DEFERRED 2015 ELECTRICITY STATEMENT OF OPPORTUNITIES

FOR THE WHOLESALE ELECTRICITY MARKET

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AUSTRALIAN ENERGY MARKET OPERATOR

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 2016, although AEMO has incorporated more recent information where practical.

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Version control

Version	Release date	Changes
1	16/6/2016	

EXECUTIVE SUMMARY

This Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) presents AEMO's electricity peak demand and operational consumption[1] outlook for the South West interconnected system (SWIS) in Western Australia (WA) over the 10-year forecast period 2016–17 to 2025–26.

Published as part of the 2015 Reserve Capacity Cycle, this Deferred 2015 WEM ESOO[2] contains peak demand and operational consumption forecasts across a range of weather and demand growth scenarios. The report highlights the 10% probability of exceedance (POE)[3] peak demand forecast used to determine the Reserve Capacity Target (RCT) for the 2017–18 Capacity Year.[4]

Key findings

- Based on the 10% POE peak demand forecast, the 2017–18 RCT has been determined as 4,552 megawatts (MW).
- 10% POE peak demand is forecast to grow at an average annual rate of 1.4%[5] over the 10-year forecast period. The forecast growth rate for peak demand has not statistically changed since the 2014 ESOO[6] (0.8%). The peak demand forecasts are lower for the first five years of the outlook period, but higher during the outer years beyond 2021–22.
- Annual operational consumption is forecast to grow slowly at an average annual rate of 1.0% over the 10-year forecast period.
- An all-time peak demand occurred in summer 2015–16 when 4,013 MW was observed in the 17:30 to 18:00 trading interval on 8 February 2016.
- Rooftop photovoltaic (PV)[7] is estimated to have reduced peak demand on 8 February 2016 by 96 MW, or 2.3%, from 4,109 MW to 4,013 MW. AEMO estimates that rooftop PV shifted peak demand by an hour, from the 16:30 to 17:00 trading interval to the 17:30 to 18:00 trading interval, reducing the peak by a further 95 MW.
- The capacity cost allocation mechanism – the Individual Reserve Capacity Requirement (IRCR) – provides an effective incentive for contestable customers to reduce electricity use during periods of high demand. Action taken by customers in response to the IRCR reduced load by 77 MW during the peak demand interval on 8 February 2016.
- Based on the current level of installed and committed capacity, and assuming there are no changes to the capacity outlook, no new generation or Demand Side Management (DSM) capacity will be required in the SWIS over the forecast period.
- The ongoing WA Government Electricity Market Review (EMR) has implemented changes to the Reserve Capacity Mechanism that will affect the 2015 and all future Reserve Capacity

[1] Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.
[2] Publication of this ESOO was postponed from June 2015, following direction from the WA Minister for Energy to defer aspects of the 2015 Reserve Capacity Cycle (which relates to the procurement of capacity for the 2017–18 Capacity Year), in light of the EMR. More information on the EMR is available at http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx.
[3] POE refers to 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.
[4] A period of 12 months commencing on 1 October and ending on 1 October of the following calendar year.
[5] The Deferred 2015 WEM ESOO provides low, expected and high demand growth cases based on different levels of economic growth. Unless otherwise indicated, demand growth forecasts in this executive summary are based on expected levels of economic growth.
[6] The ESOO prepared as part of the deferred 2014 Reserve Capacity Cycle published in June 2015, referred to as the 2014 ESOO in this report. Available at: http://wa.aemo.com.au/docs/default-source/Reserve-Capacity/2014-electricity-statement-of-opportunities76EBFFC3E047.pdf?sfvrsn=0.
[7] Rooftop PV is defined as installed residential and commercial systems with a capacity of less than 100 kW and eligible for Small-scale Technology Certificates under the Renewable Energy Target.

Cycles. These changes are expected to reflect the economic value of capacity and reduce the cost of capacity procured to meet the RCT.

- The reduction of 380 MW of Synergy's plant generation capacity may contribute to meeting Australia's emissions reduction targets, though how much will be determined once the specific Facilities to be retired have been confirmed.

Reserve Capacity Target

The RCT for the 2017–18 Capacity Year has been determined as 4,552 MW. This is calculated as the 10% POE peak demand forecast, plus a reserve margin.

AEMO estimates that installed or committed capacity[8] will exceed the RCT by 1,066 MW, or 23%, for the 2017–18 Capacity Year. Excess capacity is forecast to decrease to 206 MW by the 2025–26 Capacity Year, based on the current level of installed capacity and assuming no further changes to the WEM Rules. Therefore no new generation or DSM capacity is projected to be required in the SWIS over the forecast period.

The WA Government announced in April 2016 that Synergy will reduce 380 MW of plant generation capacity by 1 October 2018. This would reduce excess capacity to 622 MW, or 11.8%, in the 2018–19 Capacity Year, assuming no other changes in the installed capacity level.

Peak demand and operational consumption forecasts 2016–17 to 2025–26

AEMO forecasts the 10% POE peak demand to increase at an average annual rate of 1.4% over the next 10 years, as shown in Table 1.

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

Scenario	2016–17 (MW)	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)	2020–21 (MW)	5-year average annual growth	10-year average annual growth
10% POE	4,073	4,145	4,209	4,263	4,303	1.4%	1.4%
50% POE	3,819	3,885	3,943	3,991	4,023	1.3%	1.3%
90% POE	3,598	3,659	3,712	3,755	3,779	1.2%	1.3%

Source: AEMO and National Institute of Economic and Industry Research (NIEIR)

The 10% POE 10-year average annual growth rate listed in Table 1 is marginally different from the growth rate published in the 2014 ESOO, largely due to the 10% POE event that occurred in summer 2015–16, resulting in a recalibration of the forecasting models. While the forecasts provided by the National Institute of Economic and Industry Research (NIEIR) are on the high side of AEMO expectations in the outer years, AEMO has cross-examined these numbers and considers the difference between the 2014 ESOO and the Deferred 2015 WEM ESOO annual peak demand growth rates to be within the bounds of forecast error. Uncertainty is introduced from variability over the coming decade in the growth rate of rooftop PV, changing energy consumption behaviour, new technology, and tariff projections.

The RCT for the 2017–18 Capacity Year of 4,552 MW is consistent with the RCT of 4,557 MW for the 2016–17 Capacity Year.

AEMO expects operational consumption to increase at an average annual rate of 1.0% over the next 10 years. While low, the growth in operational consumption is predicated on current policy settings for the non-contestable customer segment. Changes to tariff and regulatory policies have the potential to further decrease operational consumption over the forecast horizon.

[8] Defined as all capacity that was assigned Capacity Credits for the 2016–17 Capacity Year.

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

Table 2 Operational consumption forecasts for different demand growth scenarios

Scenario	2016–17 (GWh)	2017–18 (GWh)	2018–19 (GWh)	2019–20 (GWh)	2020–21 (GWh)	5 year average annual growth	10 year average annual growth
High	18,913	19,529	20,042	20,462	20,973	2.6%	2.7%
Expected	18,584	18,895	19,067	19,135	19,259	0.9%	1.0%
Low	18,476	18,557	18,515	18,364	18,251	-0.3%	-0.2%

Source: NIEIR with AEMO input

Trends in SWIS peak demand

The summer 2015–16 system peak of 4,013 MW was observed in the 17:30 to 18:00 trading interval on 8 February 2016. This was during a period of four consecutive days when maximum temperatures exceeded 40°C (measured at the Perth Metro weather station) between 7 and 10 February 2016. Peak demand on 8 February 2016 was a record for the SWIS, exceeding the previous highest demand of 3,857 MW observed on 25 January 2012.

Peak demand and associated temperature statistics for the past nine years are shown in Table 3. This year's peak demand (4,013 MW) was 7.2% higher than last year's peak demand (3,744 MW), and 4% higher than the previous record peak demand (3,857 MW) for the SWIS.

Table 3 SWIS system peak, 2008 to 2016

Date	Peak demand (MW)	Maximum temperature during trading interval (°C)	Trading interval commencing	Daily maximum temperature (°C)
8 February 2016	4,013	40.2	17:30	42.5
5 January 2015	3,744	40.8	15:30	44.4
20 January 2014	3,702	37.4	17:30	38.3
12 February 2013	3,732	35.4	16:30	40.5
25 January 2012	3,857	40.0	16:30	41.0
16 February 2011	3,735	37.5	16:30	39.0
25 February 2010	3,766	39.5	16:00	41.5
11 February 2009	3,515	39.5	15:30	39.7
28 February 2008	3,392	36.9	15:00	41.5

Source: AEMO and Bureau of Meteorology

Although consumers are using more electrical appliances, growth in energy delivered from the electricity network has softened, due to decreases in average consumption per connection. This is because a proportion of electricity consumption is now self-generated from onsite rooftop PV systems, and new, more energy-efficient appliances are replacing older models.

The adoption of energy management systems and batteries is expected to continue this trend by enabling households to have greater control over when and how much electricity they consume.

Peak demand and its timing have become increasingly hard to forecast. Over the last nine years, both the time of year and the time of day that peak demand occurred varied. The time of day has shifted later by two and half hours, and ranged from the first week of January to the last week of February. This can be attributed to a range of factors, particularly the rapid uptake of rooftop PV and customer responses to the capacity cost allocation mechanism (the IRCR).

As shown in Table 3, peak demand has in the past typically occurred in the late afternoon, when people arrive home from work or school and turn on air conditioning. In 2014 and 2016, peak demand was around one hour later than in previous years, occurring in the 17:30 to 18:00 trading interval rather than the 16:30 to 17:00 trading interval observed from 2011 to 2013. The 2015 peak was unusually early in the day, because a large proportion of the residential population would have been at home following the New Year break. In addition, business and industrial electricity users would not have been operating at full capacity.

The increasingly unpredictable nature of peak demand presents a range of challenges. This affects the accuracy of the RCT, which is based on the 10% POE peak demand forecast, and increases the risk of procuring too much or too little capacity. Setting an incorrect RCT would affect the Reserve Capacity Price (RCP) — the price paid to Capacity Credit holders — which may not adequately reflect the economic value of capacity, and may send inappropriate price signals to the market.

Impact of rooftop PV systems

Underlying electricity consumption[9] continues to grow due to increased use of electrical appliances, including reverse cycle air-conditioning and entertainment devices. However, strong uptake of rooftop PV has contributed to a reduction in average consumption per connection from the electricity network, allowing residential and commercial customers to generate some of their electricity needs onsite. This has reduced the growth in operational consumption.

Rooftop PV reduced peak demand by 191 MW in summer 2015–16 as a result of:

- Shifting the timing of peak demand by one hour from the trading interval starting at 16:30 to the trading interval starting at 17:30, reducing peak demand by 95 MW.
- Generation from rooftop PV reducing peak demand by 96 MW or 2.3%, from 4,109 MW to 4,013 MW.

Growth of rooftop PV installations has continued to affect both the level and timing of peak demand over the last five years. Actual peak demand over the five highest demand days for 2012 to 2016 is compared in Table 4 with the estimated peak that would have occurred without rooftop PV.

Table 4 Effect of rooftop PV on peak demand, 2012 to 2016[a]

Date	Trading interval commencing	Peak demand (MW)	Estimated peak demand without rooftop PV (MW)	Estimated peak trading interval commencing without rooftop PV	Reduction in peak demand from rooftop PV (MW)	Reduction in peak demand from peak time shift (MW)
8 February 2016	17:30	4,013	4,204	16:30	96	95
5 January 2015	15:30	3,744	3,931	14:30	165	32
20 January 2014	17:30	3,702	3,757	15:30	81	29
12 February 2013	16:30	3,732	3,816	13:30	81	6
25 January 2012	16:30	3,857	3,918	15:00	72	19

[a] This table has been updated from previous editions of the ESOO to reflect the latest data from the Australian PV Institute.

AEMO expects the strong growth of rooftop PV capacity in the SWIS to continue. Technological, commercial and regulatory factors, as well as increasing environmental awareness, continue to drive this strong uptake. Key factors include:

- Government incentives – rebates on rooftop PV installations continue to be accessible by residential and commercial customers through the Commonwealth Government's Renewable Energy Target (RET) providing discounts for systems.

[9] Underlying electricity consumption refers to everything consumed onsite, and includes electricity provided by localised generation from rooftop PV, battery storage and embedded generators, or by the electricity grid.

- Declining system costs – continued falls in retail prices for residential and commercial rooftop PV systems are making renewable systems more financially viable for customers.
- Increasing electricity tariffs – higher electricity tariffs have increased costs to customers and may cause them to reassess their electricity consumption behaviour. This, in turn, may lead to greater use of rooftop PV, and potentially battery storage in the future.
- Changes in consumer attitudes and consumption behaviour – electricity consumers are becoming more aware of existing and emerging technologies such as rooftop PV and battery storage, and are considering ways to optimise their electricity consumption behaviour.

Response to the Individual Reserve Capacity Requirement

Data for the 2015–16 summer peak shows that the allocation of capacity costs through the IRCR continues to encourage customers to reduce consumption during periods of high demand. At the time of the 2015–16 system peak, 57 customers responded to the IRCR price signal, reducing total system demand by 77 MW. This was almost double the response recorded during the 2014–15 peak, when 20 customers reduced demand by 42 MW.

The response to the IRCR mechanism for the past five years is shown in Table 5. The increasing volatility of the timing of peak demand days has made it more difficult for large users to predict days on which to respond, resulting in varying responses over the past five years. This year, large industrial users were well-prepared for the peak demand; it displayed characteristics of a typical peak and the Bureau of Meteorology accurately forecast the heatwave four days in advance, allowing sufficient time for customers to plan a response. Some customers chose to reduce consumption over the entire week in which peak demand occurred, when weather forecasts indicated a run of at least four consecutive days of temperatures
over 40°C.

Table 5 IRCR response on peak demand days, 2012 to 2016

Date	Peak demand (MW)	Time of peak	Estimated IRCR reduction (MW)	Number of customers responding
8 February 2016	4,013	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

Electricity Market Review

Since 2014, the WA Government has been considering changes to the WEM through the EMR. The EMR is currently in the implementation phase, where changes to the WEM Rules and Market Procedures are expected to affect the 2015 and future Reserve Capacity Cycles.

Transitional arrangements have been implemented for the 2015 and future Reserve Capacity Cycles, until an auction design (for Capacity Credit allocation) has been implemented. These include:

- Adjusting the formula for the RCP.
- Harmonising DSM availability requirements with scheduled generators.
- Introducing a new price for DSM capacity based on expected dispatch and the value of customer reliability.

These measures are intended to reduce the cost of procuring capacity to meet the RCT in the short and long term, as well as to reduce the current level of excess capacity in the WEM. Other proposed changes resulting from the EMR include modifications to the energy and ancillary services markets, including the Balancing Market and Short Term Energy Market.

Emissions reduction and renewable energy policy

Australia has committed to achieving a 26% to 28% reduction in emissions by 2030 (relative to 2005 levels) as part of its obligations to keep global temperature increases to below 2°C, agreed at the 2015 Paris Climate Conference. The detailed policy settings to achieve this have yet to be developed. The reduction of 380 MW of Synergy's plant generation capacity may contribute to meeting emissions targets. How much will only be determined once Synergy announces which Facilities will be retired and the impact based on fuel type and dispatch frequency is determined.

Due to the uncertainty of WA policy and proposed retirements, AEMO has only provided a general commentary around this aspect in the Deferred 2015 WEM ESOO.

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CHAPTER 1. INTRODUCTION

1.1 Background and context

This Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) is published as part of the 2015 Reserve Capacity Cycle, which relates to capacity required in the South West interconnected system (SWIS) in Western Australia (WA) for the 2017–18 Capacity Year.[10]

A key purpose of this Deferred 2015 WEM ESOO is to set the Reserve Capacity Target (RCT) for the 2017–18 Capacity Year. The RCT is the amount of generation and Demand Side Management (DSM) capacity required to satisfy the Planning Criterion, which AEMO determines in accordance with the WEM Rules.

The Planning Criterion ensures there is enough capacity in the SWIS to meet peak demand based on a one-in-ten year peak event, plus a reserve margin to cover outages and the ancillary services required to maintain system security.

The Deferred 2015 WEM ESOO presents AEMO's outlook for peak demand and operational consumption[11] in the SWIS across a number of different scenarios, and has been developed to provide relevant information to current and potential stakeholders in the SWIS. AEMO uses weather adjusted historical figures[12] in various places throughout this report and focuses on the 10% probability of exceedance (POE)[13] forecasts, which are used to set the RCT.

1.1.1 Deferral of the 2015 and 2016 Reserve Capacity Cycles

Due to a Ministerial Direction in March 2015 to defer aspects of the 2015 Reserve Capacity Cycle, the Deferred 2015 WEM ESOO is being published in June 2016.

In March 2016, the WA Public Utilities Office (PUO) requested that AEMO consider deferring:

- The opening of the certification window for the deferred 2015 Reserve Capacity Cycle, from 1 May 2016 to 1 June 2016.
- Aspects of the 2016 Reserve Capacity Cycle, for a period of 12 months.

As such, the ESOO for the 2016 Reserve Capacity Cycle (for the 2018–19 Capacity Year) is expected to be published in June 2017.

Further information on the deferral of aspects of the 2015 and 2016 Reserve Capacity Cycles is available on AEMO's website.[14]

1.2 Structure of this report

The structure of the report is as follows:

- Chapter 2 provides background information on the WEM, including market structure, load duration curves, diversity of supply since market start in 2006, and the characteristics of generation capacity in the SWIS.
- Chapter 3 discusses:
  - The summer 2015–16 peak demand in the SWIS, the factors that contributed to it, and historical trends since 2008.

[10] All references to years are Capacity Years throughout this report, unless otherwise specified.
[11] Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid.
[12] Adjusted to what would have been expected during a 10% POE weather event.
[13] POE refers to 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.
[14] See http://wa.aemo.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

  - Factors affecting peak demand, including the Individual Reserve Capacity Requirement (IRCR) and uptake of commercial and residential rooftop photovoltaic (PV).[15]
  - Recent trends in consumption by residential, commercial, and large industrial customers.
- Chapter 4 provides an explanation of the forecasting methodology and a discussion of factors affecting the forecasts, including the uptake of new technologies.
- Chapter 5 presents the peak demand and operational consumption forecasts from 2016–17 to 2025–26.
- Chapter 6 reconciles actual demand and energy data for 2015–16 against the forecasts presented in the 2014 ESOO[16] and discusses revisions of assumptions and improvements made in the Deferred 2015 WEM ESOO.
- Chapter 7 presents the RCT for each Capacity Year of the Long Term Projected Assessment of System Adequacy (PASA) Study Horizon and discusses future investment opportunities for the SWIS.
- Chapter 8 provides information about issues affecting the WEM, including the EMR, emissions targets, renewable energy policy, and infrastructure developments in the SWIS.
- Appendices provide further information, including the Availability Curves and peak demand and operational consumption forecasts for all scenarios.

A data register containing the data for the figures in this report is available on AEMO's website.[17]

[15] Rooftop PV is defined as installed residential and commercial systems with a capacity of less than 100 kW and eligible for Small-scale Technology Certificates under the Renewable Energy Target.
[16] The ESOO prepared as part of the deferred 2014 Reserve Capacity Cycle published in June 2015, referred to as the 2014 ESOO in this report. Available at http://wa.aemo.com.au/docs/default-source/Reserve-Capacity/2014-electricity-statement-of-opportunities76EBFFC3E047.pdf?sfvrsn=0.
[17] Available at http://wa.aemo.com.au/home/electricity/electricity-statement-of-opportunities.

CHAPTER 2. CHARACTERISTICS AND EVOLUTION OF THE WEM

This chapter provides background information on the WEM, including market structure, load duration curves and minimum load, diversity of supply since market start in 2006, and the characteristics of generation capacity in the SWIS.

2.1 The WEM

The WEM operates in the SWIS, which delivers electricity to around 1.1 million customers across an area of 261,000 square kilometres, stretching from Kalbarri in the north to Kalgoorlie in the east and Albany in the south, as shown in Figure 1. The SWIS is an isolated network; it is not connected to the electricity network in the other Australian states and territories that form the National Electricity Market (NEM). The Reserve Capacity Mechanism (RCM) was designed to ensure the SWIS has enough generation, DSM, and network capacity to supply all of its electricity requirements.

Figure 1 Map of the SWIS

2.1.1 Load duration curves

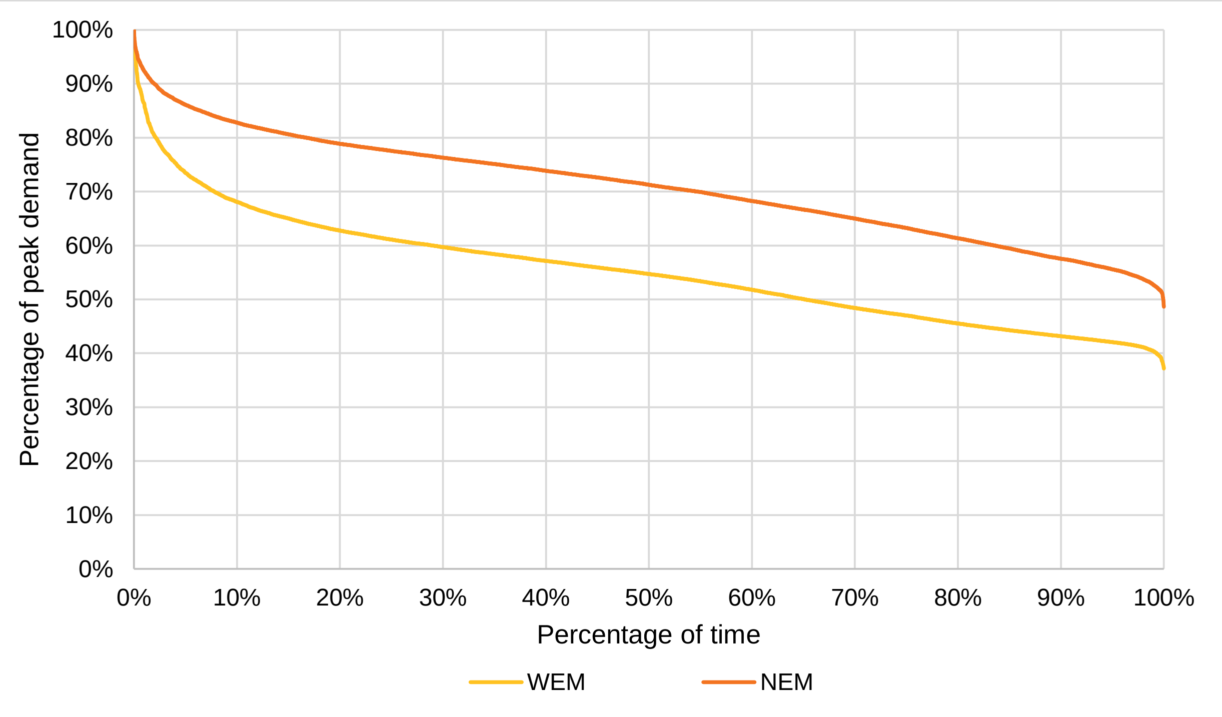
The load duration curve shows variation in demand over a period of time, and indicates the extremity of an electricity system's peak demand — the fewer trading intervals where load is greater than 90% of peak demand, the more severe the peak. Typically, in the SWIS, 90% or more of the peak demand is used for less than 1% of the time (around three days per year).

The load duration curve for the WEM for the 2014–15 Capacity Year (1 October 2014 to 1 October 2015) is shown in Figure 2. It highlights the need for a capacity market to provide sufficient incentives for peaking generation to be available when required and help determine the correct mix of generation types. For example, it is better to use peaking generators for short periods when demand is at its highest, due to high running costs.

Capacity payments via the RCM allow generators to recover long run marginal costs, while meeting short run marginal costs through payments in the energy market. As a result, the WEM has lower price caps in the energy markets compared to other, energy-only electricity markets (where generators recover long and short run marginal costs through the energy market) around the world.

The WEM and NEM load duration curves are compared in Figure 2. The WEM has a sharper peak than the NEM, with around 32% of the load used for 10% of the time, compared to 17% in the NEM. In addition, the minimum load in the NEM is higher than for the WEM at 49% of peak demand, compared to 37% in the WEM. The WEM is significantly smaller than the NEM, with an average peak demand of around 3,800 MW compared to 31,000 MW in the NEM.

Figure 2 Load duration curve for the 2014–15 Capacity Year



2.2 Market mechanisms in the WEM

The WEM includes mechanisms for both capacity and energy. This provides opportunities for investors in generation capacity, who can choose to participate in the energy market only, or in both energy and capacity markets. The energy market includes several options for trading – the balancing market, the Short Term Energy Market (STEM), and various ancillary services markets. Currently, Blair Fox's West Hills wind farm is the only Facility which operates solely in the energy market.[18]

The various market mechanisms in the WEM are summarised in Table 6, including a brief description and key features.

[18] CleanTech Energy's Richgro biogas Facility has operated in the energy market since December 2015 and was assigned Capacity Credits for the 2016–17 Capacity Year commencing on 1 October 2016.

Table 6 Market mechanisms in the WEM

Market mechanism	Brief description
Reserve Capacity Mechanism	Ensures enough capacity is available to meet the system peak demand.
Balancing market	A mandatory gross pool market that determines economic dispatch of generation to meet system demand.
Short Term Energy Market	A day ahead contractual market, allowing Market Participants to trade around bilateral positions for the following day.
Load rejection reserve ancillary service	A market for generators capable of rapidly decreasing output in the event of a sudden loss of demand, such as in the case of a system fault.
Load following ancillary service (LFAS)	Ensures that the target frequency range (49.8 to 50.2 hertz) is met 99% of the time by balancing demand and supply. Includes LFAS up and LFAS down.
Spinning reserve ancillary service	Capacity (may be from a generation Facility, Dispatchable Load, or interruptible load) held in reserve to respond rapidly in the event of an unexpected outage of a generation Facility.
Dispatch support ancillary service	Generators capable of maintaining voltage levels in the power system, as well as other services not covered by other ancillary service markets.
System restart ancillary service	Enables part of the power network to be re-energised by black start-equipped generation capacity following a complete, system-wide black out.

2.3 Diversity in the WEM

2.3.1 Capacity Credits by Market Participant

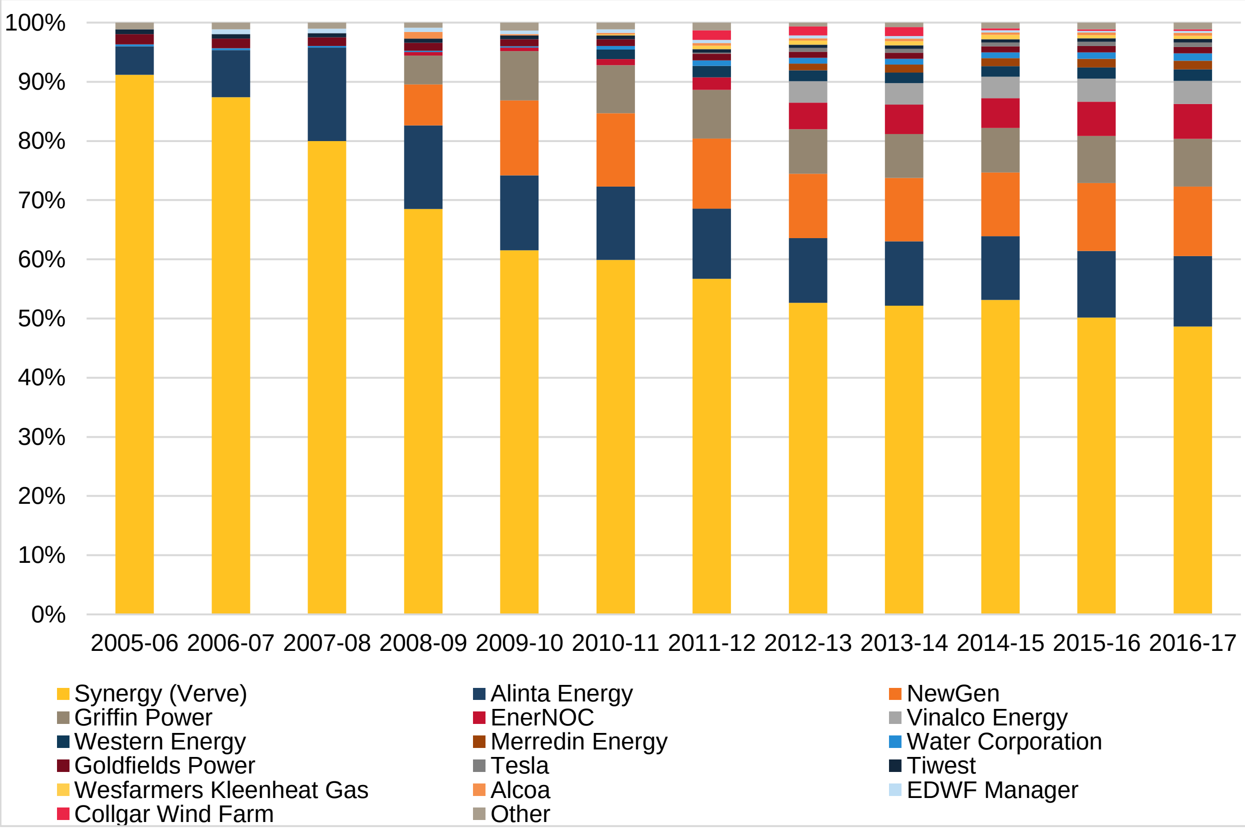
The WEM has a range of different generation types, and has become more competitive. Since the market started in 2006, the number of Market Participants has increased more than three-fold, with 34 Market Participants holding Capacity Credits in the 2016–17 Capacity Year, compared with 10 in 2005–06.

