NATIONAL ELECTRICITY FORECASTING REPORT OVERVIEW

FOR THE NATIONAL ELECTRICITY MARKET

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document in connection with its national transmission planning and operational functions for the National Electricity Market. This report is based on information available as at 1 June 2015 unless otherwise specified.

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EXECUTIVE SUMMARY

This 2015 National Electricity Forecast Report (NEFR) overview is a snapshot of operational consumption and maximum demand[1] forecasts in the National Electricity Market (NEM) over the short term (2014–15 to 2017–18), in a medium consumption scenario.[2] Key forecasts are outlined below.

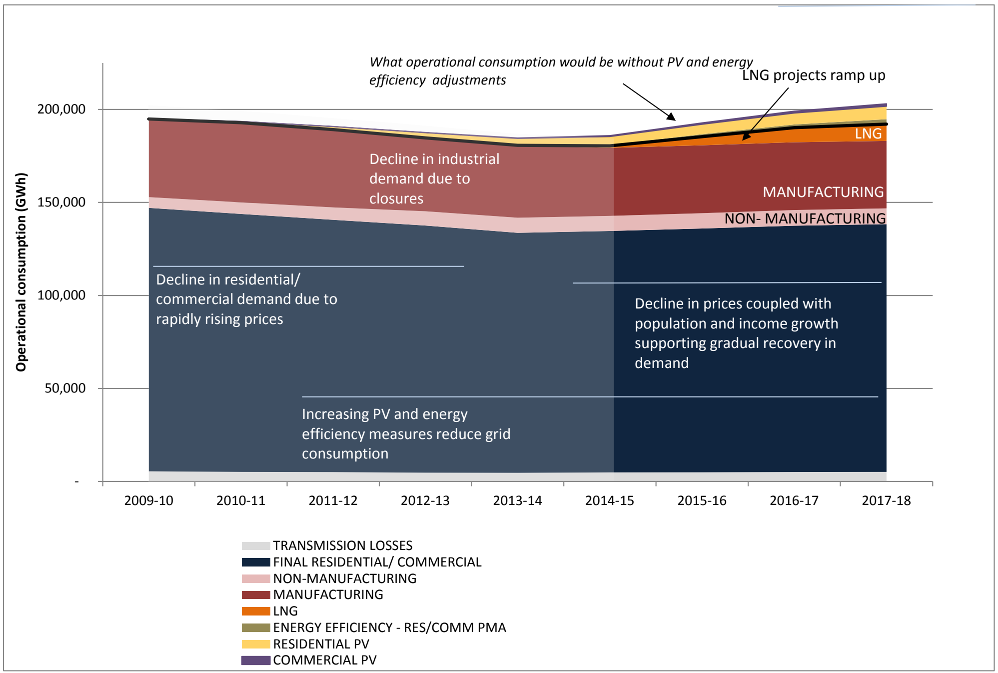
Annual operational consumption

Operational consumption plateaus – Operational consumption has been falling since 2008–09, when it reached its peak of 194,971 gigawatt hours (GWh). In 2014–15, operational consumption is expected to be comparable to the previous year (180,390 GWh, compared with 180,653 GWh in 2013–14.) This is attributed to the ramp-up of Liquefied Natural Gas (LNG) projects in Queensland, and recovery in residential and commercial consumption in New South Wales, which offset the closure of the Point Henry aluminium smelter in Victoria.

LNG leads recovery – Operational consumption is forecast to recover over the next three years by around 2.1% per annum. This is attributed to LNG developments in Queensland (1.5%), population growth, and demand elasticity in response to changing retail electricity prices (0.6%). This is partially offset by continued energy efficiency initiatives. Industrial consumption (excluding LNG) is forecast to be flat despite the phased closure of vehicle manufacturing. By the end of the three year period, NEM operational consumption is forecast to be around 192,131 GWh.

Figure 1 summarises key points about operational consumption in the NEM. It shows the impact of the continued uptake of rooftop photovoltaic (PV) – AEMO has modelled residential and commercial PV separately for the first time in the 2015 NEFR – and energy efficiency measures.

Figure 1 NEM annual operational consumption to 2017–18



[1] Operational consumption refers to electricity used over a period of time that is supplied by the transmission grid. Maximum demand is the electricity used at a specific time, measured over a 30-minute period.

[2] Other forecasts for the medium-term (2017–18 to 2024–25) and long-term (2024–25 to 2034–35), forecasts based on low and high consumption scenarios, and detailed summaries for each NEM region, are in the accompanying report, Detailed Summary of 2015 Electricity Forecasts.

Maximum demand

Queensland forecast to exceed record maximum demand – Queensland's historic maximum demand was 8,897 megawatts (MW) in 2009–10. Even under milder weather conditions, Queensland is forecast to exceed its historic record in 2015–16, due to the ramp-up of LNG operations.

Rooftop PV continues to push maximum demand to later in the day – Rooftop PV has shifted the maximum demand time in South Australia from 17:30 to 18:30. Queensland and Victoria are expected to follow a similar trend, with maximum demand occurring at later times.

