] The first time was 2013-14.

[84] 20 January 2019 was the hottest day of the 2018-19 Capacity Year.

Figure 23 **Demand profile on the peak demand day and underlying peak demand day, 2018-19**

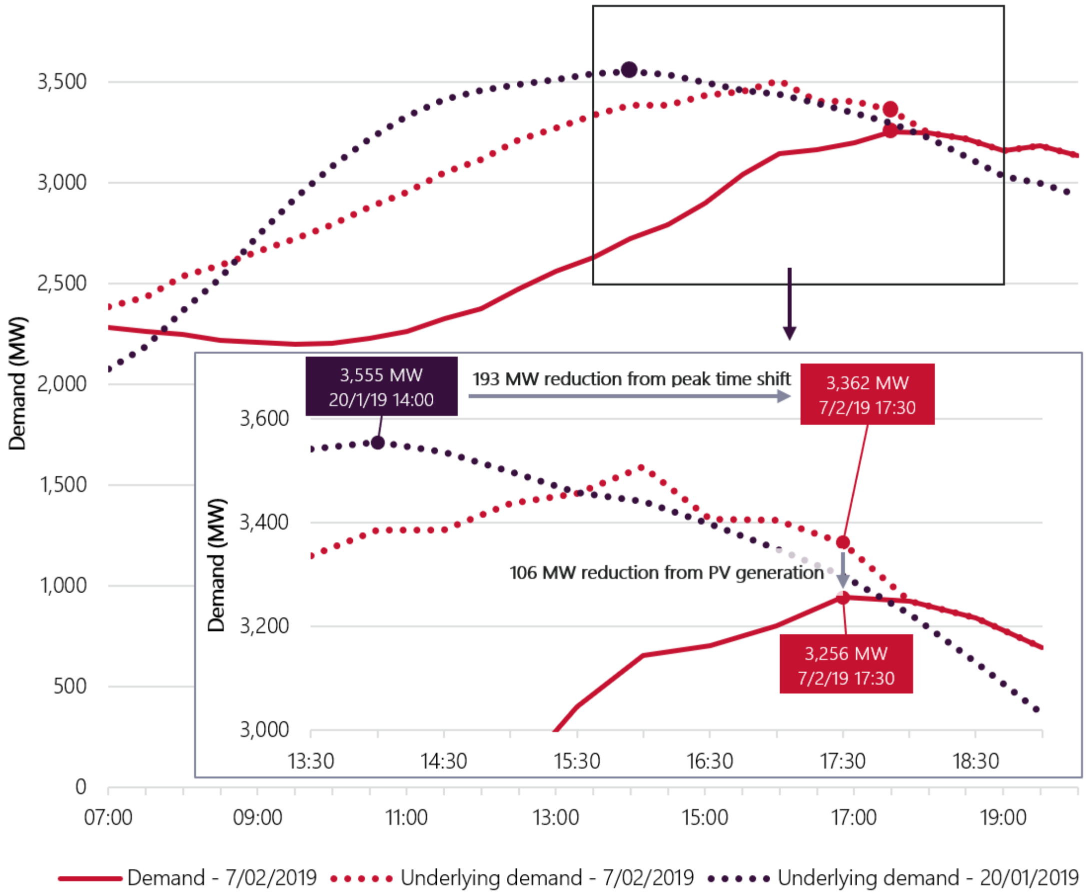
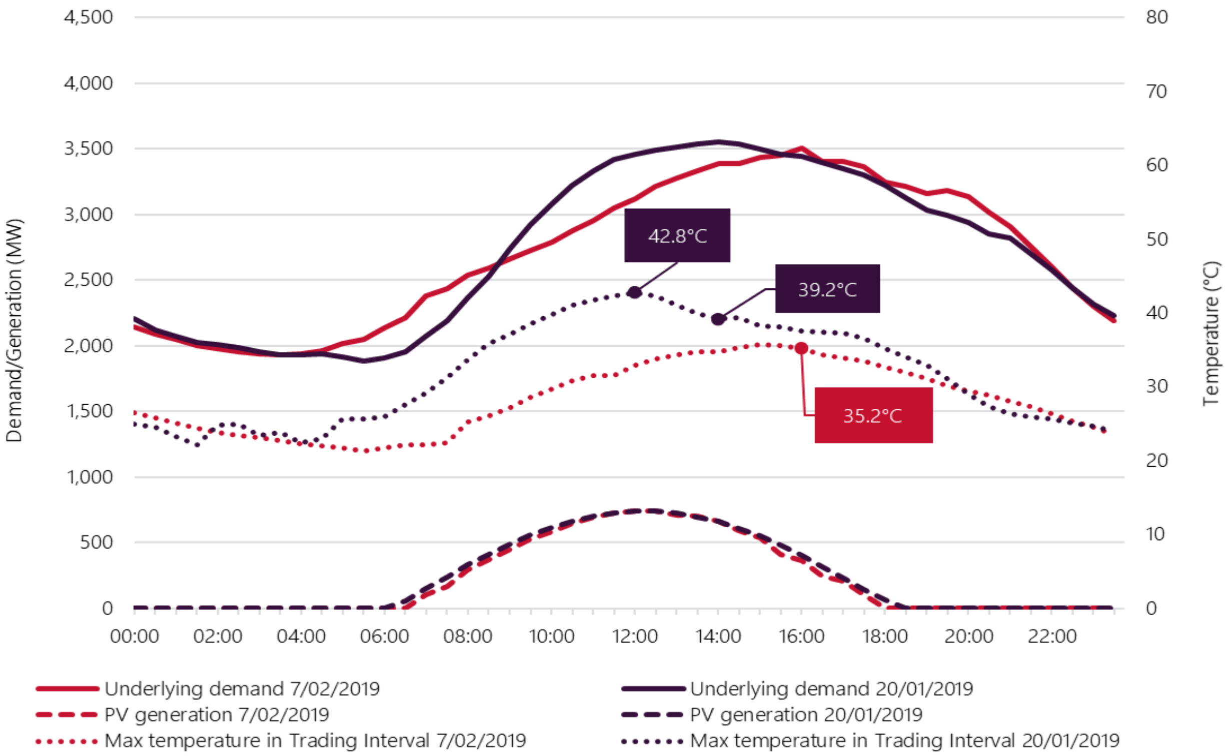


Figure 24 compares the underlying demand profiles alongside estimated PV generation on both days and illustrates the following:

- While the overall shapes of the underlying demand profiles on 20 January 2019 and 7 February 2019 were quite different, the estimated PV generation profile remained quite similar on both days, with a generally smooth output indicative of clear sunny days and a maximum at noon (726 MW on 20 January 2019 compared to 742 MW on 7 February 2019).
  - Behind the meter PV generation dropped off slightly earlier on 7 February 2019 than it did on 20 January 2019, leading to slightly higher demand later in the evening on 7 February 2019.
- Underlying peak demand on 20 January 2019 occurred on the hottest day of the 2018-19 Capacity Year, two hours after temperatures peaked at 42.8°C at noon. Underlying demand was unusually high for a Sunday[85], 21.7 MW greater than the next highest underlying peak demand (on Friday, 1 February 2019, in the Trading interval commencing 13:30). If the high temperatures experienced on 20 January 2019 had been experienced on a weekday, it could have been the peak demand day.
- Underlying demand peaked earlier on 20 January 2019 than it did on 7 February 2019. The underlying peak on 20 January 2019 occurred at 14:00, when high levels of behind the meter PV generation significantly reduced demand.
  - Temperature played a role in the early underlying peak demand on 20 January 2019, with temperatures dropping by 3.6°C (from 42.8°C to 39.2°C) from 12:00 to 14:00 and reducing underlying demand later in the day.

[85] Sunday is traditionally the day of the week with lowest demand. Underlying peak demand on 20 January 2019 was the highest underlying Sunday peak since market start in 2006.

Figure 24 Underlying demand and behind the meter PV generation profile on the peak demand day and underlying peak demand day, 2018-19



Over the last eight years, the continued growth of behind the meter PV installations has affected the level and timing of peak demand. Behind the meter PV generation depends on the season and time of day, with generation being highest around midday in summer. Table 12 compares actual peak demand for each year in the past eight years with the estimated underlying peak demand.

In 2018-19, the reduction in peak demand due to behind the meter PV (106 MW) was outweighed by the reduction in peak demand (193 MW) due to the shift in time of peak demand.

Table 12 Effect of behind the meter PV on peak demand, 2011-12 to 2018-19

Capacity Year	Month	Trading Interval commencing	Peak demand (MW)	Estimated underlying peak demand (MW)	Estimated underlying peak Trading Interval	Reduction in peak demand from PV generation (MW)	Reduction in peak demand from peak time shift (MW)
2018-19	Jan/Feb[A]	17:30	3,256	3,555	14:00	106	193
2017-18	Mar	17:30	3,616	3,727	16:30	12	99
2016-17	Dec	17:00	3,543	3,767	15:00	153	71
2015-16	Feb	17:30	4,004	4,147	16:30	63	81
2014-15	Jan	15:30	3,744	3,902	14:30	136	22
2013-14	Jan[A]	17:30	3,702	3,767	16:30	46	19
2012-13	Feb	16:30	3,739	3,806	14:00	55	12
2011-12	Jan	16:30	3,860	3,931	15:30	42	29

A. Underlying peak demand occurred on a different day in the same Capacity Year.

While it remains to be seen whether this year's unusually low peak demand marks a departure from historical norms, or whether 2018-19 is simply an outlier, AEMO will continue to monitor these trends going forward.

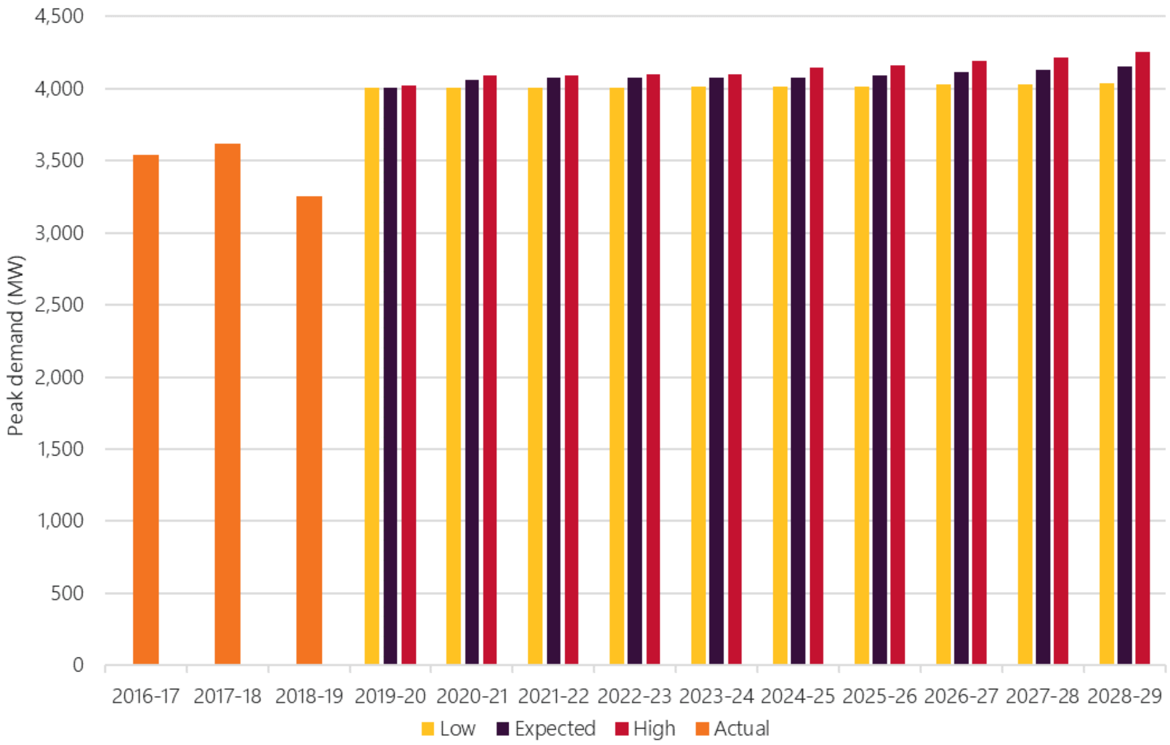
4.2 Peak demand forecasts

Over the 2019-20 to 2028-29 period, in the expected growth scenario, the 10% POE summer peak demand is forecast to grow from 4,007 MW in 2019-20 to 4,152 MW in 2028-29. The 10% POE, 50% and 90% POE summer peak demand are all forecast to grow at an average annual rate of 0.4%. The 10% POE peak demand forecasts under the three different demand growth scenarios are shown in Figure 25 alongside actual peak demand since 2016-17.

Over the outlook period, expected winter peak demand is forecast to grow at an average annual rate of 0.3% for the 10% POE scenario and 0.4% for the 50% POE and 90% POE scenarios. Winter peak demand is forecast to remain lower than summer peak demand for all scenarios over the outlook period. Summer peak demand remains consistently above winter peak demand by at least 173 MW, even when a mild summer peak (90% POE or 50% POE) is compared against a colder-than-usual (10% POE) winter. A full set of summer peak demand forecasts is in Appendix A6, and winter peak demand forecasts are in Appendix A7, as well as the 2019 WEM ESOO data register.

In light of the most recent summer and winter peaks being equal, AEMO will continue to monitor the difference between winter and summer peak demand.