The share of Capacity Credits held by Synergy (formerly Verve Energy[19]) has decreased. This has largely been due to load growth and a Ministerial direction limiting Synergy to 3,000 MW of capacity[20], allowing other Market Participants to enter the market. In 2016–17, Synergy accounts for 49% of Capacity Credits, down from 91% at market start. The next two largest Capacity Credit holders, Alinta Energy and NewGen, account for around 12% of Capacity Credits each.

This increase in diversity represents a maturing market, with more private sector investment and competition. The allocation of Capacity Credits by Market Participant since market start is shown in Figure 3.

[19] The WA Government merged Verve Energy and Synergy on 1 January 2014, with the new entity trading as Synergy.
[20] See http://wa.aemo.com.au/docs/default-source/Reserve-Capacity/2006_capacity_cap_direction.pdf?sfvrsn=2.

Figure 3 Proportion of Capacity Credits by Market Participant, Capacity Year 2005–06 to 2016–17



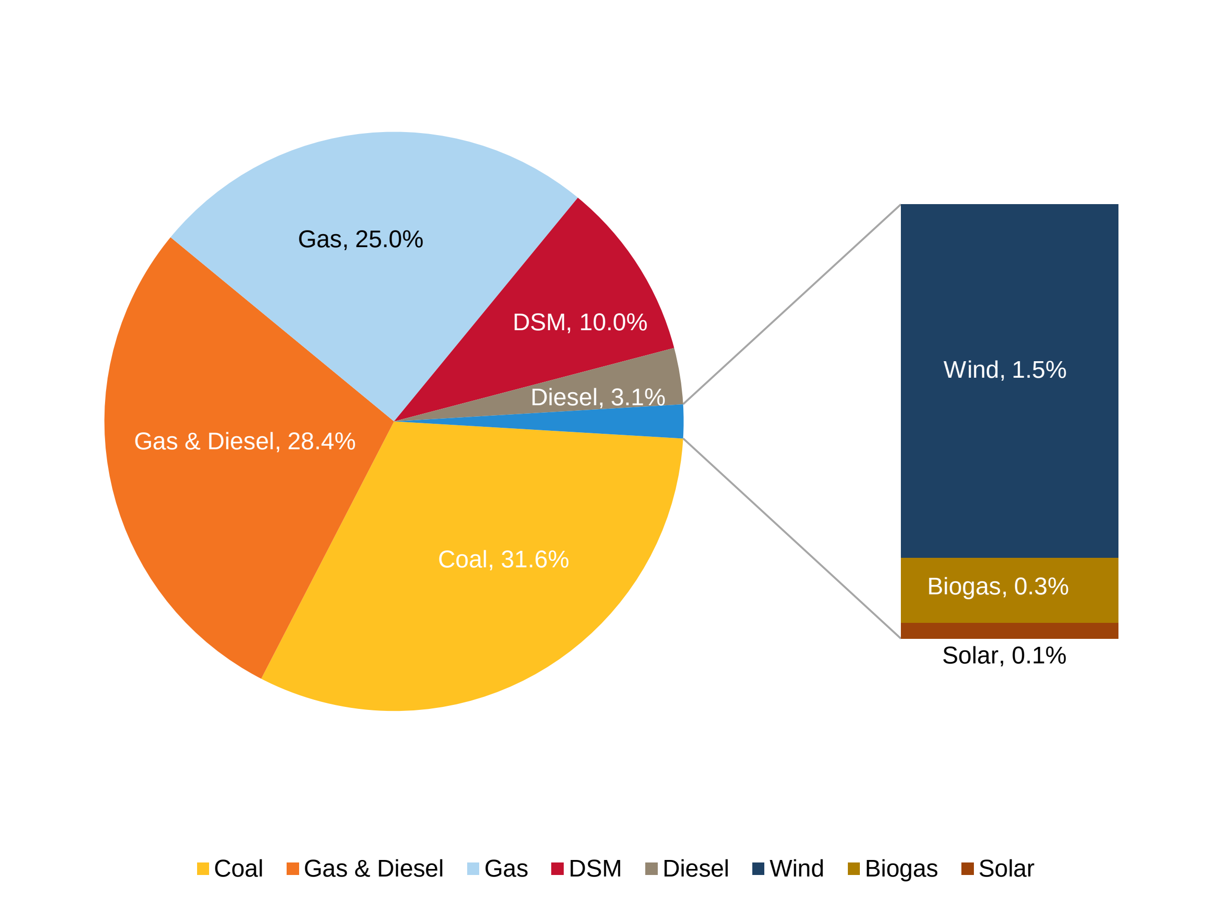
2.3.2 Capacity Credits by fuel type

There is a diverse mix of fuel types operating in the WEM. Since 2005–06, the WEM's reliance on primary fossil fuels (coal and gas) has reduced, with a total of 12% of Capacity Credits now allocated to diesel, DSM, and renewable generation. This compares with only 5% at market start. Dual-fuel capacity (gas/diesel) accounts for a 28% share.

Fuel diversity in the market is integral to maintaining security of supply, as well as supporting competition between technologies and generators. It mitigates events such as a restriction in the supply of one fuel that may otherwise result in a failure of the electricity system or supply disruptions. For example, fuel diversity in generation Facilities was essential in minimising the impact of two gas supply disruptions in 2008 and 2011.

The proportion of Capacity Credits by fuel type in the WEM is shown in Figure 4.

Figure 4 Proportion of Capacity Credits by fuel type[a], Capacity Year 2016–17



[a] Based on the capability of the power station. This may differ from the fuel type the Facility is certified for.

Over the period 2005–06 to 2016–17:

- The share of fossil fuel (coal, diesel and gas) generation capacity has fallen from 95% to 88%.
- The proportion of Capacity Credits assigned to renewable generators has remained relatively stable, averaging 2%.
- The proportion of Capacity Credits assigned to DSM tripled between 2010–11 and 2016–17, from around 3% to 10%.

Renewable energy as a share of Capacity Credits is expected to grow in the future as a result of the Commonwealth Government's Large-scale Renewable Energy Target (LRET). Further information on this is provided in Section 8.2.1.

2.4 Facilities operating in the SWIS

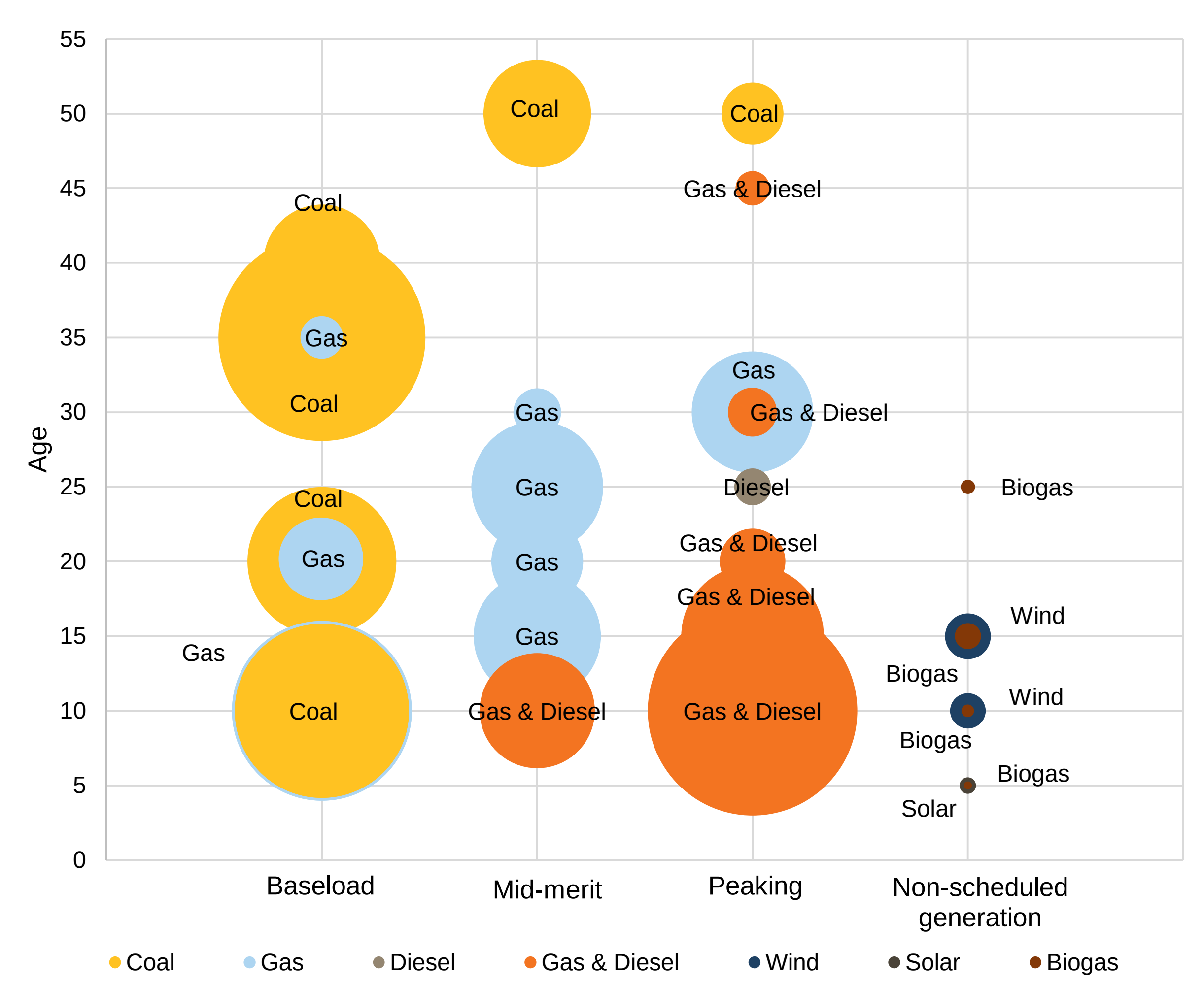
There are currently 67 generation Facilities in the SWIS[21], comprising 48 scheduled and 19[22] intermittent non-scheduled generators, in addition to 27 DSM Facilities. This section focuses on the characteristics of the generation Facilities operating in the SWIS, including fuel types, classification (peaking, mid-merit or baseload), energy output, and Capacity Credits assigned.

[21] Individual units for the 2016–17 Capacity Year. When units are grouped (for example, Muja 1, 2, 3, and 4 make up Muja AB) there are 26 power stations.

[22] Includes Blair Fox Karakin, which does not currently hold Capacity Credits but participates in the energy market.

The characteristics, including age, fuel capability and classification, of the Facilities currently operating in the SWIS are shown in Figure 5. Generation utilisation excludes full outages. The size of the bubbles represents the Capacity Credits granted for the 2016–17 Capacity Year. Baseload capacity is defined as capacity used more than 70% of the time, mid-merit as capacity used between 10% and 70% of the time, and peaking capacity as capacity used for less than 10% of the time. Capacity definitions are based on the number of intervals each Facility has operated over the past year, adjusted for full outages.

Figure 5 Facilities operating in the SWIS by age, fuel capability, and classification



In summary:

- Of the 2,492 MW of baseload generation capacity, around half (1,266 MW) is older than 20 years.
- Approximately 60% of coal-fired capacity is over 35 years old.
- The oldest generation facility in the SWIS is more than 50 years old.
- The majority of the intermittent generators are less than 15 years old.
- Around 40% of peaking generation is less than 10 years old and capable of operating on either gas or diesel.
- Most baseload generation capacity is coal or gas with no alternate fuel capability.

The scheduled generators in the SWIS, the quantity of energy generated by each, and the Capacity Credits assigned for the 2014–15 Capacity Year are shown in Table 7.

Table 7 Non-renewable power stations in the SWIS, 2014–15 Capacity Year

Power station (units included)	Participant	Classification	Energy generated[a]		Capacity Credits	
			GWh	Share (%)	MW[b]	Share (%)
Alcoa Wagerup	Alcoa	Baseload	87	0.6	24	0.5
Alinta Pinjarra (1 and 2)	Alinta Energy	Baseload	1,776	11.4	265	5.4
Alinta Wagerup (1 and 2)	Alinta Energy	Peaking	163	1.1	358	7.3
Bluewaters (1 and 2)	Bluewaters	Baseload	3,125	20.1	433	8.8
Cockburn	Synergy	Mid-merit	478	3.1	232	4.7
Collie	Synergy	Baseload	1,943	12.5	317	6.5
Kalamunda	Landfill Gas & Power	Peaking	0	0.0	1	0.0
Kemerton (11 and 12)	Synergy	Peaking	89	0.6	291	5.9
Kwinana gas turbine	Synergy	Peaking	0	0.0	15	0.3
Kwinana high efficiency gas turbines (2 and 3)	Synergy	Peaking	763	5.0	190	3.9
Merredin	Merredin Energy	Peaking	1	0.0	82	1.7
Muja AB (1, 2, 3 and 4)	Vinalco	Mid-merit[c]	138	0.9	220	4.5
Muja CD (5, 6 , 7 and 8)	Synergy	Baseload	3,491	22.5	807	16.5
Mungarra (1, 2 and 3)	Synergy	Mid-merit[d]	84	0.5	96	2.0
NewGen Kwinana	NewGen Kwinana	Baseload	2,160	13.9	320	6.5
NewGen Neerabup	NewGen Neerabup	Peaking	54	0.3	331	6.8
Parkeston	Goldfields Power	Peaking	0	0.0	61	1.2
Perth Energy Kwinana	Western Energy	Peaking	2	0.0	108	2.2
Perth Power Partnership Kwinana	Synergy	Baseload	527	3.4	80	1.6
Pinjar A (1 and 2)	Synergy	Peaking	4	0.0	62	1.3
Pinjar B (3, 4, 5 and 7)	Synergy	Peaking	17	0.1	146	3.0
Pinjar C (9 and 10)	Synergy	Mid-merit	294	1.9	217	4.4
Pinjar D (11)	Synergy	Mid-merit	154	1.0	120	2.4
Tesla Geraldton	Tesla	Peaking	0	0.0	10	0.2
Tesla Kemerton	Tesla	Peaking	0	0.0	10	0.2
Tesla Northam	Tesla	Peaking	0	0.0	10	0.2
Tesla Picton	Tesla	Peaking	0	0.0	10	0.2
Tiwest Cogeneration	Tiwest	Baseload	164	1.1	33	0.7
West Kalgoorlie (1 and 2)	Synergy	Peaking	1	0.0	53	1.1

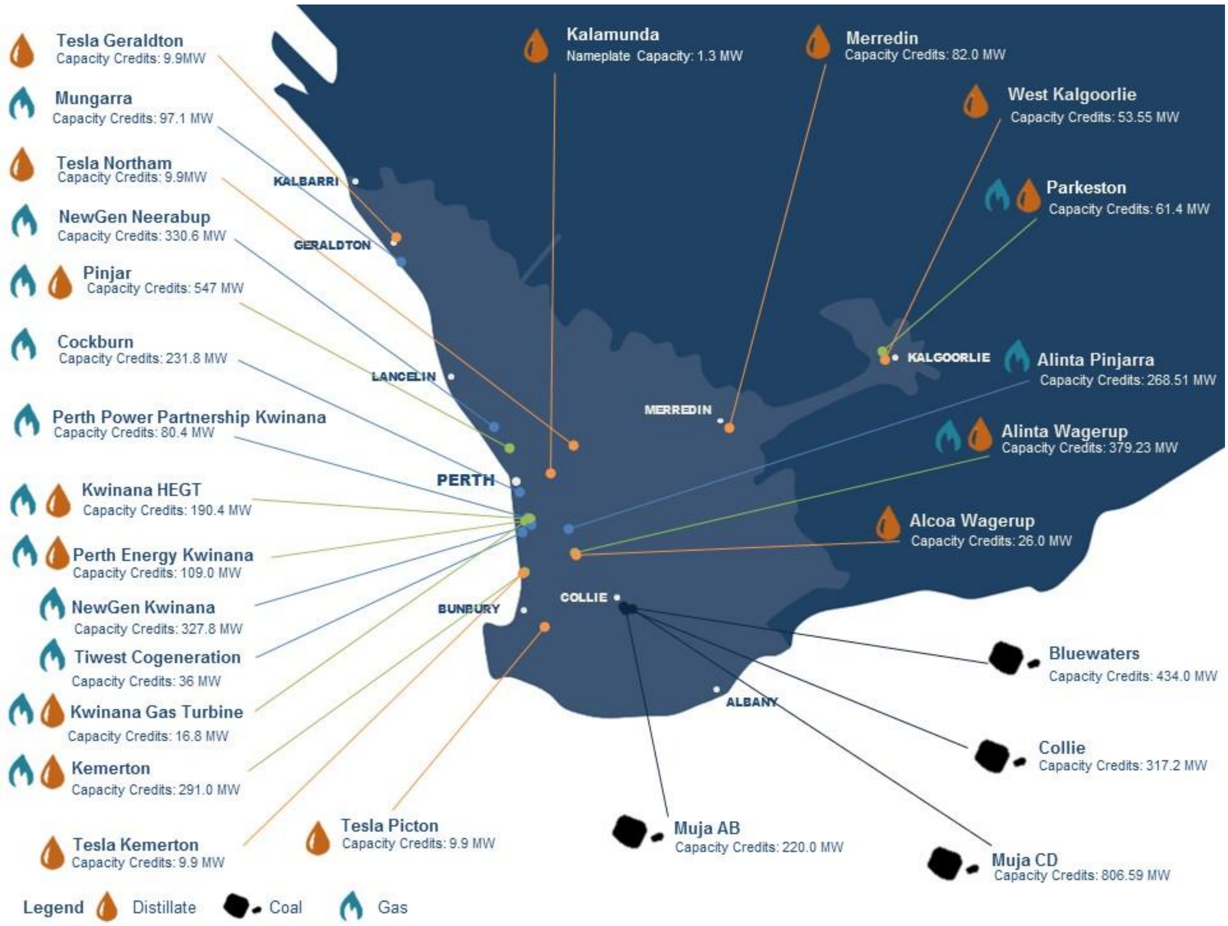
[a] Energy generated is calculated from Supervisory Control and Data Acquisition (SCADA) data.
[b] Rounded to the nearest integer.
[c] Unit 3 operates as peaking.
[d] Unit 2 operates as peaking.

At 807 MW, Muja CD is the largest power station in the SWIS, with four units accounting for 17% of Capacity Credits and 23% of the energy generated in the 2014–15 Capacity Year. Pinjar is the next largest power station, with nine units accounting for 546 MW and 11% of the Capacity Credits assigned for the 2014–15 Capacity Year.

While the nameplate capacity of a power station is somewhat correlated with the amount of energy it generates over a year, it largely depends on its age and classification, as well as the frequency and number of hours it runs. For example, NewGen Kwinana generated more than four times as much energy as Pinjar, despite being around half the size, in the 2014–15 Capacity Year. Newer generators are generally able to run for more hours before needing a maintenance outage.

The location and Capacity Credits assigned for the 2016–17 Capacity Year for the non-renewable energy Facilities in the SWIS are shown in Figure 6.

Figure 6 Non-renewable energy map for the SWIS



2.4.1 Facility outages and availability

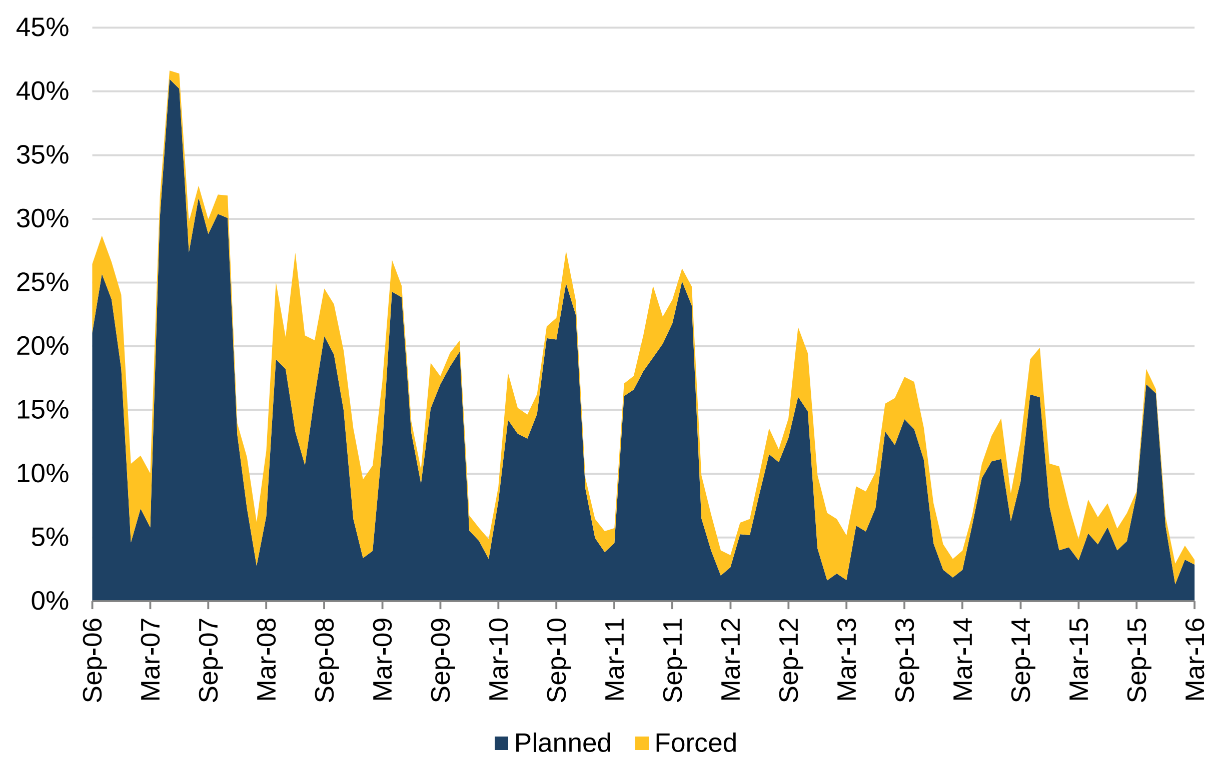
Total outage rates (planned and forced[23]) as a percentage of the Capacity Credits assigned are shown in Figure 7. This measures the total average outage rate of all Market Participants supplying capacity in the SWIS.

Average monthly planned and forced outages have been declining in the SWIS since 2006, a trend that continued in 2015–16. This suggests the majority of generation that has been assigned Capacity Credits is available to meet peak demand.

Outage rates are typically lower over summer periods, when demand is expected to be the highest. However, outages were unusually high during summer 2014–15, reflecting higher than normal forced outages. After this period of high outages during 2014–15, outages returned to more typical levels in summer 2015–16 (around 2%).

[23] In this section, forced outage rates include consequential outages (an outage that is unrelated to and not caused by the generator).

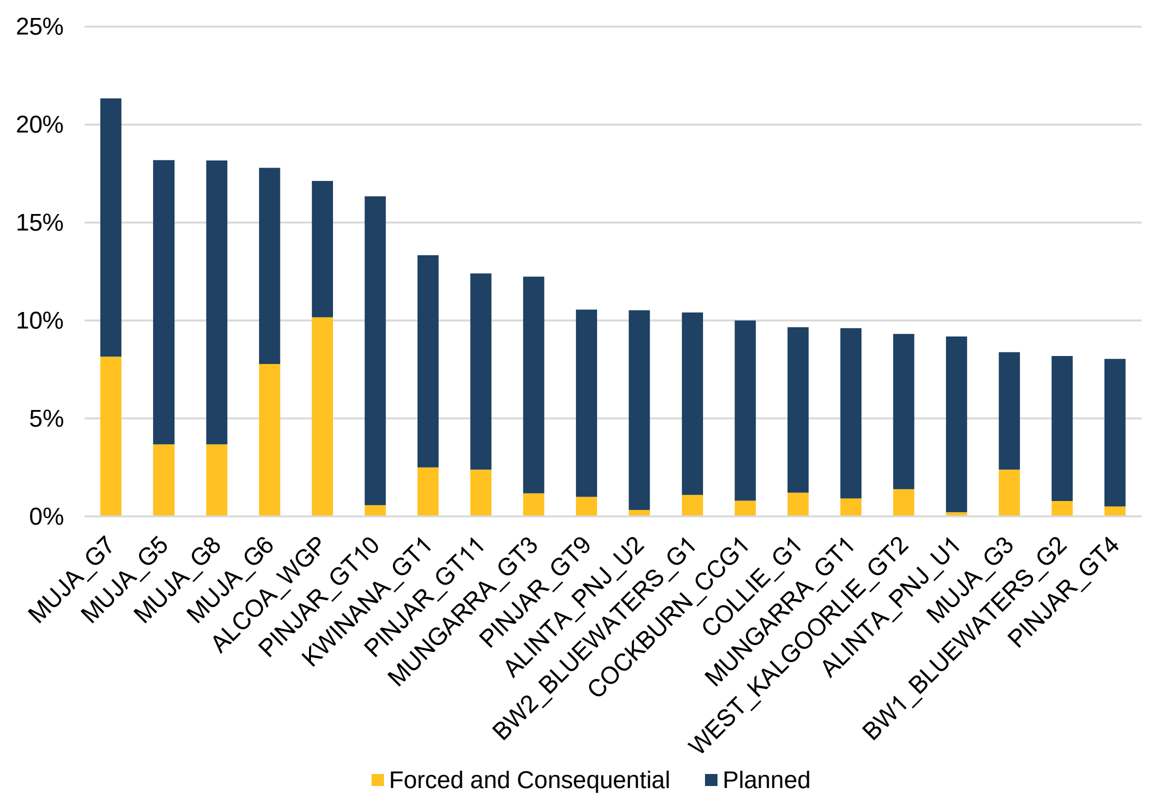
Figure 7 Total monthly average outage percentage, September 2006 to March 2016[a]



[a] The operation date for Muja AB is when refurbishment was completed and the Facilities returned to service.

The 20 Facilities with the highest level of outages over the previous 36 months are shown in Figure 8. Combined outage rates for Muja CD (units 5, 6, 7 and 8) were the highest at between 15% and 20%. Alcoa's Wagerup Facility had similarly high outage rates at around 17%, and had the highest forced outage rate of around 10%.

Figure 8 Outages by Facility for the 36 months to February 2016[a, b]



[a] Retired Facilities and intermittent generators are excluded.
[b] Presented by Facility to show individual unit outages, which can vary with age. For example, Pinjar_GT11 has higher outage rates than Pinjar_GT5, largely because it is older.

High outage rates, and in particular high forced outage rates, are generally correlated with the age of the Facility and the frequency of operation. For example, Muja CD (average age of 32.5 years), Pinjar (average age of 24 years), and Alcoa Wagerup (31 years) have the highest outage rates in the WEM. Large baseload generators (Muja CD, Bluewaters and Collie) have high outage rates, indicating that this capacity may not always be reliable or available for dispatch.

2.4.2 Renewable energy

Renewable generators in the SWIS, the quantity of energy generated by each, and the Capacity Credits assigned for the 2014–15 Capacity Year are shown in Table 8.