Minimum demand

South Australia sees impact of rooftop PV – In 2014–15, South Australia recorded an operational demand of 790 MW at 13:30 on 26 December 2014, South Australia's lowest operational demand since NEM commencement and lower than any evening demand in South Australia. At this time, rooftop PV output was 445 MW. Based on the continued uptake of rooftop PV and its contribution to supply, by 2023–24, rooftop PV is expected to offset 100% of demand generated from the grid. AEMO is investigating this scenario and the possible consequences of such an event on system security and reliability.

ABOUT THE 2015 NEFR

The National Electricity Forecasting Report (NEFR) provides independent electricity consumption forecasts over a 20-year outlook period for the National Electricity Market (NEM), and for each NEM region.[3]

The forecasts are developed based on three scenarios – low, medium and high consumption – that reflect different levels of consumer engagement and economic growth. The medium scenario is considered the most likely, and is the focus of this report.

In 2015, the following suite of NEFR resources is available:

Resource	Description	Available
2015 National Electricity Forecasting Report Overview	This document. An overview of the forecasts for the NEM medium scenario over the short term (2014–15 to 2017–18).	June 2015
Detailed Summary of 2015 Electricity Forecasts	A detailed summary of forecasts for the NEM and each individual NEM region for the 20-year outlook period for the medium scenario, and a comparison with the low and high consumption scenarios.	June 2015
Forecasting Dynamic Interface http://forecasting.aemo.com.au/	A web-based portal where users can view graphs and key results, apply their own filters and download NEFR data.	June 2015
Emerging Technologies Information Paper	An outline of AEMO's initial modelling of the impact of battery storage, electric vehicles and fuel switching in the 20-year NEFR outlook period.	June 2015
Forecasting Methodology Information Paper	A detailed report on the methodology and assumptions for each component of the NEFR.	July 2015
Supplementary Reports	Consultant reports related to the NEFR, and additional information.	From June 2015

Key definitions

AEMO forecasts are reported as:

- **Annual operational consumption:** electricity used by residential, commercial, and large industrial consumers drawn from the electricity grid, including transmission losses.[4] It is measured in gigawatt hours (GWh) and the forecasts are presented on a "sent-out"[5] basis.
- **Operational maximum (minimum) demand:** the highest (lowest) level of electricity drawn from the transmission grid at any one time in a year measured on a daily basis, averaged over a 30 minute period. It is measured in megawatts (MW) and the forecasts are presented "as generated".[6]

Operational consumption = Residential and commercial consumption / Large industrial consumption / Transmission losses

Residential and commercial consumption = Underlying consumption − Rooftop PV − Energy efficiency adjustment

Large industrial consumption = Underlying consumption − Embedded generation

Underlying consumption refers to everything consumed on site, and can be provided by localised generation from rooftop PV and embedded generators, or by the electricity grid.

Operational demand = Operational demand from all consumers + Energy used in transmission and distribution + Auxiliary loads

[3] New South Wales includes the Australian Capital Territory.
[4] Supplied by scheduled, semi-scheduled and significant non-scheduled generating units. Refer to AEMO's definitions here.
[5] Measured at the connection point between the generating system and the network.
[6] Measured at the terminals of a generating system.

Key improvements in the 2015 NEFR

Table 1 shows key improvements that AEMO implemented in the 2015 NEFR, based on feedback from the 2014 report. Additional forecasts and tools AEMO has developed, for this report and supporting documents, are listed below the table.

Table 1 Key improvements in the 2015 NEFR

Sector	Improvements
Residential and commercial	• Factored in different drivers for each region to reflect regional market differences. • Modelled asymmetric price elasticities where possible, capturing different consumer responses to price increases and decreases.
Rooftop photovoltaic (PV)	• Forecast residential and commercial PV separately for the first time, to capture the different drivers in each sector. • Included commercial PV projects greater than 100 kilowatts (kW) in the modelling for the first time.
Energy efficiency	• Incorporated updated data on federal programs. • Included new data from New South Wales schemes.
Large industrial loads	• Increased the sample size of large industrial customers surveyed, from 93 to 115. • Applied an economic sectoral approach in the medium to longer term forecasts.
Maximum demand	• Directly incorporated large industrial load into the model. • Modified the model to include temperature and day-of-week interactions, by modelling the demand for workdays and non-workdays separately. • Improved the methodology for estimating the impact of energy efficiency.

Operational minimum demand

In 2015, for the first time, operational minimum demand forecasts have been developed for South Australia to investigate the impact on the network of residential and commercial rooftop PV. South Australia was chosen as the first region because it has the highest penetration of rooftop PV. AEMO intends to develop minimum demand forecasts for the other NEM regions.

Emerging technologies

While this report focuses on short-term forecasts, the NEFR estimates operational consumption and maximum demand over a 20-year horizon. In this timeframe, new technologies are likely to emerge in the market, and these may have an impact on operational consumption and/or maximum demand. The strong uptake of rooftop PV is a recent example of how a technology can change the market.

The 2015 NEFR forecasts do not explicitly include emerging technologies and trends such as battery storage, electric vehicles and fuel switching.

