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2014 Electricity Statement of Opportunities

June 2015

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Executive summary

This Electricity Statement of Opportunities (ESOO) presents the Independent Market Operator's (IMO) forecast of electricity peak demand and sent out energy for the South West interconnected system (SWIS) in Western Australia for the forecast period 2015-16 to 2024-25.

This ESOO, which is prepared as part of the 2014 Reserve Capacity Cycle[1], contains peak demand and energy forecasts across a range of weather and economic scenarios. In particular, it highlights the 10 per cent probability of exceedance (PoE) peak demand forecast which is used to determine the Reserve Capacity Target (RCT) for the 2016-17 Capacity Year.

Key findings

The key findings in this ESOO are:

- 10 per cent PoE peak demand is forecast to grow at an average annual rate of 0.8 per cent[2] over the forecast period 2015-16 to 2024-25;
- sent out energy is forecast to grow at an average annual rate of 1.3 per cent[3] over the forecast period;
- peak demand for summer 2014-15 was 3,744 MW, observed in the 15:30 to 16:00 trading interval on 5 January 2015;
- solar photovoltaic (PV) systems continue to have a significant impact; systems are getting larger, more widespread, and are shifting peak demand in the SWIS to later in the day. The effect of solar PV systems will continue to grow as systems become cheaper and new technology such as battery storage supports their adoption;
- the Wholesale Electricity Market (WEM) has become increasingly competitive, with a healthy mix of capacity types. The number of Market Participants has increased three-fold since market start and about 150 contestable customers per month switched retailers during 2013-14;
- 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 a total of 42 MW during the peak demand interval on 5 January 2015. While only 20 customers (less than half the number of customers that responded during the previous year's peak) reduced their consumption during this peak trading interval, this reduction was strong and a similar total quantity as last year (total of 49 MW) despite the early peak in 2014-15;
- based on the 10 per cent PoE peak demand forecast, the 2016-17 RCT is 4,557 MW; and

1 Publication of this ESOO was postponed from June 2014, following direction from the Minister for Energy to defer aspects of the 2014 Reserve Capacity Cycle (which relates to the procurement of capacity for the 2016-17 Capacity Year), in light of the Electricity Market Review. The IMO published the SWIS Electricity Demand Outlook in June 2014 to provide updated demand forecasts and other market information.

2 Expected case economic growth.

3 Expected case economic growth.

- based on the current level of installed and committed capacity, no new generation or Demand Side Management (DSM) capacity will be required in the SWIS over the forecast period.

These findings and other related issues are discussed further in the sections that follow.

Peak demand and sent out energy forecasts 2015-16 to 2024-25

The IMO forecasts the 10 per cent PoE peak demand to increase at an average annual rate of 0.8 per cent over the next 10 years[4]. Table ES.1 shows the 10, 50 and 90 per cent PoE scenarios.

Table ES.1: Peak demand forecasts for different weather scenarios, expected case

Scenario	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	2019-20 (MW)	5 year average annual growth	10 year average annual growth
10% PoE	4,114	4,149	4,191	4,223	4,244	0.8%	0.8%
50% PoE	3,858	3,886	3,924	3,951	3,968	0.7%	0.7%
90% PoE	3,634	3,657	3,690	3,713	3,726	0.6%	0.7%

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

The IMO forecasts sent out energy to increase at an average annual rate of 1.3 per cent over the next 10 years[5]. The high, expected and low scenarios are shown in Table ES.2. These forecasts reflect different economic scenarios and corresponding solar PV system growth scenarios.

Table ES.2: Sent out energy forecasts

Scenario	2015-16 (GWh)	2016-17 (GWh)	2017-18 (GWh)	2018-19 (GWh)	2019-20 (GWh)	5 year average annual growth	10 year average annual growth
High	18,986	19,498	20,010	20,349	20,543	2.0%	2.5%
Expected	18,731	19,015	19,353	19,548	19,625	1.2%	1.3%
Low	18,541	18,705	18,931	18,970	18,893	0.5%	0.5%

Source: NIEIR

Trends in SWIS peak demand

The summer 2014-15 system peak was 3,744 MW, observed in the 15:30 to 16:00 trading interval on 5 January 2015. The quantity of demand at peak was similar to recent years (see Table ES.3), which is consistent with the IMO's view that peak demand growth is flattening.

The IMO attributes this slowdown in peak demand growth to several factors. These factors include the impact of solar PV systems, Western Australia's economic outlook, and changes in customer behaviour such as large industrial customers reducing consumption during periods of peak demand to minimise their exposure to capacity costs.

[4] Expected case economic growth, 2015-16 to 2024-25.
[5] Expected case economic growth forecast.

Table ES.3: SWIS system peak, 2011 to 2015

Peak date	Peak demand (MW)	Maximum temperature during trading interval (degrees Celsius)	Trading interval starting	Daily maximum temperature (degrees Celsius)
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

Source: Bureau of Meteorology and IMO

The 2014-15 peak occurred much earlier in the summer than usual. System demand in the SWIS usually peaks in late January or in February, when term one commences at schools and people have returned to work after the New Year holidays. Peak demand typically follows several days of high temperatures, and is caused by people returning home from school or work and switching on air conditioning to cool their homes, in addition to business load.

The IMO considers the 2014-15 system peak occurred early because:

- **January 5 was exceptionally hot** (44.4 degrees Celsius) – the third highest January temperature ever recorded for Perth; and
- **there were few prolonged periods of consecutive hot days (over 36 degrees Celsius) during the 2014-15 summer** – the only time maximum temperatures exceeded 34 degrees across four or more consecutive days was from 4 to 7 January 2015.

On 5 January 2015, a large proportion of residential customers would have still been at home, following the New Year break. This explains why the peak occurred earlier than usual in the trading interval starting at 15:30, instead of the assumed system peak in the trading interval starting at 16:30.

Impact of solar PV systems

The IMO estimates solar PV systems reduced the 2014-15 peak by 187 MW[6]. Table ES.4 compares actual peak demand over the five highest demand days for 2011 to 2015 with the estimated peak that would have occurred without solar PV.

[6] Based on total installed capacity of 435 MW in January 2015.

Table ES.4: Effect of solar PV on peak demand, 2011 to 2015

Peak date	Time of peak	Peak demand (MW)	Estimated peak demand without solar (MW)	Estimated time of peak without solar	Reduction in peak demand from solar
5 January 2015	15:30	3,744	3,931	15:30	5.0%
20 January 2014	17:30	3,702	3,757	16:30	1.5%
12 February 2013	16:30	3,732	3,816	16:00	2.2%
25 January 2012	16:30	3,857	3,918	15:00	1.6%
16 February 2011	16:30	3,735	3,754	16:30	0.5%

Source: IMO

In addition to reducing peak demand, solar PV systems have shifted the peak time to later in the day (the 5 January 2015 outlier being an exception). Of the peak days over the past five years, the IMO estimates three of these would have occurred earlier if no solar PV systems had been installed, as shown in Table ES.4.

The IMO expects the impact of solar PV systems on peak demand will keep growing. Data provided by Synergy shows:

- the number of residential systems has grown from 63,384 in 2010-11 to more than 160,000 in January 2015;
- the proportion of residential customers with solar PV systems has increased from 7.3 per cent in 2010-11 to 17.6 per cent in January 2015;
- the average system size has increased by 30 per cent, from 1.9 kW to 2.5 kW; and
- the average system size for new installations has increased by 70 per cent, from 2.3 kW in June 2011 to 3.9 kW in January 2015[7].

In addition to residential installations, small-scale solar PV systems are becoming financially viable for commercial customers with prices of commercial PV systems falling and larger systems becoming available for commercial installation.

Based on an assumed output of 27 per cent of nameplate capacity at the time of system peak, solar PV systems are forecast to reduce peak demand by 379 MW in 2024-25[8], as well as potentially shifting the system peak to the trading interval starting at 19:30.

Emerging technology such as battery storage is also likely to influence future electricity consumption behaviours. Products such as Tesla's Powerwall are expected to be available from 2016, and EnerNOC (the largest DSM provider in the WEM) has recently announced it will collaborate with Tesla on the deployment and management of energy storage systems in commercial and industrial buildings in the United States[9]. In Western Australia, Alinta Energy is considering offering solar and battery systems, however, no time frame has been given for availability of this product[10]. Installation of battery storage systems is expected to allow

[7] Based on Clean Energy Regulator data.
[8] 10 per cent PoE forecast scenario, expected case economic growth
[9] More information is available at http://investor.enernoc.com/releasedetail.cfm?ReleaseID=910188.
[10] See https://au.news.yahoo.com/thewest/wa/a/28289418/alintas-solar-plan-to-cut-bills/.

customers to store electricity generated by solar PV systems during the day for use during peak tariff periods.

The IMO has updated its assumptions for solar PV system uptake in all three economic scenarios and has included the effect of battery storage in the forecasts from 2020. In particular, the high case now assumes non-linear growth in installed PV capacity. This case represents stronger uptake in solar PV systems (and a slightly greater amount of installed battery storage) compared to the expected or low case forecasts.

Diversity and competition in the Wholesale Electricity Market

The WEM has become increasingly competitive, with a healthy mix and diversity of generation capacity and DSM. Since 2005-06 the number of Market Participants has increased three-fold, with 30 Market Participants holding Capacity Credits in the 2015-16 Capacity Year, compared with 10 at market start.

Synergy's share of Capacity Credits also continues to decrease. In 2015-16 Synergy (formerly Verve Energy) only held 50 per cent of Capacity Credits, down from 88 per cent at market start in 2006.

There is also a strong mix of fuel types operating in the WEM. Since 2005-06, reliance on the primary fossil fuels (coal and gas) has reduced, with a total of 15 per cent of Capacity Credits now allocated to liquid, DSM and renewable generation, compared to only 7 per cent at market start. Energy generated from renewable sources has almost doubled since 2007, accounting for 9 per cent of sent out energy in 2014.

Table ES.5 provides a snapshot of the increasing diversity and competition in the WEM since market start.

Table ES.5: Key indicators of diversity and competition in the WEM, 2005-06 and 2014-15

Indicator	2005-06	2014-15	Total growth over period
Number of Market Participants assigned Capacity Credits	10	26	160%
Synergy (Verve Energy) share of Capacity Credits	91%	52%	-43%
Share of Capacity Credits for capacity other than coal and gas	28%	34%	21%
Number of registered Market Customers (including retailers)	10	31	210%

Source: IMO

This steady increase in diversity represents a maturing market, which is also reflected in growing competition and greater choice of energy providers. There are currently 18 retailers competing for around 32,000 contestable customers in the SWIS. Data provided by the Economic Regulation Authority indicates around 150 customers per month switched retailers during 2013-14[11].

[11] See https://www.erawa.com.au/cproot/13009/2/20141119%202014%20Ministers%20Report%20Discussion%20Paper.pdf.

Response to the Individual Reserve Capacity Requirement

Data for the 2014-15 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 2014-15 system peak, 20 customers responded to the IRCR price signal, reducing total system load by 42 MW. A similar response occurred during the summer 2013-14 peak, when 44 customers reduced load by 49 MW.

Although the number of customers that responded during the peak interval in 2014-15 was less than half that of 2013-14, the magnitude of their total reduction was similar. This demonstrates the IRCR continues to be an effective mechanism.

The IMO considers it likely that the early peak (5 January) was the main reason why fewer customers responded, as many would not have been operating at full capacity following the New Year break. The IMO analysed the IRCR response for other high load days in January and February 2015 and found response levels were greater, with up to 38 customers reducing load by more than 88 MW in one instance.

Reserve Capacity Target

The RCT for the 2016-17 Capacity Year is 4,557 MW.

This is a 562 MW decrease from the 2015-16 requirement published in the 2013 ESOO. This is largely a result of revisions to the peak demand forecasts, which include:

- lower growth in temperature sensitive load;
- higher levels of installed small-scale solar PV system capacity; and
- lower economic growth assumptions.

The IMO estimates capacity already in place or under construction will exceed the RCT by 1,126 MW in 2016-17. This is an increase of 216 MW compared to 2015-16.

The estimated RCT for 2024-25 is 4,828 MW. Based on this, and the current level of existing or committed capacity, no new generation or DSM capacity is likely to be required in the SWIS over the forecast period 2015-16 to 2024-25.

The Electricity Market Review

In 2014 the Minister for Energy launched the State Government's two-phase Electricity Market Review (EMR). Due to the commitments and likelihood of reforms emerging from the EMR, the Minister for Energy directed the IMO to defer most aspects of the 2014 Reserve Capacity Cycle. To support this direction, the IMO decided to defer publication of the 2014 ESOO to ensure the 2016-17 RCT could be set using the most up to date information available prior to the certification of Reserve Capacity for the 2016-17 Capacity Year.

The Minister has also directed the IMO to defer most aspects of the 2015 Reserve Capacity Cycle (for the 2017-18 Capacity Year), including deferring the 2015 ESOO until June 2016[12].

The EMR has also led the Minister to reject the following proposed changes to the Wholesale Electricity Market Rules (Market Rules), which would have affected the obligations of capacity providers:

- Incentives to Improve Availability of Scheduled Generators (RC_2013_09);
- Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10); and
- Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refund Regime (RC_2013_20).

Phase two of the EMR commenced in March 2015 and includes four work streams:

- network regulation;
- market competition;
- institutional arrangements; and
- WEM improvements.

The IMO notes the WEM improvements work stream considers reforms to the Reserve Capacity Mechanism and the introduction of a constrained grid energy market with competitive and co-optimised markets for Ancillary Services (among other changes).

[12] The IMO has published updated timetables for the 2014 and 2015 Reserve Capacity Cycles on its website: http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

Contents

1. Introduction

1.1 Background and context

This Electricity Statement of Opportunities (ESOO) is published as part of the 2014 Reserve Capacity Cycle, which relates to the capacity required in the South West interconnected system (SWIS) in Western Australia for the 2016-17 Capacity Year.

A key purpose of this ESOO is to set the Reserve Capacity Target (RCT) for the 2016-17 Capacity Year. The RCT is the amount of generation and Demand Side Management (DSM) capacity required to satisfy the Planning Criterion, which the Independent Market Operator (IMO) determines in accordance with the Wholesale Electricity Market Rules (Market 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. As a result, this ESOO highlights the 10 per cent probability of exceedance (PoE) peak demand forecast – the one-in-ten-year forecast – to determine this conservative capacity requirement.

This report also presents the IMO's outlook for electricity peak demand and sent out energy for the SWIS across a number of different scenarios. It provides analysis and commentary about current and future trends in the SWIS, and is designed for use by Market Participants, prospective investors and other interested parties.

1.1.1 Delay to the publication of the Electricity Statement of Opportunities

Publication of this ESOO was postponed from June 2014, following a direction from the Minister for Energy to defer certain aspects of the 2014 Reserve Capacity Cycle in light of the current Electricity Market Review (EMR). The IMO published the SWIS Electricity Demand Outlook (SEDO) in June 2014[13], which contained all of the information usually published in an ESOO except for the RCT and Availability Curves[14].

The IMO received a further direction from the Minister for Energy on 13 March 2015 to defer certain aspects of the 2015 Reserve Capacity Cycle until 2016. As such, the ESOO for the 2015 Reserve Capacity Cycle is expected to be published in June 2016.

Further information on the Ministerial directions and deferral of aspects of the 2014 and 2015 Reserve Capacity Cycles is available on the IMO website[15].

1.2 Structure of this report

The structure of the report is as follows:

- **chapter 2** provides an overview of electricity demand in the SWIS, including the system peak demand, load duration curves, load factor, and the daily demand profile;

[13] Available at: http://www.imowa.com.au/home/electricity/electricity-statement-of-opportunities.
[14] Assuming the RCT is met, the Availability Curve indicates the minimum amount of capacity required to be provided by generation capacity to ensure the energy requirements of users are satisfied.
[15] Available at: http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

- **chapter 3** discusses factors affecting demand, including population, energy efficiency, large customer consumption, the allocation of capacity costs, and solar photovoltaic (PV) systems;
- **chapter 4** presents the peak demand and energy forecasts from 2015-16 to 2024-25. It also provides an explanation of the forecasting methodology and a discussion of factors affecting the forecasts, including the uptake of solar PV systems and batteries;
- **chapter 5** reconciles actual data for 2014-15 with the forecast presented in the 2014 SEDO, and compares the forecasts in this report with previous editions of the ESOO;
- **chapter 6** presents the evolution of capacity in the Wholesale Electricity Market (WEM) since market start in 2006, including market diversification;
- **chapter 7** discusses future opportunities for investing in capacity in the SWIS, and sets the RCT for each year of the Long Term Projected Assessment of System Adequacy (LT PASA) Study Horizon (2015-16 to 2024-25); and
- **chapter 8** explains the Reserve Capacity Mechanism (RCM) and also discusses other current issues in the Western Australian electricity sector including infrastructure developments and the State Government's EMR.

2. Characteristics of the SWIS

The SWIS delivers electricity to around 1.1 million customers across an area of 261,000 square kilometres stretching to Kalbarri in the north, Kalgoorlie in the east and Albany in the south. The SWIS is an isolated network; it is not connected to the electricity networks in the other Australian states and territories that form the National Electricity Market (NEM). This means the SWIS must have enough generation, DSM and network capacity to supply all of its electricity requirements.

Due to Western Australia's hot, dry climate, the SWIS system peak typically occurs during the summer, driven by several consecutive days of high temperatures in Perth (over 36 degrees Celsius) and air conditioning usage.

2.1 System peak

2.1.1 Summer 2014-15 peak demand

Peak demand for summer 2014-15 was 3,744 MW, recorded in the 15:30 to 16:00 trading interval on 5 January 2015. A peak day this early in January is unusual for the SWIS, as many businesses and educational institutions would not have been operating.

The earliest peak day in the last five years has been 20 January 2014, while the latest was 25 February 2010. The 5 January peak day is therefore highly irregular for the SWIS and the IMO considers the 2014-15 peak demand to be an outlier for the purposes of trend analysis.

The peak time of the trading interval starting at 15:30 was also unusual, occurring more than an hour earlier than expected. The system peak normally occurs when residential load increases as people arrive home from work or school – doors and windows having been closed all day, the house is hot and people turn on their air conditioning to cool their home quickly. Consistent with this trend, in each of the previous five years peak demand was observed between 16:30 and 17:30.

A peak occurring in the trading interval starting 15:30 means a greater proportion of the instantaneous demand was offset by solar PV than would have been if the peak was later in the day (section 2.3 contains more detail).

There are several reasons why the system peak may have occurred so early in the year and earlier in the day:

- **January 5 was exceptionally hot** – temperatures on the peak day reached a maximum of 44.4 degrees Celsius. This is the third-highest January temperature in 119 years of records for the Perth Metro weather station;
- **no prolonged hot periods in late January or February** – typically, peak demand occurs during several consecutive days of high temperatures (over 36 degrees Celsius), combined with warm nights (over 20 degrees Celsius). Conditions similar to these only occurred twice during the summer of 2014-15;
    - 4 to 7 January 2015 (Sunday to Wednesday), when maximum temperatures were above 34 degrees Celsius each day (and is the period when the system peak occurred); and

- o 26 to 28 January 2015 (Monday to Wednesday), when maximum temperatures were above 36 degrees Celsius each day.

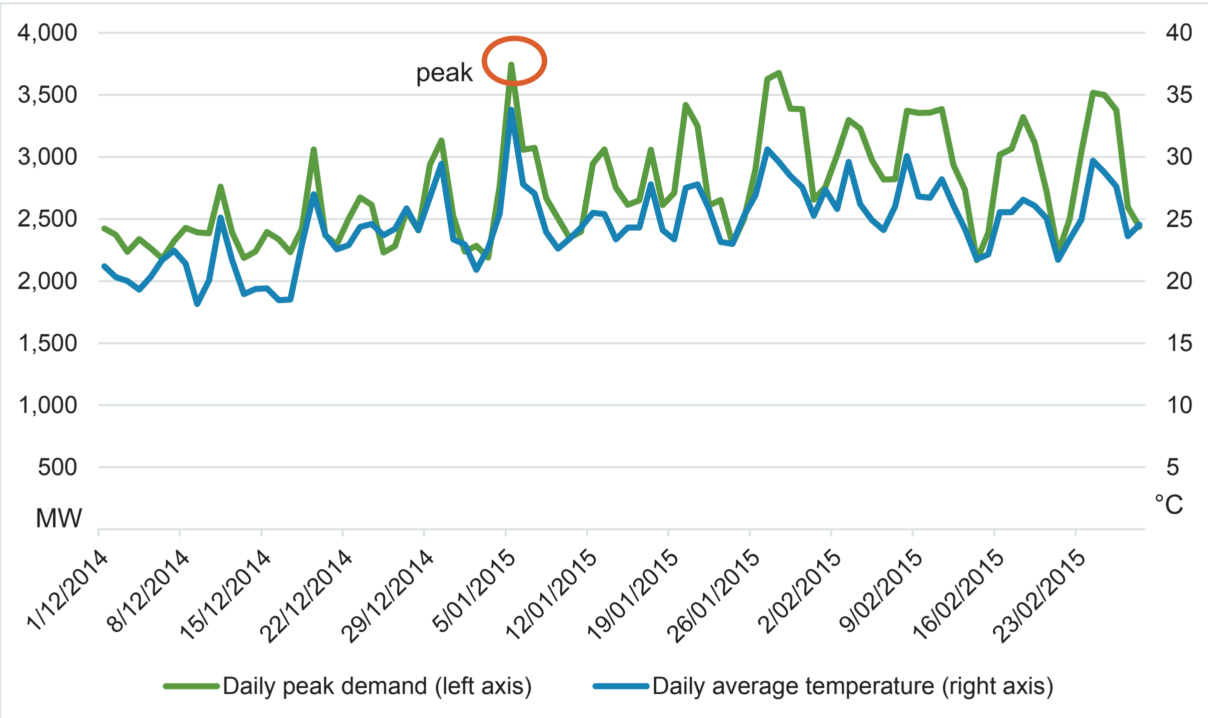
  Peak demand did not occur during 26 to 28 January because, in addition to one of these days being a public holiday, overnight temperatures were relatively mild (less than 20 degrees Celsius). Moreover, although the maximum temperature exceeded 38 degrees Celsius on several other days over the 2014-15 summer, these were isolated with relatively mild temperatures on the days either side (around 30 to 32 degrees Celsius);

- **maximum temperature was reached in the early afternoon** – the temperature reached its maximum of 44.4 degrees Celsius at 13:00, two and a half hours before peak demand was recorded, and remained over 34 degrees Celsius until 18:30; and

- **people were still at home and most businesses were on holidays** – the peak fell on the first business day following the New Year break. Business and industrial electricity users would not have been operating at full capacity. Schools and universities were closed. It is likely most of the peak load on 5 January was driven by residential air conditioning.

Figure 2.1 shows the correlation between peak demand and the daily average temperature. Generally, peak demand increases when daily average temperature is high.

Figure 2.1: Daily peak demand and average temperature, December 2014 to February 2015



Source: IMO and Bureau of Meteorology

2.1.2 Comparison with previous years

Table 2.1 shows peak demand and associated temperature statistics for the past five years. The temperature at the time of system peak on 5 January 2015 was 41 degrees Celsius, which is warmer than in the previous four years.

Table 2.1: Comparison of peak demand days, 2011 to 2015

Day	Peak demand (MW)	Maximum temperature during trading interval (degrees Celsius)	Trading interval	Daily maximum temperature (degrees Celsius)
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

Source: Bureau of Meteorology and IMO

Peak demand for summer 2014-15 was 1.1 per cent higher than the summer 2013-14 peak. The system peak has remained around 3,700 MW for the past three years, after declining by 3.3 per cent between 2011-12 and 2012-13.

2.2 Load duration curves

2.2.1 What is the load duration curve?

The load duration curve shows variation in demand over a period of time. The graph plots demand, in descending order, for each 30-minute trading interval. The y-axis represents the amount of load being utilised in the system, with 100 per cent being the system load at the time of peak demand. The x-axis represents the percentage of trading intervals where the load was at its highest.

The curve indicates the extremity of a system's peak – the fewer trading intervals where load is greater than 90 percent of peak demand, the more severe the peak. Typically, in Western Australia 90 per cent of the load is utilised less than 1 per cent of the time.

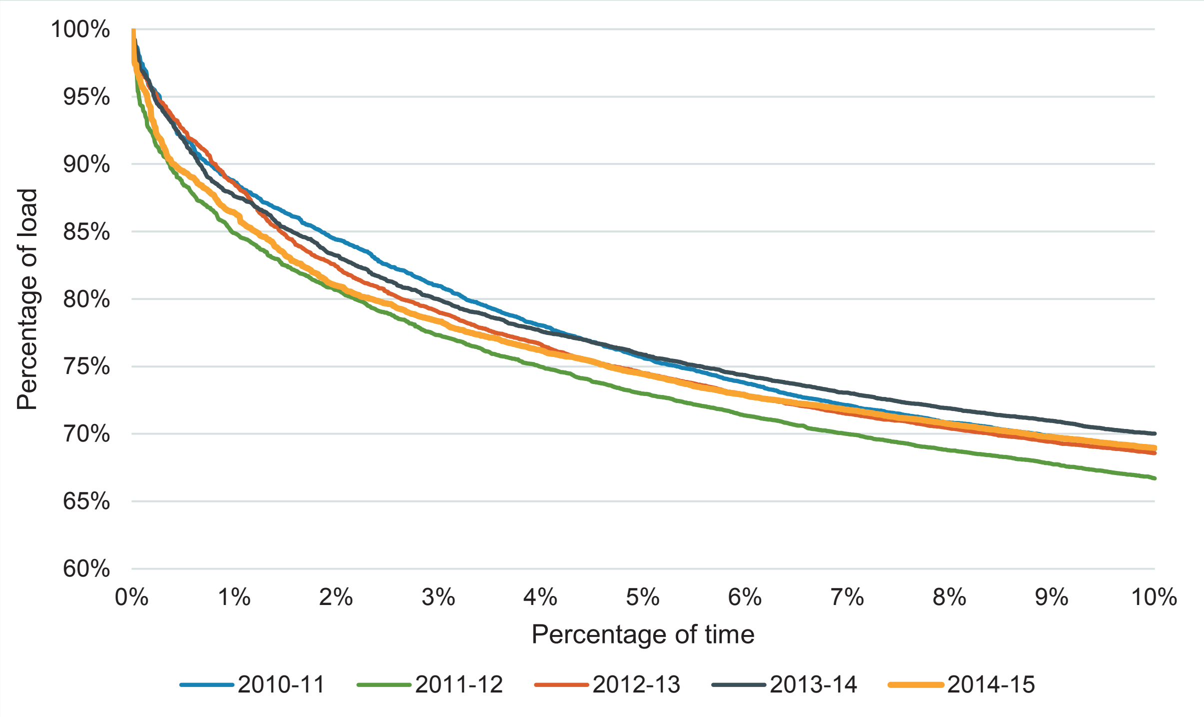
The load duration curve helps determine the mix of generation types, as different types of generation are best suited to different types of load. For example, it is better to use peaking generators for short periods when demand is at its highest. Although peaking generators typically require a smaller investment to build than base load generators, the running costs of peaking generators are generally higher, and they are not well suited to providing energy for extended periods.

2.2.2 SWIS 2014-15 load duration curve

Figure 2.2 shows SWIS load duration curves for the past five years[16]. The load duration curve for 2014-15 is similar to previous years although for 2014-15 the curve drops off quite sharply (at 1 per cent of the time the load is around 87 per cent, whereas for other years it is still around 90 per cent). This shows that there were fewer peak days in 2014-15 compared with the previous four years.

In previous years load exceeded 90 per cent of peak demand for between 0.4 and 0.8 per cent of trading intervals (between 1.5 and 3.0 days). For 2014-15, load exceeded 90 per cent of peak demand for only 0.4 per cent of trading intervals (around 1.5 days).