Table 8 Renewable energy Facilities in the SWIS, 2014–15 Capacity Year[a]

Facility	Participant	Energy source	Nameplate capacity (MW)	Energy generated[b]		Capacity Credits[c]	
				GWh	Share (%)	MW	Share (%)
Albany	Synergy	Wind	21.6	56	3.3	10.4	8.0
Atlas	Perth Energy	Biogas	1.123	4	0.3	0.7	0.5
Bremer Bay[d]	Synergy	Wind	0.6	2	0.1	0.0	0.0
Collgar	Collgar Wind Farm	Wind	206	686	40.0	20.1	15.6
Denmark	Denmark Community Windfarm	Wind	1.6	5	0.2	1.3	1.0
Emu Downs	EDWF Manager	Wind	80	250	14.6	22.4	17.3
Grasmere	Synergy	Wind	13.8	39	2.3	6.1	4.8
Greenough River	Synergy	Solar	10	22	1.3	5.9	4.5
Henderson	Waste Gas Resources	Biogas	3.195	18	1.0	2.3	1.8
Kalbarri	Synergy	Wind	1.6	4	0.2	0.3	0.2
Karakin	Blair Fox	Wind	5	6	0.3	1.4	1.1
Mount Barker	Mt.Barker Power Company	Wind	2.43	6	0.3	1.0	0.8
Mumbida	Mumbida Wind Farm	Wind	55	187	10.9	18.2	14.1
Red Hill	Landfill Gas & Power	Biogas	4	24	0.8	2.8	2.2
Rockingham	Perth Energy	Biogas	4	14	0.8	2.5	2.0
South Cardup	Perth Energy	Biogas	3.369	26	1.5	2.5	1.9
Tamala Park	Landfill Gas & Power	Biogas	5.0	34	2.0	3.9	3.0
Walkaway	Alinta Energy	Wind	89.1	338	19.7	27.5	21.3

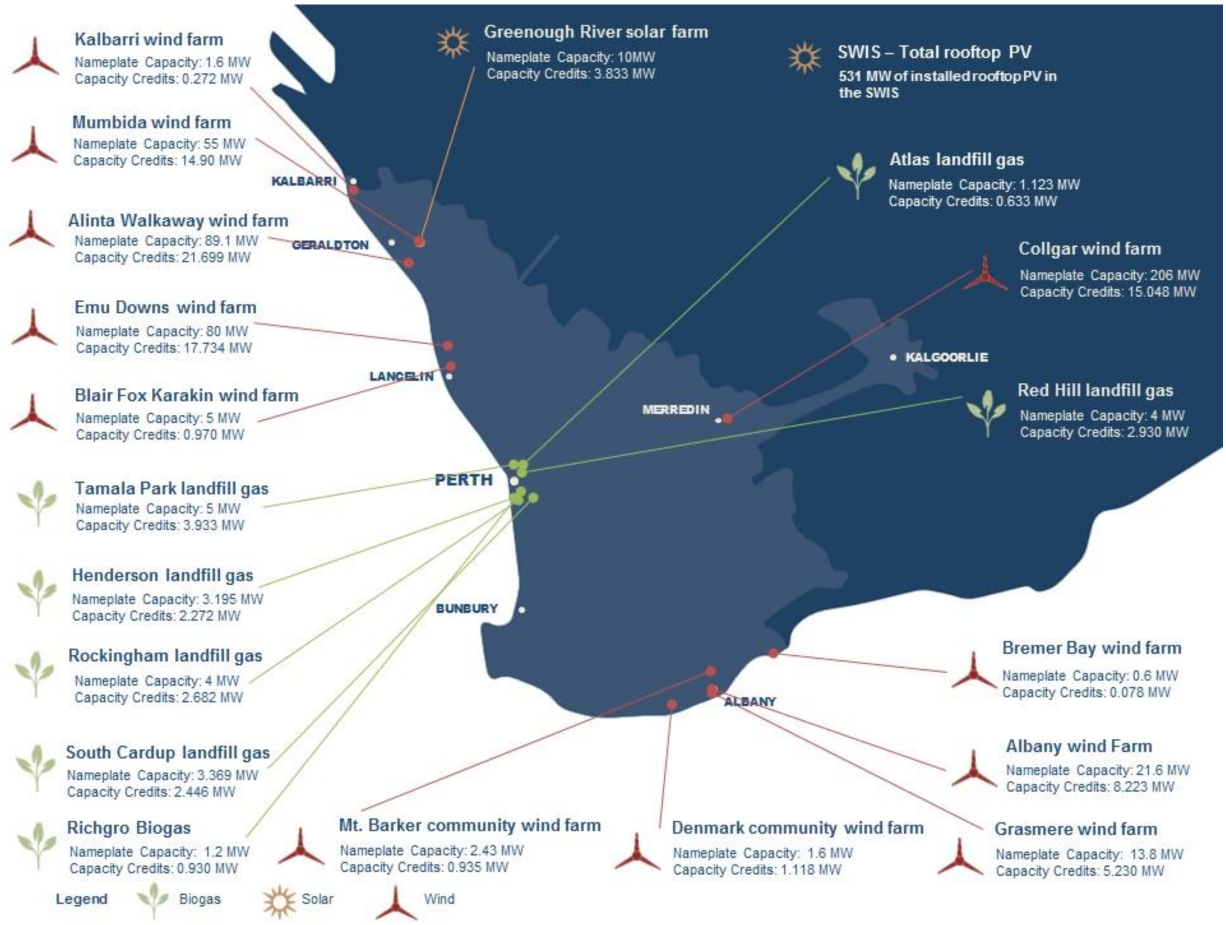
[a] CleanTech Energy's Richgro Biogas Facility (BIOGAS01) was not operating in the 2014–15 Capacity Year and is not included in this table.
[b] Energy generated is calculated based on SCADA data.
[c] Rounded to one decimal place.
[d] Bremer Bay wind farm did not hold Capacity Credits for the 2014–15 Capacity Year.

A total of 129 MW of renewable generation has been assigned Capacity Credits in the SWIS (based on the Capacity Credits assigned for the 2014–15 Capacity Year). Wind generators account for 84% of this capacity, with biogas and solar making up 11% and 5%, respectively. The four largest wind farms (Collgar, Emu Downs, Mumbida, and Walkaway) account for more than two thirds of the total renewable capacity.

Energy generation is dependent on the nameplate capacity of the Facility, with the larger wind farms contributing more energy than smaller landfill gas Facilities. Collgar Wind Farm, the largest generator based on 206 MW of nameplate capacity, accounted for around 40% of the total energy generated by intermittent generators in the 2014–15 Capacity Year. The next largest generator, Walkaway Wind Farm (89.1 MW nameplate capacity), accounted for nearly 20% of energy generated.

The location, nameplate capacity, and Capacity Credits assigned for the 2016–17 Capacity Year of the renewable energy Facilities in the SWIS are shown in Figure 9. In addition, the map shows the total installed rooftop PV capacity.

Figure 9 Renewable energy map for the SWIS



Source: AEMO and Clean Energy Regulator (CER)

CHAPTER 3. PEAK DEMAND AND CUSTOMER CONSUMPTION

Peak demand in the SWIS has historically been driven by consecutive days of high temperatures in Perth (over 36°C).

This chapter discusses:

- The summer 2015–16 peak demand in the SWIS, the factors that contributed to it, and historical trends since 2008.
- Factors affecting peak demand, including the IRCR and uptake of commercial and residential rooftop PV.
- Recent trends in consumption by residential, commercial and large industrial customers.

3.1 Peak demand in the SWIS

3.1.1 Summer 2015–16 peak demand

The summer 2015–16 system peak was 4,013 MW and was observed in the 17:30 to 18:00 trading interval on 8 February 2016.

This was during a period of four consecutive days between 7 and 10 February 2016 when maximum temperatures exceeded 40°C (measured at the Perth Metro weather station). Peak demand on 8 February 2016 was a record for the SWIS, exceeding the previous highest demand of 3,857 MW observed on 25 January 2012.

In addition to setting this new record for peak demand, in the summer of 2015–16 there were 19 trading intervals over three separate days when peak demand exceeded the previous record of 3,857 MW. On 14 March 2016, demand was within 1% of the 8 February 2016 peak.

Peak demand has been shifting later in the day and usually occurs in the late afternoon, when people arrive home from work or school and turn on air conditioning. Trends over previous years show that peak demand occurred:

- In the 16:30 to 17:00 trading interval from 2010–11 to 2012–13.
- Around one hour later, in the 17:30 to 18:00 trading interval, in 2013–14 and 2015–16.
- Unusually early in 2014–15 in the 15:30 to 16:00 trading interval, during the holiday period (on 5 January 2015).

The reasons for this shift in the time of peak demand for the last five years are discussed in Section 3.3.

3.1.2 Historical peak demand

Peak demand and associated temperature statistics for the past nine years are shown in Table 9.

This year's peak demand (4,013 MW on 8 February 2016) was 7.2% higher than last year's peak (3,744 MW), and 4% higher than the previous record peak demand for the SWIS (3,857 MW on 25 January 2012).

Table 9 Comparison of peak demand days, 2007–08 to 2015–16

Date	Peak demand (MW)	Maximum temperature during trading interval (°C)	Trading interval commencing	Daily maximum temperature (°C)
8 February 2016	4,013	40.2	17:30	42.5
5 January 2015	3,744	40.8	15:30	44.4
20 January 2014	3,702	37.4	17:30	38.3
12 February 2013	3,732	35.4	16:30	40.5
25 January 2012	3,857	40.0	16:30	41.0
16 February 2011	3,735	37.5	16:30	39.0
25 February 2010	3,766	39.5	16:00	41.5
11 February 2009	3,515	39.5	15:30	39.7
28 February 2008	3,392	36.9	15:00	41.5

Source: AEMO and Bureau of Meteorology (BOM)

Peak demand and its timing have become increasingly hard to forecast. Over the last nine years, both the time of year and the time of day that peak demand occurred varied. The time of day has shifted later by two and half hours, and ranged from the first week of January to the last week of February. This can be attributed to a range of factors, particularly the rapid uptake of rooftop PV and customer responses to the capacity cost allocation mechanism (the IRCR). A more detailed discussion has been provided in Sections 3.2 to 3.4.

As shown in Table 9, peak demand has in the past typically occurred in the late afternoon, when people arrive home from work or school and turn on air conditioning. In 2014 and 2016, peak demand was around one hour later than in previous years, occurring in the 17:30 to 18:00 trading interval rather than the 16:30 to 17:00 trading interval observed from 2011 to 2013. The 2015 peak was unusually early in the day, because a large proportion of the residential population would have been at home following the New Year break. In addition, business and industrial electricity users would not have been operating at full capacity.

The increasingly unpredictable nature of peak demand presents a range of challenges. This affects the accuracy of the RCT, which is based on the 10% POE peak demand forecast, and increases the risk of procuring too much or too little capacity. Setting an incorrect RCT would affect the Reserve Capacity Price (RCP) — the price paid to Capacity Credit holders — which may not adequately reflect the economic value of capacity, and may send inappropriate price signals to the market.

3.2 Individual Reserve Capacity Requirement

Data for the summer 2015–16 peak shows that the allocation of capacity costs via the IRCR mechanism continues to encourage customers to reduce consumption during periods of high demand.

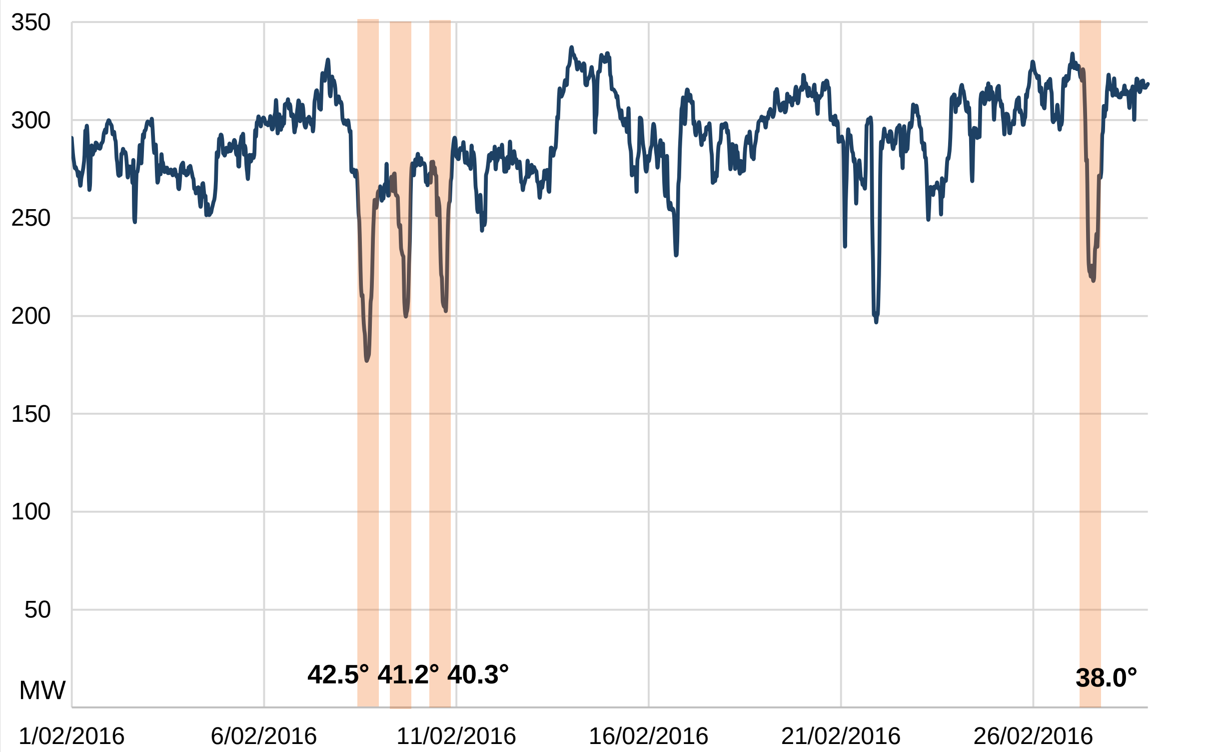
To fund the RCM, AEMO assigns an IRCR to each Market Customer based on the peak demand usage from its customer base in the previous hot summer season. Specifically, the IRCR is a quantity (in MW) determined based on the median consumption of each metered load in a Market Customer's portfolio during the 12 system peak intervals from the previous hot season (defined as 1 December to 31 March). The IRCR is then used to allocate the cost of Capacity Credits acquired through the RCM.

As a result, the IRCR provides customers with a financial incentive to reduce consumption during periods of peak demand and consequently reduce their exposure to Capacity Credit payments.

At the time of the 2015–16 peak demand, 57 customers reduced consumption, resulting in a total load reduction of 77 MW. This was almost double the response observed during the 2014–15 peak demand, when 20 customers reduced load by 42 MW. The low reduction in 2014–15 was due to peak demand occurring during the New Year break, when large customers were running at lower output.

The consumption of the 57 most responsive loads to the IRCR during February 2016 is shown in Figure 10. The shaded areas on the graph highlight the afternoons of the three hottest days in February 2016, and the maximum temperature on each of those days. The low load period between 21:00 and 23:30 on 21 February 2016 was caused by an outage for one large customer and was not an IRCR response.

Figure 10 IRCR response for 57 customers, February 2016



The response to the IRCR mechanism for the past five years is shown in Table 10. The increasing volatility of the timing of peak demand days has made it more difficult for large users to predict days on which to respond, resulting in varying responses over the past five years. In 2015–16, large industrial users were well-prepared for the peak demand; it displayed characteristics of a typical peak and the BOM accurately forecast the heatwave four days in advance, allowing sufficient time for customers to plan a response. Some large loads chose to reduce consumption over the entire week in which peak demand occurred, when weather forecasts indicated a run of at least four consecutive days of temperatures over 40°C.

Table 10 IRCR response on peak demand days, 2012 to 2016

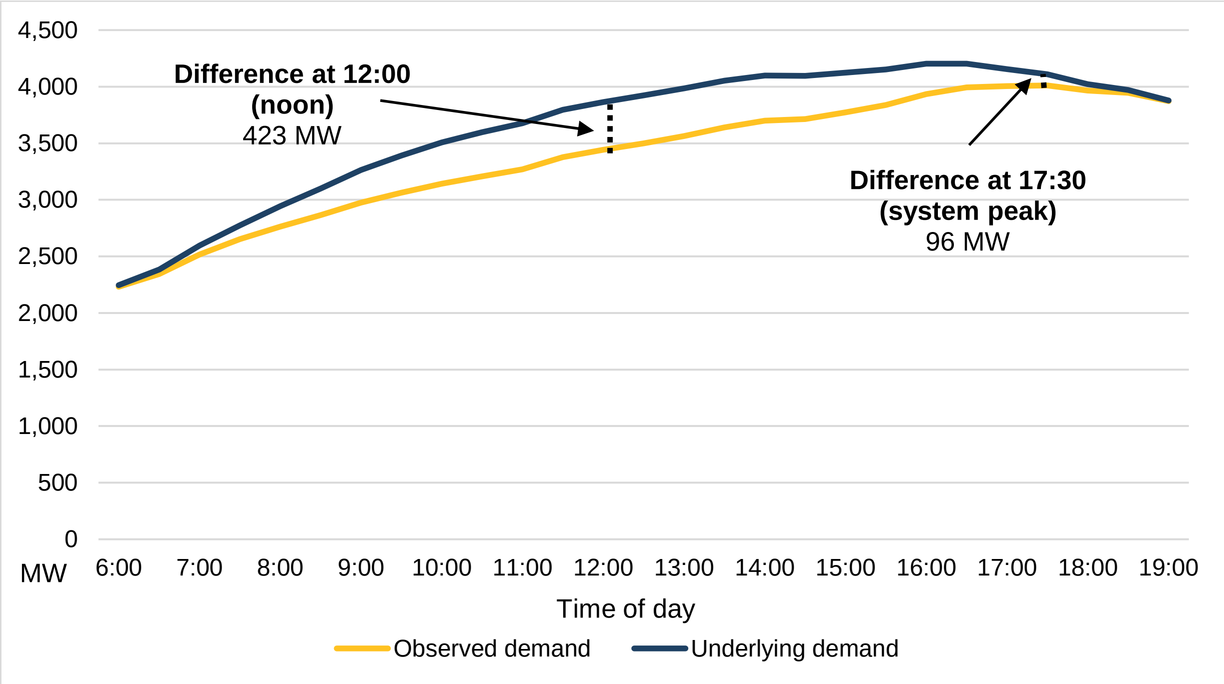
Date	Peak demand (MW)	Trading interval commencing	Estimated IRCR reduction (MW)	Number of customers responding
8 February 2016	4,013	17:30	77	57
5 January 2015	3,744	15:30	42	20
20 January 2014	3,702	17:30	50	44
12 February 2013	3,732	16:30	65	59
25 January 2012	3,857	16:30	50	59

3.3 Effect of rooftop PV on peak demand

The effect of rooftop PV[24] on peak demand depends on the time of day that peak demand occurs, due to the output profile of a PV system, which is highest at noon and falls during the afternoon.

In Figure 11, the actual demand profile on 8 February 2016 is compared to AEMO's estimate of the demand that would have occurred if no rooftop PV had been installed (underlying demand[25]).

Figure 11 Daily daytime demand profile, observed and estimated without rooftop PV, 8 February 2016



Estimated peak demand excluding the effects of rooftop PV is estimated as 4,204 MW, 4.8% higher than the observed peak demand of 4,013 MW on 8 February 2016.

Rooftop PV reduced peak demand by 191 MW as a result of:

- Shifting the timing of peak demand by one hour, from the trading interval starting at 16:30 to the trading interval starting at 17:30, reducing peak demand by 95 MW.
- Generation from rooftop PV reducing peak demand by 96 MW or 2.3%, from 4,109 MW to 4,013 MW.

The continued growth of rooftop PV installations has affected both the level and timing of peak demand over the last five years, discussion of which has been provided in Section 3.4. Actual peak demand over the five highest demand days for 2012 to 2016 is compared with the estimated peak that would have occurred without rooftop PV in Table 11.

[24] Defined as small-scale commercial and residential PV systems less than 100 kW eligible for Small-scale Technology Certificates under the Renewable Energy Target.
[25] Underlying demand refers to everything consumed on site, and can be provided by localised generation from rooftop PV, battery storage, and embedded generators, or by the electricity grid.

Table 11 Effect on rooftop PV on peak demand, 2012 to 2016

Date	Trading interval commencing	Peak demand (MW)	Estimated peak demand without rooftop PV (MW)	Estimated peak trading interval commencing without rooftop PV	Reduction in peak demand from rooftop PV (MW)	Reduction in peak demand from peak time shift (MW)
8 February 2016	17:30	4,013	4,204	16:30	96	95
5 January 2015	15:30	3,744	3,931	14:30	165	32
20 January 2014	17:30	3,702	3,757	15:30	81	29
12 February 2013	16:30	3,732	3,816	13:30	81	6
25 January 2012	16:30	3,857	3,918	15:00	72	19

3.4 Small-scale rooftop PV systems

3.4.1 Rooftop PV system growth

Small-scale residential and commercial rooftop PV systems allow electricity customers to generate a proportion of their electricity needs onsite. Any excess generation is exported to the electricity network, for which customers may receive a payment.[26] While rooftop PV systems do not directly reduce electricity consumption, they do reduce the quantity of electricity that needs to be delivered from the network during daylight hours, affecting average demand from the network per connection.

Key statistics for rooftop PV systems installed by Synergy's customers eligible for the Renewable Energy Buyback Scheme (REBS)[27], as well as the average new installation size for all customers published by the CER, for the period 2010–11 to 2015–16 are shown in Table 12.

The number of rooftop PV systems grew from 60,913 in 2010–11 to 179,576 in February 2016. Roughly one in five (22.5%) residential customers in the SWIS now has rooftop PV installed, making WA the third highest state for dwellings with rooftop PV as a proportion of total dwellings, behind Queensland (29.6%) and South Australia (28.8%).[28]

Table 12 Key statistics for residential rooftop PV systems, 2010–11 to 2015–16

Year	Number of REBS systems[a]	Proportion of customers with rooftop PV installed[a] (%)	Average system size (kW)[a]	Average new installation size (kW)[b]
2010–11	60,913	7.3	1.9	2.3
2011–12	92,938	10.9	2.0	2.3
2012–13	119,943	13.3	2.1	3.1
2013–14	141,347	15.4	2.3	4.4
2014–15	165,721	17.6	2.4	4.6
2015–16 (until February 2016)	179,576	Not available	2.6	4.5
Average annual growth (2010–11 to 2014–15)	28.4	24.6	6.0	18.9

Source: CER and Synergy
[a] Sourced from Synergy.
[b] Sourced from CER.

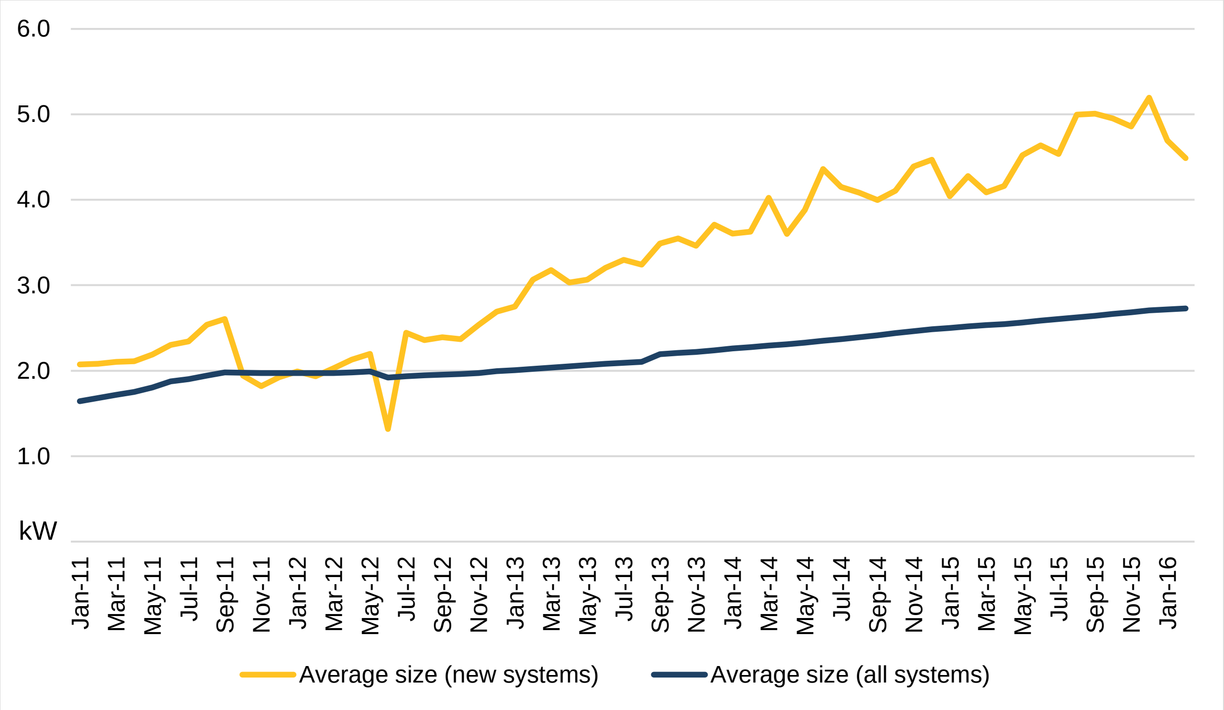
Average system size increased from 1.9 kW in June 2011 to 2.7 kW in February 2016, due to a doubling of the average system size for new installations, from 2.3 kW in June 2011 to 4.5 kW in

[26] Currently, only residential and some non-profit and charity organisations are eligible to receive payments for exported energy generated from a rooftop PV system.
[27] Defined as residential customers, not-for-profit organisations or educational institutions who install a rooftop PV system between 500 watts and 5 kW. See https://synergy.net.au/Your-home/Help-and-advice/Solar-credits-and-upgrades/Am-I-eligible-for-REBS.
[28] Based on data from the Australian PV Institute, available at http://pv-map.apvi.org.au/.

February 2016. This increase in system size is associated with falling prices for rooftop PV systems, and reflects a greater number of systems installed by commercial customers, which would typically be larger than a residential system.

Data from CER shows a similar trend for residential and commercial customers in the SWIS, as shown in Figure 12. The average size of new rooftop PV systems installed per month since December 2010 has grown rapidly, compared with the average system size of all systems in the SWIS. The fall in installation size in June 2012 was an outlier related to a government policy decision, when the Solar Credits multiplier was reduced, leading to a large number of small systems being installed. The average size of new systems returned to trend growth levels the following month.

Figure 12 Average size of monthly rooftop PV system installations, January 2011 to February 2016

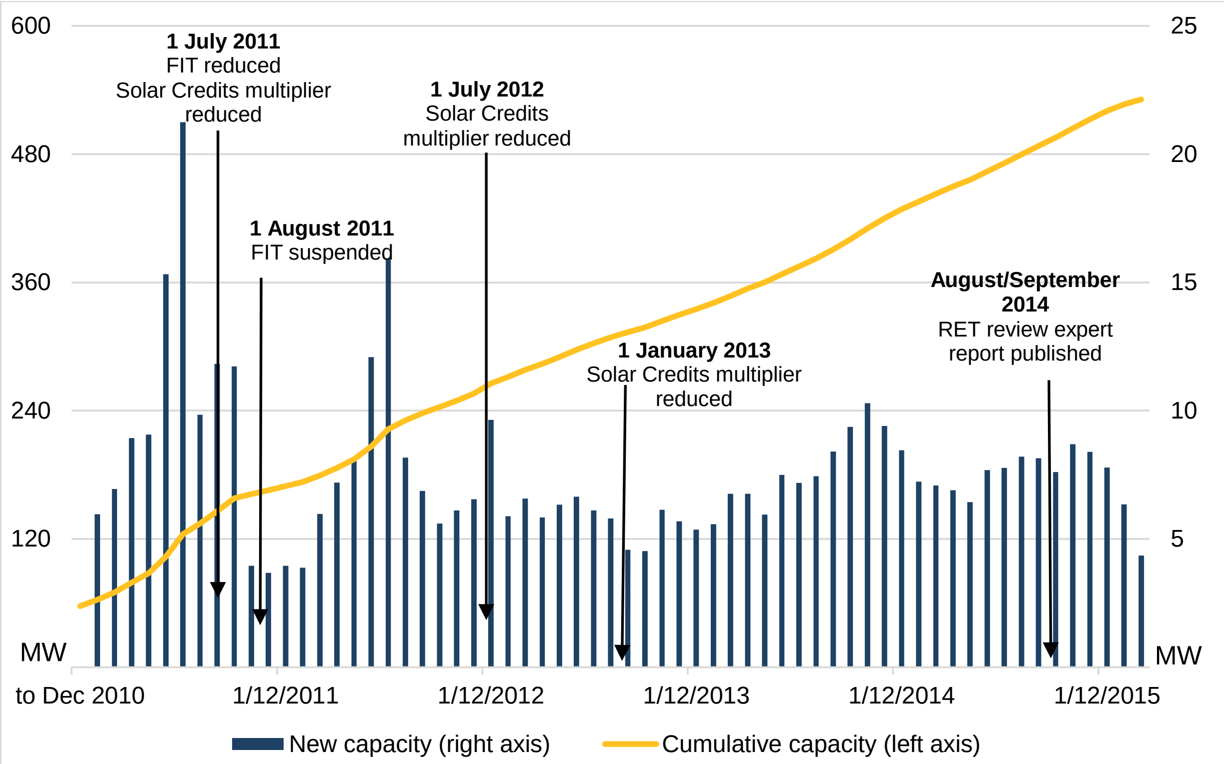


Source: CER

Installed rooftop PV capacity has increased at a rate between the expected and high case forecasts published in the 2014 ESOO. Based on CER data, at the end of February 2016, installed capacity in the SWIS was 531.1 MW. The 2014 ESOO forecast installed rooftop PV capacity to reach 530 MW by June 2016 in the expected case, and 559 MW in the high case. Monthly installations of rooftop PV during 2015 were in line with the assumptions from the low case in the 2014 ESOO at 1,666 per month, but the average system size was higher than the 4.5 kW forecast in the low case at around 5 kW, resulting in roughly 7.7 MW of capacity being installed each month in 2015.

Monthly and cumulative capacity installed between December 2010 and February 2016 is shown in Figure 13. Installed rooftop PV capacity has increased from 63 MW in January 2011 to 531 MW in February 2016 (an average annual increase of 53%).

Figure 13 Monthly and cumulative installed rooftop PV system capacity, December 2010 to February 2016



Source: CER

Government incentives that helped drive uptake in residential rooftop PV systems during 2011 did not apply to commercial installations. However, as electricity prices have increased and the cost of rooftop PV has fallen, the value proposition for commercial rooftop PV has improved, leading to a greater number of commercial customer installations.

The increase in rooftop PV installations is driven in part by a fall in the average prices of rooftop PV systems. The cost of residential and commercial rooftop PV systems has continued to fall, as shown in Table 13 and Table 14.[29] Specifically:

- The cost of residential systems has decreased by 30% for a 1.5 kW system since 2012.
- The cost to install a larger, 5 kW system has roughly halved since 2012.
- Prices for large commercial systems (100 kW) have fallen substantially, by around 25% since 2014.

The fall in price for larger residential and commercial rooftop PV is one of the drivers increasing the average new installed system size in the SWIS.

Table 13 Average rooftop PV system installation costs in Perth, August 2012 to February 2016

	August 2012		February 2016	
	Cost per Watt	Total cost	Cost per Watt	Total cost
1.5 kW	$2.15	$3,222	$1.50	$2,248
5 kW	$2.34	$11,683	$1.17	$5,829

Source: Solar Choice[30]

[29] Price data has been obtained from Solar Choice. All costs include installation and discounts for Small-scale Technology Certificates.
[30] Available at: http://www.solarchoice.net.au/blog/category/installation-advice/solar-system-prices-2/?main.