Figure 25 10% POE forecast peak demand under different growth scenarios, 2019-20 to 2028-29

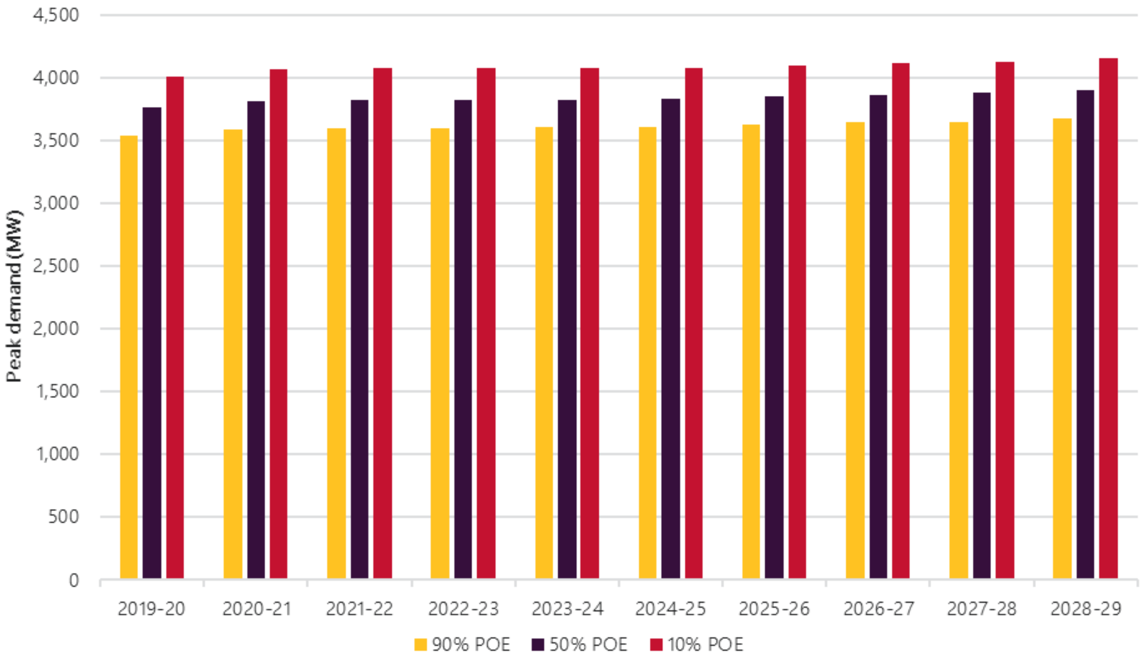


Source: AEMO and ACIL Allen.

The variation in growth rates between the low, expected, and high demand growth scenarios reflects different economic growth and population forecasts (see Sections 3.4.1 and 3.4.2), block loads and EVs. Projected behind the meter PV and battery uptake rates remain the same in all demand scenarios (see Section 3.3).

The expected peak demand forecasts under different weather scenarios (10% POE, 50% POE, and 90% POE) are shown in Figure 26.

Figure 26 10% POE, 50% POE, and 90% POE peak demand forecasts under the expected demand growth scenario, 2019-20 to 2028-29



Source: ACIL Allen.

4.3 Reconciliation with previous forecasts

4.3.1 2018-19 reconciliation

The actual peak demand for 2018-19 was 3,256 MW, 891 MW lower than the 10% POE forecast and 654 MW lower than the 50% POE forecast published in the 2018 WEM ESOO. The main reasons for peak demand being lower than expected were unusually low 2018-19 peak demand temperature conditions (examined further in Sections 4.1.2 and 4.1.4) and residual errors in last year's peak demand model.

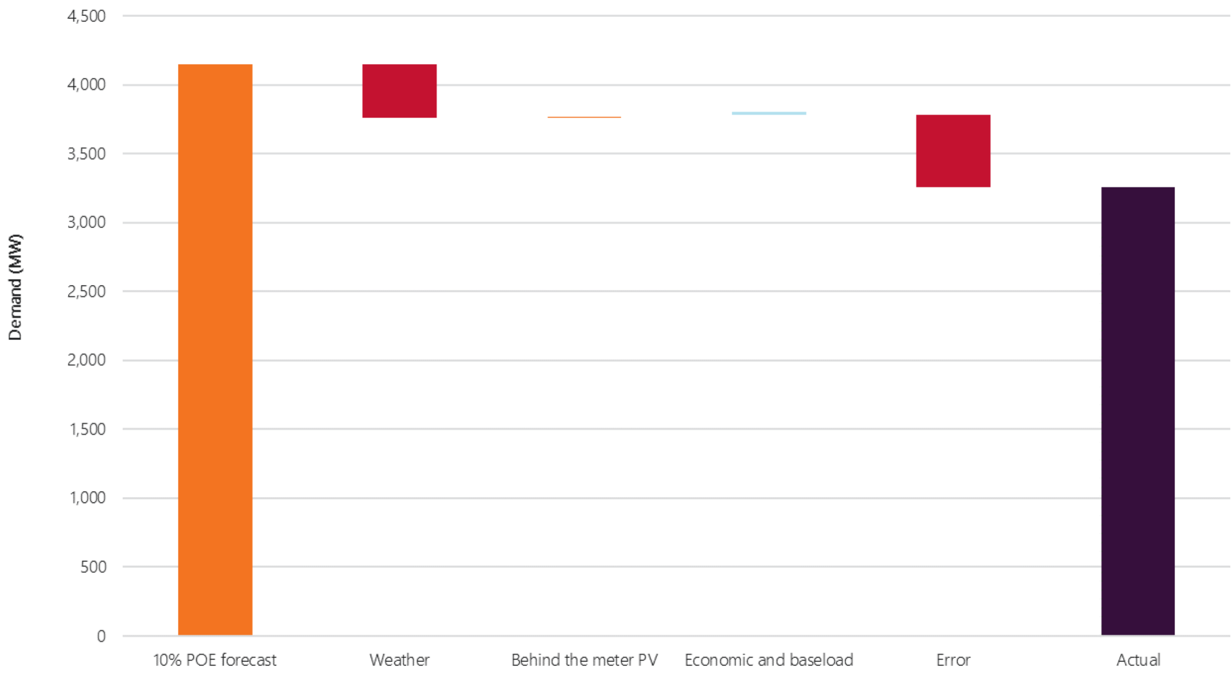
The variance between the 2018-19 actual peak demand and the 2018-19 10% POE forecast from the 2018 WEM ESOO is shown in Figure 27. The variance can be broken down as follows:

- Weather effects (-383 MW) – temperature conditions on the day of peak demand were significantly milder than those observed historically on peak demand days. Sections 4.1.2 and 4.1.4 investigate weather effects on the 2018-19 peak demand in more detail.
- Behind the meter PV (-4 MW) – the effect of behind the meter PV at the time of peak demand (at 17:30 in February) was estimated in the 2018 WEM ESOO forecast, and behind the meter PV installations were only slightly higher than previously forecast.
- Economic and baseload effects (+22 MW) – economic growth was similar to the forecast at 2.4%[86].
- Error (-525 MW) – the error term is used to account for any factors that are excluded from the model or where there are more complex inter-relationships between variables compared to the model specification. These sources of variance cannot be individually quantified and are captured by the error term. As peak demand in 2018-19 was the lowest since market start in 2006 by a margin of 110 MW, it was not well estimated by the parameters developed based on previous historical observations. This year's significant

[86] As the complete data set for the 2018-19 financial year is not yet available, the actual economic growth figure is AEMO's best understanding based on available data.

error term is indicative of the increasing complexity of peak demand forecasting due to changes in weather conditions (see Section 4.1.2).

Figure 27 Forecast reconciliation, 2018-19 peak demand



Source: ACIL Allen and AEMO.

4.3.2 Changes from previous forecasts

The summer peak demand forecasts presented in the 2019 WEM ESOO are lower than the forecasts in the 2018 WEM ESOO, particularly towards the end of the outlook period, as Table 13 shows. In the 2018 WEM ESOO, the 10% POE expected scenario peak demand was forecast to grow at an average annual rate of 0.6%, while the peak demand growth forecast is a lower average annual rate of 0.4% in this 2019 WEM ESOO.

Table 13 Difference between 10% POE expected scenario forecasts, 2018 WEM ESOO and this 2019 WEM ESOO (MW)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
2018 WEM ESOO forecast	4,152	4,174	4,193	4,219	4,242	4,270	4,293	4,323	4,365
2019 WEM ESOO forecast	4,007	4,063	4,075	4,074	4,078	4,079	4,092	4,117	4,128
Difference	-145	-111	-118	-145	-164	-191	-201	-206	-237

Source: ACIL Allen.

There are several reasons for lower peak demand forecasts in this 2019 WEM ESOO, as detailed in Chapter 3, including:

- Changes to the specification of the forecasting model.
- Revisions to the treatment of behind the meter PV and block loads.

- Weaker economic growth forecasts. While the rate of peak demand growth has decreased, peak demand is still forecast to grow slowly over the outlook period due to economic growth and the addition of new block loads.

5. Historical and forecast operational consumption

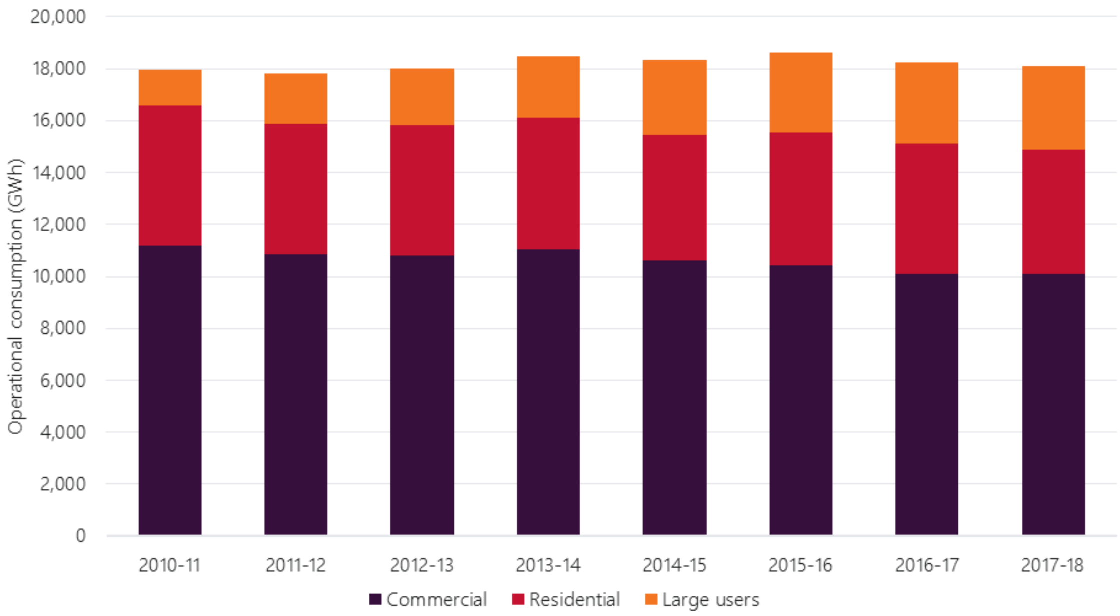
Operational consumption is forecast to decline at an annual average rate of 0.4%.

This is lower than the forecasts published in the 2018 WEM ESOO. Key drivers for lower forecasts include the continued trend of decreasing residential consumption, revised behind the meter PV forecasts, and methodology improvements.

5.1 Historical operational consumption

A breakdown of total operational consumption in the SWIS between 2010-11 and 2017-18 is shown in Figure 28. Data in all charts and tables is presented in financial years unless otherwise specified.

Figure 28 Total operational consumption in the SWIS, 2010-11 to 2017-18



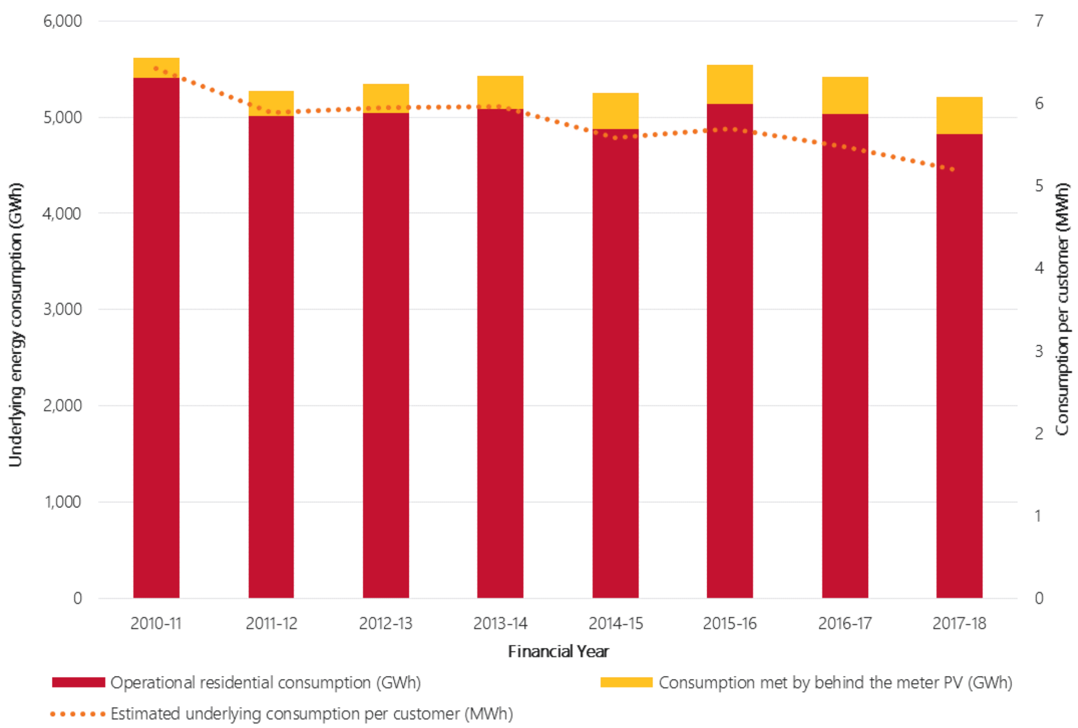
Source: AEMO and Synergy.