Instead, AEMO has developed a set of forecasts and user tools that demonstrate the potential impact of emerging technologies on operational consumption and maximum demand forecasts. These will be released as a supplementary Emerging Technologies Information Paper in June 2015.

CONTENTS

TABLES

FIGURES

CHAPTER 1. NEM ANNUAL OPERATIONAL CONSUMPTION

1.1 Overview of forecasts

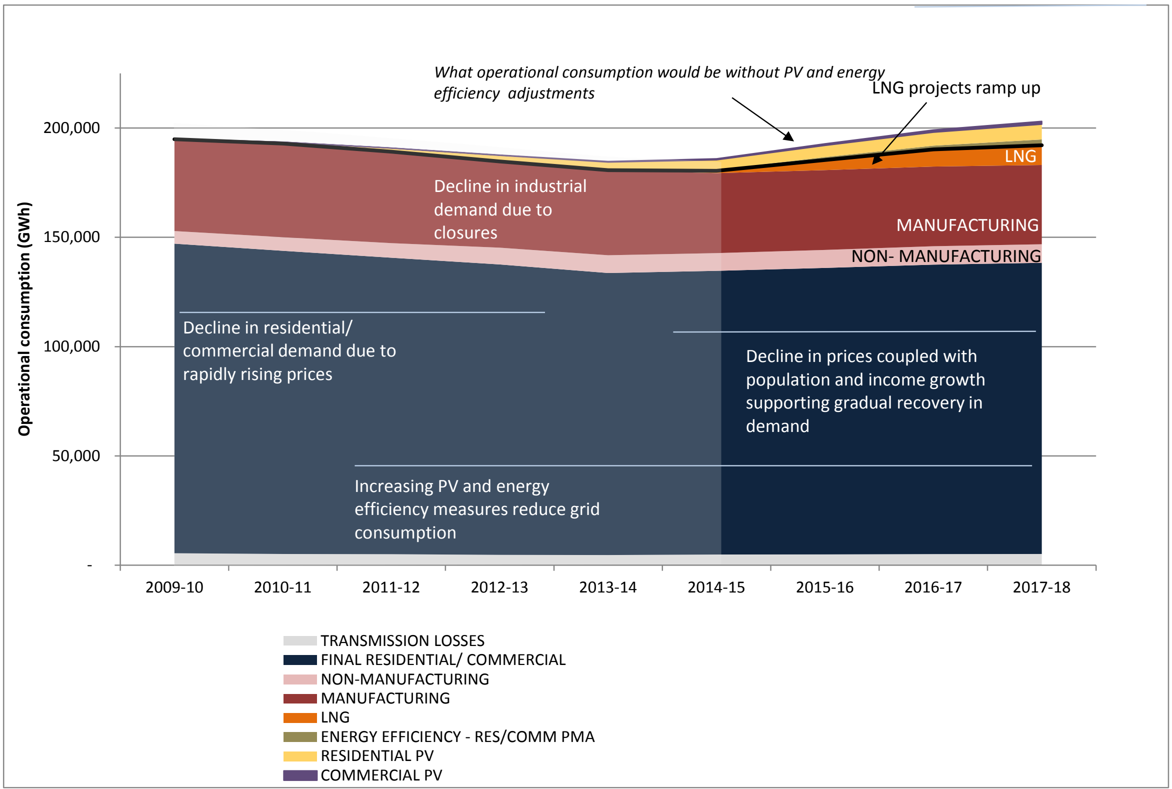
NEM annual operational consumption by sector is shown in Figure 2 below.

In the past year, consumption was relatively flat, decreasing by 0.1% from 180,653 GWh in 2013–14 to an estimated[7] 180,390 GWh in 2014–15.

Across the NEM, in the short term, AEMO is forecasting:

- Operational consumption to recover from 180,390 GWh to 192,131 GWh, an average annual increase of 2.1%, driven mainly by the ramp-up of LNG projects in Queensland.
- Excluding LNG, an average annual increase of 0.7%.
- A slight recovery in consumption in the residential and commercial sector[8], mainly due to population growth, with continued decline in consumption per capita.
- Continued uptake of energy efficiency savings and rooftop PV installations, meaning a partial offset of underlying consumption.

Figure 2 NEM operational consumption by key component to 2017–18



7 The 2014–15 value is based on nine months of actual data from July 2014 to March 2015 and three months of forecast data. The last quarter of data is not available until July, after the release of this report. Also, rooftop PV is based on six months of actual data and six months of forecast data.

8 Throughout the NEFR, "residential and commercial" includes light industrial consumption.

1.2 Comparison to the 2014 NEFR

As shown in Figure 3 below, the medium forecast for operational consumption is higher than the published 2014 NEFR medium forecast. It is, in fact, closer to the 2014 high consumption forecast.