Table 14 Average commercial rooftop PV system installation costs in Perth, May 2014 to February 2016[31]

	May 2014		February 2016	
	Cost per Watt	Total cost	Cost per Watt	Total cost
10 kW	$1.56	$15,608	$1.58	$15,829
100 kW	$1.77	$176,867	$1.34	$134,203

Source: Solar Choice[32]

3.4.2 Strong uptake of rooftop PV is expected to continue

AEMO expects the strong growth of rooftop PV capacity in the SWIS to continue. Technological, commercial and regulatory factors, as well as increasing environmental awareness, continue to drive this strong uptake. Key factors include:

- Government incentives – rebates on rooftop PV installations continue to be accessible by residential and commercial customers through the Commonwealth Government's Renewable Energy Target (RET) providing discounts for systems.
- Declining system costs – continued falls in retail prices for residential and commercial rooftop PV systems are making renewable systems more financially viable for customers.
- Increasing electricity tariffs – increases in electricity tariffs have increased costs to customers and may cause them to reassess their electricity consumption behaviour. This may lead to greater use of solar, and potentially battery storage in the future.
- Changes in consumer attitudes and consumption behaviour – electricity consumers are becoming more aware of existing and emerging technologies such as rooftop PV and battery storage, and are considering ways to optimise their electricity consumption behaviour.

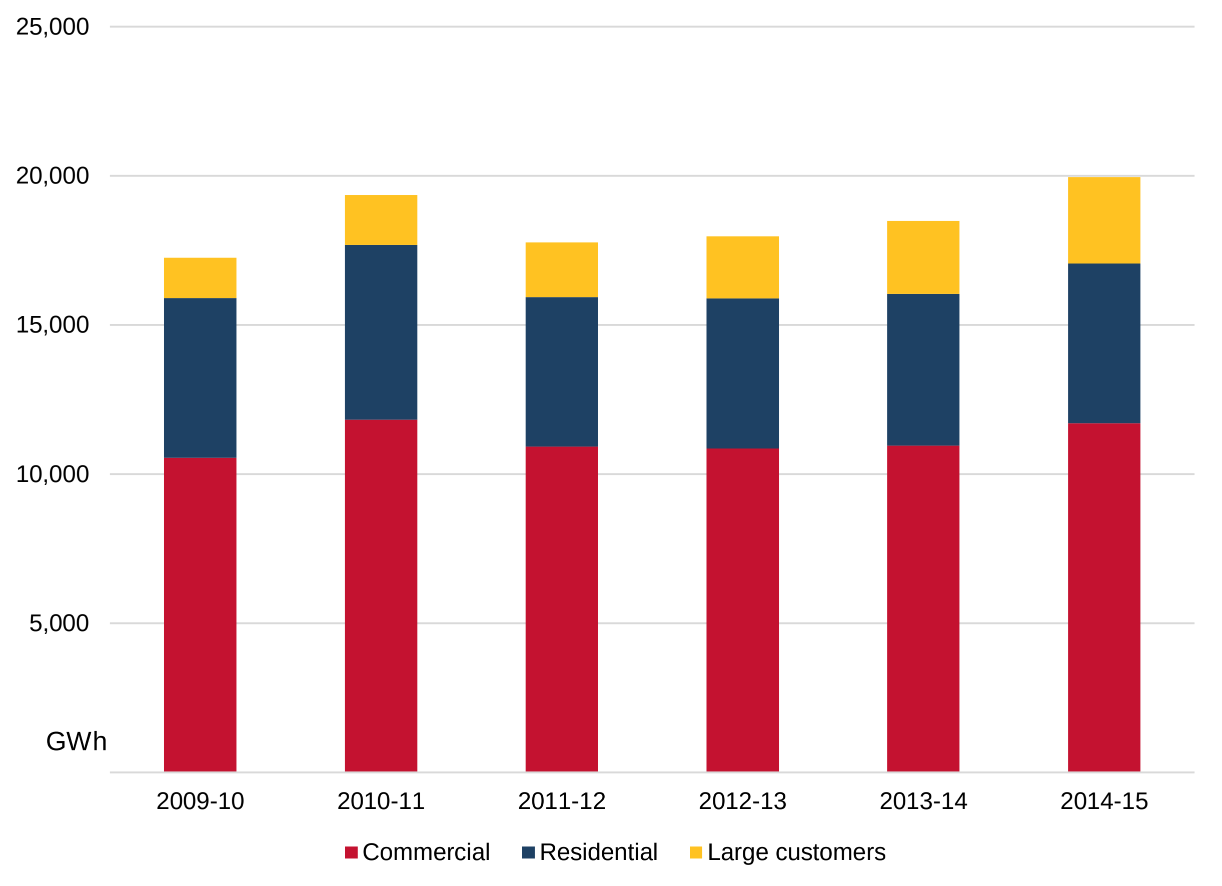
3.5 SWIS electricity consumption

Underlying electricity consumption continues to grow due to increased use of electrical appliances, including reverse cycle air-conditioning and entertainment devices. However, average consumption per connection from the electricity network has fallen, largely as a result of growth in rooftop PV, which has allowed residential and commercial customers to generate some of their electricity needs onsite. This has reduced the growth in operational consumption.

Residential and commercial underlying electricity consumption between 2009–10 and 2014–15 is shown in Figure 14. Commercial consumption accounts for around 75% of total SWIS electricity consumption, with about a fifth of this commercial demand accounted for by nine large commercial customers (individual customers with an average demand of at least 20 MW). Despite falling operational residential consumption, total operational consumption grew by 15.7% between 2009–10 and 2014–15, driven by increases in consumption for commercial customers.

[31] Data for commercial systems have only been available since May 2014.
[32] Available at: http://www.solarchoice.net.au/blog/category/installation-advice/solar-system-prices-2/?main.

Figure 14 Total operational consumption in the SWIS, 2009–10 to 2014–15



3.5.1 Residential

WA population growth is an important contributor to SWIS residential electricity demand. However, recent residential consumption data shows increases in residential connections do not necessarily lead to a corresponding increase in total electricity consumption.

As shown in Table 15, between 2008–09 and 2014–15, operational residential consumption decreased from 5,103 GWh to 4,875 GWh, despite the number of residential customers increasing at an average annual rate of 1.8%. Over the same period, average electricity use per connection fell at an average annual rate of 2.4%.

Table 15 Key statistics for residential customers, 2008–09 to 2014–15

Financial year	Total number of connections[a]	Growth in connections (%)	Residential electricity sales (GWh)	Growth in sales (%)	Average annual consumption per connection (kWh)	Growth in consumption per connection (%)
2008–09	832,192	NA	5,103	NA	6,131	NA
2009–10	846,042	1.6	5,350	4.8	6,324	3.2
2010–11	874,195	3.3	5,406	1.0	6,184	-2.2
2011–12	894,210	2.3	5,008	-7.4	5,600	-9.4
2012–13	900,396	0.7	5,040	0.6	5,598	-0.1
2013–14	910,700	1.1	5,081	0.8	5,579	-0.3
2014–15	940,379	3.3	4,875	-4.1	5,184	-7.1

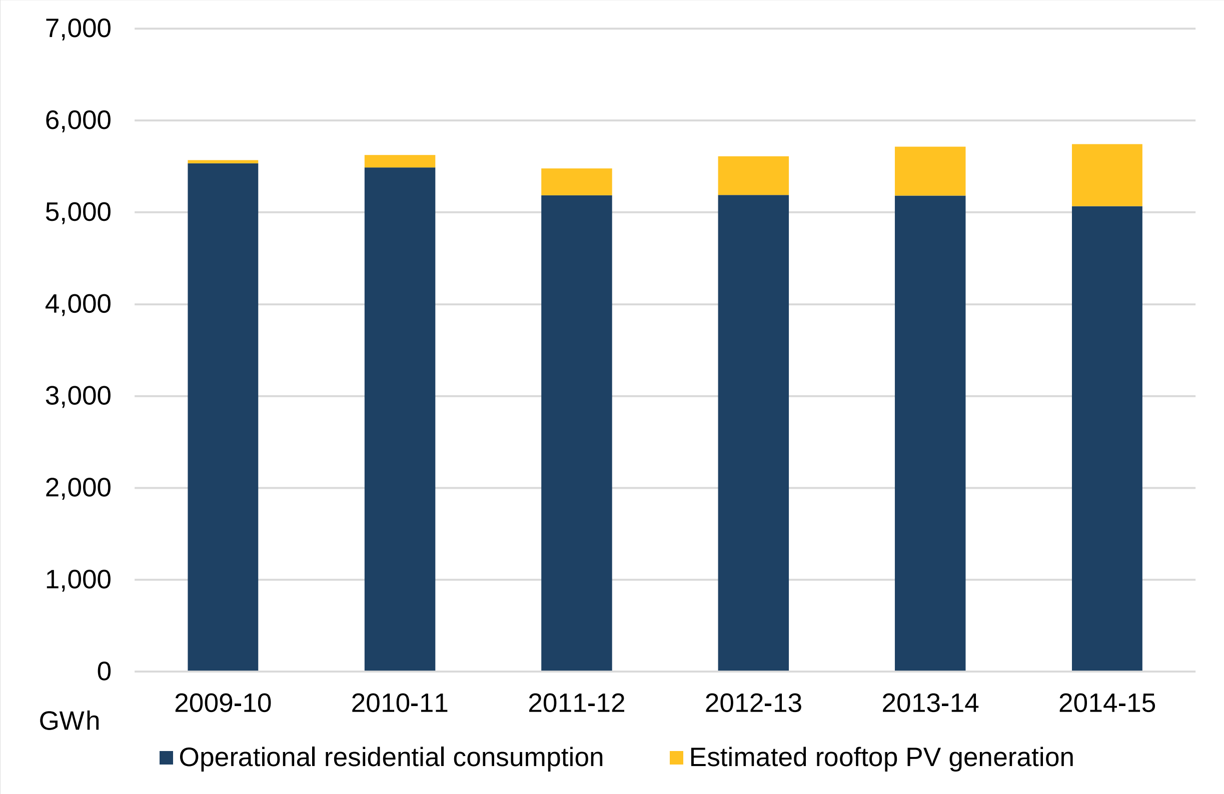
Source: Synergy
[a] The total number of residential customers includes regulated and unregulated tariffs.

The long-term decline in average per-connection consumption can be explained by various factors including improved energy efficiency standards, changing demographics, and the uptake of rooftop PV systems. AEMO is undertaking further analysis to better understand the dynamics that have led to a decline in per-connection residential consumption.

Energy efficiency initiatives have contributed particularly to the fall in operational residential consumption. New building regulations, such as the six star rating, mandate a minimum energy efficiency requirement for new dwellings and commercial buildings, improving the energy efficiency of newer housing stock. This reduces the growth in operational residential electricity consumption drawn from the network over the long term.

AEMO's estimate of underlying residential electricity consumption between 2009–10 and 2014–15 is shown in Figure 15. Underlying residential consumption rose by 3.1% between 2009–10 and 2014–15, with particularly strong growth of 4.3% between 2011–12 and 2013–14. However, most of this has been met by increased generation from rooftop PV systems, rather than from the electricity network.

Figure 15 Underlying residential consumption in the SWIS, 2009–10 to 2014–15



Source: AEMO with Synergy input

The sharp fall in underlying residential demand between 2010–11 and 2011–12 is likely related to rapid increases in residential electricity prices from 2009. The large increase in estimated rooftop PV generation between 2010–11 and 2011–12 was driven by high installations of rooftop PV capacity following the introduction of the WA Government's feed-in tariff, which was open for applications between 2010 and 2011.

3.5.2 Large customers

Nine large customers in the SWIS account for around 20% of total electricity consumption, with average demand ranging from 20 to 140 MW per customer. Between 2009–10 and 2014–15, large commercial consumption grew following the commencement of several large projects connected to the SWIS.

Although the large customers account for a significant proportion of electricity consumption, they do not contribute notably to the system peak, because these customers are not temperature sensitive, so do not increase demand when temperatures are high.

At the time of system peak on 8 February 2016, large customers accounted for about 151 MW, or 3.8%, of the peak demand. This proportion would typically be higher, but two of the large customers were on outages at the time of system peak.

CHAPTER 4. FORECAST METHODOLOGY AND ASSUMPTIONS

This chapter describes the methodology used to forecast peak demand and operational consumption for this report. It includes a summary of input assumptions used in the forecasts, including the economic outlook, population growth, block loads, uptake of rooftop PV and battery storage, and the IRCR response during peak demand periods.

There have been incremental improvements to the forecasting methodology used in previous ESOOs, primarily in modelling of rooftop PV and battery storage technologies. Input assumptions have been updated to reflect the most recent information available.

4.1 Methodology

AEMO engaged the National Institute of Economic and Industry Research (NIEIR) to prepare an economic outlook, and peak demand and operational consumption forecasts. NIEIR's forecasting methodology is described in the following sections.

4.1.1 Peak demand forecasts

As peak demand in the SWIS directly relates to average temperature, NIEIR produced peak demand forecasts based on three different weather scenarios, as required by clause 4.5.10 of the WEM Rules:

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

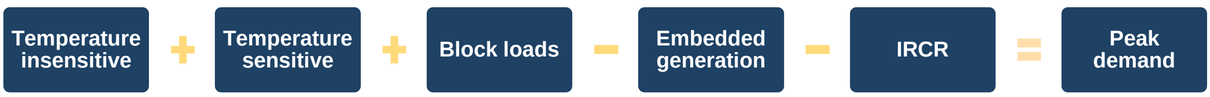
A POE reflects the likelihood of the forecast peak demand being exceeded as a result of extremely hot weather or prolonged high temperatures. For example, a 10% POE forecast represents a forecast that has a 10% probability of being exceeded (one in ten years), whereas a 90% POE forecast represents a lower forecast, which is likely to be exceeded nine in ten years. A 50% POE forecast (the median forecast) is expected to be exceeded, on average, one in two years. A 10% POE forecast will be more conservative for capacity planning purposes than a 90% POE forecast.

As noted in Chapter 1, the RCT is determined based on a 10% POE peak demand scenario, as required by clause 4.5.9 of the WEM Rules.

Economic growth is a factor in the system peak demand. NIEIR applied three forecasts of economic growth (high, expected, and low) to each of the weather scenarios. This resulted in a total of nine peak demand forecasts. The high, expected, and low case forecasts referred to in this report reflect different economic scenarios and different levels of rooftop PV system and battery storage uptake, as well as different response levels to the IRCR mechanism.

The methodology for calculating peak demand is shown in Figure 16.

Figure 16 Components of peak demand forecasts



- **Temperature insensitive** load includes the proportion of residential and commercial consumption that does not vary according to temperature. This includes electricity for general office use, industrial equipment, cooking, lighting, entertainment equipment, and standby use.

- **Temperature sensitive** load is electricity used for heating and cooling, and is therefore directly related to temperature.
- **Block loads** are large industrial customers in the SWIS and are generally considered to be temperature insensitive. They are forecast separately from the rest of the system based on historical operating patterns.
- **Embedded generation** is typically the electricity generated by rooftop PV systems and battery storage.
- **IRCR** is the estimated reduction in demand from commercial and industrial customers on peak demand days to minimise their exposure to capacity costs.

AEMO currently receives metered data only at the total SWIS level (data for connection points such as substation or customer connection level is not received). Transmission or other network constraints were not considered in the forecasts.

4.1.2 Operational consumption forecasts

Operational consumption forecasts were estimated using an econometric model that forecast energy sales[33] by tariff class for the industrial, commercial and residential sectors. Transmission and distribution line losses were then added to the energy sales forecasts.

The industry classes used to forecast commercial and industrial energy sales are shown in Table 16. The industry classes were forecast using economic growth, electricity price, and weather assumptions.

Table 16 Industry classes used to forecast energy sales in the WEM

Customer class	Industry class
Commercial	Water and sewerage Construction Wholesale and retail trade Transport and storage Communication Finance, property, and business services Public administration and defence Community services Recreation, personal, and other services
Industrial	Agriculture, forestry, fishery, and hunting Mining Manufacturing sub-sectors • Food, beverages, and tobacco • Textiles, clothing, and footwear • Wood and wood products • Chemicals, petroleum, and coal • Paper and paper products • Non-metallic minerals • Basic metal products • Fabricated metal products • Transport equipment • Other machinery and equipment • Miscellaneous

The residential sales forecast is driven by income growth, population growth, weather, and electricity prices. Residential sales were then added to commercial and industrial sales to form total sales.

33 Energy sales are defined as the quantity of electricity delivered to the customer, with an adjustment for losses.

4.2 Temperature sensitive and temperature insensitive demand

The factors which affect temperature sensitive and temperature insensitive demand include:

- The economic outlook.
- Population growth.
- Electricity prices.

These are discussed in Section 4.2.1 to Section 4.2.3.

4.2.1 Economic outlook

NIEIR developed projections for the WA economy using available data up to December 2015. The expected case economic outlook produced for the next five years shows a slowdown in growth compared to recent history for the next two years, followed by a return to a level approaching long-term average annual growth by the end of the forecast period.

Between 2016–17 and 2020–21, economic growth in WA is expected to slow in line with weaker international commodity markets. In recent years, WA's economy has been driven by construction of major resource projects. Many of these projects, including Gorgon LNG and the Roy Hill iron ore project, have been completed and are exporting commodities. Future economic growth in WA is therefore expected to be driven by increasing exports rather than construction expenditure (captured under business investment in Table 17).

Commodity exports require less labour and investment than the construction of new projects, limiting growth in domestic labour demand for the next five years. Recent falls in commodity prices, particularly for iron ore and oil, are expected to constrain export earnings. This results in more conservative forecasts of economic growth compared to those published in the 2014 ESOO and the December 2015 Gas Statement of Opportunities for WA.[34]

NIEIR's forecasts of major economic indicators for the **expected case** for the 2015–16 to 2020–21 period are summarised in Table 17. Appendix B contains economic forecasts for the high and low cases.

Table 17 Key economic indicator forecasts for WA, expected case, 2015–16 to 2020–21[35]

Measure	2015–16 (%)	2016–17 (%)	2017–18 (%)	2018–19 (%)	2019–20 (%)	2020–21 (%)	Average annual growth (%)
Private consumption	1.7	2.5	2.7	3.0	3.2	3.2	2.9
Private dwelling investment	1.4	4.5	2.0	0.9	-0.7	-0.9	1.2
Business investment	-15.9	-10.0	-3.9	-0.2	1.5	3.9	-1.7
Government consumption	3.3	3.5	3.0	3.0	2.6	2.3	2.9
Government investment	-4.2	10.6	2.0	-0.9	-1.1	4.8	3.1
State final demand	-3.8	-0.7	1.0	2.2	2.5	3.1	1.6
Gross state product	2.2	3.2	3.2	2.6	1.8	2.6	2.7
Population	1.5	1.6	1.7	1.7	1.8	1.8	1.7
Employment	1.3	1.2	1.2	1.2	1.2	1.3	1.2

Source: NIEIR

[34] Available at: http://wa.aemo.com.au/home/gas/gas-statement-of-opportunities.
[35] Please note that the categories in this table may not align with those used in WA Treasury's budget.

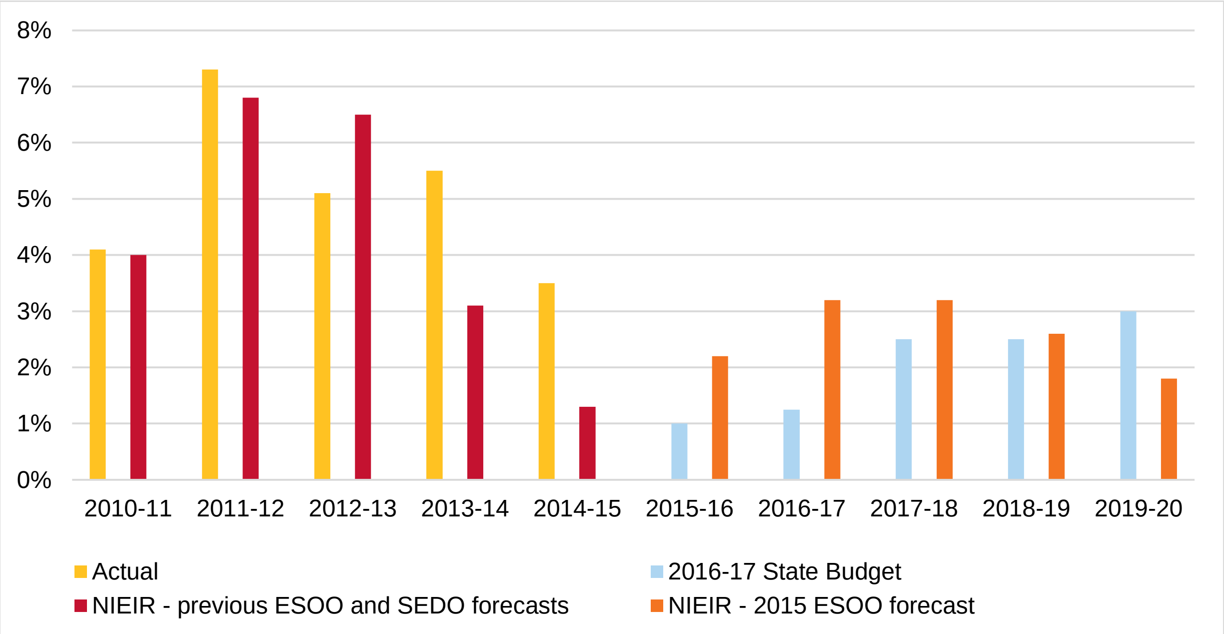
In summary:

- Private dwelling investment is forecast to increase between 2015–16 and 2018–19 as housing projects, including apartment complexes, are completed, then to fall from 2019–20 as demand for new housing declines, due to slowing population growth compared to the previous five years (average of 2.6% growth per year).
- Business investment is projected to decline between 2015–16 and 2018–19, reflecting the completion of major iron ore and natural gas projects, then to recover from 2019–20 as the economy diversifies away from resources-related industry and non-resource related investment recovers.
- Government investment is forecast to decline between 2015–16 and 2017–18, as the State Government reduces its capital expenditure and major infrastructure projects are completed, including the Perth Stadium ($1.3 billion) and Perth Children's Hospital ($1.2 billion).
- WA's gross state product (GSP) is forecast to grow at an average annual rate of 2.7% between 2015–16 and 2020–21, supported by increasing commodity exports and private consumption expenditure.

NIEIR's and the WA Treasury's[36] GSP forecasts for 2015–16 to 2019–20 are compared in Figure 17. WA Treasury forecasts for 2015–16 to 2017–18 are more conservative than NIEIR's (up to 2 percentage points lower). However, in 2019–20 Treasury's forecasts are around 1.2 percentage points higher than NIEIR's. The main differences between NIEIR and the WA Treasury's forecasts are:

- Treasury forecast lower non-government investment in 2016–17 to 2017–18.
- Treasury forecast significantly lower dwelling investment in 2016–17.
- The forecasts used different assumptions for the labour market (in particular, NIEIR forecast stronger employment across the outlook period).

Figure 17 Comparison of GSP forecasts, NIEIR and WA Treasury, 2010–11 to 2019–20



Source: ABS[37], NIEIR, and WA Treasury[38]

[36] As published in the 2016–17 State Budget, available at: http://www.ourstatebudget.wa.gov.au/.
[37] Source: ABS, *Australian National Accounts: State Accounts, 2014-15*, catalogue number 5220.0, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/E6765105B38FFFC6CA2568A9001393ED?OpenDocument.
[38] Source: WA Treasury, *2016-17 State Budget*, available at: http://www.ourstatebudget.wa.gov.au/.

NIEIR's economic forecasts in the last five ESOO and SEDO reports are compared with actual data in Figure 17. The comparison suggests it has been more difficult to forecast WA's economic growth over the last two years.

4.2.2 Population growth

High population growth is generally correlated with growth in total electricity consumption delivered by the network, although most of its impact is likely to be offset by other factors, such as customer behaviour (to manage their electricity costs) and alternative energy supplies (such as rooftop PV systems). The factors that could cause electricity consumption growth to be lower than growth in customer numbers have been discussed in Chapter 3.

The population of the area supplied by the SWIS is estimated to have increased by 3.2% from 2.48 million in 2012–13 to 2.56 million in 2014–15, with the vast majority of this growth occurring in Perth.

NIEIR forecast population growth at a rate of 1.7% per year between 2015–16 and 2020–21. This is expected to drive growth in new dwelling construction, which in turn supports increasing electricity consumption, although, as noted above, this growth is likely to be offset by other factors, as discussed in Section 3.5.

4.2.3 Electricity tariff forecasts

NIEIR forecast nominal electricity prices to increase for contestable customers (using more than 50 MWh per annum) at a pace consistent with inflation (at around 2% to 3%) over the forecast period.

By contrast, electricity prices for non-contestable customers (residential and smaller commercial customers consuming less than 50 MWh per year) are regulated in WA. NIEIR forecast that the real long-run residential price elasticity is –0.25; that is, for every 1% increase in the real retail price of electricity, residential operational consumption decreases by 0.25%.

NIEIR's assumptions for non-contestable customers are in line with those published in the 2016–17 State Budget, with prices forecast to increase by 3% in 2016–17. WA Treasury has forecast future increases of 7% every year of the period 2017–18 to 2019–20.

4.2.4 Peak demand and operational consumption assumptions

Peak demand forecast assumptions

The high, expected, and low economic growth scenarios (which are applied to the 10%, 50% and 90% POE weather scenarios), included the following economic outlook with population forecast to grow at an average rate of 1.7% for each case:

- High case: 3.7% average annual GSP growth.
- Expected case: 2.8% average annual GSP growth.
- Low case: 1.8% average annual GSP growth.

Operational consumption forecast assumptions

The high, expected, and low operational consumption forecast scenarios assumed the same GSP and population growth as the economic growth scenarios used in the peak demand forecasts, and included the following additional assumptions:

- High case:
  - 1.4% average annual growth in residential energy sales.
  - 4.4% average annual growth in commercial energy sales.
  - 1.6% average annual growth in industrial energy sales.

- Expected case:
  - 0.8% average annual growth in residential energy sales.
  - 1.9% average annual growth in commercial energy sales.
  - 1.0% average annual growth in industrial energy sales.
- Low case:
  - 0.5% average annual growth in residential energy sales.
  - 0.4% average annual growth in commercial energy sales.
  - 0.5% average annual growth in industrial energy sales.

4.3 Block loads

Block loads are temperature insensitive loads that operate continuously. AEMO considers 20 MW to be the minimum threshold for new block loads. They are an important input into the forecasting process, accounting for around 20% of total operational consumption and 4% of the 2015–16 peak demand of 4,013 MW (more information about historical block load consumption is in Section 3.5.2).

NIEIR included operational block loads in its forecasts of peak demand and operational consumption (generally in the temperature insensitive component). Forecasts for these loads were based on recent observed consumption levels.

AEMO has not accounted for any new block loads in the Deferred 2015 WEM ESOO.

The forecasts in the 2014 ESOO included an allowance for one block load in the high case. Due to recent commodity price falls and based on publicly available information, AEMO considers that this block load is unlikely to commence operation during the forecast period, and has removed it from the forecasts.

4.4 Rooftop PV assumptions

AEMO has developed a set of forecasts of rooftop PV system uptake in the SWIS over the 10-year forecast horizon. The forecast methodology has been refined and improved since the 2014 ESOO.

Using the capacity forecasts and observations on system efficiency, AEMO has developed the following forecasts for rooftop PV:

- Installed capacity.
- The effect on peak demand.
- Annual energy generation.

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

4.4.1 Installed capacity

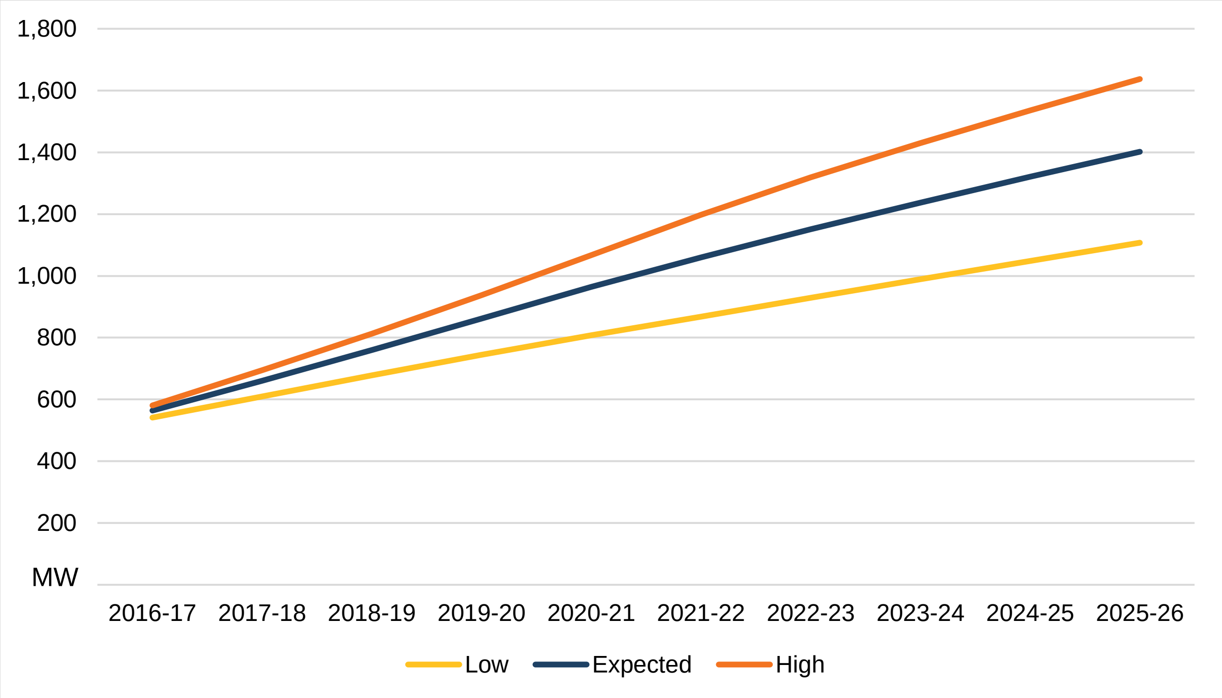
AEMO forecast rooftop PV capacity installed in the SWIS using the methodology described in AEMO's *Emerging Technologies Information Paper*[39], which was published with the *2015 National Electricity Forecasting Report* (NEFR).[40] The model has been updated with parameter settings relevant to WA.