Total operational consumption has remained relatively consistent since 2010-11, increasing at an average annual rate of 0.1%. Commercial and residential consumption (which accounts for more than 80% of total SWIS electricity consumption) have both fallen since 2010-11, at an average annual rate of 1.5% and 1.6% respectively.

Growth in large user consumption over the same period, at an average annual rate of 13%, has offset the decline in both commercial and residential consumption. This strong growth reflected new block loads (including desalination plants and large mines) coming online. However, the average annual increase in consumption by large users slowed to around 2.6% between 2015-16 and 2017-18.

Since 2010-11, underlying residential consumption has decreased at an average annual rate of 1.1%. AEMO's estimates of historical underlying residential consumption, representing both electricity consumed from the SWIS and consumption met by behind the meter PV are shown in Figure 29.

Figure 29 Underlying residential consumption in the SWIS, 2010-11 to 2017-18



Source: AEMO calculations based on Synergy data.

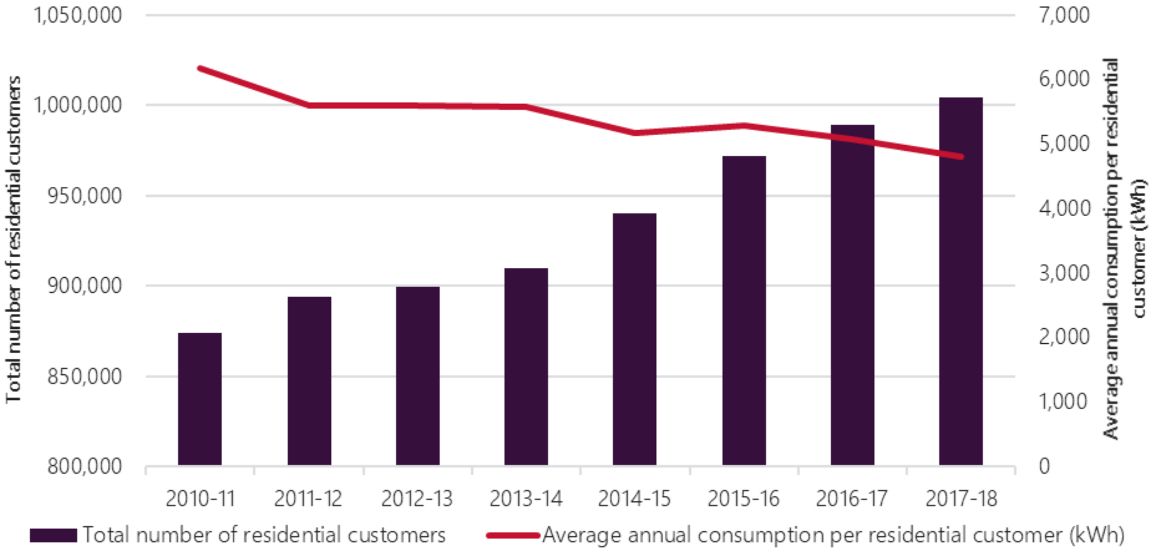
The decrease in underlying residential consumption can be attributed to improved building and household efficiency, and more energy efficient appliances (such as LED lighting and inverter reverse-cycle air-conditioning) replacing older, less efficient appliance stock.

Total residential operational consumption has fallen at an average annual rate of 1.6% between 2010-11 and 2017-18, despite the number of residential customers increasing at an average annual rate of 2% over the same period supported by growing population, as shown in Figure 30.

However, consumption per residential customer has declined at an average annual rate of 3.6%, partly due to behind the meter PV uptake displacing consumption from the SWIS, combined with efficiency improvements. Average consumption has fallen at a faster rate than growth in new connections, placing downward pressure on residential operational consumption.

AEMO expects the decreasing operational consumption trend to continue over the outlook period.

Figure 30 Total number of residential customers and the average annual consumption per residential customer in the SWIS, 2010-11 to 2017-18[A]

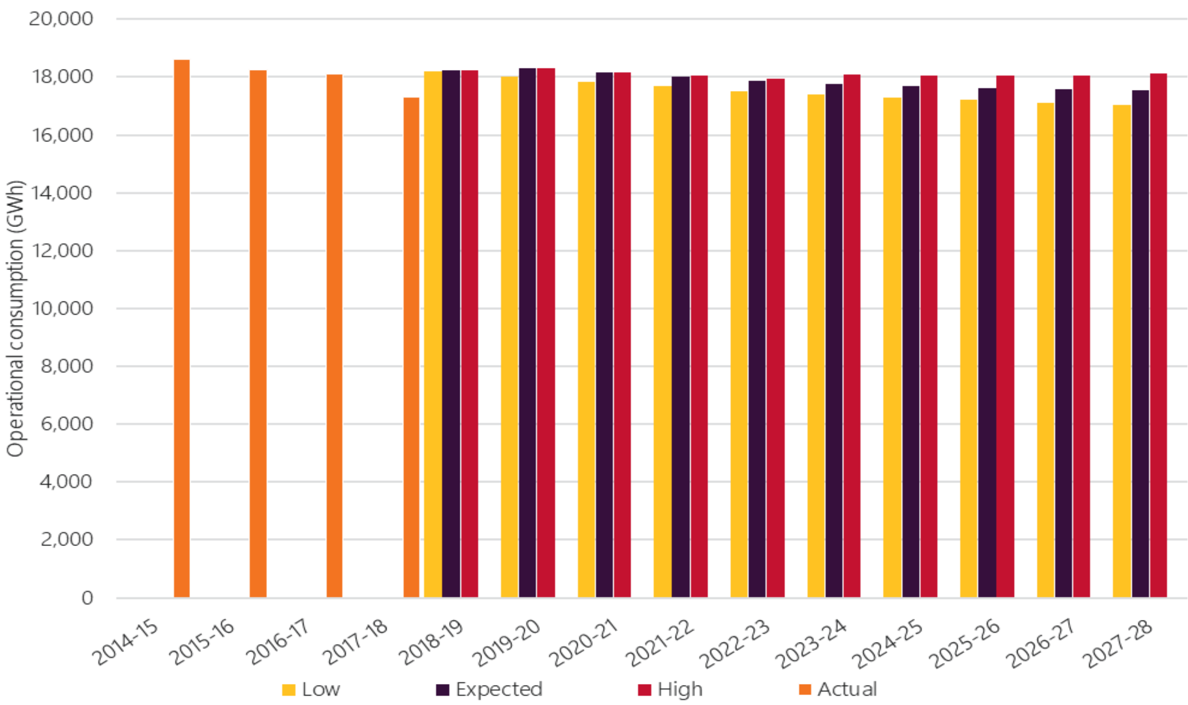


A. The total number of residential customers includes regulated and unregulated tariffs based on contract counts.

5.2 Operational consumption forecasts

Figure 31 shows operational consumption forecasts for low, expected, and high demand growth scenarios.

Figure 31 Operational consumption forecasts under different growth scenarios, 2019-20 to 2028-29[A]



A. The 2018-19 value is based on actual metered data from AEMO's systems to February 2019 and estimates for March to June 2019 (see Section 5.3 for further information).
Source: ACIL Allen.

From 2019-20 to 2028-29[87], operational consumption is forecast to decrease at an average annual rate of:

- 0.7% in the low growth scenario, from 18,191 GWh in 2019-20 to 17,024 GWh in 2028-29.
- 0.4% in the expected growth scenario, from 18,221 GWh in 2019-20 to 17,543 GWh in 2028-29.
- 0.1% in the high growth scenario, from 18,225 GWh in 2019-20 to 18,112 GWh in 2028-29.

The different growth rates reflect variation in the economic growth, EV, and block load forecasts. A full set of operational consumption forecasts is provided in Appendix A8.

Operational consumption is forecast to decline across all growth scenarios over the outlook period, due to:

- Residential consumption falling at an average annual rate of 1.4% (in the expected growth scenario), continuing the trend of declining consumption per residential connection (see Section 5.1 for further information).
- Consumption met by behind the meter PV generation is forecast to grow for both residential and commercial customers at an average annual rate of 7.3% and 13.7% respectively (in the expected growth scenario). This will continue to reduce operational consumption (see Section 3.3.1 for further information).

In the expected growth scenario, the decline in operational consumption as noted above is forecast to be slightly offset by:

- Energy use by EVs growing at an average annual rate of 49.2%. However, EVs are only forecast to contribute 150 GWh (0.9%) to operational consumption by 2028-29 (see Section 3.3.3 for further information on the EV forecasts).
- Block load consumption is forecast to grow at 1.1% over the outlook period to reach 3,668 GWh (21% of total operational consumption) by 2028-29, driven by the introduction of three new block loads by 2021-22 amounting to a total of 567 GWh (see Section 3.4.3 for further information). Existing block loads are expected to remain relatively stable over the outlook period.

5.3 Reconciliation

5.3.1 2018-19 reconciliation

The 2018-19 operational consumption reconciliation presents AEMO's preliminary explanation of forecast variations. At the time this report is being written, the 2018-19 financial year is incomplete, so the analysis is based on actual data available at the time and estimates for the remainder of the financial year.

Actual operational consumption in 2018-19 is estimated as 17,319 GWh[88], which is 5.3% lower than the forecast under the expected growth scenario published in the 2018 WEM ESOO (18,296 GWh). AEMO expects this variation to be attributed to:

- Weather effects – there were fewer CDD than forecast based on long-term averages, particularly in November 2018 and January 2019, and fewer HDD, particularly in July and October 2018 (see Section 3.2.3 and Section 4.1.2 for further information). This resulted in lower than expected operational consumption.
- Behind the meter PV – behind the meter PV generation is higher than forecast in both the expected and high growth scenarios, resulting in lower than expected operational consumption.
- Large loads– large loads have been operating below their normal consumption levels.

AEMO will publish a separate reconciliation report at the end of the financial year and present a more detailed analysis of the operational consumption forecast variations.

[87] Operational consumption is forecast in financial years.

[88] Based on actual metered data from AEMO's systems to February 2019 and estimates for March to June 2019.

5.3.2 Changes from previous forecasts

For the first time, AEMO is forecasting declining operational consumption, at an annual average rate of 0.4%. In comparison, in the 2018 WEM ESOO, operational consumption in the expected growth scenario was forecast to grow at an average annual rate of 0.9%. Table 14 shows the difference in forecasts across the outlook period.

Table 14 Difference between operational consumption expected scenario forecasts, 2018 WEM ESOO and this 2019 WEM ESOO (GWh)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
2018 WEM ESOO	18,307	18,382	18,506	18,660	18,820	19,032	19,279	19,561	19,871
2019 WEM ESOO	18,221	18,289	18,151	18,008	17,864	17,775	17,694	17,629	17,569
Difference	-86	-93	-355	-652	-956	-1,257	-1,585	-1,932	-2,301

Source: ACIL Allen.

The reduction in AEMO's operational consumption forecasts is attributed to several factors, including:

- Revised assumptions around when customers turn on air-conditioning to be more reflective of customer behaviour:
  - Residential customers are assumed to use air-conditioning when the average daily temperature exceeds 26°C.
  - Non-residential customers are assumed to use air-conditioning when the average daily temperature exceeds 24°C.
- Higher behind the meter PV forecasts compared to previous years, to reflect recent trends in uptake by both residential and commercial customers.

Further information about the changes in methodology can be found in Chapter 3.

6. Reserve Capacity Target

This chapter reports the RCT determined for each Capacity Year of the 2019 Long Term PASA Study Horizon from the 2019-20 to 2028-29 Capacity Years. The RCT determined for the 2021-22 Capacity Year sets the RCR[89] for the 2019 Reserve Capacity Cycle.

The RCR for the 2019 Reserve Capacity Cycle is 4,482 MW, and no capacity shortfall is anticipated across the 2019 Long Term PASA Study Horizon.

6.1 Overview

The RCT is AEMO's estimate of the total amount of generation and DSM capacity required in the SWIS to satisfy part (a) (annual expected 10% POE peak demand forecast) and part (b) (annual EUE) of the Planning Criterion[90] for a Capacity Year. The RCT is set for each Capacity Year of the 10-year Long Term PASA Study Horizon.

To date, the RCT has been set by part (a) of the Planning Criterion due to a sufficient amount of capacity available to then meet part (b). This remains the case for the 2019 Long Term PASA study.

In accordance with part (a) of the Planning Criterion, the RCT is calculated as the sum of:

- Annual 10% POE peak demand forecast under the expected demand growth scenario.
- An Intermittent Loads allowance of 4 MW[91].
- A reserve margin set by the sent-out capacity of the largest generating unit, NewGen Neerabup (331 MW)[92], measured at 41°C. This is greater than 7.6% of the sum of the expected 10% POE peak demand forecast and the Intermittent Loads allowance and so takes priority.
- A load following ancillary service (LFAS)[93] capacity requirement of 72 MW[94] to maintain system frequency.

