AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Electricity Statement of Opportunities

June 2018

A report for the Wholesale Electricity Market

Important notice

PURPOSE

AEMO has prepared this document to provide market data and technical information about opportunities in the Wholesale Electricity Market in Western Australia. This publication is based on information available to AEMO as at 31 March 2018, although AEMO has incorporated more recent information where possible.

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VERSION CONTROL

Version	Release date	Changes
1	15/6/2018	

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 growth scenarios for the 10-year Long Term PASA Study Horizon for the 2018-19 to 2027-28 Capacity Years[2].

The WEM ESOO is one of the key aspects of the Reserve Capacity Mechanism (RCM), which ensures sufficient capacity is available to meet reliability targets set under the Long Term PASA study for the SWIS. This WEM ESOO report highlights the 10% probability of exceedance (POE)[3] peak demand forecast under the expected demand growth scenario[4] used to determine the Reserve Capacity Target (RCT)[5] for the 2020-21 Capacity Year.

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

Key findings

- Based on the 10% POE peak demand forecast, the RCT has been determined as 4,581 megawatts (MW) for the 2020-21 Capacity Year.
- The 10% POE peak demand is forecast to grow at an average annual rate of 0.6% over the outlook period. This is lower than the 2017 WEM ESOO forecast of 1.6%6.
- Annual operational consumption is forecast to grow slowly, at an average annual rate of 0.9% over the outlook period. This is lower than the 2017 WEM ESOO forecast of 1.2%.
- Rapid uptake of rooftop photovoltaic (PV)7 continues to reduce peak demand and operational consumption. Rooftop PV installations are forecast to grow at an average annual rate of 8.7% over the outlook period under the expected growth scenario. AEMO expects 134 MW of rooftop PV to be installed annually on average, resulting in 2,273 MW of total installed rooftop PV by 2027-28.
- AEMO does not expect rooftop PV uptake to shift peak demand to any time later than 18:00 for at least the first three years of the outlook period, as solar radiance levels are minimal after this time.
- New renewable energy generation capacity is expected to participate in the RCM, particularly grid-scale solar PV and wind facilities. This is likely to increase the excess capacity and reduce the Reserve Capacity Price (RCP) for the 2020-21 Capacity Year, and increase the capacity level over the outlook period.
- The Generator Interim Access (GIA) arrangement 8, developed as a short-term solution to network congestion, will continue to accommodate network access for development of renewable generation projects within its capacity limit until October 2022.

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1 Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.

2 A Capacity Year commences at the Trading Interval starting at 8:00 AM on 1 October and ends at 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 that 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 is more conservative than the 50% and 90% POE forecasts for capacity planning purposes.

4 This 2018 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 RCT is AEMO's estimate of the total amount of generation or Demand Side Management capacity required in the SWIS to satisfy the Planning Criterion for a Capacity Year. The RCT is set for each Capacity Year of a 10-year Long Term PASA Study Horizon.

6 The 2017 WEM ESOO is available at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf.

7 Rooftop PV is defined as installed residential and commercial PV systems with a capacity of less than 100 kW and eligible for Small-scale Technology Certificates under the Renewable Energy Target.

8 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, 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.

- As part of the WA Government's electricity reform program, changes to the assignment of Capacity Credits to account for network constraints are expected to be in place for the 2020 Reserve Capacity Cycle[9], which may affect existing and new generators.
- The Demand Side Management (DSM) RCP for the 2018-19 Capacity Year is $23,631 per MW[10].

Reserve Capacity Target

The RCT for the 2020-21 Capacity Year is 4,581 MW, calculated as the 10% POE peak demand forecast plus a reserve margin[11] (including transmission losses, allowing for Intermittent Loads) and maintaining the Minimum Frequency Keeping Capacity Requirements[12].

Excess capacity fell from 14% for the 2017-18 Capacity Year to 4% for the 2018-19 Capacity Year, predominantly due to a Ministerial Direction[13] and consequently the retirement of some of Synergy's Facilities[14] with a total nameplate capacity of 437 MW[15]. For the 2019-20 Capacity Year, excess capacity increased slightly to 5% due to the entry of two renewable facilities (wind and solar) under the GIA arrangement.

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 307 MW (6.7%) for the 2020-21 Capacity Year. By the end of the outlook period, the level of excess capacity is forecast to reduce to 115 MW (2.4%) due to forecast peak demand growth.

Demand Side Management (DSM) Reserve Capacity Price

The DSM RCP is required to be set in the WEM ESOO published three months before the price takes effect. For the 2018-19 Capacity Year, the DSM RCP is $23,631 per MW[16].

Peak demand and operational consumption forecasts 2018-19 to 2027-28

Developing accurate peak demand forecasts affects the accuracy of the RCT, which is based on the 10% POE peak demand forecast, and increases the risk of setting an inappropriate RCT 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 WA electricity industry (such as uptake in rooftop PV, batteries and electric vehicles (EV)), which are adding additional variability and uncertainty in peak demand. In response, AEMO is continuing to improve its forecasting systems and analysis.

AEMO forecasts the 10% POE peak demand to increase at an average annual rate of 0.4% over the next five years and 0.6% over the 10-year growth period, as presented in Table 1.

These growth rates are lower than the peak demand forecasts published in the 2017 WEM ESOO. The variance between the two forecasts by the end of the outlook period is 476 MW[17]. This is largely due to the lower economic[18] and population[19] growth outlook that drives underlying growth in peak demand and operational consumption for this 2018 WEM ESOO. Improvements have been made to the forecasting methodology to reduce peak demand sensitivity to temperature to better reflect observed trends over the past 10 years.

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[9] Security-constrained economic dispatch is expected to commence in 2022. The Public Utilities Office intends to have the required amendments to the WEM Rules in place to allow the first Reserve Capacity Cycle under the constrained access model to occur in 2020. Available at https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Roadmap-reform-work-program.pdf.

[10] This DSM RCP for the 2018-19 Capacity Year is based on the forecast Expected DSM Dispatch Quantity and published in accordance with clause 4.5.13(i) of the WEM Rules. The RCP paid to generators for the 2018-19 and 2019-20 Capacity Years is $138,760/MW and $126,683/MW respectively; see https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price.

[11] The reserve margin is calculated as the greater of 7.6% of the sum of the 10% POE peak demand and Intermittent Loads forecasts, and the largest generating unit in the SWIS.

[12] The Minimum Frequency Keeping Capacity has the meaning given in clause 3.10.1(a) of the WEM Rules.

[13] WA Parliament, 2016. Electricity Corporations Act 2005 – Ministerial Direction. Available at http://parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914903a6b61c1cde6d034044825806e0027dedb/$file/4903.pdf.

[14] Government of Western Australia, Media statement, 5 May 2017, "Synergy to reduce electricity generation cap by 2018". Available at https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.

[15] Two of the four units at the Muja AB coal-fired generation facility (240 MW nameplate capacity) were retired on 30 September 2017, and the remaining two units were deregistered from the market on 30 April 2018. Three gas-fired electricity generation assets, with nameplate capacity totalling 197 MW, are designated for retirement by 1 October 2018.

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

[17] The variance was calculated based on the peak demand forecasts for the 2026-27 Capacity Year.

[18] The Australian Bureau of Statistics (ABS) has made revisions to the annual national accounts for the entire time series data, available at http://www.abs.gov.au/ausstats/abs@.nsf/Lookup/5204.0Feature+Article12016-17. The revisions resulted in lower historical WA Gross State Product (GSP) values, which is a major factor leading to lower WA GSP forecasts for this 2018 WEM ESOO.

[19] ABS' population estimates for the recent intercensal period (September 2011 to June 2016) have been updated using information from the 2016 Census of Population and Housing. The rebased population estimates for this period are lower. Available at http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/3101.0Main%20Features3Sep%202017?opendocument&tabname=Summary&prodno=3101.0&issue=Sep%202017&num=&view=.

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

Scenario	2018-19 (MW)	2019-20 (MW)	2020-21 (MW)	2021-22 (MW)	2022-23 (MW)	5-year average annual growth (%)	2027-28 (MW)	10-year average annual growth (%)
10% POE	4,146	4,152	4,174	4,193	4,219	0.4	4,365	0.6
50% POE	3,909	3,914	3,928	3,951	3,983	0.5	4,113	0.6
90% POE	3,689	3,696	3,699	3,719	3,760	0.5	3,892	0.6

Source: AEMO and ACIL Allen.

Operational consumption forecasts for the high, expected, and low growth scenarios are shown in Table 2. These forecasts reflect different economic growth scenarios and corresponding rooftop PV system and EV growth scenarios.

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

Scenario	2018-19 (GWh)	2019-20 (GWh)	2020-21 (GWh)	2021-22 (GWh)	2022-23 (GWh)	5-year average annual growth (%)	2027-28 (GWh)	10-year average annual growth (%)
High	18,320	18,368	18,488	18,668	18,890	0.8	20,772	1.4
Expected	18,296	18,307	18,382	18,506	18,660	0.5	19,871	0.9
Low	18,271	18,243	18,268	18,333	18,417	0.2	19,002	0.4

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

AEMO expects operational consumption to increase at an average annual rate of 0.5% over the next five years and 0.9% over the entire outlook period.

For the non-contestable customer segment (which made up 27.5% of the total operational consumption in the 2016-17 financial year), declining operational consumption is predicated on current policy settings. This is largely because forecast uptake of rooftop PV outpaces underlying consumption[20] growth driven by economic and population growth.

Trends in SWIS peak demand

Peak demand and associated temperature statistics for the past 10 years are outlined in Table 3.

Peak demand has been around 3,700 MW (with the exception of 2015-16) over the past 10 years. Peak demand over the 2017-18 summer period was the second-lowest summer peak observed in the SWIS since 2009[21], and was the first time since 2007 that peak demand occurred in March.

The trend in the past 10 years of summer peak demand occurring later in the day was driven by the continued growth of rooftop PV installations in the SWIS[22]. AEMO does not expect rooftop PV uptake to shift the peak demand to any time later than 18:00 for at least the first three years of the outlook period, as solar radiance levels are minimal after this time.

Peak demand may shift to later in the evening subject to the uptake of battery storage in the future. However, the timeframe for this is uncertain and depends largely on the uptake of batteries and residential tariff structure.

[20] Underlying consumption refers to all electricity (in MWh) consumed onsite, which can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.

[21] Peak demand for the 2016–17 Capacity Year has been updated to 3,543 MW at 17:00 on 21 December 2016 from the value presented in the 2017 WEM ESOO, which reported 3,670 MW at 17:00 on 1 March 2017. Updated meter data has resulted in a change in the peak demand value and the day on which it occurred. This peak demand was the lowest summer peak observed in the SWIS since 2009.

[22] See Chapter 4 of this WEM ESOO for further information.

Table 3 SWIS system peak, 2008-09 to 2017-18

Capacity Year	Date	Peak demand (MW)	Trading Interval commencing	Maximum temperature during interval (°C)	Daily maximum temperature (°C)
2017–18	13 March 2018	3,616	17:30	36.2	38.4
2016–17	21 December 2016[A]	3,543	17:00	38.0	42.7
2015–16	8 February 2016	4,004	17:30	41.0	42.6
2014–15	5 January 2015	3,744	15:30	41.1	44.1
2013–14	20 January 2014	3,702	17:30	36.9	38.5
2012–13	12 February 2013	3,732	16:30	36.0	41.1
2011–12	25 January 2012	3,857	16:30	39.1	39.9
2010–11	16 February 2011	3,735	16:30	37.5	39.0
2009–10	25 February 2010	3,766	16:00	39.5	41.5
2008–09	11 February 2009	3,515	15:30	39.5	39.7

Source: AEMO and Bureau of Meteorology.
A. Peak demand for 2016-17 has been updated from the value presented in the 2017 WEM ESOO to reflect updated meter data.

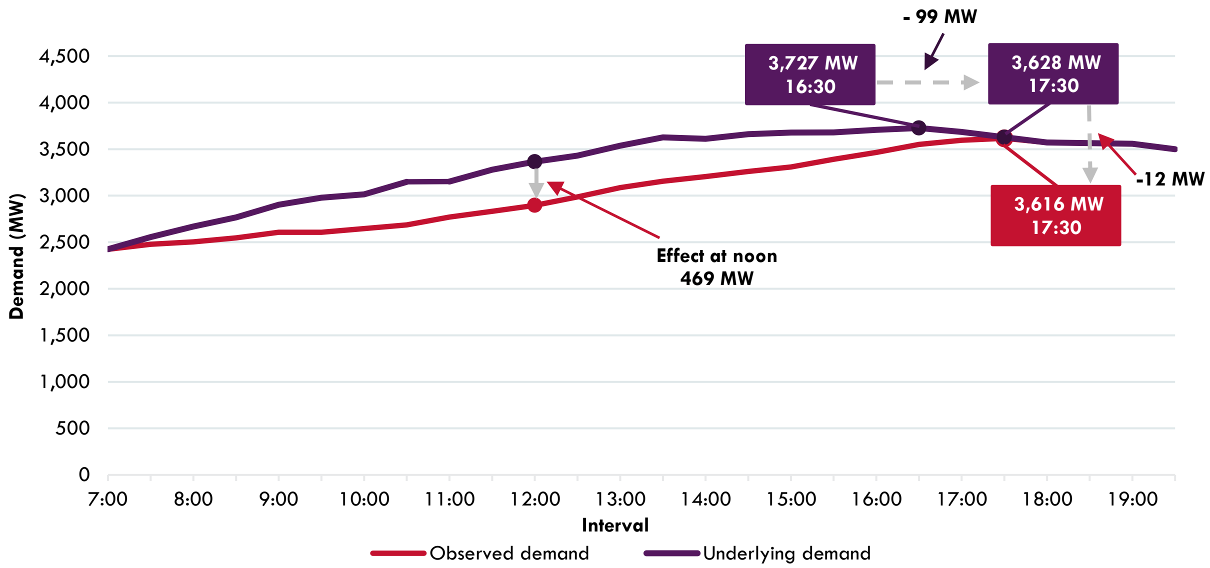
Impact of rooftop PV systems

Growth in installed capacity of rooftop PV systems during the 2016-17 Capacity Year was the strongest on record. However, the estimated 111 MW reduction of the 2017-18 summer peak demand contributed by rooftop PV was significantly lower than the 224 MW reduction for the 2016-17 summer peak. This is because the 2017-18 peak occurred in mid-March, and half an hour later (in the Trading Interval commencing at 17:30).

The 111 MW reduction in peak demand, as shown in Figure 1, is attributed to the following factors:

- A shift in the timing of peak demand by one hour, from the Trading Interval starting at 16:30 to the Trading Interval at 17:30. Underlying demand[23] was estimated to be 3,727 MW at 16:30 compared to 3,628 MW at 17:30. This shift of the peak to a later time reduced underlying demand by 99 MW.
- Rooftop PV generation during the 17:30 reduced peak demand by 12 MW from 3,628 MW to 3,616 MW.

Figure 1 Daily daytime demand profile, observed and estimated without rooftop PV, 13 March 2018



[23] Underlying demand refers to all electricity (in MW) consumed on site, and can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.

In the 2016-17 Capacity Year, approximately 170 MW of new rooftop PV was installed, representing an increase in total rooftop PV capacity in the SWIS of approximately 28%. AEMO expects the strong growth of rooftop PV capacity in the SWIS to continue over the 10-year outlook period. This is expected to result in 2,273 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 the 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. At the time of the 2017-18 peak demand, 36 customers reduced consumption, resulting in total load reduction of 41 MW. This is the lowest IRCR response on a peak day to date, largely due to the cooler than usual summer, which made it challenging for customers to predict the timing of peak demand.

WA Government's electricity industry reform program

In August 2017, the Minister for Energy announced an electricity industry reform program to be completed by the Public Utilities Office (PUO). There are three key elements of the reform program:

1. Moving to a constrained network model for access to Western Power's network, which will require the implementation of security-constrained market and dispatch arrangements, and changes to the consideration of network congestion in the RCM.
2. Reviewing Reserve Capacity pricing arrangements.
3. Implementing a light-handed regulatory regime in the Pilbara to facilitate third-party access to Horizon Power's network, including implementing an independent system operator.

Further information about the electricity industry reform, including proposed timeframes, can be found on the PUO's website[24]. AEMO will continue to monitor these changes as they are developed, and will include the impacts of these changes in future WEM ESOO publications.

[24] See https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Electricity-Sector-Reform-Initiatives/.

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1. Introduction

The Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) is published yearly to present AEMO's Long Term Projected Assessment of System Adequacy (PASA) for the South West interconnected system (SWIS) in Western Australia (WA).

The Reserve Capacity Mechanism (RCM) in the WEM aims to ensure that sufficient generation and Demand Side Management (DSM) capacity is available in the SWIS to meet electricity peak demand and limit expected energy shortfalls[25] to 0.002% of annual energy consumption throughout the year.

This 2018 WEM ESOO supports the operation of the RCM for the 2018 Reserve Capacity Cycle[26]. It presents the peak demand and operational consumption forecasts over the 10-year Long Term PASA Study Horizon from the 2018-19 to 2027-28 Capacity Years[27], and associated key forecasting insights.

The key purpose of this 2018 WEM ESOO is to determine the Reserve Capacity Requirement (RCR) for the 2018 Reserve Capacity Cycle. This is the quantity of generation and DSM capacity required under the RCM in the 2020-21 Capacity Year.

This 2018 WEM ESOO has been developed to provide relevant information to Market Participants to help them make informed decisions concerning investments in the WEM, by providing an outlook on peak demand and operational consumption in the SWIS under a range of scenarios.

[25] The expected energy shortfall is the expected unserved energy, which refers to a forecast by AEMO of the aggregate amount in MWh by which the demand for electricity exceeds the supply of electricity.

[26] The 2018 Reserve Capacity Cycle aims to ensure sufficient generation and DSM for the 2020-21 Capacity Year.

[27] A Capacity Year commences at the Trading Interval starting at 8:00 AM on 1 October and ends at 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 provides background information on the diversity of existing Facilities throughout the WEM, based on Market Participant, fuel type and Facility characteristics. More information on existing generation and DSM capacity can be found in the 2018 Request for Expressions of Interest (REOI)[28].

2.1 Existing capacity diversity

2.1.1 Capacity Credits by Market Participant

The number of Market Participants participating in the RCM has increased from nine at market start in 2005, to 30 Market Participants holding Capacity Credits for the 2019-20 Capacity Year[29].

2.1.2 Capacity Credits changes

- Following a 2016 Ministerial Direction[30], four Synergy non-renewable generation assets, with a total Capacity Credit allocation of 387 megawatts (MW), were designated for retirement. One of these Facilities, Muja AB[31], has already retired. The remaining three Facilities are due for retirement by 1 October 2018[32].
- The proportion of Capacity Credits held by Synergy has decreased from 91% at market start to 53% for the 2019-20 Capacity Year. This is primarily due to the entry of non-Synergy Facilities in the WEM and changes to the market share of DSM, coupled with the retirement of Synergy Facilities.
- Alinta Sales and NewGen Power are the next two largest Capacity Credit holders for the 2019-20 Capacity Year, holding approximately 14.8% and 13.5% of the total assigned Capacity Credits.
- Two new Committed renewable generators were assigned Capacity Credits for the 2019-20 Capacity Year:
  - New Market Participant Merredin Solar Farm Nominee (Mersolar_PV1), with 29.317 MW of Capacity Credits.
  - Alinta Sales' Badgingarra wind farm (Badgingarra_WF1), with 35.625 MW of Capacity Credits.

2.1.3 Capacity Credits by fuel type

The WEM has a diverse mix of fuel types to facilitate security of electricity supply and support competition between various technologies and generators. Figure 2 shows the current market share by fuel type in the WEM.

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[28] AEMO, *2018 Request for Expressions of Interests for the WEM*, published January 2018 and available at http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Expressions-of-interest.

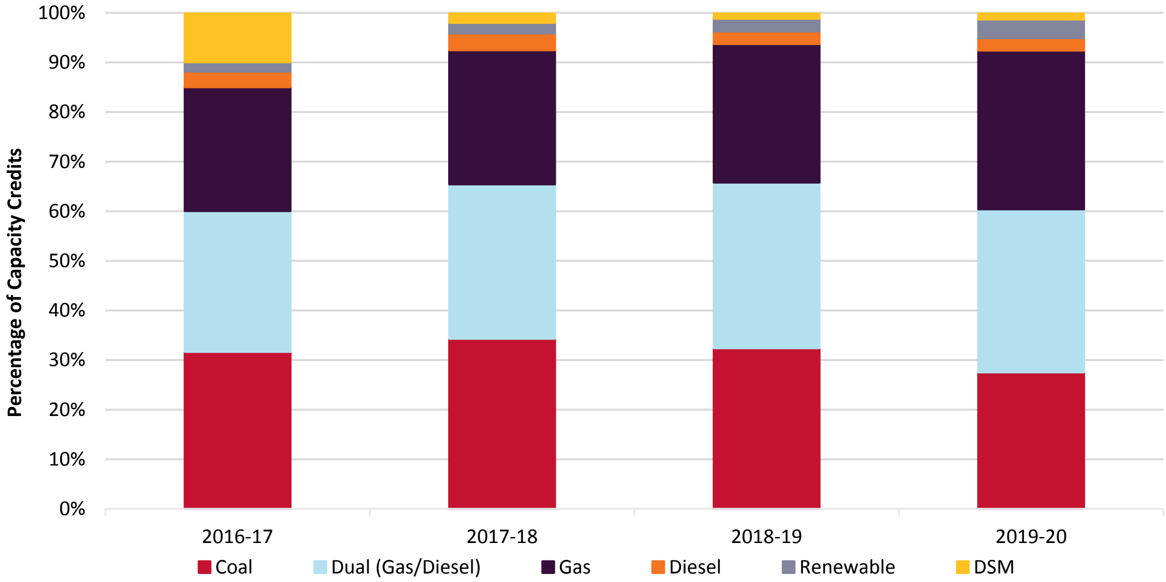
[29] AEMO, Capacity Credits assigned since market start, available at http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Assignment-of-capacity-credits.

[30] WA Parliament, 2016. Electricity Corporations Act 2005 – Ministerial Direction. Available at http://parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914903a6b61c1cde6d034044825806e0027dedb/$file/4903.pdf.

[31] Muja AB plants were owned by Vinalco Energy, which is a fully owned subsidiary of Synergy.

[32] Synergy media release, 5 May 2017, "Synergy to Reduce Generation Capacity by 380 MW", available at https://www.synergy.net.au/About-us/News-andannouncements/Media-releases/Synergy-to-Reduce-Generation-Capacity-by-380-MW.

Figure 2 Proportion of Capacity Credits by fuel, 2016-17 to 2019-20 Capacity Years



Minor changes in the share of Capacity Credits by fuel type occurred between 2018-19 and 2019-20:

- The total capacity share of renewables has increased by 1.2% (from 2.5% to 3.7%).
- DSM market share has increased marginally, from 1.2% to 1.4%. This is attributed to an increase of approximately 5 MW of DSM Capacity Credits associated with Synergy and Wesfarmers Kleenheat Gas.

More information on generation capacity by fuel type in the SWIS (including the generation fuel mix from 2005-06 to 2018-19) is presented in the 2018 REOI.

2.2 Existing Facilities

The total Capacity Credits assigned for the 2019-20 Capacity Year is 4,887.97 MW. Currently, 62 Facilities are assigned Capacity Credits in the WEM, comprising[33]:

- 39 Scheduled Generators.
- 21 Non-Scheduled Generators.
- Two DSM Facilities.