The changes in the 2015 NEFR forecasts are due to:

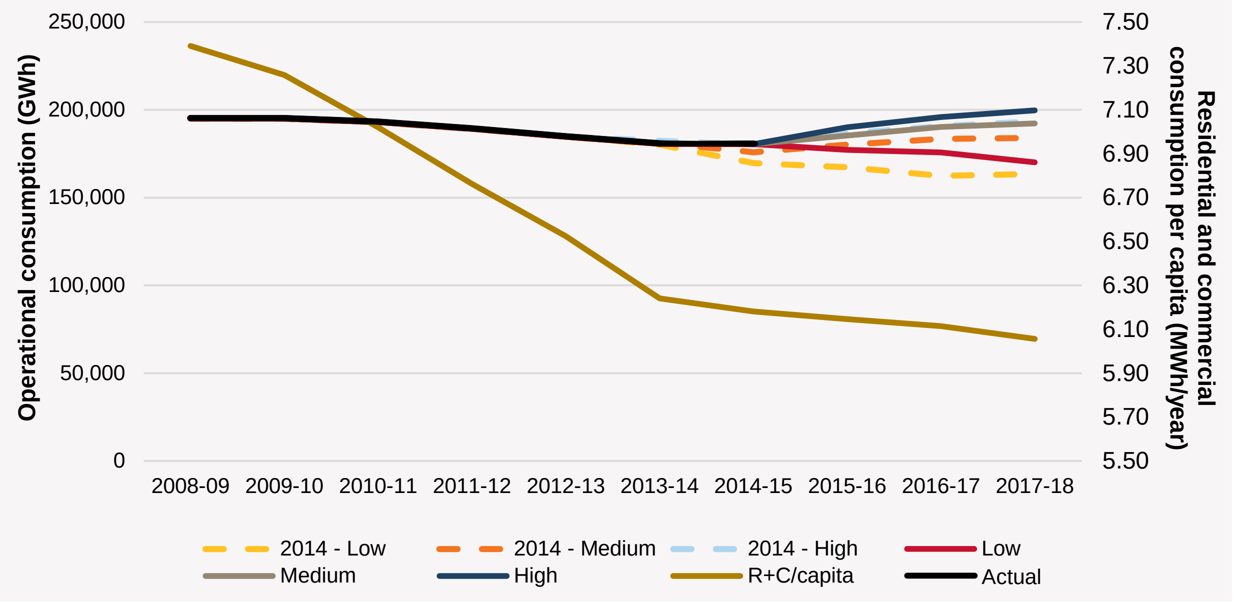
- A recovery in underlying consumption in the residential and commercial sector, driven by a fall in electricity prices after the repeal of the carbon price. Per capita consumption is falling more slowly than in the last two years, and more slowly than AEMO forecast in the 2014 NEFR:
  - In the 2014 NEFR, per capita consumption was forecast to decrease by 4.4% from 2014–15 to 2017–18, to 5.9 megawatt hours (MWh) per year.
  - The 2015 NEFR forecasts show a smaller decline, with per capita consumption reducing by only 2% from 2014–15 to 2017–18, to 6.1 MWh/year.
- A decrease in forecast rooftop PV, which increases consumption drawn from the grid. This update is due to an overestimate of uptake over the last year, and separate modelling in the 2015 NEFR of rooftop PV in the residential and commercial sectors.
- Revisions to the estimated electricity used per terajoule of LNG produced, which have increased forecast LNG consumption.[9] (The estimated volume of exports remains the same.)
- Recovery in industrial consumption in some sectors, due to factors including the fall in the Australian dollar.

1.3 Overview of historical operational consumption

As shown in Figure 3, operational consumption has been declining in the NEM since 2008–09.

In the five years to 2014–15, operational consumption declined by 14,461 GWh to an estimated 180,390 GWh, an average annual decline of 1.5%.

Figure 3 NEM operational consumption forecasts to 2017–18



[9] Converting raw gas to LNG requires energy across the supply chain. While the LNG projects source much of their electricity from embedded generators, they also consumer electricity from the grid. See Lewis Grey Advisory, Projections of Gas and Electricity Used in LNG, 15 April 2015 for more details.

Residential and commercial consumption decreased in this period due to drivers including:

- Rapidly rising electricity prices.
- Uptake of rooftop PV in all regions, supported by federal and state government incentive schemes.
- Implementation of energy efficiency schemes, supported by government incentives, and other energy efficiency savings through the replacement of aging appliances.
- Greater customer awareness of energy usage, and changes in behaviour.

From 2010–11 there has been a net decline in industrial consumption, with some sectors experiencing increases and others decreases.

Increased consumption from the non-manufacturing sector was driven by:

- Expansion in coal mining in New South Wales and Queensland.
- Growth in metal ore mining in New South Wales and South Australia.
- Testing of new desalination plants in South Australia and Victoria.

This increase in the non-manufacturing sector was offset by declining consumption in the manufacturing sector, attributable to:

- The closure of two aluminium smelters, Kurri Kurri in New South Wales in 2012 and Point Henry in Victoria from 2014.
- Curtailment of steel-making capacity, including at the Port Kembla steel mill in New South Wales.
- Decline in consumption from vehicle manufacturers in Victoria and South Australia.
- A net decline in other manufacturing sectors.

The decline in operational consumption across the NEM has slowed in the last two years, decreasing by only 0.1% from 2013–14 to 2014–15.