[89] The RCR determines the quantity of Capacity Credits required to be procured through the RCM for the relevant Reserve Capacity Cycle. In contrast to the RCT that could be updated in a future Long Term PASA study, once an RCR is set for the relevant Reserve Capacity Cycle, it remains unchanged.

[90] The Planning Criterion is outlined in clause 4.5.9 of the WEM Rules and explained in more detail in Chapter 3.

[91] Intermittent Loads' contribution is calculated based on clause 4.5.2A (b) of the WEM Rules.

[92] Based on the level of Capacity Credits assigned for the 2020–21 Capacity Year.

[93] LFAS is a type of ancillary service that ensures the target frequency range (49.8 to 50.2 hertz) is met 99% of the time by balancing demand and supply. See https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Ancillary-services.

[94] With increasing levels of large and small scale renewable generation connecting to the SWIS, AEMO expects the LFAS capacity requirement to increase, and the change will be reflected in future WEM ESOO reports. The reforms to the ancillary services framework as part of the WA Government's electricity industry reform program that are underway and may also change this LFAS capacity requirement.

6.2 Forecast capacity requirements

The RCT, set by the expected 10% POE peak demand requirement of the Planning Criterion for each Capacity Year of the 2019 Long Term PASA Study Horizon is shown in Table 15.

The RCT determined for the 2021-22 Capacity Year is 4,482 MW, which sets the RCR for the 2019 Reserve Capacity Cycle. This is lower than:

- The RCT for the 2021-22 Capacity Year (4,600 MW) forecast in the 2018 WEM ESOO.
- The RCR for the 2020-21 Capacity Year (4,581 MW) set in the 2018 WEM ESOO.

In both cases, this is due to a lower 10% POE peak demand forecast[95].

Table 15 Reserve Capacity Targets (MW)[A]

Capacity Year	10% POE Peak demand	Intermittent Loads	Reserve margin	Load following	Total
2019-20[B]	4,007	4	331	72	4,414
2020-21[B]	4,063	4	331	72	4,470
2021-22	4,075	4	331	72	4,482
2022-23	4,074	4	331	72	4,481
2023-24	4,078	4	331	72	4,485
2024-25	4,079	4	331	72	4,486
2025-26	4,092	4	331	72	4,499
2026-27	4,117	4	331	72	4,524
2027-28	4,128	4	331	72	4,535
2028-29	4,152	4	331	72	4,559

A. All figures have been rounded to the nearest MW.
B. Figures have been updated to reflect the current forecasts. However, the RCR set in the 2017 WEM ESOO for the 2017 Reserve Capacity Cycle and the RCR set in the 2018 WEM ESOO for the 2018 Reserve Capacity Cycle do not change.

6.3 Availability Classes

Certified Reserve Capacity (CRC) is classified into two classes based on capacity availability[96]:

- Availability Class 1 relates to generation capacity and any other capacity that is expected to be available for dispatch for all Trading Intervals, allowing for outages or other restrictions.
- Availability Class 2 relates to capacity that is not expected to be available for dispatch for all Trading Intervals.

The Long Term PASA determines the minimum capacity required to be provided by Availability Class 1 capacity for a relevant Capacity Year. The Availability Class 2 capacity allowance is equal to the RCT less the Availability Class 1 requirement. Capacity shortfalls occur when:

- Availability Class 1 capacity is less than the minimum Availability Class 1 capacity requirement.
- Availability Class 1 and Availability Class 2 capacity is less than the RCT.

[95] See Chapter 4 for further information.

[96] As defined in clause 4.11.4 of the WEM Rules.

The minimum Availability Class 1 capacity requirement and the capacity associated with Availability Class 2 are determined by the 2019 Long Term PASA study for the 2020-21 and 2021-22 Capacity Years, as outlined in Table 16. A more detailed explanation on the methodology is provided in Appendix A1.

Table 16 Availability Classes (MW)

	2020-21A	2021-22
Minimum capacity required to be provided by Availability Class 1	4,110	3,657
Capacity associated with Availability Class 2	360	825
RCT	4,470	4,482

A. Figures have been updated to reflect the current forecasts. However, the capacity requirements for the two Availability Classes for the 2020-21 Capacity Year, determined in the 2018 WEM ESOO, remains unchanged.
Source: RBP.

The minimum capacity required to be provided by Availability Class 1 for the 2020-21 Capacity Year, as outlined in Table 16, has increased by 164 MW from the value published in the 2018 WEM ESOO (3,946 MW), and the capacity associated with Availability Class 2 capacity has decreased by 275 MW.

These changes are primarily due to projected lower capacity availability in November 2020:

- A large amount of dispatchable generation capacity is scheduled to be on planned outages in November 2020, as submitted by Market Participants in their responses to AEMO's 2019 Long Term PASA information request. These outages increase the minimum amount of Availability Class 1 capacity required to avoid unserved energy in the reliability model for the 2020-21 Capacity Year.
- An increased amount of solar generation ramps down during evening hours in November 2020, which decreases the amount of available generation further.
- Lower level of the Availability Class 2 capacity (DSM) is available for the model to dispatch in November 2020, the shoulder month to meet the load[97].

The minimum capacity required to be provided by Availability Class 1 for the 2021-22 Capacity Year is 453 MW lower than the 2020-21 Capacity Year. This is due to less dispatchable generation capacity being scheduled for planned outages during November 2021.

6.4 Availability Curves

The Availability Curve is a two-dimensional duration curve of the forecast minimum capacity requirement for each Trading Interval over a Capacity Year[98]. The minimum capacity requirement for each Trading Interval is calculated as the sum of the forecast demand for that Trading Interval, reserve margin, Intermittent Load allowance, and the LFAS capacity requirement.

The 2019 Long Term PASA study develops the Availability Curves for the 2020-21 and 2021-22 Capacity Years using the following steps:

- Forecast load for all Trading Intervals using the scaling methodology described in Section 3.2.4 based on the expected peak demand and operational consumption forecasts.
- Add the reserve margin, Intermittent Load allowance, and the LFAS capacity requirement determined in Table 15.

[97] The DSM optimisation model used in the reliability study allocating hourly DSM to minimise the peak subject to availability constraints as required under clause 4.5.12(b)(i) of the WEM Rules. This means that most of the DSM is dispatched in summer months when demand is generally the highest (for further information, see RBP's report).

[98] As defined in clause 4.5.10(e) of the WEM Rules.

A more detailed explanation and graphs of the Availability Curves are provided in Appendix A1 and RBP's report.

6.5 DSM Reserve Capacity Price

AEMO is required to calculate the Expected DSM Dispatch Quantity (EDDQ) and the DSM Activation Price in accordance with the Market Procedure[99]. The EDDQ and the DSM Activation Price are used to determine the DSM Reserve Capacity Price (RCP). The formula used to determine the DSM RCP is:

$$\text{DSM RCP} = (\text{Expected DSM Dispatch Quantity} + 0.5) \times \text{DSM Activation Price}$$

A detailed explanation of the methodology used to calculate the EDDQ is provided in Appendix A2.

The DSM RCP for the 2019-20 Capacity Year is $16,990.38/MW. The EDDQ and the DSM Activation Price for the 2019-20 Capacity Year are 0.0078 MWh per DSM Capacity Credit and $33,460/MWh respectively. AEMO has assigned 66 MW of DSM Capacity Credits under Availability Class 2 for the 2019-20 Capacity Year.

The DSM RCP is estimated to remain relatively consistent over the outlook period, as outlined in Table 17. The estimates are based on the following assumptions for the 2020-21 to 2028-29 Capacity Year:

- DSM Capacity Credits remain unchanged at 66 MW[100].
- The DSM Activation Price of $33,460/MWh remains unchanged.
- The DSM capacity assigned under Availability Class 2 is expected to be available for dispatch for at least 12 hours a day and 200 hours in total for a Capacity Year[101].

Table 17 Expected DSM Dispatch Quantity and DSM RCP, 2019-20 to 2028-29

Capacity Year	Expected DSM Dispatch Quantity (MWh per DSM Capacity Credit)	DSM RCP ($/MW)
2019-20	0.0078	$16,990.38
2020-21	0.0027	$16,820.85
2021-22	0.0034	$16,842.34
2022-23	0.0063	$16,942.12
2023-24	0.0070	$16,964.42
2024-25	0.0035	$16,846.40
2025-26	0.0060	$16,930.76
2026-27	0.0008	$16,755.15
2027-28	0.0189	$17,363.10
2028-29	0.0028	$16,822.07

Source: RBP.

Overall, the EDDQ is lower over the 2019 Long Term PASA Study Horizon compared to the EDDQ values published in the 2018 WEM ESOO. This is attributed to lower EUE when no DSPs are dispatched, primarily due

[99] Market Procedure: *Determination of the DSM Dispatch Quantity and DSM Activation Price*, at http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Procedures.

[100] Based on information provided by Market Participants.

[101] As required in clause 4.10.1(f) of the WEM Rules.

to lower peak demand forecasts. Low variation in the EDDQ is a result of averaging the EDDQ calculated based on each of the five historical LDCs[102]. This is in comparison to the 2018 WEM ESOO, which estimated the EDDQ based on one averaged LDC.

The EDDQ estimates from the 2020-21 Capacity Year to the end of the Long Term PASA Study Horizon will be updated in the 2020 WEM ESOO. At that time, AEMO will request new information from Market Participants and reassess all outage information.

6.6 Opportunities for investment

6.6.1 Supply-demand balance

To forecast the supply-demand balance over the 2019 Long Term PASA Study Horizon, AEMO has assumed that:

- No additional generation is retired from the generation capacity of the 2020-21 Capacity Year over the forecast period (see Appendix A3 for detailed information).
- The total DSM Capacity Credits for the entire forecast period remains unchanged at 66 MW from the 2020-21 Capacity Year.
- No new committed capacity[103] commences operation over the Long Term PASA Study Horizon, other than new Facilities that were assigned Capacity Credits for the 2019-20 and 2020-21 Capacity Years.
- No probable projects[104] are developed over the Long Term PASA Study Horizon.

Figure 32 shows the forecast supply-demand balance for the 2019-20 to 2028-29 Capacity Years. It compares the RCT with the expected level of capacity for each Capacity Year of the 2019 Long Term PASA Study Horizon. The expected level of capacity is assumed to remain consistent with the total number of Capacity Credits assigned for the 2020-21 Capacity Year. The forecast supply-demand balance for the high and low demand growth scenarios can be found in Appendix A3.

Available capacity (existing and committed) is expected to be sufficient to meet the RCT throughout the forecast period, provided there are no further generation or DSM capacity retirements, long-term outages, or further changes to the WEM Rules[105].

A more detailed capacity outlook for the 2019-20 to 2021-22 Capacity Years is outlined in Table 18.

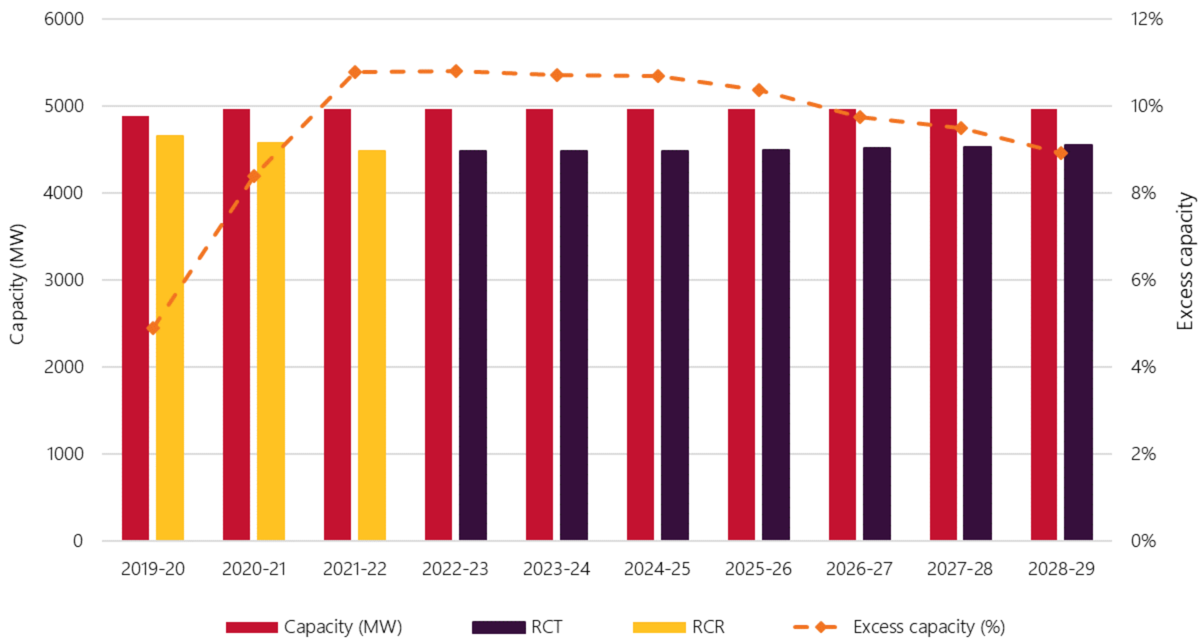
[102] See Appendix A2 and RBP's report for further information.