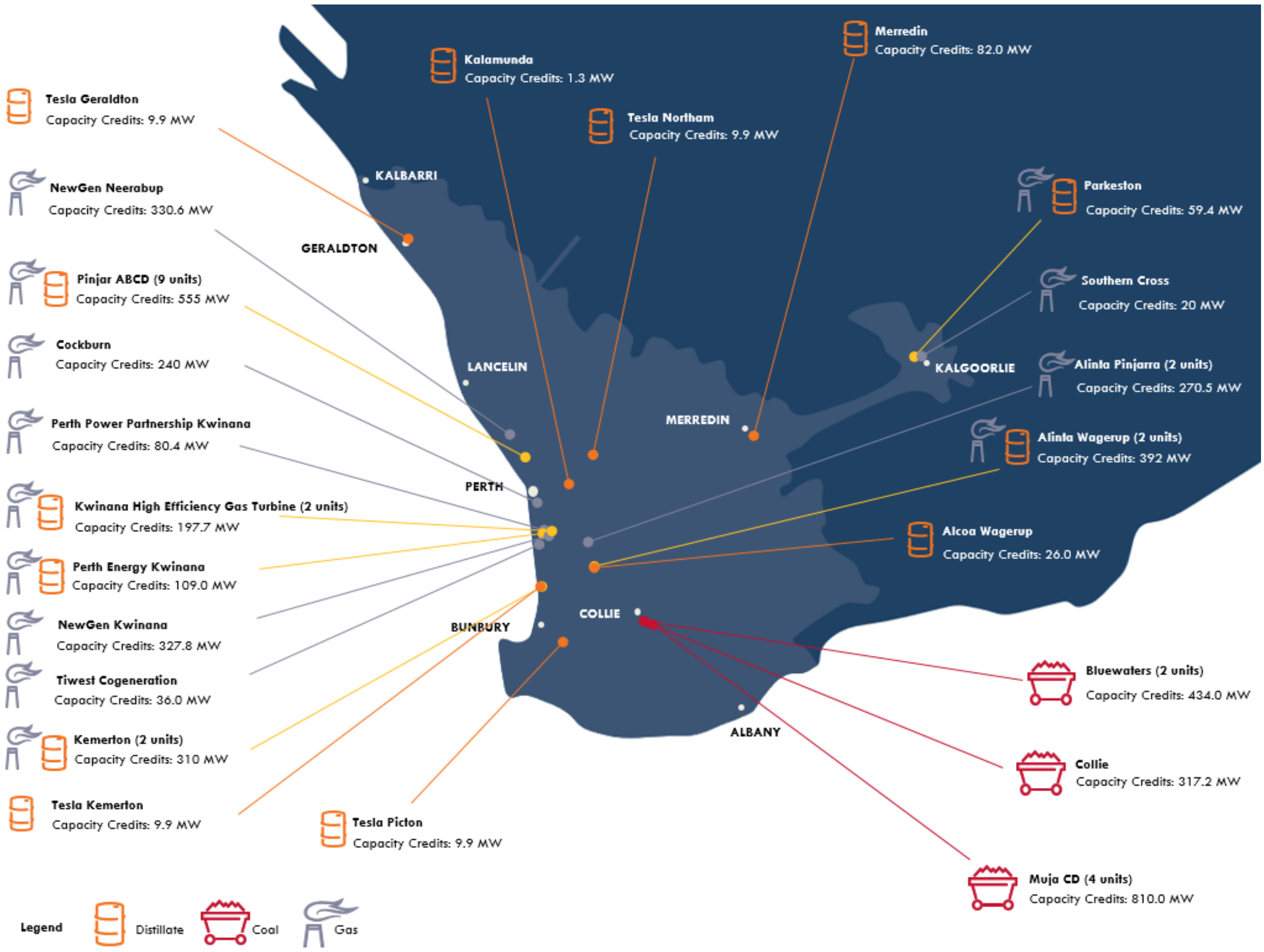
2.2.1 Facility types

Scheduled Generators

The location and the Capacity Credits assigned to Scheduled Generators in the SWIS for the 2019-20 Capacity Year are shown in Figure 3.

[33] The definitions of Scheduled Generator, Non-Scheduled Generator, and DSM are provided in Chapter 11 of the WEM Rules. All renewable Facilities currently holding Capacity Credits in the SWIS are classified as Non-Scheduled Generators, where the generation system has a rated capacity that equals or exceeds 0.005 MW and the generation system is an Intermittent Generator (clause 2.29.4(a) of the WEM Rules). Intermittent Generators cannot be scheduled because their level of output is dependent on factors beyond the operator's control (such as wind).

Figure 3 Scheduled Generators map for the SWIS, 2019-20



Key points related to Scheduled Generators in the SWIS are:

- At 810 MW, Muja CD remains the largest power station, with four units[34] accounting for 16.6% of Capacity Credits assigned for the 2019-20 Capacity Year. Following the retirement of four non-renewable generation assets, the total quantity of Capacity Credits assigned to Scheduled Generators for the 2019-20 Capacity Year (4,638.5 MW) is 340 MW less than the total in the 2017-18 Capacity Year (4,978 MW)[35].
- Pinjar is the second largest power station, with nine units accounting for 555 MW[36] and 11.4% of the Capacity Credits assigned for the 2019-20 Capacity Year.

Non-Scheduled Generators

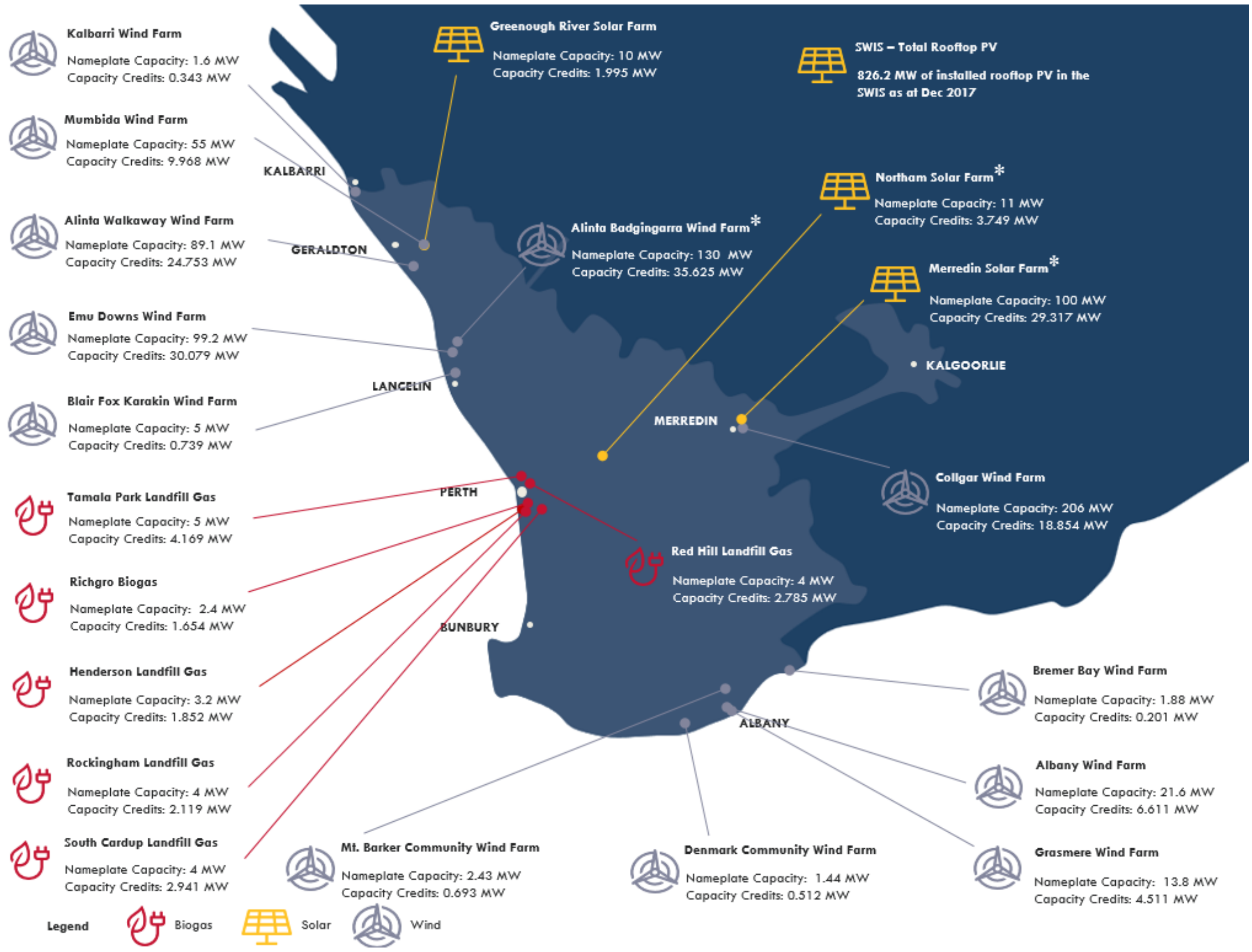
The location of Non-Scheduled Generators in the SWIS, their nameplate capacity and the quantity of Capacity Credits assigned to them for the 2019-20 Capacity Year are shown in Figure 4. For comparison, the total installed rooftop photovoltaic (PV) capacity in the SWIS at the end of December 2017 (826.2 MW) is shown in Figure 4.

[34] Muja CD comprises Muja units G5, G6, G7, and G8 with 195, 193, 211, and 211 MW of Capacity Credits respectively.

[35] AEMO, *2017 Electricity Statement of Opportunities for the WEM*, June 2017, page 3, available at https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[36] Pinjar is comprised of nine units with Capacity Credits of 31.200 MW (PINJAR_GT1), 30.300 MW (PINJAR_GT2), 37.000 MW (PINJAR_GT3), 37.000 MW (PINJAR_GT4), 37.000 MW (PINJAR_GT5), 36.500 MW (PINJAR_GT7), 111.000 MW (PINJAR_GT9), 111.000 MW (PINJAR_GT10), and 124.000 MW (PINJAR_GT11), which sum up to an aggregate Capacity Credits of 555 MW.

Figure 4 Non-Scheduled Generators map for the SWIS, 2019-20



* Facilities under construction.

Key points related to Non-Scheduled Generators in the SWIS are:

- The total quantity of Capacity Credits assigned to renewable generation facilities for the 2019-20 Capacity Year (183 MW) is 73 MW more than that for the 2017-18 Capacity year (110 MW)[37]. This increase is due to the development of new renewable Facilities[38]. Unlike most Scheduled Generators, Non-Scheduled Generators generally hold a proportion of Capacity Credits that is lower than their nameplate capacity. This is due to the methodology[39] used to assign Certified Reserve Capacity (CRC) to Non-Scheduled Generators to account for intermittency.
- Wind generators hold 73% of the 183 MW of Capacity Credits assigned to renewable generation. The share of Capacity Credits for grid-scale PV and biogas have increased from 14% to 19% and 4% to 8% respectively between 2017-18 and 2019-20.
- With 35.6 MW assigned, Alinta's new Badgingarra wind farm (nameplate capacity of 130 MW) is the largest renewable Capacity Credit holder for the 2019-20 Capacity Year.
- Merredin Solar Farm Nominee's new Merredin solar Facility (nameplate capacity of 100 MW) holds the highest quantity of Capacity Credits for a solar PV facility, with 29.3 MW assigned for the 2019-20 Capacity Year.

[37] See https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Assignment-of-capacity-credits.

[38] These include Northam Solar Farm, Emu Downs upgrade (solar), Tamala Park upgrade (biogas) in the 2018-19 Capacity Year, Badgingarra Wind Farm, and Merredin Solar Farm, in the 2019-20 Capacity Year.

[39] In the RCM, the assignment of CRC occurs before the assignment of Capacity Credits, and essentially sets the maximum quantity of Capacity Credits that can be assigned. The quantity of CRC assigned to Non-Scheduled Generators is determined in accordance with the Relevant Level Methodology. See clause 4.11.2(b) and Appendix 9 of the WEM Rules and AEMO's website for more information on the Relevant Level Methodology: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Certification-of-reserve-capacity.

2.2.2 Facility size comparison

The nameplate capacity and Capacity Credits assigned for the 2019-20 Capacity Year are displayed in order of size in Figure 5. The combined nameplate capacity of rooftop PV is presented as a comparison alongside these Facilities.

Figure 5 Nameplate and Capacity Credit comparison (Facilities larger than 50 MW)

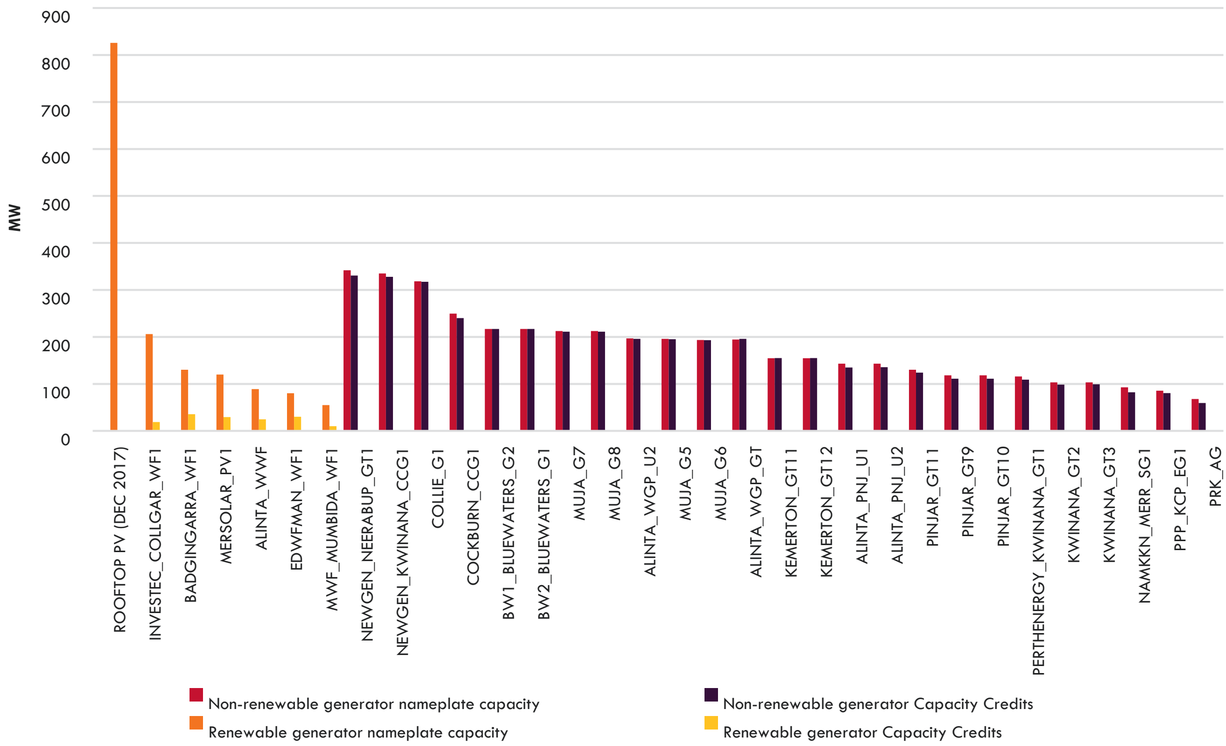


Figure 5 illustrates the following points:

- If taken as an aggregate, rooftop PV is the largest generator (826.2 MW) in the SWIS. This is larger than Muja CD (with an installed nameplate capacity of 854 MW and 810 MW of Capacity Credits for four generation units), the largest coal-fired generator in the SWIS, and more than twice the size of the single largest generation unit, NewGen Neerabup (331 MW of Capacity Credits and 342 MW of nameplate capacity).
- Rooftop PV cannot be assigned Capacity Credits under the current WEM Rules. However, it does contribute to a lower peak demand by reducing demand from consumers and thus reducing the Reserve Capacity Target (RCT). This contribution is estimated to be 111 MW for the 2017-18 summer peak (see Table 11 in Chapter 4). The 2020-21 RCT is 159 MW lower than it would be with no rooftop PV installed in the SWIS (see Chapter 3 for details).
- As rooftop PV reduces peak demand, it reduces Market Customers' Individual Reserve Capacity Requirement (IRCR)[40] obligations. This reduction effect will vary depending on the timing of the 12 Peak Trading Intervals used for the IRCR calculation.

Scheduled Generators are generally assigned a quantity of Capacity Credits that is similar to their nameplate capacity. Non-Scheduled Generators generally hold a quantity of assigned Capacity Credits that is lower than their nameplate capacity due to the Relevant Level Methodology (see Section 2.2.1).

2.2.3 Facility characteristics

AEMO has classified baseload, mid-merit, and peaking Facilities as follows:

- **Baseload capacity** relates to Facilities that operate more than 70% of the time.
- **Mid-merit capacity** relates to Facilities that operate between 10% and 70% of the time.

[40] IRCR is the mechanism used to fund the RCM. See AEMO's website for further information on the IRCR, at https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Individual-reserve-capacity-requirement-information.

- **Peaking capacity** relates to Facilities that operate less than 10% of the time.

Capacity has been classified based on the number of Trading Intervals in the 2016-17 Capacity Year during which each Facility operated, adjusted for full outages[41].

While the quantity of Capacity Credits assigned to a Facility indicates its capability to provide capacity during peak demand periods, this is not necessarily related to the total energy generated by a Facility over the course of a year.

Factors such as operating cost per megawatt hour (MWh), age, and classification play a role in a Facility's total energy output. Newer generators are generally more fuel-efficient and capable of operating for longer periods without an outage, so have a higher energy output. Facilities that are designed to provide baseload generation, such as coal-fired generators, generally have lower fuel costs and are designed to operate continually, so will continue to operate at lower demand times when wholesale electricity prices are low.

For example, in the 2016-17 Capacity Year, NewGen Kwinana was around nine years old and is a combined cycle plant[42] so operated as baseload, while Pinjar was around 27 years old, is comprised of several open cycle gas turbines and most of its units operated as peaking capacity. As a result, NewGen Kwinana generated almost four times as much energy as Pinjar in this Capacity Year, despite being more than 200 MW smaller in size.

Facilities currently operating in the SWIS by age, fuel capability, and classification are shown in Figure 6. The size of the bubbles represents the quantity of Capacity Credits assigned for the 2019-20 Capacity Year. The quantity of Capacity Credits assigned to each bubble is given in Figure 6.

Figure 6 Facilities operating in the SWIS by age, fuel capability, and capacity classification [A,B]

A. Facilities' ages are rounded up to the nearest multiple of five.
B. Bubble sizes presented in numbers are Capacity Credit quantities in MW.

In summary:

- More than 50% of total Capacity Credits assigned for the 2019-20 Capacity Year are currently operating as baseload (2,519.6 MW).
- Out of 2,519.6 MW of baseload capacity, around 936 MW (37%) is more than 20 years old, 1,385.5 MW (55%) is between 10 and 20 years old, and 197.7 MW (8%) is less than 10 years old.
- 29% of total Capacity Credits (1,418 MW) is classified as mid-merit generation.
- 14.3% of total Capacity Credits (701 MW) is peaking generation.
- The remaining 3.7% of total Capacity Credits (183.5 MW) is non-scheduled generation.

[41] A full outage is defined as the quantity of a Facility's capacity on outage being equal to its quantity of assigned Capacity Credits.

[42] Combined cycle plants take waste heat from an open cycle gas turbine to operate a steam turbine to improve the overall plant efficiency.

- With the retirement of Muja AB, the oldest generation Facility in the SWIS is now the Muja CD Facility, a 39-year-old coal-fired generator.
- The majority of Non-Scheduled Generators (94%) are less than 15 years old.
- Apart from the Kwinana High Efficiency Gas Turbine, which is a 197.7 MW dual gas/diesel Facility, all baseload generation capacity is either coal- or gas-fired generation.

3. Forecast methodology and assumptions

This chapter describes the methodology and assumptions used to undertake the Long Term PASA study for the 2018-19 to 2027-28 Capacity Years to meet the Planning Criterion outlined in the WEM Rules. It includes a summary of methodologies for peak demand and operational consumption[43] forecasts and the expected energy shortfall (unserved energy)[44] assessment.

This chapter presents supporting forecasts and input assumptions used in the peak demand and operational consumption forecasts, including:

- Economic outlook.
- Population growth.
- New block loads.
- Rooftop PV, battery storage, and electric vehicle (EV) uptake.

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[45]. The Planning Criterion is that there should be sufficient available capacity in each Capacity Year during the Long Term PASA Study Horizon[46].

- Part (a) of the Planning Criterion relates to meeting the highest demand in a half-hour Trading Interval. It is assessed using the peak demand forecasts, presented in Chapter 4.
- Part (b) ensures adequate levels of energy can be supplied throughout the year. It is 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.

The outcome of the Long Term PASA determines whether the peak demand-based capacity requirement in part (a) or the energy-based requirement in part (b) sets the RCT[47] for each year of the 10-year Long Term PASA Study Horizon (2018-19 to 2027-28). The RCT determined for the 2020-21 Capacity Year sets the RCR for the 2018 Reserve Capacity Cycle.

Section 3.2 summarises the methodologies used to assess both elements of the Planning Criterion.

3.2 Forecast methodology

3.2.1 Overview

The general forecasting methodology taken by AEMO's consultants to provide the key forecasting inputs for this 2018 WEM ESOO is broadly consistent with that used for the NEM ESOOs[48]. The demand forecasts are based on the same parameters, such as weather, number of connections and economic growth. The same consultant was used to provide

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[43] Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.

[44] The expected energy shortfall is the expected unserved energy, which refers to a forecast by AEMO of the aggregate amount in MWh by which the demand for electricity exceeds the supply of electricity.

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

[46] The Long Term PASA Study Horizon is defined as the 10-year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle (1 October 2018 for the 2018 Reserve Capacity Cycle).

[47] The RCT is AEMO's estimate of the total amount of generation 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.

[48] Differences in the detailed requirements of the approach include timing of studies, some source data specifically obtained for the WEM (e.g. EV and battery uptake), and 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.

economic and population forecasts for both the WEM and NEM as input to the ESOO forecasts. Both use a market modelling approach to assess EUE.

AEMO engaged ACIL Allen to develop the peak demand and operational consumption forecasts for this WEM ESOO. Sections 3.2.2 and 3.2.3 describe the general methodologies that ACIL Allen used to develop these forecasts. ACIL Allen adopted a similar approach to forecasting as in previous years, with improvements made to the assumptions associated with the impact of the IRCR response on the peak demand forecasts, rooftop PV, and batteries.

AEMO engaged Robinson Bowmaker Paul (RBP) to carry out reliability forecasts, including EUE. Section 3.2.4 presents the methodology that RBP used to forecast EUE and assess system reliability.

ACIL Allen's methodology report, *Peak demand and energy forecasts for the South West interconnected system*, and RBP's methodology report, *Assessment of system reliability and development of the Availability Curve for the South West interconnected system*, have been published on AEMO's website[49].

3.2.2 Peak demand forecasts

ACIL Allen applied an econometric approach to forecasting peak demand in the SWIS. A statistical relationship between historical peak demand and key drivers including weather and economic factors was established, which was then used to forecast peak demand.

Peak demand forecasts developed by ACIL Allen were based on three different probability of exceedance (POE[50]) weather scenarios:

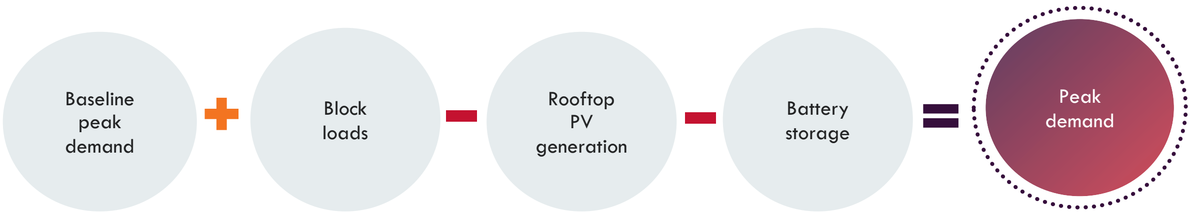
- 10% POE.
- 50% POE.
- 90% POE.

Economic growth is a primary factor in determining the system peak demand. ACIL Allen applied three forecasts of demand growth (low, expected, and high) to each of the weather scenarios, for a total of nine peak demand forecasts.

The low, expected, and high scenario forecasts referred to in this 2018 WEM ESOO reflect different economic and population scenarios, different levels of new block loads (at least 20 MW), and different levels of rooftop PV and battery storage uptake. Further information about economic, population, block loads, rooftop PV and battery storage forecasts and assumptions is provided in Section 3.3.

The peak demand forecasts were developed by applying the adjustments to the baseline peak demand econometric forecasts. The baseline peak demand forecasts were adjusted by adding potential block loads connecting to the network and netting off the contribution of rooftop PV and battery storage generation. The methodology for calculating peak demand is shown in Figure 7.

Figure 7 Components of peak demand forecasts



Unlike in previous WEM ESOOs, the baseline peak demand forecasts were not adjusted to account for expected IRCR responses. Instead, the modelling assumed that the expected IRCR responses were consistent with those observed historically. The baseline peak demand regression model captured this impact, as it was embedded in historical demand data.

The forecasting model used to develop the baseline peak demand forecasts was adjusted by removing the WA Gross State Product (GSP) and temperature interaction components. These adjustments alleviated peak demand sensitivity to temperatures, and resulted in lower peak demand growth rates that better reflected observed trends, compared to the model applied in the 2017 WEM ESOO[51].

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[49] See: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[50] POE means the likelihood that 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 is more conservative than the 50% and 90% POE forecasts for capacity planning purposes.

[51] See Section 5.5 of ACIL Allen's report for more detailed information.

3.2.3 Operational consumption forecasts

ACIL Allen used econometric models to develop its operational consumption forecasts.

The residential and non-residential (including commercial and industrial) operational consumption forecasts were developed separately to account for the total operational consumption forecasts in the SWIS. Synergy currently supplies all residential connections[52] and provided residential customer account numbers and tariff data to AEMO for use in the development of the forecasts. The amount of historical consumption attributed to non-residential consumption was calculated as the difference between residential consumption (from Synergy) and total consumption.

Key economic, demographic, and weather parameters[53] were identified as the major factors affecting energy consumption. Forecasts for the economic and demographic parameters used to develop the operational consumption forecasts under the low, expected, and high scenarios are in Section 3.3.

3.2.4 Reliability assessment

The reliability assessment was undertaken with the aim of limiting EUE to no more than 0.002% of annual operational consumption for each year of the Long Term PASA Study Horizon. RBP applied a combination of fundamental market modelling and Monte Carlo analysis for the assessment.