Figure 2.2: Load duration curves, 2010-11 to 2014-15

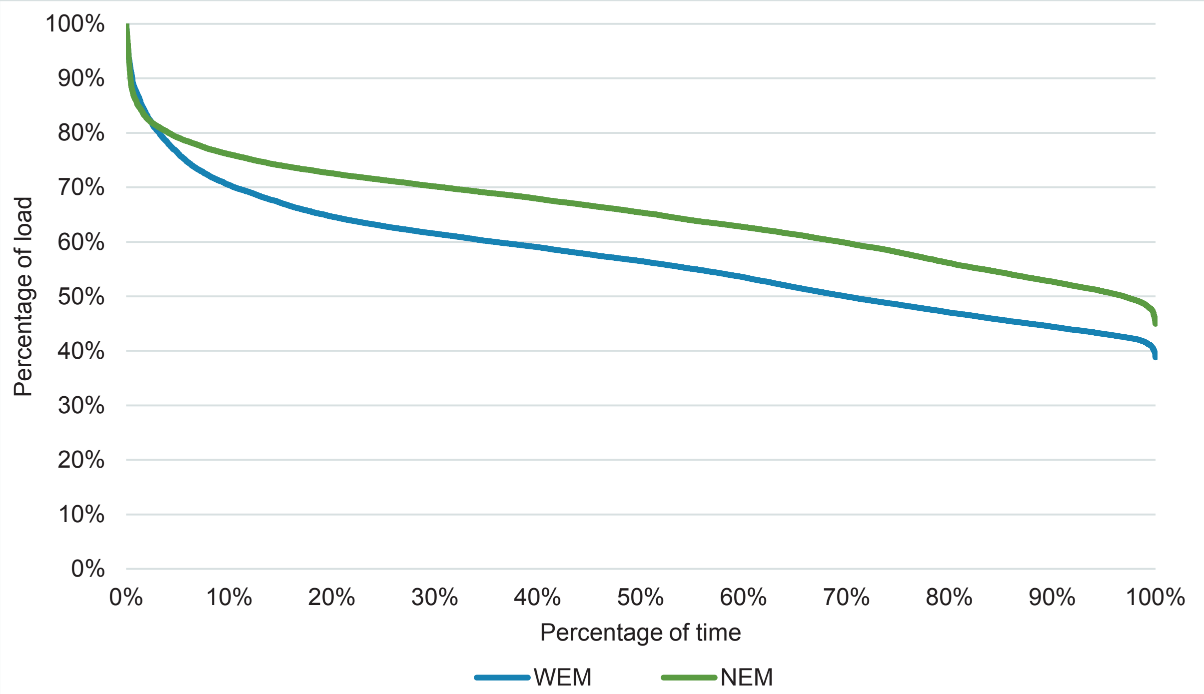


Source: IMO

[16] Where a year is defined as April to March (for this figure only).

Figure 2.3 shows the load duration curve for the WEM and the NEM for the 2014 calendar year.

Figure 2.3: Load duration curve, WEM and NEM, 2014



Source: IMO and Australian Energy Market Operator (AEMO)

In summary:

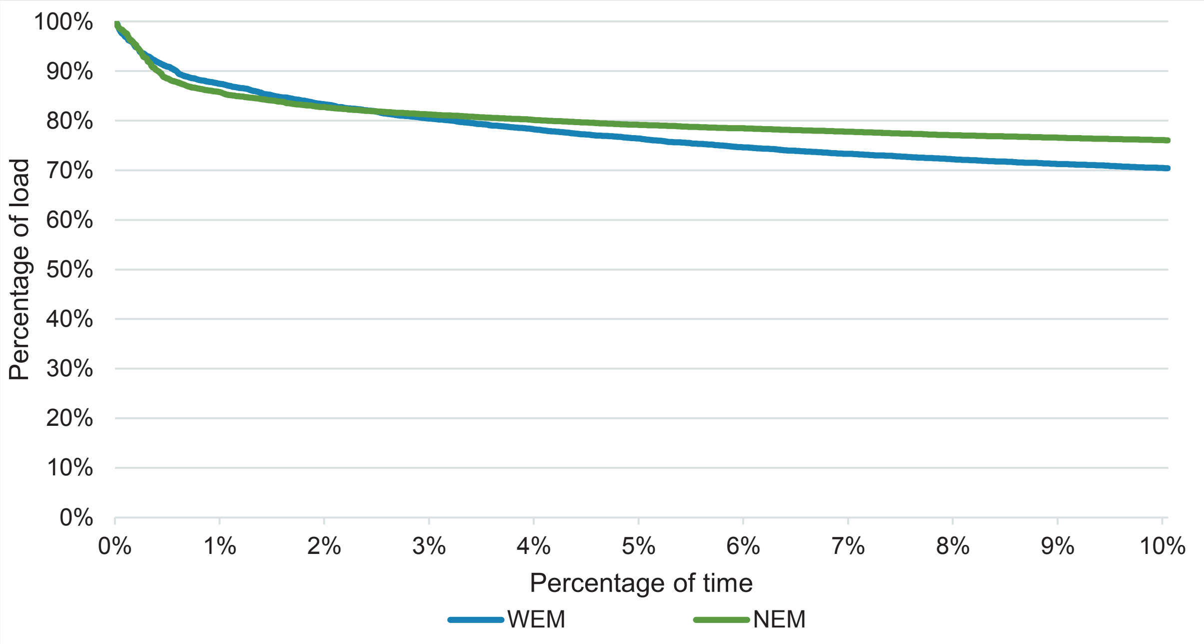
- the minimum load for the NEM was 45 per cent of peak demand, while the minimum load for the WEM was 39 per cent of peak demand (the greater the variance between minimum load and peak demand, the greater the requirement for peaking generation);
- demand in the WEM exceeded 80 per cent of the peak demand for 11 days (3 per cent of the time) and exceeded 75 per cent of the peak demand for 21 days (6 per cent of the time); and
- demand in the NEM exceeded 80 per cent of the peak demand for 15 days (4 per cent of the time) and exceeded 75 per cent of the peak demand for 45 days (12 per cent of the time).

In 2014, peaking generation was required in the WEM for more than twice the number of days it was required in the NEM. This indicates that there is a greater requirement for peaking generation in the WEM compared to the NEM.

Demand volatility in the WEM arises from high penetration of air conditioning, variability of temperature (especially hot summer conditions) and the concentration of demand in a small geographical area – a hot day in Perth will affect the majority of customers in the WEM. In contrast, the geographical spread of the NEM means demand will usually peak in different regions at different times – a hot day in Melbourne is less likely to coincide with a similarly hot day in Sydney or Brisbane.

Figure 2.4 shows the critical peak demand for the NEM and the WEM. While both are characterised by a sharp summer peak, the curve for the NEM is not as steep as the WEM. This is because the WEM requires a large amount of capacity for only a few trading intervals each year.

Figure 2.4: Critical peak demand, WEM and NEM, 2014



Source: IMO and AEMO

For the WEM, around 30 per cent of peak demand occurred for 10 per cent of the year, while in the NEM, only 24 per cent of peak demand occurred.

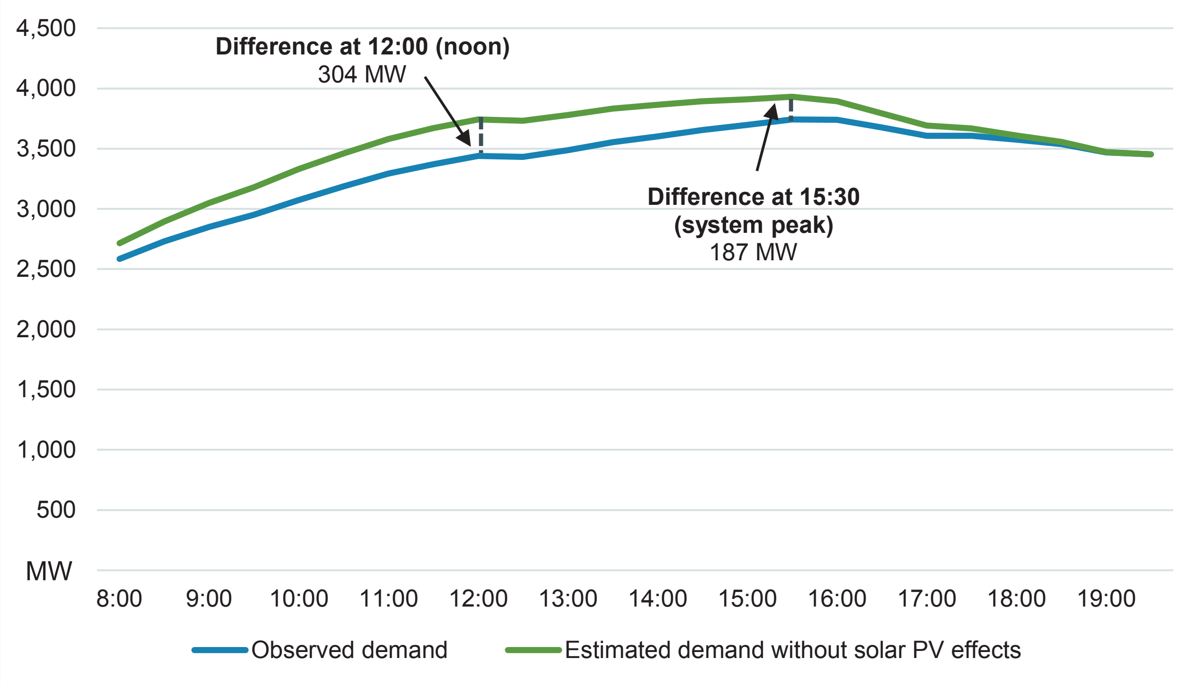
2.3 Daily demand profile

The daily demand profile shows the different levels of instantaneous demand at different times throughout the day.

Figure 2.5 shows the observed daily day-time demand profile for 5 January 2015 compared with the profile estimated to have occurred if no solar PV systems were installed. The estimated daily demand profile is higher, showing the amount of demand that would have been delivered by the electricity network in the absence of rooftop solar PV systems.

Since peak demand occurred earlier in the day than has historically been observed, solar PV systems reduced the observed peak by more than expected.

Figure 2.5: Daily day-time demand profile, observed and estimated without solar PV, 5 January 2015



Source: IMO

Table 2.2 compares actual peak demand for the three highest load days in summer 2014-15 and estimated peak demand without generation from solar PV systems. This shows how solar PV systems played a significant role in reducing demand on the network during 2014-15.

Table 2.2: Effect of solar on peak demand, selected peak days during summer 2014-15

Date	Time of peak	Peak demand (MW)	Estimated peak demand without solar (MW)	Estimated time of peak without solar	Reduction in peak demand from solar
5 January 2015	15:30	3,744	3,931	15:30	187 MW (5.0%)
24 February 2015	16:00	3,517	3,681	14:00	164 MW (4.5%)
25 February 2015	17:00	3,498	3,640	16:00	142 MW (3.9%)

Source: IMO

This data also demonstrates that solar PV systems affect peak demand differently subject to the time and day of the peak.

Table 2.3 shows actual peak demand for the past five years compared to the estimated peak demand if there were no solar PV systems installed in the SWIS.

Table 2.3: Effect of solar PV on peak demand, 2011 to 2015

Peak date	Time of peak	Peak demand (MW)	Estimated peak demand without solar (MW)	Estimated time of peak without solar	Reduction in peak demand from solar
5 January 2015	15:30	3,744	3,931	15:30	5.0%
20 January 2014	17:30	3,702	3,757	16:30	1.5%
12 February 2013	16:30	3,732	3,816	16:00	2.2%
25 January 2012	16:30	3,857	3,918	15:00	1.6%
16 February 2011	16:30	3,735	3,754	16:30	0.5%

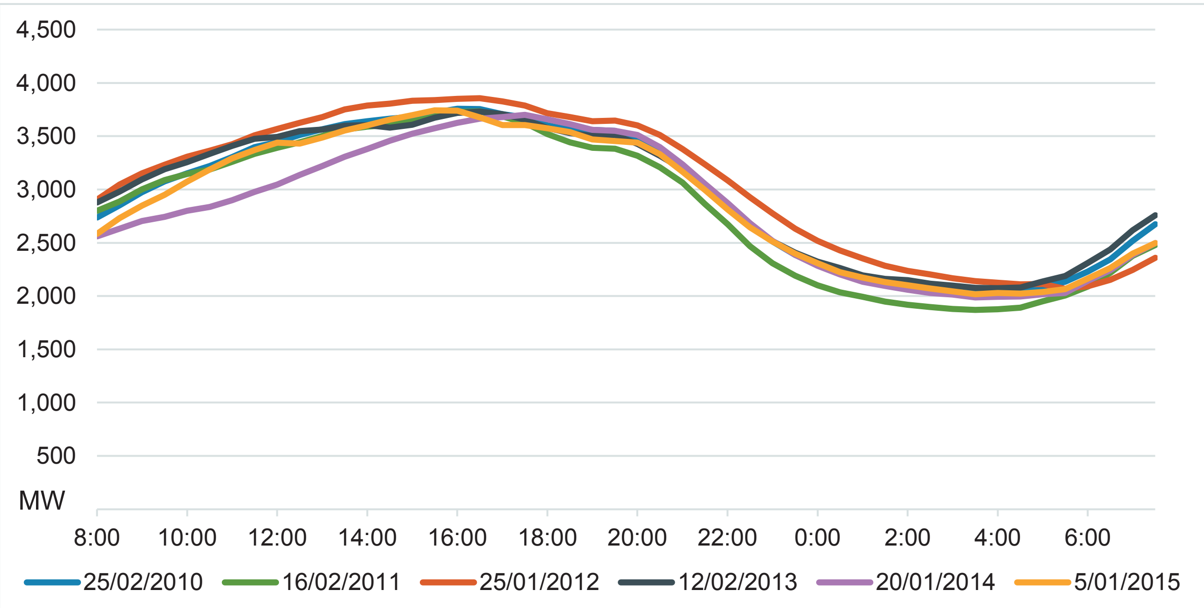
Source: IMO

Growth in installed solar PV system capacity has impacted on peak demand over the past four years from 19 MW in 2010-11 to 187 MW in 2014-15.

As shown in Table 2.2 and Table 2.3, the effect of solar PV systems on peak demand is related to the time of system peak – they will affect a later peak less than an earlier peak. Therefore solar PV systems had an exaggerated effect on the peak in 2014-15 when compared to other years. This is because not only has there been a considerable growth in solar PV installations over recent years, but the peak this year occurred at 15:30, when PV systems were generating at around 40 per cent of their nameplate capacity, compared to only 27 per cent at 16:30.

Figure 2.6 shows the load profiles on peak demand days from 2009-10 to 2014-15.

Figure 2.6: Peak day load profiles, 2010 to 2015



Source: IMO

Despite the early peak on 5 January 2015, solar PV still appears to be a key driver of peak demand occurring later in the day. Of the six highest load days in the 2014-15 summer, five peaked later in the afternoon, when solar PV systems were estimated to have been generating less than earlier in the afternoon.

More information on solar PV systems in the SWIS is provided in section 3.5.

3. Customer demand in the SWIS

This chapter discusses some of the factors affecting demand for electricity including population, energy efficiency, electricity prices, large customer consumption, allocation of capacity costs through the Individual Reserve Capacity Requirement (IRCR) and solar PV system generation.

3.1 Population growth

Population growth is an important contributor to growth in electricity demand. An increase in population would generally require an increase in residential dwellings (for example, houses and apartments). As the number of new dwellings increase, so does the number of new customer connections.

However, recent residential consumption data indicates an increase in connections does not necessarily lead to an increase in total electricity consumption. Factors such as rising prices, rapid uptake of solar PV systems, and improved efficiency in appliances and buildings are influencing consumption trends and offsetting load growth. These factors are discussed in section 3.2.

Western Australia's population increased at an average annual rate of 3 per cent between 2003-04 and 2013-14. Completed new dwellings increased by almost 6 per cent (20,812 new dwellings) in 2013. New dwellings then grew substantially, by over 25 per cent (26,131 new dwellings) in 2014.

Table 3.1 shows key data for SWIS residential customers (defined as customers paying the A1 residential tariff or the SM1 SmartPower residential time of use tariff) between 2008-09 and 2013-14.

Table 3.1: Key statistics for residential customers, 2008-09 to 2013-14

Year	Total number of connections	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	5,102	NA	6,131	NA
2009-10	845,511	1.6%	5,349	4.8%	6,326	3.2%
2010-11	873,701	3.3%	5,403	1.0%	6,184	-2.2%
2011-12	893,750	2.3%	5,005	-7.4%	5,600	-9.4%
2012-13	899,356	0.6%	5,035	0.6%	5,598	0.0%
2013-14	909,680	1.1%	5,044	0.2%	5,545	-1.0%

Source: Synergy

In summary, during the period 2008-09 to 2013-14:

- customer numbers **increased** by nearly 10 per cent;
- total residential electricity sales **decreased** by 1.1 per cent; and
- average electricity use per connection fell by 10 per cent.

Regulations are in place to mandate a minimum energy efficiency requirement for new dwellings and commercial buildings, details of which are provided in chapter 8. This implies newer housing stock will be, on average, more energy efficient than older stock. The IMO expects this to limit growth in energy consumption over the long term, rather than cause significant falls in energy consumption year to year.

3.2 Other factors affecting residential and commercial consumption

The Western Australian market allows retail contestability for customers using more than 50 MWh of electricity a year, while smaller customers have no choice of retailer. Regulated tariffs have increased by around 76 per cent (nominal) for residential customers (based on usage charges expressed in cents per kWh). According to the 2015-16 State Budget[17], prices are projected to continue to increase as the State Government seeks to charge electricity users fully cost-reflective tariffs.

The IMO considers that while recent electricity price increases have contributed to the reduced average consumption per connection, a significant portion of the reduction is due to customers taking action such as:

- installing a solar PV system – increases in volumetric residential electricity tariffs and government subsidies encouraged installations initially, but recently installations have been driven by cheaper solar PV systems available on the market;
- installing more energy efficient appliances – the introduction of Minimum Energy Performance Standards (MEPS) in 1999 means that appliances purchased after 2009 are up to 40 per cent more efficient than appliances purchased in the 1990s[18] (chapter 8 contains more information); and
- changing consumption behaviour (for example, switching off lights in unoccupied rooms) – the number of customers using Synergy's SmartPower time of use tariff has increased at a faster rate than those on the standard tariff. This indicates customers are shifting consumption to access lower off-peak prices, as well as reducing overall consumption in response to economic and environmental drivers.

The growth in solar PV systems is a major contributor to reduced average consumption. Between January 2011 and January 2015, the total installed PV capacity in the SWIS grew from 63 MW to 435 MW (section 3.5 contains more detail). Even if there is no change to the structure of electricity tariffs[19], rising prices and falling costs for solar PV systems are expected to continue to drive households' investment in solar PV systems.

With regard to energy efficient appliances, the Australian Bureau of Statistics' (ABS) Energy Use and Conservation Survey found that in 2014 around half of the Australian

[17] Available at: http://www.ourstatebudget.wa.gov.au/.
[18] Source: YourHome, 2013, *Appliances*, accessed 6 May 2015, available at: http://www.yourhome.gov.au/energy/appliances.
[19] Recent reports suggest price structure reform is unlikely in the short-term. See https://au.news.yahoo.com/thewest/regional/south-west/a/27788337/solar-users-power-rise-axed/.

households that bought new appliances cited the star rating of the appliance as a factor in their purchase decision, compared with around 40 per cent in 2005[20]. This indicates that in addition to appliances becoming more efficient due to initiatives such as MEPS, many customers value more efficient options from the range of appliances available. Anecdotal evidence also suggests that households are replacing appliances much more frequently than in the past.

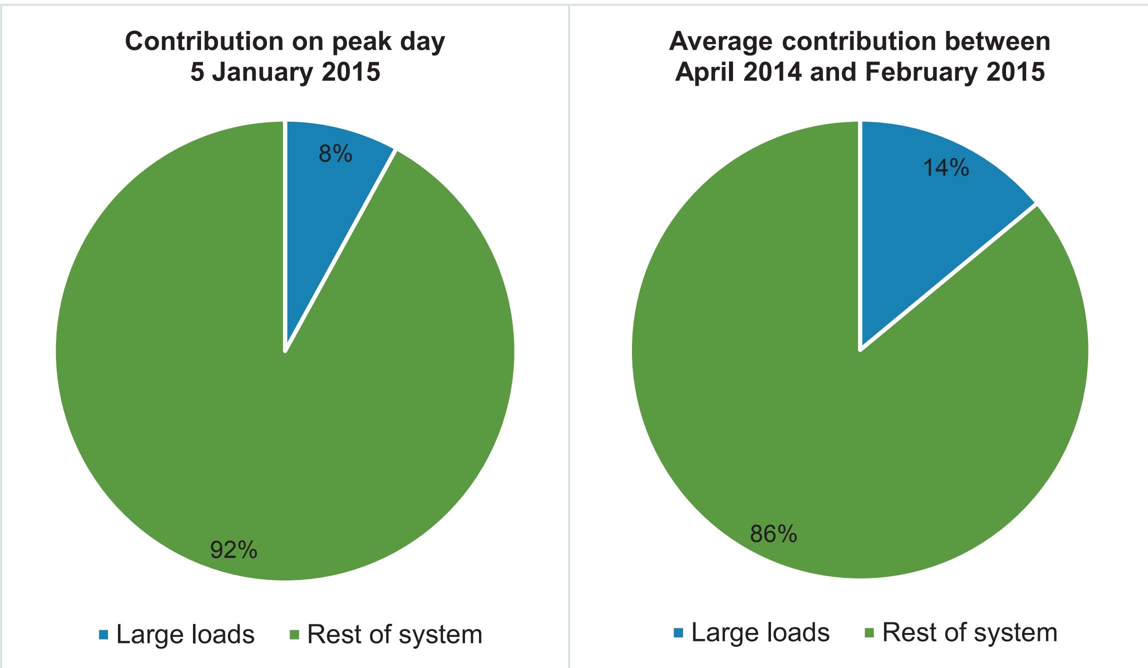
3.3 Large customer consumption

The IMO considers the minimum threshold for a large load to be 20 MW. There are currently nine large loads in operation in the SWIS, ranging in size from 20 to 140 MW. These include mining operations and large industrial users.

Figure 3.1 shows the contribution of the nine large loads to the system peak and the average load over a year. Key findings are:

- **large loads are a major contributor to overall average demand** – over the period April 2014 to February 2015 these customers' average load was around 300 MW, or 14 per cent of the average total system load of 2,099 MW; and
- **large loads consumption patterns are relatively flat and are not a major driver of the system peak** – these customers have relatively stable energy use throughout the year, regardless of the time or day of the week. Consumption from these loads has been consistent for several years. At 15:30 on 5 January 2015, these loads accounted for 290 MW, or 8 per cent, of the 3,744 MW system peak.

Figure 3.1: Contribution of large loads to total system load, 2014-15



Source: *IMO*

[20] Source: ABS, *Environmental Issues: Energy Use and Conservation, Mar 2011*, catalogue number 4602.0.55.001, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/4602.0.55.001Mar%202014?OpenDocument.

3.4 Individual Reserve Capacity Requirement

Data for the summer 2014-15 peak shows that the allocation of capacity costs via the IRCR mechanism continues to encourage customers to reduce consumption during periods of high demand.

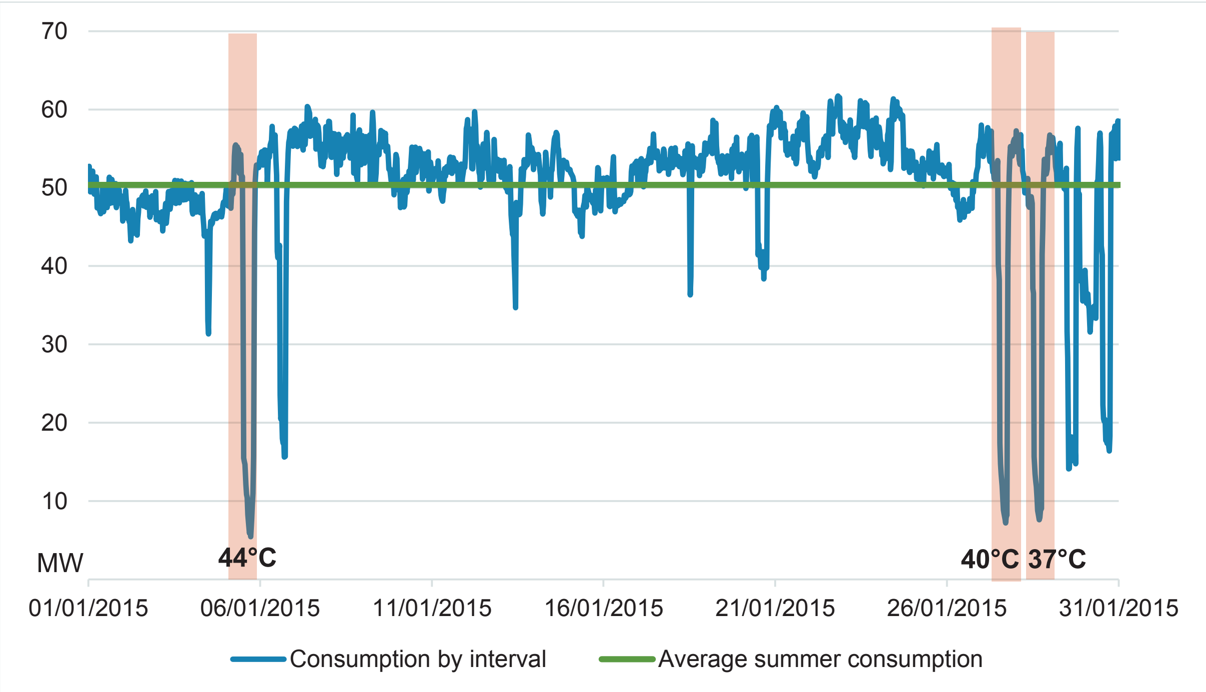
To fund the RCM, the IMO assigns an IRCR to each Market Customer based on the peak demand usage from its customer base in the previous hot summer season. Specifically, the IRCR is a quantity (in MW) determined based on the median consumption of each metered load in a Market Customer's portfolio during 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 an incentive to reduce consumption during the system peak, as lower peak consumption will reduce the capacity costs allocated to them in the following Capacity Year.

At the time of the 2014-15 system peak, 20 customers reduced consumption resulting in a total load reduction of 42 MW. A similar response to the IRCR occurred during the summer 2013-14 peak, when 44 customers reduced load by 49 MW.

Figure 3.2 represents the 20 most responsive loads during January 2015. The peach shaded areas on the graph show the afternoons of the three hottest days (based on mean daily temperature) in January 2015, and the maximum temperature on each of these days.

Figure 3.2: IRCR response for 20 customers, January 2015



Source: IMO

Although the number of customers that responded in 2014-15 was less than half that of 2013-14, the IRCR reduction was strong and at a similar level to last year. This indicates the IRCR continues to be an effective mechanism to reduce consumption during peak demand periods. The IMO considers it likely that the early peak (5 January) was the main reason fewer customers responded, as many would not have been operating at full capacity following the New Year break.

Given the unusual peak day, the IMO has also analysed the IRCR response for other high load days over the 2014-15 summer. The results of this analysis are shown in Table 3.2.

Table 3.2: IRCR response for high load days, summer 2014-15

Date	Peak demand (MW)	Time of peak	Estimated IRCR reduction (MW)	Number of customers responding
5 January 2015	3,744	15:30	42.0	20
27 January 2015	3,626	16:30	88.3	38
28 January 2015	3,676	16:30	86.0	38
30 January 2015	3,385	16:30	47.2	27
3 February 2015	3,296	16:00	76.5	22

Source: IMO

Table 3.2 shows that both the estimated reduction and the number of customers responding to the IRCR were higher on these days than 5 January, with 38 customers reducing consumption by over 88 MW on 27 January 2015.

Average reduction per customer for the summer 2014-15 system peak was 2.1 MW in 2014-15 compared to 1.1 MW in 2013-14. Over the past three years, 91 unique customers have reduced consumption to minimise exposure to IRCR, with an average reduction of 1.4 MW. If all of these customers responded at the average rate, the potential annual reduction driven by the IRCR would be more than 120 MW.

3.5 Small-scale solar photovoltaic systems

3.5.1 Solar photovoltaic system growth

Small-scale solar PV systems[21] are those installed on residential and commercial rooftops and connected to the electricity grid. These systems allow customers to generate their own electricity and export any excess generation to the network, for which they may receive a payment.

While solar PV systems do not directly reduce demand, they do reduce the quantity of electricity that needs to be delivered by the network during daylight hours, therefore affecting average demand from the network per connection.

[21] The Commonwealth Government defines small-scale solar PV systems as systems that have a nameplate capacity of less than 100 kW.

Table 3.3 shows key statistics for solar PV systems installed by Synergy's **residential customers**, as well as the average new installation size for all customers published by the Clean Energy Regulator (CER), for 2010-11 to 2014-15.