[103] Committed capacity for a Capacity Year refers to new DSM or generation capacity that holds Capacity Credits for the relevant Capacity Year but have not previously held Capacity Credits for a past Reserve Capacity Cycle.

[104] Probable projects refer to Facilities have not already received Capacity Credits for a previous Reserve Capacity Cycle but have been granted Certified Reserve Capacity for the current Reserve Capacity Cycle, as outlined in clause 2.10.3 of the Market Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion.

[105] The amount of capacity assigned to Non-Scheduled Generators is determined in accordance with the Relevant Level Methodology (RLM) as outlined in Appendix 9 of the WEM Rules. The ERA completed the RLM review in March 2019. As a result of the review, ERA has recommended changing the current method and intends to develop a rule change proposal. Any changes to the RLM Methodology as a result of the review may change existing and committed Non-Scheduled Generators' capacity assumed over the outlook period.

Figure 32 Forecast supply-demand balance, 2019-20 to 2028-29[A,B]



A. 2019-20 and 2020-21 capacity values are actuals, the remainder are forecasts.
B. Excludes 2019 Expressions of Interest (EOI) submissions.

Table 18 Capacity outlook in the SWIS, 2019-20 to 2021-22 Capacity Years[A]

Capacity category	2019-20 (MW)[B]	2020-21 (MW)[C]	2021-22 (MW)[D]
Existing generating capacity[E]	4,757	4,809	4,900
Existing DSM capacity[E]	66	66	66
Committed DSM capacity[F]	0	0	0
Committed generation[F] capacity	65	92	0
Total capacity	4,888	4,966	4,966
RCR	4,660	4,581	4,482
Excess capacity	228 (4.9%)	385 (8.4%)	484 (10.8%)

A. All capacity values are in terms of assigned Capacity Credits, rounded to the nearest integer.
B. Capacity values are Capacity Credits assigned for the 2017 Reserve Capacity Cycle.
C. Capacity values are Capacity Credits assigned for the 2018 Reserve Capacity Cycle. The reduction in existing generating capacity in the 2020-21 Capacity Year compared to the 2019-20 Capacity Year is due to year-on-year changes to Non-Scheduled Generator Capacity Credits due to the RLM.
D. Capacity outlook for the 2021-22 Capacity Year is based on Capacity Credits assigned for the 2018 Reserve Capacity Cycle. It is assumed that this capacity outlook remains unchanged for the 2022-23 to 2028-29 Capacity Years.
E. Existing generation and DSM capacity are capacity that holds Capacity Credits for the relevant Capacity Year and held Capacity Credits for the previous Capacity Year.
F. Committed capacity for a Capacity Year refers to new DSM or generation capacity that holds Capacity Credits for the relevant Capacity Year but have not previously held Capacity Credits for a previous Reserve Capacity Cycle.

For the 2020-21 Capacity Year, excess capacity increased considerably from 228 MW (4.9%) in the 2019-20 Capacity Year to 385 MW (8.4%), primarily due to the entry of new intermittent generation capacity[106] and a decrease in the RCR.

Excess capacity is forecast to increase to 484 MW (10.8%) in the 2021-22 Capacity Year as a result of a lower RCR determined for the 2019 Reserve Capacity Cycle.

The 2019 Long Term PASA study has considered the network constraints that are applicable to the Constrained Access Facilities[107]. No localised supply restrictions are expected to exist in the SWIS that influence the capacity ability to satisfy the RCT in each Capacity Year over the Long Term PASA Study Horizon.

However, circumstances may change over the forecast period. In particular, the level of capacity that is made available to the market over the Long Term PASA Study Horizon may be affected by changes to the WEM Rules implemented under the WA Government's Energy Transformation Strategy (ETS), including the proposed pricing arrangements[108] (see Section 7.1 for more information). Project proponents, investors, and developers should make their own independent assessments of future possible supply and demand conditions.

AEMO does not include capacity offered through EOI submissions for the 2021-22 Capacity Year in the expected supply-demand balance, because EOIs do not necessarily include all future proposed projects, and only a few proposed projects progress through the CRC process.

6.6.2 Expressions of Interest and excess capacity in the SWIS

Under clause 4.1.4 of the WEM Rules, AEMO is required to run an EOI process each year. The EOI process for the 2019 Reserve Capacity Cycle closed on 1 May 2019 and AEMO received two EOIs. One non-intermittent generation project with an estimated output of 32 MW at 41°C and one intermittent generation project with an estimated CRC assignment of 0.4 MW were proposed for the 2021-22 Capacity Year[109].

While the EOI process provides an indication of potential future capacity, a project proposed in an EOI does not necessarily progress to a committed project for the relevant Capacity Year. Also, as the EOI process is not mandatory, new projects that skip the EOI process are still eligible to apply for CRC and be assigned CRC.

Table 19 shows the amount of nameplate capacity offered for each Capacity Year under the EOI process, compared with the amount of EOI capacity that was eventually certified and the total new capacity certified for that Capacity Year.

Table 19 New capacity offered through the EOI compared to capacity certified, 2014-15 to 2021-22 (MW)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
New capacity offered	214	59	56	0	42	323	10	32.4[A]
New capacity offered and certified	0	0.4	0	0	0	65	0	TBD
Total other new capacity certified[B]	31	35	18	12	16	0	93	TBD

A. Estimated Capacity Credits assignment provided by the EOI proponents.
B. New capacity that was not offered through an EOI but received Capacity Credits for the relevant Capacity Year.

[106] See Chapter 2 for more detailed information.

[107] As defined in chapter 11 of the WEM Rules and the RBP report.

[108] WA PUO. Improving Reserve Capacity pricing signals – a recommended capacity pricing model, *Final Recommendations Report*, February 2019. Available at https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Final-Recommendations-Report-Improving-Reserve-Capacity-pricing-signals.pdf.

[109] 2019 Expressions of Interest Summary Report, available at https://www.aemo.com.au/-/media/Files/Electricity/WEM/Reserve_Capacity_Mechanism/EOI/2019/2019-Expressions-of-Interest-Summary-Report.pdf.

7. Current market issues and developments

This chapter highlights market developments and issues being experienced in the SWIS that are particularly relevant to the RCM, including:

- Changes to RCP arrangements.
- Reserve Capacity payments and IRCR liability.
- Current Economic Regulation Authority (ERA) WEM reviews and rule changes.
- The rise of DER and utility-scale renewable energy.
- Embracing DER and planning for a future energy system.
- Infrastructure developments in the SWIS.

7.1 Changes to the RCP arrangements

With the aim of increasing the economic efficiency of the RCM, the Public Utilities Office (PUO) is amending the current WEM Rules relating to Reserve Capacity pricing.

The changes are intended to reflect the true value of capacity[110]. Facilities that are currently assigned Capacity Credits will be subject to the proposed pricing arrangement but will have a floor and ceiling cap to prevent full exposure to possible pricing extremes in the first 10 years following the introduction of these changes. The amendments suggest that DSM capacity will be remunerated in the same manner as other generation capacity participating in the RCM.

7.2 Reserve Capacity payments and IRCR liability

All new large-scale generation in the SWIS for the last five years has been renewable, and generators that have retired over the past few years have been Scheduled Generators. This trend is likely to continue over the near term, with an additional 545 MW (nameplate capacity) of new large-scale renewable generation that may connect to the SWIS by 2020.

There is an increasing mismatch between the peak demand profile of the SWIS and the generation profile of behind the meter PV technologies, as peak demand shifts into the evening when the capacity factor of behind the meter PV declines greatly. This divergence is now manifesting in the RLM used to calculate the capacity value for NSGs. It particularly impacts large-scale PV Facilities participating in the RCM, which experienced an average decrease in assigned Capacity Credits of 11.5% between the 2016 and 2017 Reserve Capacity Cycles, and 26.5% between the 2017 and 2018 Reserve Capacity Cycles.

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[110] WA PUO, Improving Reserve Capacity pricing signals – a recommended capacity pricing model, *Final Recommendations Report*, February 2019, at https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Final-Recommendations-Report-Improving-Reserve-Capacity-pricing-signals.pdf.

The shift of the SWIS peak demand profile into late evening is diminishing the commercial opportunity for Market Customers to reduce their IRCR liability with behind the meter PV generation. However, it may become increasingly commercial to consider deploying behind the meter storage technologies alongside solar generation to offset IRCR liabilities.

7.3 Current ERA WEM reviews and rule changes

The ERA is required to complete reviews of methodologies underlying processes and calculations in the WEM Rules. This section lists methodologies that have been reviewed, or for which reviews have begun, since the last WEM ESOO was published in 2018.

The Relevant Level methodology

The RLM review[111] (capacity valuation for NSGs), which relates to the calculation of the capacity value for NSGs under the RCM, was completed by the ERA in March 2019. This review identified improvements needed in the current RLM, and concluded that:

- The current methodology does not provide an accurate forecast of the capacity contribution of NSGs to reliability in the SWIS, and
- A new method is required.

The ERA has proposed a new method (the Proposed Method) which will:

- Use historical time series data of NSGs and Scheduled Generators, and demand, to forecast the capacity value of the NSG fleet two years ahead.
- Allocate a fleet capacity value to each type of intermittent technology class – currently biogas, solar, and wind generation – and then distribute technology class capacity values to individual NSGs in a technology class, based on their output during low capacity surplus periods in the SWIS.
- Use statistical and probability-based model concepts.
- Continue to calculate capacity values for NSGs as the WEM evolves and accommodates the introduction of new technology, such as storage, as it enters the system.

The next steps following this release of the RLM review are for the Proposed Method to be developed as a Rule Change Proposal specifying the details.

Rules and methodologies still under review by the ERA

Table 20 lists WEM Rules and methodologies which the ERA is still reviewing. Further information will be made available on the ERA's website[112].

Table 20 List of WEM reviews being undertaken by the ERA

Methodology under review	Estimated time to completion
Benchmark Reserve Capacity Price Market Procedure and Energy Price Limits	Mid to late 2019
Planning Criterion and peak demand forecasting	Early 2020
Outage planning process and ancillary service requirements	Late 2020 or early 2021

[111] For more information, see https://www.erawa.com.au/cproot/20328/2/Relevant%20level%20method%20review%202018%20-%20Final%20report.pdf.

[112] For more information, see https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews.

7.4 The rise of DER and large-scale renewable energy

One of the most significant challenges facing the operators of the SWIS is the rapid rise of DER. This now includes more than 1.1 gigawatts of connected behind the meter PV. Collectively, this is the single largest generator in the SWIS, and it is not centrally monitored or coordinated.

At the same time, large-scale renewable generation continues to increase rapidly, and dispatchable thermal synchronous generation is being displaced[113]. Dispatchable thermal synchronous generation Facilities presently provide the SWIS with system security services – such as inertia, frequency control, system strength, and voltage control – which are needed to keep the SWIS functioning securely. As the quantity of synchronous generation dispatched in the SWIS declines, supplying these services is becoming increasingly reliant on fewer Facilities.

Where there is insufficient demand and/or commercial incentive to keep synchronous generation on-line and supporting system security, credible events could eventuate in cascading failures across the SWIS. The SWIS could become inoperable under its present operating parameters. AEMO forecasts that the SWIS will reach an instantaneous non-synchronous generation level of 65% in 2024[114] – a penetration limit equal to that set by the grid operators for Ireland and Northern Ireland (Eirgrid and SONI) following extensive system studies and the development of grid support services and products. This level of instantaneous renewable energy integration has been acknowledged as the highest recorded level in the world[115].

Table 21 shows a possible distribution of system security breaches where operational demand was below the 700 MW[116] threshold.

Table 21 Indicative distributions of system security risks

	Possible distribution		
	2022	**2024**	**2026**
Months where risks occur	Sept-Oct	Sept-Dec	May occur throughout the year: Jan, Mar, Jul-Dec
Lowest operational demand	600 MW	350 MW	100 MW
Number of hours affected on the worst day	3 hours	6 hours	7 hours
Maximum number of households requiring disconnection	Up to 60,000	Up to 200,000	Up to 300,000
Total hours in the year below 700 MW threshold	10 hours	50 hours	150 hours

7.5 Embracing DER and planning for a future energy system

With the energy industry going though such a significant transformation, AEMO believes immediate reviews of technical standards and regulatory and market constructs are required. This should be undertaken with expedient and careful design to implement or incentivise new technologies in the SWIS – such as

[113] AEMO, *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS*, March 2019, at www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf.

[114] The analysis was undertaken as a consequence of AEMO's existing obligations under the WEM Rules. More sophisticated and expansive analysis (and a broader range of inputs) is warranted to determine the impact of DER on the power system and market outcomes. AEMO's capacity to undertake this further analysis will be dependent on any expanded scope of functions and requirements it receives under the WEM Rules to provide AEMO the mandate to undertake this analysis and to recover the costs of activities performed in relation to these expanded functions and requirements.

[115] See www.eirgridgroup.com/newsroom/record-renewable-energy-o/index.xml.

[116] AEMO's analysis in its *Integrating Utility-scale renewables and distributed energy resources in the SWIS* (https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf) report identified 700 MW of operational demand as an initial threshold below which system security in the SWIS could be at risk.

synchronous compensation, energy storage, and increased inverter capabilities – that can support system security as the power system changes.

While these technical standards and regulatory and market constructs are being put into place under a single umbrella over the short term (see the WA Government's ETS in Section 7.5.1 below), there are a number of immediate activities currently underway that will assist with embracing DER on the SWIS. These are summarised below.