The assessment was carried out in two phases:

- Phase 1: Forecast load duration curves (LDCs) over the Long Term PASA Study Horizon. Forecast load duration curves for each year in the Long Term PASA Study Horizon were developed by scaling up the historical average load profile to match the 50% POE peak demand and expected energy forecasts for each Capacity Year in the Long Term PASA Study Horizon [54].
- Phase 2: Undertake reliability assessment. This assessment determined the amount of Reserve Capacity required to limit the EUE to 0.002% of forecast annual demand for each year in the Long Term PASA Study Horizon. The assessment was based on the LDCs developed in Phase 1.
  - A market modelling tool was applied to simulate the dispatch of thermal and other generation resources in a multi-regional transmission framework in the SWIS. The dispatch simulation used the forecast LDCs, the expected available capacity[55], and the outages, to yield an estimate of unserved energy. No constraints on network capacity were modelled, due to the current unconstrained network access regime[56]. The model did not assume the presence of any network security constraints, because standards, procedures and technical codes are in place to ensure system security is maintained[57].
  - The Monte Carlo analysis was applied to run the market model over a large number of iterations with probabilistically simulated forced outages. The EUE was calculated as the average of total estimates of unserved energy of the Monte Carlo runs.
  - The EUE was then calculated as a percentage of annual demand. If the percentage is less than or equal to 0.002%, the RCT will be set by part (a) of the Planning Criterion. If the percentage is greater than 0.002%, expected available capacity will be increased to reassess the EUE until the percentage is less than or equal to 0.002%. The RCT will be set by part (b) of the Planning Criterion.

In line with past trends, the RCT was set by part (a) of the Planning Criterion for each Capacity Year over the Long Term PASA Study Horizon. Detailed information about the forecast RCT results are provided in Chapter 6.

3.3 Supporting forecasts and results

The baseline peak demand and operational consumption forecasts were driven by the economic and population growth outlook. The baseline peak demand forecasts were adjusted to account for the impact of rooftop PV and battery storage uptake, and the new block load forecast. The baseline operational consumption forecasts were adjusted to account for the contribution of rooftop PV and EV.

AEMO engaged an independent economic forecaster to provide the forecasts for WA GSP and population. For rooftop PV, battery storage, and EV uptake, AEMO commissioned ACIL Allen to provide the forecasts under the low,

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

53 Daily maximum and minimum temperature data for the Perth Airport weather station was collected from the Bureau of Meteorology (BOM) covering the period from 1 January 1987. See section 5.4 of ACIL Allen's report for more detailed information.

54 It can reasonably be assumed that 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 The expected available capacity was assumed to be equal to the forecast RCT for each Capacity Year over the Long Term PASA Study Horizon.

56 As part of the WA Government's electricity reform program, the move from the current unconstrained network to a constrained network access model is expected to occur by 2022. See https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Electricity-Sector-Reform-Initiatives/.

57 AEMO operates the SWIS in accordance with the operating and Ancillary Services standards in the WEM Rules, the Power System Operation Procedures and relevant technical codes to ensure the maintenance of system security.

expected, and high growth scenarios. Detailed information is published in ACIL Allen's methodology report, *Peak demand and energy forecasts for the South West interconnected system*[58].

These supporting forecasts and assumptions are discussed in the following sections.

3.3.1 Economic outlook

An independent economic forecaster developed low, expected and high projections for WA GSP, as presented in Table 4. These GSP forecasts were provided to ACIL Allen for use in the peak demand and operational consumption forecasts.

The forecasts are lower than in the 2017 WEM ESOO. This is primarily because the Australian Bureau of Statistics (ABS) revised the annual national accounts for the entire historical time series[59]. The revisions resulted in lower historical WA GSP values and, consequently, lower WA GSP forecasts.

Table 4 WA GSP forecasts, 2018-19 to 2022-23 financial years

Scenario	2018-19 (%)	2019-20 (%)	2020-21 (%)	2021-22 (%)	2022-23 (%)	Average annual 10-year growth (%)
High	2.8	3.2	3.8	4.0	3.9	3.9
Expected	2.6	2.9	3.4	3.6	3.5	3.4
Low	2.3	2.5	3.0	3.1	2.9	2.8

Source: Independent economic forecaster.

For the first two years, the GSP growth forecasts assume that investment in the mining sector will start to recover and that liquefied natural gas exports will increase. In the long term, the GSP growth forecasts are primarily driven by outlooks of population, labour force participation, household income, productivity, industrial production, services activity and exchange rates.

The high-level assumptions underpinning the GSP forecasts are as follows:

- Population growth assumptions, as discussed in Section 3.3.2.
- Labour force participation was assumed to decline based on an ageing Australian population. The participation rate is consistent across all scenarios.
- Household income was assumed to grow and return to historical growth levels.
- Productivity growth (measured by output per worker) was applied to the population estimates, and was based on historical data.
- Industrial production activity was assumed to shrink as a portion of WA economic output, while the service sectors were assumed to continue to grow and replace industrial production activity.
- The Australian dollar to United States dollar exchange rate was forecast to depreciate to approximately 71 cents over the next five years.

3.3.2 Population growth

While population growth is correlated with peak demand and operational consumption, the effect is partly offset by rooftop PV and energy efficiency improvements (particularly building energy efficiency). The population forecasts are outlined in Table 5. The forecasts for the expected scenario are based on WA Department of Treasury's forecasts between 2017-18 and 2020-21[60], Western Australia Tomorrow (2015) forecasts between 2021-22 and 2024-25[61], and the economic forecaster's business outlook for 2026-27 and 2027-28.

In the absence of detailed SWIS-specific data, WA population growth rates were assumed to be in line with SWIS population growth rates. The population served by the SWIS is estimated to have been 2.57 million in 2016-17, with population growth forecast to grow at an average of 1.7% per annum in the expected growth scenario over the forecast period.

[58] See: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[59] Available at: http://www.abs.gov.au/ausstats/abs@.nsf/Lookup/5204.0Feature+Article12016-17.

[60] Available at https://www.treasury.wa.gov.au/Treasury/Economic_Data/Economic_Forecasts/.

[61] Western Australia Tomorrow. 2015. Available at: https://www.planning.wa.gov.au/publications/6194.aspx.

The ABS's population estimates for the recent intercensal period (September 2011 to June 2016) have been updated using information from the 2016 Census of Population and Housing. The rebased population estimates for this period are lower, and consequently population growth forecasts are lower than in the 2017 WEM ESOO[62].

Table 5 WA population growth, 2018-19 to 2022-23 financial year

Scenario	2018-19 (%)	2019-20 (%)	2020-21 (%)	2021-22 (%)	2022-23 (%)	Average annual 10-year growth (%)
High	1.6	1.9	2.3	2.3	2.2	2.1
Expected	1.2	1.5	1.8	1.8	1.8	1.7
Low	0.8	1.1	1.3	1.3	1.3	1.2

Source: Independent economic forecaster.

3.3.3 Block loads

Block loads are temperature insensitive large loads that operate almost continuously. AEMO considers 20 MW to be the minimum size for a new block load. Information about historical block load consumption is in Section 5.1.

AEMO developed the block load forecasts based on historical consumption and anticipated new block loads, and provided the block load forecasts to ACIL Allen for use in the peak demand and operational consumption forecasts.

Two new block loads were included in the high growth scenario forecasts in the 2017 WEM ESOO – an upgrade to an existing mine site and the development of a new mineral processing plant. These loads have been included in the expected and high growth scenario forecasts in this 2018 WEM ESOO, and the projects are anticipated to increase demand by approximately 25 MW from early 2019, and by 36 MW (total) from 2023.

AEMO engaged with external industry stakeholders, including Western Power and the Department of Jobs, Tourism, Science and Innovation, in deciding to include the new block loads in the expected growth scenario forecasts as well as in the high growth scenario forecasts, in this 2018 WEM ESOO.

3.3.4 Rooftop PV uptake outlook

ACIL Allen developed the following rooftop PV forecasts[63] under the low, expected, and high growth scenarios:

- Installed capacity.
- The effect on baseline operational consumption.
- The effect on baseline peak demand.

An overview of the methodology, assumptions, and inputs used to develop these forecasts is presented in the following sections, including the methodology applied to develop a solar capacity factor trace[64]. Further details on the methodology and assumptions can be found in ACIL Allen's report[65].

Installed capacity forecasts and assumptions

The rooftop PV installed capacity forecasts were based on regression analysis of historical financial returns to rooftop PV systems and associated rates of uptake in the SWIS. The high-level assumptions used to develop the rooftop PV capacity forecasts in the different growth scenarios are shown in Table 6.

[62] Available at http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/3101.0Main%20Features3Sep%202017?opendocument&tabname=Summary&prodno=3101.0&issue=Sep%202017&num=&view.

[63] All rooftop PV assumptions reported in this section refer to gross quantities (total energy generated from all rooftop PV systems in the SWIS).

[64] Solar traces are a measure of the capacity factor of solar panels for each half-hour Trading Interval.

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

Table 6 Rooftop PV forecast - main assumptions

Assumption	Low scenario	Expected scenario	High scenario
Population	Low forecast scenario	Medium forecast scenario	High forecast scenario
Real system price decline per annum	0%	1.5%	3.5%
The Renewable Energy Buyback Scheme	7 cents	7 cents	7 cents
Small-scale Technology Certificate (STC) price	$40	$40	$40

Source: ACIL Allen.

Figure 8 Installed rooftop PV system capacity forecast, 2017-18 to 2027-28 financial years

Source: Clean Energy Regulator and ACIL Allen.

Total installed PV capacity forecasts as shown in Figure 8 are higher across all scenarios than the forecasts in the 2017 WEM ESOO. This is because actual rooftop PV uptake in 2017-18 was higher than previously forecast. Last year's expected scenario forecast for 30 June 2018 was 843 MW, but actual installations increased faster than forecast and reached 826 MW in December 2017, based on the latest data available from the Clean Energy Regulator (CER)[66].

The rooftop PV capacity forecasts for all scenarios have stronger average growth rates over the forecast period than the forecasts presented in the 2017 WEM ESOO. While the strong uptake seen over the past year is forecast to continue for the next couple of years, it is projected to stabilise at longer-term average historical installation rates. The forecast growth rates slow towards the end of the forecast period, and are expected to be similar to the corresponding rates in the 2017 WEM ESOO. This projected stabilisation is attributed to real electricity prices being assumed to remain stable after 2019, the decreasing Small-scale Technology Certificates (STCs) received under the Small-scale Renewable Energy Scheme, and the decline of the number of available premises for installation.

The continued strong uptake of rooftop PV systems will continue to assist in reducing summer peak demand and carbon emissions, however, it will create operational challenges in the SWIS which will need to be addressed (see Chapter 7).

Historical and averaged daily capacity factor traces

The methodology for developing rooftop PV capacity factors in the SWIS has been updated this year to better account for underperforming systems.

[66] Based on SWIS postcodes installations sourced from CER, and available at http://www.cleanenergyregulator.gov.au/DocumentAssets/Pages/Postcode-data-for-small-scale-installations.aspx.

These factors from last year's methodology were identified as potentially overestimating rooftop PV capacity factors:

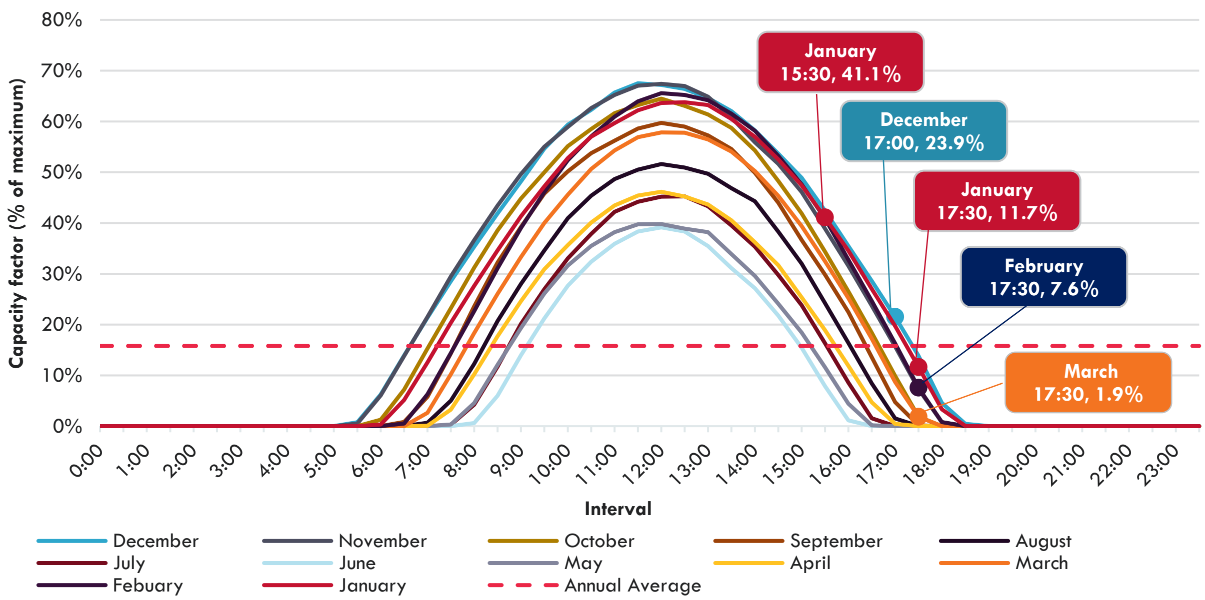
- The 2017 capacity factor curves were developed from data for a sample of PV systems in the SWIS taken from the PVoutput.org database. This data was processed to remove reporting errors, such as where systems had an incorrect nameplate capacity, so as to exclude PV systems that exceeded 102% or never exceeded 90% of their rated capacity. This resulted in an average capacity factor for rooftop PV over the year of 18.3%. AEMO has reviewed this methodology, and concluded that it excluded some underperforming/shaded and faulty units, resulting in PV capacity factors that are higher than the SWIS average.
- At any given time, a proportion of PV systems in the SWIS will be on outage due to faults. The timing and duration of these faults depends on the quality of the system installed and the behaviour of the system owner. While AEMO is not aware of any information that estimates the number of PV systems on outage in the SWIS at any given time, there is some evidence from other networks that suggests failure rates as high as 18% after seven years[67]. While inverter reliability may have improved since this study of inverters installed in 2000, it indicates that failed units need to be considered when estimating energy generated from rooftop PV.
- A proportion of rooftop PV units are poorly aligned or shaded. The PVoutput.org database is voluntary, so users who submit their PV generation data are likely to be more active users who are more inclined to optimise and maintain their systems to maximise their capacity factors. As a result, this dataset may have a higher average capacity factor than all the installed systems in the SWIS.

AEMO developed this year's capacity factor curves from the output of rooftop PV systems sampled[68] in the SWIS. Historical output data from systems in this study takes into consideration a broader range of system performance.

This output data was compared to irradiance values obtained from the Bureau of Meteorology (BOM) and used to develop a set of monthly regression equations. These equations were applied to irradiance data in the SWIS (derived from a spread of weather stations around the Perth metropolitan area) to produce a historical SWIS rooftop PV capacity factor trace.

Compared to the 2017 WEM ESOO numbers, this methodology resulted in lower rooftop PV capacity factor curves and reduced rooftop PV output performance in all intervals, including during peak demand times. The historical solar capacity factor trace was 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 rooftop PV in the SWIS [A,B]



A. All capacity factor values are half-hourly averages and all times are half-hour interval start times (for example, the average capacity factor in January between 15:30 and 16:00 is 41.1%).
B. The colour boxes indicate the months and intervals when the system peaks occurred over the last five Capacity Years.

These solar traces were used to determine the effect of rooftop PV on peak demand and operational consumption forecasts.

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[67] Ausgrid, "Solar PV System Performance", presentation by R. Simpson to ATRAA Conference, 27 July 2012, available at https://www.ausgrid.com.au/-/media/Files/Customer-Services/Homes/Solar/PV_Performance_Ausgrid_July2012.pdf.

[68] The sample was comprised of SolarCity rooftop PV units with gross interval metering installed.

Because solar traces are based on actual data, they implicitly incorporate variations in the physical alignment of panels, lifecycle performance degradation, and an averaged effect of variations in solar irradiance. The average yearly capacity factor calculated from the trace is 15.8%.

This value was derived from a sample of PV generation in the SWIS, so a bias may have been introduced into the study. However, AEMO considers that it is a better reflection of the average rooftop PV capacity factor in the SWIS. AEMO will continue to investigate system performance and failure rates to further improve this model.

Months and Trading Intervals when the system peaks occurred over the last five Capacity Years are shown in Figure 9. The average capacity factors for these peak intervals indicate that the rooftop PV's impact on peak demand is highly sensitive to the month and the time of the system peak.

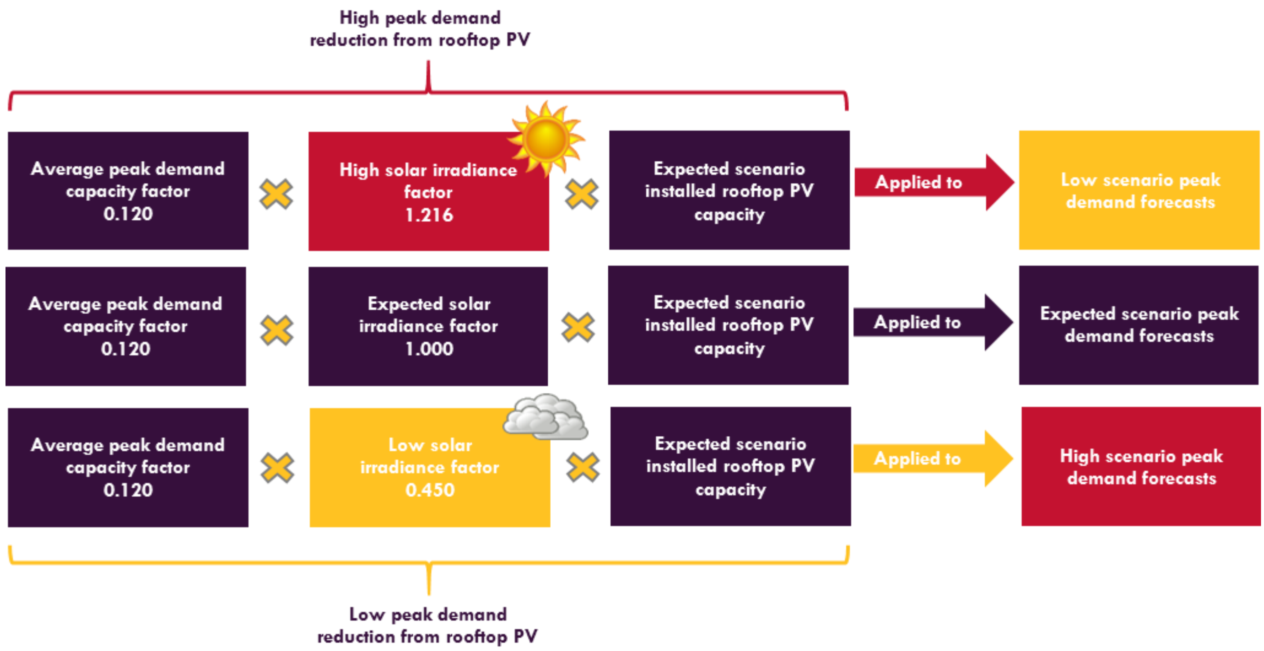
Effect on baseline peak demand

AEMO calculated the expected effect of rooftop PV on peak demand by accounting for:

- The time of day when peak demand occurs.
- The expected level of solar irradiance at the time of system peak.

The process for calculating the effect of rooftop PV on peak demand is illustrated in Figure 10. It has been modified from last year to reflect the use of the expected rooftop PV uptake across the low, expected, and high peak demand scenarios.

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



Based on recent observations, AEMO considers it likely that peak demand will continue to occur during the 17:00 to 18:00 period, as the effect of PV generation falls due to reduction of solar radiance levels after this time in summer. Peak demand may shift to a later time, subject to the uptake of battery storage in the future. However, the timeframe for this is uncertain and depends largely on the cost of batteries and the residential tariff structure.

The steps for calculating the effect of rooftop PV on peak demand were:

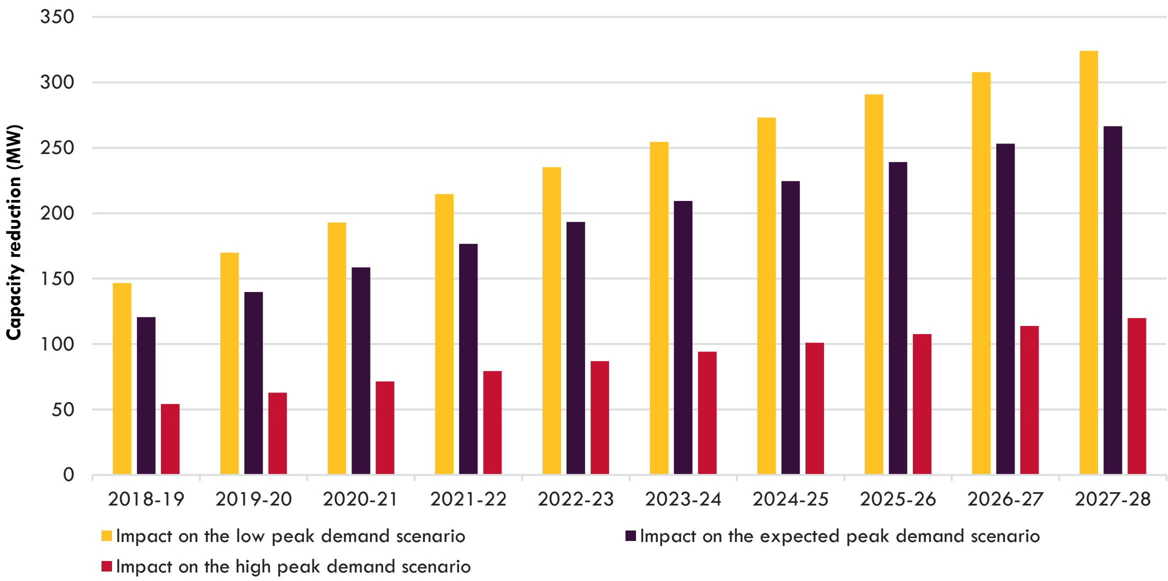
1. The average capacity factor for rooftop PV was calculated over the 17:00 to 18:00 period in February (the assumed peak time) from the monthly average solar trace. The result was a capacity factor of 12%.
2. This capacity factor was multiplied by the expected scenario rooftop PV capacity forecast to obtain the expected scenario peak demand reduction from rooftop PV.
3. The capacity factor for variations in solar irradiance was adjusted for the high and low scenario peak demand reduction from rooftop PV (see section on solar irradiance effects below) as follows:
   - For low peak demand reduction, a derating factor of 0.45 was applied to account for a cloudier than normal day, to give an adjusted capacity factor of 5.4%. This was applied to the expected scenario forecast for installed rooftop PV capacity to give the effect on high scenario peak demand.

– For high peak demand reduction, an uprating factor of 1.216 was applied to account for a sunnier than normal day, to give an adjusted capacity factor of 14.5%. This was applied to the expected scenario forecast for installed rooftop PV capacity to give the effect on low scenario peak demand.

The expected rooftop PV uptake was applied across low, expected, and high peak demand scenarios. This is a different approach to last year's methodology, which applied the high uptake to the high peak demand scenario, and the low take-up to the low peak demand scenario. This change has been made because rooftop PV uptake has been more strongly driven by factors such as installation cost and electricity prices, rather than general macroeconomic drivers like GSP growth.

The higher-than-average solar irradiance factor was applied to the low peak demand scenario, and the lower-than-average factor was applied to the high peak demand scenario, to maximise the forecast band between the low and high peak demand scenarios. The low, expected, and high forecast reductions from rooftop PV developed using the process described above[69] is shown in Figure 11.

Figure 11 Peak demand reduction from rooftop PV systems, 2018-19 to 2027-28 A



A. The impact was calculated based on rooftop PV uptake forecasts in February under the expected growth scenario.
Source: AEMO and ACIL Allen.

Solar irradiance effects

AEMO has investigated the historical relationship between peak demand and solar irradiance levels in the SWIS, and found there is a limited correlation between daily solar irradiance and peak demand days[70]. To account for this correlation, AEMO has calculated rating factors to represent the expected reduction or increase in rooftop PV system performance based on variations in solar irradiance.

The irradiance figures determined for the Perth metropolitan region[71] were averaged over the past seven Hot Seasons[72]. In using irradiance levels as a proxy for system generation, AEMO has implicitly assumed a linear relationship between irradiance and rooftop PV performance.

The solar capacity factor traces developed for this 2018 WEM ESOO are based on actual data, which account for an average solar irradiance level. Therefore, no irradiance factor adjustment was applied to the expected peak demand scenario. For the high peak demand scenario, solar irradiance was assumed to be lower than average, so a derating factor was applied to calculate a lower rooftop PV output. For the low peak demand scenario, solar irradiance was assumed to be higher than average so an uprating factor was applied.

The distribution of daily solar irradiance measured at six sites across the Perth metropolitan region for December to March (the likely timing of the system peak) over the past seven Hot Seasons is shown in Figure 12. This shows that

[69] The forecasts presented in the figure use slightly different rooftop PV capacity values than those in Appendix D as they have been adjusted to align to a February peak.

[70] Refer to Deferred 2015 WEM ESOO, Figure 23, available at http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[71] Irradiance data was collected from six weather stations located in the Perth metropolitan region, including Armadale, Mandurah, Perth, Perth Airport, Swanbourne, and Wanneroo. Available at http://www.bom.gov.au/climate/data/index.shtml?bookmark=193.