Table 3.3: Key statistics for solar PV systems, 2010-11 to 2014-15

Measure	2010-11	2011-12	2012-13	2013-14	2014-15[22]	Average annual growth
Number of systems*	63,384	97,722	132,621	146,890	164,483	26.9%
Proportion of customers with PV installed*	7.3%	10.9%	14.7%	16.1%	17.6%	24.6%
Average system size (kW)*	1.9	2.0	2.1	2.4	2.5	7.1%
Average new installation size (kW)**	2.3	1.3	3.2	4.4	3.9[23]	14.1%

Source: CER and Synergy

Note: * Synergy, ** CER

In summary:

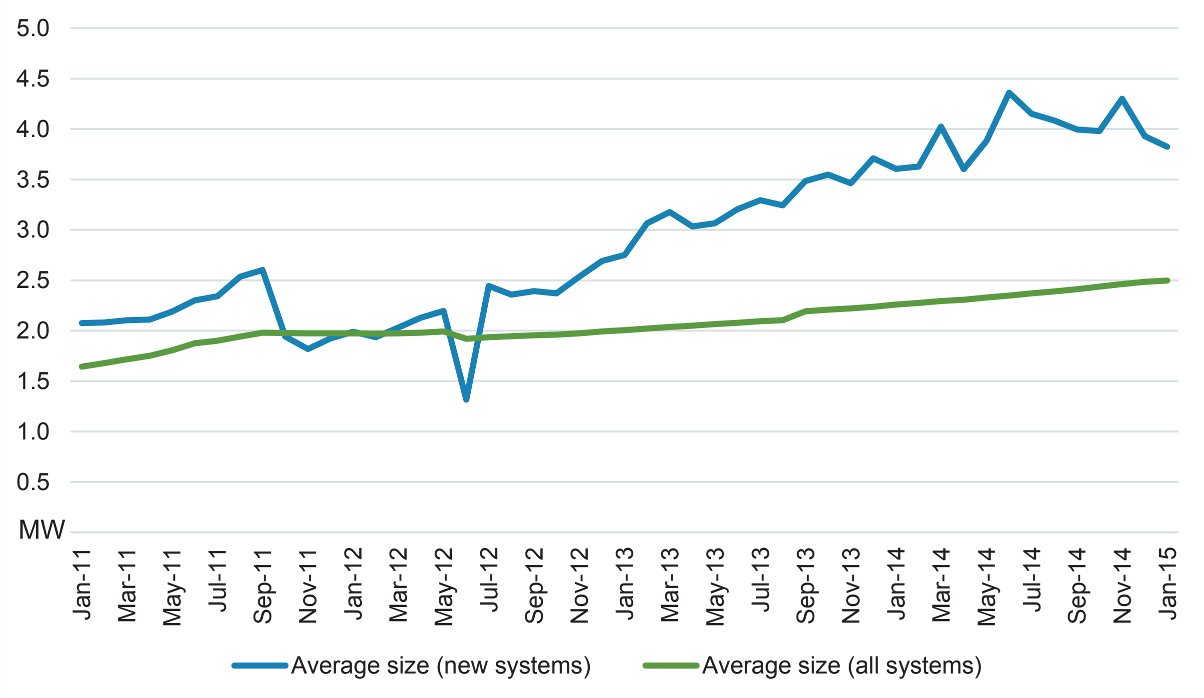
- the number of systems has grown from around 63,384 in 2010-11 to more than 160,000 in January 2015;
- the proportion of residential customers with solar PV systems installed has increased from 7.3 per cent in 2010-11 to 17.6 per cent in January 2015;
- the average system size has increased by 30 per cent, from 1.9 kW to 2.5 kW; and
- the average system size for new installations has increased by 70 per cent, from 2.3 kW in June 2011 to 3.9 kW in January 2015.

Data from the CER shows a similar trend across residential and commercial customers. Figure 3.3 shows the average size of solar PV systems installed in each month compared with the average system size of all systems in the SWIS. The average system size of new installations has increased, from 2.1 kW in January 2011 to 3.9 kW in January 2015. This increase in system size is likely associated with falling prices for solar PV systems, but may also reflect a greater number of systems installed by large commercial and industrial customers, which would typically be larger than a residential solar PV system.

However, while the number of large commercial installations may be increasing, the CER data shows overall average system sizes consistent with the Synergy data in Table 3.3. This suggests that commercial systems still account for a relatively small proportion of the total number of systems installed in the SWIS. Many early adopters of commercial solar PV systems are likely to have installed relatively small systems due to the high cost and limited availability of large systems at the time (although the cost and availability of large systems is improving).

[22] Year to date to February 2015.
[23] As at January 2015.

Figure 3.3: Average size of monthly solar PV system installations, January 2011 to January 2015



Source: CER

The 2014 SEDO included a high customer response scenario in addition to the usual high, expected and low case forecasts, which assumed more aggressive uptake of solar PV systems. This scenario was intended to show the effects of high levels of solar PV system penetration in the SWIS.

Installed solar PV system capacity has increased faster than forecast in the 2014 SEDO. In January 2015, installed capacity was 435 MW, 19 MW higher than forecast in the high case in the 2014 SEDO. However, installed capacity remains lower than forecast in the 2014 SEDO high customer response scenario (451 MW).

The high case solar PV system forecast in this ESOO is similar to the high customer response scenario published in the SEDO. The expected case solar PV forecast in this ESOO is similar to the high case in the SEDO. The forecasts for solar PV systems are explained in more detail in section 4.2.3.

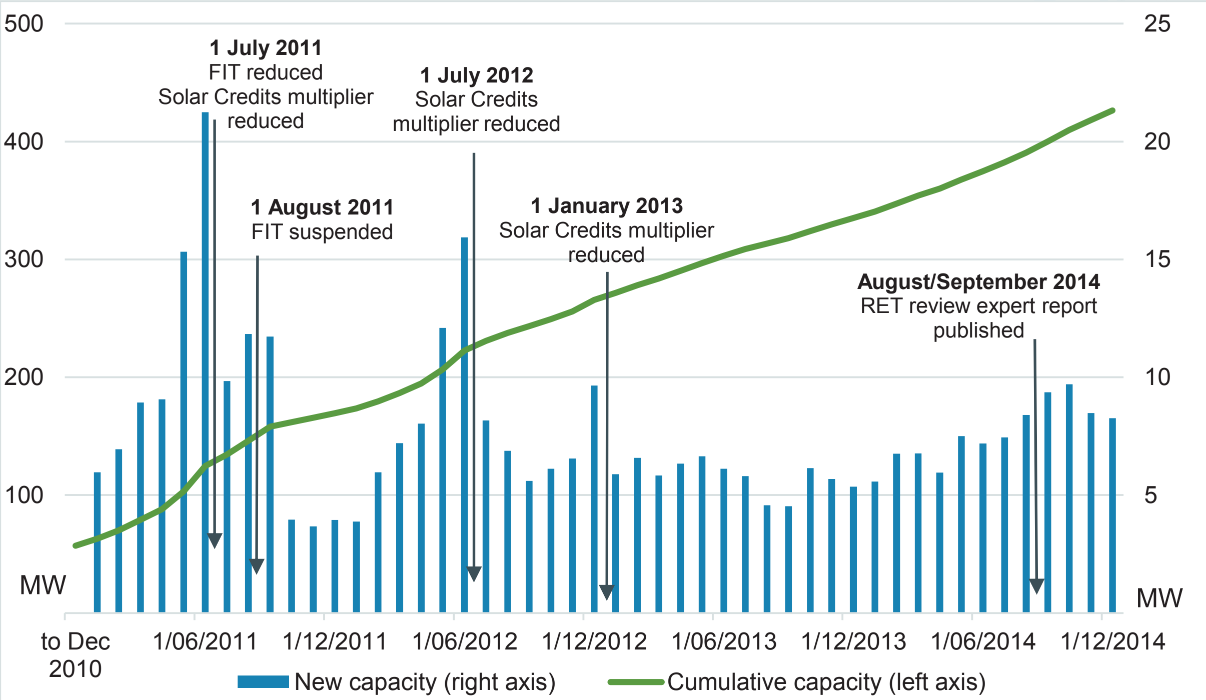
Government incentives that helped drive uptake in residential solar PV systems during 2011 did not apply to commercial installations. However, as electricity prices have increased and the cost of solar PV systems has reduced, the value proposition for commercial solar PV systems has improved, leading to a greater number of commercial customer installations. According to the solar energy quote comparison service Solar Choice, the price of a solar PV system has fallen from $2.40 per watt installed in August 2012 to $1.75 in February 2015[24].

The drop in installation size (as shown in Figure 3.3) in June 2012 was associated with the reduction in the Solar Credits multiplier, which led to a large number of small systems being installed. This month was an outlier related to a government policy decision, with the average size of new systems returning to trend growth levels the following month.

[24] More information is available at: http://www.solarchoice.net.au/blog/category/installation-advice/solar-system-prices-2/.

Figure 3.4 shows monthly and cumulative installed solar PV system capacity in the SWIS over the past three years. Installed solar PV system capacity has increased from 63 MW in January 2011 to 435 MW in January 2015 (an average annual increase of 62 per cent).

Figure 3.4: Monthly and cumulative installed solar PV system capacity, December 2010 to January 2015



Source: CER

3.5.2 Factors affecting uptake of demand-side technology

As shown in section 3.5.1, installed PV capacity in the SWIS has grown strongly in the last five years. While the IMO expects installed PV capacity to continue to increase, the rate at which this happens and the effect on peak demand depends on a number of technological, commercial and regulatory factors, as well as increasing environmental awareness, including:

- **government incentives** – strong government incentives were offered for early adopters of residential solar PV systems, including feed-in tariffs and Renewable Energy Certificate multipliers (including Solar Credit multipliers). Although the Solar Credit multipliers were decreased in 2012 and 2013, rebates on solar installations continue to be available through the Commonwealth Government's Renewable Energy Target (RET);
- **declining installation costs** – in addition to residential installations, small-scale solar PV systems are becoming financially viable for commercial customers. Prices for commercial PV systems are falling as costs for panels and inverters decrease and installation becomes more efficient. Larger systems for commercial installation (up to 100 kW) are also eligible to receive credits from the RET scheme. Growth in commercial solar PV system installation is expected to drive a continued increase in the average system size for the SWIS;
- **new technology** – emerging technology such as battery storage and electric vehicles are likely to change electricity consumption behaviours. While electric vehicles would appear to remain several years away from significant use in the SWIS, battery storage may

become a financially viable option in the near future. Products such as Tesla's Powerwall are expected to be available from 2016. EnerNOC, the biggest DSM provider in the WEM, has recently announced it will collaborate with Tesla on the deployment and management of energy storage systems in commercial and industrial buildings in the United States[25]. In Western Australia, Alinta Energy is considering offering solar and battery systems, however, no time frame is given for availability of this product[26]. Synergy has also indicated intentions to sell solar panels to households[27]. Battery systems would allow customers to store electricity generated from a solar PV system to consume when the system is not generating; and

- **pricing models and policy** – changes in pricing models for electricity, as well as various government policies, will affect investment in new technology. Decreasing electricity sales are putting pressure on network operators and regulators to raise fixed connection prices as a means of recovering capital costs, although to date the State Government has decided not to make such changes to the structure of regulated retail tariffs, which currently seek to recover the vast majority of costs through volumetric charges. Movements to time-based tariff structures are expected to encourage customers to shift consumption to off-peak times. A new RET[28] of 33,000 GWh has been confirmed and will potentially increase investment in renewable generation after months of uncertainty in the industry.

[25] See http://investor.enernoc.com/releasedetail.cfm?ReleaseID=910188.
[26] See https://au.news.yahoo.com/thewest/wa/a/28289418/alintas-solar-plan-to-cut-bills/.
[27] See https://au.news.yahoo.com/thewest/wa/a/28464981/synergy-to-sell-homes-solar-panels/.
[28] See http://www.abc.net.au/news/2015-05-18/breakthrough-in-renewable-energy-target-deal/6477748.

4. Peak demand and energy forecasts, 2015-16 to 2024-25

This chapter presents peak demand and energy forecasts for the period 2015-16 to 2024-25. It also includes the forecasting methodology, factors affecting the forecasts and solar PV system forecasts.

4.1 Methodology

The IMO engaged the National Institute of Economic and Industry Research (NIEIR) to prepare an economic outlook, peak demand and energy 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 produces peak demand forecasts based on three different weather scenarios:

- 10 per cent PoE;
- 50 per cent PoE; and
- 90 per cent PoE.

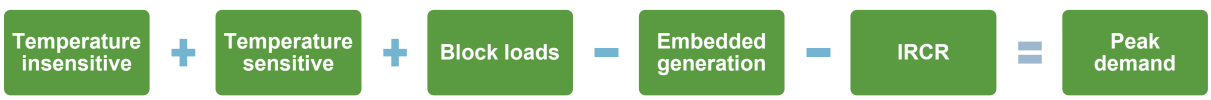
The PoE numbers relate to the likelihood of the forecast peak being exceeded as a result of extremely hot weather or prolonged high temperatures. For example, the 10 per cent PoE forecast represents a forecast that has a 10 per cent probability of being exceeded (one-in-ten-years), whereas a 90 per cent PoE forecast represents a lower forecast, which is likely to be exceeded in nine-in-ten-years. The 50 per cent PoE forecast can be considered the most likely to occur, with this forecast expected to be exceeded, on average, one-in-two-years.

As noted in chapter 1, this ESOO highlights the 10 percent PoE peak demand scenario as this is required to determine the RCT.

Economic growth is also a factor in the system peak. NIEIR applies three forecasts of economic growth (high, expected and low) to each of the weather scenarios. This results in a total of nine peak demand forecasts. The high, expected and low case forecasts referred to in this ESOO reflect different economic scenarios and different levels of solar PV system uptake.

Figure 4.1 shows the methodology for calculating peak demand.

Figure 4.1: 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 the largest customers in the SWIS and are generally considered to be temperature insensitive. New block loads are forecast separately from the rest of the system.
- **Embedded generation** is typically the electricity produced by solar PV systems.
- **IRCR** is the estimated reduction in demand from commercial and industrial customers on hot days to minimise their exposure to capacity costs.

The forecasting methodology relies on historical demand data at the SWIS level. As the IMO does not receive regional consumption or peak demand data, no transmission constraints are specifically considered when preparing these forecasts.

4.1.2 Energy forecasts

Energy sent out forecasts are estimated using an econometric model that projects energy sales by tariff class for industry and residential sectors. Transmission and distribution line losses are then added to the forecast.

Energy sales are split into 20 industry classes and the residential sector. The industry classes are forecast using economic growth, electricity price and weather assumptions. The residential sales forecast considers average sales per residential connection point, which is driven by real income growth, weather and real electricity prices.

4.2 Factors affecting the forecasts

As part of its forecasting methodology, NIEIR takes into account the following factors that may influence peak demand and energy:

- factors affecting temperature sensitive and temperature insensitive demand, including:
    - the economic outlook;
    - population growth; and
    - electricity prices;
- block loads;
- embedded generation, in particular solar PV systems and battery storage; and
- customer response to the IRCR mechanism.

These factors are discussed in the following sections.

4.2.1 Temperature sensitive and temperature insensitive demand

4.2.1.1 Economic outlook

NIEIR developed projections for the Western Australian economy using available data up to December 2014. The economic outlook produced for the next five years shows a slowdown in growth levels for the next two years (at around 2.8 per cent), followed by a return to a level approaching long-term average annual growth (4.7 per cent for 2004-05 to 2013-14).

The Western Australian economy is driven by investment in the resources and related industries. Economic growth is therefore heavily influenced by demand for the commodities exported by Western Australia, particularly into Asia. Over the last decade Western Australia experienced significant growth in resources-related investment, with an $85 billion investment in 2013-14.

In the period 2014-15 to 2019-20, economic growth in Western Australia is expected to slow in line with weaker international commodity markets. In recent years, Western Australia's economy has been driven by construction of major resource projects. Many of these projects are scheduled to move into their production phase during the next two-to-three years, implying that economic growth will be more dependent on exporting these resources. However, exporting commodities requires less labour and less investment than the construction of new projects, limiting growth in domestic demand. 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 SEDO and the December 2014 Gas Statement of Opportunities[29].

Table 4.1 outlines NIEIR's forecasts of major economic indicators for the **expected case** for the 2014-15 to 2019-20 period, in Western Australia. Appendix C contains economic forecasts for the high and low cases.

Table 4.1: Key economic indicator forecasts, expected case, Western Australia, 2014-15 to 2019-20[30]

Measure	Value*	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Private consumption	$93.8 billion	2.3%	2.2%	1.7%	2.7%	3.0%	2.2%
Private dwelling investment	$11.2 billion	8.4%	15.9%	4.0%	2.1%	-1.2%	-5.0%
Business investment	$67.6 billion	-8.9%	1.0%	0.7%	3.1%	3.2%	4.4%
Government consumption	$28.2 billion	3.6%	0.9%	2.1%	1.6%	1.6%	1.8%
Government investment	$9.2 billion	-12.7%	-1.3%	-0.4%	3.2%	4.1%	0.5%
State final demand	$210.0 billion	-1.5%	2.2%	1.6%	2.7%	2.6%	2.2%
GSP	$256.5 billion	1.3%	1.9%	3.7%	3.9%	2.6%	1.8%
Population	2,556,400	2.6%	2.0%	2.0%	2.0%	2.0%	2.0%
Employment	1,342,800	2.1%	-1.7%	0.8%	1.1%	2.0%	1.7%

Source: NIEIR

Note: * Base year 2013-14, actual

[29] Available at: http://www.imowa.com.au/home/gas/gas-statement-of-opportunities.
[30] Please note that the categories in this table may not align with those used in the Western Australian Treasury's budget.

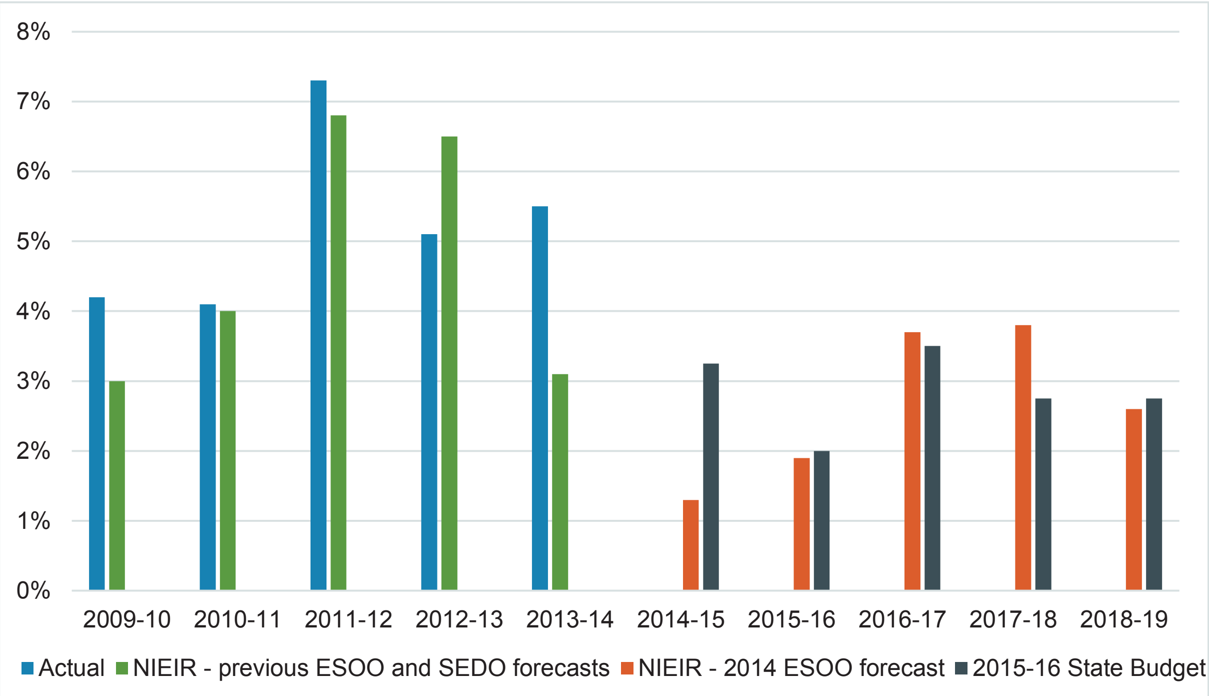
In summary:

- Western Australia's gross state product (GSP) is forecast to grow at an average annual rate of 2.8 per cent between 2014-15 and 2019-20, supported by increasing commodity exports and private consumption expenditure;
- business investment is projected to decline in 2014-15, reflecting the completion of several major iron ore and natural gas projects, then slowly recover from 2017-18; and
- government investment is forecast to decline for the 2014-15 to 2016-17 period, as the State Government reduces its capital expenditure and major infrastructure projects are completed, including the Fiona Stanley Hospital ($1.8 billion) and Perth Children's Hospital ($1.2 billion).

Figure 4.2 shows NIEIR's and the Western Australian Treasury's[31] GSP forecasts for 2014-15 to 2018-19. NIEIR's forecasts for 2014-15 and 2015-16 are more conservative than Treasury's, being up to 2 percentage points lower.

However, in 2017-18 NIEIR's forecasts are around 1.1 percentage points higher than Treasury's. This figure also compares NIEIR's economic forecasts reported in the last five ESOO and SEDO reports. The comparison suggests it has been more difficult to forecast Western Australia's economic growth over the last two years.

Figure 4.2: Comparison of GSP forecasts, NIEIR and Western Australian Treasury, 2009-10 to 2018-19



Source: ABS[32], NIEIR and Western Australian Department of Treasury[33]

[31] As published in the 2015-16 State Budget, available at: http://www.ourstatebudget.wa.gov.au/.
[32] Source: ABS, *Australian National Accounts: State Accounts, 2013-14*, catalogue number 5220.0, available at: http://abs.gov.au/AUSSTATS/abs@.nsf/ProductsbyCatalogue/E6765105B38FFFC6CA2568A9001393ED?OpenDocument.
[33] Source: Western Australian Treasury, *2015-16 State Budget*, available at: http://www.ourstatebudget.wa.gov.au/.

The main differences between NIEIR and the Western Australian Treasury's forecasts are:

- NIEIR assumes lower iron ore volumes for 2014-15 and 2015-16;
- NIEIR assumes lower overall mining output and exports; and
- both forecasts use different assumptions for the construction sector (in particular, NIEIR assumes large major resource projects are completed during 2015 and 2016).

4.2.1.2 Population growth

Population growth is an indirect driver of electricity consumption. 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 solar PV systems.

The population of the area supplied by the SWIS is estimated to have increased from 2.37 million in 2012-13 to 2.42 million in 2013-14 (2.1 per cent), with the vast majority of this growth occurring in Perth, which grew from 1.97 million to 2.02 million (2.5 per cent) over the same period.

NIEIR has forecast population growth at a rate of 2.0 per cent per year between 2014-15 and 2019-20. 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 (see section 3.2).

4.2.1.3 Electricity prices

Electricity prices will continue to influence electricity consumption, as customers modify energy usage to manage their costs. Electricity prices in the contestable market are set by individual retailers based on the wholesale electricity price. There are currently 18 Market Participants registered as retailers competing for around 32,000 contestable customers in the SWIS. The Economic Regulation Authority[34] estimates about 150 customers a month switched retailers in the contestable market during 2013-14.

NIEIR's forecasts assume nominal electricity price increases for contestable customers will keep pace with inflation (at around 2 to 3 per cent) over the forecast period.

By contrast, electricity prices for non-contestable customers (those consuming less than 50 MWh per year, which includes residential and smaller commercial customers) are regulated in Western Australia. NIEIR assumes the real long-run residential price elasticity is -0.25; that is, for every one per cent increase in the real retail price of electricity, residential energy demand decreases by 0.25 per cent.

NIEIR's assumptions for non-contestable customers are in line with those published in the 2015-16 State Budget. Prices are forecast to increase by 4.5 per cent in 2015-16, followed by future increases of 7 per cent a year for the remainder of the forecast period. However, actual price increases in the last three years for the non-contestable market have been above inflation but lower than that outlined in the budget at 4.5 per cent.

[34] See https://www.erawa.com.au/cproot/13009/2/20141119%202014%20Ministers%20Report%20Discussion%20Paper.pdf.

Peak demand and energy assumptions

Taking into account the factors that affect peak demand and energy forecasts (discussed in section 4.2), NIEIR has applied several assumptions to develop the high, expected and low scenarios for the peak demand and energy forecasts. These are summarised below.

Peak demand forecast assumptions

The high, expected and low economic growth scenarios (which are applied to the 10, 50 and 90 per cent PoE weather scenarios), include the following economic outlook and population assumptions for the forecast period:

- high case:
    - 4.1 per cent average annual growth in GSP; and
    - 2.2 per cent average annual growth in population.
- expected case:
    - 3.0 per cent average annual growth in GSP; and
    - 2.0 per cent average annual growth in population.
- low case:
    - 2.1 per cent average annual growth in GSP; and
    - 1.7 per cent average annual growth in population.

Energy forecast assumptions

The high, expected and low energy forecast scenarios assume the same GSP and population growth as the economic growth scenarios used in the peak demand forecasts, and include the following additional assumptions:

- high case:
    - -0.3 per cent average annual growth in residential sales;
    - 4.6 per cent average annual growth in commercial sales; and
    - 3.8 per cent average annual growth in industrial sales.
- expected case:
    - 0.5 per cent average annual growth in residential sales;
    - 1.9 per cent average annual growth in commercial sales; and
    - 1.9 per cent average annual growth in industrial sales.
- low case:
    - 0.1 per cent average annual growth in residential sales;
    - 0.4 per cent average annual growth in commercial sales; and

- 1.5 per cent average annual growth in industrial sales.

The fall in residential sales forecast in the high case is associated with higher growth in solar PV systems compared to the other two scenarios (section 4.2.3 contains more detail on the PV assumptions in each scenario).

4.2.2 Block loads

The peak demand forecasts include forecasts of new block loads identified by the IMO. Block loads are an important input into the forecasting process due to their size relative to the rest of the system. These loads operate continuously and are not generally sensitive to temperature. The IMO considers 20 MW to be the minimum threshold for new block loads.

NIEIR includes operational block loads in its forecasts of peak demand and energy (generally in the temperature insensitive component). Forecasts for these loads are based on recent consumption levels calculated by extracting meter data for each load.

The 2014 SEDO included an allowance for three new block loads in 2014-15 in the expected case. Of these, two are now operating at stable performance levels and are no longer considered in the new block load forecasts. Their consumption has instead been included in NIEIR’s forecasts of peak demand and energy.

The forecasts in this ESOO include an allowance for one new block load in the high case. This load is forecast to come online in 2021-22 at 30 MW, increasing to 70 MW by 2024-25. The energy contribution of this load is estimated to be 131 GWh in 2021-22, increasing to 491 GWh by 2024-25.

4.2.3 Embedded generation, solar photovoltaic systems, battery storage and other technology

The effect of solar PV systems is incorporated in the peak demand and sent out energy forecasts to show the residual amount of total customer demand that needs to be delivered through the network. For each economic scenario, NIEIR has modelled the potential effect of increasing amounts of grid-connected solar PV systems and the introduction of battery storage systems on peak demand and sent out energy.

While solar PV systems are established technology, batteries are expected to be the first of a range of complementary demand-side technology that will become available in the future. Battery storage could greatly affect demand for electricity in the SWIS. Based on recent advances in battery technology, the IMO assumes widespread installation of battery systems will commence in 2020.

The following sections outline the solar PV and battery assumptions applied in the peak demand and energy forecasts and note other issues related to embedded generation and new technology which the IMO is monitoring.

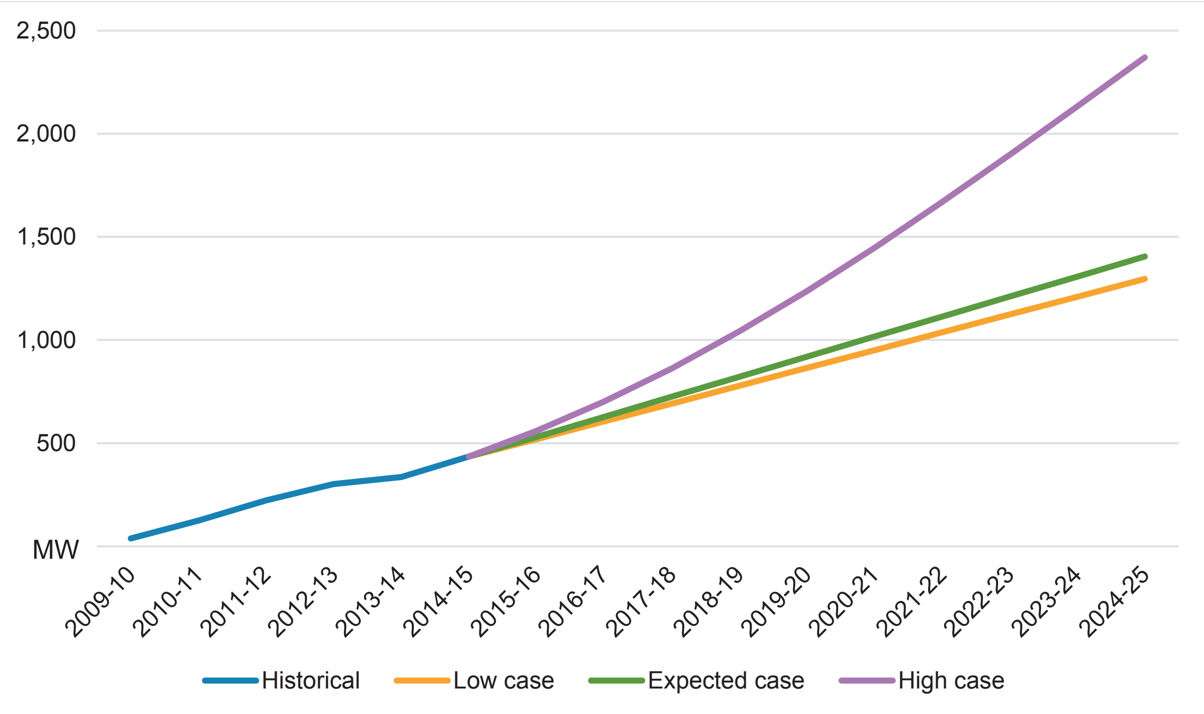
4.2.3.1 Solar photovoltaic system forecasts

Solar PV systems reduce the quantity of electricity needed to be delivered by the network, as they enable customers to self-generate a portion of their electricity requirements. Energy and peak demand forecasts are adjusted to account for the amount of solar PV system capacity expected to be installed.