Between 2016–17 and 2025–26, installed capacity of rooftop PV is forecast to grow at an average annual rate of 10.6%[41], resulting in an additional 820 MW of rooftop PV capacity installed in the SWIS.

[39] Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information.
[40] Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.
[41] Expected case.

The forecast installed capacity of rooftop PV systems in the SWIS in the high, expected, and low cases are shown in Figure 18.[42]

Figure 18 Installed rooftop PV system capacity, 2016–17 to 2025–26



Strong growth in commercial system installations, which are typically larger than residential systems, is the key driver of growth in installed rooftop PV capacity over the forecast period. In the expected case, installed commercial capacity is projected to increase at twice the rate (18%) of residential capacity (8.6%). The difference between forecast commercial and residential growth reflects the lower starting capacity of the commercial sector and the tempering effect of high penetration rates of solar installations in the residential sector.

4.4.2 Annual energy generation

Based on Australian PV Institute (APVI) data, AEMO estimates that 1 MW of rooftop PV capacity installed in the SWIS will generate 1.55 GWh of energy over a year. Multiplying this by the installed capacity forecasts (as shown in Figure 18), AEMO projects that between 836 GWh and 896 GWh of energy will be generated from rooftop PV in 2016–17.

Changes over time in the efficiency of the installed rooftop PV capacity base will alter the generation multiplier. Factors that influence system efficiency include lifecycle performance degradation, the physical alignment of new panels, and technological improvements. AEMO is in the process of improving the methodology used to forecast generation, and this will be a key area of focus for the ESOO to be published in 2017.

4.4.3 Effect on peak demand

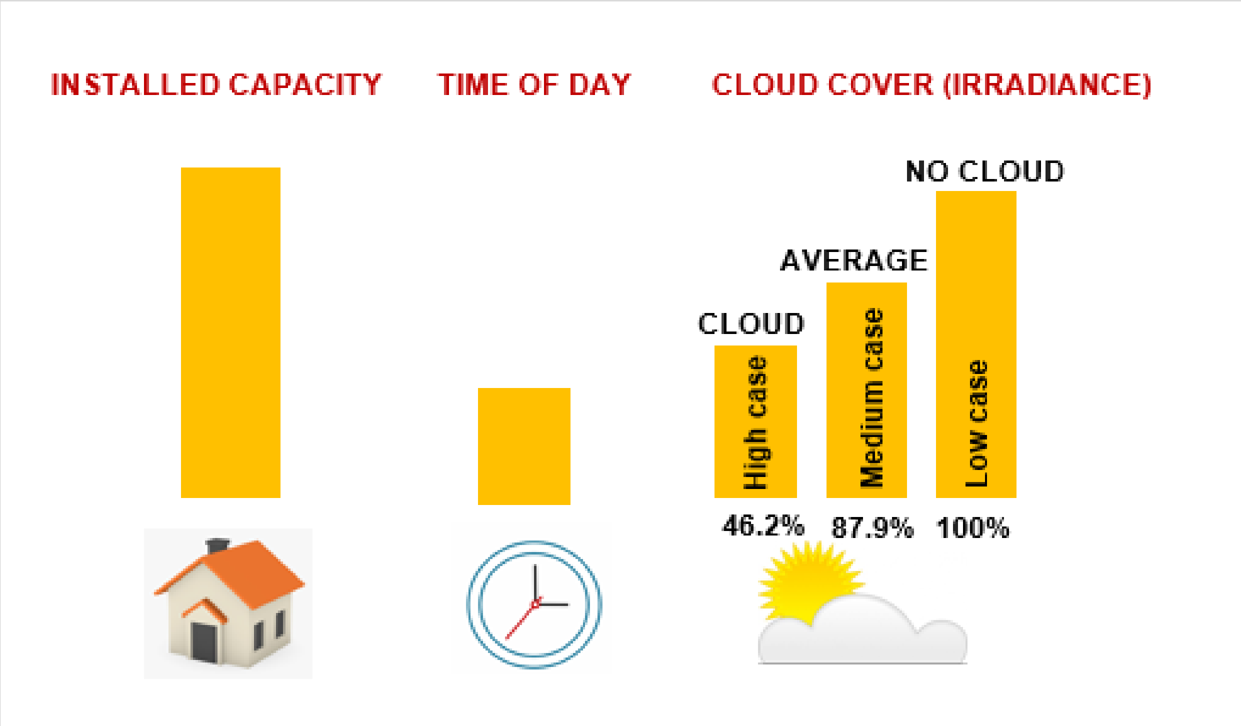
AEMO calculated the expected effect of rooftop PV on peak demand by accounting for:

- The time of day that peak demand occurs.
- The expected level of solar irradiance.

[42] These forecasts include all residential and commercial rooftop PV and exclude generation-scale PV such as Greenough River.

The process for calculating the effect of rooftop PV on peak demand is shown in Figure 19. The output profile of a rooftop PV system at 16:30 on a cloudless day in February was estimated first. This gave an estimate of the performance of a typical rooftop PV system during each trading interval. AEMO then adjusted this figure to account for solar irradiance, which is the expected level of cloud cover on a typical day in February. This was then applied to the total installed capacity to calculate the effect on peak demand.

Figure 19 Calculation of the effect of rooftop PV on peak demand



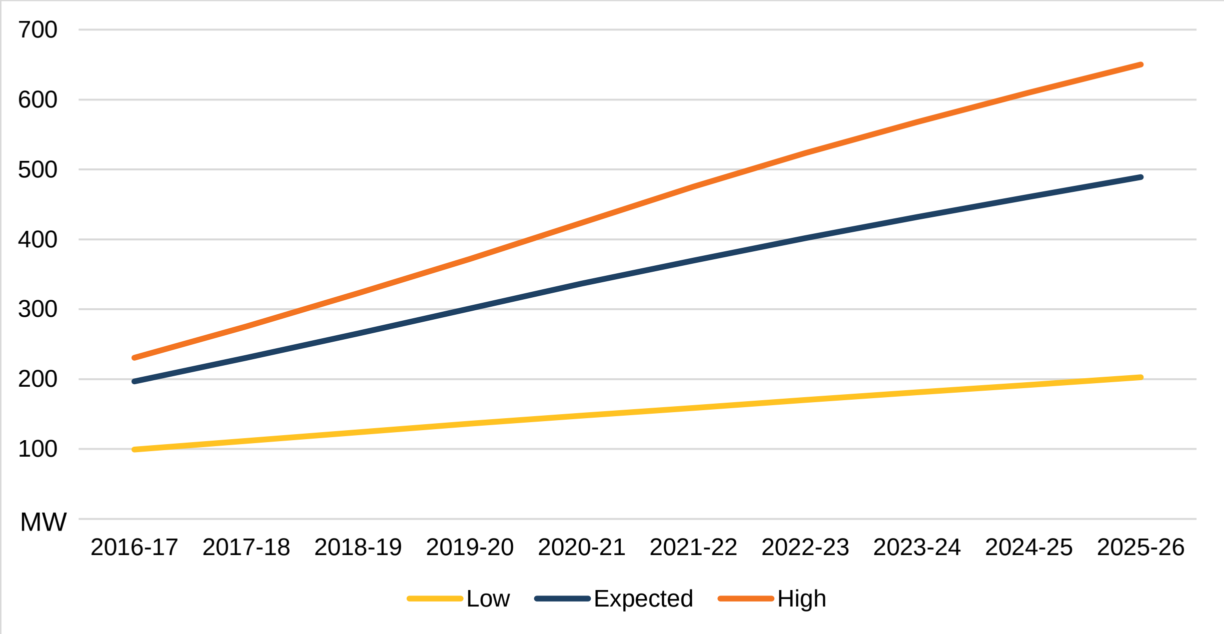
The calculation above resulted in the following assumptions and effects:

- High case[43]: high level of cloud cover (46.2% of maximum solar irradiance). The effect of rooftop PV on peak demand is 18.3% of rooftop PV installed capacity.365
- Expected case: expected level of cloud cover (87.9% of maximum solar irradiance). The effect of rooftop PV on peak demand is 34.9% of rooftop PV installed capacity.
- Low case[44]: not adjusted for cloud cover. The effect of rooftop PV on peak demand is 39.7% of rooftop PV installed capacity.

The forecast reduction in peak demand associated with the installed capacity forecasts discussed in Section 4.4.1 is shown in Figure 20.

[43] Corresponds with a low level of rooftop PV output, and therefore a high level of demand which needs to be supplied from the electricity network.
[44] Corresponds with a high level of rooftop PV output, and therefore a low level of demand which needs to be supplied from the electricity network.

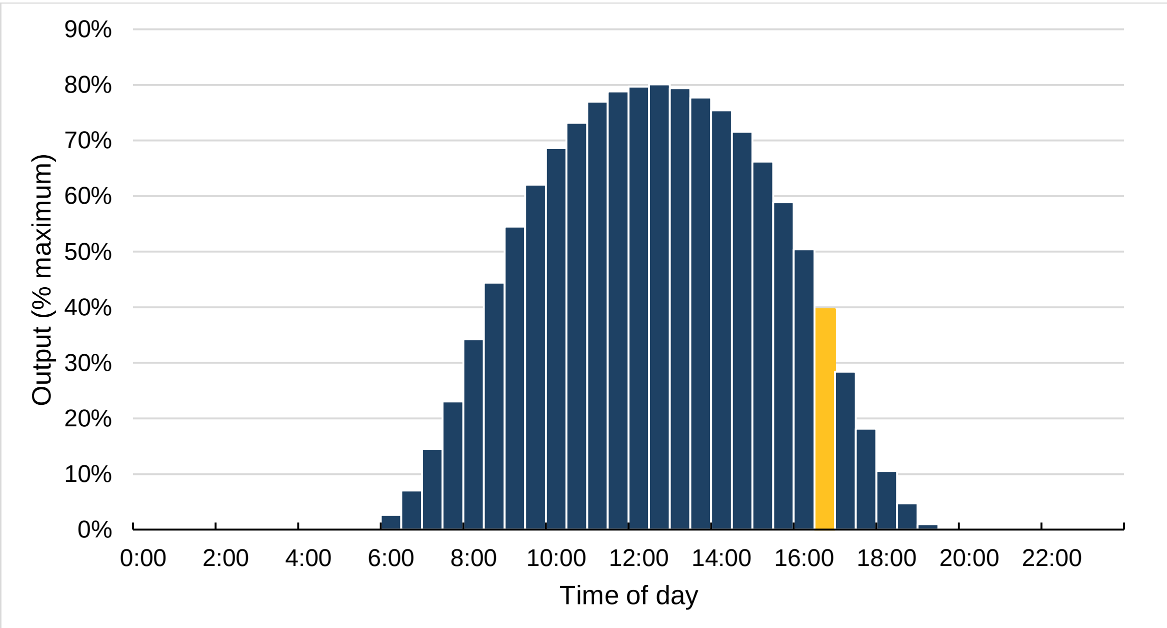
Figure 20 Peak demand reduction from rooftop PV systems, 2016–17 to 2025–26



Time of day effects

The output profile of a typical rooftop PV system on a cloudless day in February is shown in Figure 21. In the highlighted 16:30 to 17:00 trading interval, the representative rooftop PV system is expected to be producing 39.7% of its nameplate capacity.

Figure 21 Output profile of a typical rooftop PV system on a cloudless day in February in the SWIS[45]



On a cloudless day, peak rooftop PV generation was assumed to occur in the 12:30 to 13:00 trading interval. During the system peak on 8 February 2016 at 17:30, the representative rooftop PV system in

[45] Calculated by AEMO based on data from the APVI.

the Perth metropolitan region was producing 18.2% of its nameplate capacity. Based on this analysis, a 5 MW increase in the installed capacity of rooftop PV is estimated to reduce 2015–16 peak demand by about 1 MW.

These results are highly sensitive to assumptions around the time of the system peak, which is becoming increasingly unpredictable. The forecasts assumed a gradual shift in peak demand from the current trading interval commencing at 17:30 to the trading interval commencing at 18:30. This shift in the peak demand by one hour is expected to reduce the output from a representative rooftop PV system to 4.7% of maximum output in the expected case.

Changes in the alignment of new rooftop PV panels will alter the representative generation profile. A west-facing panel will generate more energy during the afternoon than a north-facing panel, which will have a similar output pattern to the representative profile shown in Figure 21. Therefore, a west-facing panel will reduce peak demand more than a north-facing panel. AEMO will continue to monitor national and WA trends in panel orientation.

Solar irradiance effects

To account for the effect of cloud cover on the output of a rooftop PV system, AEMO calculated a de-rate factor representing the expected reduction in system performance based on solar irradiance. The irradiance figures determined for the Perth metropolitan region have been averaged over the past six years.

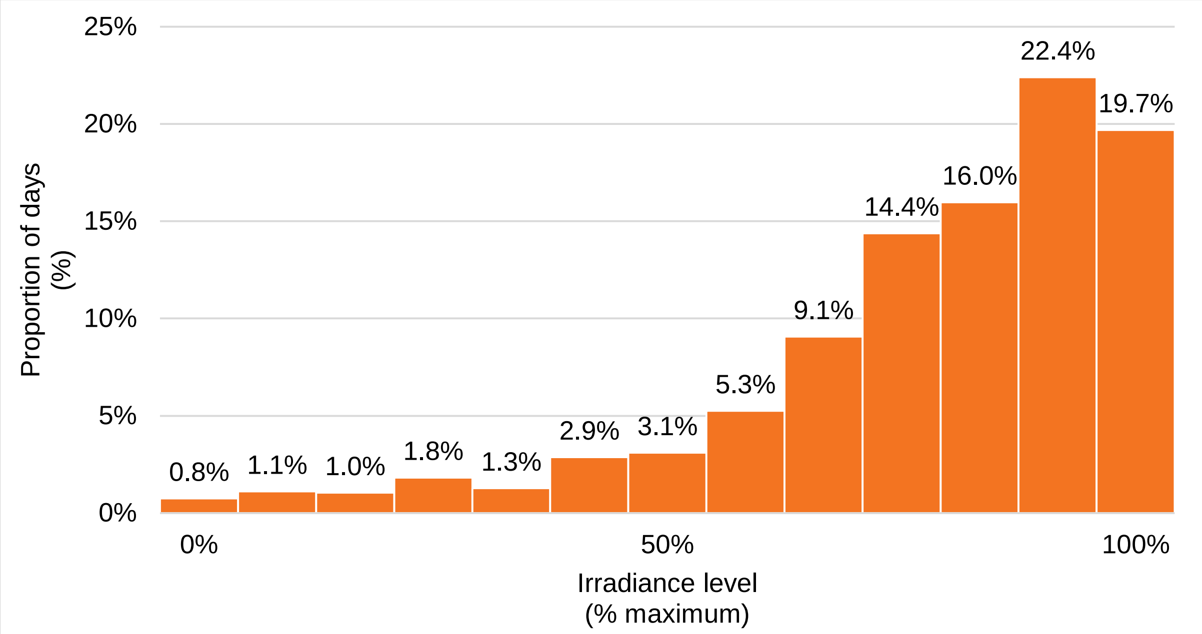
In using irradiance levels as a proxy for system generation, AEMO has implicitly assumed a linear relationship between irradiance and rooftop PV performance.

This analysis resulted in the following assumptions in each scenario:

- High: ninety-fifth percentile irradiance level equalling 46.2% of maximum rooftop PV output.
- Expected: median irradiance levels equalling 87.9% of maximum rooftop PV output.
- Low: fifth percentile irradiance levels equalling 100% of maximum rooftop PV output.

The distribution of daily solar irradiance measured at six sites across the Perth metropolitan region for January to March, reflecting the likely timing of the system peak, is shown in Figure 22. This figure shows that Perth has a high level of solar irradiance over summer, with around 90% of summer days observing greater than 50% of the maximum possible solar irradiance, indicating that significant cloud cover is uncommon during summer in Perth.

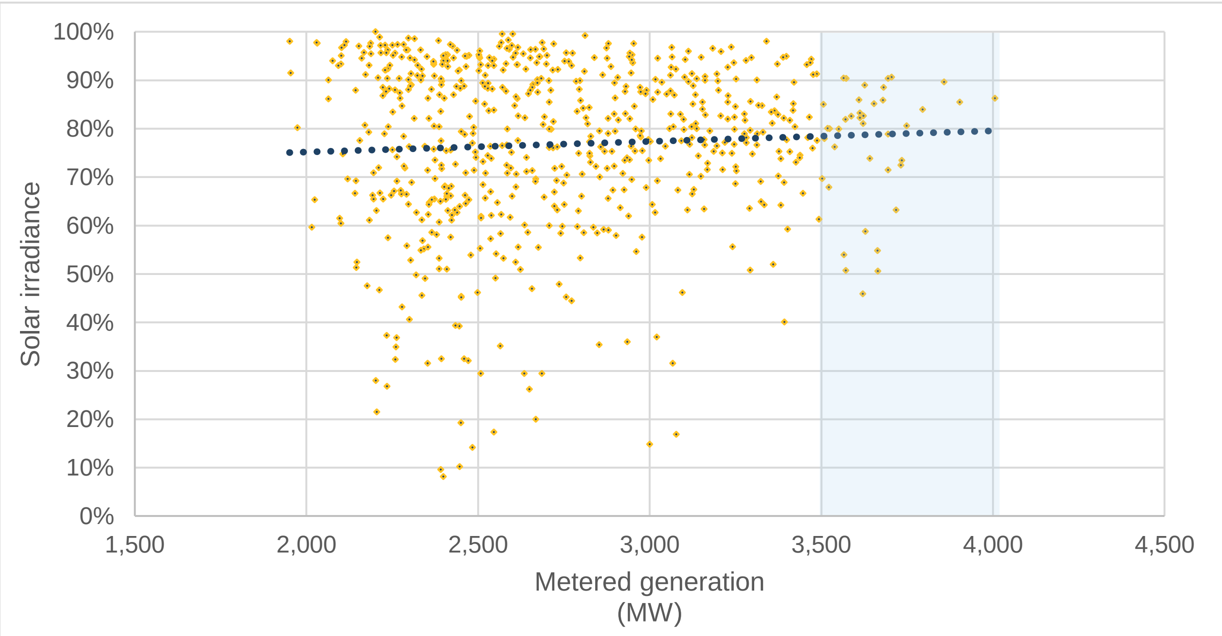
Figure 22 Variability in daily solar irradiance levels during summer, 2011 to 2016



Source: Bureau of Meteorology

In addition to the above analysis, AEMO has investigated the historic relationship between peak demand and solar irradiance levels in the SWIS. There is limited correlation between daily solar irradiance and metered generation in the SWIS, despite high levels of solar irradiance being associated with high temperatures, as shown in Figure 23. The shaded area on the graph depicts the range that peak demand is expected to reach, while the blue trend line shows the limited correlation between irradiance and metered generation.

Figure 23 Correlation between daily solar irradiance and peak demand during summer, 2011 to 2016



4.5 Battery storage forecasts

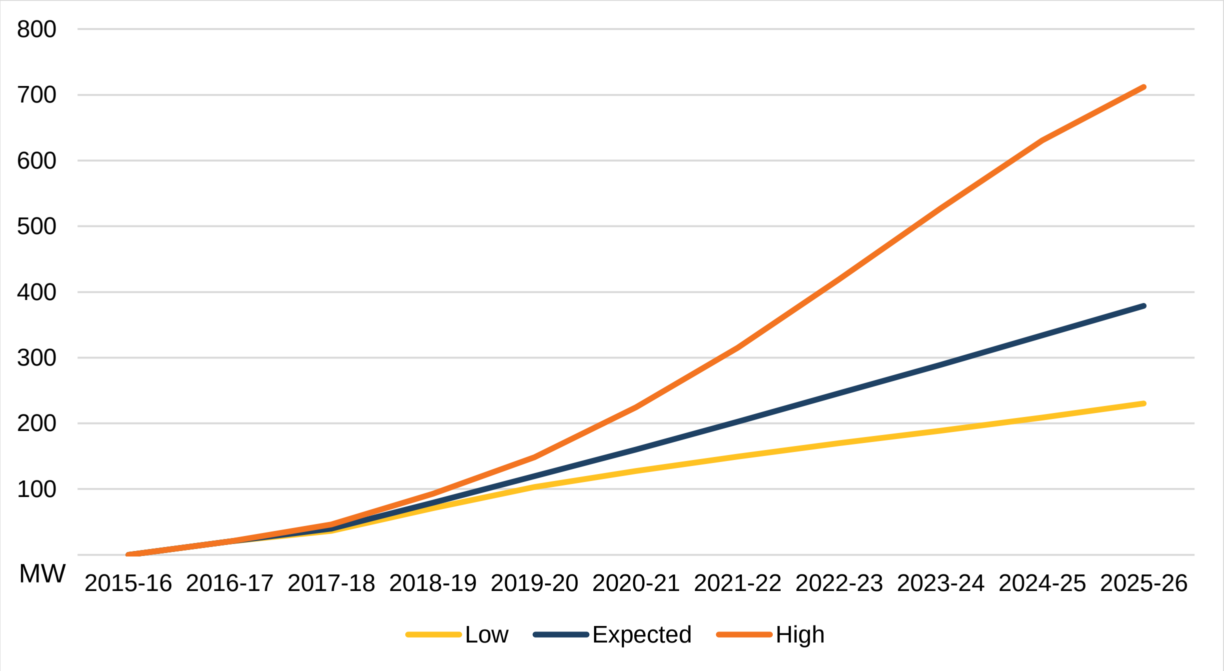
AEMO engaged Jacobs to forecast the installed capacity of small-scale grid connected battery storage systems in the SWIS. This is the same approach as that taken for forecasting battery storage in the 2016 NEFR.

The assumptions used to forecast battery storage installed capacity and the effect on peak demand were:

- Batteries are charged at a constant rate from a rooftop PV system between 06:00 and 14:00.
- The battery systems do not charge from the grid due to existing tariff structures.
- The battery discharges at a constant rate between 14:30 and 19:30.
- Assumed 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.
- There are no pricing signals to encourage non-contestable customers to optimise storage decisions to align with periods of high demand in the SWIS.

The installed capacity forecasts in the high, expected, and low case scenarios are shown in Figure 24. The forecasts assumed that each battery storage installation is paired with a rooftop PV system.

Figure 24 Installed capacity of battery systems, 2015-16 to 2025-26



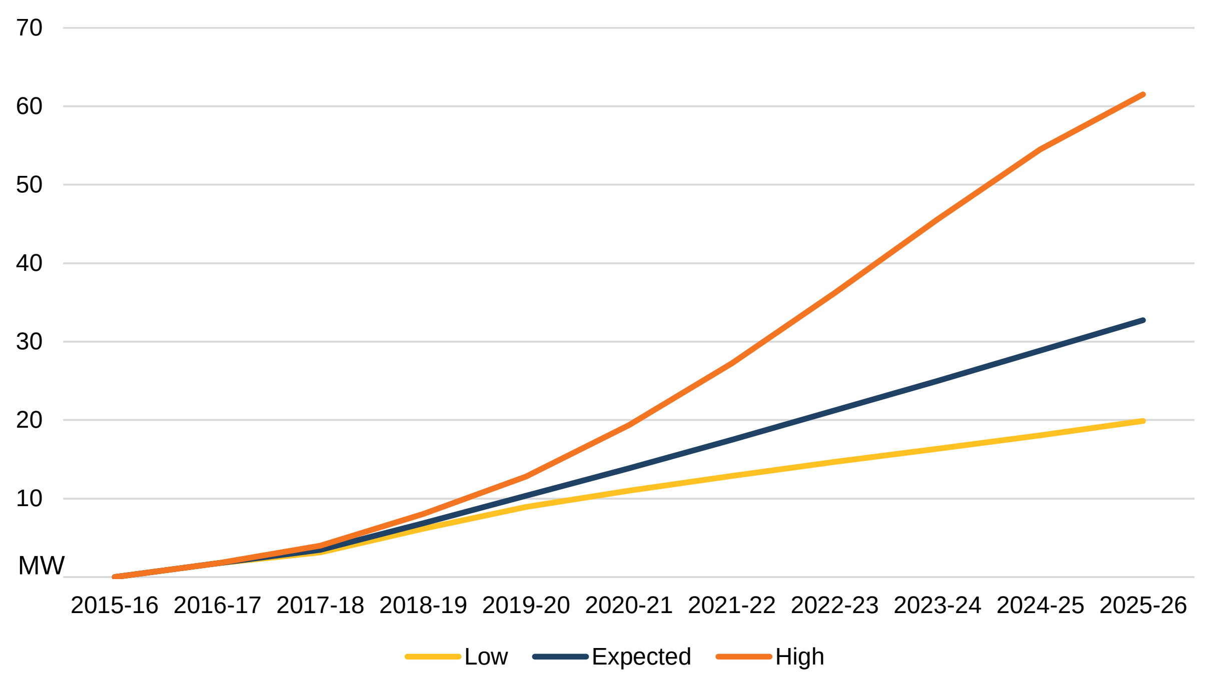
Source: Jacobs

4.5.1 Impact on peak demand

The expected impact of battery storage on peak demand is shown in Figure 25. Consumers currently have no price incentive to increase the discharge rate of the battery during periods of peak demand, particularly considering that this would decrease the efficiency and operating life of the battery system.

Hence, AEMO considers the effect of battery storage on peak demand will be limited under the expected and low case scenarios.

Figure 25 Reduction in peak demand from battery storage, 2015-16 to 2025-26



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 or usage patterns. Therefore, AEMO has adopted linear charge-discharge assumptions to predict the likely impact of distributed battery technology on peak demand.

4.6 Individual Reserve Capacity Requirement

Peak demand forecasts were adjusted to account for the effect of customers reducing consumption during peak times to minimise capacity costs allocated through the IRCR mechanism.

AEMO assumed that the IRCR response would remain consistent with that observed during the peak trading interval on 8 February 2016 at 77 MW throughout the forecast period.

Changes to certification requirements and payments for DSM capacity as a result of the EMR are expected to cause some DSM to exit the RCM. In this case, AEMO expects a proportion of the loads associated with those Facilities may respond to the IRCR mechanism, thus increasing the total response. This is discussed further in Section 8.1.2.

CHAPTER 5. PEAK DEMAND AND OPERATIONAL CONSUMPTION FORECASTS, 2016–17 TO 2025–26

This chapter presents the peak demand and operational consumption forecasts for the 10-year forecast period.

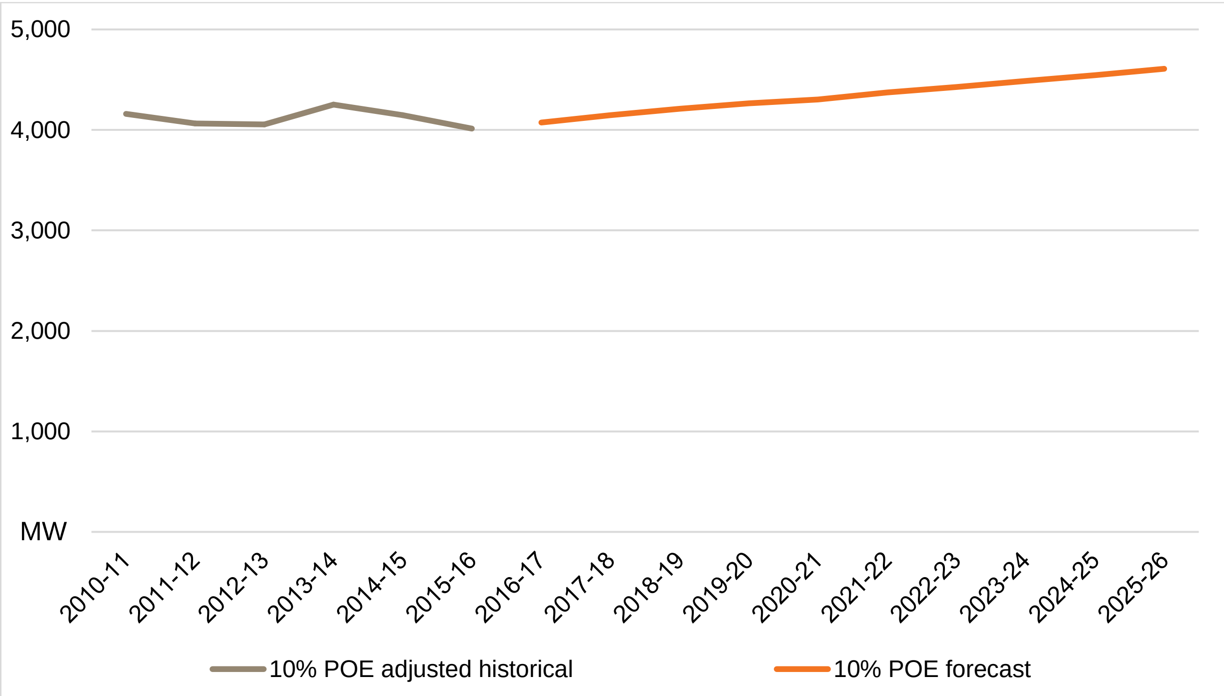
5.1 Peak demand forecasts

In summary, over the 10-year period:

- The 10% POE peak demand forecast grows at an average annual rate of:
  - 2.0% in the high demand growth scenario.
  - 1.4% in the expected demand growth scenario.
  - 0.8% in the low demand growth scenario.
- The 50% and 90% POE peak demand forecasts grow at an average rate of 1.3%.
- The 10% and 50% POE winter peak demand forecasts grow at an average annual rate of 1.1%.
- The 90% POE winter peak demand forecast grows at an average annual rate of 1.0%.