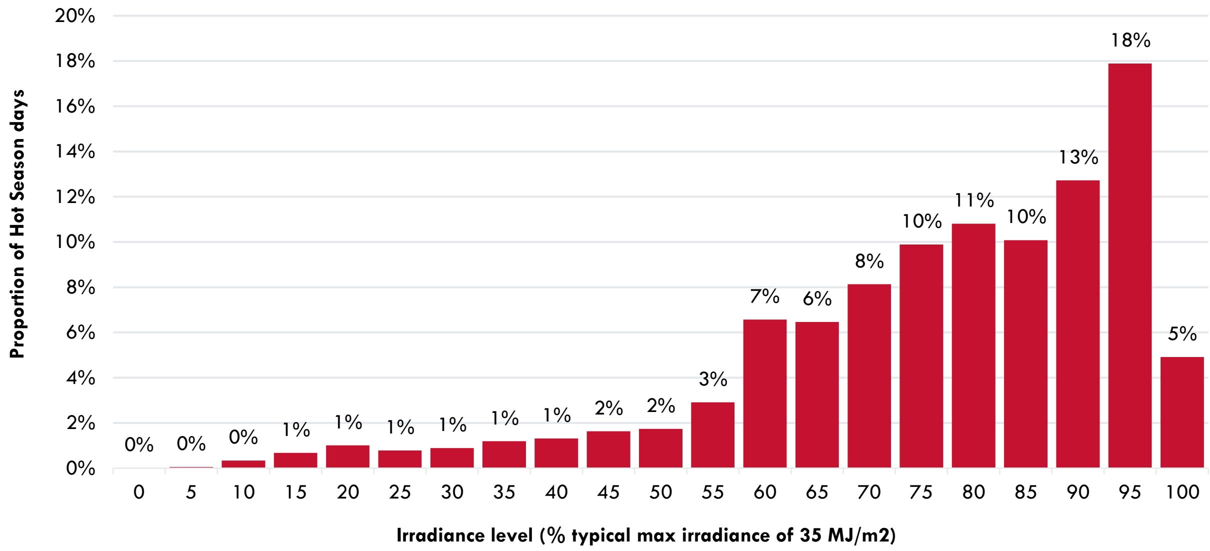
[72] The Hot Season is defined in the WEM Rules as the period commencing at the start of the Trading Day beginning on 1 December and ending at the end of the Trading Day finishing on 1 April.

Perth has a high level of solar irradiance over summer, with around 90% of summer days observing more than 50% of the maximum possible solar irradiance.

The following assumptions were derived from the irradiance analysis presented in Figure 12:

- High solar reduction at peak (associated with low peak demand scenario) – ninety-fifth percentile irradiance level equalling 121.6% of average rooftop PV output.
- Expected solar reduction at peak – median irradiance levels equalling rooftop PV output based on the average monthly solar capacity factor traces.
- Low solar reduction at peak (associated with high peak demand scenario) – fifth percentile irradiance levels equalling 45% of rooftop PV output.

Figure 12 Variability in daily solar irradiance levels during Hot Season, 2011 to 2018 A



A. Irradiance data was collected from Armadale, Mandurah, Perth, Perth Airport, Swanbourne, and Wanneroo weather stations.
Source: BOM.

Effect on baseline operational consumption

To estimate the future reduction in operational consumption from rooftop PV, and for consistency with the approach applied for rooftop PV's effect on baseline peak demand, the expected rooftop PV uptake forecasts were applied across the low, expected, and high operational consumption forecasts. The effect on operational consumption was forecast by multiplying the expected rooftop PV system installation forecasts by the average rooftop PV capacity factor from the solar traces.

The forecast reduction in operational consumption from rooftop PV is 3,074 gigawatt hours (GWh) by the end of the forecast period (the 2027-28 financial year), or 13.4% of the total baseline forecast operational consumption.

3.3.5 Battery storage forecasts

The battery storage forecasts are for small-scale residential and commercial customers only, and exclude grid-scale systems used for energy arbitrage or network stability purposes. The forecasts were developed under the low, expected, and high growth scenarios.

The high-level assumptions[73] used to forecast battery storage installed capacity are outlined in Table 7.

[73] For detailed assumptions, see ACIL Allen methodology report, available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

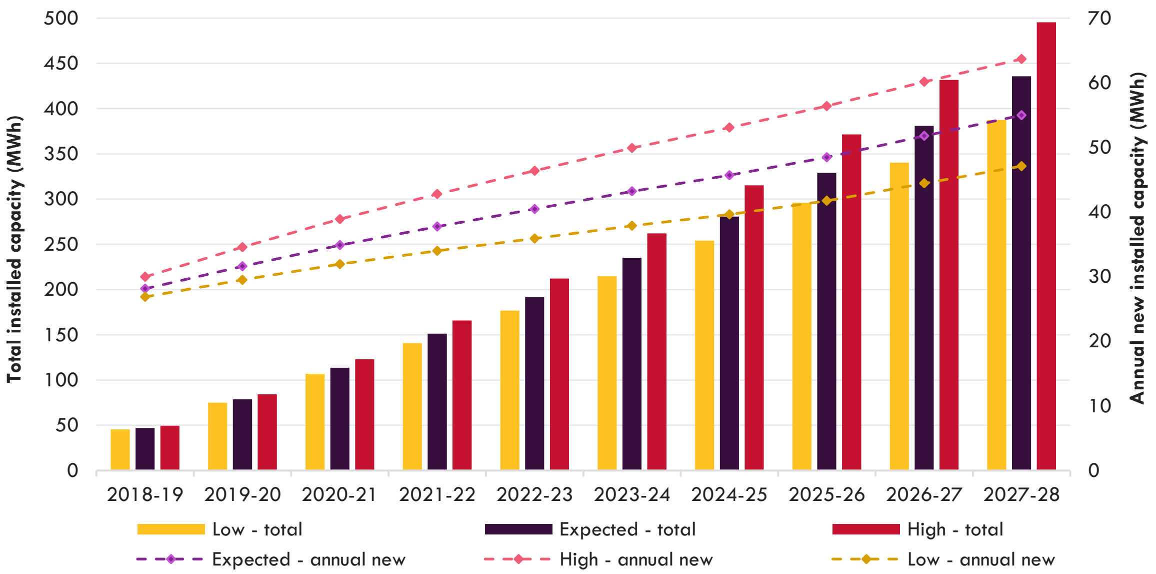
Table 7 Battery forecast - main assumptions

Assumption	Low Scenario	Expected Scenario	High Scenario
Population	Low forecast scenario	Medium forecast scenario	High forecast scenario
Battery pack life (years)	10	10	10
Real system price decline per annum	3%	5%	8%
Efficiency	90%	90%	90%
Cycle depth	80%	80%	80%

Source: ACIL Allen.

The battery installed capacity forecasts in the low, expected, and high growth scenarios are shown in Figure 13. The forecasts assumed that each battery storage installation is paired with a rooftop PV system. Under the expected growth scenario, the installed capacity of battery systems in the SWIS was projected to increase at an annual average growth rate of 28% from 47 MWh in June 2019 to 436 MWh in June 2028. This rate of growth is primarily attributed to the expected reduction in the cost of battery systems over the forecast period.

Figure 13 Installed capacity of battery systems, 2018-19 to 2027-28 financial years



Source: ACIL Allen.

Impact on peak demand

The impact of batteries on peak demand depends on how the unit is operated. There are currently insufficient battery storage units installed in the SWIS to derive an output profile, and consumers have no price incentive to increase the discharge rate of the battery during periods of peak demand beyond the level of their own consumption. The effect on system peak has been forecast based on the following assumptions:

- Charge and discharge rates do not breach the technical constraints of currently available battery storage technology.
- Battery systems are not sensitive to small changes in the availability or timing of rooftop PV generation.
- The battery system is only used to time-shift the consumption of generation from rooftop PV systems, so does not charge from the grid.
- There are insufficient time-of-use tariff signals to encourage non-contestable customers to optimise storage decisions to align with periods of high demand in the SWIS.

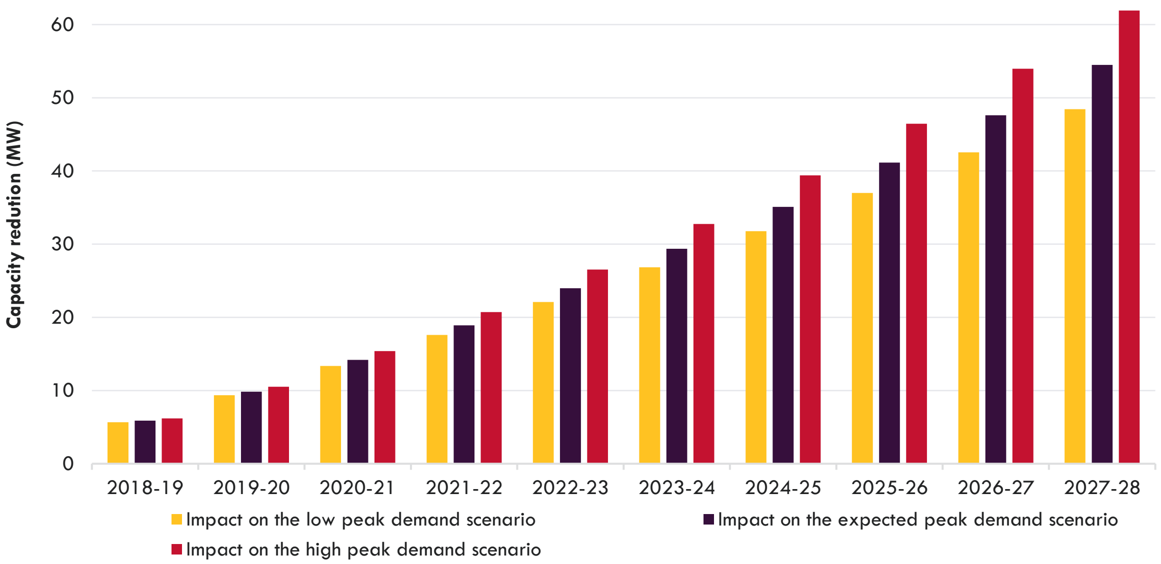
Last year, a linear discharge over a four-hour period that included the system peak was assumed. This year, a more conservative value was used to account for the possibility of consecutive hot days increasing home energy use and reducing the energy available in battery storage to meet peak demand.

Consequently, the assumed impact of battery storage on peak demand is 12.5% of installed storage capacity (MWh) at peak, as shown in Figure 14.

Based on CER data, as of March 2018 there were approximately 500 distributed battery installations in WA[74]. This number only counts batteries installed alongside a new rooftop PV installation, and is based on voluntary reporting, so it is likely to be lower than the actual number.

AEMO continues to monitor trends in battery uptake and usage. The forecasting methodology for the effect of batteries on peak demand will be updated as further units are installed and included in future WEM ESOOs.

Figure 14 Peak demand reduction from battery storage, 2018-19 to 2027-28



Source: AEMO and ACIL Allen.

3.3.6 Electric vehicle assumptions

ACIL Allen developed the EV forecasts[75], based on the vehicle uptake outlook and projection of the market share of EVs, using a logistical model. The forecasts of EV uptake were developed under the low, expected, and high growth scenarios, taking into account different population forecasts (see Section 3.3.2) and EV cost reduction rates. The high-level assumptions[76] used to forecast EV uptake are shown in Table 8.

Table 8 EV uptake forecast - main assumptions

Assumption	Low scenario	Expected scenario	High scenario
Population	Low forecast scenario	Medium forecast scenario	High forecast scenario
Real percentage decline in EV costs	4%	7.5%	9%
Average distance travelled per day (kilometres)	36.4	36.4	36.4
EV range increase per year	3%	3%	3%

Source: ACIL Allen.

[74] http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

[75] The EV forecasts were for the uptake of plug-in hybrid electric vehicles and electric vehicles in passenger and light commercial vehicles classes.

[76] For detailed assumptions refer to ACIL Allen's Methodology, available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

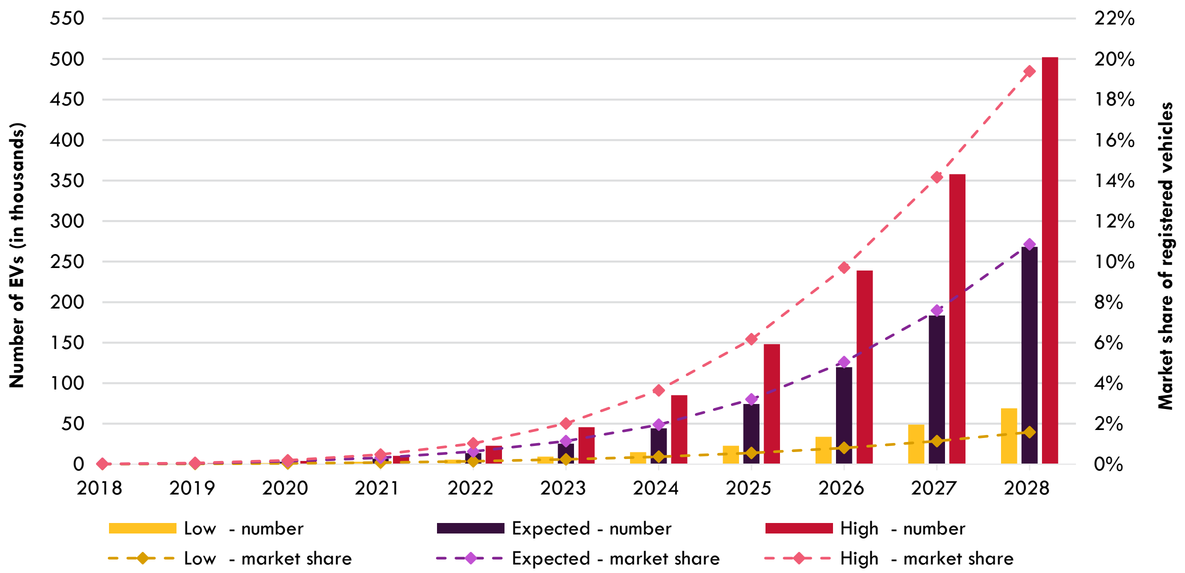
Using the EV uptake forecasts, the impact of EV energy consumption on future energy demand in the SWIS has been projected under the low, expected, and high growth scenarios, considering the energy intensity and average travelling distance of EVs.

EV uptake forecasts

The forecast EV uptake and market share in the SWIS is shown in Figure 15. The EV proportion of the stock of registered vehicles was projected to reach 1.6%, 10.9%, and 19.4% by 2028 under the low, expected and high growth scenarios respectively. Projections for EV uptake assumed a slow start, due to limited infrastructure, the narrow range of models currently available, and the cost relative to conventional petrol or diesel vehicles. The market share of EVs has been projected to undergo a rapid growth phase driven by improvements in the relative financial attractiveness of EVs from the late 2020s.

The range between the high and low forecasting scenarios is relatively wide. This is partly due to uncertainty regarding decisions on industry policy, such as vehicle fleet emission standards, which could influence the EV uptake rate.

Figure 15 Projected number and market share of EVs, 2018 to 2028 calendar years

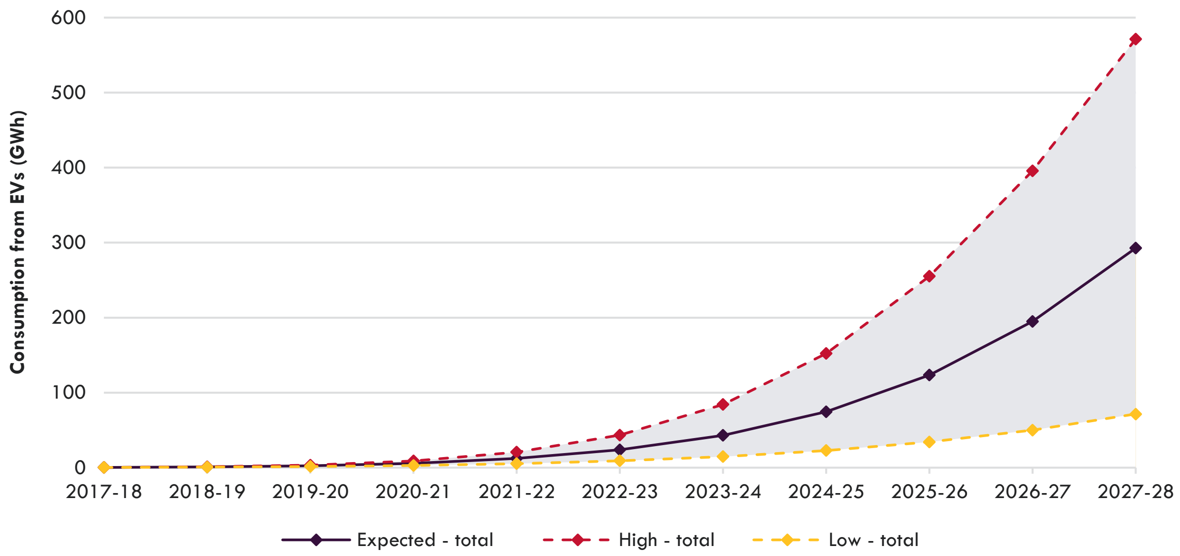


Source: ACIL Allen.

EV impact on operational consumption

The forecast effect of EVs on operational consumption in the SWIS is shown in Figure 16. Under the expected scenario, EV energy consumption is forecast to be 293 GWh by the 2027-28 financial year, accounting for approximately 1.5% of total operational consumption. Under the high and low scenarios, EV energy consumption is forecast to reach 571 GWh (2.8%) and 72 GWh (0.4%) by the 2027-28 financial year respectively.

Figure 16 EV contribution to operational consumption, 2017-18 to 2027-28 financial years



Source: ACIL Allen.

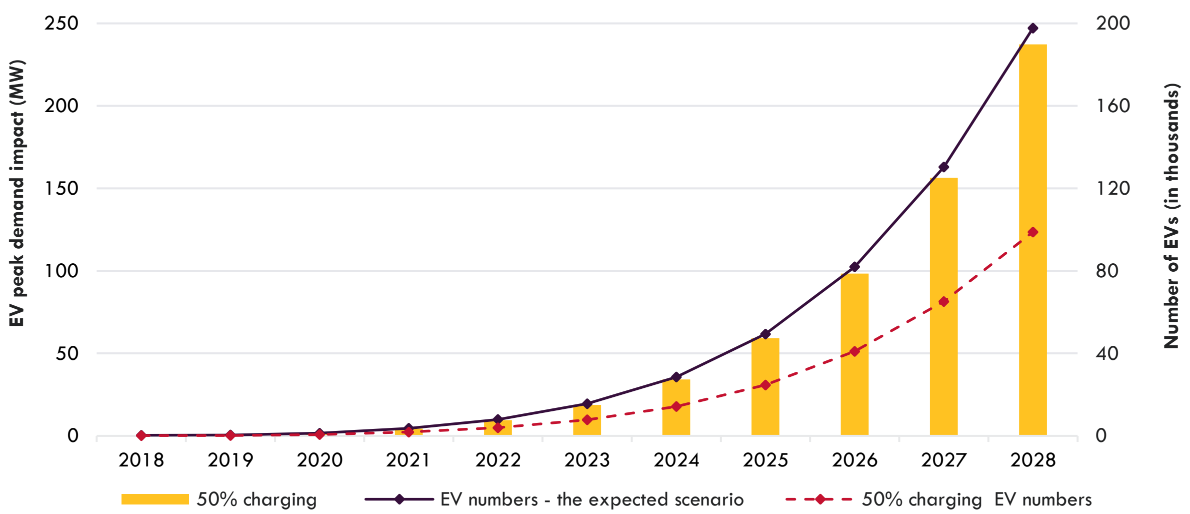
EV impact on peak demand

In this 2018 WEM ESOO, it is assumed that EVs will have a negligible impact on peak demand over the forecast period. The basis for this assumption is that new tariff structures are expected to discourage the charging of EVs during peak demand times, and the charging of EVs is unlikely to affect peak demand until there is a significant increase in the number of EVs in use. Synergy launched an EV home tariff plan in November 2017 to encourage charging of EVs during off-peak demand times (23:00 to 04:00 daily)[77].

AEMO has conducted a high-level analysis of the potential impact of EVs on peak demand over the forecast period. This analysis shows the importance of establishing effective incentives around controlled charging to accommodate EV uptake by 2028.

The potential impact of EVs on peak demand over the forecast period is shown in Figure 17. The data in Figure 17 is based on two assumptions. The first assumption is that EVs use Level 1 (2.4 kW) charging at a constant rate over a 10-hour period that includes the system peak time. The second assumption is that 50% of the EV uptake forecast under the expected growth scenario are charging at the system peak time.

Figure 17 EV impact on peak demand under an uncoordinated charging regime, 2017-18 to 2027-28 [A]



A. The impact was calculated based on EV uptake forecasts in February under the expected growth scenario.
Source: AEMO and ACIL Allen.

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77 See: https://www.synergy.net.au/Your-home/Energy-plans/Electric-Vehicle-Home-Plan.

If it is assumed that there is no strong off-peak charging incentive in place and that 50% of EVs are charging at the system peak time, then EV uptake could potentially add more than 237 MW to peak demand in 2027-28, accounting for approximately 5.4% of the forecast 10% POE peak demand under the expected scenario. Further, if it is assumed that EVs use Level 2 (7 kW) charging, the impact of EVs on peak demand would be even more significant. Moreover, charging EVs during peak demand times would put significant strain on the residential distribution infrastructure.

The impact of EVs on peak demand depends on the number of EVs charging at the peak demand time. Regardless of the tariff structure, based on estimated uptake rates, EVs are expected to have a limited impact on peak demand over the next five years, due to low EV uptake. From 2024, without financial incentives to encourage off-peak charging, the impact of EVs on peak demand could increase rapidly.

The effective management of EV uptake 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. The assumption of the impact on peak demand will be updated as the market penetration level changes and will be included in future WEM ESOOs.

4. Historical and forecast peak demand

This chapter presents analysis of trends in peak demand in the SWIS over the past 10 years and forecasts for the 2018-19 to 2027-28 outlook period. The chapter includes a reconciliation with AEMO's previous forecasts, particularly for the 2017-18 summer peak demand.

4.1 Historical peak demand

4.1.1 Summer 2017-18 peak demand

The 2017-18 summer peak demand was 3,616 MW and was observed in the 17:30 to 18:00 Trading Interval on 13 March 2018, the hottest day of the summer period. This was the second lowest peak demand since 2009.

The 2017-18 summer period was mild in WA compared to previous years. On average, February was around 1.4°C cooler than the long-term average, while January was 0.5°C cooler[78]. Historically the Perth metropolitan area has experienced at least four days above 40°C during summer, but none occurred during the 2017-18 summer period (the hottest day was 38.4°C). However, March was warmer than usual, by around 0.5°C on average.

The IRCR response was lower than in the past, and the effect of rooftop PV was less significant, as a result of the unusually late peak demand day. Section 4.1.4 and Section 4.1.5 describe these effects in more detail.

4.1.2 Historical summer peak demand

Peak demand has been around 3,700 MW (with the exception 2015-16) over the past seven years, as shown in Table 9.

Peak demand for the 2016–17 Capacity Year has been updated to 3,543 MW at 17:00 on 21 December 2016 from the value presented in the 2017 WEM ESOO, which reported 3,670 MW at 17:00 on 1 March 2017. Updated meter data has resulted in a change in the peak demand value and the day on which it occurred. This peak demand was the lowest summer peak observed in the SWIS since 2009.

Table 9 Comparison of peak demand days, 2011-12 to 2017-18 A

Date	Peak demand (MW)	Trading Interval commencing	Maximum temperature during Trading Interval B (°C)	Daily maximum temperature B (°C)
13 March 2018	3,616	17:30	36.2	38.4
21 December 2016	3,543	17:00	38.0	42.7
8 February 2016	4,004	17:30	41.0	42.6
5 January 2015	3,744	15:30	41.1	44.1
20 January 2014	3,702	17:30	36.9	38.5
12 February 2013	3,732	16:30	36.0	41.1
25 January 2012	3,857	16:30	39.1	39.9

A. Capacity Years. For example, the peak demand for the 2016-17 Capacity Year occurred on 21 December 2016.
B. Measured at the Perth Airport weather station (station identification number 9021).
Source: AEMO and BOM.

[78] Based on data from the Perth Airport weather station. Long term averages were calculated using data from 1980 to 2018.