While solar PV systems reduce peak demand and energy, the effects are limited by the time of day. This is because the peak output for solar PV panels (typically around noon) does not coincide with the system peak (typically around 16:30). For the most recent peak demand observed on 5 January 2015, the impact of PV systems was more significant as it occurred relatively early, at 15:30 (as discussed in chapter 2).

Figure 4.3 shows the installed solar PV system capacity forecast for three different installation rate scenarios; high, expected and low adopted for the equivalent economic forecast scenarios.

Figure 4.3: Installed solar PV system capacity, 2009-10 to 2024-25



Source: IMO and NIEIR

Installation rates vary for the three different cases. For the expected and low cases, linear installation rates are assumed as follows:

- 1,800 systems per month at 4.5 kW per system (8.1 MW per month) in the **expected case**; and
- 1,600 systems per month at 4.5 kW per system (7.2 MW per month) in the **low case**.

The **high case** assumes non-linear growth in installed PV capacity. This represents a more extreme uptake in solar PV systems, similar to the high customer response scenario included in the 2014 SEDO. The key assumptions for this scenario include:

- saturation rates for installed PV systems of 75 per cent of residential dwellings and 90 per cent of commercial premises by 2035;
- initial average system sizes of 4.5 kW in 2015-16, increasing to 10 kW by 2024-25; and
- installation rates of around 14 MW per month (on average) over the first five forecast years, followed by rates of around 19 MW a month on average for the remainder of the forecast period.

Table 4.2 shows the average system sizes for new installations in the high, expected and low case forecasts compared to actual figures.

Table 4.2: Actual and forecast average solar PV system sizes for new installations, selected years

Year	Actual (kW)	High (kW)	Expected (kW)	Low (kW)
2010-11	2.3			
2014-15	3.9			
2015-16		4.5	4.5	4.5
2024-25		10.0	4.5	4.5

Source: CER and IMO

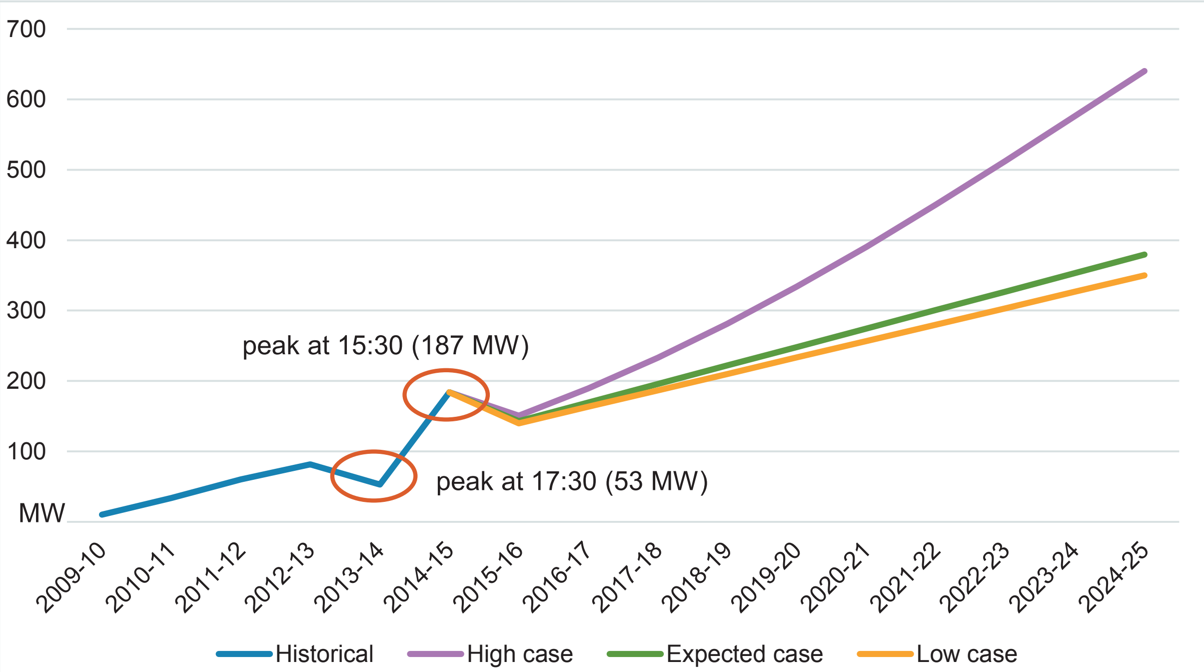
Under the high case, the number of systems installed per month is initially higher than in the expected and low case scenarios, but slows in the outer years as the number of systems approaches the saturation point. The slowdown in the number of installations is offset by a greater average system size, meaning the installation rate (in MW) for the high case is significantly higher in the outer forecast years compared to the expected and low cases.

By way of comparison, in 2014 solar PV systems were installed at an average rate of 1,918 systems (7.9 MW) per month (refer to section 3.5 for more information).

In the expected scenario, PV capacity is forecast to grow from 435 MW in 2014-15 to 1,405 MW by 2024-25. Installed PV capacity is forecast to grow to 2,371 MW in 2024-25 in the high case, and 1,296 MW in the low case. On average, this is expected to shift the peak demand to later in the day – possibly as late as 19:30 by the end of the forecast period.

Figure 4.4 shows the forecast reduction in system peak demand from solar PV systems, based on an assumed output of 27 per cent of nameplate capacity at the time of system peak.

Figure 4.4: Peak demand reduction from solar PV systems, 2009-10 to 2024-25



Source: IMO and NIEIR

Solar PV systems are forecast to reduce the peak demand by 379 MW in the expected case by 2024-25, growing from an estimated 187 MW reduction in 2014-15.

As discussed in section 2.3, the lower contribution of solar PV in 2013-14 compared to 2014-15 is the result of the timing of peak demand. In 2013-14, the peak occurred at 17:30, when the generation from solar PV systems is lower. The 2014-15 peak occurred at 15:30, when the output from solar PV systems is higher. As NIEIR's forecasts assume peak demand occurs at 16:30, the forecast contribution of solar PV systems for 2015-16 is lower than 2014-15.

Appendix D contains the complete set of solar PV system forecasts.

4.2.4 Battery storage forecasts

Battery storage is included in peak demand and energy forecasts for the first time in this ESOO. Residential battery systems are expected to be available on a limited basis in the market from 2016. However, the IMO expects widespread uptake remains several years away. Therefore, battery storage is considered in the forecasts from 2020 onwards.

Based on the most recent available information at time of publication, the following assumptions around battery storage have been incorporated in each of the high, expected and low forecast scenarios:

- batteries are installed with a solar PV system and charge from the generation output of the solar PV system only (the battery does not charge from the grid);
- the accompanying solar PV system is sized such that the total output is either used to charge the battery or used within the dwelling (it does not export excess electricity);
- only residential dwellings install battery systems;
- the battery charges between 06:00 and 14:00, and discharges until 20:00;
- charge and discharge rates for the battery are linear; and
- an assumed average installed battery size of 7 kWh capacity.

Table 4.3 shows the peak demand reduction applied to each forecast scenario to account for battery storage.

Table 4.3: Reduction in peak demand from battery storage, 2019-20 to 2024-25

Scenario	2019-20 (MW)	2020-21 (MW)	2021-22 (MW)	2022-23 (MW)	2023-24 (MW)	2024-25 (MW)
High	0.8	1.5	2.7	4.9	9.2	16.7
Expected	0.7	1.3	2.3	3.9	6.6	10.7
Low	0.7	1.2	2.1	3.4	5.2	7.9

Source: IMO

In addition, the IMO assumes the following numbers of 7 kWh capacity battery storage systems are expected to be installed over the forecast period:

- 1,309 systems in 2015-16 in the high case, growing to 26,268 systems in 2024-25;

- 1,157 systems in 2015-16 in the expected case, growing to 16,863 systems in 2024-25; and
- 1,081 systems in 2015-16 in the low case, growing to 12,444 systems in 2024-25.

Battery storage is a relatively new technology and it is expected that more suppliers will release products in the future. The IMO will continue to monitor developments in this area and will update these assumptions in future ESOOs as required.

The peak demand and energy forecasts, discussed in sections 4.3 and 4.4, have been adjusted to account for the effect of the above amounts of battery storage.

4.2.4.1 Other embedded generation and other technology

There are a number of large loads in the SWIS supplied (in whole or part) by local embedded generation. While the IMO estimates there is around 500 MW of embedded generation supplying these loads, the IMO has limited visibility on system gross demand for loads with embedded generation as only net consumption from the SWIS is recorded.

In developing peak demand and energy forecasts, assumptions about consumption by these loads are made based on historical net consumption values and information collected directly from the participants. However, it should be noted that changes in future operations (contracts and consumption behaviour) could present risks to the forecasts if they are not known by the IMO in advance. For example, if a large customer supplied by an embedded generator considered that the cost of electricity supplied by the network would be lower than their embedded generation costs, the customer may significantly increase its consumption from the SWIS.

Changes to the WEM design to accommodate a constrained grid, as part of the reforms being developed in phase two of the EMR (see section 8.2 for more information) may also prompt a change in how these loads and embedded generators are represented in future ESOO forecasts.

Other technology, such as electric cars, is also expected to change electricity use. However, the IMO has not considered these technologies due to uncertainty around uptake and effect on customer behaviour and a lack of data about their effects.

The IMO will continue to monitor developments in embedded generation, battery storage and other new technology, as well as other forms of customer response (for example IRCR, discussed below) and will update these assumptions in future ESOOs if required.

4.2.5 Individual Reserve Capacity Requirement

Peak demand forecasts are also adjusted by a forecast of the response to IRCR by customers in the SWIS.

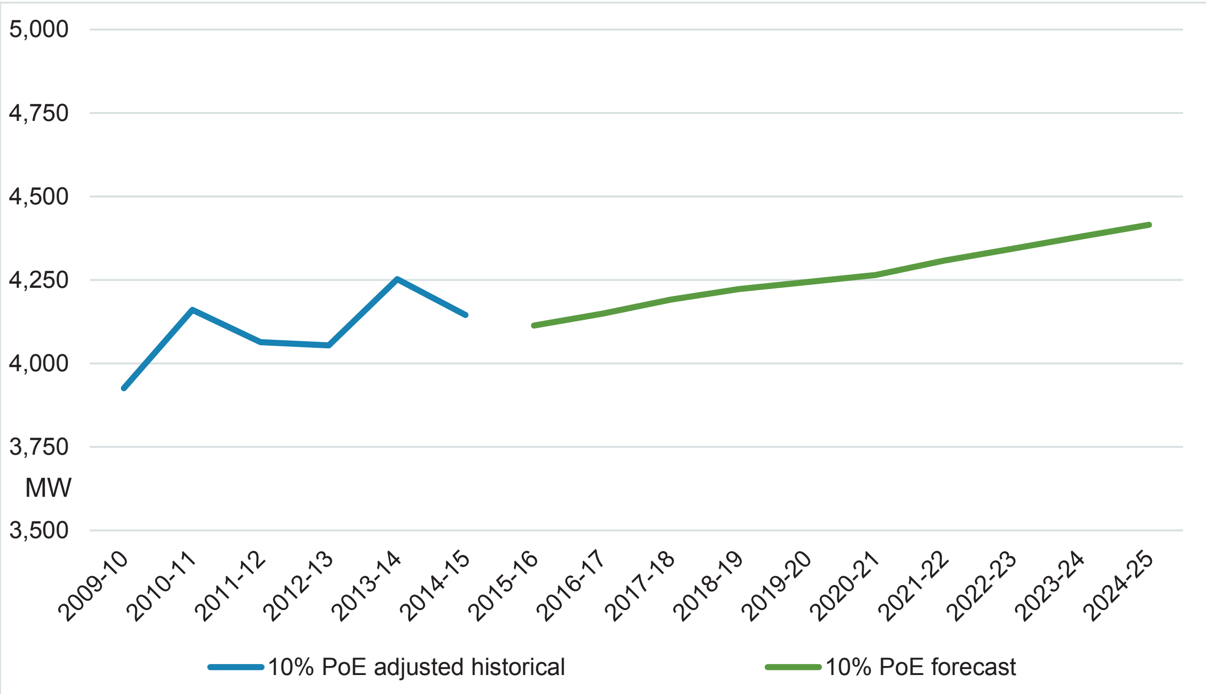
The forecasts in this ESOO include an allowance for 45 MW of demand reduction for each of the high, expected and low cases, reflecting the level of IRCR response observed in the past two years. This is assumed to occur at the time of system peak, as assumed in the forecast at 16:30.

4.3 Peak demand forecasts

Figure 4.5, Figure 4.6 and Table 4.4 show the 10, 50 and 90 per cent PoE peak demand forecasts from 2015-16 to 2024-25, with the **expected case** growth scenario applied.

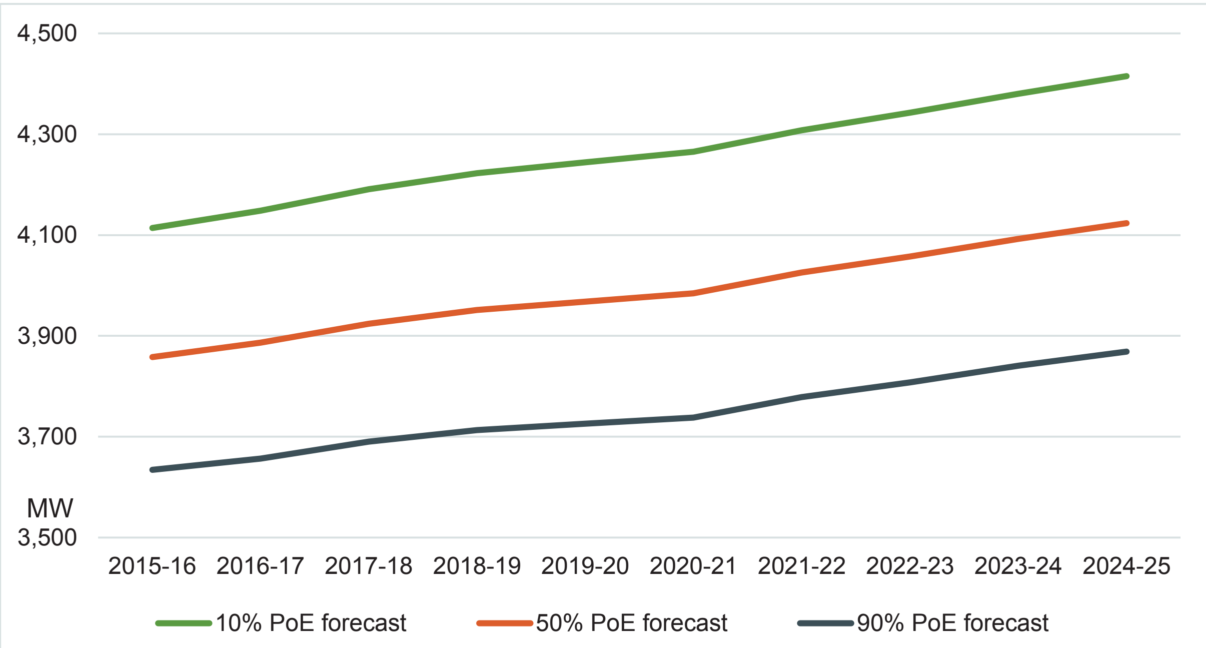
The peak demand forecasts presented in this section assume a peak occurring in February at 16:30.

Figure 4.5: Peak demand, expected case, 2009-10 to 2024-25



Source: NIEIR

Figure 4.6: Peak demand forecasts under different PoE scenarios, expected case, 2015-16 to 2024-25



Source: NIEIR

Table 4.4: Peak demand forecasts for different weather scenarios, expected case

Scenario	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	2019-20 (MW)	5 year average annual growth	10 year average annual growth
10% PoE	4,114	4,149	4,191	4,223	4,244	0.8%	0.8%
50% PoE	3,858	3,886	3,924	3,951	3,968	0.7%	0.7%
90% PoE	3,634	3,657	3,690	3,713	3,726	0.6%	0.7%

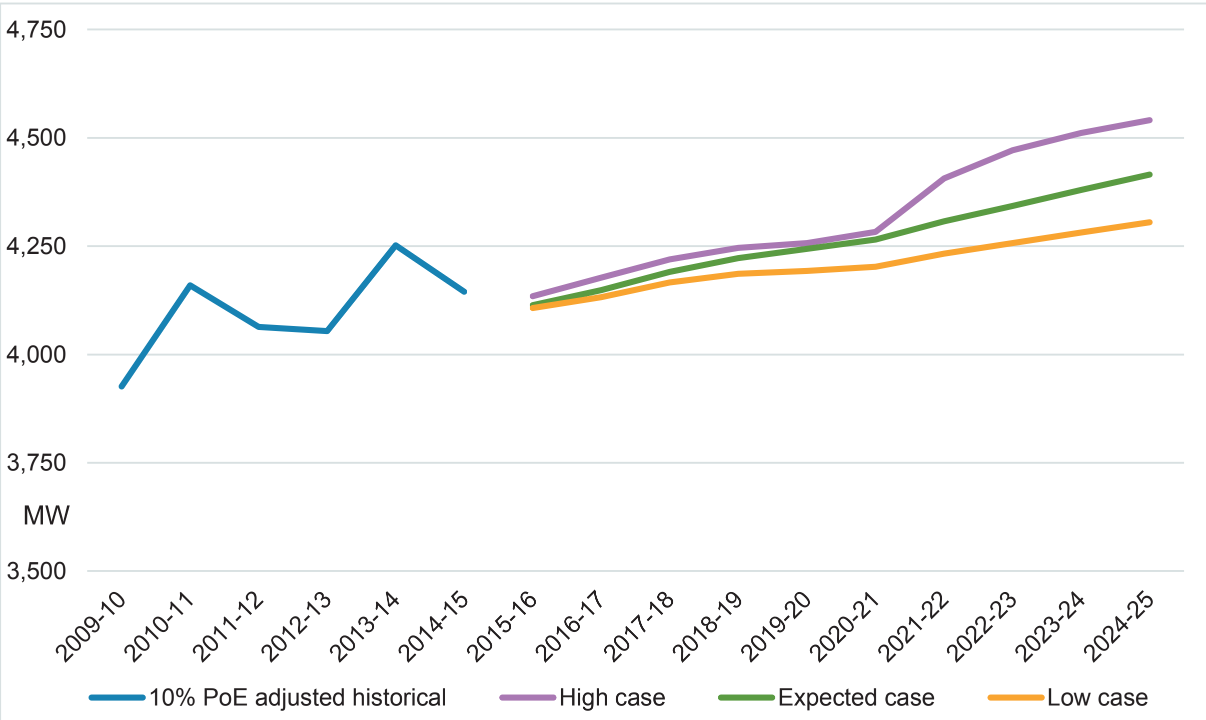
Source: NIEIR

In summary:

- the 10 per cent PoE peak demand forecast is expected to grow at an average annual rate of 0.8 per cent over the 10 year period to 2024-25; and
- the 50 and 90 per cent PoE peak demand forecasts are expected to grow at an average rate of 0.7 per cent over the 10 year period to 2024-25.

Figure 4.7 and Table 4.5 show the 10 per cent PoE forecasts for all three economic growth scenarios.

Figure 4.7: Peak demand, 10 per cent PoE, under different economic growth scenarios, 2009-10 to 2024-25



Source: NIEIR

Table 4.5: Peak demand forecasts for different economic growth scenarios, 10 per cent PoE

Scenario	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)	2018-19 (MW)	2019-20 (MW)	5 year average annual growth	10 year average annual growth
High	4,134	4,177	4,220	4,246	4,257	0.7%	1.0%
Expected	4,114	4,149	4,191	4,244	4,244	0.8%	0.8%
Low	4,107	4,133	4,167	4,193	4,193	0.5%	0.5%

Source: NIEIR

In summary, from 2014-15 to 2024-25, peak demand for the 10 per cent PoE forecasts is:

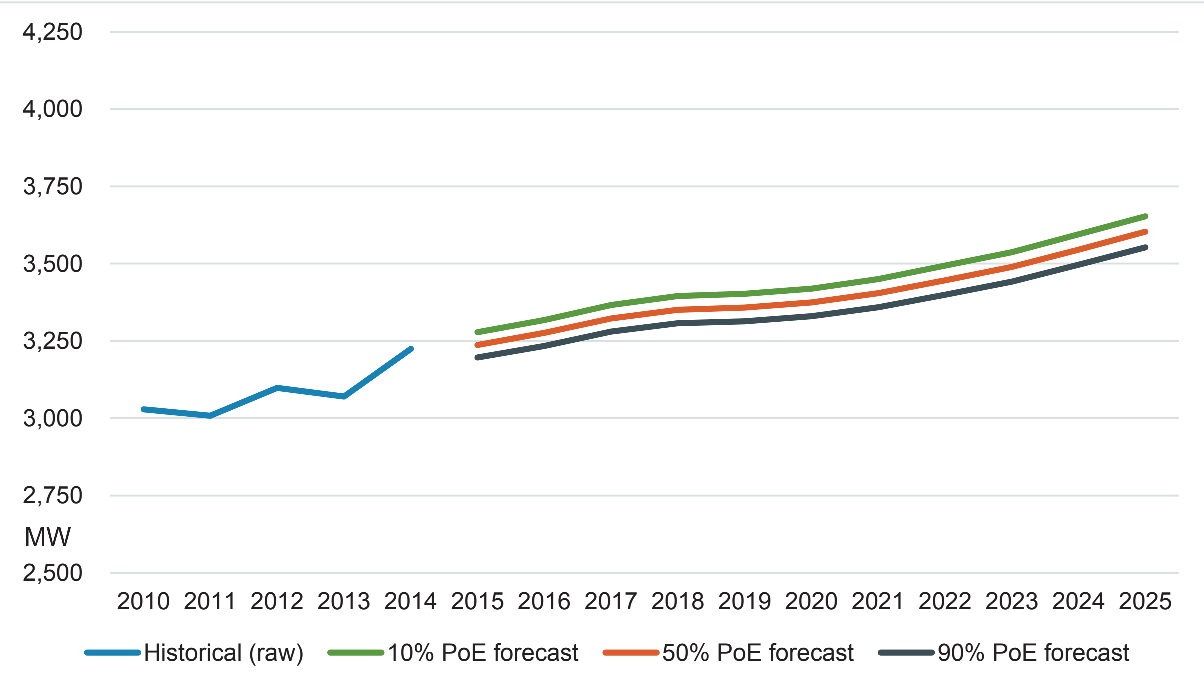
- in the high case, forecast to grow at an average rate of 1.0 per cent.
- in the expected case, forecast to grow at an average annual rate of 0.8 per cent; and
- in the low case, forecast to grow at an average annual rate of 0.5 per cent.

These growth rates reflect different economic growth forecasts, as well as changes in block load and solar PV assumptions.

Appendix E contains the full set of summer peak demand forecasts.

Figure 4.8 shows the 10, 50 and 90 per cent PoE winter peak demand forecasts with the **expected case** growth scenario applied. Please note that winter peak forecasts are for calendar years.

Figure 4.8: Winter peak demand, expected case forecasts, 2010 to 2025



Source: IMO and NIEIR

In summary:

- the 10 and 50 per cent PoE winter peak demand forecasts are expected to grow at an average annual rate of 1.1 per cent over the 10 year period to 2025; and
- the 90 per cent PoE peak demand forecast is expected to grow at an average rate of 1.0 per cent over the 10 year period to 2025.

Consistent with current demand patterns in the SWIS, winter peak demand is forecast to be considerably lower than summer peak demand across all scenarios over the period 2015-16 to 2024-25.

Appendix F contains the full set of winter peak demand forecasts.

4.4 Energy forecasts

Figure 4.9 shows the high, expected and low scenario energy forecasts under the three different economic growth scenarios compared to raw, non-weather adjusted sent out energy.

Figure 4.9: Energy forecasts under different economic growth scenarios, 2009-10 to 2024-25

Source: IMO and NIEIR

Table 4.6 presents the sent out energy forecasts in the high, expected and low cases.

Table 4.6: Sent out energy forecasts

Scenario	2015-16 (GWh)	2016-17 (GWh)	2017-18 (GWh)	2018-19 (GWh)	2019-20 (GWh)	5 year average annual growth	10 year average annual growth
High	18,986	19,498	20,010	20,349	20,543	2.0%	2.5%
Expected	18,731	19,015	19,353	19,548	19,625	1.2%	1.3%
Low	18,541	18,705	18,931	18,970	18,893	0.5%	0.5%

Source: NIEIR

In summary, from 2014-15 to 2024-25:

- the high case energy is forecast to grow at an average annual rate of 2.5 per cent;
- the expected case energy is forecast to grow at an average annual rate of 1.3 per cent; and
- the low case energy is forecast to grow at an average annual rate of 0.5 per cent.

These growth rates reflect different economic growth forecasts, as well as changes in block load and solar PV assumptions.

Appendix G contains the full set of sent out energy forecasts.

4.5 Comparison of peak demand forecast with simulation model

To validate the peak demand forecasts, NIEIR has compared its forecasts to an alternative simulation-based model called PeakSim (also produced by NIEIR).

The IMO's 2012 review of the ESOO forecasting process[35] advocated adoption of a simulation model as a complement to the current econometric forecasting methodology (outlined in section 4.1).

The IMO has presented the forecasts of this simulation model (PeakSim) for the first time in this ESOO.

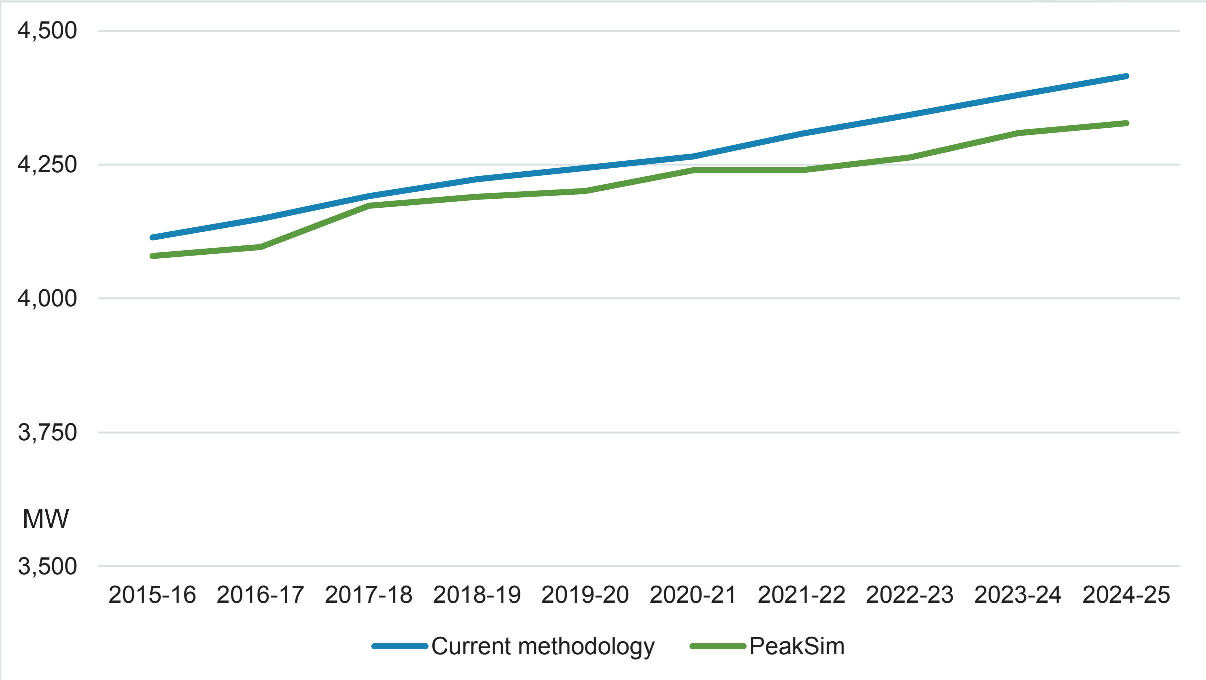
It has not been feasible to use PeakSim before now, as simulation models require a substantial amount (at least 10 years) of historical demand and energy data in order to produce realistic forecasts. However, NIEIR now considers there is now sufficient data to produce a reliable comparison to traditional forecasts.

It is too early to adopt the PeakSim model as a primary forecast tool, even though the results of this model look encouraging. However, PeakSim is a valuable check for the current forecasting model. The IMO will continue to use it as a validation tool for the current model forecast results and may consider adopting it as the primary model in the future, once its performance has been established.

[35] See http://www.imowa.com.au/docs/default-source/Reserve-Capacity/forecasting_process_review_2012_final_report.pdf?sfvrsn=2.

Figure 4.10 compares the 10 per cent PoE peak demand forecasts derived from PeakSim and the current methodology.

Figure 4.10: Comparison of 10 per cent PoE, peak demand forecasts from PeakSim and the current methodology, 2015-16 to 2024-25



Source: NIEIR

The results show the:

- PeakSim forecasts are between 20 MW and 90 MW lower than those using the current methodology; and
- PeakSim average annual growth forecast of 0.7 per cent is consistent with the current forecasting methodology (0.8 per cent).

While the forecast produced by the current methodology is slightly higher, comparison of the two models suggests there is minimal difference between the PeakSim and econometric results. This suggests NIEIR's current forecasting methodology using revised assumptions are reasonably sound.