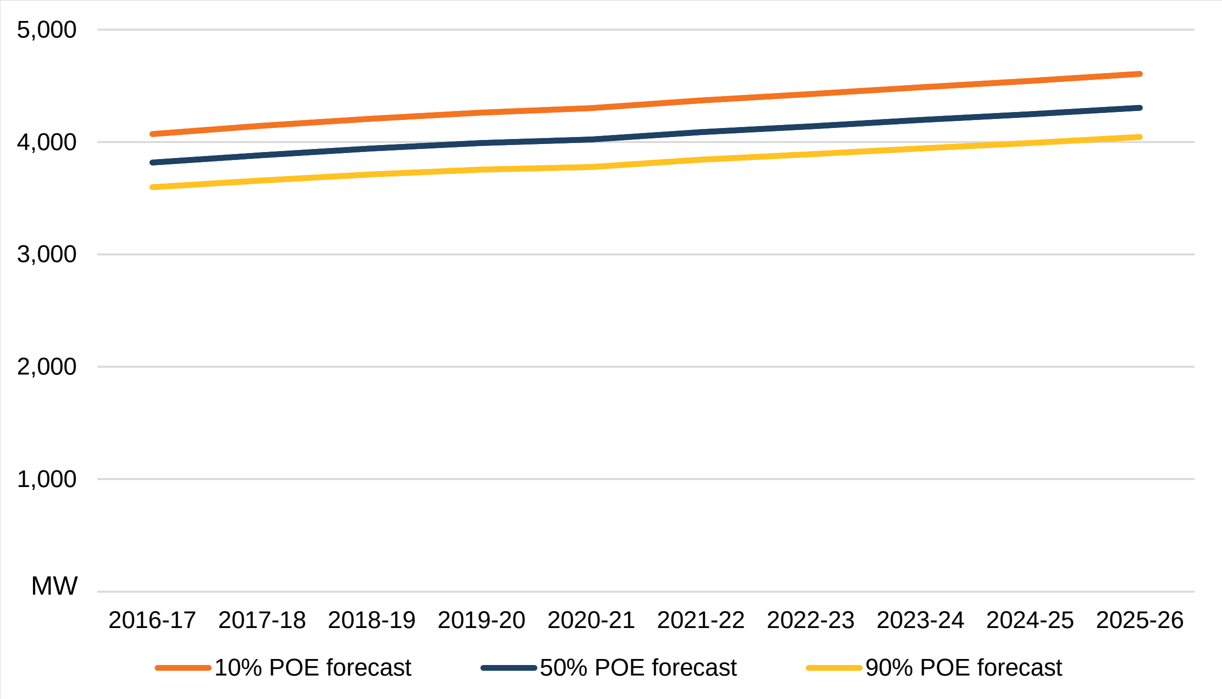
The 10%, 50% and 90% POE peak demand forecasts, with expected demand growth, over the forecast period are shown in Figure 26 and Figure 27, and Table 18.

Figure 26 Peak demand, expected demand growth, 2010–11 to 2025–26



Source: NIEIR

Figure 27 Peak demand forecasts under different POE scenarios, expected demand growth, 2016–17 to 2025–26



Source: NIEIR

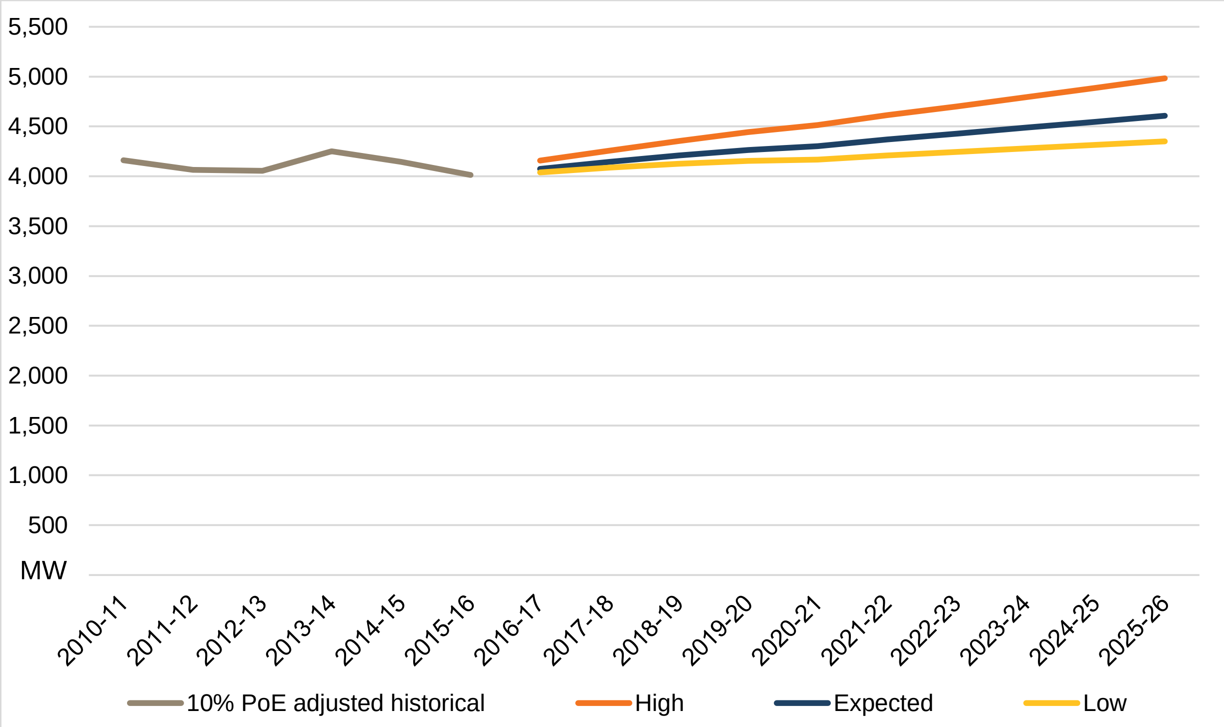
Table 18 Peak demand forecasts for different weather scenarios, expected demand growth

Scenario	2016–17 (MW)	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)	2020–21 (MW)	5 year average annual growth	10 year average annual growth
10% POE	4,073	4,145	4,209	4,263	4,303	1.4%	1.4%
50% POE	3,819	3,885	3,943	3,991	4,023	1.3%	1.3%
90% POE	3,598	3,659	3,712	3,755	3,779	1.2%	1.3%

Source: NIEIR

The 10% POE forecasts for all three demand growth scenarios (high, expected, and low) are shown in Figure 28 and Table 19.

Figure 28 Peak demand, 10% POE, under different demand growth scenarios, 2010–11 to 2025–26



Source: NIEIR

Table 19 Peak demand forecasts for different demand growth scenarios, 10% POE

Scenario	2016–17 (MW)	2017–18 (MW)	2018–19 (MW)	2019–20 (MW)	2020–21 (MW)	5 year average annual growth	10 year average annual growth
High	4,157	4,259	4,355	4,443	4,516	2.1%	2.0%
Expected	4,073	4,145	4,209	4,263	4,303	1.4%	1.4%
Low	4,040	4,087	4,126	4,153	4,168	0.8%	0.8%

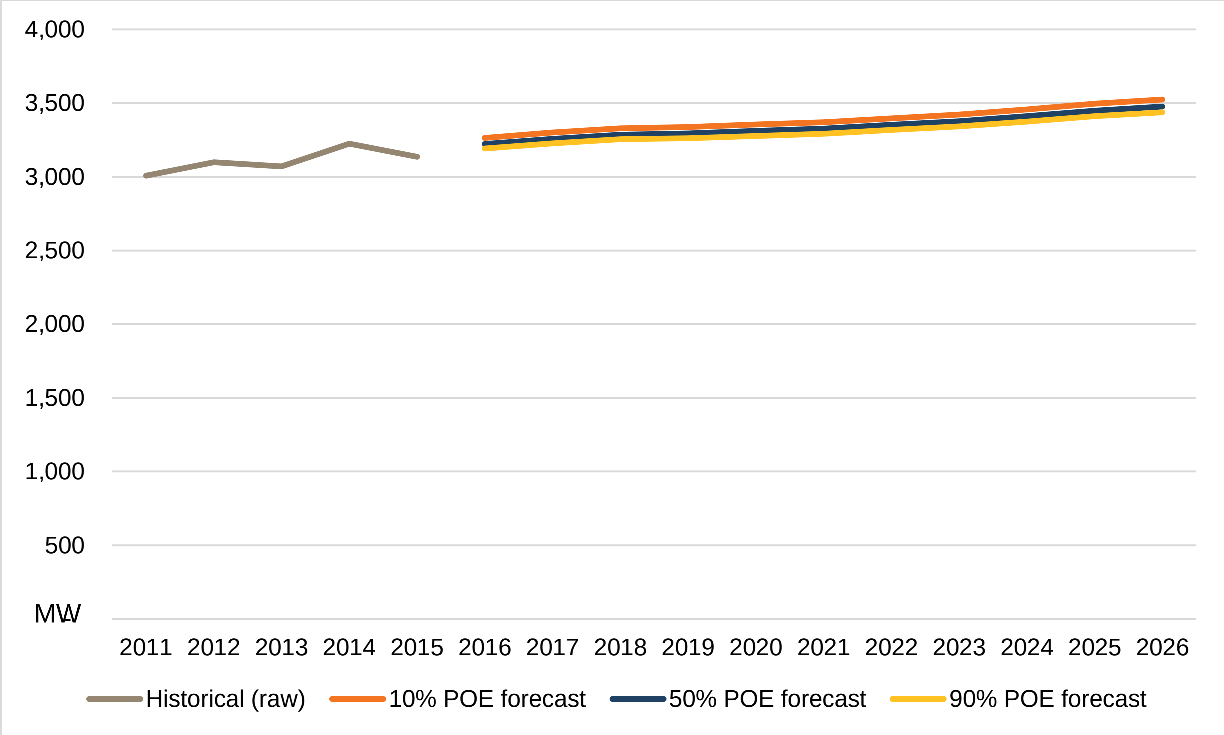
Source: NIEIR

These growth rates reflect different economic growth forecasts, as well as changes in rooftop PV and battery storage assumptions.

The full set of summer peak demand forecasts has been provided in Appendix E.

The 10%, 50%, and 90% POE expected demand growth scenario winter peak demand forecasts are shown in Figure 29.

Figure 29 Winter peak demand, expected case forecasts, 2011 to 2026[a]



Source: NIEIR
[a] Winter peak demand forecasts are for calendar years.

Consistent with current demand patterns in the SWIS, winter peak demand is forecast to remain lower than summer peak demand across all scenarios over the forecast period.

The full set of winter peak demand forecasts has been provided in Appendix F.

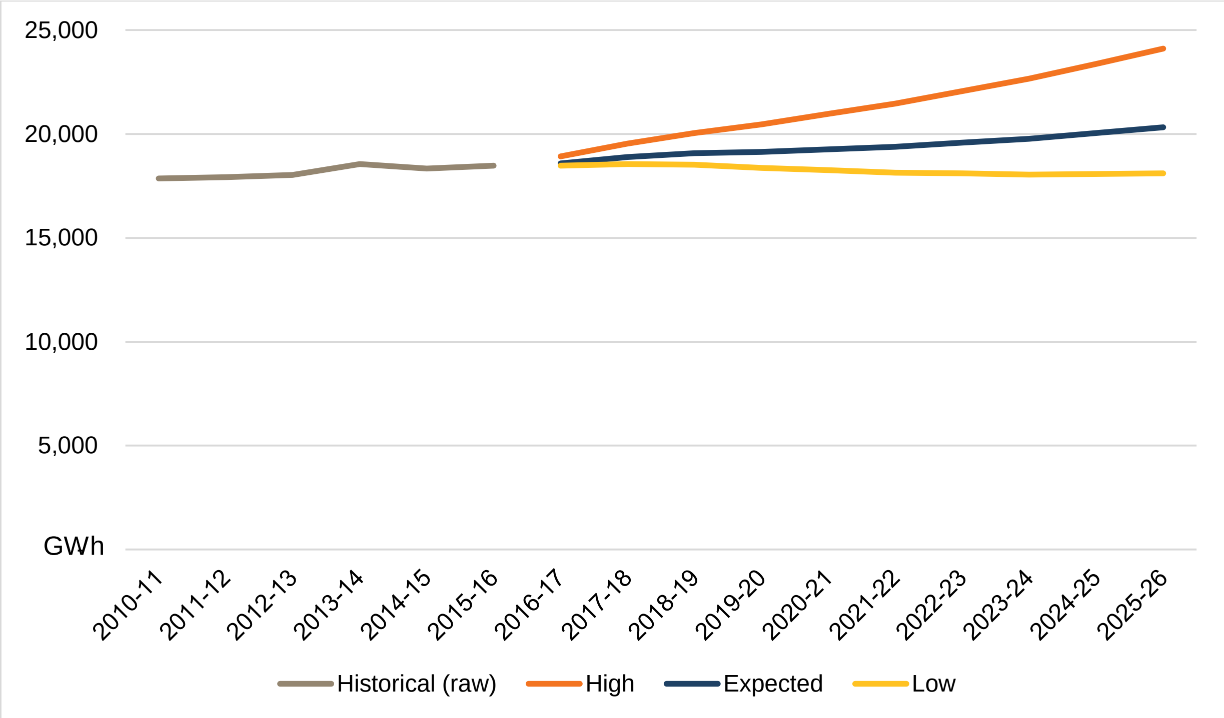
5.2 Operational consumption forecasts

In summary, from 2016–17 to 2025–26, operational consumption is forecast to grow at an average annual rate of:

- 2.7% in the high demand growth scenario.
- 1.0% in the expected demand growth scenario.
- –0.2% in the low demand growth scenario.

The high, expected, and low demand growth scenario operational consumption forecasts are shown in Figure 30 and Table 20.

Figure 30 Operational consumption forecasts under different demand growth scenarios, 2010–11 to 2025–26



Source: NIEIR

Table 20 Operational consumption forecasts

Scenario	2016–17 (GWh)	2017–18 (GWh)	2018–19 (GWh)	2019–20 (GWh)	2020–21 (GWh)	5 year average annual growth	10 year average annual growth
High	18,913	19,529	20,042	20,462	20,973	2.6%	2.7%
Expected	18,584	18,895	19,067	19,135	19,259	0.9%	1.0%
Low	18,476	18,557	18,515	18,364	18,251	-0.3%	-0.2%

Source: NIEIR

These growth rates reflect different economic growth forecasts, as well as changes in rooftop PV and battery storage assumptions.

The full set of operational consumption forecasts has been provided in Appendix G.

CHAPTER 6. FORECAST RECONCILIATION

This chapter discusses forecast performance against actual observations, as well as how peak demand and operational consumption forecasts have changed from previous editions of the ESOO since 2012.

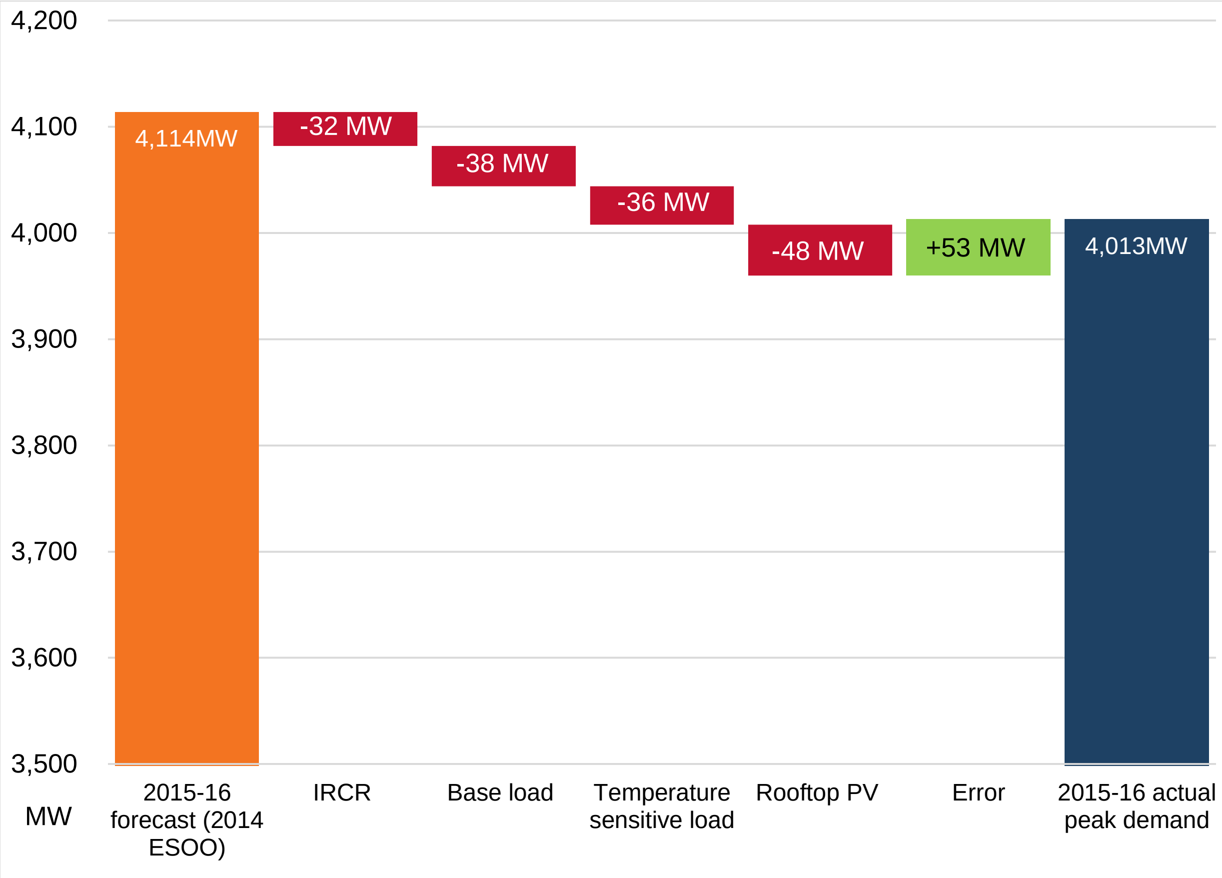
6.1 Base year reconciliation

6.1.1 Peak demand

AEMO prepares forecasts based on different weather conditions (the 10%, 50%, and 90% POE forecasts). When reviewing the variance between the forecast and actual peak demand, it is important to separate the effect of warmer or cooler than average temperatures from other sources of variance. This provides an understanding of the amount of variance that can be attributed to weather, and the amount that can be attributed to other factors such as customer behaviour and economic activity.

The variance between the summer 2015–16 actual peak demand and the 2015–16 forecast from the 2014 ESOO is shown in Figure 31.

Figure 31 Peak demand variance analysis, 2015–16, 10% POE expected demand growth scenario



Source: AEMO and NIEIR

The actual peak demand for the 2015–16 summer was 4,013 MW, which is 101 MW (2.5%) lower than was forecast in the 2014 ESOO. The peak demand interval occurred on 8 February 2016 during a period of four consecutive high temperature days, with the maximum temperature reaching 40.2°C at the time of peak. AEMO considers this to be a 10% POE weather event. As a result, no temperature adjustment has been made to the raw demand figure to align to a 10% POE weather event.

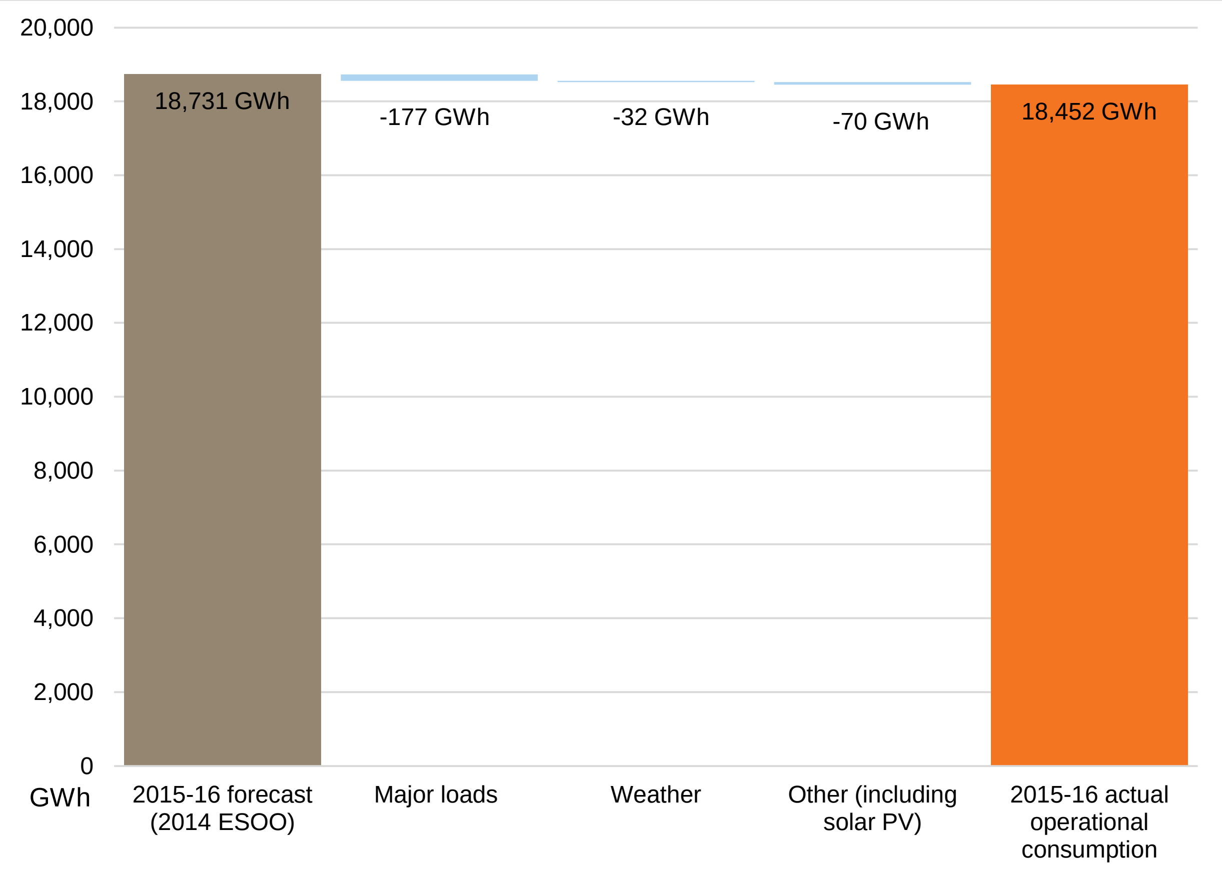
The main sources of variance between the 2015–16 forecast published in the 2014 ESOO (4,114 MW) and the actual figure (4,013 MW) are:

- **Peak reduction from IRCR response (-32 MW)** – the IRCR reduction was nearly double the forecast response of 45 MW. BOM accurately forecast the heatwave four days in advance, allowing customers to plan a response.
- **Economic and base load effects (-74 MW)** – a number of factors contributed to this variance, including lower than expected population growth and business investment (Section 4.2.1 contains more detail).
- **Peak reduction by rooftop PV systems (-48 MW)** – this year, AEMO has improved the methodology for calculating the effect of rooftop PV on peak demand, based on generation data from the APVI and solar irradiance data from BOM. This has resulted in lower estimates for the peak demand contribution than were used in the 2014 ESOO forecasts.
- **Error (+53 MW)** – other minor sources of forecast variance which cannot be individually quantified.

6.1.2 Operational consumption

The variance between the actual operational consumption in 2015–16 and forecast operational consumption from the 2014 ESOO is shown in Figure 32.

Figure 32 Operational consumption variance analysis, 2015–16[a]



[a] Financial year.

Actual operational consumption was 18,452 GWh, which was 1.5% lower than forecast. This small variation can be attributed mainly to the slower than expected economic growth in WA, particularly in the resource sector which accounts for the majority of large loads in the SWIS. Large customers account for around 20% of total SWIS operational consumption (Section 3.5.2 provides more detail).

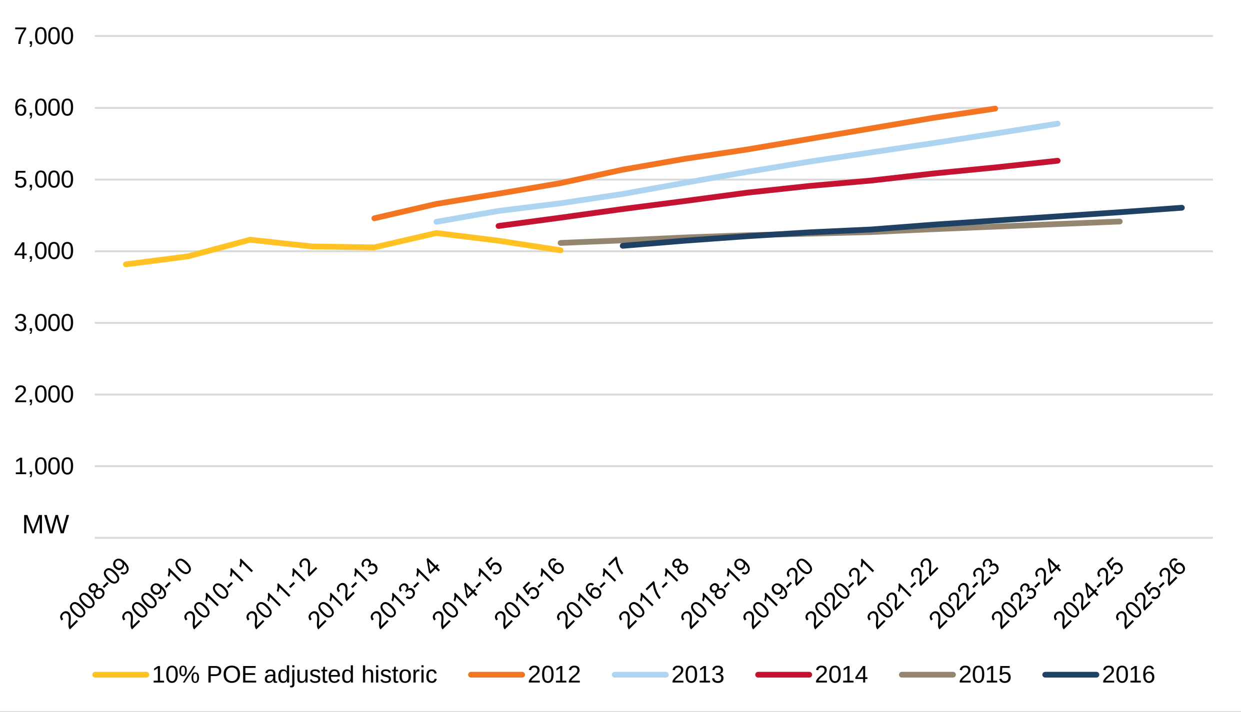
6.2 Changes between previous forecasts

6.2.1 Peak demand

NIEIR's peak demand forecasts published in previous editions of the WEM ESOO since 2012 are shown in Figure 33. The 10% POE 10-year average annual growth rate in this year's ESOO is marginally different from the growth rate published in the 2014 ESOO, largely due to the 10% POE event that occurred in summer 2015–16, resulting in a recalibration of the forecasting models.

While the forecasts provided by NIEIR are on the high side of AEMO expectations in the forecast years beyond 2020–21, AEMO has cross-examined these numbers and considers the difference between the 2014 ESOO and the Deferred 2015 WEM ESOO annual peak demand growth rates to be reasonable and to fall within the bounds of forecast error. Uncertainty is introduced in the next decade from variability in the growth rate of rooftop PV, changing energy consumption behaviour, and new technology and tariff projections.

Figure 33 Change between peak demand 10% POE, expected case forecasts, 2012 to 2016 forecasts



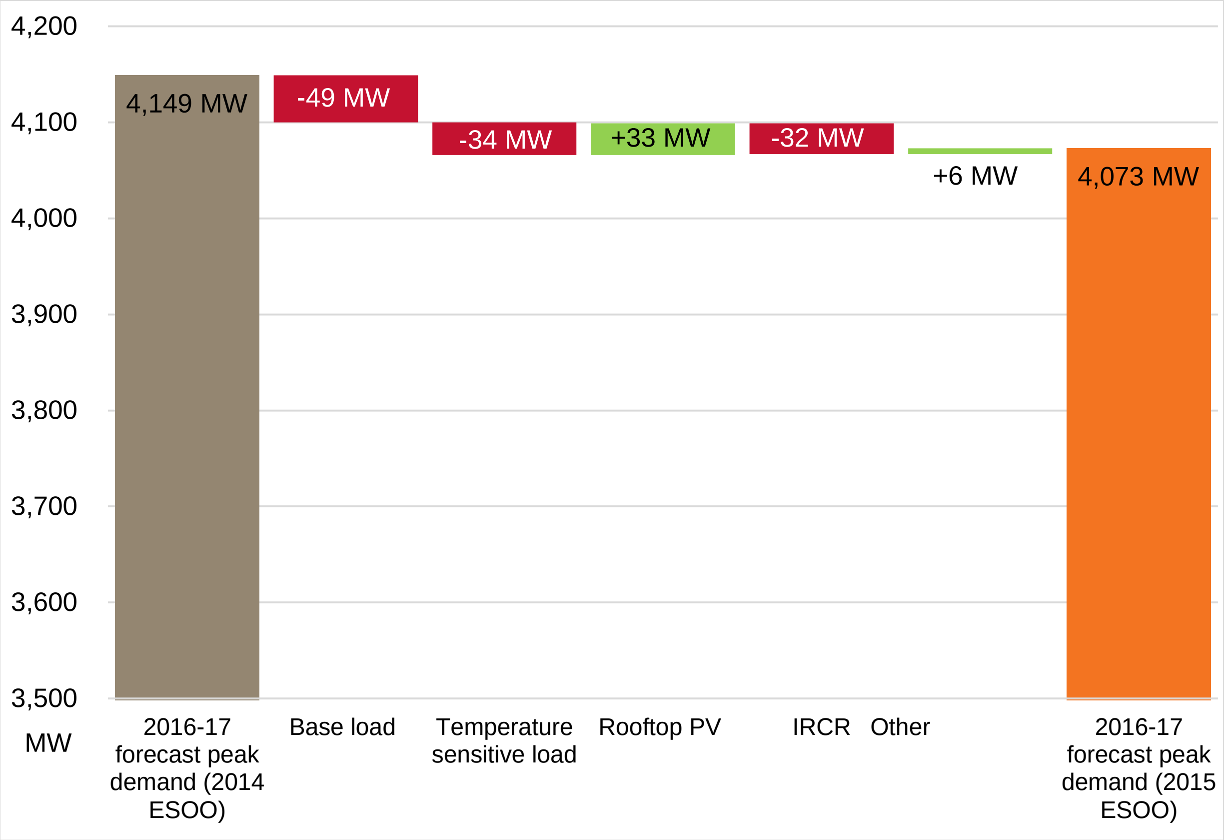
Source: NIEIR

The change between the 2016–17 forecast peak demand published in the 2014 ESOO and the revised forecast in Chapter 5 of this report is shown in Figure 34. The revised 2016–17 forecast is 1.9% (76 MW) lower than the forecast in the 2014 ESOO. The decrease can be attributed to:

- A reduction in the forecast for temperature sensitive load and base load, due to a downward revision in the WA economic forecasts.
- The effect of rooftop PV on peak demand having been reduced since the 2014 ESOO forecasts, reflecting an improvement in the forecasting model to account for cloud cover.