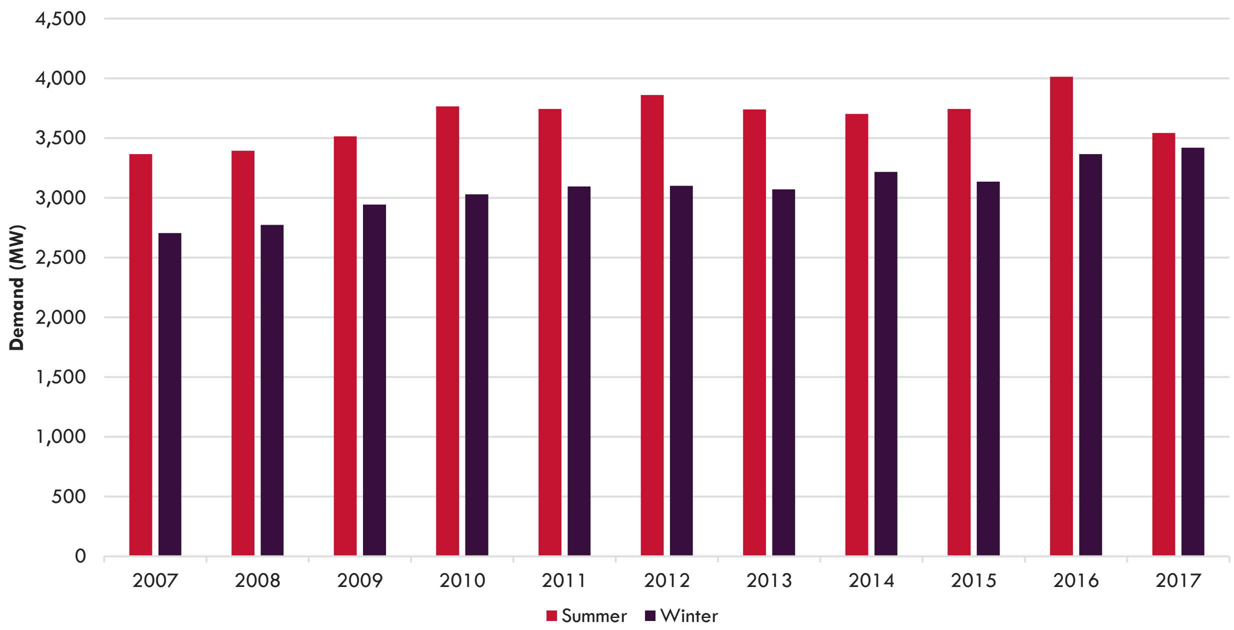
Before 2014, peak demand has typically occurred in the Trading Interval commencing at 16:30, but over the last four years it has shifted to a later time, to the Trading Intervals commencing at 17:00 or 17:30. This shift has largely been associated with the uptake of rooftop PV systems.

Peak demand is expected to continue to occur in the trading interval commencing 17:00 or 17:30 in the future. Strong uptake of battery systems may allow customers to use generation from rooftop PV systems for consumption during the evening. However, commercial load declines after 18:00, which may prevent peak demand from shifting later into the evening. Technologies that affect residential demand in the evening, such as EVs, are discussed in Chapter 3.

4.1.3 Difference between summer and winter peak demand

Summer and winter peak demand have shown different growth trends over the past 10 years (see Figure 18). In the past five years, winter peak demand has continued to grow while summer peak demand has fallen.

Figure 18 Summer and winter peak demand, 2007 to 2017 calendar years



Winter peak demand usually occurs in either June or July during the Trading Interval commencing at 18:00, and is lower than summer peak demand. Between 2007 and 2012, the winter peak was, on average, around 670 MW lower than the summer peak. However, over the past five years, winter peak demand grew at an average annual rate of 2.5%, while summer peak demand declined at an average annual rate of 1.3%. As a result, the difference between summer and winter peak demand has narrowed to around 400 MW (on average) over the past five years. However, it should be noted that year on year variations in the weather have a large influence on the actual values shown in Figure 18. For example, an unusually cold year will result in a higher winter peak demand and a lower summer peak demand.

The most recent winter peak demand was 3,419 MW and occurred in the Trading Interval commencing at 18:00 on 31 July 2017. This was the highest winter peak demand since market start in 2006 and compared to an all-time high summer peak demand of 4,004 MW on 8 February 2016. It was around 1.6% more than the previous year's winter peak of 3,366 MW, and only 124 MW lower than the 2016-17 summer peak demand. The last two winter peaks have been particularly high, likely due to colder-than-usual winter weather.

Rooftop PV has no effect on the winter peak demand, because the winter peak falls after sunset. In contrast, summer peak demand generally occurs when there is sufficient sunlight for rooftop PV systems to reduce demand from the electricity network. The strong uptake in rooftop PV since 2011 has largely contributed to the narrowing gap between summer and winter peak demand.

If growth in winter peak demand continues to outpace growth in summer peak demand the SWIS may see a winter peak that is higher than the summer peak, at some point in the next 10 years. However, it is anticipated that this would only occur if the SWIS experienced a particularly cold winter followed by a mild summer. The 10% POE summer peak demand is forecast to remain higher than the 10% POE winter peak demand throughout the forecast period. AEMO will continue to monitor this trend in future WEM ESOOs.

4.1.4 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[79].

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 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 to reduce their exposure to capacity payments.

The estimated reduction in peak demand associated with IRCR response since 2012 is shown in Table 10. There is no clear trend in the IRCR responses over the past seven years, with demand reductions varying from 41 MW to 77 MW and the number of customers responding between 20 and 59. The IRCR response on 13 March 2018 is the lowest to date at 41 MW, roughly the same as the IRCR response observed on 5 January 2015 (which was during a holiday period). The relatively low result for 2018 was largely due to the cooler than usual summer, which made predicting the timing of peak demand difficult for Market Customers.

Table 10 IRCR response on summer peak demand days, 2012 to 2018

Date	Daily peak demand (MW)	Time of peak demand	Estimated IRCR reduction (MW)	Number of customers responding
13 March 2018	3,616	17:30	41	36
21 December 2016 A	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

A. The estimated IRCR response for the 2016-17 peak demand has been recalculated to reflect updated demand data (see Section 4.1.2 for further information).

The average IRCR response on peak demand days over the past seven years is 54 MW, with the highest response to date being 77 MW on 8 February 2016. This relatively high response corresponded to a predictable peak demand, which occurred following a succession of hot days that were accurately forecast ahead of time by BOM. Other IRCR Trading Intervals have been harder for Market Customers to predict, as they occurred at various times including December and March, resulting in lower IRCR response rates.

Over the past three years, 100 unique customers have responded, indicating that the IRCR mechanism encourages electricity users to reduce demand at peak times. Out of those unique customers, only seven responded on all three peak demand days, demonstrating that it is difficult to predict the IRCR intervals, or that there are other factors which affect a customer's ability to reduce demand.

4.1.5 Effect of rooftop PV on peak demand

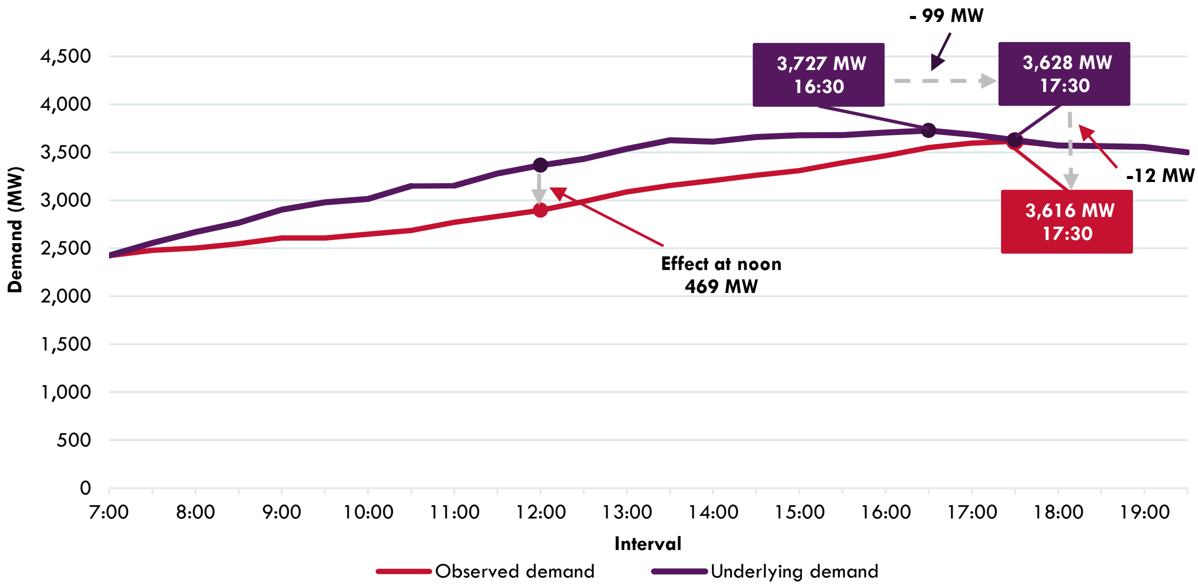
The effect of rooftop PV on peak demand depends on the month of day and the time of day when peak demand occurs, due to the output profile of a PV system which is highest at noon and falls during the afternoon.

In Figure 19, the actual demand profile on 13 March 2018 is compared to AEMO's estimate of the demand that would have occurred if no rooftop PV had been installed (underlying demand)[80]. Underlying peak demand is estimated as 3,727 MW at 16:30, 3.1% higher than the actual peak demand of 3,616 MW at 17:30 on 13 March 2018.

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

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

Figure 19 Daily daytime demand profile, observed and estimated without rooftop PV, 13 March 2018



The continued growth of rooftop PV installations has affected the level and timing of peak demand over the last seven years. Actual peak demand for each year in the past seven years is compared with the estimated underlying peak demand in Table 11.

Table 11 Effect of rooftop PV on peak demand, 2011-12 to 2017-18

Date	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)
13 March 2018	17:30	3,616	3,727	16:30	12	99
21 December 2016 A	17:00	3,543	3,767	15:00	153	71
8 February 2016	17:30	4,004	4,147	16:30	63	81
5 January 2015	15:30	3,744	3,902	14:30	136	22
20 January 2014	17:30	3,702	3,767	16:30	46	19
12 February 2013	16:30	3,739	3,806	14:00	55	12
25 January 2012	16:30	3,860	3,931	15:30	42	29

A. The estimated effect of rooftop PV for the 2016-17 peak demand has been recalculated to reflect updated demand data (see Section 4.1.2 for further information).

Rooftop PV reduced peak demand by 111 MW, due to a combination of the following factors:

- A shift in the timing of peak demand by one hour, from the Trading Interval starting at 16:30 to the Trading Interval starting at 17:30. Underlying demand was estimated to be 3,727 MW at 16:30 compared to 3,628 MW at 17:30. The shift of the peak to a later time reduced demand by 99 MW.
- Generation from rooftop PV during the 17:30 peak. This reduced peak demand by 12 MW from 3,628 MW to 3,616 MW.

Further information about how rooftop PV is expected to affect peak demand in the future can be found in Section 3.3.4.

4.2 Peak demand forecasts

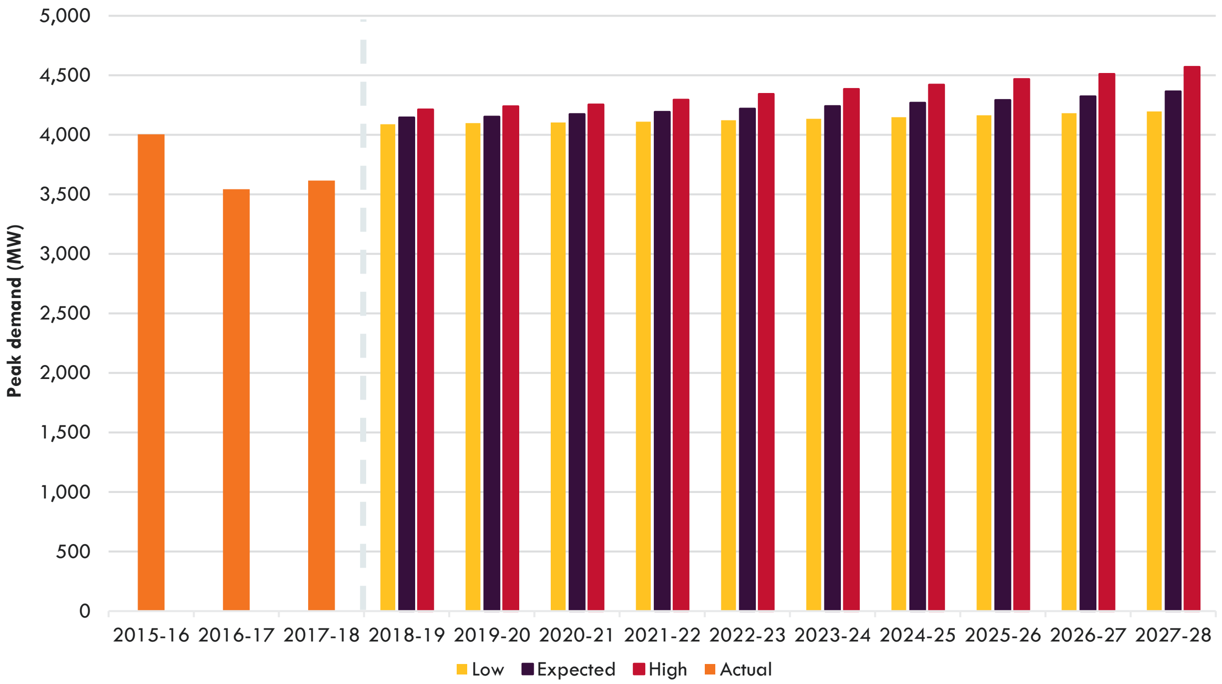
Over the 2018-19 to 2027-28 period, in the expected growth scenario:

- The 10% POE summer peak demand is forecast to grow from 4,146 MW in 2018-19 to 4,365 MW in 2027-28, an average annual rate of 0.6%.
- The 50% and 90% POE summer peak demand is forecast grow at an average annual rate of 0.6%.
- The 10%, 50%, and 90% POE winter peak demand is forecast to grow at an average annual rate of 1.1%.

The 10% POE peak demand forecasts under the three different demand scenarios are shown in Figure 20, with actual peak demand since 2015-16.

A full set of summer peak demand forecasts is presented in Appendix F, while winter peak demand forecasts can be found in Appendix G. Consistent with current demand patterns in the SWIS (see Section 4.1.3), winter peak demand is forecast to remain lower than summer peak demand for all scenarios over the forecast period, although the gap is reducing.

Figure 20 10% POE forecast peak demand under different growth scenarios, 2018-19 to 2027-28



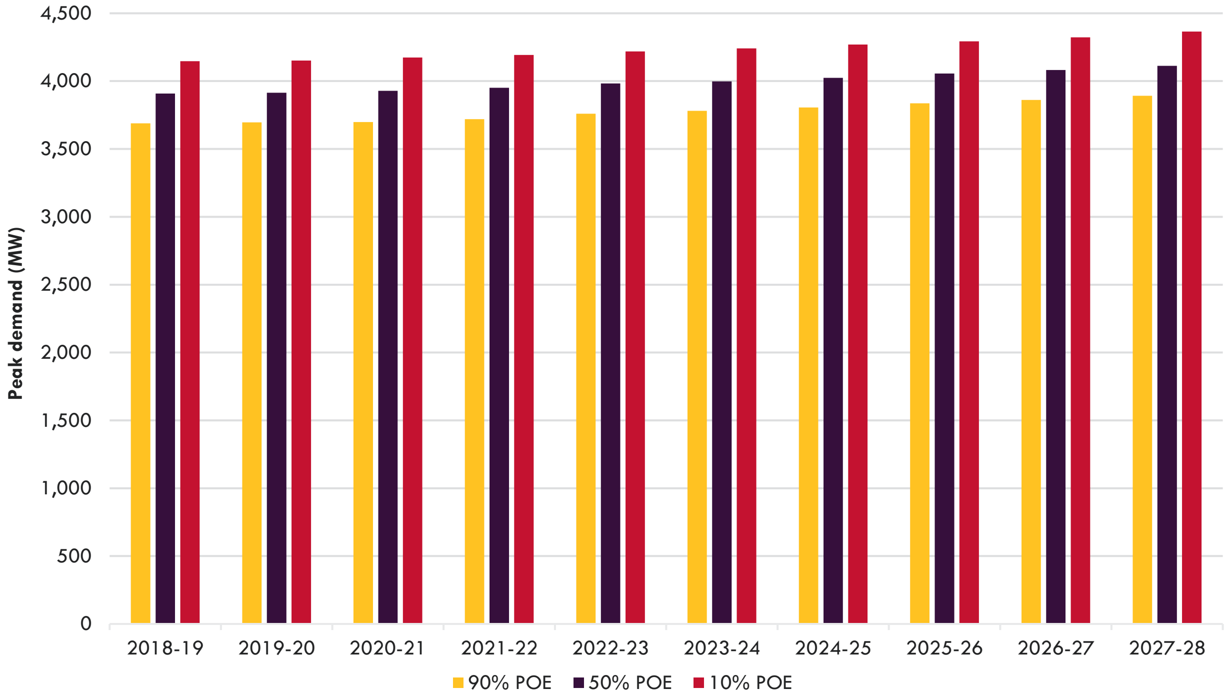
Source: AEMO and ACIL Allen.

The variation in growth rates between the low, expected, and high demand scenarios reflects different:

- Economic growth and population forecasts (see Section 3.3.1 and Section 3.3.2).
- Rooftop PV assumptions (see Section 3.3.4).
- Projected battery uptake rates (see Section 3.3.5).

The expected peak demand forecasts under different weather scenarios (10%, 50%, and 90% POE) are shown in Figure 21.

Figure 21 10%, 50%, and 90% POE peak demand forecasts under the expected demand growth scenario, 2018-19 to 2027-28



Source: ACIL Allen.

4.3 Reconciliation with previous forecasts

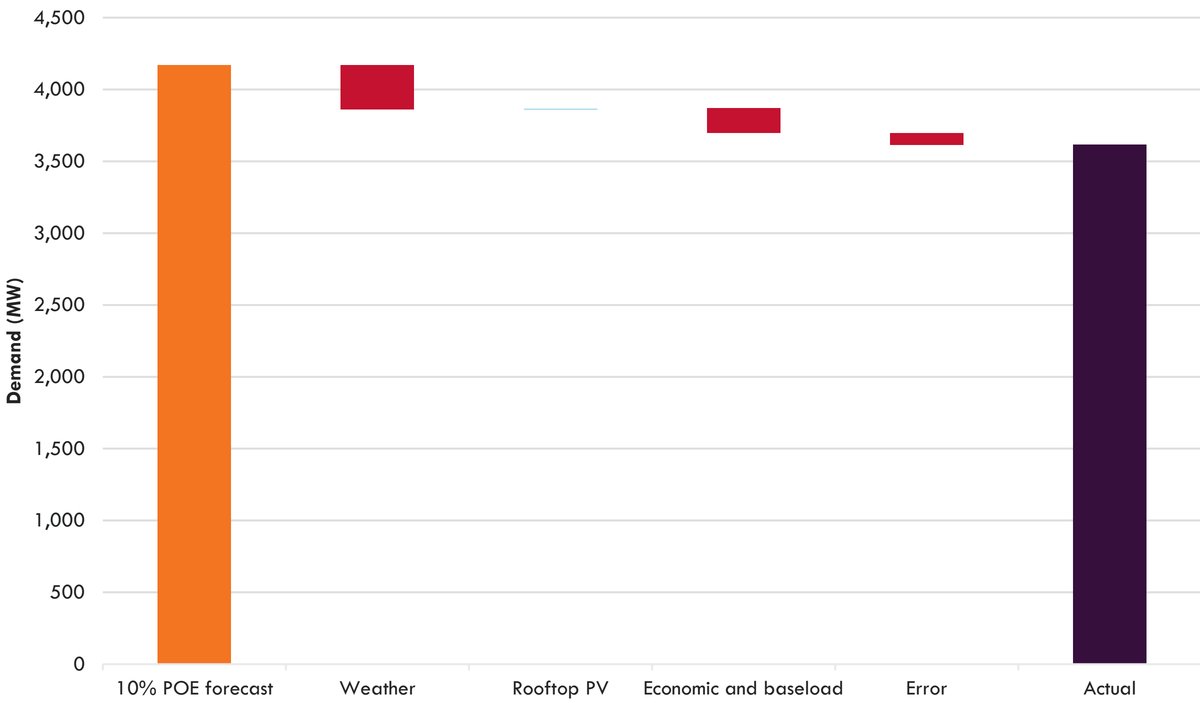
4.3.1 2017-18 reconciliation

The actual peak demand for 2017-18 was 3,616 MW, which was 553 MW lower than the 10% POE forecast published in the 2017 WEM ESOO. The main reasons for lower-than-expected peak demand were relatively mild weather and slower-than-forecast economic growth. The combined effect of these factors reduced peak demand by an estimated 480 MW (87% of the total variance).

The variance between the 2017-18 actual summer peak demand and the 2017-18 10% POE forecast from the 2017 WEM ESOO is shown in Figure 22. The variance can be broken down as follows:

- Weather effects (-309 MW) – the weather, particularly on the peak day and surrounding days, was milder than usual. ACIL Allen has estimated that the weather on the peak day was equivalent to about a 93% POE.
- Rooftop PV (9 MW) – the timing of peak demand (at 17:30 in March) resulted in a lower rooftop PV effect compared to an expected February peak, but this was more than offset by higher rooftop PV installations during 2017 (see Section 4.1.5 for further information).
- Economic and baseload effects (-171 MW) – economic growth was slower than forecast at around 0.3% compared to a forecast of 2.4%.
- Error (-82 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 (e.g. the model includes temperature, but humidity and rainfall may also contribute to peak demand). These sources of variance cannot be individually quantified and are captured by the error term.

Figure 22 Forecast reconciliation, 2017-18 peak demand



Source: ACIL Allen and AEMO.

4.3.2 Changes from previous forecasts

The summer peak demand forecasts presented in this 2018 WEM ESOO are lower than the forecasts published in the 2017 WEM ESOO, particularly towards the end of the outlook period, as shown in Table 12. The 10% POE expected scenario peak demand was forecast to grow at an average annual rate of 1.6% in the 2017 WEM ESOO, while peak demand growth has fallen to an average annual rate of 0.6% in this 2018 WEM ESOO.

Table 12 Difference between 10% POE expected scenario forecasts, 2017 WEM ESOO and this 2018 WEM ESOO

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
2017 WEM ESOO forecast (MW)	4,213	4,253	4,326	4,401	4,466	4,541	4,626	4,707	4,799
2018 WEM ESOO forecast (MW)	4,146	4,152	4,174	4,193	4,219	4,242	4,270	4,293	4,323
Difference (MW)	-66	-101	-151	-208	-247	-300	-356	-415	-476

Source: ACIL Allen.

There are a number of reasons for lower peak demand forecasts in this 2018 WEM ESOO compared to those published in the 2017 WEM ESOO, including:

- Changes to the specification of the forecasting model (see Section 3.2.2 and ACIL Allen's methodology report for more information).
- An increase in rooftop PV installed capacity forecasts, particularly in the earlier years of the forecast period. However, the effect of higher installation rates has been partially offset by lower capacity factors (see Section 3.3.4 for more information).
- Lower population and economic growth forecasts, largely due to updates to historical data obtained from the ABS (see Section 3.3.2 for more information).

5. Historical and forecast operational consumption

This chapter:

- Discusses historical operational consumption in the SWIS, including the key drivers of recent trends.
- Presents operational consumption forecasts for the 2018-19 to 2027-28 outlook period.
- Compares the operational consumption forecast with forecasts from previous WEM ESOOs.
- Reconciles actual operational consumption for 2017-18 with the forecast from the 2017 WEM ESOO.

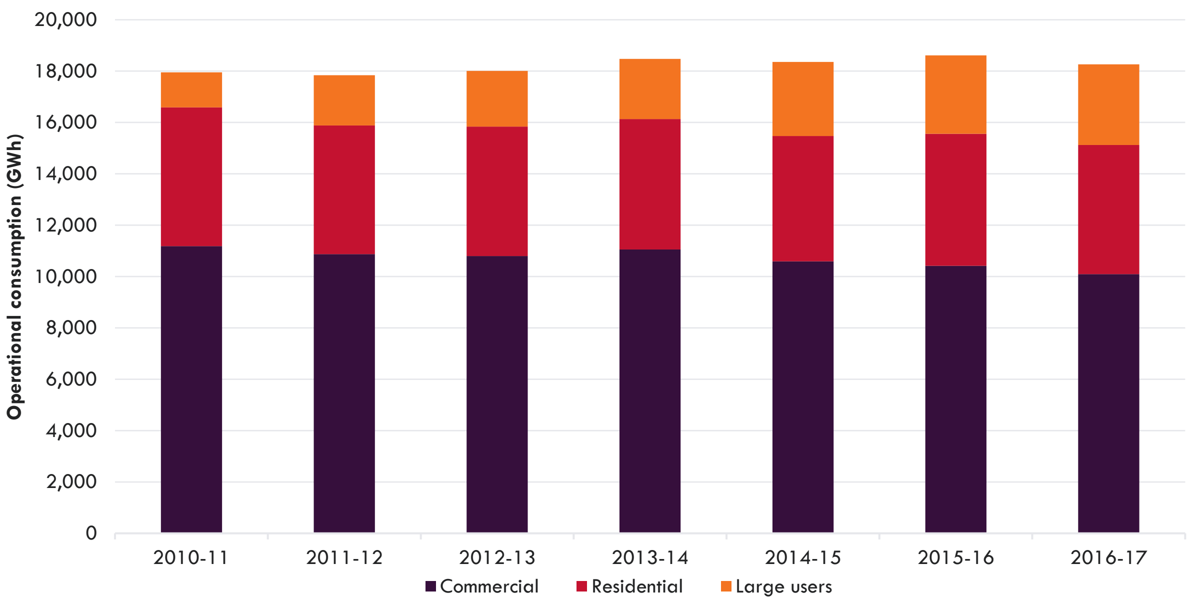
5.1 Historical operational consumption

A breakdown of total operational consumption in the SWIS between 2010-11 and 2016-17 is shown in Figure 23. Data in all charts and tables is from Synergy unless otherwise specified.