4.5.1 How the PeakSim model works

PeakSim takes half-hourly load and temperature data to produce a model of the intra-day relationship between temperature and electricity demand. Using historical data, the model creates synthetic distributions of demand and temperature using bootstrapping. Bootstrapping preserves the relationship between temperature and demand while allowing for other effects of load behaviour changes (for example, solar PV penetration and the effect of global warming on recent and future temperature trends).

The model adopted by NIEIR assigns a higher probability of distributions sampled from more recent historical data (using a re-weighted bootstrap), as NIEIR considers more recent weather events and system behaviour to be a better indicator of the future.

An advantage of PeakSim is its ability to generate forecasts across the entire PoE distribution, allowing the IMO to compare the most recent peaks against a comparative history, not only at the 10, 50 and 90 per cent PoE levels generated by the existing model.

5. Forecast reconciliation

This chapter discusses forecast performance against actual observations, as well as how demand and energy forecasts have changed over time.

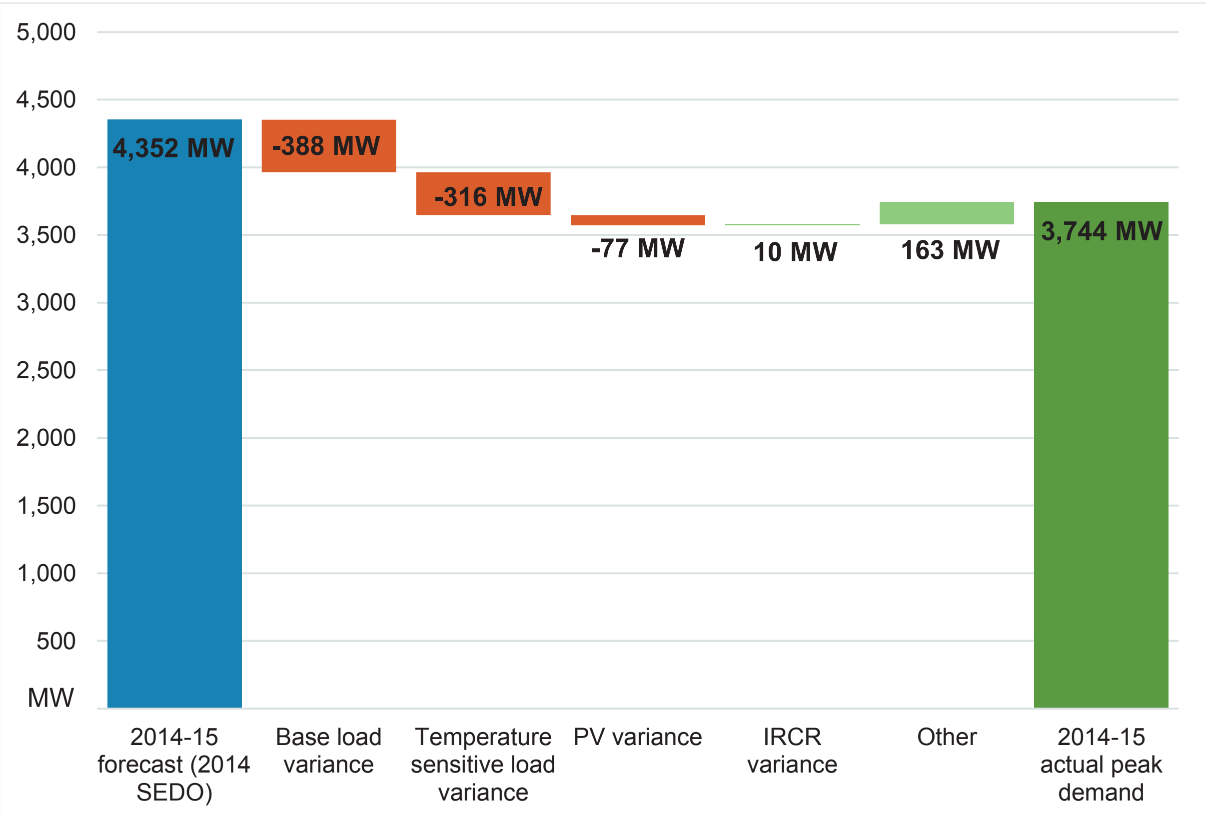
5.1 Base year reconciliation

The IMO prepares forecasts based on different weather conditions (the different PoE forecasts), therefore when reviewing the variance between the forecast and actual peak it is important to separate the effect of warmer or cooler than average temperatures. This provides an understanding of how much of the variance can be attributed to weather and how much can be attributed to other factors such as economic activity and customer behaviour. As a result, the IMO uses weather-adjusted historical figures in various places throughout this report and focuses on the 10 per cent PoE forecasts, which is used to set the RCT.

The month in which peak demand occurs can also cause variance from forecasts, as economic activity levels and temperature can differ significantly from month to month. NIEIR's forecasts assume a system peak will occur during February, however, January peaks have been observed in three of the past five years. The IMO will continue to monitor the month in which peak demand occurs and will consider updating this assumption should the peak continue to be observed in January.

Figure 5.1 shows the variance between the summer 2014-15 actual peak demand and the 2014-15 forecast from the 2014 SEDO.

Figure 5.1: Peak demand variance analysis, 2014-15, 10 per cent PoE expected case



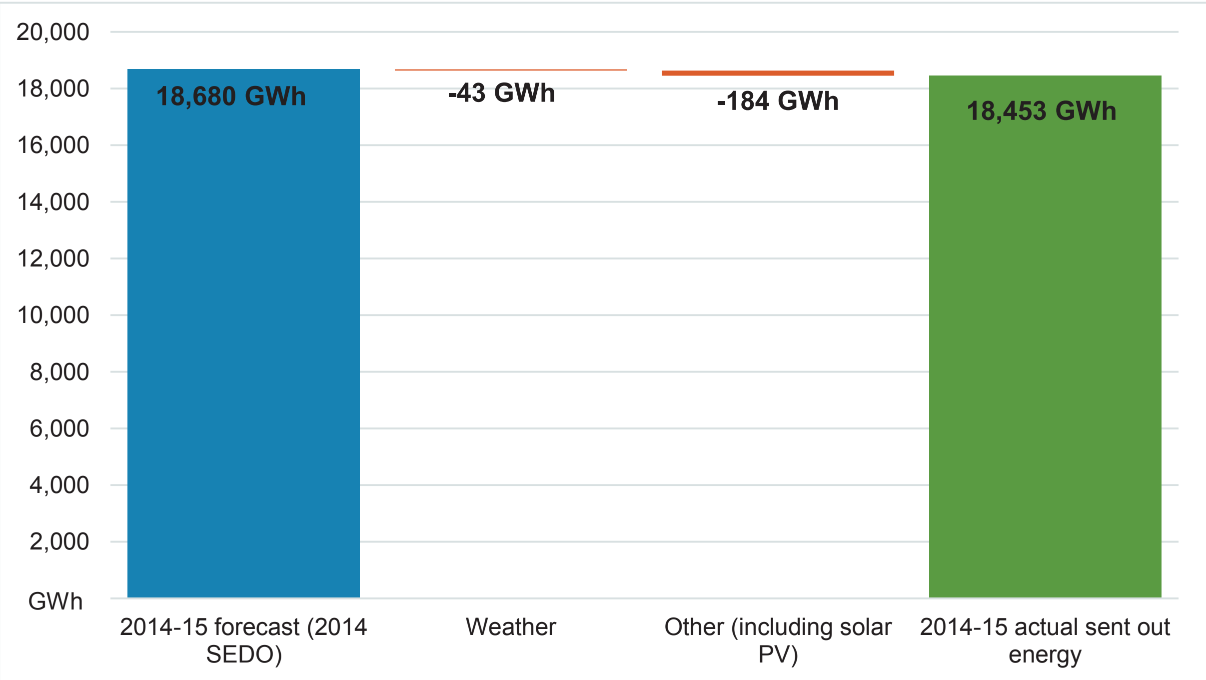
Source: IMO and NIEIR

Peak demand was 3,744 MW, which is 608 MW (16 per cent) lower than forecast. The temperature on the peak day was close to a 10 per cent PoE event; therefore, no upwards adjustment has been made to the raw demand figure to estimate what would have occurred on a 10 per cent PoE day. The main sources of variance are:

- **economic and base load effects (704 MW)** – business activity was lower than usual on 5 January compared to later in January or in February. This is partly because 5 January was the Monday after the New Year break, meaning some businesses would have been closed or operating at less than full capacity. In addition, schools and most other educational institutions do not reopen until February. Residential load is also estimated to have been lower than usual, with a proportion of residential customers away on holiday;
- **peak reduction by solar PV systems (77 MW)** – the irregular, early afternoon January peak coincided with greater generation from distributed solar PV than was forecast in the 2014 SEDO. Had the peak occurred later in the afternoon, as is normally expected, this variance would have been smaller;
- **peak reduction from IRCR response (10 MW)** – the IRCR reduction was slightly lower than forecast as a result of the unusual peak time and day, which some customers would have been unprepared for; and
- **other variance (163 MW) –** other sources of forecast variance which cannot be individually quantified.

Figure 5.2 shows the variance between actual sent out energy in 2014-15[36] and forecast sent out energy from the 2014 SEDO.

Figure 5.2: Sent out energy variance analysis, 2014-15



Source: IMO and NIEIR

[36] This figure is based on eight months' actual data and four months' estimates.

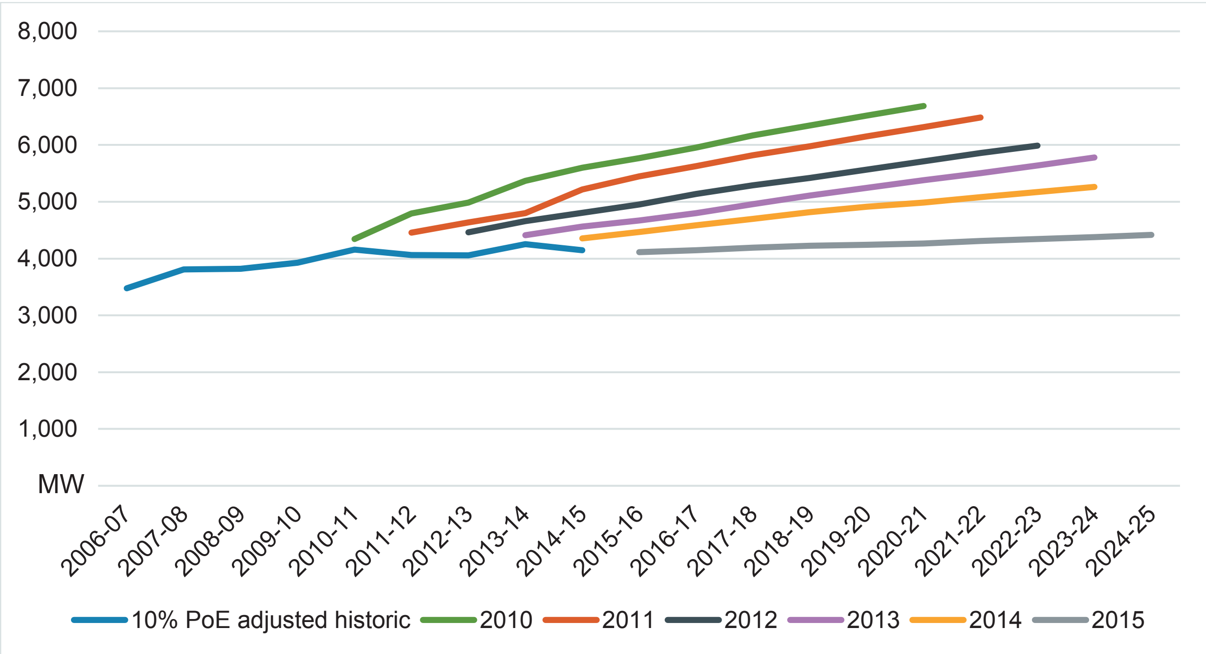
Actual sent out energy was 1.3 per cent lower than forecast. This small variation is attributed to the average temperature being cooler than expected over the year and actual solar PV system capacity being higher than forecast, reducing energy consumption from the network across the year.

5.2 Changes between previous forecasts

Figure 5.3 shows NIEIR's peak demand forecasts since 2010. Each forecast has been lower than the previous year's forecast, with the 2015 peak demand forecast the lowest of the six compared. Forecasts are adjusted each year to account for historical data and changes to assumptions including:

- block load assumptions;
- the methodology for forecasting temperature sensitive load;
- the incorporation of solar PV system effects in the forecasts starting in the 2012 ESOO;
- the consideration of IRCR responses in the forecasts starting in the 2013 ESOO; and
- economic growth assumptions.

Figure 5.3: Change between peak demand 10 per cent PoE, expected case forecasts, 2010 to 2015 forecasts



Source: NIEIR

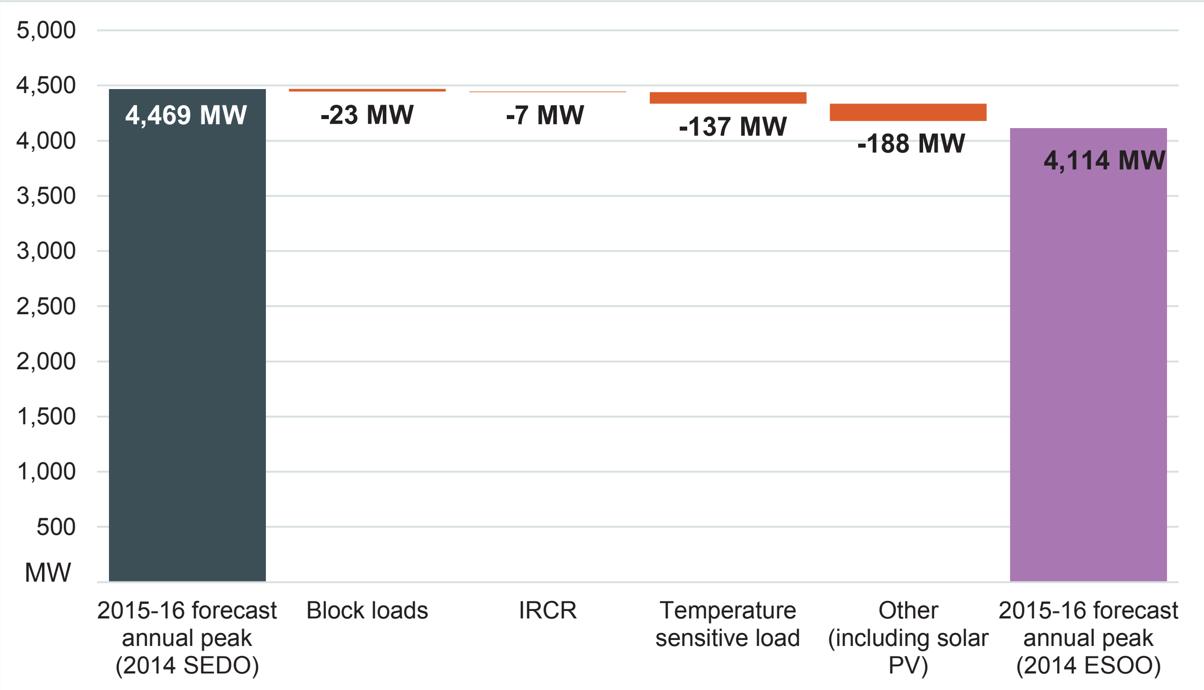
The large difference between the 2011 and 2012 forecast was due to a change in block load assumptions and the introduction of solar PV system forecasting. The change from 2014 to 2015 reflects reductions in forecasts of temperature sensitive load (consistent with falling demand per household), higher forecasts of solar PV and lower economic growth forecasts.

Figure 5.4 shows the change between the 2015-16 forecast peak provided in the 2014 SEDO and the revised forecast provided in this ESOO. The revised 2015-16 forecast peak is

7.9 per cent (355 MW) lower than the forecast in the 2014 SEDO. The difference between the two forecasts can be attributed to:

- higher forecast capacity for solar PV systems (the 2015 forecast assumes solar PV capacity of 530 MW compared to the 473 MW forecast last year);
- a reduction in the forecast for temperature sensitive load;
- changes in commodity prices;
- reduced economic growth forecasts;
- changes in assumptions for block loads;
- the growing customer response to the IRCR; and
- other minor network related assumptions, such as line losses.

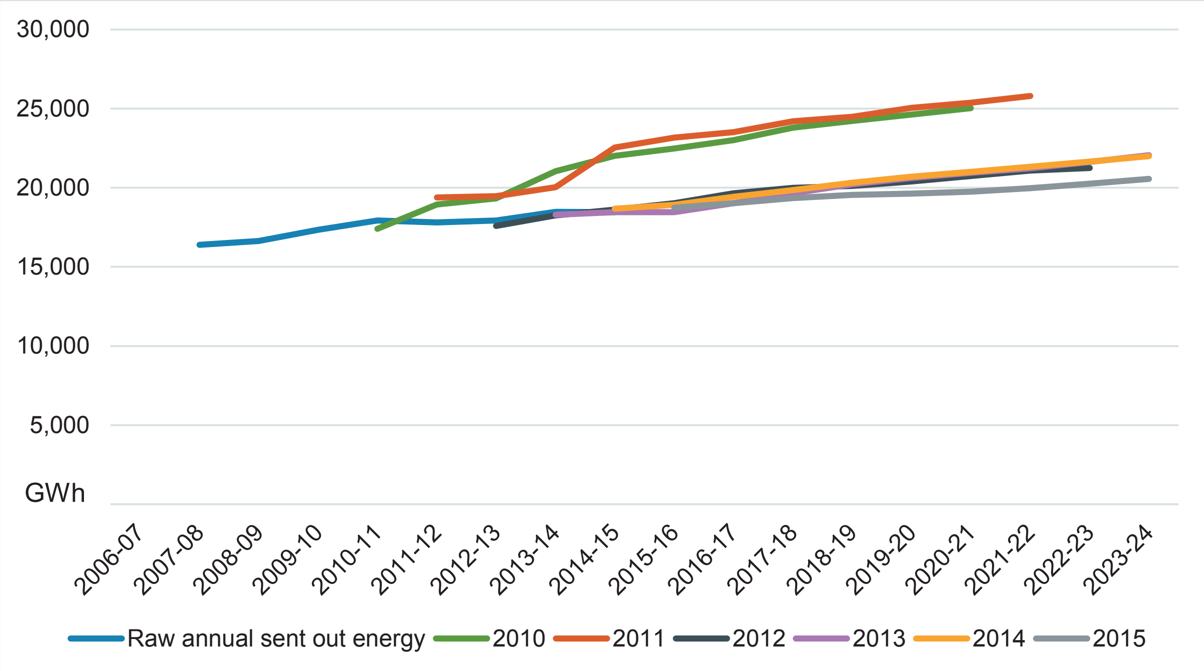
Figure 5.4: Change between peak demand 10 per cent PoE forecasts for 2015-16, 2014 SEDO and 2015 forecasts



Source: NIEIR

Figure 5.5 shows sent out energy forecasts since 2010. Flattening growth in sent out energy has resulted in lower forecasts for 2012 through to 2015 compared with 2010 and 2011.

Figure 5.5: Change between sent out energy expected case forecasts, 2010 to 2015 forecasts



Source: IMO and NIEIR

Revision of assumptions for the sent out energy forecasts in 2012 resulted in a large change between the 2011 and 2012 forecasts. These revisions include:

- the introduction of solar PV system effects into the forecast in 2012;
- a reduction in the forecast for block loads; and
- updated price assumptions resulting from unexpected, substantial increases in regulated electricity tariffs by the State Government, including the lagged effect of price rises in 2009 and 2010 (prices increased by around 70 per cent between 2009 and 2012).

The forecasts between 2012 and 2015 have been broadly consistent, with variances explained by differences in economic growth assumptions and small changes in actual data. The 2015 forecasts also reflect higher forecasts of solar PV.

The IMO has also determined that the variance between the 2014 and 2015 forecasts of sent out energy for 2015-16 was 196 GWh, or less than 2 per cent (from 18,927 GWh published in the 2014 SEDO to 18,731 GWh in this ESOO). Most of this variance is due to revisions to the base year (2014-15), where the actual was lower than the forecast in the 2014 SEDO.

6. Evolution of the Wholesale Electricity Market

This chapter discusses changes in the WEM since market start. It covers market diversification, structural changes, infrastructure developments, the EMR and other factors that may affect the future development of the market.

6.1 Market diversification

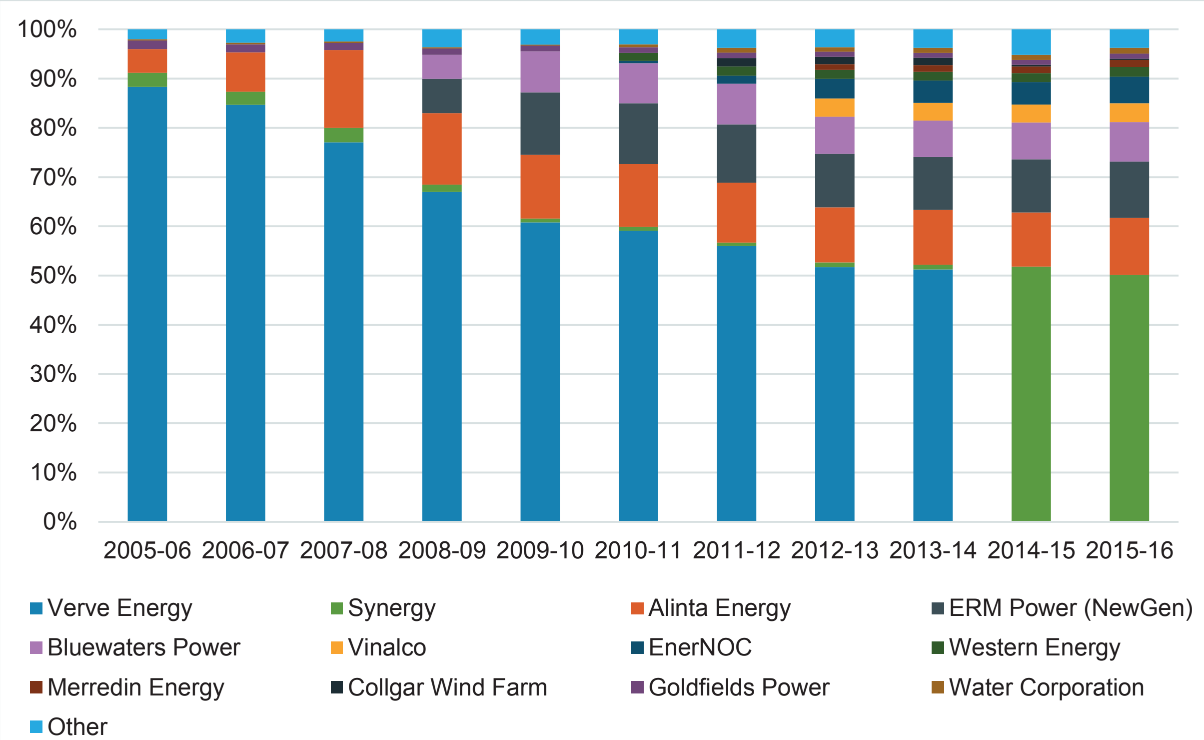
6.1.1 Capacity Credits by Market Participant

The WEM has become increasingly competitive, with a healthy mix of diversity and generation capacity. Since 2005-06 the number of Market Participants has increased three-fold, with 30 Market Participants holding Capacity Credits in the 2015-16 Capacity Year, compared with 10 at market start.

Synergy's share of Capacity Credits (formerly Verve Energy[37]) continues to decrease, boosting diversity even further. In 2015-16 Synergy only held 50 per cent of Capacity Credits, down from 88 per cent at market start in 2005-06. The next two largest Capacity Credit allocations are to Alinta Energy and ERM Power, which account for approximately 11 per cent each.

This steady increase in diversity represents a maturing market, with growing competition and greater choice. Figure 6.1 shows the Capacity Credit allocation by Market Participant since market start.

Figure 6.1: Proportion of Capacity Credits by Market Participant, Capacity Year 2005-06 to 2015-16



Source: IMO

[37] The State Government merged Verve Energy and Synergy on 1 January 2014, with the new entity trading as Synergy.

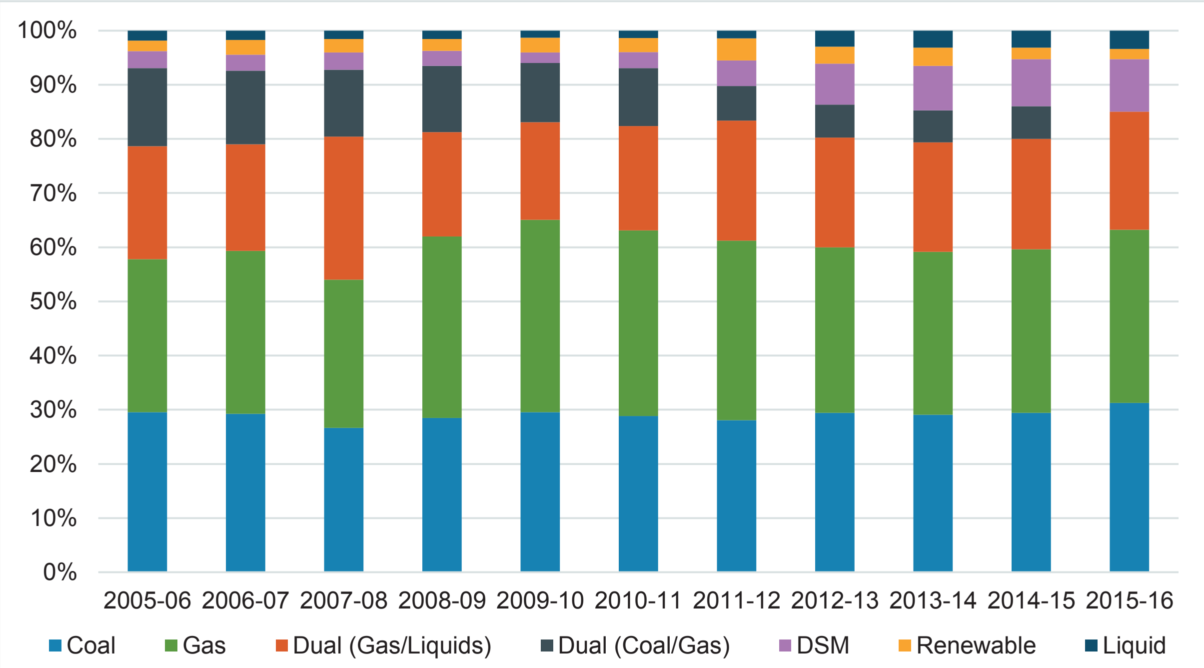
6.1.2 Capacity Credits by fuel type

There is a healthy 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 15 per cent of Capacity Credits now allocated to liquid, DSM and renewable generation. This compares with only 7 per cent at market start. Dual-fuel capacity (gas/liquids) maintains a 22 per cent share of capacity.

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.

Figure 6.2 shows generation capacity in the SWIS by fuel type.

Figure 6.2: Percentage of Capacity Credits by fuel type, 2005-06 to 2015-16



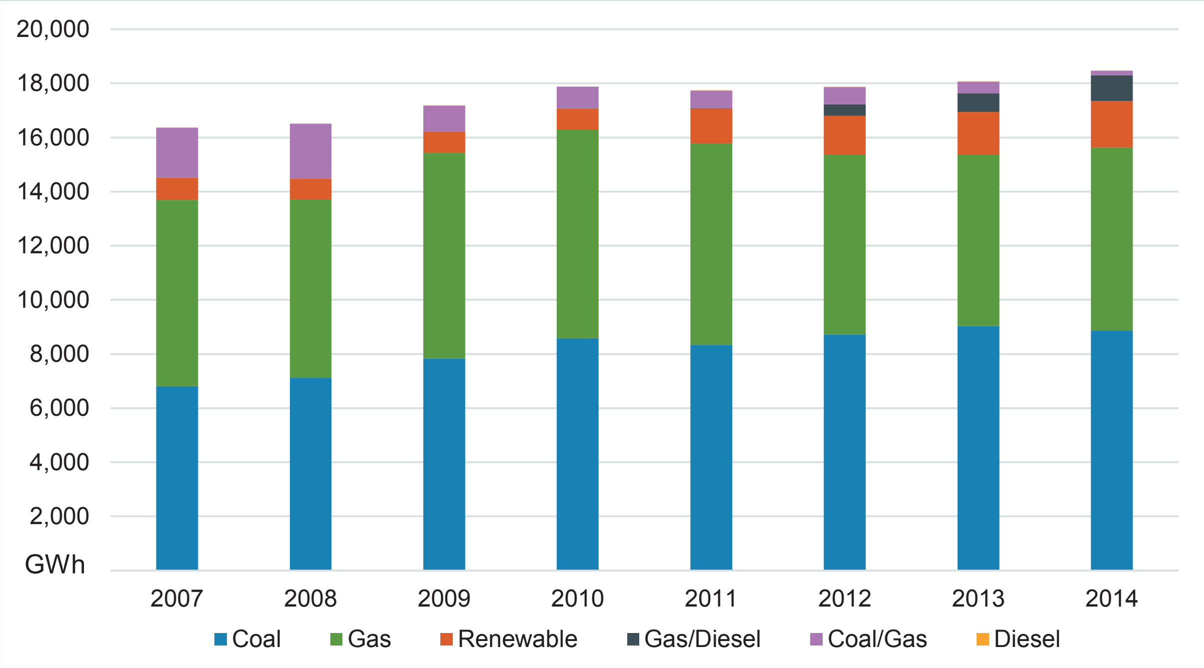
Source: IMO

In summary, over the period 2005-06 to 2015-16:

- the share of fossil fuel (coal and gas) generation capacity has fallen from 93 per cent to 85 per cent;
- the proportion of Capacity Credits assigned to renewable generators has remained relatively stable, averaging three per cent; and
- the proportion of Capacity Credits assigned to DSM tripled between 2010-11 and 2015-16, from around three per cent to 10 per cent.