The residential and commercial sector saw a slight recovery in consumption, driven by:

- The repeal of the carbon price, lowering electricity prices, which contributed to increased underlying consumption.
- A slowdown in uptake of rooftop PV in most regions, which reduced the offset in consumption drawn from the grid.

There is also a possibility that consumers have been changing their behaviour, as suggested by the almost flat per capita consumption over the last year. As consumers implement more energy efficiency measures, they see a diminishing margin of return on their efforts and so have less incentive to continue changing their behaviour. Indeed, a key finding of the recent Queensland Household Energy Survey 2014 was that customers were becoming less active in their efforts to reduce electricity consumption and were no longer responding to “bill shock”.[10]

The resulting flattening of residential and commercial consumption has been accompanied by the commencement of LNG operations in Queensland, which also offset the decline in consumption in the manufacturing sector noted above.

1.4 Residential and commercial consumption forecasts

Key points

- In the NEM, forecast residential and commercial consumption per capita continues to decline, with population growth a key driver for any increase in consumption. However, this rate of decline has slowed compared to recent years, and in Tasmania and Victoria it is relatively flat.

[10] https://www.ergon.com.au/__data/assets/pdf_file/0003/205608/Queensland-Household-Energy-Survey-Summary-Report-2014.pdf

- This indicates a change in consumer behaviour in response to a fall in prices and an increase in average income per capita, as well as potentially less active energy management.

Methodology

AEMO forecasts the residential and commercial sectors together. Forecasts in this sector are influenced by:

- Underlying trends in consumption from households and businesses.
- The impact of factors that reduce the amount of electricity sourced from the grid, including the uptake of localised technologies such as rooftop PV, and energy efficiency measures.

Underlying consumption refers to the electricity used by the residential and commercial sector whether or not it is drawn from the electricity grid. It is driven by factors including income (represented as Gross State Product (GSP)), population, electricity prices, and weather.[11]

To determine consumption drawn from the grid, AEMO offsets the underlying consumption with projected contributions from rooftop PV and additional energy efficiency measures not already captured in the underlying consumption.

AEMO forecasts residential and commercial consumption in two stages:

1. It develops forecasts per capita, to capture underlying usage trends by removing the impact of population growth.
2. It uses population forecasts to derive the total consumption forecasts.

Overview of NEM forecasts and drivers

As shown in Figure 3, per capita consumption has been declining steadily since 2008–09, impacted by the drivers identified above.

In 2012–13, there was a sharp decrease in the rate of decline in per capita consumption. This was mainly attributable to the end of state solar premium feed-in-tariff schemes, resulting in slower (but still sizable) growth in uptake of rooftop PV. Per capita consumption continues to decline at this slower rate over the forecast period.

Consumption in the residential and commercial sector is forecast to recover from 129,743 GWh to 133,163 GWh (0.9% annually) over the short term:

- Although consumption is recovering, per capita consumption continues to decline, indicating population growth is a key driver of this increase.
- Underlying consumption is recovering due to a forecast decline in electricity prices in most regions, and projected growth in income per capita.[12]
- Rooftop PV continues to display strong growth (18% annually), with continued installations in both the residential and commercial sectors:
  - Residential PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability of PV. Programs that incentivised the historical uptake of PV helped to establish a local industry and drove a reduction in PV technology and installation costs.
  - Uptake of PV in the commercial sector has been more recent, and driven by a combination of federal and state government incentive programs such as the Clean Technology Investment Fund and SRES, the continued decrease in PV costs making the business case more attractive, a continuing focus by businesses on sustainability initiatives, and an increased marketing push by installers into this sector.

[11] AEMO modelling used unpublished GSP data provided by KPMG, and population data from the Australian Bureau of Statistics.
[12] See Frontier Economics, Electricity market forecasts: 2015, April 2015 for explanation of price forecasts.

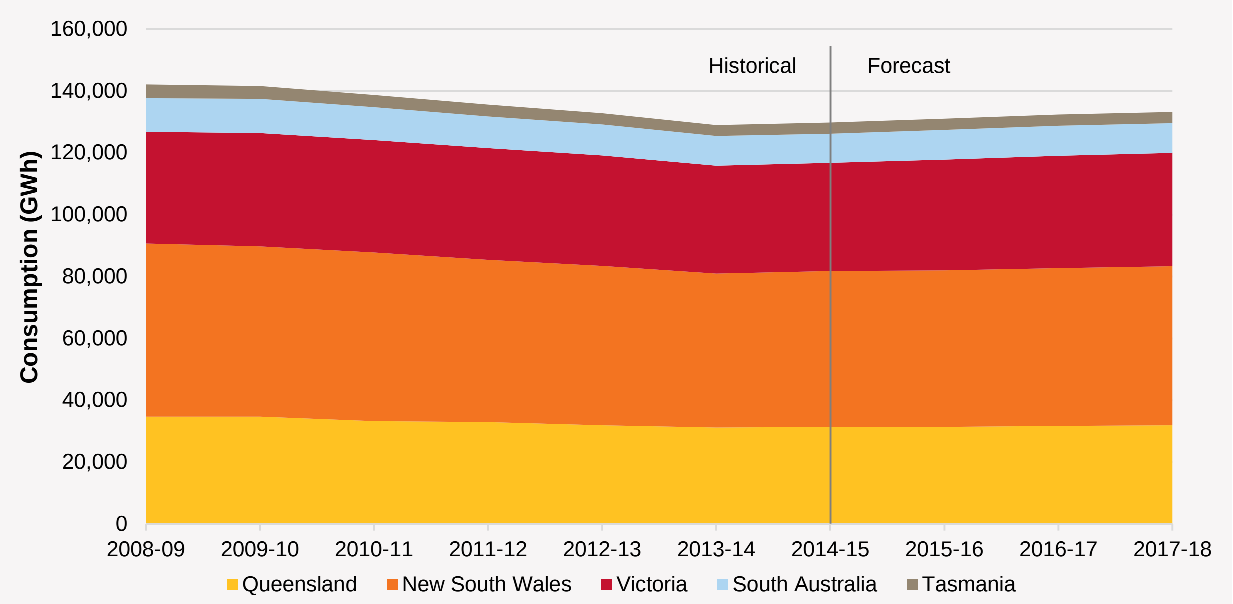
- Total energy efficiency savings, while lower than in recent years, increase strongly (10% annually), driven by government schemes.