Total operational consumption has remained relatively consistent since 2013-14, increasing at an average annual rate of 0.3% since 2010-11. This can be attributed to:

- Commercial and residential consumption (which accounts for more than 80% of total SWIS electricity consumption) has fallen at an average annual rate of 1.7% and 1.2% respectively.
- Strong growth in consumption by large users (primarily desalination plants) at an average annual rate of 14.9% over the same period has offset the declines in commercial and residential consumption.

Figure 23 Total operational consumption in the SWIS, 2010-11 to 2016-17 financial years



Source: AEMO and ACIL Allen.

5.1.1 Residential

WA's population growth was historically correlated to changes in residential electricity consumption in the SWIS, but this no longer appears to be as directly the case.

Between 2007-08 and 2009-10, residential consumption grew at a rate roughly equal to population growth. However, between 2010-11 and 2016-17, average consumption per customer decreased at an average annual rate of 3%, and now increases in residential connections no longer automatically lead to a corresponding overall increase in electricity consumption as shown in Table 13.

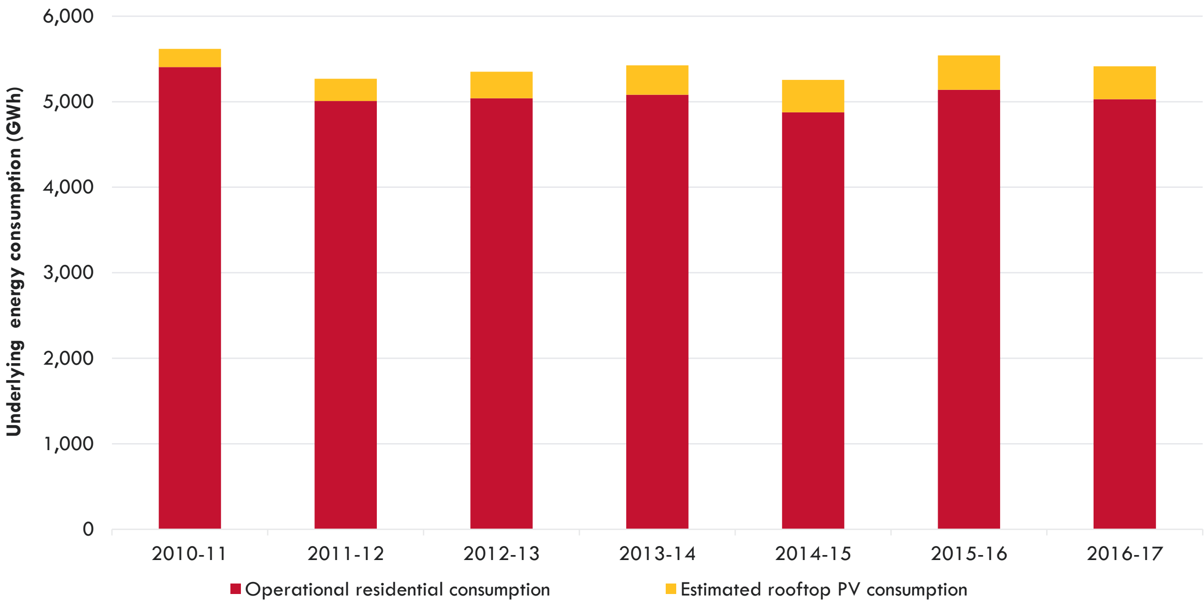
Table 13 Key statistics for residential customers, 2007-08 to 2016-17 financial years

Capacity Year	Total number of residential customers A	Growth in customer numbers (%)	Residential electricity sales (GWh)	Growth in sales (%)	Average annual consumption per residential customer (kWh)	Growth in consumption per residential customer (%)
2010-11	874,195	-	5,406	-	6,184	-
2011-12	894,210	2.3	5,008	-7.4	5,600	-9.4
2012-13	899,796	0.6	5,040	0.6	5,601	0.0
2013-14	910,116	1.1	5,081	0.8	5,583	-0.3
2014-15	940,379	3.3	4,875	-4.1	5,184	-7.1
2015-16	972,189	3.4	5,139	5.4	5,286	2.0
2016-17	988,015	1.6	5,030	-2.1	5,091	-3.7

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

AEMO's estimates of historical underlying residential consumption, representing the combination of electricity consumed from the grid and electricity self-generated from rooftop PV, are shown in Figure 24.

Figure 24 Underlying residential consumption in the SWIS, 2010-11 to 2016-17 financial years



Underlying consumption has remained relatively stable since 2010-11, decreasing at an average annual rate of 0.6% between 2010-11 and 2016-17. This can be attributed to improved housing efficiency, and energy efficient appliances (such as LED lighting and inverter reverse cycle air conditioning) replacing older, less efficient stock.

As Figure 24 shows, residential customers are generating some of their electricity needs on site, displacing consumption from the grid. Residential consumption from rooftop PV has increased at an annual average rate of 10.5% between

2010-11 and 2016-17. AEMO expects the trend of decreasing operational consumption to continue during the forecast period.

5.2 Operational consumption forecasts

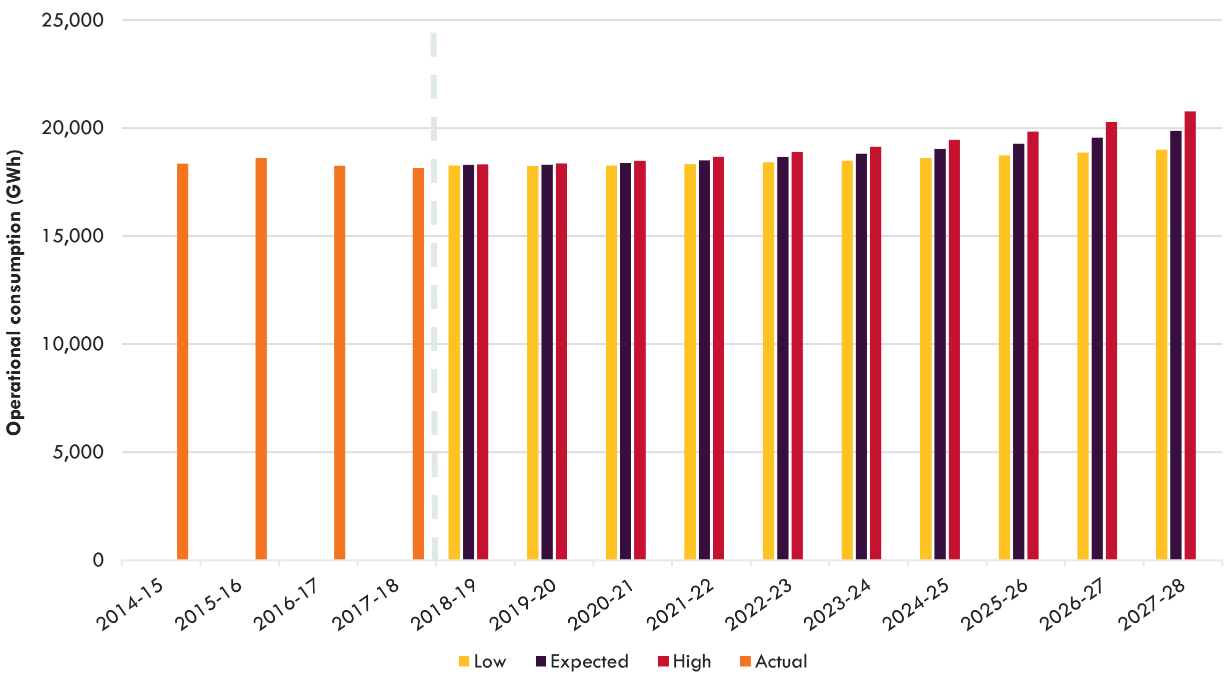
While residential consumption is forecast to remain stagnant, some growth in non-residential consumption (commercial and industrial) is anticipated. Non-residential consumption makes up a larger proportion of total consumption (approximately 75%) than residential consumption, so some growth in total operational consumption is still expected. This growth is driven primarily by forecast economic growth.

From 2018-19 to 2027-28[81], operational consumption is forecast to grow at an average annual rate of:

- 0.4% in the low growth scenario, from 18,271 GWh in 2018-19 to 19,002 GWh in 2027-28.
- 0.9% in the expected growth scenario, from 18,296 GWh in 2018-19 to 19,871 GWh in 2027-28.
- 1.4% in the high growth scenario, from 18,320 GWh in 2018-19 to 20,772 GWh in 2027-28.

The operational consumption forecasts for the low, expected and high demand growth scenarios are shown in Figure 25. The variation in growth rates reflects different economic growth forecasts. A full set of operational consumption forecasts is provided in Appendix H. Further information about the drivers of these forecasts can be found in Chapter 3.

Figure 25 Operational consumption forecasts under different growth scenarios, 2018-19 to 2027-28 financial years



Source: ACIL Allen.

5.3 Reconciliation with previous forecasts

5.3.1 2017-18 reconciliation

Actual operational consumption in 2017-18 is estimated as 18,153 GWh[82], which was 3.5% lower than the forecast published in the 2017 WEM ESOO (18,819 GWh). This variation can be attributed to:

- Economic effects (-533 GWh) – economic growth was slower than forecast, at around 2.1% compared to a forecast of 3.0%.

[81] Operational consumption is forecast in financial years.

[82] Based on actual metered data from AEMO's systems to March 2018 and estimates for April to June 2018.

- Weather effects (+110 GWh) – there were more cooling degree days[83] than predicted based on long-term averages, particularly in November and December 2017, resulting in higher than expected operational consumption.
- Rooftop PV (+138 GWh) – revised capacity factors have resulted in a lower estimate for rooftop PV generation compared to the forecast (for further information see Section 3.3.4).
- Error (-381 GWh) – 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 (e.g. the model includes temperature, but humidity and rainfall may also contribute to operational consumption). These sources of variance cannot be individually quantified and are captured by the error term.

5.3.2 Changes from previous forecasts

Operational consumption forecasts have remained consistent since 2015. Operational consumption is forecast to grow at an average annual rate of 0.9% across the 10-year outlook period under the expected growth scenario, a small decrease from the growth rate of 1.2% forecast in the 2017 WEM ESOO.

This small change can be attributed to a decrease in residential consumption forecasts compared to the 2017 WEM ESOO forecasts. For the first time, AEMO is forecasting average negative growth in residential consumption across the 10-year outlook period. Changes to residential consumption forecasts are supported by the trend of declining residential consumption over the past seven years (see Section 5.1.1 for further information), even when the growth in operational consumption from EVs over the outlook period is included (see Section 3.3.6 for further information).

[83] Summer in 2017-18 experienced less high temperature days, however, the average temperatures more frequently exceeded 18 Degrees Celsius, which resulted in more cooling degree days. For detailed information, refer to ACIL Allen's Methodology Report, available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

6. Reserve Capacity Target

This chapter discusses future opportunities for investing in capacity in the SWIS, and sets the RCT for each year of the Long Term PASA Study Horizon from the 2018-19 to 2027-28 Capacity Years. The RCT determined for the 2020-21 Capacity Year sets the RCR[84] for the 2018 Reserve Capacity Cycle.

The RCR for the 2018 Reserve Capacity Cycle is 4,581 MW, and no capacity shortfall is anticipated across the Long Term PASA Study Horizon.

6.1 Overview

The RCT is AEMO's estimate of the total amount of generation or DSM capacity required in the SWIS to satisfy part (a) (annual forecast peak demand) and part (b) (annual EUE) of the Planning Criterion[85] for a Capacity Year. The RCT is set for each Capacity Year of a 10-year Long Term PASA Study Horizon.

To date, the RCT has been set by annual forecast peak demand (part (a) of the Planning Criterion) due to sufficiently high levels of plant availability. This remains the case for the 2018 Reserve Capacity Cycle.

Between 2018-19 and 2026-27 in the Long Term PASA Study Horizon, the capacity of the largest generating unit, NewGen Neerabup (331 MW)[86], measured at 41°C, has set the level of reserve margin, being greater than 7.6% of the forecast peak demand. For the 2027-28 Capacity Year, the reserve margin is set by 7.6% of the forecast peak demand, due to an increase in forecast peak demand over the Long Term PASA Study Horizon.

The quantity of load following ancillary service (LFAS)[87] capacity required for maintaining system frequency is forecast to be 72 MW for the 2018 Reserve Capacity Cycle.

The RCT for each year in the Long Term PASA Study Horizon is outlined in Section 6.2.

6.2 Forecast capacity requirements

The RCT for each Capacity Year of the Long Term PASA Study Horizon, set by annual forecast peak demand, is shown in Table 14.

The RCT determined for the 2020-21 Capacity Year is 4,581 MW. This is lower than the forecast 2020-21 RCT (4,733 MW) published in the 2017 WEM ESOO, as a result of lower peak demand forecasts. This sets the RCR for the 2018 Reserve Capacity Cycle.

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84 The RCR determines the quantity of Capacity Credits required to be procured through the RCM for the relevant Reserve Capacity Cycle.

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

86 Based on the level of Capacity Credits assigned for the 2019–20 Capacity Year.

87 LFAS is a type of ancillary service that is used to continuously balance supply and demand, so that the SWIS operates within the normal frequency bands specified in the Technical Rules (49.8 to 50.2 hertz) for 99% of the time. See https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Security-and-reliability/Ancillary-services.

Table 14 Reserve Capacity Targets A

Capacity Year	Peak demand (MW)	Intermittent Loads (MW) C	Reserve margin (MW)	Load following (MW)	Total (MW)
2018-19 B	4,146	4	331	72	4,553
2019-20 B	4,152	4	331	72	4,559
2020-21	4,174	4	331	72	4,581
2021-22	4,193	4	331	72	4,600
2022-23	4,219	4	331	72	4,626
2023-24	4,242	4	331	72	4,649
2024-25	4,270	4	331	72	4,677
2025-26	4,293	4	331	72	4,700
2026-27	4,323	4	331	72	4,730
2027-28	4,365	4	332	72	4,773

A. All figures have been rounded to the nearest integer.
B. Figures have been updated to reflect the current forecasts. However, the RCRs set in the 2017 WEM ESOO for the 2016 and 2017 Reserve Capacity Cycles do not change (4,620 MW for 2018-19 and 4,660 MW for 2019-20).
C. Intermittent Loads have been accounted for as required by clause 4.5.2A of the WEM Rules.

6.3 Availability Curves

Capacity in the SWIS is assigned one of two Availability Classes[88], defined as follows:

- Availability Class 1 relates to all generation capacity, and any other capacity[89] that is expected to be available to be dispatched for all trading intervals in a Capacity Year, allowing for outages or other specified restrictions on availability.
- Availability Class 2 relates to capacity that is not expected to be available to be dispatched for all trading intervals in a Capacity Year.

Capacity from Availability Class 1 can be used to meet the requirement for Availability Class 2.

Assuming that the RCT is just met, the Availability Curve indicates the minimum amount of capacity that must be provided by generation and other capacity that is expected to be available for dispatch, to ensure that the energy requirements of consumers are met. The Availability Curves for the 2019-20, and 2020-21 Capacity Years are shown in Table 15.

Table 15 Availability Curves

	2019-20 (MW)	2020-21 (MW)
Capacity associated with Availability Class 1	3,919 A	3,946
Capacity associated with Availability Class 2	640 A	635

A. Figures have been updated to reflect the current forecasts. However, the 2019-20 Availability Curve set in the 2017 WEM ESOO for the 2017 Reserve Capacity Cycle has not changed.
Source: RBP.

The Availability Class 1 capacity set for the 2019-20 Capacity Year, as outlined in Table 15, is higher than the 2019-20 value published in the 2017 WEM ESOO (3,823 MW), and the Availability Class 2 capacity is lower (837 MW). These changes are due to:

- A number of concurrent planned generator outages in the lower demand shoulder months (October/November), as submitted by Market Participants in their responses to AEMO's Long Term PASA information request for this 2018 WEM ESOO. These outages increase the minimum amount of Availability Class 1 capacity required to avoid unserved energy in the reliability model for the 2019-20 Capacity Year.

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

[89] Examples are Interruptible Loads, Demand Side Programmes and Dispatchable Loads.

- Greater levels of solar generation ramping down during evening hours compared to previous years.

The 2017 WEM ESOO set the Availability Class requirements for the 2019-20 Capacity Year, so Availability Class 1 and Availability Class 2 capacity required for the 2017 Reserve Capacity Cycle will remain as 3,823 MW and 837 MW respectively, as required by the WEM Rules.

A more detailed explanation and graphs of the capacity requirements are provided in Appendix A and the associated methodology report[90].

When assigning Capacity Credits, the WEM Rules do not limit the amount of Capacity Credits assigned to any Availability Class where the Market Participant nominates an intention to bilaterally trade capacity.

6.4 DSM Reserve Capacity Price

AEMO is required to calculate the Expected DSM Dispatch Quantity (EDDQ) and the DSM Activation Price in accordance with a Market Procedure[91]. 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 all DSM RCP parameters is provided in Appendix B.

The DSM RCP for the 2018-19 Capacity Year is $23,631.25/MW. The EDDQ and the DSM Activation Price for the 2018-19 Capacity Year are 0.2063/MWh and $33,460/MWh respectively. AEMO has assigned 57.426 MW of DSM Capacity Credits under Availability Class 2 for the 2018-19 Capacity Year.

After the 2018-19 Capacity Year, AEMO has assumed a quantity of DSM Capacity Credits of 66 MW[92] and the DSM Activation Price remains unchanged throughout the forecast period to estimate the expected DSM RCP in Table 16. As required by the WEM Rules, 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 year.

Table 16 Expected DSM dispatch and DSM RCP, 2018-19 to 2027-28

Capacity Year	Expected DSM Dispatch Quantity (MWh)	DSM RCP ($/MW)
2018-19	0.2063	$23,631.25
2019-20	0.0144	$17,210.81
2020-21	0.0000	$16,730.00
2021-22	0.0114	$17,110.62
2022-23	0.0350	$17,902.16
2023-24	0.0079	$16,995.78
2024-25	0.0205	$17,417.10
2025-26	0.0017	$16,786.08
2026-27	0.0005	$16,747.30
2027-28	0.0174	$17,312.38

The DSM RCP is expected to remain relatively consistent over the outlook period. The DSM RCP for the 2018-19 Capacity Year is higher. This is due to a higher EDDQ forecast in 2018-19, based on a conservative assumption that several Facilities will have concurrent major planned outages in this Capacity Year.

The reason for this conservative assumption is that AEMO is unable to assess the probability of concurrent major planned outages being approved at a future time, as this will depend on a number of significant factors (such as forced outages, weather and system security) when the outages are proposed to be taken. For this reason, all outage

[90] RBP, 2018. *Assessment of System Reliability And Development Of The Availability Curve For The South West Interconnect System*. Available at https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

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

[92] Based on information provided by Market Participants.

information provided by Market Participants has been included in the EDDQ calculation. The inclusion of major planned outages increases the EDDQ, due to the increase in the forecast level of unserved energy.

The EDDQ estimates from the 2019-20 Capacity Year to the end of the Long Term PASA Study Horizon will be updated in the 2019 WEM ESOO. At that time, AEMO will reassess all outage information, including historical information, to forecast outages in the outer years of the forecast, and request new information from Market Participants.

6.5 Opportunities for investment

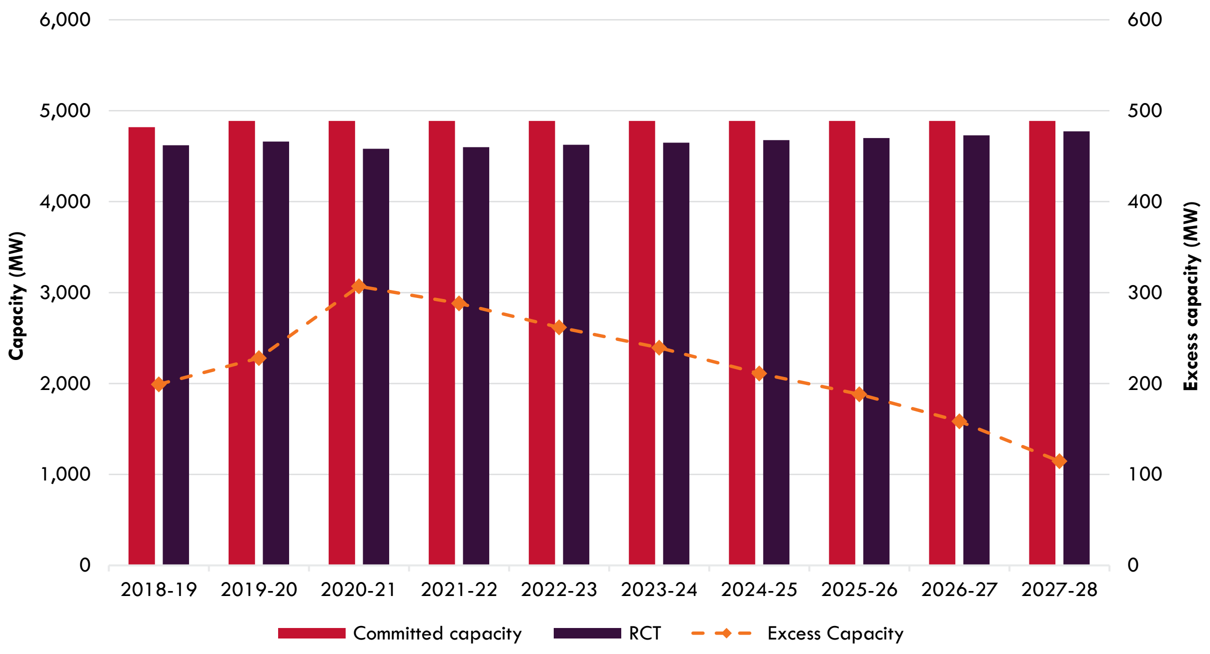
6.5.1 Supply-demand balance

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

- The SWIS generation capacity for the 2019-20 Capacity Year is the baseline, and no additional generation is retired from the generation capacity of the 2019-20 Capacity Year over the Long Term PASA Study Horizon (see Appendix J for detailed information).
- The total quantity of DSM capacity for the Long Term PASA Study Horizon will remain unchanged at 66 MW from the 2019-20 Capacity Year.
- No new committed[93] capacity will commence operation over the Long Term PASA Study Horizon, other than new Facilities that were assigned Capacity Credits for the 2018-19 and 2019-20 Capacity Years.
- No new probable projects[94] are assumed over the Long Term PASA Study Horizon.

The expected supply-demand balance between the 2018-19 and 2027-28 Capacity Years is shown in Figure 26. This compares the RCT with the expected level of capacity for each Capacity Year of the Long Term PASA Study Horizon. It is assumed that the expected level of capacity will remain consistent with the total number of Capacity Credits assigned for the 2019-20 Capacity Year. The supply-demand balance for the high and low demand growth scenarios can be found in Appendix C.

Figure 26 Supply-demand balance excluding 2018 Expressions of Interest (EOI) submissions, 2018-19 to 2027-28 [A,B]



A. 2018-19, 2019-20, and 2020-21 RCT values are final values based on this year's and previous year's ESOOs, the remainder are forecasts and subject to change.
B. 2018-19 and 2019-20 committed capacity credit values are actuals, based on previous Reserve Capacity Cycles, the remainder are forecasts and subject to change.

[93] Committed projects refer to Facilities that are yet to enter service, but have already received Capacity Credits for a previous Reserve Capacity Cycle, as outlined in clause 2.10.4 of the Market Procedure: Undertaking the Long Term PASA and Conducting a Review of the Planning Criterion.

[94] Probable projects refer to Facilities that have not received Capacity Credits for a previous Reserve Capacity Cycle, but have been granted CRC 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.

Installed and committed capacity is expected to be sufficient to meet the RCT throughout the Long Term PASA Study Horizon, provided there are no further generation or DSM capacity retirements, long-term outages, or further changes to the WEM Rules[95].

No localised supply restrictions within SWIS subregions are anticipated, because the SWIS is currently operated as an unconstrained network.

A more detailed capacity outlook for the 2018-19 to 2020-21 Capacity Years is outlined in Table 17.

Total capacity[96] is expected to increase between the 2018-19 and 2019-20 Capacity Years, primarily due to 65 MW of non-scheduled generation capacity entering the market.

Excess capacity is expected to increase for the 2020-21 Capacity Year compared to the 2019-20 Capacity Year, due to a decrease in the calculated RCT (see Section 6.2). From the 2021-22 Capacity Year, excess capacity is expected to decrease due to peak demand growth. However, some level of excess capacity is forecast to remain through to the 2027-28 Capacity Year.

Table 17 Capacity outlook in the SWIS, 2018-19 to 2020-21 Capacity Years [A]

Capacity category	2018-19 (MW)	2019-20 (MW)	2020-21 (MW)
Existing generating capacity	4,746	4,757	4,822 [B]
Existing DSM capacity	57	66	66 [B]
Committed new projects [C]	16	65	0 [B]
Probable new projects	0	0	0 [B]
Total capacity	4,819	4,888	4,888 [B]
RCT	4,620	4,660	4,581
Excess capacity	199 (4.3%)	228 (4.9%)	307 (6.7%) [B]

A. All capacity values are in terms of Capacity Credits assigned, and are rounded to the nearest integer.
B. Forecast outlook values are based on the supply-demand balance assumptions detailed above.
C. Committed new projects include upgrades which roll into existing generation capacity after the first year. Variations are due to year-on-year changes to Non-Scheduled Generation Capacity Credits due to the Relevant Level methodology.