Figure 6.3 shows total sent out energy by fuel type for the calendar years 2007 to 2014.

Figure 6.3: Energy generation by fuel type, 2007 to 2014 calendar year



Source: IMO

In summary, over the period 2007 to 2014:

- total generation from coal increased from 6,816 GWh to 8,857 GWh;
- energy from gas generators declined from 6,873 GWh to 6,778 GWh;
- energy generated from renewable sources more than doubled (826 GWh to 1,713 GWh), accounting for nine per cent of total sent out energy in 2014; and
- generation from dual-fuel and diesel facilities declined from 1,855 GWh to 1,116 GWh, reflecting the gradual retirement of the Kwinana Power Station, which included:
  - the retirement of units G3 and G4 in 2007-08;
  - the retirement of units G1 and G2 in 2010-11; and
  - the retirement of units G5 and G6 in 2014-15.

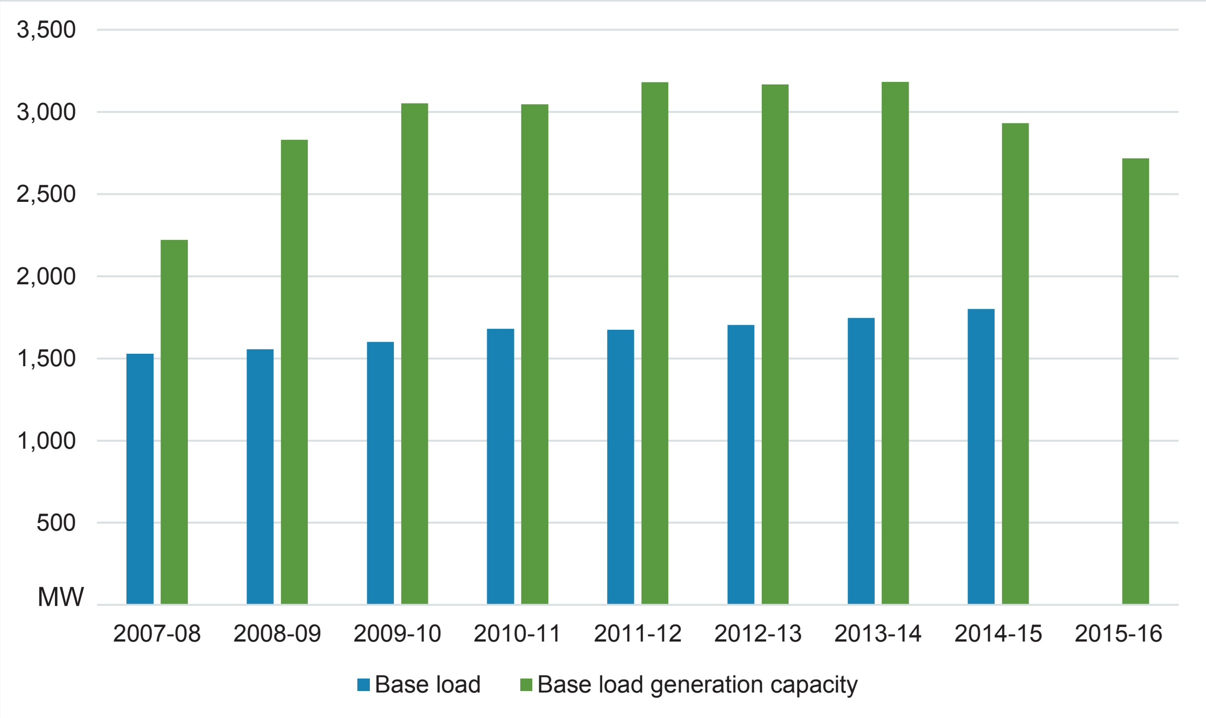
6.1.3 Load characteristics and generation mix

The mix of capacity types is driven to an extent by variation in demand throughout the year. As discussed in section 2.2, the load duration curve for the SWIS shows a system characterised by sharp summer peaks and a large variance between minimum and peak demand. Based on this load duration curve, a mix of base load, mid-merit, and peaking facilities is desirable in the SWIS.

6.1.3.1 Base load and base load generation capacity

Base load is the level of demand required for 75 per cent of the year. Figure 6.4 shows the base load generation and actual base load from 2007-08 to 2015-16.

Figure 6.4: Base load generation capacity compared to actual base load, 2007-08 to 2015-16



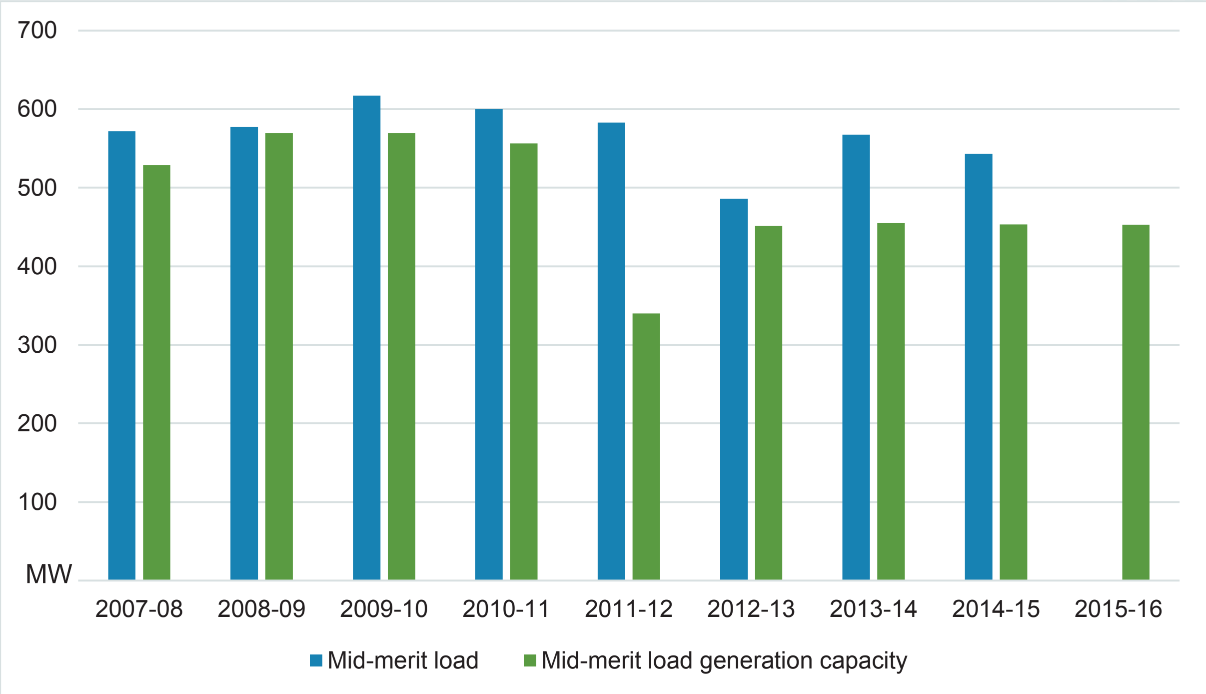
Source: IMO

There remains a significant level of excess base load generation capacity in the SWIS. However, this has decreased in recent years due to the retirement of Kwinana G5 (177.5 MW) and Kwinana G6 (185 MW) during the 2014-15 Capacity Year.

6.1.3.2 Mid-merit load and mid-merit generation capacity

Mid-merit load is the additional demand exceeded for at least 25 per cent of the year. Figure 6.5 shows mid-merit load generation capacity compared with actual mid-merit load from 2007-08 to 2015-16.

Figure 6.5: Mid-merit load generation capacity compared to actual mid-merit load, 2007-08 to 2015-16



Source: IMO

Mid-merit load has been greater than mid-merit load generation capacity in all years, which indicates some base load or peaking generation is filling part of the mid-merit role. The fall in mid-merit load between 2011-12 and 2012-13 was caused by an unusual load profile in 2011-12, which reverted to normal the following year.

The decline in mid-merit load generation capacity in 2011-12 was due to the decommissioning of Kwinana G1 and G2 (216 MW). Mid-merit capacity rose again in 2012-13 with the start-up of the refurbished Muja G3 and G4 (110 MW).

6.1.3.3 Peaking load and peaking load generation capacity

Peaking load is the additional demand exceeded for less than 25 per cent of the year. Figure 6.6 shows peaking load generation capacity compared with the actual peaking load from 2007-08 to 2015-16. Peaking capacity includes both peaking generation capacity and DSM.

Figure 6.6: Peaking load generation capacity compared to actual peaking load, 2007-08 to 2015-16

Source: IMO

Peaking capacity grew from 1,210 MW in 2008-09 to 2,512 MW in 2014-15.

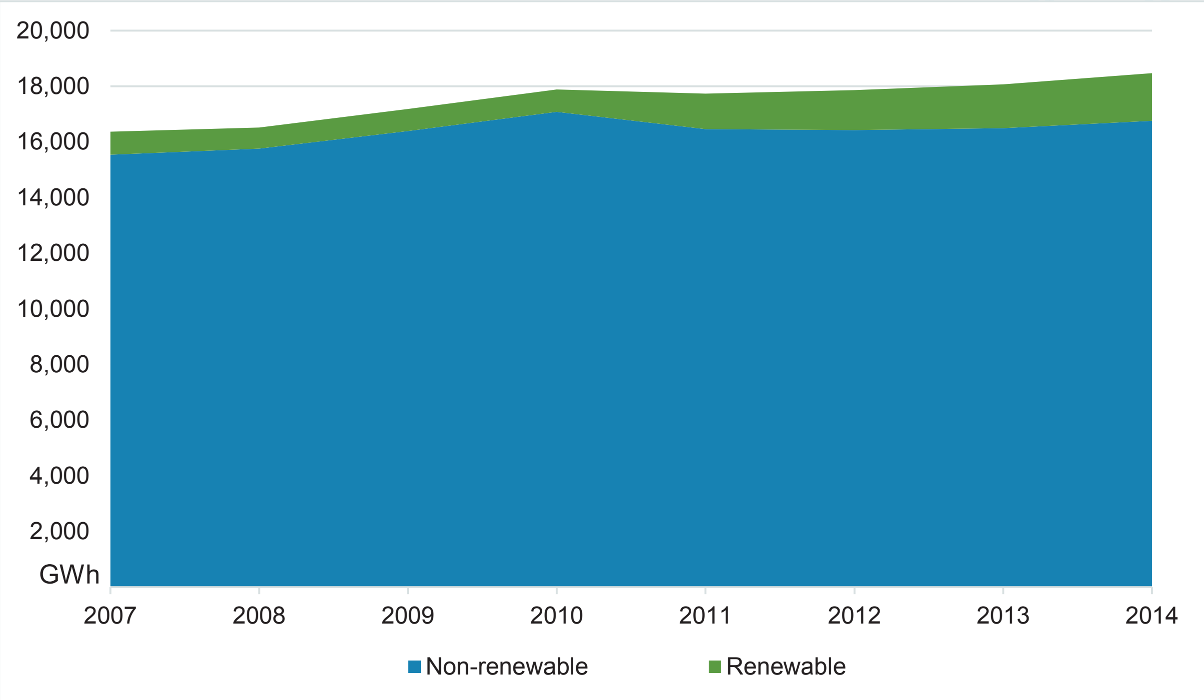
6.2 Renewable energy

There are a total of 19 renewable energy facilities operating in the WEM, including 11 wind farms, seven landfill gas facilities and one solar PV farm[38]. The amount of renewable energy generation capacity has increased from 826 GWh in 2005-06 to 1,713 GWh in 2014-15.

[38] Figures do not include small-scale solar PV systems. This section refers only to renewable energy facilities that are registered as intermittent generators in the WEM.

Figure 6.7 shows the amount of renewable energy, excluding small scale solar PV, compared to total wholesale electricity generation between 2007 and 2014.

Figure 6.7: Renewable and non-renewable electricity generation, 2007 to 2014 calendar year



Source: *IMO*

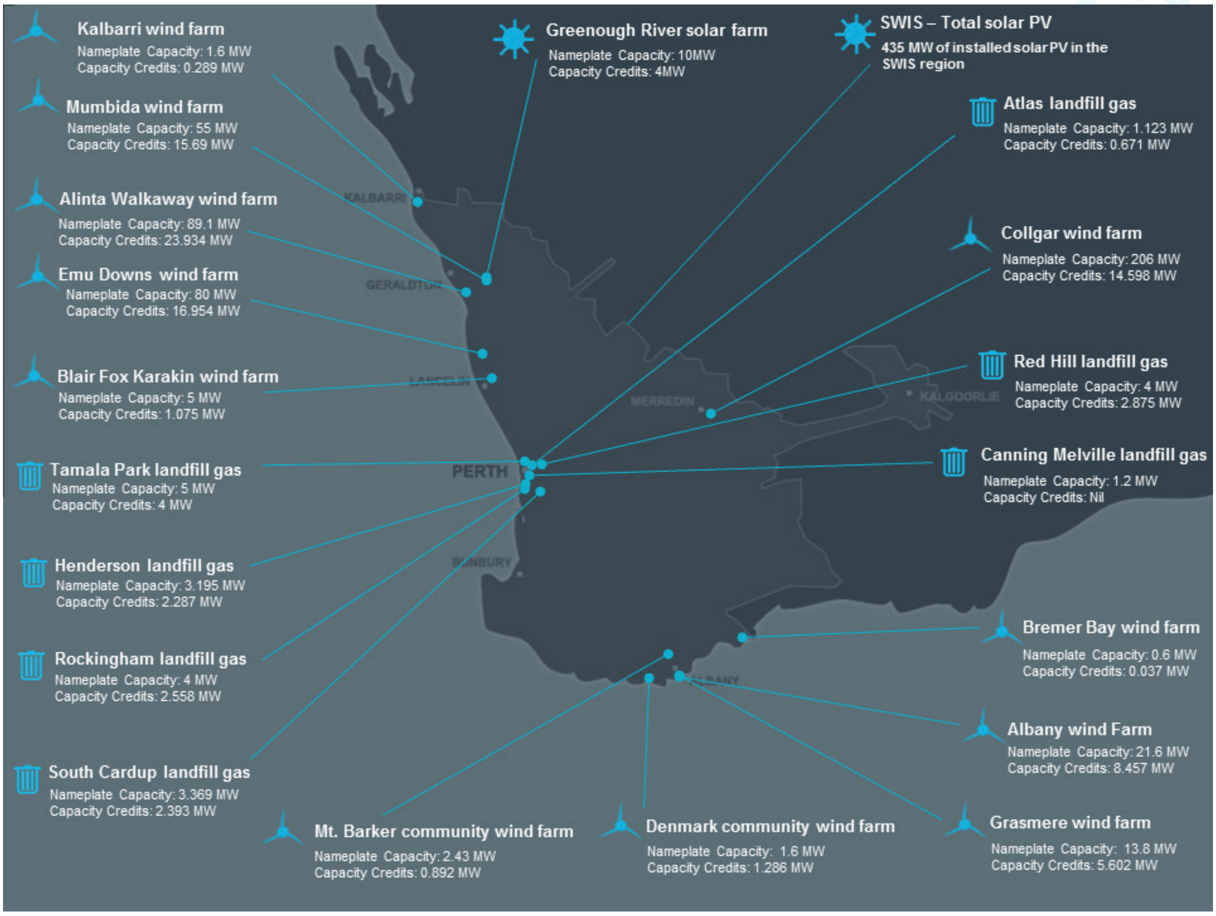
In summary:

- renewable energy generation grew at an average annual rate of 11 per cent between 2007 and 2014;
- average annual growth in non-renewable generation over the same period was one per cent; and
- the share of renewable generation as a proportion of total generation almost doubled, from five per cent in 2007 to nine per cent in 2014[39].

[39] This is based on nameplate capacity not Capacity Credits allocated.

Figure 6.8 shows the location, nameplate capacity, and 2015-16 assigned Capacity Credits for renewable energy facilities in the SWIS. The total number of Capacity Credits assigned to these facilities for 2015-16 is 108.9 MW. The map also shows the amount of installed small-scale solar PV system capacity.

Figure 6.8: Renewable energy map for the SWIS



Source: CER and IMO

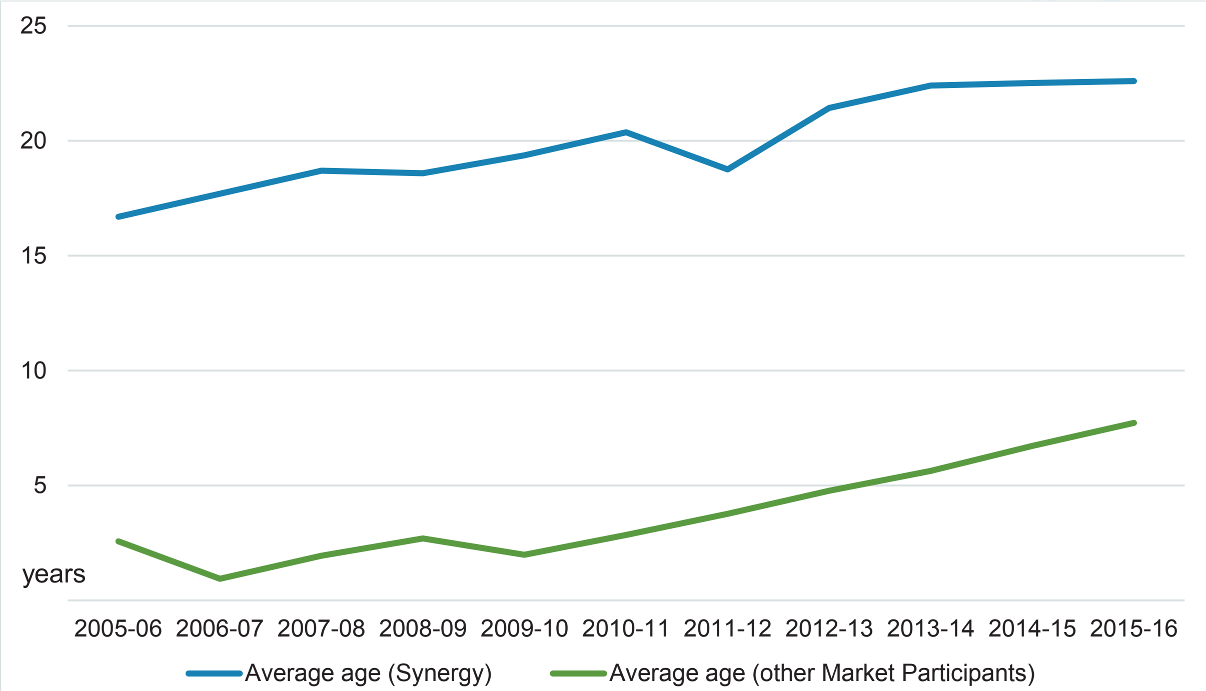
Alinta's Walkaway wind farm (23.93 MW) has the largest allocation of Capacity Credits, while Synergy's Bremer Bay wind farm (0.037 MW) has the smallest.

6.3 Age and availability of generation capacity

The IMO expects the average age of generation capacity to increase over the medium term. Other than the recent Kwinana Power Station decommissioning, the IMO is not aware of any forthcoming generation plant retirements. Current capacity levels in the SWIS suggests new investment will be limited.

Figure 6.9 shows the average age, weighted by Capacity Credits, for Synergy's generation capacity compared with other Market Participants from 2005-06 to 2015-16.

Figure 6.9: Average age of generation capacity, Synergy and other Market Participants, 2005-06 to 2015-16



Source: IMO

In summary:

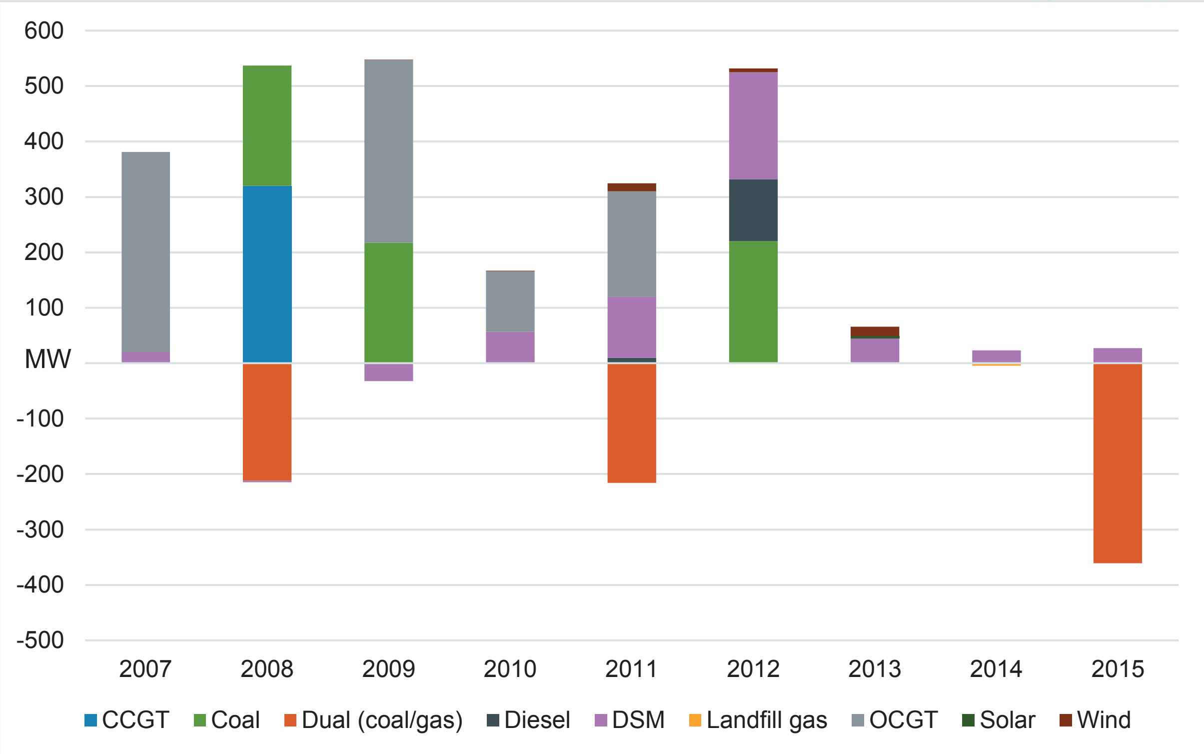
- the average age of Synergy's generation capacity has increased from 16.7 years in 2005-06 to 22.6 years in 2015-16 (based on assigned Capacity Credits);
- the average age of generation capacity owned by other Market Participants has increased from 2.6 years to 7.7 years (based on assigned Capacity Credits);
- around one third of Synergy's total Capacity Credits are assigned to generation capacity built before 1990; and
- more than 95 per cent of capacity owned by other Market Participants was built after 2003.

The falls in average age for Synergy facilities over this period reflect the staged retirement of the Kwinana Power Station over the period from 2007-10 to 2014-15. However, the average age did not fall in 2014-15, despite the retirement of Kwinana G5 and G6, due to the ageing of the remaining generation capacity. The average age remained roughly steady between 2013-14 and 2014-15.

In addition, two new High Efficiency Gas Turbine units were commissioned by Verve Energy (now Synergy) at Kwinana during 2011 (190 MW Capacity Credits). The average age increased again in 2012-13 and 2013-14 when the refurbished Muja AB facility was commissioned, which was originally built during the 1960s. Assuming Synergy does not commission any new capacity or retire ageing capacity, the average age of its generation capacity will exceed 30 years by 2023-24.

Figure 6.10 shows the entry and exit of generation capacity in the SWIS by fuel type from 2007 to 2015.

Figure 6.10: Entry and exit of generation capacity in the SWIS by fuel type, 2007 to 2015



Source: IMO

In summary, over the period 2007 to 2015:

- the net increase in generation capacity was 2,228 MW, with 3,057 MW of capacity commissioned and 829 MW retired;
- most retired capacity was dual-fuel coal/gas facilities (789 MW);
- around one third (974 MW) of the new capacity commissioned was open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT) facilities;
- DSM contributed 439 MW of new capacity;
- renewable energy facilities (including landfill gas, large scale solar and wind facilities but excluding small-scale solar PV) contributed 38 MW of new capacity[40]; and
- new diesel generation accounted for 127 MW of total new capacity, most of which (112 MW) was commissioned during 2012.

For a full list of facilities and assigned Capacity Credits, see Appendix H.

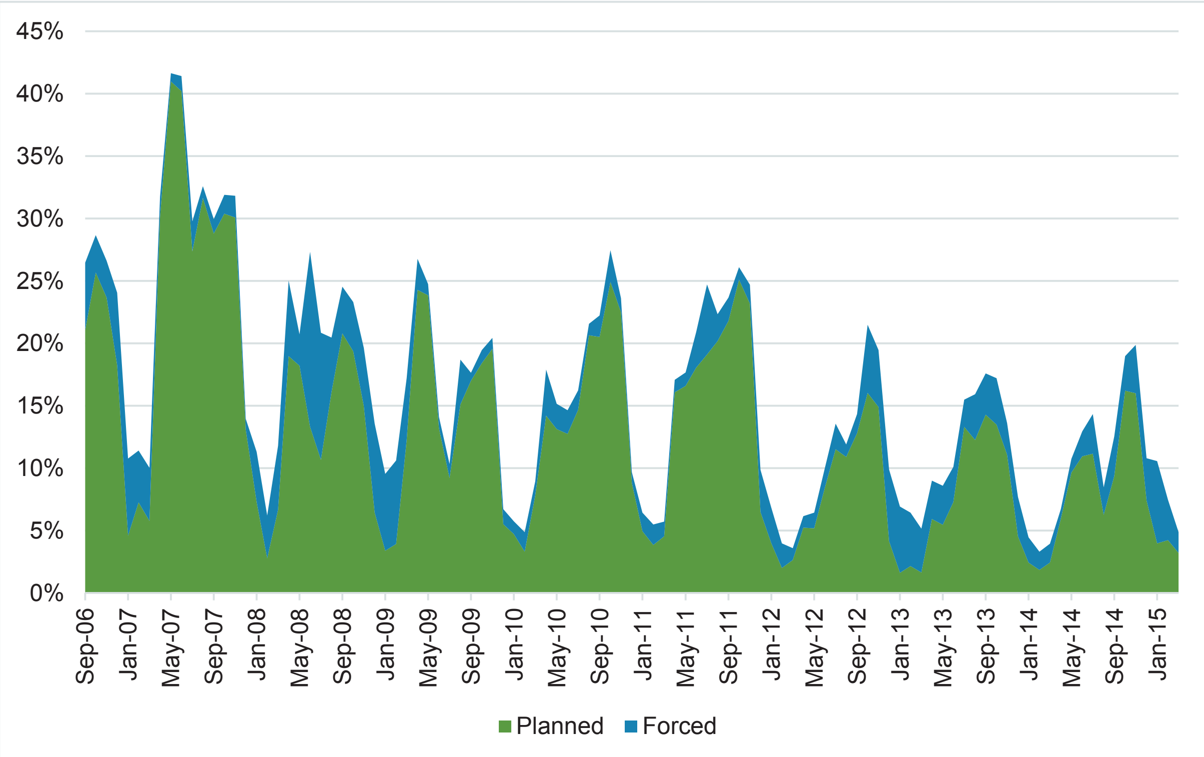
[40] Based on Capacity Credits assigned for the 2014-15 Capacity Year. This figure has changed over time with the introduction of the Relevant Level Methodology, and is lower than the total nameplate capacity of these facilities of 361 MW.

Figure 6.11 shows total outage rates (planned and forced) as a percentage of the allocated Capacity Credits in the market. This measures the total average outage rate of all Market Participants supplying capacity to the SWIS.

Average monthly planned and forced outages have been declining in the SWIS since 2006. This suggests the majority of generation that has been assigned Certified Reserve Capacity (CRC) is available to meet peak demand. However, the total monthly average (calculated per interval) outage rate (including both planned and forced outages) increased slightly during 2014-15, with monthly average outage rates reaching a maximum of approximately 19 per cent in October 2014, compared with 18 per cent in September 2013.

Outage rates are typically lower over summer periods, when demand is expected to be the highest. However, outage rates for summer 2014-15 were significantly higher than in previous years. The average planned outage rate increased from approximately three per cent during summer 2013-14 to five per cent in summer 2014-15, although it was similar to the rates experienced in earlier years. Of particular note was the increase in the forced outage rate in 2014-15 when compared to the previous year, which doubled from approximately two per cent to four per cent.