Infrastructure to support DER integration

To facilitate the delivery of market mechanisms and related DER products and services that support the provision of energy and network services traditionally performed by synchronous generation, Western Power is planning to install 238,000 advanced meters through a three-year meter replacement program, at a cost of $215 million[117]. The Advanced Meters program will bring greater transparency of behind the meter power quality and flows, and increase the opportunity for the customer to better engage with the grid and their DER assets. This increased visibility of power flow will:

- Help AEMO deliver more accurate forecasts (real-time, short-term, and long-term) and consequently reduce security risks in the face of increasing variability.
- Ultimately promote the economically efficient, safe, and reliable production and supply of electricity in the SWIS.

Large-scale storage trials

Entities affected by the significant increase in DER are undertaking trials such as the Alkimos Beach and Meadow Springs trials of energy storage technologies, using what are also called 'front-of-the-meter' large-scale batteries to store energy generated by behind the meter PV systems[118]. These trials are testing a number of commercial products and services of interest to both Market Participants and consumers.

AEMO VPP trials in the NEM

AEMO has secured funding from the Australian Renewable Energy Agency for VPP demonstrations in the NEM to advance the integration of DER[119]. The VPP demonstrations will provide evidence-based learning towards the integration of DER (such as behind the meter PV systems, batteries, and controllable-load devices), operated using software and communications technology to provide energy and network services traditionally performed by a conventional power plant. AEMO is currently developing the enrolment documents and terms and conditions for participation, and will publish these on its website[120].

Economics and Industry Standing Committee enquiry into microgrids

The WA Parliament's Economics and Industry Standing Committee (EISC) is finalising an inquiry into the potential for microgrids and associated technologies that contribute to supplying affordable, secure, reliable, and sustainable energy in metropolitan and regional Western Australia. The inquiry will focus on key enablers, barriers, and other factors affecting the development of microgrids and electricity network operations. AEMO's written submission to the inquiry and evidence transcript can be found on the EISC's website[121].

An Interim Report was released in April 2019[122].

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[117] See https://westernpower.com.au/energy-solutions/projects-and-trials/advanced-meters-puts-the-power-in-your-hands/.

[118] See https://www.synergy.net.au/Our-energy/Future-energy/Alkimos-Beach-Energy-Storage-Trial and https://westernpower.com.au/community/news-opinion/powerbank-brings-bulk-battery-storage-to-wa-homes-in-australian-first-trial/.

[119] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations.

[120] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations.

[121] See http://www.parliament.wa.gov.au/Parliament/commit.nsf/(EvidenceOnly)/8C9FB0B8AA10E88D4825823B0019BAA3?opendocument.

[122] See www.parliament.wa.gov.au/Parliament/commit.nsf/(Report+Lookup+by+Com+ID)/B78DC78FC2007FAE482583D7002E3073/$file/Microgrids%20Report-%20Part%201-%20FINAL%20for%20web.pdf.

7.5.1 WA Government's Energy Transformation Strategy

In response to the immediate requirement for a unified co-ordinated plan that includes all relevant WEM agencies, the WA Government has developed an ETS[123]. The ETS will be overseen by the Energy Transformation Taskforce, supported by the Energy Transformation Implementation Unit, and will be delivered under three work streams, as summarised in Table 22.

Table 22 Energy Transformation Strategy workstream elements

Workstream	Workstream elements
Whole of System Plan	• Identify best options for investment that maintains security and reliability. • Efficient integration of renewable energy and identify opportunities for energy storage. • Provide guidance to regulators and industry regarding efficient power system investment, and policy makers in the future needs of the power system.
Foundation Regulatory Frameworks	• Improving access to the SWIS by transitioning existing network access arrangements to a constrained network access model; a new process for allocating Capacity Credits that is consistent with a constrained network environment; new arrangements for the dispatch of generators in the WEM, and market systems to incorporate security-constrained economic dispatch principles. • Delivering the Future Power System: – Power System Security and Reliability: New Essential System Services Framework; Generator Performance Standards; Regulatory Architecture and Governance; Reliability Standards. – Future Market Operations: security-constrained economic dispatch; Synergy Facility Bidding; Reserve Capacity Mechanism under Constrained Access; Controls for efficient market outcomes.
DER	• DER Roadmap.

While the DER Roadmap will be developed by the Energy Transformation Taskforce in line with AEMO's *Integrating Utility-scale Renewables and DER in the SWIS* report[124], AEMO identifies the following aspects as key focus areas within the DER Roadmap:

- Improving DER inverter standards.
- Establishing a dynamic DER register.
- Removing barriers to and incentivising integrated Distributed Energy Storage Devices.
- Considering new roles for aggregators, a Distribution System Operator (or equivalent)[125], and other service providers.

7.6 Infrastructure developments in the SWIS

While strategies that support a future energy system are being developed, Western Power continues to manage and operate the SWIS infrastructure in its current state and format.

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.

[123] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/03/McGowan-Government-launches-Energy-Transformation-Strategy.aspx.

[124] At www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf.

[125] Refers to one type of DER integration platform supporting coordination and optimisation of multiple DER aggregators operating at distribution level. For more information regarding DER integration platform options, see www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2018/OEN-Final.pdf.

7.6.1 Western Power's Applications and Queuing Policy

Western Power's Applications and Queuing Policy (AQP)[126] 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.

7.6.2 Network access for generators

Several areas in the network have very limited network capacity[127] to support new generator connections on a reference service basis without significant network augmentation while an unconstrained network access model is in place. Key limitations are presented in Western Power's 2017 Annual Planning Report (APR)[128].

A new network access regime is being developed under the ETS and will consider:

- Existing network constraints/congestion.
- The effect of the new regime on existing generators.
- Generator dispatch outcomes.
- Revenue projections.
- Generation supply adequacy.

Different options for network access regimes, including a fully constrained regime, are currently being considered for the WEM.

While the new network access regime is being considered, a GIA solution was launched in July 2018, with the aim of providing a constrained access connection for the GIA generators to facilitate further connections to the SWIS.

The GIA solution can currently support the connection of a maximum of 900 MW of new renewable energy to the SWIS. The first GIA generator, Badgingarra Wind Farm (133 MW), connected under the GIA and was commissioned in January 2019. Additional renewable generation capacity totalling 515 MW is expected to connect by October 2020, including Yandin Wind Farm (214 MW), the Warradarge Wind Farm (184 MW), the Merredin Solar Farm (100 MW) and a solar upgrade (17.5 MW) to the Badgingarra Wind Farm.

Western Power's 2017 APR describes the network configuration and available network capacity to support new load and generation connections.

7.6.3 Connecting new loads

Both the Electricity Network Access Code and WEM Rules contemplate application of non-network solutions to address network limitations. Non-network options may be provided by a Network Control Service (NCS) and/or DSM.

Where Western Power identifies a network limitation affecting the connection of a new block load, network augmentation as well as alternative options (such as NCS, demand management or connecting on a non-reference service basis) will be considered. Proponents who have installed (or are planning to install) generation capacity or DSM capacity capable of providing network support should contact Western Power to discuss these opportunities.

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[126] Applications and Queuing Policy, at https://www.erawa.com.au/electricity/electricity-access/western-power-network/western-powers-network-access-arrangements/western-power-access-arrangement-period-2017-2022.

[127] Modelling the impacts of constrained network access, Public report, Public Utilities Office, 1 October 2018.

[128] Western Power 2017. Annual Planning Report 2017, at https://westernpower.com.au/about/reports-publications/annual-planning-report-2017/. The 2017 report is the most recent available APR.

Western Power continues to work with large mining customers, local government, and other stakeholders in the Mid-West, Eastern Goldfields, and South West regions to facilitate their energy needs. Key activities include:

- Substantial interest from lithium-based industries – Western Power has connected, or is in the process of connecting, about 110 MW of new mining and processing loads in the Kwinana and South West regions.
- Undertaking several projects in the Eastern Goldfields region to increase network capacity in the area, including:
  - Replacement of static VAR compensators[129] at West Kalgoorlie terminal.
  - Installing a third 220/132 kilovolt transformer at West Kalgoorlie terminal and additional static synchronous compensators.

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

A1. Determination of the Availability Curve

The Availability Curve is a modelled two-dimensional LDC[130] used to ensure that there is sufficient capacity in each Trading Interval over a Capacity Year to meet the sum of:

1. The forecast demand for that Trading Interval; and
2. The difference between the RCT for the relevant Capacity Year and the maximum of the demand quantities calculated in Step 1.

For the 2019 WEM ESOO, the Availability Curve has been determined for the 2020-21 and 2021-22 Capacity Years (the second and third Capacity Years in the Long Term PASA Study Horizon).

RBP determined the Availability Curves by:

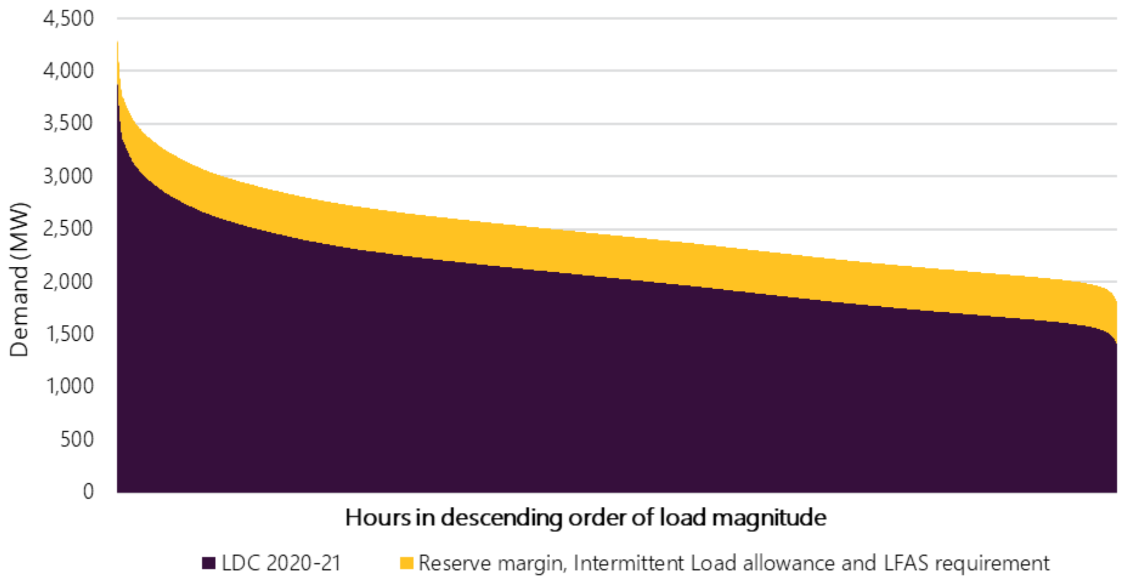
1. Determining the base load profile as follows:
   - Taking the historical load profiles from the five most recent complete Capacity Years (2013-14 to 2017-18).
   - Averaging the five historical load profiles to produce one base LDC.
2. Forecasting the LDC for the 2020-21 and 2021-22 Capacity Years by scaling the base load profile from Step 1 as follows:
   - Basing load for the first 24 hours on the 10% POE expected case peak demand forecast, as required under clause 4.5.10(e)(i) of the WEM Rules.
   - Basing load for the remaining hours (25 to 8,760) on a 50% POE expected case peak demand forecast.
   - Applying a smoothing function to the first 72 hours of the estimated LDC.
3. Adding the reserve margin, Intermittent Load allowance and LFAS requirements to the forecast LDC as required under clause 4.5.10(e)(ii) of the WEM Rules.

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 LDC. Consequently, the forecast minimum capacity requirements from the twenty-fourth hour onwards are expected to match the load under the 50% POE expected case peak demand scenario.

Further information about the Availability Curve determination can be found in RBP's report. Figure 33 and Figure 34 show the Availability Curves determined for the 2020-21 and 2021-22 Capacity Years, respectively.

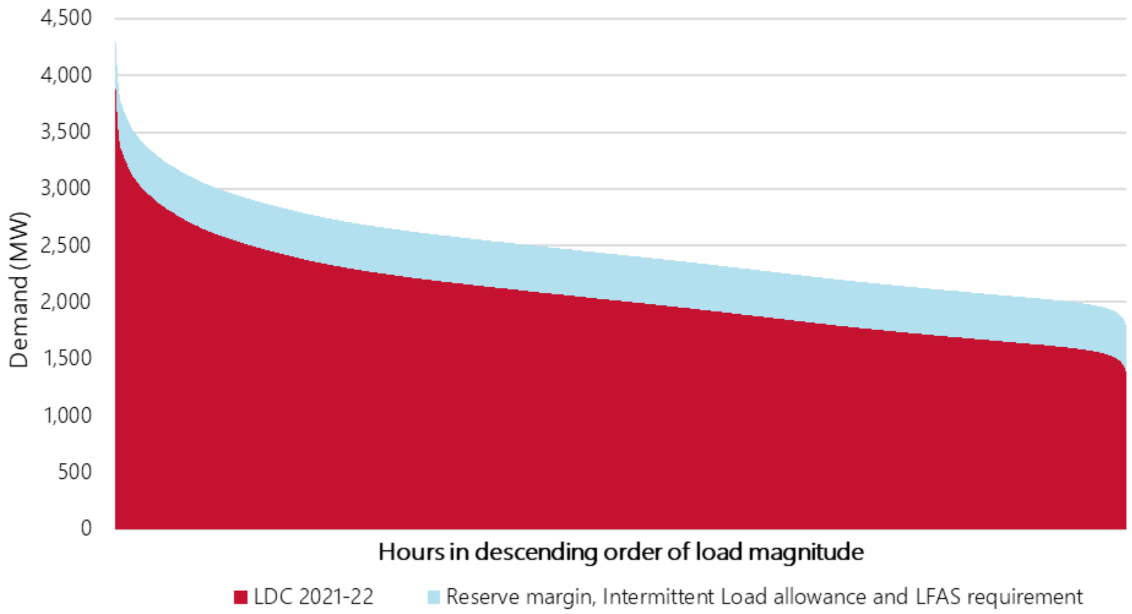
[130] As required under clause 4.5.10(e) of the WEM Rules.