Overview of state forecasts

Figure 4 shows consumption by state.

New South Wales (including the ACT), Victoria and Queensland are the largest contributors to NEM residential and commercial consumption, representing 38.9%, 26.9% and 24.2% of consumption respectively in 2014–15. In the same year, South Australia represented only 7.3% and Tasmania 2.8% of consumption. This means trends in the three largest regions drive changes in overall NEM residential and commercial consumption.

Figure 4 Residential and commercial consumption by state to 2017–18



The drivers of underlying consumption in each region are:

- In Queensland, population grows 2% annually while GSP per capita increases at an annual rate of 1.3%. The increase in electricity prices is moderated from 2013–14, but still continues.
- In New South Wales, population and GSP per capita both grow steadily over the forecast period (1.3% annually). Electricity prices have fallen over the last year due to the repeal of the carbon price, and they are forecast to fall in the short term based on expected reduction in network tariffs.[13]
- In South Australia, population and GSP per capita both grow at an average annual rate of 1.0%. Electricity prices continue the decline that began in 2013–14.
- In Victoria, population grows at 1.8% annually, while GSP per capita has a slower annual growth (0.8%). Electricity prices decline in 2014–15 and 2015–16, then remain relatively stable.
- In Tasmania, population grows over the forecast period (0.6% annually), and GSP per capita recovers from a recent plateau and has an annual growth of 1.8%. Electricity prices have declined since 2012–13, and are forecast to continue declining to 2017–18.

[13] The electricity forecasts were based on the draft price determination by the Australian Energy Regulator. See Frontier Economics, Electricity market forecasts: 2015, April 2015. Since then, the AER released its final determination http://www.asx.com.au/asxpdf/20150430/pdf/42y72pwpypwkbs.pdf. This decision is subject to appeal.

As outlined in Table 2 below, the continued uptake of rooftop PV and energy efficiency savings offset trends in underlying consumption. In some regions, this offset negates any recovery in underlying consumption, while in others, such as Victoria, it only partially moderates the recovery in underlying consumption. As noted above, Victoria constitutes a large proportion of the NEM residential and commercial load, and so is responsible for much of the sector's increase in consumption across the NEM.

Table 2 Residential and commercial consumption by state over the period 2014–15 to 2017–18

	Forecast (GWh)	Average annual change	Per capita consumption (MWh/year)	Drivers
Queensland	31,414 to 31,920	0.5%	6.5 to 6.2	The recovery in underlying consumption is moderated by the continued uptake of rooftop PV and energy efficiency. Overall consumption remains relatively flat.
New South Wales	50,414 to 51,390	0.6%	6.3 to 6.2	Rooftop PV and energy efficiency offset around 70% of the recovery in underlying consumption, which is driven by a recent fall in electricity prices.
South Australia	9,436 to 9,559	0.4%	5.5 to 5.4	The recovery in underlying consumption is offset by continued uptake of rooftop PV and energy efficiency, tempering any net change in consumption.
Victoria	34,903 to 36,665	1.7%	5.87 to 5.85	Recovery in underlying consumption due to a recent fall in electricity prices is offset only partially by the continued uptake of rooftop PV and energy efficiency.
Tasmania	3,567 to 3,629	0.5%	6.90 to 6.88	Growth in income and declining electricity prices lead to recovery in underlying consumption that is offset by the continued uptake of rooftop PV, tempering any net change in consumption.

Table 3 shows the increase in rooftop PV uptake in both the residential and commercial sectors. The 2015 NEFR is the first time that AEMO has modelled these sectors separately. This allows the forecasts to capture the different drivers of uptake in each sector, in particular the different signals for investment decisions.