Figure 6.11: Total monthly average outage percentage, September 2006 to March 2015



Source: IMO

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 LT PASA Study Horizon (2015-16 to 2024-25).

7.1 Planning Criterion

The RCT ensures there is sufficient generation and DSM capacity to meet the following two elements of the Planning Criterion (outlined in clause 4.5.9 of the Market 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 per cent[41] of the forecast peak demand (including transmission losses and allowing for intermittent loads); and

ii. the maximum capacity, measured at 41 degrees Celsius, of the largest generating unit;

while maintaining the Minimum Frequency Keeping Capacity[42] 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; and

(b) limit expected energy shortfalls to 0.002 per cent of annual energy consumption (including transmission losses).

Part (a) relates to meeting the highest maximum demand in a half-hour trading interval. Part (b) ensures that 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.

As was the case in all Reserve Capacity Cycles to date, for the 2016-17 Capacity Year the peak demand-based capacity requirement in part (a) exceeds the energy-based requirement in part (b). In 2016-17, this difference is more than 400 MW. As such, it is likely the peak demand forecast will continue to set the RCT for the near term.

The capacity required to meet peak demand for each year in the LT PASA Study Horizon (2015-16 to 2024-25) is shown in Table 7.1 in section 7.2.

7.1.1 Part (a) of the Planning Criterion

For most of the LT PASA Study Horizon, with the exception of the 2023-24 and 2024-25 period, the capacity of the largest generating unit, Collie (331 MW), measured at 41 degrees Celsius, has set the level of reserve margin in all years until 2023-24. This is because it is greater than the 7.6 per cent of the forecast maximum demand.

41 This reserve margin has reduced from 8.2 per cent to 7.6 per cent as a result of Rule Change Proposal: 5-Yearly Review of Planning Criterion (RC_2012_21), which commenced on 1 May 2013 and first applied to the 2013 Reserve Capacity Cycle. See http://www.imowa.com.au/RC_2012_21 for more information.

42 Also known as load following ancillary service capacity.

In past ESOOs, the 7.6 per cent of forecast peak demand has set the reserve margin. This year, the peak demand forecasts have reduced compared to previous forecasts (see chapter 4 for more details).

In 2014-15 System Management advised the quantity of load following ancillary service capacity required for maintaining system frequency would be 72 MW for the foreseeable future[43].

The forecast allowance for intermittent loads has also fallen compared to the 2013 ESOO. This is based on currently available information about the consumption patterns of these loads.

7.1.2 Part (b) of the Planning Criterion

Although the annual peak demand occurs in summer, the availability of capacity is crucial for system reliability throughout the year. Generators are regularly taken out of service for maintenance to ensure on-going reliability. These plant outages are typically scheduled in the lower load periods of autumn, spring and, to a lesser extent, winter. The outage scheduling process in the Market Rules is designed to ensure orderly planning of outages.

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 supply capacity. Part (b) of the Planning Criterion requires this shortfall to be no more than 0.002 per cent of the annual forecast demand. This is reported as the Availability Curve in section 7.3.

To date, load factors and plant availability have been such that the RCT has been set by part (a) of the Planning Criterion, relating to annual peak demand.

7.2 Forecast capacity requirements

Table 7.1 reports the RCT for each year of the LT PASA Study Horizon, as determined by the peak demand requirement of the Planning Criterion.

[43] At the time of preparing this report, ancillary service requirements for 2015-16 have not been set.

Table 7.1: Reserve Capacity Targets[44]

Year	Maximum demand (MW)	Intermittent loads (MW)	Reserve margin (MW)	Load following (MW)	Total (MW)
2014-15	4,105	5	331	72	4,513
2015-16	4,114	5	331	72	4,522
2016-17	4,149	5	331	72	4,557
2017-18	4,191	5	331	72	4,599
2018-19	4,223	5	331	72	4,631
2019-20	4,244	5	331	72	4,652
2020-21	4,265	5	331	72	4,674
2021-22	4,308	5	331	72	4,716
2022-23	4,343	5	331	72	4,751
2023-24	4,380	5	333	72	4,790
2024-25	4,415	5	336	72	4,828

Source: IMO

The RCT for the 2014 Reserve Capacity Cycle (2016-17 Capacity Year) is 4,557 MW. This is a reduction of 562 MW from the 2015-16 RCT of 5,119 MW published in the 2013 ESOO[45].

Table 7.2 provides a summary of the difference between the 2015-16 RCT published in the 2013 ESOO and the 2016-17 RCT in this ESOO.

Table 7.2: Comparison of the 2015-16 Reserve Capacity Target in the 2013 ESOO and the 2016-17 Reserve Capacity Target in this ESOO

Component	Change (MW)
2015-16 RCT (2013 ESOO)	5,119
Reduction in peak demand forecast*	- 504
Reduction in reserve margin for 2015-16*	- 35
Reduction in intermittent loads*	- 11
Reduction in load following requirement	- 12
2016-17 RCT (this ESOO)	4,557

Source: IMO

* Note: Includes the contribution of the 7.6 per cent reserve margin

[44] All figures in MW and rounded to the nearest integer.
[45] A RCT was not published in the 2014 SEDO.

The reduction in the peak demand forecast (504 MW) is the main component of this reduction in the RCT. The key factors that have contributed to this reduction in the peak demand forecast include:

- the estimated contribution of small-scale solar PV generation to meeting peak demand continues to increase. Installed PV capacity has increased from 271.5 MW in January 2013 to 435 MW in January 2015; and
- NIEIR has updated its model for temperature sensitive load to adjust for the latest data on residential energy consumption.

7.3 Availability Curve

Capacity in the SWIS is assigned to four Availability Classes, where each class reflects the maximum number of hours per year that the capacity is available. This approach recognises the value of DSM but ensures the reduced availability of DSM compared to generation capacity is considered when assessing system reliability.

Four Availability Classes are defined in Appendix 3 of the Market Rules as follows:

- Class 1 relates to generation capacity that is available for all trading intervals other than when an outage applies;
- Class 2 relates to capacity from DSM[46] that is available for at least 72 hours per year;
- Class 3 relates to capacity from DSM that is available for at least 48, but less than 72, hours per year; and
- Class 4 relates to capacity from DSM that is available for at least 24, but less than 48, hours per year.

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 remainder of the RCT can be met by further generation capacity or by DSM.

Table 7.3 shows the Availability Curve information for the 2015-16, 2016-17 and 2017-18 Capacity Years.

[46] May be provided by DSM, interruptible loads or dispatchable loads.

Table 7.3: Availability Curve information

	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)
Clause 4.5.12(a) of the Market Rules:			
Capacity required for more than 24 Hours	4,243	4,276	4,316
Capacity required for more than 48 Hours	3,889	3,915	3,950
Capacity required for more than 72 Hours	3,795	3,821	3,856
Clause 4.5.12(b) of the Market Rules:			
Minimum generation required	3,917	3,852	3,879
Clause 4.5.12(c) of the Market Rules:			
Capacity associated with Availability Class 1	3,917	3,852	3,879
Capacity associated with Availability Class 2	0	63	71
Capacity associated with Availability Class 3	326	361	366
Capacity associated with Availability Class 4	279	281	283

Source: PA Consulting

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

Compared to the 2013 ESOO, the proportion of capacity associated with Availability Class 1 has reduced for the 2015-16 and 2016-17 Capacity Years by 477 MW and 726 MW, respectively. This is the result of further revisions to the solar PV system forecasts and the adjustments to the temperature sensitive load forecasts.

The Market Rules do not limit the amount of Capacity Credits assigned to any Availability Class where there is intent to bilaterally trade.

7.4 Opportunities for investment

7.4.1 Supply-demand balance

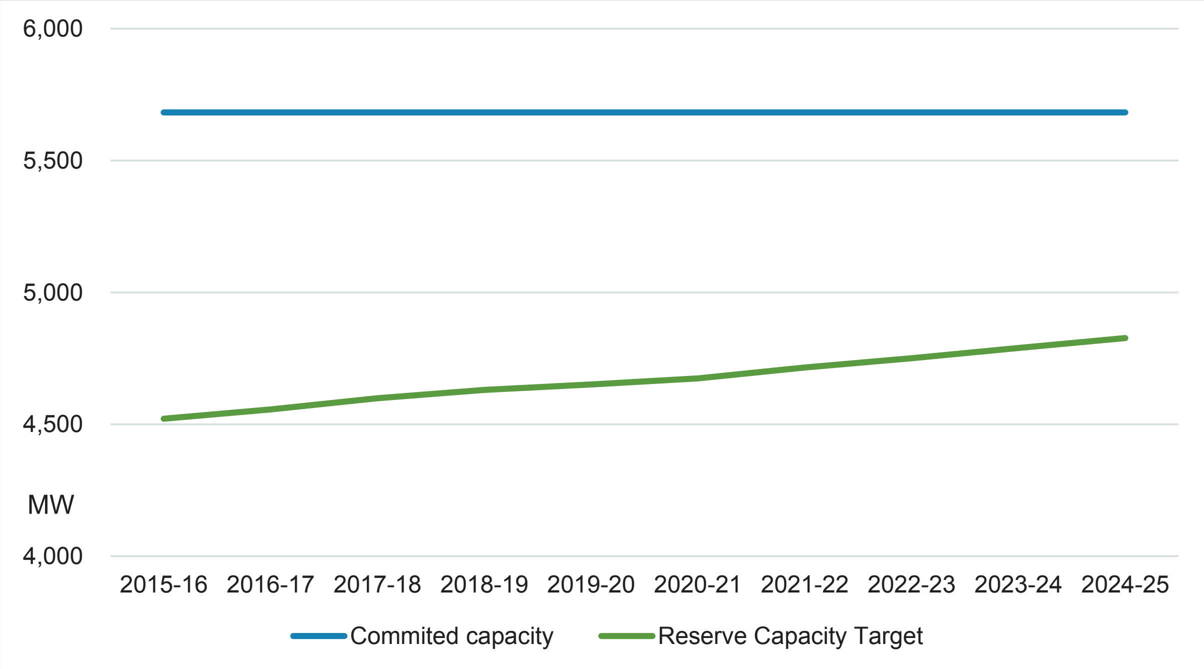
To assess the supply-demand balance, it is assumed that:

- committed capacity is expected to remain unchanged from the 2015-16 Capacity Year and continues to remain at this level until 2024-25 (i.e. no new capacity is assigned Capacity Credits between 2016-17 and 2024-25 and there are no additional retirements of any committed capacity over the forecast period); and
- there are no changes to the RCM over the forecast period.

This level of committed capacity is then compared to the RCT for each year.

Figure 7.1 shows the supply-demand balance between 2015-16 and 2024-25. This is based on the 10 per cent PoE expected case peak demand forecast shown in Table 7.1, and includes the estimated intermittent loads, load following ancillary service capacity and the reserve margin.

Figure 7.1: Supply-demand balance, 2015-16 to 2024-25



Source: IMO

Figure 7.1 shows committed capacity is expected to be more than sufficient to satisfy the RCT until the end of the forecast period in 2024-25. The IMO estimates there will be around 1,161 MW of excess capacity in the SWIS in 2015-16, reducing to 1,126 MW in 2016-17. Excess capacity is expected to steadily decrease to 855 MW by the end of the forecast period as peak demand is forecast to increase.

Table 7.4 summarises the level of excess capacity in the SWIS for the 2015-16, 2016-17 and 2017-18 Capacity Years.

Table 7.4: Capacity in the SWIS, 2015-16 to 2017-18

	2015-16 (MW)	2016-17 (MW)	2017-18 (MW)
Existing generating capacity	5,133	5,133	5,133
Existing DSM capacity	550	550	550
Committed new capacity	0	0	0
RCT	4,522	4,557	4,599
Excess capacity	1,161	1,126	1,084

Source: IMO

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. Project proponents, investors and developers should make independent assessments of the possible supply and demand conditions.

7.4.2 Opportunity to retire and decommission

As discussed in the previous section, it is expected that there will be an excess of 855 MW of capacity in the SWIS by the end of the forecast period. This may provide an opportunity for Market Participants to retire or decommission their less efficient facilities.

7.4.3 Expressions of Interest and excess capacity in the SWIS

Under section 4.2 of the Market Rules, the IMO is required to run an Expression of Interest (EOI) process each year. The most recent EOI process identified proposals[47] for 56.05 MW of new Reserve Capacity for the 2016-17 Capacity Year.

While the EOI process provides an indication of potential future capacity, an EOI submission does not necessarily translate into certified capacity. Some of the capacity submitted under the EOI process may potentially be developed for subsequent Reserve Capacity Cycles. In 2013, EOIs were received for 59 MW of potential new capacity but only 0.4 MW of this capacity was assigned Capacity Credits for the 2015-16 Capacity Year.

Table 7.5 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. The low quantity of capacity offered this year continues the downward trend in new capacity being offered through the EOI process.

Table 7.5: Capacity offered through the EOI compared to capacity certified, 2007 to 2014

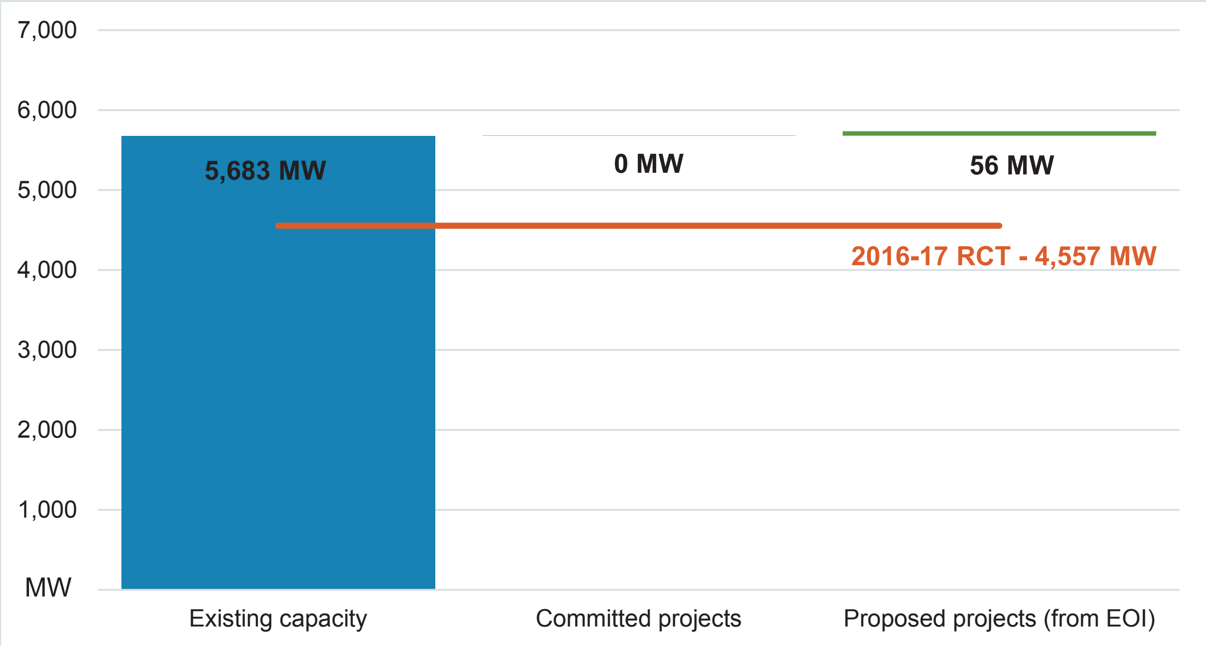
Reserve Capacity Cycle	2007	2008	2009	2010	2011	2012	2013	2014
Capacity offered (MW)	1,192	1,036	1,279	644	337	214	59	56
Capacity offered and certified (MW)	370	24	454	391	33	0	0.4	N/A
Total other capacity certified	205	113	123	135	7	25	15	N/A

Source: IMO

Figure 7.2 and Figure 7.3 show the outlook for the 2016-17 and 2017-18 Capacity Years, including existing capacity, committed projects, and proposed projects from the 2014 EOI. The total existing capacity is more than sufficient to meet the RCTs of 4,557 MW in 2016-17 and 4,599 MW in 2017-18, respectively. Consequently, there is limited opportunity for new investment in the near term.

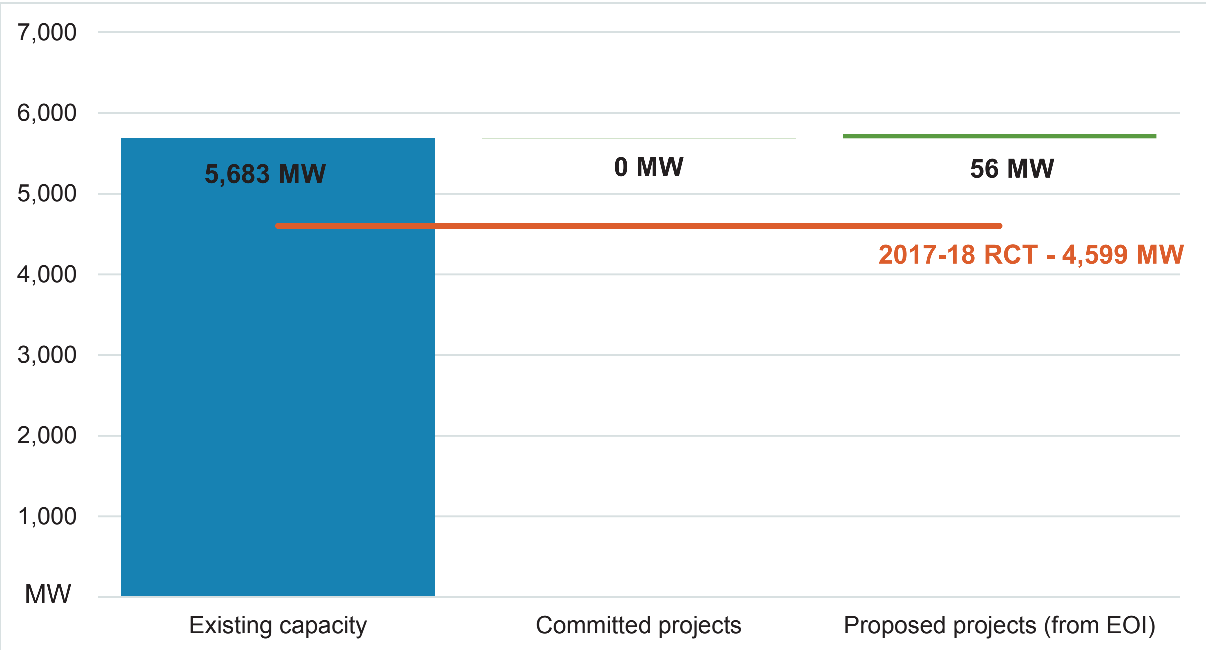
[47] See http://www.imowa.com.au/home/electricity/reserve-capacity/expressions-of-interest.

Figure 7.2: SWIS capacity outlook, 2016-17



Source: IMO

Figure 7.3: SWIS capacity outlook, 2017-18



Source: IMO

8. The Reserve Capacity Mechanism and other information

This chapter discusses the general RCM process, including the steps that must be followed to be assigned CRC for the 2014 Reserve Capacity Cycle (which relates to the 2016-17 Capacity Year). The chapter outlines the State Government's EMR, recent infrastructure developments in the SWIS and other issues that may impact the Western Australian electricity sector.

8.1 The Reserve Capacity Mechanism process

The RCM process follows the steps outlined below:

- the IMO determines the Maximum Reserve Capacity Price and calculates a preliminary RCT;
- EOI for CRC are sought from Market Participants, which are summarised and published on the IMO's website;
- the IMO publishes the ESOO, which sets the RCT;
- Market Participants submit applications for CRC;
- the IMO assigns CRC to facilities, and Market Participants indicate their intention to either bilaterally trade capacity or offer the capacity into the Reserve Capacity Auction;
- the IMO advises whether sufficient capacity has been procured through bilateral trades, and announces whether a Reserve Capacity Auction is required. If the RCT has been met, the Reserve Capacity Auction will be cancelled. If sufficient capacity has not been procured, the IMO will advise that it will run a Reserve Capacity Auction to secure the remaining quantity; and
- the IMO runs the Reserve Capacity Auction if required[48].

As discussed in section 8.2, most aspects of the 2014 Reserve Capacity Cycle were deferred by 12 months following a direction from the Minister for Energy. As a result of the direction, the IMO cancelled the Reserve Capacity Auction for the 2014 Reserve Capacity Cycle. The revised 2014 Reserve Capacity Cycle timetable for the 2014 Reserve Capacity Cycle is available from the IMO's website[49].

To receive CRC, a facility must meet the requirements of clause 4.10.1 of the Market Rules concerning network access and environmental approvals. Both of these processes can be lengthy. The IMO encourages potential developers to contact Western Power[50] and the Western Australian Environmental Protection Authority[51] at the earliest opportunity. In seeking certification for generation facilities, Market Participants must provide full details of their fuel supply and transport contract arrangements with appropriate supporting documents.

Further information on the certification of Reserve Capacity process is available on the IMO's website[52].

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48 A Reserve Capacity Auction has not been held to date.
49 Available at: http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.
50 Contact details for Western power are available at: http://www.westernpower.com.au/electricity-retailers-generators-generator-and-transmission-connections.html.
51 Contact details for the Department of Environment Regulation are available at: http://www.epa.wa.gov.au/Policies_guidelines/EAGs/Pages/default.aspx?cat=Environmental%20Assessment%20Guidelines&url=Policies_guidelines/EAGs.
52 Available at: http://www.imowa.com.au/home/electricity/reserve-capacity/certification-of-reserve-capacity.

8.2 State Government Electricity Market Review

In 2014, the Minister for Energy launched the State Government's two-phase EMR. The EMR has three objectives:

- reducing costs of production and supply of electricity and electricity related services, without compromising safe and reliable supply;
- reducing government exposure to energy market risks, with a particular focus on having future generation built by the private sector without government investment, underwriting or other financial support; and
- attracting to the electricity market private-sector participants that are of a scale and capitalisation sufficient to facilitate long-term stability and investment[53].

Phase one of the review is complete. A discussion paper[54] and an options paper[55] were released in August 2014 and March 2015 respectively.

Phase two of the EMR was announced by the Minister for Energy on 24 March 2015. The Government has developed four work streams that capture proposed reform projects. The four work streams[56] are:

1. Network Regulation;
2. Market Competition;
3. WEM Improvements; and
4. Institutional Arrangements.

The IMO notes the WEM Improvements work stream includes two broad projects:

1. reforming the RCM; and
2. reforms to energy market operations and processes (including to accommodate a constrained network, introduce competitive, co-optimised ancillary service markets and reform the design of the Short Term Energy Market).

More information on phase two and the work streams of the EMR are available on the Department of Finance's website[57].

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[53] Available at: https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx.
[54] Available at: https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/electricity-market-review-discussion-paper.pdf.
[55] Available at: https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Electricity-Market-Review-Options-Paper-December-2014.pdf.
[56] Available at: http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Scope-of-Work-and-Program-Overview-EMR-Phase-2.pdf.
[57] Available at: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review_-_Phase_2.aspx.

8.2.1 *Impact of the EMR*

The EMR has ongoing impacts for the RCM and proposed changes to the Market Rules, which would have implications for capacity providers in the WEM. In particular:

- deferral of most aspects of the 2014 and 2015 Reserve Capacity Cycles; and
- rejection and deferral of changes to the Market Rules and elements of the Market Rules Evolution Plan (MREP)[58].

These issues are discussed below.

8.2.1.1 Deferral of the 2014 and 2015 Reserve Capacity Cycles

In April 2014 the IMO received a Ministerial direction to defer certain processes related to the 2014 Reserve Capacity Cycle by 12 months. As a consequence, publication of the ESOO for the 2014 Reserve Capacity Cycle (this document) was deferred to June 2015 and the IMO cancelled the 2014 Reserve Capacity Auction.

In March 2015, the IMO received another Ministerial direction[59] that requires the IMO to defer the following components of the 2015 Reserve Capacity Cycle (which relates to the procurement of capacity for the 2017-18 Capacity Year) until 2016:

- request for EOI;
- publication of the ESOO report;
- applications for CRC and the assessment of these applications;
- Bilateral Trade Declarations;
- assignment of Capacity Credits; and
- related steps such as provision of Reserve Capacity Security.

As a consequence of the deferral, the IMO has also cancelled the 2015 Reserve Capacity Auction.

The IMO has published updated timetables for the 2014 and 2015 Reserve Capacity Cycles on the IMO website[60].

8.2.1.2 Status of Rule Changes and Market Rules Evolution Plan

In 2013 and 2014, the IMO sought to progress several changes to the Market Rules, including:

- Incentives to Improve Availability of Scheduled Generators (RC_2013_09);
- Harmonisation of Supply-Side and Demand-Side Capacity Resources (RC_2013_10);
- Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refunds Regime (RC_2013_20);

[58] Available at: http://www.imowa.com.au/home/electricity/projects/market-rules-design-review.
[59] Available at: http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3912685aee37087c425fe17048257e0b0027d4ba/$file/2685.pdf
[60] Available at: http://www.imowa.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

- Limit to Early Entry Capacity Payments (RC_2013_21); and
- Formalisation of the Process for Maintenance Applications (RC_2015_03).

In May 2014, the Minister for Energy rejected RC_2013_09 and RC_2013_10 on the grounds that "the costs to implement the amendments may not be recovered in light of possible reforms emanating from the Electricity Market Review"[61]. On 13 May 2015, RC_2013_20 was also rejected by the Minister[62] as a result of the EMR.

A number of other rule change proposals, including RC_2013_21 and RC_2015_03, have also been deferred by the IMO in light of the EMR. More information on each of these rule change proposals is available on the IMO website[63].

The IMO has also deferred progression of the MREP while it considers the outcomes of the EMR, expecting many of the MREP improvements to ultimately be included in the different EMR work streams.

8.3 Infrastructure developments in the SWIS

8.3.1 Mid-West Energy Project (Southern Section)

Western Power's Mid-West Energy Project (Southern Section) is a 330 kV double circuit transmission line from Neerabup to Eneabba, which was completed and energised on 31 March 2015. On 6 May 2015, Western Power provided the following update:

- the project provides a double circuit 330 kV line (initially operated as one 330 kV and one 132 kV circuit) from Neerabup to Eneabba, where it connects to a 330 kV line already constructed to provide supply to the Karara Mining load. A 330/132 kV terminal station has also been established at Three Springs;
- Western Power is now rearranging the 132 kV circuits between Eneabba, Three Springs and the Three Springs Terminal. This is expected to be complete by July 2015; and
- Western Power is dismantling the existing 132 kV circuit from Eneabba to Three Springs to Koolanooka (Golden Grove tee point). These works are scheduled to start in mid-2015.

Contact Western Power[64] for the latest information on the Mid-West Energy Project or on the process for connection to the network.

8.3.2 Transmission network restrictions on the SWIS

Western Power, in collaboration with the Department of Planning and the Western Australian Planning Commission, maintains a geospatial map viewer called the Network Capacity Mapping Tool (NCMT)[65]. The NCMT is available to the general public and includes a 20-year trend forecast of available capacity at Western Power zone substations on the peak day each year.

[61] Available at: http://www.imowa.com.au/docs/default-source/rules/rule-change/RC_2013_10/rc_2013_10-notice-of-rejection-by-the-minister.pdf?sfvrsn=0.
[62] See http://www.imowa.com.au/home/electricity/rules/rule-changes/rejected/rule-change-rc_2013_20.
[63] Available at: http://www.imowa.com.au/home/electricity/rules/rule-changes.
[64] See http://www.westernpower.com.au/customer-service-contact-us.html.
[65] See http://www.westernpower.com.au/ldd/ncmtoverview.html.

8.3.3 Opportunities for the provision of Network Control Services

The Electricity Networks Access Code 2004 (Access Code) requires Western Power to efficiently minimise costs when implementing a solution to remove a network constraint. Western Power must consider network and non-network options.

The Access Code and Market Rules contemplate the use of network control services as a non-network option. Network control services may be provided by generation and/or DSM.

During the next five years, Western Power expects several areas of the SWIS to require transmission capacity augmentations or network control services. More information is provided in section 6 of Western Power's 2014-15 Annual Planning Report[66]. Proponents who have (or are planning) generation capacity or DSM capable of providing network support are invited to contact Western Power[67].

8.4 Other factors affecting the Western Australian energy market

8.4.1 Renewable Energy Target review

The Commonwealth Government's RET review report was published in August 2014[68]. The report found the economic landscape has shifted significantly since the RET scheme was adopted in 2010. Demand for electricity is declining and forecasts of electricity demand in the future are now much lower. As a result, the RET scheme has contributed to surplus generation capacity across both the NEM and WEM. This is exerting downward pressure on wholesale electricity prices but increasing retail electricity bills by approximately four per cent.

Information on the RET review is available from the Commonwealth Government Department of Prime Minister and Cabinet's website[69].

In May 2015, a 'bi-partisan' agreement was reached to lower the RET from 41,000 GWh to 33,000 GWh, although legislation is yet to be introduced to the Commonwealth Parliament to formalise the revised target[70]. It should be noted that this is an Australia-wide target and does not prescribe a specific or minimum level of renewable energy in the SWIS.