- An increase in the forecast for the IRCR response over the outlook period, based on analysis of the summer 2015–16 IRCR response (see Section 3.2).

Figure 34 Change between peak demand 10% POE forecasts for 2016–17, 2014 ESOO and Deferred 2015 WEM ESOO

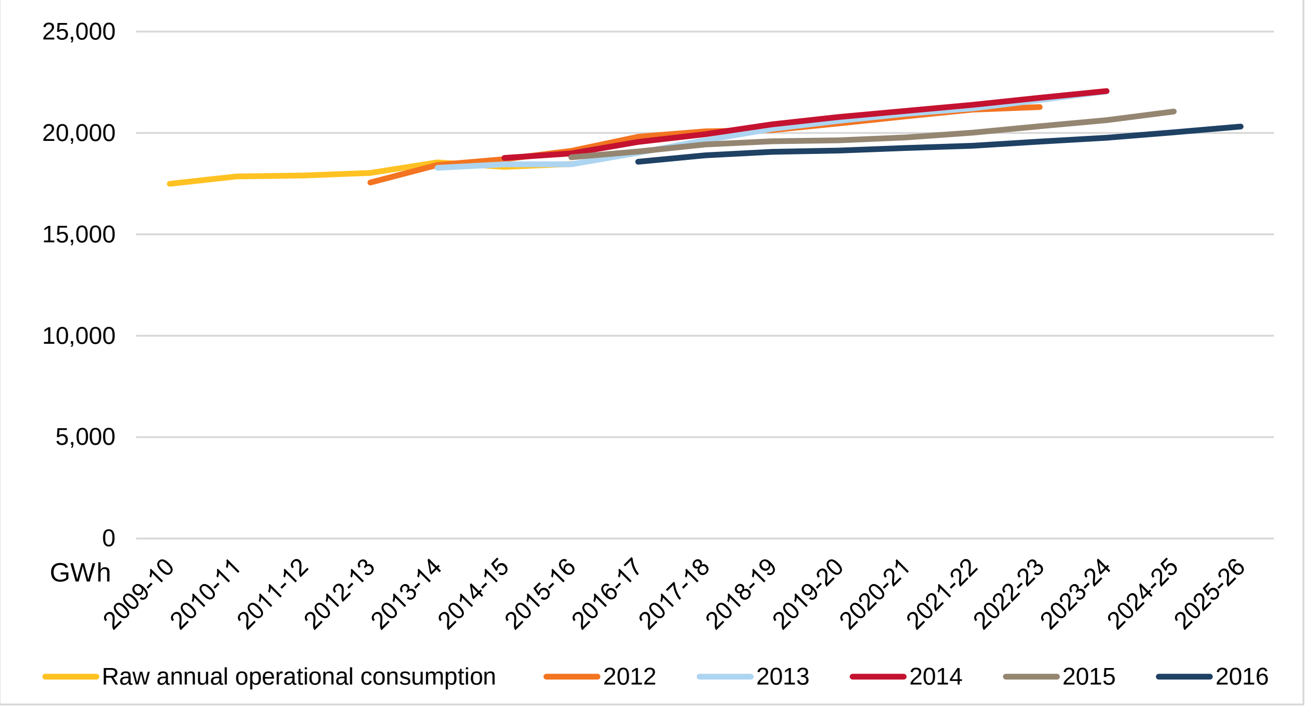


Source: AEMO and NIEIR

6.2.2 Operational consumption

Operational consumption forecasts since 2012 are shown in Figure 35. These forecasts have been consistent for the past five years, with this year's forecasts being slightly lower than previous editions of the WEM ESOO. Operational consumption in this ESOO is forecast to grow at an average annual rate of 1% across the 10-year outlook period. This is a slight downward revision from the 2014 ESOO forecast, broadly consistent with variances in economic growth assumptions and higher forecasts of rooftop PV and battery storage.

Figure 35 Change between operational consumption expected case forecasts, 2012 ESOO to Deferred 2015 WEM ESOO forecasts



Source: AEMO and NIEIR

CHAPTER 7. 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 (2015–16 to 2024–25 for the 2015 Reserve Capacity Cycle).[46]

7.1 Planning Criterion

The RCT ensures there is sufficient generation and DSM capacity in each Capacity Year during the Long Term PASA Study Horizon to meet two elements of the Planning Criterion (outlined in clause 4.5.9 of the WEM Rules):

a) Meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

   i. 7.6%[47] of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

   ii. The maximum capacity, measured at 41°C, of the largest generating unit.

   while maintaining the Minimum Frequency Keeping Capacity[48] for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten.

b) Limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses).

Part (a) of the Planning Criterion relates to meeting the highest demand in a half-hour trading interval. Part (b) ensures adequate levels of energy can be supplied throughout the year.

The Planning Criterion applies to the provision of generation and DSM capability. It does not specifically include transmission reliability planning, or cover for a major fuel disruption such as a sudden or prolonged gas supply disruption.

To date for the RCT determination, the peak demand-based capacity requirement in part (a) has exceeded the energy-based requirement in part (b). For the 2017–18 Capacity Year, this difference is 675 MW.

The RCT for each year in the Long Term PASA Study Horizon is in Section 7.2.

7.1.1 Part (a) of the Planning Criterion

Between 2015–16 and 2020–21 in the Long Term PASA Study Horizon, the capacity of the largest generating unit, NewGen Neerabup (331 MW)[49], measured at 41°C, has set the level of reserve margin, being greater than 7.6% of the forecast peak demand (8.0%). For Capacity Year 2021–22 and beyond, the requirement of 7.6% of the forecast peak demand sets the reserve margin.

System Management has advised that the quantity of load following ancillary service (LFAS) capacity required for maintaining system frequency is 72 MW for the foreseeable future, provided there are no changes to 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 2015 for the 2015 Reserve Capacity Cycle).
[47] This reserve margin was reduced from 8.2% to 7.6% as a result of Rule Change Proposal: 5-yearly Review of the Planning Criterion (RC_2012_21), which commenced on 1 May 2013 and first applied to the 2013 Reserve Capacity Cycle. See http://wa.aemo.com.au/home/imo/rules/rule-changes/commenced/rule-change-rc_2012_21 for more information.
[48] Also known as load following ancillary service (LFAS) capacity.
[49] Based on the level of Capacity Credits assigned for the 2016–17 Capacity Year.

7.1.2 Part (b) of the Planning Criterion

Although annual peak demand in the SWIS occurs in summer, the availability of capacity is crucial for system reliability throughout the year. Generators undergo regular maintenance to ensure ongoing reliability. These outages are typically scheduled in the lower load periods of autumn, spring, and, to a lesser extent, winter. The scheduling process in the WEM Rules is designed to ensure sufficient capacity is available to meet the short-term demand forecast.

Detailed modelling of the entire power system is completed to ensure there is sufficient capacity to accommodate plant maintenance and unplanned (or 'forced') outages throughout the year. The result is an estimate of the percentage of demand that would not be met due to insufficient available capacity. Part (b) of the Planning Criterion requires this shortfall to be no more than 0.002% of the annual forecast demand (see the Availability Curves in Section 7.3).

To date, the RCT has been set by part (a) of the Planning Criterion, relating to annual forecast peak demand, due to sufficiently high levels of plant availability.

7.2 Forecast capacity requirements

The RCT, set by the peak demand requirement of the Planning Criterion, for each year of the Long Term PASA Study Horizon is shown in Table 21.

Table 21 Reserve Capacity Targets[a]

Capacity Year	Peak demand (MW)	Intermittent Loads (MW)	Reserve margin (MW)	Load following (MW)	Total (MW)
2015–16[b]	4,032	4	331	72	4,439
2016–17[b]	4,073	4	331	72	4,480
2017–18	4,145	4	331	72	4,552
2018–19	4,209	4	331	72	4,616
2019–20	4,263	4	331	72	4,670
2020–21	4,303	5	331	72	4,711
2021–22	4,371	4	333	72	4,780
2022–23	4,428	4	337	72	4,841
2023–24	4,487	4	341	72	4,904
2024–25	4,545	4	346	72	4,967
2025–26	4,606	4	350	72	5,032

[a] All figures have been rounded to the nearest integer.
[b] Figures have been updated to reflect the current forecasts. However, the RCTs set in the 2013 and 2014 ESOOs have not changed.

The RCT determined for the 2015 Reserve Capacity Cycle (for the 2017–18 Capacity Year) is 4,552 MW. This is 5 MW lower than the 2016–17 RCT of 4,557 MW published in the 2014 ESOO. The change accounts for revisions to the peak demand forecasts (4 MW) and a reduction in the allowance for Intermittent Loads (1 MW).

7.3 Availability Curves

Changes to the WEM Rules implemented for the EMR include reducing the number of Availability Classes from four to two. Previously, there were four Availability Classes and capacity was allocated on the basis of the maximum number of hours the capacity was available to be dispatched. Under the new WEM Rules, two Availability Classes are defined as follows:

- Class 1 relates to generation capacity and any other capacity that is available to be dispatched for all trading intervals other than when an outage applies.

- Class 2 relates to capacity that is not expected to be available to be dispatched for all trading intervals.

Capacity from an Availability Class with higher availability can be used to meet the requirement for an Availability Class with lower availability.

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

The Availability Curves for the 2016–17, 2017–18 and 2018–19 Capacity Years are shown in Table 22.

Table 22 Availability Curves

	2016–17 (MW)	2017–18 (MW)	2018–19 (MW)
Clause 4.5.12(b) of the WEM Market Rules			
Capacity associated with Availability Class 1	3,760	3,792	3,861
Capacity associated with Availability Class 2	720	760	755

Source: PA Consulting

A more detailed explanation and graphs of the capacity requirements are provided in Appendix A.

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.

7.4 DSM dispatch quantity and price

The EMR has introduced different pricing for DSM and generation Facilities. This requires AEMO to calculate the Expected DSM Dispatch Quantity and the DSM Activation Price. These are then used to determine the DSM RCP as follows:

$$\text{DSM RCP} = \left(\frac{\text{Expected DSM Dispatch Quantity}}{\text{Capacity Credits assigned to DSM}} + 0.5\right) \times \text{DSM Activation Price}$$

The results of this calculation are shown in Table 23. In line with the PUO's assumptions in the *Final Report: Reforms to the Reserve Capacity Mechanism*[50], AEMO has assumed 250 MW of Capacity Credits are assigned to DSM and the DSM Activation Price is $33,460/MWh throughout the forecast period to calculate the values in the table.

Table 23 Expected DSM dispatch and DSM RCP, 2017–18 to 2024–25

Capacity Year	Expected DSM dispatch (MWh)	Estimated DSM RCP ($/MW)[a]
2017–18	6.1	17,546
2018–19	9.1	17,948
2019–20	13.7	18,564
2020–21	22.2	19,701
2021–22	22.2	19,701
2022–23	22.2	19,701
2023–24	22.2	19,701
2024–25	22.2	19,701

[a] Rounded to the nearest dollar.

[50] See http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Reforms-to-the-Reserve-Capacity-Mechanism-Final-Report.pdf.

7.5 Opportunities for investment

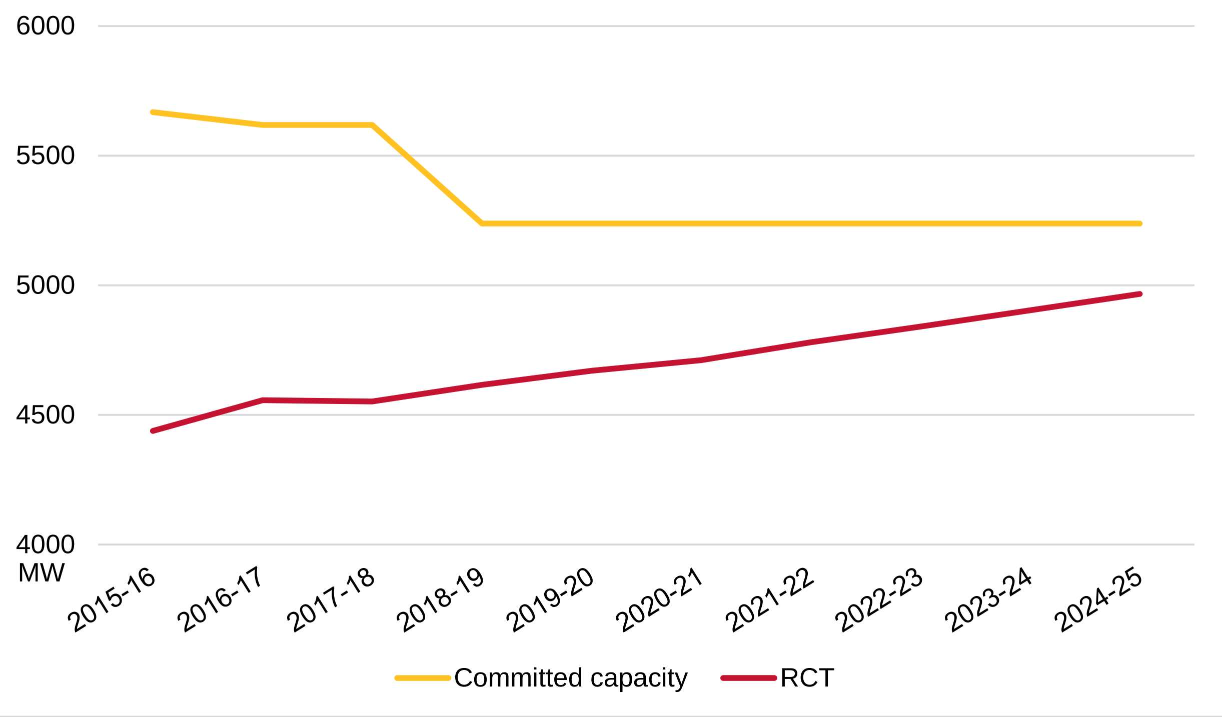
7.5.1 Supply-demand balance

To assess the supply-demand balance, AEMO has assumed that:

- Synergy reduces 380 MW of plant generation capacity by 1 October 2018, in accordance with the public announcement from the Minister for Energy.
- No other generation or DSM Facilities are retired over the forecast period.
- No new capacity commences operation for the forecast period.

The supply-demand balance between 2015–16 and 2024–25 is shown in Figure 36, which compares the RCT with the expected level of capacity for each Capacity Year of the Long Term PASA Study Horizon. Installed and committed capacity is expected to be sufficient to meet the RCT until the end of the Long Term PASA Study Horizon in 2024–25, provided there are no further changes to the WEM Rules.

Figure 36 Supply-demand balance, 2015–16 to 2024–25



The supply-demand balance for the high and low demand growth scenarios can be found in Appendix B.

The capacity outlook for the next three Capacity Years is shown in Table 24. Capacity decreased between 2015–16 and 2016–17 with the retirement of Synergy's Worsley cogeneration (107 MW) and Geraldton (15.4 MW) Facilities, partially offset by an increase in capacity associated with NewGen Kwinana (7.8 MW), CleanTech's Richgro biogas plant (0.9 MW), and two new DSM Facilities (9 MW).

AEMO estimates there will be around 1,066 MW (23%) of excess capacity in the SWIS in the 2017–18 Capacity Year, reducing to 622 MW (13%) in the 2018–19 Capacity Year as a result of the reduction of

380 MW of Synergy's plant generation capacity. Excess capacity is expected to steadily decrease to 271 MW by 2024–25, due to higher peak demand growth in the outer forecast years beyond 2020–21.[51]

Table 24 Capacity in the SWIS, 2016–17 to 2018–19 Capacity Years

	2016–17 (MW)	2017–18 (MW)	2018–19 (MW)
Existing generating capacity	5,058	5,058	5,058
Existing DSM capacity	560	560	560
Retired capacity	122	0	380
Committed new capacity	18	0	0
Proposed projects (from EOI)	0	0	42
Total existing capacity	5,618	5,618	5,238
RCT	4,557	4,552	4,616
Excess capacity	1,061	1,066	622

This analysis suggests it is likely no new capacity will be required in the SWIS in the next ten years. However, circumstances may change over the period through to 2024–25. In particular, the level of capacity is expected to be affected by the changes to the WEM Rules implemented by the EMR. The transitional changes include:

- Transitional arrangements for the period before the first auction, including a revised formula for calculating the RCP and paying DSM capacity a different price than generators.
- Harmonising DSM and generator availability requirements.
- Improving incentives for all capacity to be available for dispatch, by returning capacity refunds to Market Generators rather than Market Customers.

AEMO expects that some DSM capacity will exit the market as a result of the change to the pricing methodology and availability requirements.[52] The amount of DSM remaining in the market will be apparent to AEMO following the close of the certification window on 1 July 2016. In addition, the higher availability requirements on generators may result in some generation capacity exiting the market. Project proponents, investors, and developers should make independent assessments of the possible supply and demand conditions.

7.5.2 Expressions of Interest and excess capacity in the SWIS

Under clause 4.1.4 of the WEM Rules, AEMO is required to run an Expression of Interest (EOI) process each year. The EOI for the 2015 and 2016 Reserve Capacity Cycles closed on 2 May 2016.[53] No new capacity was proposed for the 2017–18 Capacity Year, and one intermittent generation project with a nameplate capacity of 42 MW was proposed for the 2018–19 Capacity Year.

While the EOI process provides an indication of potential future capacity, an EOI submission does not necessarily translate into certified capacity. Alternatively, some of the capacity submitted under the EOI process may potentially be developed for subsequent Reserve Capacity Cycles. For instance, in 2014, EOIs were received for 56 MW of potential new capacity but none of this capacity was assigned Capacity Credits for the 2016–17 Capacity Year.

[51] The final report on the RCM released by the EMR states that an auction will be held when excess capacity either reaches a preliminary level of between 5% and 6% or by 2021, whichever occurs earlier. See https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Reforms-to-the-Reserve-Capacity-Mechanism-Final-Report.pdf.

[52] The PUO expects that 250 MW of DSM will remain in the market. See https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Reforms-to-the-Reserve-Capacity-Mechanism-Final-Report.pdf.

[53] The deferral of the 2016 Reserve Capacity Cycle excluded the EOI process, which had already commenced at the time of the PUO's request.

Table 25 shows the amount of capacity offered each year under the EOI process, compared with the amount of capacity that was actually certified, as well as all other capacity certified in that year.

Table 25 Capacity offered through the EOI compared to capacity certified, 2014–15 to 2018–19

	2014–15	2015–16	2016–17	2017–18	2018-19
Capacity offered (MW)	214	59	56	0	42
Capacity offered and certified (MW)	0	0.4	0	NA	NA
Total other capacity certified	25	15	18	NA	NA

CHAPTER 8. OTHER ISSUES

This chapter provides information about government reforms affecting the RCM, as well as covering infrastructure developments within the SWIS.

8.1 The WA Government's Electricity Market Review

8.1.1 Workstreams overview

The WA Minister for Energy launched the EMR in March 2014 with three objectives:

1. Reducing costs of production and supply of electricity and electricity related services, without compromising safety and reliability.
2. Reducing government exposure to energy market risks, focusing on having future electricity generation built by the private sector without government investment, underwriting or other financial support.
3. Attracting to the electricity market private-sector participants that are of a scale and capitalisation to facilitate long-term stability and investment.

Phase two of the EMR commenced in March 2015. It consists of four workstreams that capture proposed reform projects, summarised below:

1. Network regulation – transferring regulation of the Western Power network to the national framework and regulator.
2. Market competition – introducing full retail contestability; removing barriers to entry; and adopting the national metering framework.
3. Institutional arrangements – introducing an independent rule change approval body, transferring system management functions to AEMO, and introducing a WA reliability panel.
4. WEM improvements – reforming the current RCM and energy market operations and processes (including implementing a constrained network model, developing competitive co-optimised ancillary service markets and reforming STEM).

The proposed reforms from the WEM improvements workstream will have substantial impacts on current and future Reserve Capacity Cycles.

More information on the proposed reforms is available on the Department of Finance's website.[54] AEMO recommends that current and potential Market Participants consult the Department of Finance's website regularly, to ensure they have access to up-to-date EMR-related information.

8.1.2 Reforming the current RCM

On 7 April 2016, the PUO published a final report[55] for consultation detailing the proposed changes to the RCM, along with the draft WEM Rules. The major changes included:

- The adoption of an auction to procure capacity, with the first auction to occur when excess capacity falls to between a preliminary level of 5% and 6%, or in 2021 (whichever occurs first).
- Transitional arrangements for the period before the first auction, including a revised formula for calculating the RCP and paying DSM Facilities a different price than generators.
- Harmonising DSM and generator availability requirements.

[54] See https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx.

[55] Public Utilities Office, WA Department of Finance. *Final Report: Reforms to the Reserve Capacity Mechanism.* Available at: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Wholesale_Electricity_Market_Improvements.aspx.

- Improving incentives for all capacity to be available for dispatch, by returning capacity refunds to Market Generators rather than Market Customers.

These changes are intended to reduce the cost of procuring capacity to meet the RCT. Some reforms will be implemented by 1 June 2016, and others will be implemented for future Reserve Capacity Cycles.

The PUO estimates, in the *Final Report: Reforms to the Reserve Capacity Mechanism*, that 250 MW of DSM capacity will remain in the market following changes to the RCM, a reduction of 310 MW from the current level. In future, a proportion of the 310 MW of exiting DSM capacity may choose to instead reduce their capacity liability as an IRCR liable customer. AEMO has modelled the impact of loads associated with DSM Facilities responding to the IRCR mechanism on future peak events. Under conservative assumptions, an IRCR response of 105 MW to 170 MW is foreseeable, which would change the timing of the peak interval from 17:30 to 19:30. This change would:

- Require IRCR responding customers to modify when they respond.
- Increase the proportion of peak demand associated with the notional wholesale meter from 47% to 52%.

8.1.3 Reforming the energy market operations and processes

On 14 March 2016, the PUO published a Position Paper[56] detailing proposed changes to the energy and ancillary services markets and mechanisms, including:

- Adopting a security-constrained market design.
- Co-optimisation of energy and ancillary services.
- Facility bidding for all Market Participants.
- Five minute dispatch cycle.
- Ex-ante pricing.

These proposed reforms are intended to improve the WEM’s efficiency and reduce costs to Market Participants. For example, co-optimised dispatch will allow a dispatch engine algorithm to optimise the provision of energy and multiple ancillary services in a way that minimises costs to the market while maintaining system security. Adopting a security-constrained market design will increase transparency, and produce higher quality forecasts and information to Market Participants regarding locations where new capacity or network investment will deliver the greatest value to consumers.

Moving to a security-constrained market design is expected to affect the certification process for all Facilities in the SWIS, but the effect of this is currently unclear.

These changes will align some of the operations in the WEM more closely with those in the NEM and other electricity markets globally. The changes are proposed to take effect on 1 July 2018.

8.2 Federal government policy

8.2.1 Renewable energy policy

The LRET is a national target for renewable generation to reach 33,000 GWh, or about 23.5 per cent[57] of Australia’s forecast electricity generation, in 2020. In March 2016, the percentage of electricity

[56] Public Utilities Office, WA Department of Finance. *Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms.* Available at: https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Position-paper-Energy-Market-Operations-and-Processes.pdf.

[57] Australian Federal Minister for the Environment and Minister for Industry and Science media release, “Certainty and growth for renewable energy”, 23 June 2015. Available at: http://www.environment.gov.au/minister/hunt/2015/pubs/mr20150623.pdf.

generated in Australia from renewable sources was 12.75%.[58] This is a national target, and no obligations are conferred on individual states to meet a specified proportion of the target.

In addition to the LRET, the Commonwealth Government maintains the following funds to encourage the development of renewable energy:

- Clean Energy Finance Corporation (CEFC) – develops finance instruments for renewable energy, low-emissions technology and energy efficiency initiatives. The CEFC focuses on projects that are close to commercial deployment.
- Australian Renewable Energy Agency (ARENA) – established to improve competitiveness and increase supply of renewable energy by 2022. ARENA has a budget of $2.5 billion to invest in projects to achieve this aim.
- Clean Energy Innovation Fund (CEIF)[59] – $1 billion fund to support commercialisation of emerging technologies, with funding of $100 million available each year for 10 years. This will be managed jointly by ARENA and the CEFC and will commence 1 July 2016.[60]

The Commonwealth Government policies and funding available are expected to increase penetration of renewable energy over the next 10 years. However, since these are national schemes, it is unclear how much investment in renewable energy will occur in the WEM, particularly given the current levels of excess capacity. A limited number of EOI for renewable energy projects have been received in the past two years (see Section 7.5.2), and no new large-scale renewable energy generators have been installed since 2013.[61] AEMO will continue to monitor the effect of renewable energy policy in the WEM.

8.2.2 Emissions reduction policy

Australia has committed to achieving a 26% to 28% reduction in emissions by 2030 (relative to 2005 levels) as part of its obligations to keep global temperature increases to below 2°C, as agreed at the 2015 Paris Climate Conference. The effects of emissions targets on the WEM are unclear at this stage. There is currently 1,778 MW of coal-fired capacity[62] operating in the WEM, a large proportion of which is owned by the WA Government through Synergy, with limited incentive to retire this capacity. Retiring this capacity would be expected to increase balancing prices in the WEM, given that most of this capacity would need to be replaced with gas-fired generation.

ACIL Allen estimates that electricity generators in the SWIS produced 12 million tonnes (mt) of carbon dioxide equivalent in 2005. Adopting the Australia-wide target of a reduction of 26 to 28% relative to 2005 emissions levels would require reducing emissions to between 8.6 mt and 8.9 mt by 2030.

Of the coal-fired generators currently operating in the SWIS, Muja AB has the highest emissions intensity, followed by Muja CD and Collie. For gas or dual gas/diesel generators, Mungarra has the highest emissions intensity, with Pinjarra and Pinjar the next highest. Kwinana HEGT, Cockburn, and NewGen Kwinana have the lowest emissions intensity in the SWIS. Retiring emissions-intensive peaking or mid-merit Facilities such as Muja AB and Mungarra may not reduce emissions, as these plants do not operate for long periods.

A detailed analysis of emissions targets in the SWIS will be an area of focus for the ESOO to be published in June 2017.

58 Australian Clean Energy Regulator, "2016 Renewable Energy Target liability obligations set", 15 March 2016. Available at: http://www.cleanenergyregulator.gov.au/RET/Pages/News%20and%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96fcfe&ItemId=229.

59 Prime Minister of Australia media release, "Turnbull Government taking strong new approach to clean and renewable energy innovation in Australia", 23 March 2016. Available at: https://www.pm.gov.au/media/2016-03-23/turnbull-government-taking-strong-new-approach-clean-and-renewable-energy.

60 Australian Renewable Energy Agency media release, "ARENA welcomes new commitment to renewable innovation", 24 March 2016. Available at: http://arena.gov.au/media/arena-welcomes-new-commitment-to-renewable-innovation/.

61 Most recent to start up in 2013 are Mumbida, Blair Fox Karakin, and Denmark wind farms, with a total capacity of 16.988 MW (based on Capacity Credits assigned for the 2016–17 Capacity Year).

62 Based on Capacity Credits assigned for the 2016–17 Capacity Year.

8.3 Infrastructure developments in the SWIS

8.3.1 Western Power's applications and queueing policy

Transmission capacity varies across the transmission network. Therefore, the ability for proposed new connections to receive transmission services (such as the transport of electricity to and from a connection) will depend on the available capacity at a given point on the network. This must be taken into account when parties are considering where to locate new connections.

At locations where transmission system capacity is at or approaching its technical limits, applicants seeking to connect new, or increase existing, generation or loads are considered to be competing with others for connection. Western Power's Applications and Queuing Policy (AQP) sets out (amongst other things) how competing applications are managed.

The EMR has announced 1 July 2018 as the target date for the introduction of a constrained network model. Most new generator applicants are expected to progress any other currently considered applications with the aim of connecting after July 2018 (subject to completion of any works necessary to connect to the Western Power network, and satisfying obligations to register with AEMO). Western Power will consider these applications as not competing with other applications for the same network capacity.