Circumstances may change over the forecast period. In particular, the quantity of capacity offered may be affected by changes to the WEM Rules implemented under the WA government's electricity industry reform program (see Section 7.1 for more information)[97], and by new projects that are not currently included in the capacity outlook. Project proponents, investors, and developers will need to make their own independent assessments of future possible supply and demand conditions.

AEMO does not include capacity offered through EOI submissions in the expected supply-demand balance, because EOIs do not necessarily include all future proposed projects, and only a few proposed projects normally progress through the capacity certification process (see Section 6.5.2 for more information).

6.5.2 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 for the 2018 Reserve Capacity Cycle closed on 1 May 2018. One intermittent generation project with a total nameplate capacity of 9.9 MW was proposed for the 2020-21 Capacity Year[98].

While the EOI process provides an indication of potential future capacity, an EOI submission does not necessarily lead to CRC. This is because intermittent generators are generally assigned a lower level of CRC than their nameplate capacity due to the operation of the Relevant Level Methodology, and some Facilities that participate in the EOI process may not be assigned CRC. Alternatively, as the EOI process is voluntary, some projects that do not participate in the EOI process may be assigned CRC.

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95 The quantity of capacity assigned to Non-Scheduled Generators is determined in accordance with the Relevant Level Methodology as outlined in Appendix 9 of the WEM Rules. The methodology is currently under review by the ERA, due to be completed by December 2018. Any amendments or changes to the Relevant Level Methodology as a result of the ERA's review may change assumptions regarding the quantity of capacity assigned to existing and committed Non-Scheduled Generators over the study horizon.

96 In terms of Capacity Credits assigned.

97 For further information, see *Improving Reserve Capacity pricing signals – alternative capacity pricing options* and *improving access to Western Power's network – Implementing Constrained Access*, available at http://www.treasury.wa.gov.au/Public-Utilities-Office/Open-Consultations-Reviews/.

98 2018 Expressions of Interest Summary Report, available at https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Expressions-of-interest.

A historical comparison of the quantity of nameplate capacity offered under the EOI process, compared with the amount of EOI capacity that was eventually certified and the total other new capacity certified, is shown in Table 18.

Table 18 Capacity offered through the EOI compared to capacity certified, 2014-15 to 2019-20

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Capacity offered (MW) A	214	59	56	0	42	323	10
Capacity offered and certified (MW)	0	0.4	0	0	0	65	N/A
Total other new capacity certified (MW)	31	35	18	12	16	0	N/A

A. Nameplate capacity.

7. Current market issues

This chapter discusses the key issues affecting electricity markets in Australia and, more specifically, the WEM, including:

- The WA Government's electricity industry reform.
- Upcoming reviews of various processes and calculations in the WEM Rules.
- Federal government policy concerning reliability guarantees, emissions targets, and renewable energy.
- Infrastructure developments in the SWIS, focussing on Western Power's current network access regime.

7.1 WA Government's electricity industry reform program

In August 2017, the Minister for Energy announced an electricity industry reform program to be completed by the Public Utilities Office (PUO). There are three key elements of the reform program:

1. Moving to a constrained network model for access to Western Power's network, which will require the implementation of security-constrained market and dispatch arrangements, and changes to the consideration of network congestion in the RCM.
2. Reviewing Reserve Capacity pricing arrangements.
3. Implementing a light-handed regulatory regime in the Pilbara to facilitate third-party access to Horizon Power's network and implementing an independent system operator.

Security-constrained economic dispatch is expected to commence in 2022. The PUO intends to have the required amendments to the WEM Rules in place to allow the first Reserve Capacity Cycle under the constrained access model to be run in 2020.

The Minister for Energy has stated that an auction mechanism to determine the RCP will not be introduced before 2021, pending the outcome of the current review. The PUO is preparing advice to the Minister for Energy on whether a capacity auction or some alternative mechanism is more suitable for the WEM. This advice is expected to be provided in September 2018.

Modelling is currently being completed to estimate the effect of introducing constrained access on existing generators[99].

Further information about the electricity industry reform program, including proposed timeframes, can be found on the PUO's website[100].

7.2 Upcoming WEM reviews

The Economic Regulation Authority (ERA) is required to complete a number of five-yearly reviews of methods that underlie various processes and calculations in the WEM Rules. Currently, the ERA plans to conduct the methodology reviews in the following order. However, the order and proposed timing may change.

- Relevant Level Methodology (for assigning CRC to intermittent generators) – by 1 April 2019.
- Benchmark Reserve Capacity Price Market Procedure and Energy Price Limits – by mid to late 2019.
- Planning Criterion and peak demand forecasting – by early 2020.
- Outage planning process and ancillary service requirements – by late 2020 or early 2021.

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99 See https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Open_consultations_reviews/Industry-Forum%20-Presentation-Constrained-Access-Modelling-13-March-2018.pdf.

100 See https://www.treasury.wa.gov.au/Public-Utilities-Office/Industry-reform/Electricity-Sector-Reform-Initiatives/.

Under the WEM Rules, the ERA is required to consult with Market Participants when undertaking these reviews. Further information is expected to be made available on the ERA's website at the appropriate time[101].

7.3 Federal government policy

Federal government energy policy affecting the WEM largely revolves around emissions and renewable energy. This section summarises the current policy settings.

7.3.1 National Energy Guarantee

The National Energy Guarantee (NEG) is currently being developed by the Energy Security Board (ESB) and is intended to help Australia meet its emissions targets while maintaining power system security and reliability. The NEG consists of two key components:

- Reliability guarantee – obligations on retailers and large users to meet a specified proportion (through forward contracts) of their aggregate load with flexible and dispatchable resources.
- Emissions guarantee – retailers and large users would be required to meet their aggregate load at a specified average emissions level.

The NEG is focused on the National Electricity Market (NEM), and at this stage there has not been any announcement on how it may be applied in the WEM, where the RCM already achieves a similar outcome to the reliability component of the NEG. Further information on the NEG and the ESB's work can be found on the Council of Australian Governments Energy Council website[102].

7.3.2 Emissions reduction

Australia has committed to reducing its emissions by between 26% and 28% before 2030 (relative to 2005 levels) as part of its obligations to keep global temperature increases to below 2°C. This is a national target, with no specific obligations on individual states to meet a specified proportion. Most of the emissions reductions to date have been achieved through vegetation, landfill gas and waste management, and agriculture, although the retirement of coal-fired electricity generation capacity in the NEM (such as Victoria's Hazelwood Power Station, in March 2017) has contributed towards emissions reductions.

In December 2017, the Commonwealth Government's Department of the Environment and Energy released a review of Australia's climate change policies[103]. Key elements of climate change policy related to the electricity industry include:

- The NEG (see Section 7.3.1).
- The Safeguard Mechanism, which imposes a sector-wide limit (called baselines) on grid-connected electricity generators that emit more than 100,000 tonnes of emissions per year. The baselines are set by the CER and are currently based on past activity between 2009-10 and 2013-14. The operation of the Safeguard Mechanism and relevant baselines is being reviewed[104].

The electricity industry accounts for more than half of Australia's total emissions (in tonnes of carbon dioxide equivalent). In the SWIS, electricity generators emitted 13.6 million tonnes of carbon dioxide in the 2016-17 financial year, in line with the previous year[105]. However, Synergy's retirement of 380 MW of coal- and gas-fired generation capacity in 2017 and 2018, combined with ongoing rooftop PV installations and grid-scale renewable projects, is expected to contribute to meeting emissions reductions targets.

7.3.3 Renewable energy

The Large-scale Renewable Energy Target (LRET) is a national target for renewable generation to reach 33,000 GWh (an estimated 23.5%) of Australia's forecast electricity generation in 2020[106]. The current LRET is expected to be met in 2020, and to continue until 2030, when payments to eligible generators will cease.

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

[102] See http://www.coagenergycouncil.gov.au/publications/energy-security-board-update.

[103] Commonwealth of Australia, *2017 Review of Climate Change Policies*, available at http://www.environment.gov.au/system/files/resources/18690271-59ac-43c8-aee1-92d930141f54/files/2017-review-of-climate-change-policies.pdf.

[104] In February 2018, the Department of the Environment and Energy released a consultation paper on the Safeguard Mechanism. Further information is available at http://www.environment.gov.au/climate-change/government/emissions-reduction-fund.

[105] Based on National Greenhouse and Energy Reporting data from the Clean Energy Regulator. Available at http://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/electricity-sector-emissions-and-generation-data.

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

In addition to the LRET, the Commonwealth Government maintains the Clean Energy Finance Corporation, the Australian Renewable Energy Agency, and the Clean Energy Innovation Fund, to encourage development of renewable energy projects.

For the 2019-20 Capacity Year, 98.770 MW[107] (280 MW nameplate capacity) of new renewable energy capacity has been assigned Capacity Credits, including:

- APA Group's 20 MW solar expansion to the existing Emu Downs wind Facility (total of 30.079 MW of Capacity Credits for the combined Facility).
- Alinta Sales' 130 MW nameplate capacity Badgingarra wind Facility (35.625 MW of Capacity Credits).
- Carnegie Clean Energy's 10 MW nameplate capacity Northam solar Facility (3.749 MW of Capacity Credits).
- Merredin Solar Farm Nominee's 120 MW nameplate capacity Merredin solar Facility (29.317 MW of Capacity Credits).

These projects are expected to contribute to meeting the LRET and reduce emissions in the WEM.

7.4 Changes to power system supply

7.4.1 Behind-the-meter resources

AEMO forecasts continuing strong growth in the installed capacity of rooftop PV and battery storage in the SWIS (see Section 3.3.4 and Section 3.3.5). While the WEM ESOO focuses on demand and energy forecasts, taking into account the effect of distributed energy resources (DER) such as rooftop PV and battery storage, increasing levels of behind-the-meter resources (on consumers' premises) will affect power system security. At the same time, DER offers opportunities for consumers and may be used, subject to sufficient incentives, to improve power system security, reliability, and wholesale market outcomes.

The WA Parliament's Economics and Industry Standing Committee (EISC) is undertaking an inquiry[108] into the potential for MicroGrids and associated technologies to contribute to supplying affordable, secure, reliable, and sustainable energy in metropolitan and regional WA. In particular, the EISC is examining how to maximise economic and employment opportunities associated with the development of MicroGrids and related technologies, and will review similar initiatives in other jurisdictions. The inquiry will focus on key enablers, barriers, and other factors affecting MicroGrids development and electricity network operations.

AEMO's written submission to the inquiry and evidence transcript can be found on the EISC's website[109]. In summary, the key points of AEMO's submission are:

- The energy industry is undergoing a rapid transformation and MicroGrids and DER will play a key role. While the growth of DER is increasingly challenging the secure operation of the power system and the efficient operation of the existing market, DER offers opportunities to supply economically efficient, secure, and reliable electricity to all consumers.
- MicroGrids offer a range of potential benefits for consumers, network and system operators, and new businesses in emerging markets.
- Consumers can reduce power usage from the grid, enabling them to be less reliant on the grid and contribute to emissions reduction, while reducing electricity bills.
  - For network operators, DER can provide load control to reduce the need to expand or replace network assets, ultimately reducing network costs which are savings that can be passed on to all consumers.
  - For system operators, DER can be used to reduce peak demand and provision of essential system services such as frequency control.
- At the individual level, the impacts of DER are relatively small, but in combination they can be significant, especially if not coordinated. The power system is shifting from an operating mode of supply following load, to one of flexible demand following more variable supply. This could impact system security and result in inefficiencies in existing market constructs due to:
  - Greater forecast inaccuracy.
  - Increased ramping and cycling of generators to offset rooftop PV.
  - Less energy being supplied by traditional generators, resulting in less synchronous generation online that provides a range of essential system services almost as a by-product.

[107] Based on Capacity Credits assigned for the 2019-20 Capacity Year. Emu Downs solar and Northam solar were initially assigned Capacity Credits for the 2018-19 Capacity Year.

[108] See http://www.parliament.wa.gov.au/parliament/commit.nsf/($all)/8C9FB0B8AA10E88D4825823B0019BAA3.

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

– Excess online generation.

- Changes to regulations, market constructs and technical arrangements are required to realise these DER opportunities and resolve these challenges.

7.4.2 Large-scale supply

As outlined in Chapters 2 and 6, all new grid-scale generation in the SWIS in recent years has been intermittent generation and all retirements have been Scheduled Generators. This trend is likely to continue, at least during the near term.

This changing generation mix is modifying the operation of the power system, because intermittent generators have different characteristics to Scheduled Generators. AEMO has already modified its operations and continues to investigate related challenges and opportunities to facilitate this changing generation mix.

Changes are likely to be needed to market constructs to realise the benefits of these new technologies while keeping the power system secure and reliable and electricity markets efficient. The PUO's generation mix modelling[110] and the WA Government's electricity market reform program will assist in considering the key changes required in the short to medium term.

7.5 Infrastructure developments in the SWIS

7.5.1 Western Power's Applications and Queuing Policy (AQP)

Western Power's AQP sets out how connection applications and access offers are managed. It is designed to manage applications in an orderly, transparent, and fair way, especially in areas 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. These milestones allow customers to review their connection requirements and grid integration requirements, and to monitor project costs as they mature to make informed decisions on how to progress.

As well as understanding the AQP, potential generators and loads need to be aware of their obligations under the Technical Rules[111] governing connection to Western Power's network. More information on the connection process and AQP can be found on Western Power's website[112].

7.5.2 Transmission network current state and future strategy

Western Power's 2017 Annual Planning Report (APR)[113] describes the network configuration and available capacity to support new generation and load connections. In cases where network capacity is limited at the nominated connection location, there may be additional requirements for network augmentation or mitigation measures such as curtailment under certain conditions, or a need to procure Network Control Service (NCS) (such as generator services).

To date, from AEMO's perspective, the development of the Western Power network appears to have been managed prudently to minimise the construction of new lines, terminals, substations, and circuits, in order to reduce capital costs.

Much of the existing ageing asset base is either approaching the end of its design life or has already exceeded it. The objective of network planning is to develop a highly-efficient electricity network that presents the optimal balance between performance and cost, over a reasonable period. One of the key requirements for meeting this objective is improving load sharing among existing 330 kilovolt (kV) and 132 kV assets to relieve congestion at the 132 kV level, particularly through increased utilisation of 330 kV infrastructure.

Given the deferral of the proposed constrained network access reforms, Western Power has been working with AEMO and the PUO to develop the Generator Interim Access (GIA) arrangement, which will support a limited number of new connections before the implementation of constrained access. The objectives of the GIA arrangement are to:

- Curtail only new generators to maintain system security (that is, not affect the contracted unconstrained access of existing generators).
- Have a dispatch objective consistent with that proposed under the WA Government's reforms (a proxy for least-cost dispatch using a 'minimise-runback' approach based on contribution to network constraint (or coefficient)).

In June 2017, the Minister for Energy gazetted[114] amendments to the WEM Rules to include a methodology to assign CRC to constrained Facilities, allowing more generators to be certified for future Reserve Capacity Cycles. These

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110 For further information, see https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Open_consultations_reviews/Modelling-the-impacts-of-constrained-access-methodology-and-assumptions.pdf.

111 Available at https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules.

112 Available at http://www.westernpower.com.au/electricity-retailers-generators-generator-and-transmission-connections.html.

113 Available at https://westernpower.com.au/about/reports-publications/annual-planning-report-2017/.

114 See https://www.slp.wa.gov.au/gazette/gazette.nsf/searchgazette/ACC44979CFEDEF4B48258147002449BB/$file/Gg125.pdf for details of the changes to the WEM Rules.

amendments to the WEM Rules will continue to apply until the reforms regarding constrained access are implemented (see Section 7.1 for more information).

7.5.3 Opportunities for Market Participants

The Electricity Networks Access Code requires Western Power to demonstrate that it has efficiently minimised costs when implementing a solution to remove a network constraint. Before committing to a solution, Western Power must consider both network and non-network options.

The Electricity Networks Access Code and the WEM Rules contemplate the application of non-network solutions to address network limitations. Non-network options may be provided by an NCS or by DSM.

Where Western Power identifies a network limitation, network augmentation as well as alternative options (such as NCS and DSM) will be considered. Proponents who have (or are planning to install) generation capacity or DSM capacity capable of providing network support will need to contact Western Power to discuss these opportunities.

A number of areas in the network have limited capacity to support new generator connections on a reference service without significant network augmentation while there is an unconstrained network access model.

Key limitations[115] that may affect new generator connections include:

- North country 132 kV capacity for flows from south to north.
- North country 132 kV capacity for flows from north to south, limited by:
  - 132 kV network capacity in the adjacent Neerabup load area.
  - 132 kV network capacity between Mungarra and Three Springs, including the Three Springs busbar for generation connected north of Three Springs.
  - 132 kV network capacity between Three Springs and Pinjar for generation connected south of Three Springs.
  - 132 kV network capacity between Three Springs substation and Three Springs terminal.
- South country 132 kV capacity for flows from south to north.
- East country 132 kV capacity for flows from east to west.
- East country 132 kV capacity for flows from west to east.
- Fault level limitations in the Kwinana and Northern terminal areas.

Other site-specific considerations may include:

- Transmission and distribution system fault levels.
- Ancillary service requirements, steady state performance, and dynamic performance.
- Power quality.
- Protection coordination.
- Impact on system capability.

More information is contained in Sections 6 and 7 of Western Power's 2017 APR, including maps indicating specific locations where network constraints exist, which can be used to identify opportunities for future load and generation connections.

At present, Western Power is assessing a number of renewable generation proposals, and in the next few years expects to connect several hundred megawatts of transmission-connected renewable generation.

[115] Illustrated in Figure 18 on page 84 of Western Power's 2017 APR.

Appendix A. Determination of the Availability Curve

The Availability Curve ensures that there is sufficient capacity at all times to satisfy both elements of the Planning Criterion outlined in clause 4.5.9 of the WEM Rules, as well as ensuring that sufficient capacity is available to satisfy the criteria for evaluating outage plans.

Assuming that the RCT is just met, the Availability Curve indicates the minimum amount of capacity that must be provided by generation capacity to ensure that the energy requirements of users are met. The remainder of the RCT can be met by further generation capacity or by DSM.

The determination of the Availability Curve is outlined below, which is consistent with clause 4.5.10(e) and clause 4.5.12 of the WEM Rules.

1. A load curve is derived from the average of the annual load curves from the last five years. The shape of this average load curve would be expected to approximate a 50% POE demand profile, so it is then scaled up to match the 10% POE peak demand and expected energy consumption for the relevant year. The peak demand interval is then set at the 10% POE forecast.
2. Experience from the most recent year with a 10% POE peak demand event in the SWIS (2015-16) indicates that the 50% POE load level was exceeded for less than 24 hours. Consequently, the Availability Curve from the twenty-fourth hour onwards would be the same, regardless of whether the 50% POE peak demand forecast or 10% POE peak demand forecast was used for the peak demand interval.
3. The reserve margin is added to the load curve (including the allowances for frequency keeping and Intermittent Loads) to form the Availability Curve.
4. A generation availability curve is developed by assuming that the level of generation matches the RCT for the relevant Capacity Year, then allowing for typical levels of Facility outages and for variation in the output of intermittent generators. For existing Facilities, future outage plans (based on information provided by Market Participants under clause 4.5.4 of the WEM Rules) are included in this consideration.
5. Generation capacity is then incrementally replaced by DSM capacity, while maintaining the total quantity of capacity at the RCT until either the Planning Criterion or the criteria for evaluating outage plans is breached. If the RCT has been set based on the peak demand criterion (10% POE plus reserve margin), then the minimum capacity required to be provided by Availability Class 1 capacity will be the quantity of generation at which either:
    i. the total unserved energy equals 0.002% of annual energy consumption, breaching the Planning Criterion; or
    ii. the spare generation capacity drops below 520 MW[116], breaching the criteria for evaluating outage plans.

The capacity associated with Availability Class 2 is the RCT less the minimum amount of capacity required to be provided by Availability Class 1. Further information on the methodology for determining the Availability Curves is set out in RBP's report[117].

The Availability Curves for the 2019-20 and 2020-21 Capacity Years are shown in Figures 27 and 28. Data is from RBP.

[116] The quantity required to provide ancillary services and satisfy the ready reserve standard, consistent with the information published in the Medium Term PASA available at: http://wa.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Data/Projected-assessment-of-system-adequacy/Medium-term-PASA-report.

[117] RBP, 2018. *Assessment of System Reliability And Development Of The Availability Curve For The South West Interconnect System*. Available at: https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

Figure 27 2019-20 Capacity Year Availability Curve

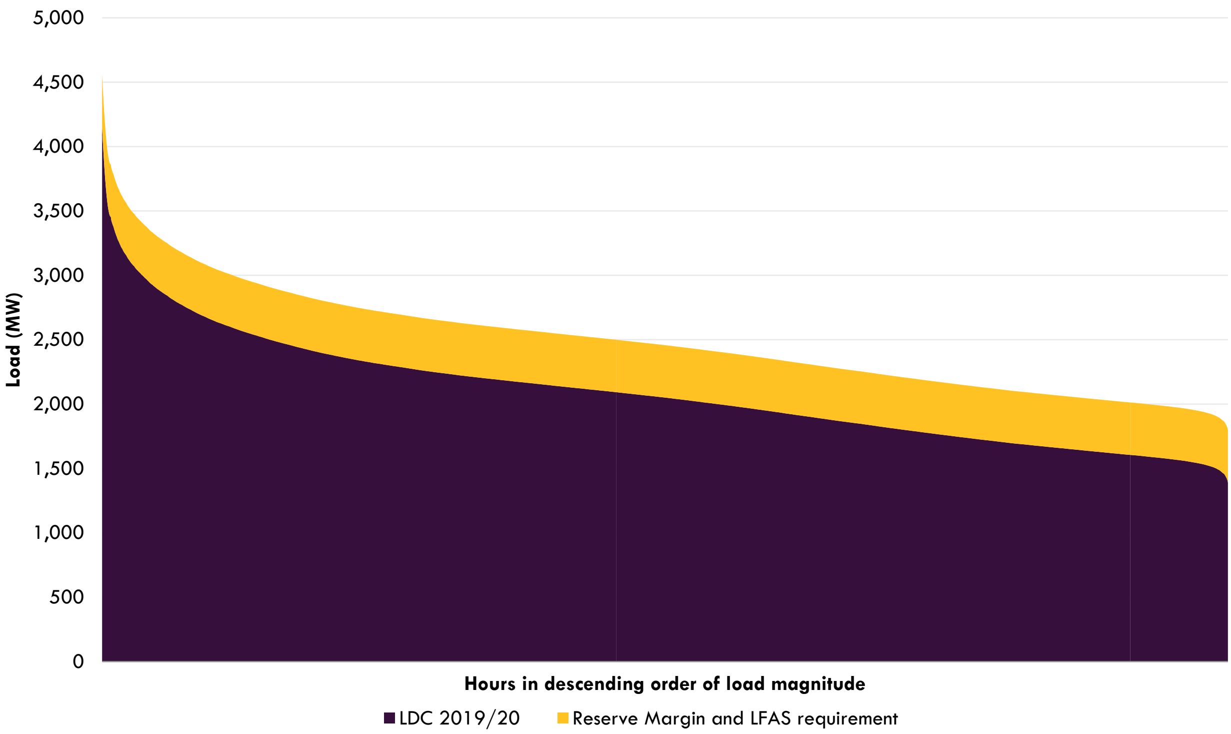
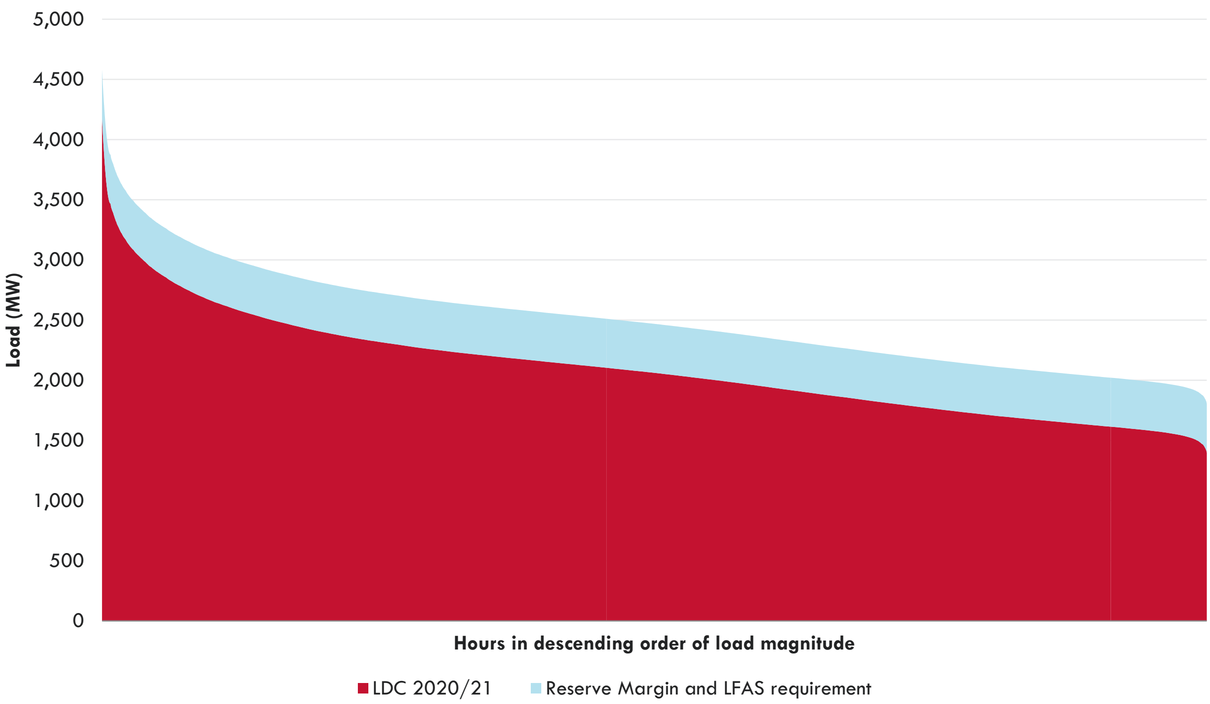


Figure 28 2020-21 Capacity Year Availability Curve



Appendix B. Expected DSM Dispatch Quantity and DSM Activation Price

The Market Procedure: Determination of the DSM Dispatch Quantity and DSM Activation Price[118] outlines the methodology that AEMO must follow when calculating the EDDQ and DSM Activation Price.