Figure 33 2020-21 Capacity Year Availability Curve



Source: RBP.

Figure 34 2021-22 Capacity Year Availability Curve



Source: RBP.

A2. Expected DSM Dispatch Quantity and DSM Activation Price

The Market Procedure: Determination of the DSM Dispatch Quantity and DSM Activation Price[131] outlines the methodology that AEMO must follow when calculating the EDDQ and DSM Activation Price.

A2.1 Expected DSM Dispatch Quantity

The EDDQ is the level of EUE avoided as a result of each DSP with Capacity Credits being dispatched for 200 hours in a given Capacity Year.

EDDQ is calculated using the following formula:

$$EDDQ_t = \frac{EUE_{(t,0)} - EUE_{(t,200)}}{CC_t}$$

where:

- $EUE_{(t,0)}$ denotes the EUE in MWh in Capacity Year t where no DSPs are dispatched.
- $EUE_{(t,200)}$ denotes the EUE in MWh in Capacity Year t where all available DSPs are dispatched for 200 hours.
- CC_t denotes the sum of all DSM Capacity Credits assigned or expected to be assigned in Capacity Year t.

RBP forecasts the EDDQ over the Long Term PASA Study Horizon based on the assessment of part (b) of the Planning Criterion (see Section 3.1 for further information) and using the forecast LDCs developed in Section 3.2.4. DSM dispatch is based on an optimisation model that dispatches DSM to minimise peak demand while accounting for availability constraints[132].

The approach to forecasting EDDQ can be summarised as follows:

1. Forecast EUE with no DSP dispatch.
   - Repeat the assessment of part (b) of the Planning Criterion as specified in Section 3.2.4 but set the capacity of all DSPs in the market to zero, so that the total available Reserve Capacity is equal to only the generation capacity.
2. Forecast EUE with DSPs dispatched for 200 hours.
   - Repeat Step 1 but adjust the forecast LDC by deducting the DSM dispatch for exactly 200 hours.
3. Calculate EDDQ by applying the formula above using the EUE forecasts derived in Steps 1 and 2.

[131] At http://aemo.com.au/-/media/Files/Electricity/WEM/Procedures/2017/Determination-of-Expected-DSM-Dispatch-Quantity-and-DSM-Activation-Price.pdf.

[132] DSM capacity must be available for dispatch for at least 12 hours a day and 200 hours in total for a Capacity Year in accordance with clause 4.10.1(f) of the WEM Rules.

Detailed information on the methodology used to calculate the EDDQ is set out in RBP's report. The forecast EDDQ over the Long Term PASA Study Horizon is shown in Table 23.

Table 23 EDDQ, 2019-20 to 2028-29

Capacity Year	EUE no DSM dispatched (MWh)	EUE DSM dispatched for 200 hours (MWh)	DSM Capacity Credits (MW)	EDDQ (MWh)
2019-20	0.6968	0.1832	66	0.0078
2020-21	0.3584	0.1792	66	0.0027
2021-22	0.2528	0.0312	66	0.0034
2022-23	1.1048	0.6864	66	0.0063
2023-24	0.9112	0.4488	66	0.0070
2024-25	0.3824	0.1528	66	0.0035
2025-26	0.6440	0.2480	66	0.0060
2026-27	0.0744	0.0248	66	0.0008
2027-28	2.0448	0.7960	66	0.0189
2028-29	0.4048	0.2232	66	0.0028

Source: RBP.

A2.2 DSM Activation Price

The DSM Activation Price represents the Value of Customer Reliability (VCR) for a given Capacity Year. The VCR is an estimate of the dollar value that customers place on the reliable supply of electricity, or an indicator of the customers' willingness to pay for uninterrupted supply. The DSM Activation Price aims to reflect the dollar value derived through a reduction of unserved energy because of DSM dispatch.

A VCR study is yet to be undertaken[133], so AEMO has determined the DSM Activation Price to be $33,460/MWh in accordance with clause 4.5.14F of the WEM Rules, based on the VCR in the NEM.

[133] AEMO, 2019. Request for Expressions of Interest for the 2019 Reserve Capacity Cycle, at https://www.aemo.com.au/-/media/Files/Electricity/WEM/Reserve_Capacity_Mechanism/EOI/2019/Request-for-Expressions-of-Interest-for-2019-Reserve-Capacity-Cycle.pdf.

A3. Supply-demand balance under different demand growth scenarios

Table 24 Supply-demand balance, high demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2019-20[A]	4,431	4,888	457
2020-21[A]	4,497	4,966	469
2021-22	4,499	4,966	467
2022-23	4,504	4,966	462
2023-24	4,506	4,966	460
2024-25	4,553	4,966	413
2025-26	4,567	4,966	399
2026-27	4,598	4,966	368
2027-28	4,624	4,966	342
2028-29	4,663	4,966	303

A. The RCT values for the 2019-20 and 2020-21 Capacity Years were determined and presented in the 2018 WEM ESOO. Updated 2019-20 and 2020-21 RCT values based on the 2019 WEM ESOO forecasts are provided in this table for information only.

Table 25 Supply-demand balance, expected demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2019-20[A]	4,414	4,888	474
2020-21[A]	4,470	4,966	496
2021-22	4,482	4,966	484
2022-23	4,481	4,966	485
2023-24	4,485	4,966	481
2024-25	4,486	4,966	480
2025-26	4,499	4,966	467
2026-27	4,524	4,966	442
2027-28	4,535	4,966	431
2028-29	4,559	4,966	407

A. The RCT values for the 2019-20 and 2020-21 Capacity Years were determined and presented in the 2018 WEM ESOO. Updated 2019-20 and 2020-21 RCT values based on the 2019 WEM ESOO forecasts are provided in this table for information only.

Table 26 Supply-demand balance, low demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2019-20[A]	4,409	4,888	479
2020-21[A]	4,412	4,966	554
2021-22	4,409	4,966	557
2022-23	4,411	4,966	555
2023-24	4,418	4,966	548
2024-25	4,419	4,966	547
2025-26	4,420	4,966	546
2026-27	4,436	4,966	530
2027-28	4,439	4,966	527
2028-29	4,445	4,966	521

A. The RCT values for the 2019-20 and 2020-21 Capacity Years were determined and presented in the 2018 WEM ESOO. Updated 2019-20 and 2020-21 RCT values based on the 2019 WEM ESOO forecasts are provided in this table for information only.

A4. Economic growth forecasts

Table 27 Growth in WA gross state product, financial year basis

Financial year	Expected (%)	High (%)	Low (%)
2018-19	2.7	2.9	2.4
2019-20	2.3	2.7	1.7
2020-21	3.1	3.6	2.5
2021-22	3.3	3.8	2.8
2022-23	3.5	3.9	3.0
2023-24	3.3	3.7	2.8
2024-25	3.6	4.1	3.1
2025-26	4.1	4.6	3.6
2026-27	4.1	4.6	3.5
2027-28	3.6	4.2	3.1
2028-29	3.5	4.1	2.9
Average growth	3.4	3.9	2.9

Source: DAE.

A5. Behind the meter PV forecasts

Table 28 Annual energy generated from behind the meter PV systems[A]

Year	Financial year basis (GWh)	Capacity Year basis (GWh)
2019-20	1,657	1,728
2020-21	1,945	1,998
2021-22	2,169	2,212
2022-23	2,377	2,425
2023-24	2,593	2,632
2024-25	2,763	2,801
2025-26	2,936	2,973
2026-27	3,104	3,140
2027-28	3,279	3,315
2028-29	3,432	3,468

A. Expected scenario only.

A6. Summer peak demand forecasts

Table 29 Summer peak demand forecasts with expected demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2019-20	4,007	3,758	3,536
2020-21	4,063	3,813	3,589
2021-22	4,075	3,819	3,597
2022-23	4,074	3,822	3,597
2023-24	4,078	3,826	3,606
2024-25	4,079	3,832	3,608
2025-26	4,092	3,847	3,625
2026-27	4,117	3,860	3,641
2027-28	4,128	3,876	3,648
2028-29	4,152	3,897	3,672
Average growth	0.4%	0.4%	0.4%

Source: ACIL Allen.

Table 30 Summer peak demand forecasts with high demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2019-20	4,024	3,778	3,556
2020-21	4,090	3,831	3,601
2021-22	4,092	3,835	3,609
2022-23	4,097	3,837	3,614
2023-24	4,099	3,852	3,622
2024-25	4,146	3,898	3,668
2025-26	4,160	3,916	3,692
2026-27	4,191	3,943	3,720
2027-28	4,217	3,974	3,756
2028-29	4,256	4,007	3,783
Average growth	0.6%	0.7%	0.7%

Source: ACIL Allen.

Table 31 Summer peak demand with low demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2019-20	4,002	3,743	3,518
2020-21	4,005	3,756	3,526
2021-22	4,002	3,751	3,533
2022-23	4,004	3,758	3,532
2023-24	4,011	3,755	3,534
2024-25	4,012	3,756	3,535
2025-26	4,013	3,765	3,540
2026-27	4,029	3,781	3,547
2027-28	4,032	3,784	3,557
2028-29	4,038	3,789	3,568
Average growth	0.1%	0.1%	0.2%

Source: ACIL Allen.

A7. Winter peak demand forecasts

Table 32 Winter peak demand forecasts with expected demand growth

Calendar year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2019	3,316	3,226	3,154
2020	3,363	3,276	3,204
2021	3,374	3,289	3,219
2022	3,382	3,292	3,222
2023	3,385	3,299	3,229
2024	3,391	3,304	3,235
2025	3,395	3,307	3,237
2026	3,403	3,313	3,245
2027	3,408	3,322	3,251
2028	3,417	3,331	3,262
Average growth	0.3%	0.4%	0.4%

Source: ACIL Allen.

Table 33 Winter peak demand forecasts with high demand growth

Calendar year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2019	3,321	3,233	3,161
2020	3,372	3,285	3,217
2021	3,386	3,298	3,229
2022	3,395	3,307	3,237
2023	3,399	3,314	3,247
2024	3,438	3,349	3,278
2025	3,451	3,360	3,291
2026	3,463	3,376	3,305
2027	3,486	3,395	3,324
2028	3,502	3,416	3,346
Average growth	0.6%	0.6%	0.6%

Source: ACIL Allen.

Table 34 Winter peak demand forecasts with low demand growth

Calendar year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2019	3,308	3,219	3,150
2020	3,325	3,237	3,166
2021	3,340	3,250	3,179
2022	3,341	3,253	3,183
2023	3,341	3,256	3,184
2024	3,342	3,258	3,188
2025	3,345	3,258	3,187
2026	3,347	3,260	3,192
2027	3,347	3,262	3,195
2028	3,350	3,266	3,193
Average growth	0.1%	0.2%	0.2%

Source: ACIL Allen.

A8. Operational consumption forecasts

Table 35 Forecasts of operational consumption (financial year basis)

Financial year	Expected (GWh)	High (GWh)	Low (GWh)
2019-20	18,221	18,225	18,191
2020-21	18,289	18,302	18,004
2021-22	18,151	18,179	17,832
2022-23	18,008	18,059	17,679
2023-24	17,864	17,952	17,521
2024-25	17,775	18,075	17,412
2025-26	17,694	18,045	17,304
2026-27	17,629	18,041	17,204
2027-28	17,569	18,054	17,101
2028-29	17,543	18,112	17,024
Average growth	-0.4%	-0.1%	-0.7%

Source: ACIL Allen.

Table 36 Forecasts of operational consumption (Capacity Year basis)

Capacity Year	Expected (GWh)	High (GWh)	Low (GWh)
2019-20	18,241	18,248	18,150
2020-21	18,268	18,284	17,964
2021-22	18,125	18,158	17,803
2022-23	17,978	18,038	17,645
2023-24	17,845	17,986	17,497
2024-25	17,761	18,073	17,391
2025-26	17,683	18,049	17,284
2026-27	17,622	18,053	17,186
2027-28	17,566	18,072	17,085
2028-29	17,543	18,137	17,010
Average growth	-0.4%	-0.1%	-0.7%

Source: ACIL Allen.