Moving to a constrained network model would require a review and changes to Western Power's AQP. The current policy and its underlying procedures will remain in place until the constrained network model is determined. Decisions on the implementation of specific reforms are expected throughout 2016–17.

Connection before July 2018 would typically require the provision of unconstrained network access, consistent with the existing access regime. This is likely to only be feasible for small generators in limited locations.

More information on Western Power's connection process and the AQP can be found on the Western Power website.[63]

8.3.2 Transmission restrictions on the SWIS

To assist potential developers, Western Power, in collaboration with the Department of Planning and the WA Planning Commission, maintains a geospatial map viewer called the Network Capacity Mapping Tool (NCMT).[64]

The NCMT is an information service available to the general public. It provides access to some of Western Power's electricity network planning information, including a 20-year trend forecast of capacity available at Western Power's zone substations during the peak day. The NCMT provides prospective customers the opportunity to determine which zone substations have the most capacity, facilitating an understanding of how anticipated load growth and future network reinforcement plans could affect the available capacity across zone substations.

The NCMT, which contains information from the 2015–16 Annual Planning Report (APR)[65], indicates that forecast load could reduce available capacity on the day of peak demand each year.

8.3.3 Summary of opportunities for Market Participants

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

[63] See http://www.westernpower.com.au/electricity-retailers-generators-generator-and-transmission-connections.html.
[64] Available at: http://www.westernpower.com.au/ldd/ncmtoverview.html.
[65] Available at: http://www.westernpower.com.au/corporate-information-annual-planning-report.html.

The Network Access Code and WEM Rules both contemplate the use of Network Control Services (NCS) as non-network options for assessment in the decision-making process. NCS may be provided by generation or DSM. In the case of a generation system, this may require a power station connected to the network to be operated for short duration during peak network load periods to provide network support. In the case of DSM, specific customers may agree to curtail load, run onsite standby generation, or disconnect for short periods, to reduce the impact on the network during times of peak network load.

Over the next five years, a number of areas in Western Power's network are expected to require transmission capacity augmentations or alternative options (such as NCS or DSM). Proponents who have (or are planning) generation or DSM capacity that is capable of providing network support are invited to contact Western Power to discuss these opportunities.

More information is contained in Section 6.19 of Western Power's 2015–16 APR, including a new map and supplementary table identifying the location and characteristics of emerging transmission constraints.

APPENDIX A. DETERMINATION OF THE AVAILABILITY CURVE

The Availability Curve ensures 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 (10% POE peak demand forecast plus reserve margin and 0.002% unserved energy), as well as ensuring that sufficient capacity is available to satisfy the criteria for evaluating outage plans.

Assuming the RCT is just met, the Availability Curve indicates the minimum amount of capacity that must be provided by generation capacity to ensure 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 follows the steps below, consistent with clause 4.5.12 of the WEM Rules.

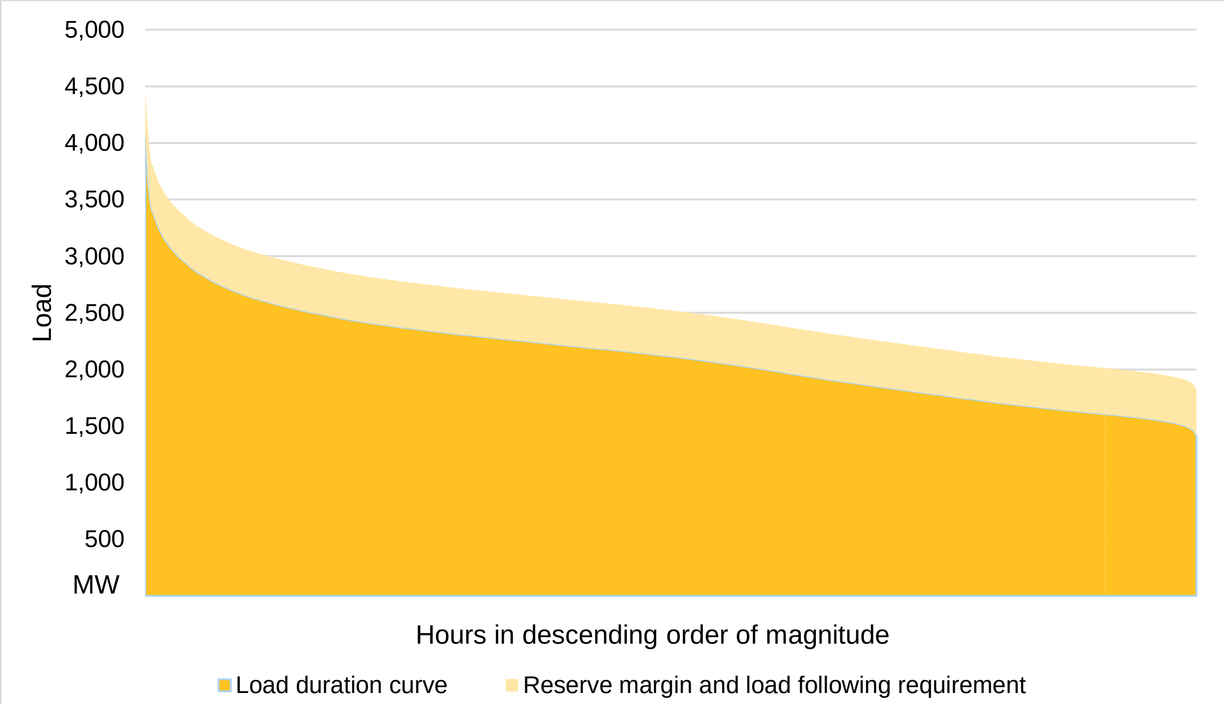
1. A load curve is developed from the average of the annual load curves from the last five years. The shape of this average load curve would be expected to approximate a 50% POE demand profile, so it is then scaled up to match the 10% POE peak demand and expected energy consumption for the relevant year. 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 year, then allowing for typical levels of plant 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:
    a. The total unserved energy equals 0.002% of annual energy consumption, thus breaching the Planning Criterion; or
    b. The spare generation capacity drops below 515 MW[66], thus 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.

The Availability Curves for the 2016–17, 2017–18 and 2018–19 Capacity Years are shown in Figure 37, Figure 38 and Figure 39.

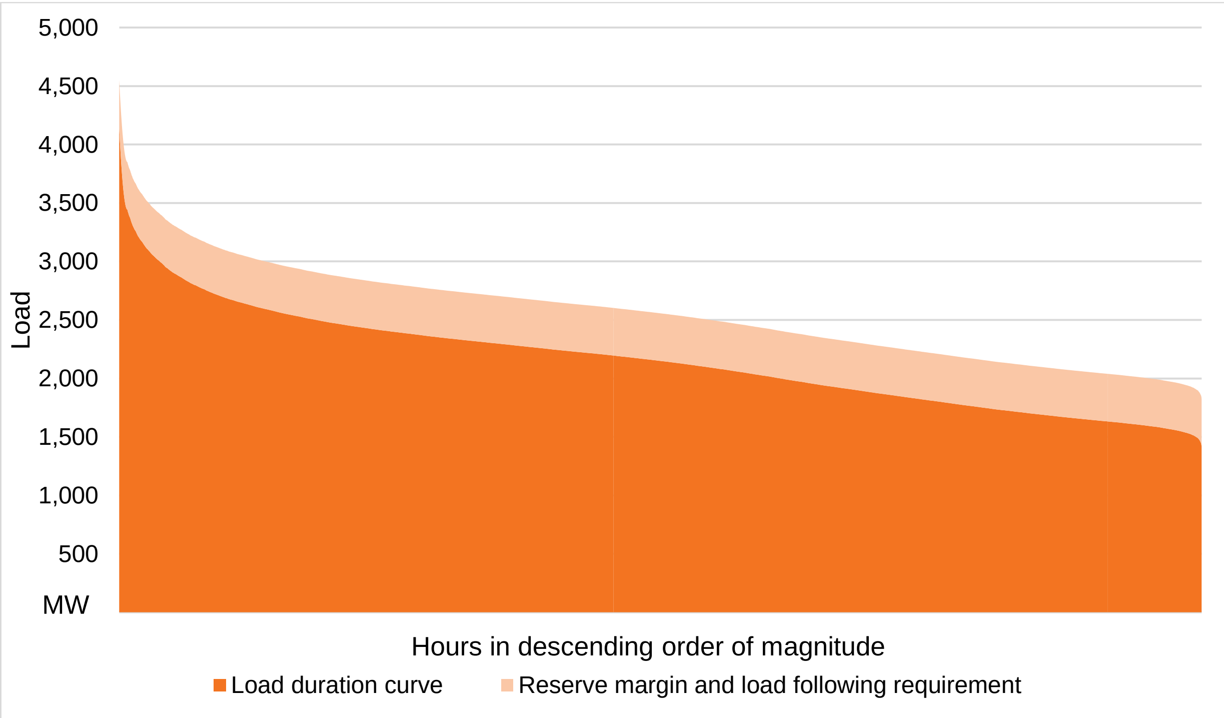
[66] The quantity required to provide ancillary services and satisfy the ready reserve standard, consistent with the information published in the Medium Term PASA at http://wa.aemo.com.au/home/electricity/market-information/pasa/medium-term-pasa-reports.

Figure 37 Availability Curve for 2016–17



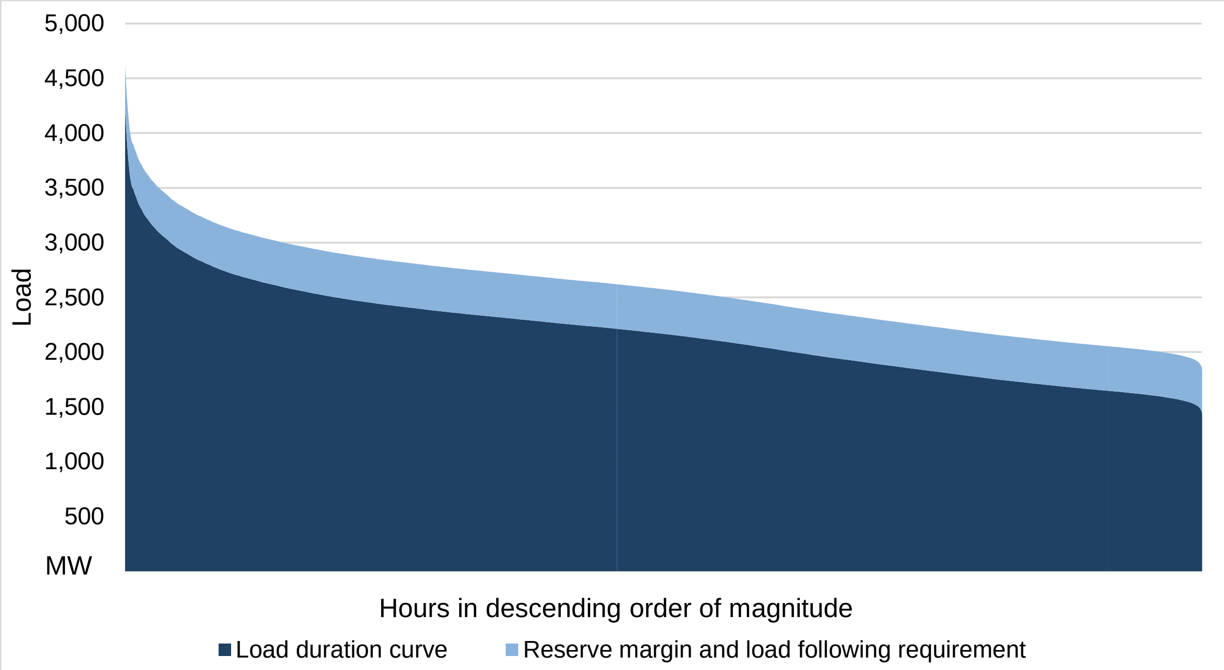
Source: PA Consulting

Figure 38 Availability Curve for 2017–18



Source: PA Consulting

Figure 39 Availability Curve for 2018–19



Source: PA Consulting

APPENDIX B. SUPPLY-DEMAND BALANCE UNDER DIFFERENT DEMAND GROWTH SCENARIOS

Table 26 Supply-demand balance, high demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2015–16	4,483	5,668	1,200
2016–17	4,564	5,618	1,054
2017–18	4,666	5,618	952
2018–19	4,762	5,238	476
2019–20	4,856	5,238	382
2020–21	4,936	5,238	302
2021–22	5,041	5,238	197
2022–23	5,134	5,238	104
2023–24	5,233	5,238	5
2024–25	5,332	5,238	-94

Table 27 Supply-demand balance, expected demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2015–16	4,439	5,668	1,229
2016–17	4,480	5,618	1,138
2017–18	4,552	5,618	1,066
2018–19	4,616	5,238	622
2019–20	4,670	5,238	568
2020–21	4,710	5,238	528
2021–22	4,780	5,238	458
2022–23	4,841	5,238	397
2023–24	4,904	5,238	334
2024–25	4,967	5,238	271

Table 28 Supply-demand balance, low demand growth

Capacity Year	RCT (MW)	Committed capacity (MW)	Balance (MW)
2015–16	4,405	5,668	1,278
2016–17	4,447	5,618	1,171
2017–18	4,494	5,618	1,124
2018–19	4,533	5,238	705
2019–20	4,560	5,238	678
2020–21	4,576	5,238	662
2021–22	4,617	5,238	621
2022–23	4,650	5,238	588
2023–24	4,686	5,238	552
2024–25	4,721	5,238	517

APPENDIX C. ECONOMIC GROWTH FORECASTS

Table 29 Growth in Australian gross domestic product

Year	Actual (%)	Expected (%)	High (%)	Low (%)
2006–07	3.8			
2007–08	3.7			
2008–09	1.7			
2009–10	2.0			
2010–11	2.2			
2011–12	3.6			
2012–13	2.7			
2013–14	2.5			
2014–15	2.2			
2015–16		2.6	3.1	2.2
2016–17		2.6	3.4	1.9
2017–18		2.8	3.8	1.7
2018–19		2.6	3.6	1.6
2019–20		2.2	3.0	1.2
2020–21		2.2	2.9	1.1
2021–22		2.3	3.1	1.5
2022–23		2.2	3.2	1.3
2023–24		2.1	3.0	1.3
2024–25		2.2	3.1	1.2
2025–26		2.4	3.1	1.5
Average growth		2.4	3.3	1.5

Source: NIEIR

Table 30 Growth in WA gross state product

Year	Actual (%)	Expected (%)	High (%)	Low (%)
2006–07	6.2			
2007–08	4.0			
2008–09	4.3			
2009–10	4.2			
2010–11	4.1			
2011–12	7.3			
2012–13	5.1			
2013–14	5.5			
2014–15	3.5			
2015–16		2.2	2.5	1.8
2016–17		3.2	4.2	2.1
2017–18		3.2	3.9	2.4
2018–19		2.6	3.5	1.6
2019–20		1.8	2.7	0.7
2020–21		2.6	3.6	1.5
2021–22		2.9	3.8	1.9
2022–23		3.2	4.1	2.1
2023–24		2.6	3.7	1.4
2024–25		3.1	4.1	2.0
2025–26		3.4	4.3	2.3
Average growth		2.8	3.7	1.8

Source: NIEIR

APPENDIX D. ROOFTOP PV FORECASTS

Table 31 Reduction in peak demand from rooftop PV systems

Year	Expected (MW)	High (MW)	Low (MW)
2016–17	197	230	99
2017–18	230	275	112
2018–19	265	323	124
2019–20	301	372	136
2020–21	336	423	148
2021–22	369	475	159
2022–23	401	523	170
2023–24	432	567	181
2024–25	461	609	192
2025–26	489	650	203

Table 32 Annual energy generated from rooftop PV systems (financial year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2016–17	871	896	836
2017–18	1,020	1,072	942
2018–19	1,174	1,257	1,048
2019–20	1,332	1,448	1,150
2020–21	1,490	1,648	1,247
2021–22	1,637	1,851	1,341
2022–23	1,778	2,037	1,436
2023–24	1,912	2,210	1,528
2024–25	2,040	2,373	1,620
2025–26	2,166	2,530	1,712

Table 33 Annual energy generated from rooftop PV systems (Capacity Year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2016–17	764	770	755
2017–18	908	940	863
2018–19	1,059	1,118	968
2019–20	1,214	1,304	1,073
2020–21	1,371	1,498	1,174
2021–22	1,527	1,699	1,271
2022–23	1,672	1,897	1,365
2023–24	1,811	2,080	1,459
2024–25	1,944	2,250	1,551
2025–26	2,072	2,412	1,643

APPENDIX E. SUMMER PEAK DEMAND FORECASTS

Table 34 Summer peak demand forecasts with expected demand growth

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		4,073	3,819	3,598
2017–18		4,145	3,885	3,659
2018–19		4,209	3,943	3,712
2019–20		4,263	3,991	3,755
2020–21		4,303	4,023	3,779
2021–22		4,371	4,089	3,843
2022–23		4,428	4,141	3,891
2023–24		4,487	4,197	3,944
2024–25		4,545	4,250	3,992
2025–26		4,606	4,306	4,045
Average growth (%)		1.4	1.3	1.3

[a] 10% POE adjusted historical.
Source: NIEIR with AEMO input

Table 35 Summer peak demand forecasts with high demand growth

Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2016–17	4,157	3,902	3,680
2017–18	4,259	3,998	3,771
2018–19	4,355	4,088	3,856
2019–20	4,443	4,170	3,932
2020–21	4,516	4,234	3,988
2021–22	4,614	4,330	4,083
2022–23	4,701	4,412	4,161
2023–24	4,793	4,500	4,245
2024–25	4,885	4,587	4,327
2025–26	4,984	4,681	4,417
Average growth (%)	2.0	2.0	2.0

Source: NIEIR with AEMO input

Table 36 Summer peak demand forecasts with low demand growth

Year	10% POE (MW)	50% POE (MW)	90% POE (MW)
2016–17	4,040	3,787	3,566
2017–18	4,087	3,829	3,604
2018–19	4,126	3,863	3,633
2019–20	4,153	3,884	3,649
2020–21	4,168	3,891	3,649
2021–22	4,210	3,931	3,688
2022–23	4,243	3,960	3,714
2023–24	4,279	3,993	3,743
2024–25	4,314	4,022	3,769
2025–26	4,352	4,056	3,799
Average growth (%)	0.8	0.8	0.8

Source: NIEIR with AEMO input

APPENDIX F. WINTER PEAK DEMAND FORECASTS

Table 37 Winter peak demand forecast with expected demand growth

Year	Actual (MW)	10% POE (MW)	50% POE (MW)	90% POE (MW)
2007–08	2,705			
2008–09	2,774			
2009–10	2,944			
2010–11	3,029			
2011–12	3,008			
2012–13	3,098			
2013–14	3,071			
2014–15	3,224			
2015–16	3,135			
2016–17		3,264	3,223	3,192
2017–18		3,330	3,259	3,227
2018–19		3,329	3,286	3,254
2019–20		3,338	3,296	3,263
2020–21		3,354	3,311	3,278
2021–22		3,370	3,326	3,293
2022–23		3,397	3,352	3,318
2023–24		3,423	3,377	3,342
2024–25		3,458	3,412	3,376
2025–26		3,496	3,449	3,412
Average growth (%)		1.1	1.1	1.0

Source: NIEIR with AEMO input

APPENDIX G. OPERATIONAL CONSUMPTION FORECASTS

Table 38 Forecasts of operational consumption (financial year basis)

Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007–08	16,387			
2008–09	16,628			
2009–10	17,342			
2010–11	17,930			
2011–12	17,813			
2012–13	17,935			
2013–14	18,478			
2014–15	18,360			
2015–16	18,452			
2016–17		18,558	18,820	18,472
2017–18		18,826	19,384	18,540
2018–19		19,019	19,908	18,520
2019–20		19,112	20,350	18,395
2020–21		19,229	20,846	18,279
2021–22		19,348	21,334	18,158
2022–23		19,539	21,906	18,121
2023–24		19,723	22,504	18,064
2024–25		19,976	23,192	18,073
2025–26		20,249	23,917	18,103
Average growth (%)		1.0	2.7	-0.2

Source: NIEIR with AEMO input

Table 39 Forecasts of operational consumption (Capacity Year basis)

Year	Actual (GWh)	Expected (GWh)	High (GWh)	Low (GWh)
2007–08	16,519			
2008–09	16,690			
2009–10	17,500			
2010–11	17,861			
2011–12	17,914			
2012–13	18,028			
2013–14	18,551			
2014–15	18,447			
2015–16	18,475			
2016–17		18,584	18,913	18,476
2017–18		18,895	19,529	18,557
2018–19		19,067	20,042	18,515
2019–20		19,135	20,462	18,364
2020–21		19,259	20,973	18,251
2021–22		19,378	21,459	18,128
2022–23		19,587	22,053	18,112
2023–24		19,770	22,657	18,050
2024–25		20,039	23,370	18,075
2025–26		20,318	24,103	18,110
Average growth (%)		1.0	2.7	-0.2

Source: NIEIR with AEMO input

APPENDIX H. FACILITY CAPACITIES

Table 40 Registered generation Facilities – existing and committed

Participant	Facility	Capacity Credits (2016–17)
Alcoa of Australia	ALCOA_WGP	26.000
Alinta Sales	ALINTA_PNJ_U1	133.869
Alinta Sales	ALINTA_PNJ_U2	134.636
Alinta Sales	ALINTA_WGP_GT	189.798
Alinta Sales	ALINTA_WGP_U2	189.434
Alinta Sales	ALINTA_WWF	21.699
Blair Fox	BLAIRFOX_KARAKIN_WF1	0.970
CleanTech Energy	BIOGAS01	0.930
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	15.048
Denmark Community Windfarm	DCWL_DENMARK_WF1	1.118
EDWF Manager	EDWFMAN_WF1	17.734
Goldfields Power	PRK_AG	61.400
Greenough River	GREENOUGH_RIVER_PV1	3.833
Griffin Power 2	BW2_BLUEWATERS_G1	217.000
Griffin Power	BW1_BLUEWATERS_G2	217.000
Landfill Gas & Power	KALAMUNDA_SG	1.300
Landfill Gas & Power	RED_HILL	2.930
Landfill Gas & Power	TAMALA_PARK	3.933
Merredin Energy	NAMKKN_MERR_SG1	82.000
Mt. Barker Power Company	SKYFRM_MTBARKER_WF1	0.935
Mumbida Wind Farm	MWF_MUMBIDA_WF1	14.900
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	327.800
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600
Perth Energy	ATLAS	0.633
Perth Energy	ROCKINGHAM	2.682
Perth Energy	SOUTH_CARDUP	2.446
Synergy	ALBANY_WF1	8.223
Synergy	BREMER_BAY_WF1	0.078
Synergy	COCKBURN_CCG1	231.800
Synergy	COLLIE_G1	317.200
Synergy	GRASMERE_WF1	5.230
Synergy	KALBARRI_WF1	0.272
Synergy	KEMERTON_GT11	145.500
Synergy	KEMERTON_GT12	145.500
Synergy	KWINANA_GT1	16.809
Synergy	KWINANA_GT2	97.700
Synergy	KWINANA_GT3	97.800
Synergy	MUJA_G5	194.594
Synergy	MUJA_G6	190.000
Synergy	MUJA_G7	211.000
Synergy	MUJA_G8	211.000

Participant	Facility	Capacity Credits (2016–17)
Synergy	MUNGARRA_GT1	32.800
Synergy	MUNGARRA_GT2	32.800
Synergy	MUNGARRA_GT3	31.500
Synergy	PINJAR_GT1	31.800
Synergy	PINJAR_GT2	31.500
Synergy	PINJAR_GT3	37.000
Synergy	PINJAR_GT4	37.000
Synergy	PINJAR_GT5	37.000
Synergy	PINJAR_GT7	37.000
Synergy	PINJAR_GT9	107.000
Synergy	PINJAR_GT10	108.700
Synergy	PINJAR_GT11	120.000
Synergy	PPP_KCP_EG1	80.400
Synergy	WEST_KALGOORLIE_GT2	34.250
Synergy	WEST_KALGOORLIE_GT3	19.300
Tesla	TESLA_GERALDTON_G1	9.900
Tesla	TESLA_KEMERTON_G1	9.900
Tesla	TESLA_NORTHAM_G1	9.900
Tesla	TESLA_PICTON_G1	9.900
Tiwest	TIWEST_COG1	36.000
Vinalco Energy	MUJA_G1	55.000
Vinalco Energy	MUJA_G2	55.000
Vinalco Energy	MUJA_G3	55.000
Vinalco Energy	MUJA_G4	55.000
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.272
Western Energy	PERTHENERGY_KWINANA_GT1	109.000

Table 41 Registered DSM Facilities – existing and committed

Participant	Facility	Capacity Credits (2016–17)	Availability Class
Amanda Australia	AMAUST_DSP_01	9.900	4
Amanda Australia	AMAUST_DSP_02	5.000	4
Amanda Energy	ADERRTL_DSP_01	0.400	4
Broadcast Australia	BAICOMMS_DSP_01	1.250	4
Cockburn Cement	CCL_DSP_01	10.000	4
EnerNOC Australia	ALINTA_DSP_01	16.300	4
EnerNOC Australia	ENERNOC_DSP_01	140.000	4
EnerNOC Australia	ENERNOC_DSP_02	56.000	4
EnerNOC Australia	ENERNOC_DSP_03	50.000	4
EnerNOC Australia	ENERNOC_DSP_04	30.000	4
EnerNOC Australia	ENERNOC_DSP_05	20.000	4
EnerNOC Australia	KANOWNA_DSP_01	11.000	4
EnerNOC Australia	LAMANCHA_DSP_01	7.000	4
Griffin Power	GRIFFIN_DSP_01	20.000	3
Synergy	SYNERGY_DSP_01	10.000	4
Synergy	SYNERGY_DSP_02	5.000	4
Synergy	SYNERGY_DSP_03	5.000	4
Synergy	SYNERGY_DSP_04	42.000	3
Synergy	SYNERGY_DSP_05	20.000	4
Water Corporation	WATERCORP_DSP_01	17.700	4
Water Corporation	WATERCORP_DSP_02	18.000	4
Water Corporation	WATERCORP_DSP_03	28.000	4
Water Corporation	WATERCORP_DSP_04	7.800	4
Wesfarmers Kleenheat Gas	PREMPWR_DSP_02	24.000	4
Wesfarmers Kleenheat Gas	PREMPWR_DSP_04	2.000	4
Wesfarmers Kleenheat Gas	PREMPWR_DSP_05	2.000	4
Wesfarmers Kleenheat Gas	PREMPWR_DSP_07	1.836	4

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GWh	Gigawatt hour
kW	Kilowatt
kWh	Kilowatt hour
mt	Million tonnes
MW	Megawatt
MWh	Megawatt hour

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
APR	Annual Planning Report
APVI	Australian PV Institute
AQP	Applications Queuing Policy
CEFC	Clean Energy Finance Corporation
CEIF	Clean Energy Investment Fund
CER	Clean Energy Regulator
CRC	Certified Reserve Capacity
DSM	Demand Side Management
DSP	Demand Side Programme
EMR	Electricity Market Review
EOI	Expressions of Interest
ERF	Emissions Reduction Fund
ESOO	Electricity Statement of Opportunities
FIT	Feed-in Tariff
GSP	Gross state product (for WA)
IRCR	Individual Reserve Capacity Requirement
LFAS	Load following ancillary service
LRET	Large-scale Renewable Energy Target
NCMT	Network Capacity Mapping Tool
NCS	Network Control Services
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NIEIR	National Institute of Economic and Industry Research
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedance
PUO	Public Utilities Office

Abbreviation	Expanded name
PV	Photovoltaic
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RCT	Reserve Capacity Target
REBS	Renewable Energy Buyback Scheme
RET	Renewable Energy Target
SCADA	Supervisory Control and Data Acquisition
STEM	Short term energy market
SWIS	South West interconnected system
WA	Western Australia
WEM	Wholesale Electricity Market

GLOSSARY

Definitions

Term	Definition
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 equivalent to 1 MW of capacity.
Capacity Year	A period of 12 months commencing on 1 October and ending on 1 October of the following calendar year.
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.
Energy sales	The quantity of electricity delivered to the customer, including losses.
Embedded generation	The energy produced by rooftop PV systems and battery systems (for the forecast period).
IRCR	The proportion of the total cost of Capacity Credits acquired through the RCM paid by each Market Customer. Determined based on the Market Customer’s contribution to peak demand during 12 peak trading intervals over the previous summer period (December to March).
Intermittent generator	A generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind speed).
Long Term PASA	A study conducted in accordance with section 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 ESOO.
Long Term PASA Study Horizon	The 10 year period commencing on 1 October of Year 1 of a Reserve Capacity Cycle.
Operational electricity consumption	The electrical energy supplied by scheduled and non-scheduled generating units, less the electrical energy supplied by rooftop PV.
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.
POE	The likelihood of a forecast being exceeded. For example, a 10% POE forecast is expected to be exceeded once in every 10 years.
REBS customers	Residential customers, not-for-profit organisations or educational institutions who install a rooftop PV system between 500 watts and 5 kW.
Reserve Capacity Cycle	A four year period covering the cycle of events described in section 4.1 of the WEM Rules.
RCM	The capacity market in the SWIS that ensures sufficient capacity is available to meet peak demand.
RCP	The price for capacity paid to Capacity Credit holders and determined in accordance with clause 4.29.1 of the WEM Rules.
RCT	AEMO’s estimate of the total amount of generation or DSM capacity required in the SWIS to satisfy the Planning Criterion.

Term	Definition
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 electricity consumption	All electricity consumed onsite that can be provided by localised generation from rooftop PV and embedded generators, or by the electricity network.