Expected DSM Dispatch Quantity

The EDDQ is the level of EUE avoided as a result of each Demand Side Programme (DSP) with Capacity Credits being dispatched for 200 hours in a given Capacity Year. EUE is energy demanded but not supplied as a result of involuntary load shedding.

The EDDQ is calculated as follows:

$$\mathrm{EDDQ}_t = \frac{\mathrm{EUE}_{(\mathrm{t},0)} - \mathrm{EUE}_{(\mathrm{t},200)}}{\mathrm{CC}_{\mathrm{t}}}$$

where:

- $\mathrm{EUE}_{(\mathrm{t},0)}$ denotes the EUE where no DSPs are dispatched.
- $\mathrm{EUE}_{(\mathrm{t},200)}$ denotes the EUE where all DSPs with Capacity Credits are dispatched for 200 hours.
- CC_{t} denotes the sum of all DSM Capacity Credits assigned.

RBP forecast the EDDQ over the Long Term PASA Study Horizon by using a combination of approaches including modelling part (b) of the Planning Criterion (see Section 3.2.4) and determining the minimum generation component of the Availability Curves (see Appendix A). That is, the EDDQ was forecast using a combination of fundamental market modelling, stochastic Monte Carlo simulation, and DSM dispatch optimisation (to ensure DSM Facilities are dispatched to minimise peak load while respecting availability constraints). The approach is summarised in further detail below:

1. Forecast EUE when DSPs are not dispatched.
   - This involved repeating the assessment of part (b) of the Planning Criterion and setting the capacity of all DSM in the market to zero. The total Reserve Capacity available was equal to only the available generation capacity. The WEM was simulated over a large number of iterations using assumptions regarding the load profile (based on a 50% POE peak and expected annual demand), availability of intermittent generators, and outages. Load and forced outages were randomised so each iteration returned a stochastic estimate of unserved energy. These unserved energy estimates were then averaged to estimate EUE, which was divided by forecast annual demand (to represent EUE as a percentage of annual demand).
2. Forecast EUE when DSPs are dispatched for 200 hours.
   - DSM was modelled separately, using an optimisation tool which dispatched all DSM capacity for exactly 200 hours in a manner that minimised the peak load while taking into account availability constraints. The hourly DSM dispatch (calculated from the optimisation model) was then subtracted from the load profile used in Step 1 above, and the new load profile was used as an input into the WEM model from Step 1. The market and Monte Carlo simulation in Step 1 was repeated and EUE recalculated.
3. The EDDQ was calculated using the EUE estimates derived in Steps 1 and 2 and applying the EDDQ formula above.

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 19.

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

Table 19 EDDQ, 2018-19 to 2027-28

Capacity Year	EUE no DSM dispatched (MWh)	EUE DSM dispatched for 200hr (MWh)	DSM Capacity Credits	EDDQ (MWh)
2018-19	19.9845	8.1402	57.426	0.2063
2019-20	0.9484	0.0000	66	0.0144
2020-21	0.0000	0.0000	66	0.0000
2021-22	0.8142	0.0635	66	0.0114
2022-23	4.8489	2.5368	66	0.0350
2023-24	0.5860	0.0617	66	0.0079
2024-25	2.3021	0.9467	66	0.0205
2025-26	0.1106	0.0000	66	0.0017
2026-27	0.0341	0.0000	66	0.0005
2027-28	1.1613	0.0126	66	0.0174

DSM Activation Price

The DSM Activation Price represents the Value of Customer Reliability 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 as a result of DSM dispatch.

A VCR study is yet to be undertaken, 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.

Appendix C. Supply-demand balance under different demand growth scenarios

Table 20 Supply-demand balance, high demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2018-19 A	4,621	4,819	198
2019-20 A	4,648	4,888	240
2020-21	4,664	4,888	224
2021-22	4,705	4,888	183
2022-23	4,755	4,888	133
2023-24	4,798	4,888	90
2024-25	4,836	4,888	52
2025-26	4,885	4,888	3
2026-27	4,930	4,888	-42
2027-28	4,991	4,888	-103

A. The RCT values for the 2018-19 and 2019-20 Capacity Years have been determined and presented in the 2017 WEM ESOO. Updated 2018-19 and 2019-20 RCT values based on the 2018 WEM ESOO forecasts are provided in this table for information only.

Table 21 Supply-demand balance, expected demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2018-19 A	4,553	4,819	266
2019-20 A	4,559	4,888	329
2020-21	4,581	4,888	307
2021-22	4,600	4,888	288
2022-23	4,626	4,888	262
2023-24	4,649	4,888	239
2024-25	4,677	4,888	211
2025-26	4,700	4,888	188
2026-27	4,730	4,888	158
2027-28	4,773	4,888	115

A. The RCT values for the 2018-19 and 2019-20 Capacity Years have been determined and presented in the 2017 WEM ESOO. Updated 2018-19 and 2019-20 RCT values based on the 2018 WEM ESOO forecasts are provided in this table for information only.

Table 22 Supply-demand balance, low demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2018-19 A	4,496	4,819	323
2019-20 A	4,505	4,888	383
2020-21	4,510	4,888	378
2021-22	4,514	4,888	374
2022-23	4,525	4,888	363
2023-24	4,535	4,888	353
2024-25	4,547	4,888	341
2025-26	4,562	4,888	326
2026-27	4,578	4,888	310
2027-28	4,591	4,888	297

A. The RCT values for the 2018-19 and 2019-20 Capacity Years have been determined and presented in the 2017 WEM ESOO. Updated 2018-19 and 2019-20 RCT values based on the 2018 WEM ESOO forecasts are provided in this table for information only.

Appendix D. Economic growth forecasts

Table 23 **Growth in WA gross state product, financial year basis**

Capacity Year	Actual (%) A	Expected (%)	High (%)	Low (%)
2006-07	6.5			
2007-08	5.0			
2008-09	3.6			
2009-10	4.6			
2010-11	4.3			
2011-12	9.4			
2012-13	6.0			
2013-14	5.9			
2014-15	2.7			
2015-16	1.0			
2016-17	-2.7			
2017-18		2.1	2.1	2.0
2018-19		2.6	2.8	2.3
2019-20		2.9	3.2	2.5
2020-21		3.4	3.8	3.0
2021-22		3.6	4.0	3.1
2022-23		3.5	3.9	2.9
2023-24		3.2	3.7	2.7
2024-25		3.6	4.1	2.9
2025-26		3.5	4.1	2.8
2026-27		3.5	4.2	2.7
2027-28		3.4	4.2	2.6
2028-29		3.3	4.1	2.5
Average growth		3.2	3.7	2.7

A. Actual GSP has been updated by the ABS since the 2017 WEM ESOO.

Appendix E. Rooftop PV forecasts

Table 24 Reduction in peak demand from rooftop PV systems A,B

Capacity Year	Expected (MW)	High (MW)	Low (MW)
2018-19	120.6	54.3	146.6
2019-20	139.7	62.9	169.9
2020-21	158.6	71.4	192.9
2021-22	176.5	79.4	214.7
2022-23	193.4	87.0	235.1
2023-24	209.3	94.2	254.5
2024-25	224.5	101.0	273.0
2025-26	239.1	107.6	290.7
2026-27	253.1	113.9	307.8
2027-28	266.5	119.9	324.0

A. Assuming a February peak between 17:00 and 18:00.
B. Expected scenario PV capacity forecast used for low, expected, and high scenarios. Low and high scenarios are adjusted for solar irradiance variations only (see Chapter 3 for further information).

Table 25 Annual energy generated from rooftop PV systems A

Capacity Year	Financial Year basis energy (GWh)	Capacity Year basis energy (GWh)
2018-19	1,363	1,411
2019-20	1,590	1,638
2020-21	1,804	1,851
2021-22	2,014	2,058
2022-23	2,211	2,252
2023-24	2,405	2,444
2024-25	2,574	2,612
2025-26	2,744	2,781
2026-27	2,908	2,942
2027-28	3,074	3,107

A. Table presents expected growth scenario only.

Appendix F. Summer peak demand forecasts

Table 26 Summer peak demand forecasts with expected demand growth

Capacity Year	Actual (MW) [A]	10% POE (MW)	50% POE (MW)	90% POE (MW)
2006-07	3,474			
2007-08	3,806			
2008-09	3,818			
2009-10	3,926			
2010-11	4,160			
2011-12	4,064			
2012-13	4,054			
2013-14	4,252			
2014-15	4,145			
2015-16	4,013			
2016-17	4,083			
2017-18	4,119			
2018-19		4,146	3,909	3,689
2019-20		4,152	3,914	3,696
2020-21		4,174	3,928	3,699
2021-22		4,193	3,951	3,719
2022-23		4,219	3,983	3,760
2023-24		4,242	3,999	3,782
2024-25		4,270	4,024	3,806
2025-26		4,293	4,056	3,836
2026-27		4,323	4,082	3,861
2027-28		4,365	4,113	3,892
Average growth (%)		**0.57**	**0.57**	**0.60**

A. 10% POE adjusted historical value.

Table 27 Summer peak demand forecasts with high demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2018-19	4,213	3,978	3,751
2019-20	4,240	4,002	3,777
2020-21	4,255	4,023	3,802
2021-22	4,295	4,054	3,833
2022-23	4,343	4,105	3,885
2023-24	4,385	4,140	3,920
2024-25	4,421	4,182	3,955
2025-26	4,468	4,228	4,004
2026-27	4,511	4,264	4,054
2027-28	4,570	4,326	4,098
Average growth (%)	**0.91**	**0.94**	**0.99**

Table 28 Summer peak demand forecasts with low demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2018-19	4,090	3,858	3,627
2019-20	4,099	3,856	3,635
2020-21	4,105	3,862	3,640
2021-22	4,110	3,866	3,651
2022-23	4,123	3,881	3,664
2023-24	4,134	3,890	3,673
2024-25	4,148	3,903	3,685
2025-26	4,164	3,919	3,700
2026-27	4,182	3,932	3,711
2027-28	4,197	3,954	3,736
Average growth (%)	**0.29**	**0.27**	**0.33**

Appendix G. Winter peak demand forecasts

Table 29 Winter peak demand forecasts with expected demand growth

Capacity Year	Actual (MW)	10% POE (MW)	50% POE (MW)	90% POE (MW)
2006-07	2,705			
2007-08	2,774			
2008-09	2,943			
2009-10	3,029			
2010-11	3,095			
2011-12	3,100			
2012-13	3,071			
2013-14	3,217			
2014-15	3,135			
2015-16	3,366			
2016-17	3,419			
2017-18		3,332	3,240	3,168
2018-19		3,382	3,290	3,217
2019-20		3,408	3,319	3,246
2020-21		3,444	3,352	3,278
2021-22		3,485	3,391	3,318
2022-23		3,537	3,443	3,369
2023-24		3,575	3,484	3,412
2024-25		3,618	3,526	3,452
2025-26		3,660	3,573	3,499
2026-27		3,709	3,622	3,548
2027-28		3,760	3,666	3,593
Average growth (%)		**1.22**	**1.24**	**1.27**

Table 30 Winter peak demand forecasts with high demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2017-18	3,341	3,253	3,179
2018-19	3,392	3,301	3,228
2019-20	3,426	3,332	3,262
2020-21	3,463	3,372	3,301
2021-22	3,504	3,413	3,339
2022-23	3,560	3,470	3,402
2023-24	3,609	3,519	3,445
2024-25	3,658	3,568	3,496
2025-26	3,712	3,621	3,548
2026-27	3,772	3,680	3,608
2027-28	3,829	3,739	3,666
Average growth (%)	**1.37**	**1.40**	**1.44**

Table 31 Winter peak demand forecasts with low demand growth

Capacity Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2017-18	3,322	3,231	3,159
2018-19	3,343	3,255	3,178
2019-20	3,368	3,280	3,205
2020-21	3,400	3,308	3,235
2021-22	3,436	3,343	3,269
2022-23	3,468	3,378	3,306
2023-24	3,502	3,412	3,339
2024-25	3,532	3,444	3,371
2025-26	3,574	3,482	3,409
2026-27	3,610	3,517	3,445
2027-28	3,649	3,551	3,479
Average growth (%)	**0.94**	**0.95**	**0.97**

Appendix H. Operational consumption forecasts

Table 32 **Forecasts of operational consumption (financial year basis)**

Financial Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007-08	16,387			
2008-09	16,639			
2009-10	17,346			
2010-11	17,952			
2011-12	17,841			
2012-13	18,009			
2013-14	18,479			
2014-15	18,358			
2015-16	18,612			
2016-17	18,262			
2017-18		18,332	18,336	18,328
2018-19		18,296	18,320	18,271
2019-20		18,307	18,368	18,243
2020-21		18,382	18,488	18,268
2021-22		18,506	18,668	18,333
2022-23		18,660	18,890	18,417
2023-24		18,820	19,136	18,495
2024-25		19,032	19,456	18,609
2025-26		19,279	19,839	18,735
2026-27		19,561	20,281	18,868
2027-28		19,871	20,772	19,002
Average growth (%)		**0.92**	**1.41**	**0.44**

Table 33 Forecasts of operational consumption (Capacity Year basis)

Capacity Year	Actual (MW)	Expected (GWh)	High (GWh)	Low (GWh)
2007-08	16,520			
2008-09	16,701			
2009-10	17,507			
2010-11	17,902			
2011-12	17,926			
2012-13	18,099			
2013-14	18,548			
2014-15	18,341			
2015-16	18,895			
2016-17	18,094			
2017-18		18,324	18,331	18,317
2018-19		18,304	18,336	18,271
2019-20		18,326	18,397	18,250
2020-21		18,416	18,535	18,288
2021-22		18,549	18,727	18,360
2022-23		18,707	18,957	18,445
2023-24		18,872	19,212	18,525
2024-25		19,097	19,551	18,645
2025-26		19,351	19,948	18,773
2026-27		19,642	20,406	18,909
2027-28		19,961	20,911	19,044
Average growth (%)		**0.97**	**1.47**	**0.46**

Appendix I. Power station information in the SWIS

Table 34 Scheduled Generators in the SWIS, 2016-17 Capacity Year

Power station (units included)	Participant	Classification	Energy generated		Capacity Credits	
			GWh	Share (%) A	MW	Share (%) A
Alcoa Wagerup	Alcoa	Baseload	103	0.6	26.000	0.5
Alinta Pinjarra (1 and 2)	Alinta Energy	Baseload	2216	13.6	268.505	5.4
Alinta Wagerup (1 and 2)	Alinta Energy	Mid-merit	245	1.5	379.232	7.7
Bluewaters (1 and 2)	Bluewaters	Baseload	2416	14.8	434.000	8.8
Cockburn	Synergy	Mid-merit	315	2.0	231.800	4.7
Collie	Synergy	Baseload	2038	12.5	317.200	6.4
Kalamunda	Landfill Gas & Power	Peaking	0	0.0	1.300	0.0
Kemerton (11 and 12)	Synergy	Peaking	95	0.6	291.000	5.9
Kwinana gas turbine	Synergy	Peaking	0	0.0	16.809	0.3
Kwinana high efficiency gas turbines (2 and 3)	Synergy	Baseload	743	4.6	195.500	3.9
Merredin	Merredin Energy	Peaking	0	0.0	82.000	1.7
Muja AB (1, 2, 3 and 4)	Vinalco	Mid-merit	191	1.2	220.000	4.4
Muja CD (5, 6, 7 and 8)	Synergy	Baseload	4316	26.5	806.594	16.3
Mungarra (1, 2 and 3)	Synergy	Peaking	14	0.1	97.100	2.0
NewGen Kwinana	NewGen Kwinana	Baseload	2097	12.9	327.800	6.6
NewGen Neerabup	NewGen Neerabup	Mid-merit	204	1.3	330.600	6.7
Parkeston	Goldfields Power	Peaking	0	0.0	61.400	1.2
Perth Energy Kwinana	Western Energy	Mid-merit	85	0.5	109.000	2.2
Perth Power Partnership Kwinana	Synergy	Baseload	556	3.4	80.400	1.6
Pinjar A (1 and 2)	Synergy	Peaking	6	0.0	63.300	1.3
Pinjar B (3, 4, 5 and 7)	Synergy	Peaking	13	0.1	148.000	3.0
Pinjar C (9 and 10)	Synergy	Mid-merit	252	1.5	215.700	4.3
Pinjar D (11)	Synergy	Mid-merit	199	1.2	120.000	2.4

Power station (units included)	Participant	Classification	Energy generated		Capacity Credits	
			GWh	Share (%) A	MW	Share (%) A
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	183	1.1	36.000	0.7
West Kalgoorlie (1 and 2)	Synergy	Peaking	1	0.0	53.550	1.1

A. Percentage share among Scheduled Generators.

Table 35 Non-Scheduled Generators in the SWIS, 2016-17 Capacity Year

Facility	Participant	Energy source	Nameplate capacity (MW)	Energy generated		Capacity Credits	
				GWh	Share (%) A	MW	Share (%) A
Albany	Synergy	Wind	21.6	53	3.1	8.223	7.8
Atlas	Perth Energy	Biogas	1.123	3	0.2	0.633	0.6
Bremer Bay	Synergy	Wind	1.88	1	0.1	0.078	0.1
Richgro Biogas	CleanTech Energy	Biogas	2.4	4	0.2	0.930	0.9
Collgar	Collgar Wind Farm	Wind	206	671	39.5	15.048	14.2
Denmark	Denmark Community Windfarm	Wind	1.6	5	0.3	1.118	1.1
Emu Downs	EDWF Manager	Wind	80	250	14.7	17.734	16.7
Grasmere	Synergy	Wind	13.8	37	2.2	5.230	4.9
Greenough River	Synergy	Solar	10	23	1.4	3.833	3.6
Henderson	Waste Gas Resources	Biogas	3.195	16	0.9	2.272	2.1
Kalbarri	Synergy	Wind	1.6	4	0.2	0.272	0.3
Karakin	Blair Fox	Wind	5	7	0.4	0.970	0.9
Mount Barker	Mt. Barker Power Company	Wind	2.43	6	0.3	0.935	0.9
Mumbida	Mumbida Wind Farm	Wind	55	190	11.2	14.900	14.1
Red Hill	Landfill Gas & Power	Biogas	3.64	26	1.6	2.930	2.8
Rockingham	Perth Energy	Biogas	4	21	1.2	2.682	2.5
South Cardup	Perth Energy	Biogas	3.369	24	1.4	2.446	2.3
Tamala Park	Landfill Gas & Power	Biogas	5	38	2.3	3.933	3.7
Walkaway	Alinta Energy	Wind	89.1	320	19	21.699	20.5

A. Percentage share among Non-Scheduled Generators.

Appendix J. Facility capacities

Table 36 Registered generation Facilities – existing and committed

Participant name	Facility name	Capacity Credits (2019-20)
Alcoa of Australia	ALCOA_WGP	26.000
Alinta Sales	ALINTA_PNJ_U1	135.000
Alinta Sales	ALINTA_PNJ_U2	135.500
Alinta Sales	ALINTA_WGP_GT	196.000
Alinta Sales	ALINTA_WGP_U2	196.000
Alinta Sales	ALINTA_WWF	24.753
Alinta Sales	BADGINGARRA_WF1 [A]	35.625
Blair Fox	BLAIRFOX_KARAKIN_WF1	0.739
Blair Fox	BLAIRFOX_WESTHILLS_WF3 [B]	0.000
Bluewaters Power 1	BW1_BLUEWATERS_G2	217.000
Bluewaters Power 2	BW2_BLUEWATERS_G1	217.000
Carnegie Clean Energy	NORTHAM_SF_PV1 [A]	3.749
CleanTech Energy	BIOGAS01	1.654
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	18.854
Denmark Community Windfarm	DCWL_DENMARK_WF1	0.512
EDWF Manager	EDWFMAN_WF1	30.079
Goldfields Power	PRK_AG	59.400
SRV GRSF Pty Ltd as Trustee for GRSF Trust	GREENOUGH_RIVER_PV1	1.995
Landfill Gas & Power	KALAMUNDA_SG	1.300
Landfill Gas & Power	RED_HILL	2.785
Landfill Gas & Power	TAMALA_PARK	4.169
Merredin Energy	NAMKKN_MERR_SG1	82.000
Merredin Solar Farm Nominee	MERSOLAR_PV1 [A]	29.317
Mt.Barker Power Company	SKYFRM_MTBARKER_WF1	0.693
Mumbida Wind Farm	MWF_MUMBIDA_WF1	9.968
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	327.800

Participant name	Facility name	Capacity Credits (2019-20)
Perth Energy	ATLAS [B]	0.000
Perth Energy	GOSNELLS [B]	0.000
Perth Energy	ROCKINGHAM	2.119
Perth Energy	SOUTH_CARDUP	2.941
Southern Cross Energy	STHRNCRS_EG	20.000
Synergy	ALBANY_WF1	6.611
Synergy	BREMER_BAY_WF1	0.201
Synergy	COCKBURN_CCG1	240.000
Synergy	COLLIE_G1	317.200
Synergy	GRASMERE_WF1	4.511
Synergy	KALBARRI_WF1	0.343
Synergy	KEMERTON_GT11	155.000
Synergy	KEMERTON_GT12	155.000
Synergy	KWINANA_GT1 [B]	0.000
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
Synergy	MUNGARRA_GT1 [B]	0.000
Synergy	MUNGARRA_GT2 [B]	0.000
Synergy	MUNGARRA_GT3 [B]	0.000
Synergy	PINJAR_GT1	31.200
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

Participant name	Facility name	Capacity Credits (2019-20)
Synergy	WEST_KALGOORLIE_GT2 [B]	0.000
Synergy	WEST_KALGOORLIE_GT3 [B]	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	1.852
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 2019-20 Capacity Year.
B. Registered Facilities that did not participate in the RCM for the 2019-20 Capacity Year.

Table 37 Registered DSM Facilities – existing and committed

Participant name	Facility name	Capacity Credits (2019-20)
Synergy	SYNERGY_DSP_04	42.000
Wesfarmers Kleenheat Gas	PREMPWR_DSP_02	24.000

Measures and abbreviations

Units of measure

Abbreviation	Unit of measure
GWh	Gigawatt hour
kV	Kilovolt
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
CER	Clean Energy Regulator
CRC	Certified Reserve Capacity
DER	Distributed Energy Resources
DSM	Demand Side Management
DSP	Demand Side Programme
EDDQ	Expected DSM Dispatch Quantity
EISC	Economics and Industry Standing Committee
EOI	Expression of Interest
ERA	Economic Regulation Authority
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EUE	Expected unserved energy
EV	Electric vehicle

Abbreviation	Expanded name
GIA	Generator Interim Access
GSP	Gross state product (for WA)
IRCR	Individual Reserve Capacity Requirement
LDC	Load Duration Curve
LFAS	Load Following Ancillary Services
LRET	Large-scale Renewable Energy Target
Long Term PASA	Long Term Projected Assessment of System Adequacy
NCS	Network Control Service
NEG	National Energy Guarantee
NEM	National Electricity Market
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PUO	Public Utilities Office
PV	Photovoltaic
RBP	Robinson Bowmaker Paul
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RCT	Reserve Capacity Target
REOI	Request for Expressions of Interest
SWIS	South West interconnected system
STC	Small-scale Technology Certificate
WA	Western Australia
WEM	Wholesale Electricity Market
WEM Rules	Wholesale Electricity Market Rules

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.
block loads	The largest customers in the SWIS that are considered to be 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.
embedded generator	Rooftop PV systems and battery systems that produce energy (for the forecast period).
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 (for example, 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 rooftop 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.
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 Mechanism (RCM)	The capacity market in the SWIS that ensures sufficient capacity is available to meet peak demand.

Term	Definition
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.
rooftop PV	Small-scale commercial and residential PV systems less than 100 kW.
solar irradiance	A measure of cloud-cover used to de-rate the output of rooftop PV systems.
underlying consumption	All electricity (in MWh) consumed on site, which can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.
underlying demand	All electricity (in MW) consumed on site, which can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.