Table 3 Rooftop PV forecasts by state over the period 2014–15 to 2017–18

	Residential[14] PV forecasts (GWh)	Commercial PV forecasts (GWh)
Queensland	1,779 to 2,892	115 to 299
New South Wales	1,012 to 1,464	204 to 490
South Australia	753 to 1,005	109 to 284
Victoria	876 to 1,429	94 to 263
Tasmania	99 to 159	12 to 28

New South Wales currently has the highest installed capacity of small commercial PV, and accounts for 35% of the new installations in this sector over the short term. Queensland, Victoria and South Australia each account for approximately 20% of new installations, and Tasmania only 2%. Despite this, New South Wales still has the lowest penetration of rooftop PV in the NEM, relative to its total consumption.

Queensland displays the highest growth in the residential sector, with an additional 1,113 GWh of generation forecast in 2017–18.

[14] Residential PV systems are defined to be those less than 10 kW.

Differences in uptake in each region occur because of the different electricity prices and solar resources. See the 2015 Forecasting Methodology Information Paper for more detail.

1.5 Industrial consumption forecasts

Key points

- Consumption by the Queensland LNG projects is forecast to increase from 1,063 GWh to 9,075 GWh (104.4% annually) as all three projects become operational and reach estimated production capacity in 2017–18.
- Non-LNG industrial consumption is expected to remain flat, from 44,674 GWh in 2014–15 to 44,736 GWh in 2017–18 (0.05% annually). Consumption in Queensland and New South Wales remains relatively flat, while the closure of several large consumers sees a decline in consumption in Victoria, offset by increases in Tasmania and South Australia.

Methodology

Industrial loads are defined as loads with typical demand greater than 10 MW.[15] This year AEMO has separated these loads into two categories, ‘manufacturing’ and ‘other’, based on the Australian and New Zealand Standard Industrial Classification (ANZSIC) code.

Short-term forecasts for this sector are developed in consultation with industrial sites via survey and interviews. This provides AEMO with the most accurate information available to determine the short-term outlook for these loads. For further information see the 2015 Forecasting Methodology Information Paper.

Overview of state forecasts

Figure 5 shows the breakdown of forecast industrial consumption by state, while Table 4 outlines the key drivers and forecasts for each state.

Queensland and New South Wales comprised 66% of total NEM industrial consumption in 2014–15, with the growth in LNG projects seeing Queensland constituting 43% of the load in 2017–18. The decline in Victorian industrial consumption is evident, as it falls below Tasmanian industrial consumption from 2015–16.

[15] This refers to customers whose demand is greater than 10 MW for at least 10% of the previous year.

Figure 5 Industrial consumption by state to 2017–18

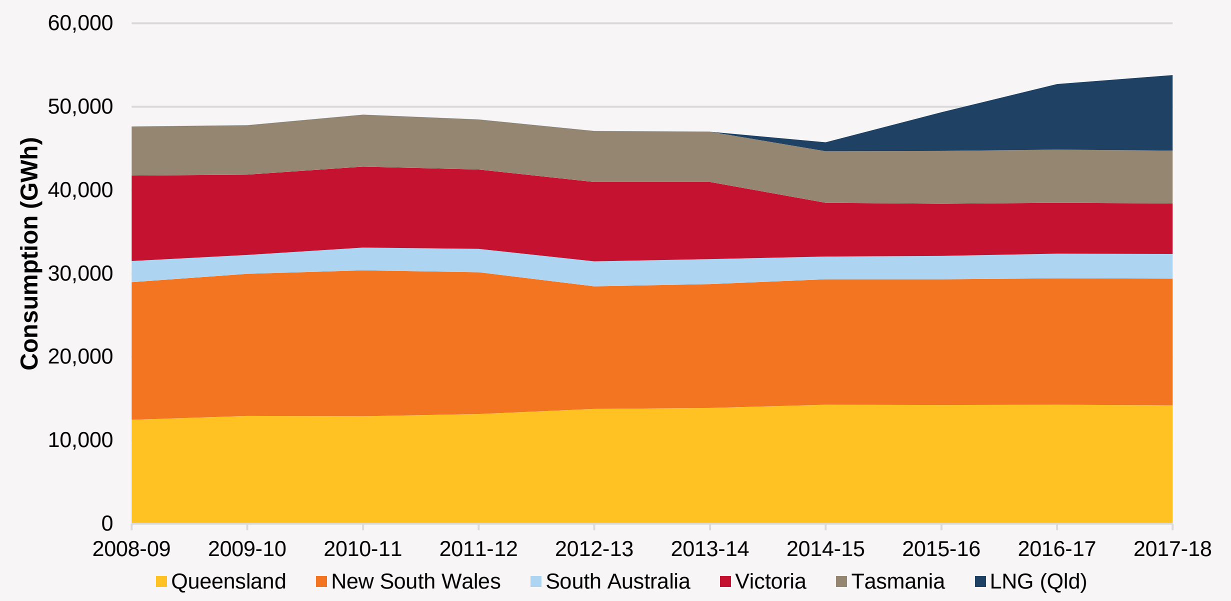


Table 4 Industrial consumption forecasts by state over the period 2014–15 to 2017–18