8.4.2 Energy efficiency policy

8.4.2.1 Appliance and equipment energy efficiency

Established in 1992, the Equipment Energy Efficiency (E3) program promotes energy efficiency in Australia through mandatory MEPS and Energy Rating Labels for electrical appliances. MEPS are currently in place for a range of equipment, including commercial, industrial and residential appliances. The Energy Rating Label system encourages consumers to purchase more energy efficient appliances by giving appliances a star rating.

66 Available at: http://www.westernpower.com.au/documents/2014-15_annual_planning_report.pdf.
67 See footnote 37 above for the link.
68 Available at: https://retreview.dpmc.gov.au/ret-review-report-0.
69 Available at: http://retreview.dpmc.gov.au/. A new target of 33,000 GWh has now been confirmed.
70 See http://www.theaustralian.com.au/national-affairs/renewable-energy-target-bipartisan-deal-finally-agreed/story-fn59niix-1227358825957.

The E3 program forecasts MEPS and Energy Rating Labels will save 2,021 PJ of energy between 2014 and 2030. Ninety-two per cent (1,859 PJ or 516.4 TWh) of this saving is expected to be in electricity[71].

8.4.2.2 Energy efficiency in buildings

New residential dwellings or major renovations to existing buildings must meet minimum energy efficiency standards mandated in the National Construction Code. House design is accredited through the Nationwide House Energy Rating Scheme (NatHERS). The minimum star rating a house design must achieve was increased from three stars in 2003 to six stars in 2010[72].

NatHERS estimates a one star house would use around 133 kWh per square metre in a year, while a three-star house would use 63 kWh per square metre. A six-star house would only use 26 kWh per square metre each year[73].

8.4.3 Emissions Reduction Fund

In November 2014, the Australian Parliament passed the *Carbon Farming Initiative Amendment Act 2014*. The Act establishes the Emissions Reduction Fund (ERF), which will provide financial incentives to households, businesses, and local and state governments to reduce carbon emissions.

According to the ERF White Paper[74], the fund will be approximately $2.55 billion, with a target of reducing emissions (measured in terms of carbon dioxide equivalent) by five per cent of 2000 levels by the year 2020.

The Commonwealth Government is developing processes and guidelines for the ERF and is currently seeking comments on the ERF safeguard mechanisms, which will be monitored using the existing National Greenhouse and Energy Reporting database. These mechanisms are expected to be implemented by 1 July 2015.

More information on the ERF is available on the CER website[75].

8.4.4 Australian Renewable Energy Agency and Clean Energy Finance Corporation

The Commonwealth Government has tabled two bills; the Australian Renewable Energy Agency (Repeal) Bill 2014 and the Clean Energy Finance Corporation (Abolition) Bill 2014. Although both bills have failed to garner sufficient parliamentary support to close these agencies, the Commonwealth Government remains committed to abolishing the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC)[76].

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[71] Source: E3 program, *Impacts of the E3 program: Projected energy, cost and emissions savings*, March 2014, available at: http://www.energyrating.gov.au/blog/2014/03/21/e3-impact-projections-report-released/.

[72] Zero stars indicates poor energy performance, while a 10 star rating reflects nearly no energy required to heat or cool the home.

[73] These figures account only for the thermal performance of the house, and not for the household makeup (that is, how many people live in the house and their ages), or the number and type of appliances in use.

[74] Available at http://www.environment.gov.au/system/files/resources/1f98a924-5946-404c-9510-d440304280f1/files/emissions-reduction-fund-white-paper_0.pdf.

[75] Available at: https://www.cleanenergyregulator.gov.au/Emissions-Reduction-Fund/About-the-Emissions-Reduction-Fund/Pages/Default.aspx.

[76] See the Letter dated 27 March 2015, from the Commonwealth Treasurer Joe Hockey to the Chair of the Board of the CEFC. Available at: http://www.cleanenergyfinancecorp.com.au/media/107304/cefc_chairs_response_to_treasurer_and_minister_for_finance_re_2015_cefc_investment_mandate.pdf.

ARENA's and the CEFC's funding, initiatives and programs remain open to applications. The Commonwealth Government has provided assurance that all existing contracts will be honoured.

8.4.5 Commonwealth Government Energy White Paper

In April 2015, the Commonwealth Government published the Energy White Paper, which outlines the Government's framework to deliver competitively priced and reliable energy supply to households, business and international markets.

The Energy White Paper states three main objectives:

- increasing competition to keep energy prices down;
- increasing energy productivity to promote growth; and
- investing in Australia's energy future.

The Commonwealth Government has indicated it will work closely with industry, state governments, and the Council of Australian Governments Energy Council to introduce energy reforms that will seek to:

- improve regulation to increase competition in both electricity and gas;
- reduce barriers imposed on new gas production;
- improve access to gas pipelines;
- remove all cross-subsidies in energy pricing;
- improve price signals for energy use;
- develop a National Energy Productivity Plan;
- improve workforce productivity in the energy sector;
- streamline regulation on energy project approvals; and
- improve the sharing of resources data across jurisdictions.

More information is available on the Commonwealth Government's Energy White Paper website[77].

[77] Available at: http://ewp.industry.gov.au/.

Appendix A. Abbreviations

- ABS – Australian Bureau of Statistics
- AEMO – Australian Energy Market Operator
- ARENA – Australian Renewable Energy Agency
- CEFC – Clean Energy Finance Corporation
- CER – Clean Energy Regulator
- CRC – Certified Reserve Capacity
- DSM – Demand Side Management
- E3 – Equipment Energy Efficiency Program
- 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 Western Australia)
- GWh – gigawatt hour
- IMO – Independent Market Operator
- IRCR – Individual Reserve Capacity Requirement
- kW – kilowatt
- kWh – kilowatt hour
- MEPS – Minimum Energy Performance Standards
- MREP – Market Rules Evolution Plan
- MW – megawatt
- MWh – megawatt hour
- NatHERS – Nationwide House Energy Rating Scheme
- NCMT – Network Capacity Mapping Tool
- NEM – National Electricity Market
- NIEIR – National Institute of Economic and Industry Research
- PoE – probability of exceedance

- PV – photovoltaic
- RCM – Reserve Capacity Mechanism
- RCT – Reserve Capacity Target
- RET – Renewable Energy Target
- SEDO – SWIS Electricity Demand Outlook
- SWIS – South West interconnected system
- TWh – terawatt hour
- WEM – Wholesale Electricity Market

Appendix B. 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 Market Rules (10 per cent PoE peak demand plus reserve margin and 0.002 per cent 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 following steps, consistent with clause 4.5.12 of the Market 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 per cent PoE demand profile, so it is then scaled up to match the 50 per cent PoE peak demand and expected energy consumption forecasts for the relevant year. The peak demand interval is then set at the 10 per cent PoE forecast.

2. Experience from the most recent year with a 10 per cent PoE peak demand event in the SWIS (2003-04) indicates that the 50 per cent 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 per cent PoE peak demand forecast or 10 per cent PoE peak demand forecast was used for the peak 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. The capacity required for more than 24 hours per year, 48 hours per year and 72 hours per year is determined from this curve (clause 4.5.12(a) of the Market Rules).

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 Market 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 per cent PoE peak demand plus reserve margin), then the minimum capacity required to be provided by generation ('minimum generation', clause 4.5.12(b) of the Market Rules) will be the quantity of generation at which either:

    (a) the total unserved energy equals 0.002 per cent of annual energy consumption, thus breaching the Planning Criterion; or

    (b) the spare generation capacity drops below 512 MW[78], thus breaching the criteria for evaluating outage plans.

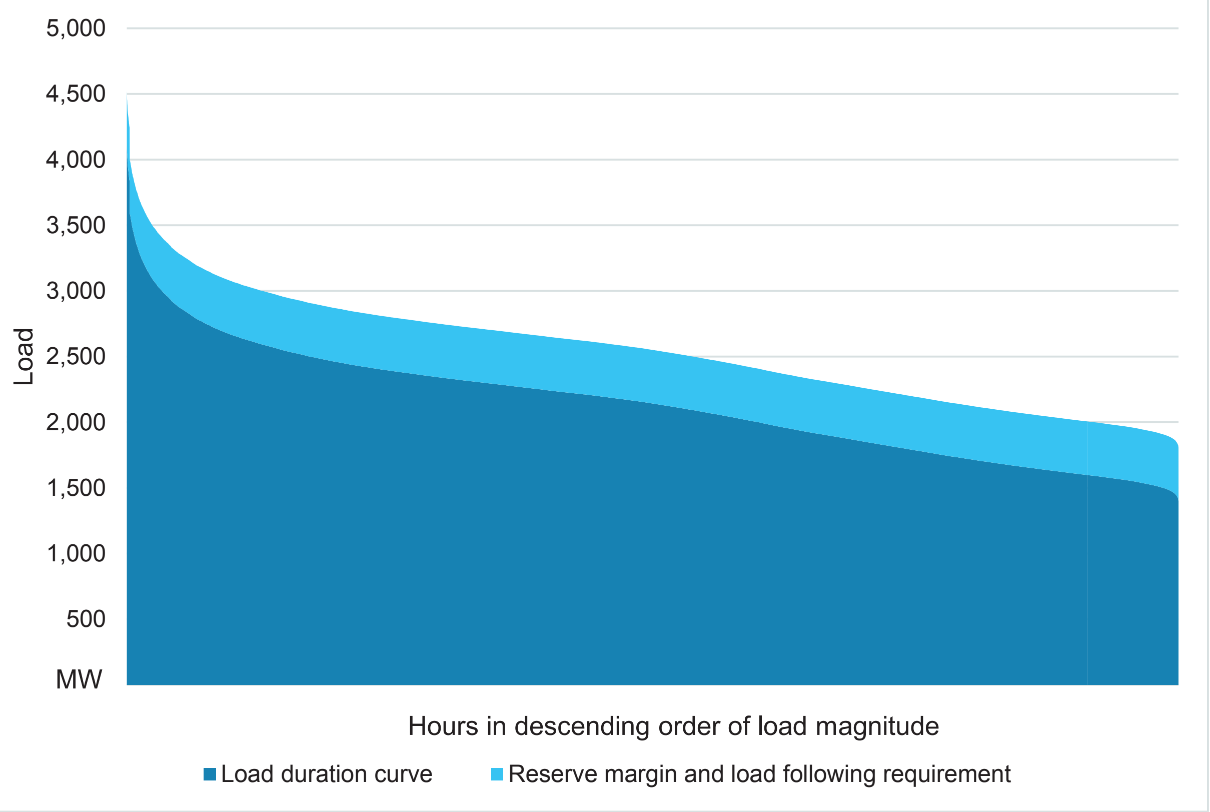
[78] The quantity required to provide ancillary services and satisfy the ready reserve standard, consistent with the information published in the Medium Term Projected Assessment of Supply Adequacy at http://www.imowa.com.au/mtpasa.html.

The capacity associated with each Availability Class is then calculated from the capacity requirement curve and the minimum generation according to the method outlined in clause 4.5.12(c) of the Market Rules, where:

- Availability Class 4 is defined as the RCT less the greater of the capacity required for more than 24 hours and the minimum generation;
- Availability Class 3 is defined as the RCT less the greater of the capacity required for more than 48 hours and the minimum generation, less the capacity associated with Availability Class 4;
- Availability Class 2 is defined as the RCT less the greater of the capacity required for more than 72 hours and the minimum generation, less the capacity associated with Availability Classes 3 and 4; and
- Availability Class 1 is defined as the RCT less the capacity associated with Availability Classes 2, 3 and 4.

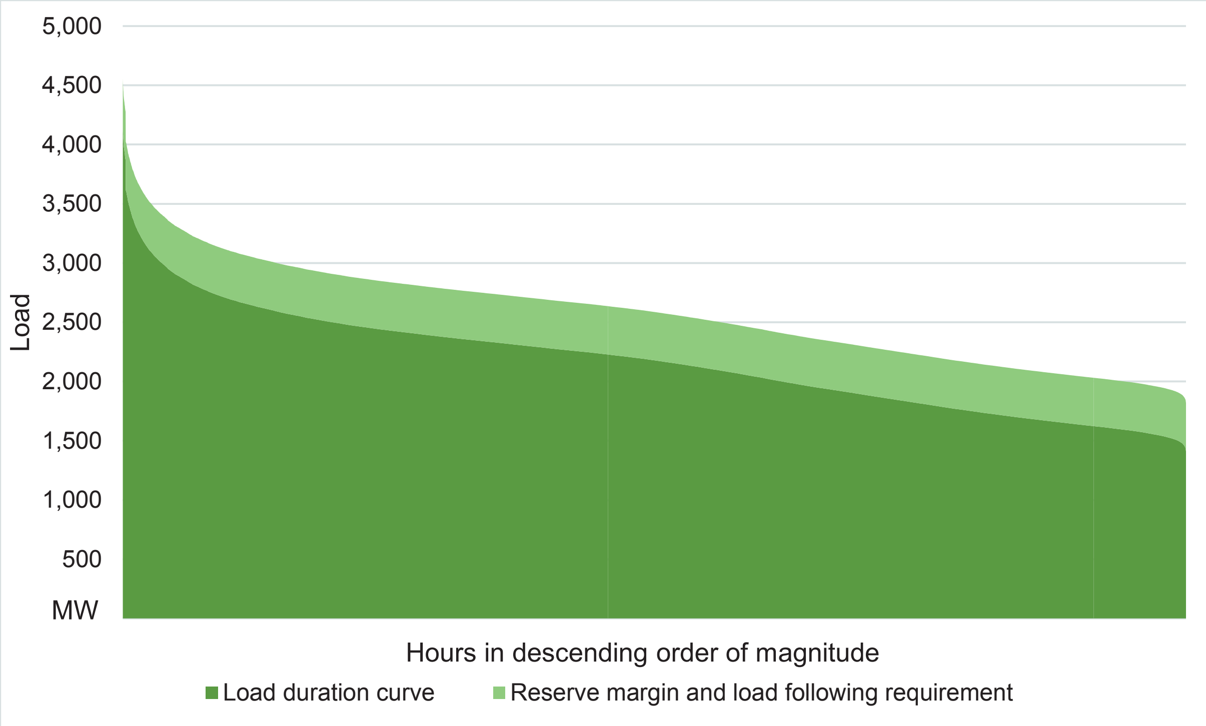
The Availability Curves for the 2015-16, 2016-17 and 2017-18 Capacity Years are shown in Figure B.1, Figure B.2 and Figure B.3 below.

Figure B.1: Availability Curve for 2015-16



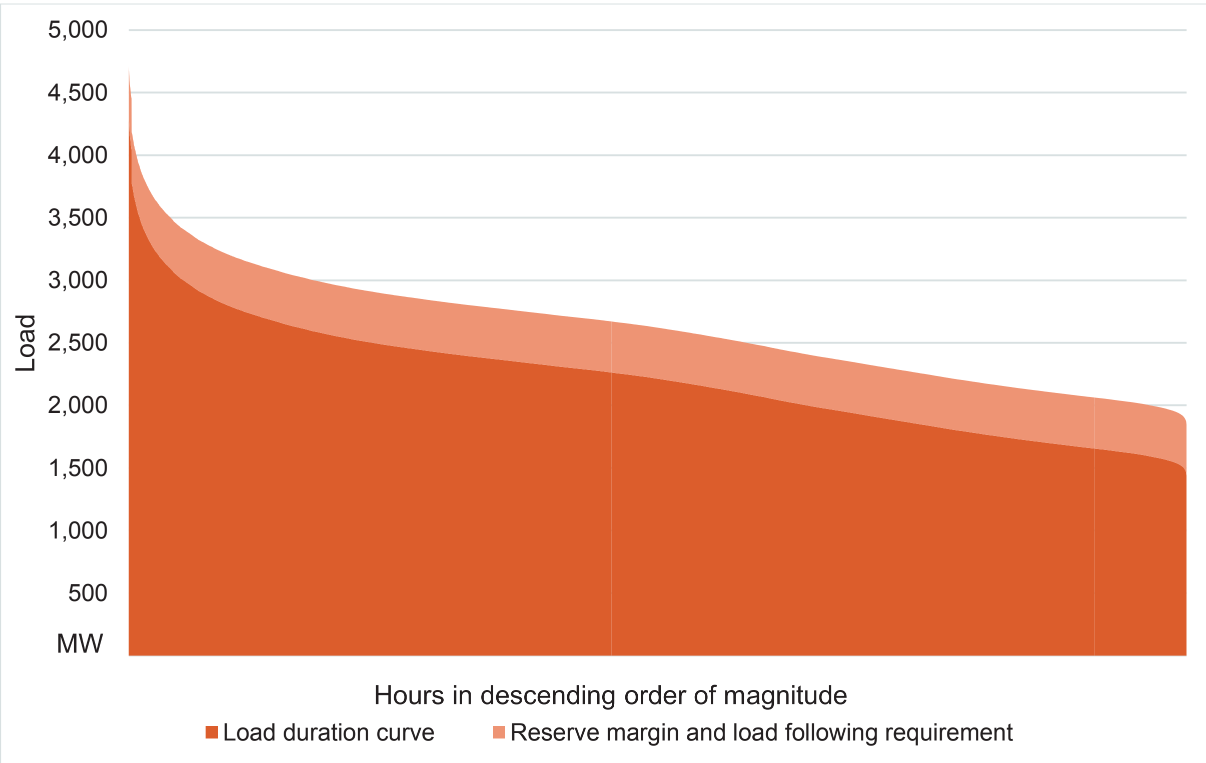
Source: PA Consulting

Figure B.2: Availability Curve for 2016-17



Source: PA Consulting

Figure B.3: Availability Curve for 2017-18



Source: PA Consulting

Appendix C. Forecasts of economic growth

Table C.1: 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		2.3	2.3	2.3
2015-16		2.5	3.4	1.5
2016-17		2.7	3.6	1.8
2017-18		3.1	3.9	2.4
2018-19		2.4	3.5	1.2
2019-20		1.5	2.4	0.3
2020-21		2.2	3.0	1.5
2021-22		2.7	3.6	1.9
2022-23		2.8	3.6	1.9
2023-24		2.6	3.6	1.8
2024-25		2.5	3.6	1.5
Average growth		**2.5**	**3.3**	**1.6**

Source: NIEIR

Table C.2: Growth in Western Australian 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		1.3	1.3	1.3
2015-16		1.9	3.1	0.8
2016-17		3.7	4.9	2.6
2017-18		3.8	4.7	3.1
2018-19		2.6	3.7	1.6
2019-20		1.8	3.0	0.8
2020-21		2.7	4.0	1.6
2021-22		3.4	4.5	2.4
2022-23		3.4	4.6	2.3
2023-24		2.8	4.2	1.6
2024-25		3.3	4.6	2.2
Average growth		**3.0**	**4.1**	**2.1**

Source: NIEIR

Appendix D. Solar photovoltaic system forecasts

Table D.1: Peak demand contribution of solar PV systems

Year	Expected (MW)	High (MW)	Low (MW)
2015-16	140	143	137
2016-17	163	170	157
2017-18	187	196	178
2018-19	210	222	198
2019-20	233	248	219
2020-21	257	274	239
2021-22	280	301	259
2022-23	303	327	280
2023-24	327	353	300
2024-25	350	379	321

Source: IMO

Table D.2: Annual energy contribution of solar PV systems (financial year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2015-16	767	783	751
2016-17	897	929	864
2017-18	1,026	1,075	978
2018-19	1,156	1,221	1,091
2019-20	1,285	1,366	1,204
2020-21	1,415	1,512	1,318
2021-22	1,545	1,658	1,431
2022-23	1,674	1,804	1,545
2023-24	1,804	1,950	1,658
2024-25	1,934	2,096	1,772

Source: IMO

Table D.3: Annual energy contribution of solar PV systems (Capacity Year basis)

Year	Expected (GWh)	High (GWh)	Low (GWh)
2015-16	799	820	779
2016-17	929	965	892
2017-18	1,058	1,111	1,006
2018-19	1,188	1,257	1,119
2019-20	1,318	1,403	1,233
2020-21	1,447	1,548	1,346
2021-22	1,577	1,694	1,459
2022-23	1,706	1,840	1,573
2023-24	1,836	1,986	1,686
2024-25	1,966	2,132	1,800

Source: IMO

Appendix E. Forecasts of summer peak demand

Table E.1: Summer maximum demand forecasts with expected case economic growth

Year	Actual (MW)[79]	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent 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		4,114	3,858	3,634
2016-17		4,149	3,886	3,657
2017-18		4,191	3,924	3,690
2018-19		4,223	3,951	3,713
2019-20		4,244	3,968	3,726
2020-21		4,265	3,984	3,738
2021-22		4,308	4,026	3,779
2022-23		4,343	4,058	3,808
2023-24		4,380	4,093	3,841
2024-25		4,415	4,124	3,869
Average growth (%)		**0.8**	**0.7**	**0.7**

Source: NIEIR

[79] 10 per cent PoE adjusted history

Table E.2: Summer maximum demand forecast with high case economic growth

Year	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2015-16	4,134	3,878	3,653
2016-17	4,177	3,914	3,683
2017-18	4,220	3,952	3,717
2018-19	4,246	3,973	3,734
2019-20	4,257	3,979	3,736
2020-21	4,283	4,001	3,753
2021-22	4,407	4,123	3,875
2022-23	4,471	4,184	3,933
2023-24	4,512	4,222	3,968
2024-25	4,541	4,247	3,990
Average growth (%)	**1.0**	**1.0**	**1.0**

Source: NIEIR

Table E.3: Summer maximum demand forecasts with low case economic growth

Year	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent PoE (MW)
2015-16	4,107	3,852	3,629
2016-17	4,133	3,872	3,643
2017-18	4,167	3,901	3,668
2018-19	4,186	3,917	3,680
2019-20	4,193	3,919	3,679
2020-21	4,202	3,924	3,679
2021-22	4,233	3,954	3,709
2022-23	4,257	3,975	3,728
2023-24	4,282	3,997	3,748
2024-25	4,305	4,017	3,765
Average growth (%)	**0.5**	**0.5**	**0.4**

Source: NIEIR

Appendix F. Forecasts of winter peak demand

Table F.1: Winter maximum demand forecast with expected case economic growth

Year	Actual (MW)	10 per cent PoE (MW)	50 per cent PoE (MW)	90 per cent 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		3,482	3,440	3,398
2016-17		3,529	3,487	3,444
2017-18		3,559	3,515	3,471
2018-19		3,566	3,521	3,477
2019-20		3,583	3,538	3,494
2020-21		3,614	3,568	3,522
2021-22		3,657	3,610	3,564
2022-23		3,701	3,653	3,606
2023-24		3,758	3,709	3,660
2024-25		3,817	3,767	3,716
Average growth (%)		**1.0**	**1.0**	**1.0**

Source: IMO and NIEIR

Appendix G. Forecasts of sent out energy

Table G.1: Forecasts of sent out energy (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	18,453			
2015-16		18,731	18,986	18,541
2016-17		19,015	19,498	18,705
2017-18		19,353	20,010	18,931
2018-19		19,548	20,349	18,970
2019-20		19,625	20,543	18,893
2020-21		19,751	20,907	18,856
2021-22		19,961	21,766	18,904
2022-23		20,256	22,446	19,034
2023-24		20,563	23,010	19,150
2024-25		20,958	23,649	19,358
Average growth (%)		**1.3**	**2.5**	**0.5**

Source: IMO and NIEIR

Table G.2: Forecasts of sent out energy (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		18,801	19,123	18,563
2016-17		19,087	19,629	18,746
2017-18		19,439	20,141	18,989
2018-19		19,597	20,436	18,979
2019-20		19,644	20,592	18,873
2020-21		19,782	20,999	18,847
2021-22		20,015	21,990	18,916
2022-23		20,331	22,621	19,066
2023-24		20,641	23,155	19,179
2024-25		21,059	23,813	19,411
Average growth (%)		**1.3**	**2.5**	**0.5**

Source: IMO and NIEIR

Appendix H. Facility capacities

Table H.1: Registered generation facilities – existing and committed

Participant Name	Facility Name	Capacity Credits (2015-16)
Alcoa of Australia	ALCOA_WGP	24.000
Alinta Sales	ALINTA_DSP_01	16.300
Alinta Sales	ALINTA_PNJ_U1	128.935
Alinta Sales	ALINTA_PNJ_U2	127.528
Alinta Sales	ALINTA_WGP_GT	180.500
Alinta Sales	ALINTA_WGP_U2	180.500
Alinta Sales	ALINTA_WWF	23.934
Blair Fox	BLAIRFOX_KARAKIN_WF1	1.075
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	14.598
Denmark Community Windfarm	DWCL_DENMARK_WF1	1.286
EDWF Manager	EDWFMAN_WF1	16.954
Goldfields Power	PRK_AG	61.400
Griffin Power 2	BW2_BLUEWATERS_G1	217.000
Griffin Power	BW1_BLUEWATERS_G2	217.000
Greenough River	GREENOUGH_RIVER_PV1	4.000
Landfill Gas and Power	KALAMUNDA_SG	1.300
Landfill Gas and Power	RED_HILL	2.875
Landfill Gas and Power	TAMALA_PARK	4.000
Merredin Energy	NAMKKN_MERR_SG1	82.000
Mt. Barker Power Company	SKYFRM_MTBARKER_WF1	0.892
Mumbida Wind Farm	MWF_MUMBIDA_WF1	15.690
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	320.000
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.600
Perth Energy	ATLAS	0.671
Perth Energy	ROCKINGHAM	2.558
Perth Energy	SOUTH_CARDUP	2.393
Synergy	ALBANY_WF1	8.457

Participant Name	Facility Name	Capacity Credits (2015-16)
Synergy	BREMER_BAY_WF1	0.037
Synergy	COCKBURN_CCG1	231.800
Synergy	COLLIE_G1	317.200
Synergy	GERALDTON_GT1	15.400
Synergy	GRASMERE_WF1	5.602
Synergy	KALBARRI_WF1	0.289
Synergy	KEMERTON_GT11	145.500
Synergy	KEMERTON_GT12	145.500
Synergy	KWINANA_GT1	14.900
Synergy	KWINANA_GT2	95.200
Synergy	KWINANA_GT3	95.200
Synergy	MUJA_G5	195.00
Synergy	MUJA_G6	190.00
Synergy	MUJA_G7	211.000
Synergy	MUJA_G8	211.000
Synergy	MUNGARRA_GT1	32.500
Synergy	MUNGARRA_GT2	31.500
Synergy	MUNGARRA_GT3	31.500
Synergy	PINJAR_GT1	32.150
Synergy	PINJAR_GT10	108.700
Synergy	PINJAR_GT11	120.00
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	108.700
Synergy	SWCJV_WORSLEY_COGEN_COG1	107.000
Synergy	WEST_KALGOORLIE_GT2	34.250
Synergy	WEST_KALGOORLIE_GT3	19.000
Synergy	PPP_KCP_EG1	80.400

Participant Name	Facility Name	Capacity Credits (2015-16)
Tesla	TESLA_PICTON_G1	9.900
Tesla	TESLA_GERALDTON_G1	9.900
Tesla	TESLA_NORTHAM_G1	9.900
Tesla	TESLA_KEMERTON_G1	9.900
Tiwest	TIWEST_COG1	32.594
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	2.287
Western Energy	PERTHENERGY_KWINANA_GT1	109.000

Source: IMO

Table H.2: Registered DSM facilities – existing and committed

Participant Name	Facility Name	Capacity Credits (2015-16)	Availability (hr/year)
Alinta Sales	ALINTA_DSP_01	16.300	24
Amanda Australia	AMAUST_DSP_01	9.900	24
Amanda Australia	AMAUST_DSP_02	5.000	24
Amanda Energy	ADERRTL_DSP_01	0.400	24
Cockburn Cement	CCL_DSP_01	10.000	24
EnerNOC Australia	ENERNOC_DSP_01	140.000	24
EnerNOC Australia	ENERNOC_DSP_02	56.000	24
EnerNOC Australia	ENERNOC_DSP_03	50.000	24
EnerNOC Australia	ENERNOC_DSP_04	30.000	24
EnerNOC Australia	ENERNOC_DSP_05	20.000	24
EnerNOC Australia	KANOWNA_DSP_01	11.000	24
Griffin Power	GRIFFIN_DSP_01	20.000	48
La Mancha Resources	LAMANCHA_DSP_01	5.260	24
Premier Power Sales	PREMPWR_DSP_02	24.000	24
Premier Power Sales	PREMPWR_DSP_04	3.000	24
Premier Power Sales	PREMPWR_DSP_05	2.000	24
Premier Power Sales	PREMPWR_DSP_06	3.000	24
Synergy	SYNERGY_DSP_01	10.000	32
Synergy	SYNERGY_DSP_02	5.000	32
Synergy	SYNERGY_DSP_03	5.000	32
Synergy	SYNERGY_DSP_04	42.000	48
Synergy	SYNERGY_DSP_05	20.000	32
Water Corporation	WATERCORP_DSP_01	21.000	24
Water Corporation	WATERCORP_DSP_02	18.000	24
Water Corporation	WATERCORP_DSP_03	24.000	24

Source: IMO

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