A9. Power station information in the SWIS

Table 37 Scheduled Generators in the SWIS, 2017-18 Capacity Year

Power station (units included)	Participant	Classification	Energy generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%)
Alcoa Wagerup	Alcoa	Baseload	128	0.8	26.000	0.5
Alinta Pinjarra (1 and 2)	Alinta Energy	Baseload	2,155	13.4	269.138	5.7
Alinta Wagerup (1 and 2)	Alinta Energy	Mid-merit	362	2.3	391.298	8.2
Bluewaters (1 and 2)	Bluewaters	Baseload	2,984	18.6	434.000	9.1
Cockburn	Synergy	Peaking	83	0.5	231.800	4.9
Collie	Synergy	Baseload	1,901	11.9	317.200	6.7
Kalamunda	Landfill Gas & Power	Peaking	0	0.0	1.300	0.0
Kemerton (11 and 12)	Synergy	Peaking	50	0.3	300.500	6.3
Kwinana gas turbine	Synergy	Peaking	0	0.0	16.809	0.4
Kwinana High Efficiency Gas Turbines (2 and 3)	Synergy	Baseload	842	5.2	196.700	4.1
Merredin	Merredin Energy	Peaking	1	0.0	82.000	1.7
Muja AB (1, 2, 3, and 4)	Vinalco	Mid-merit	0	0.0	0.000	0.0
Muja CD (5, 6, 7, and 8)	Synergy	Baseload	3,864	24.1	810.000	17.0
Mungarra (1, 2, and 3)	Synergy	Peaking	17	0.1	97.100	2.0
NewGen Kwinana	NewGen Kwinana	Baseload	2,019	12.6	327.800	6.9
NewGen Neerabup	NewGen Neerabup	Mid-merit	252	1.6	330.600	7.0
Parkeston	Goldfields Power	Peaking	8	0.0	59.400	1.2
Perth Energy Kwinana	Western Energy	Mid-merit	126	0.8	109.000	2.3
Perth Power Partnership Kwinana	Synergy	Baseload	496	3.1	80.400	1.7
Pinjar A (1 and 2)	Synergy	Peaking	5	0.0	61.964	1.3
Pinjar B (3, 4, 5, and 7)	Synergy	Peaking	8	0.0	148.000	3.1

Power station (units included)	Participant	Classification	Energy generated		Capacity Credits	
			GWh	Share (%)	MW	Share (%)
Pinjar C (9 and 10)	Synergy	Mid-merit	229	1.4	215.700	4.5
Pinjar D (11)	Synergy	Baseload	306	1.9	120.000	2.5
Tesla Geraldton	Tesla	Peaking	0	0.0	9.900	0.2
Tesla Kemerton	Tesla	Peaking	0	0.0	9.900	0.2
Tesla Northam	Tesla	Peaking	0	0.0	9.900	0.2
Tesla Picton	Tesla	Peaking	0	0.0	9.900	0.2
Tiwest Cogeneration	Tiwest	Baseload	202	1.3	36.000	0.8
West Kalgoorlie (2 and 3)	Synergy	Peaking	2	0.0	53.550	1.1

Table 38 Non-Scheduled Generators in the SWIS, 2017-18 Capacity Year

Power station (units included)	Participant	Energy source	Nameplate capacity (MW)	Energy generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%)
Albany	Synergy	Wind	21.6	54	3.06	7.809	7.1
Atlas	Perth Energy	Biogas	1.123	1	0.06	0.595	0.5
Bremer Bay	Synergy	Wind	0.6	2	0.11	0.112	0.1
Richgro Biogas	CleanTech Energy	Biogas	2.4	3	0.17	1.795	1.6
Collgar	Collgar Wind Farm	Wind	206	698	39.55	20.105	18.3
Denmark	Denmark Community Windfarm	Wind	1.44	5	0.28	0.845	0.8
Emu Downs	EDWF Manager	Wind/solar	99.2	270	15.30	17.800	16.2
Grasmere	Synergy	Wind	13.8	40	2.27	4.957	4.5
Greenough River	Synergy	Solar	10	21	1.19	3.086	2.8
Henderson	Waste Gas Resources	Biogas	3.192	15	0.85	2.140	1.9
Kalbarri	Synergy	Wind	1.6	3	0.17	0.283	0.3
Karakin	Blair Fox	Wind	5	6	0.34	0.838	0.8
Mount Barker	Mt. Barker Power Company	Wind	2.43	7	0.40	0.806	0.7
Mumbida	Mumbida Wind Farm	Wind	55	195	11.05	13.828	12.6
Red Hill	Landfill Gas & Power	Biogas	3.64	27	1.53	2.876	2.6
Rockingham	Perth Energy	Biogas	4	21	1.19	2.576	2.3
South Cardup	Perth Energy	Biogas	3.369	30	1.70	2.486	2.3

Power station (units included)	Participant	Energy source	Nameplate capacity (MW)	Energy generated		Capacity Credits	
				GWh	Share (%)	MW	Share (%)
Tamala Park	Landfill Gas & Power	Biogas	5.765	39	2.21	3.962	3.6
Walkaway	Alinta Energy	Wind	89.1	328	18.58	23.203	21.1

A10. Facility capacities

Table 39 Registered generation Facilities – existing and committed

Market Participant	Facility	Capacity Credits (2020-21)
Alcoa of Australia	ALCOA_WGP	26.000
Alinta Sales	ALINTA_PNJ_U1	137.000
Alinta Sales	ALINTA_PNJ_U2	137.000
Alinta Sales	ALINTA_WGP_GT	196.000
Alinta Sales	ALINTA_WGP_U2	196.000
Alinta Sales	ALINTA_WWF	22.035
Alinta Sales	BADGINGARRA_WF1	36.428
Alinta Sales	YANDIN_WF1 [A]	40.932
BEI WWF Pty Ltd ATF WWF Trust	WARRADARGE_WF1 [A]	36.124
Blair Fox	BLAIRFOX_KARAKIN_WF1	0.736
Blair Fox	BLAIRFOX_WESTHILLS_WF3 [B]	0.000
Bluewaters Power 1	BW1_BLUEWATERS_G2	217.000
Bluewaters Power 2	BW1_BLUEWATERS_G1	217.000
CleanTech Energy	BIOGAS_01	1.551
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	22.894
Denmark Community Windfarm	DCWL_DENMARK_WF1	0.414
EDWF Manager	EDWFMAN_WF1	26.317
Goldfields Power	PRK_AG	59.400
Landfill Gas & Power	KALAMUNDA_SG	1.300
Landfill Gas & Power	RED_HILL	2.868
Landfill Gas & Power	TAMALA_PARK	4.292
Merredin Energy	NAMKKN_MERR_SG1	82.000

Market Participant	Facility	Capacity Credits (2020-21)
Merredin Solar Farm Nominee	MERSOLAR_PV1 [A]	22.500
Metro Power Company	AMBRISOLAR_PV1	0.270
Mt. Barker Power Company	SKYFRM_MTBARKER_WF1	0.606
Mumbida Wind Farm	MWF_MUMBIDA_WF1	8.943
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	327.800
Northam Solar Project Partnership	NORTHAM_SF_PV1	2.568
Perth Energy	ATLAS	0.000
Perth Energy	GOSNELLS	0.000
Perth Energy	ROCKINGHAM	2.286
Perth Energy	SOUTH_CARDUP	3.009
Southern Cross Energy	STHRNCRS_EG	20.000
SRV AGWF Pty Ltd as trustee for AGWF Trust	ALBANY_WF1	6.434
SRV AGWF Pty Ltd as trustee for AGWF Trust	GRASMERE_WF1	4.329
SRV GRSF Pty Ltd as trustee for GRSF Trust	GREENOUGH_RIVER_PV1	9.905
Synergy	BREMER_BAY_WF1	0.190
Synergy	COCKBURN_CCG1	240.000
Synergy	COLLIE_G1	317.200
Synergy	KALBARRI_WF1	0.287
Synergy	KEMERTON_GT11	155.000
Synergy	KEMERTON_GT12	155.000
Synergy	KWINANA_GT2	98.500
Synergy	KWINANA_GT3	99.200
Synergy	MUJA_G5	195.000
Synergy	MUJA_G6	193.000
Synergy	MUJA_G7	211.000
Synergy	MUJA_G8	211.000

Market Participant	Facility	Capacity Credits (2020-21)
Synergy	MUNGARRA_GT1	0.000
Synergy	MUNGARRA_GT3	0.000
Synergy	PINJAR_GT1	31.072
Synergy	PINJAR_GT2	30.300
Synergy	PINJAR_GT3	37.000
Synergy	PINJAR_GT4	37.000
Synergy	PINJAR_GT5	37.000
Synergy	PINJAR_GT7	36.500
Synergy	PINJAR_GT9	111.000
Synergy	PINJAR_GT10	111.000
Synergy	PINJAR_GT11	124.000
Synergy	PPP_KCP_EG1	80.400
Synergy	WEST_KALGOORLIE_GT2	0.000
Synergy	WEST_KALGOORLIE_GT3	0.000
Tesla Corporation Management	TESLA_PICTON_G1	9.900
Tesla Geraldton	TESLA_GERALDTON_G1	9.900
Tesla Kemerton	TESLA_KEMERTON_G1	9.900
Tesla Northam	TESLA_NORTHAM_G1	9.900
Tronox Management	TIWEST_COG1	36.000
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	1.761
Western Australia Biomass	BRIDGETOWN_BIOMASS_PLANT [B]	0.000
Western Energy	PERTHENERGY_KWINANA_GT1	109.000

A. Candidates for Registration that hold Capacity Credits for the 2020-21 Capacity Year.
B. Registered Facilities that did not participate in the RCM for the 2020-21 Capacity Year.

Table 40 Registered DSM Facilities – existing and committed

Market Participant	Facility	Capacity Credits (2020-21)
Synergy	SYNERGY_DSP_04	42.000
Wesfarmers Kleenheat Gas	PREPWR_DSP_02	24.000

Measures and abbreviations

Units of measure

Abbreviation	Unit of measure
GW	Gigawatt
GWh	Gigawatt hour
kW	Kilowatt
kWh	Kilowatt hour
MW	Megawatt
MWh	Megawatt hour

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
AQP	Applications and Queuing Policy
BOM	Bureau of Meteorology
CDD	Cooling degree day
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAE	Deloitte Access Economics
DER	Distributed energy resources
DSM	Demand Side Management
DSP	Demand Side Programme
EDDQ	Expected DSM Dispatch Quantity
EISC	Economics and Industry Standing Committee
EOI	Expressions of Interest

Abbreviation	Expanded name
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
EUE	Expected unserved energy
EV	Electric vehicle
GIA	Generator Interim Access
GSP	Gross state product
HDD	Heating degree day
IRCR	Individual Reserve Capacity Requirement
LDC	Load duration curve
LFAS	Load Following Ancillary Service
NEM	National Electricity Market
NCS	Network Control Services
NSG	Non-Scheduled Generator
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PV	Photovoltaic
RBP	Robinson Bowmaker Paul
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
SWIS	South West interconnected system
WEM	Wholesale Electricity Market

Glossary

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

Term	Definition
baseload capacity	Facilities that operate more than 70% of the time.
behind the meter	PV and battery systems that produce energy and are connected at a customer's premises. In this WEM ESOO, behind the meter PV capacity includes both residential and commercial rooftop PV that is less than 100 kilowatts (kW) and commercial PV systems ranging between 100 kW and 30 MW.
block loads	The largest customers in the SWIS that are temperature insensitive. AEMO considers 20 MW to be the minimum threshold for a new block load.
Capacity Credit	A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equal to 1 MW of capacity.
capacity factor	The percentage of actual generation relative to the maximum theoretically possible generation based on a Facility's nameplate capacity.
Capacity Year	A period of 12 months commencing on 1 October and ending on 1 October of the following calendar year.
Demand Side Management (DSM)	A type of capacity that can reduce its consumption of electricity from the SWIS in response to a dispatch instruction. Usually made up of several customer loads aggregated into one Facility.
Demand Side Programme (DSP)	A Facility registered in accordance with clause 2.29.5A of the WEM Rules.
Individual Reserve Capacity Requirement (IRCR)	The proportion of the total cost of Capacity Credits acquired through the RCM paid by each Market Customer. Determined based on each Market Customer's contribution to peak demand during 12 peak Trading Intervals over the previous summer period (December to March).
intermittent generator	A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind speed).
Long Term Projected Assessment of System Adequacy (PASA)	A study conducted in accordance with clause 4.5 of the WEM Rules to determine the Reserve Capacity Target for each year in the Long Term PASA Study Horizon and prepare the WEM ESOO.
Long Term PASA Study Horizon	The 10 year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle.
mid-merit capacity	Facilities that operate between 10% and 70% of the time.
operational consumption	The electrical energy supplied by scheduled and non-scheduled generating units, less the electrical energy supplied by behind the meter PV.
Projected Assessment of System Adequacy (PASA)	A forecasting study undertaken by AEMO (which, for the purposes of the WEM ESOO, is the Long Term PASA).
peak demand	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) for the SWIS.
peaking capacity	Facilities that operate less than 10% of the time.

Term	Definition
probability of exceedance (POE)	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded once in every 10 years.
Reserve Capacity Cycle	A four-year period covering the cycle of events described in clause 4.1 of the WEM Rules.
Reserve Capacity Price (RCP)	The price for capacity paid to Capacity Credit holders and determined in accordance with clause 4.29.1 of the WEM Rules.
Reserve Capacity Target (RCT)	AEMO's estimate of the total quantity of generation or DSM capacity required in the SWIS to satisfy the Planning Criterion.
solar irradiance	A measure of cloud cover used to de-rate the output of behind the meter PV systems.
underlying consumption	All electricity (in MWh) consumed on site, which can be provided by behind the meter generation or the electricity grid.
underlying demand	All electricity (in MW) consumed on site, which can be provided by behind the meter generation or the electricity grid.