Region	Forecast (GWh)	Average annual rate of change	Drivers
Queensland	15,345 to 23,292	14.9%	The increase in consumption is driven by the ramp-up of the three LNG projects, which all reach full production by 2017-18. Excluding LNG, industrial consumption is expected to decrease at an average annual rate of 0.2%, mainly attributable to the closure of the Bulwer Island refinery.
New South Wales	15,045 to 15,191	0.3%	Consumption remains relatively flat, with increases driven by expansion at a gold mine offsetting any decline due to the closure of the Kurnell refinery in 2015.
South Australia	2,728 to 2,934	2.5%	Return of Port Pirie smelter to pre-2014 consumption levels following completion of redevelopment of the facility.
Victoria	6,432 to 6,061	-2.0%	Decline in manufacturing sector including closure of vehicle manufacturing plants and the final closure of Point Henry in July 2014.
Tasmania	6,187 to 6,333	0.8%	Full utilisation of plants by major customers to take advantage of recent plant improvements and/or the lower Australian dollar. Bell Bay aluminium smelter increases consumption from July 2015[16].

Over the short term, recovery in NEM industrial consumption is due to the growth in consumption from Queensland LNG projects. Excluding LNG, Queensland is similar to New South Wales in displaying little movement in industrial consumption.

The decline in Victoria is offset partially by increases in South Australia and Tasmania, with much of the decline in consumption from Victoria's industrial sector occurring in 2014–15.

[16] http://bellbayaluminium.com.au/client-assets/documents/Media%20Releases/070514-media-release-bell-bay-aluminium-announcement.pdf

CHAPTER 2. MAXIMUM DEMAND

Operational maximum demand occurs in summer in all regions except Tasmania, which is winter peaking.

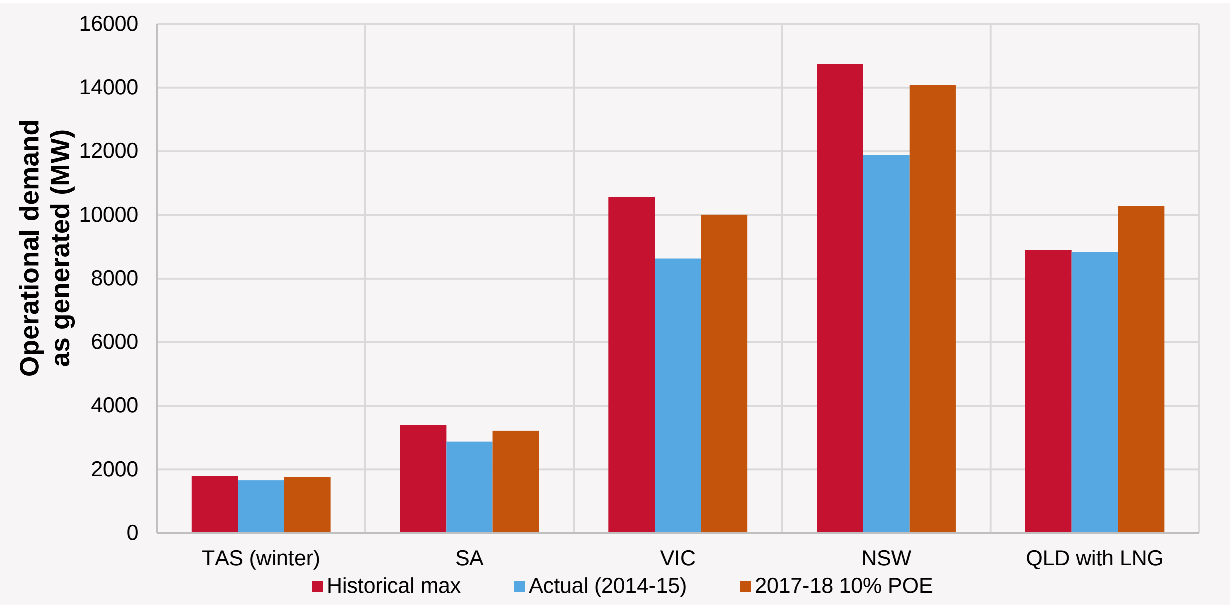
Table 5 shows the actual peak demand values for the last three years, and the forecast 10% probability of exceedance (POE)[17] maximum demand over the short term, for each region.

Table 5 Actuals and 10% POEs for operational maximum demand (MW)

Summer	Queensland	New South Wales	South Australia	Victoria	Winter	Tasmania	
2012–13	8,479	13,892	3,095	9,774	2012	1,599	Actuals
2013–14	8,374	12,027	3,281	10,313	2013	1,683	
2014–15	8,831	11,883	2,872	8,626	2014	1,656	
2015–16	9,691	13,794	3,232	9,783	2015	1,755	POEs
2016–17	10,130	13,902	3,288	9,905	2016	1,766	
2017–18	10,282	14,083	3,218	10,011	2017	1,769	

The 10% POE forecast maximum demand for each region is outlined below and summarised in Figure 6. It shows that Queensland is the only region to exceed its historical peak in the short-term outlook period, due to the ramp-up of LNG projects.

Figure 6 Comparison of historical and forecast 10% POE maximum demand (MW)



[17] A probability of exceedance (POE) refers to the likelihood that a maximum demand forecast will be met or exceeded. A 10% POE maximum demand projection is expected to be exceeded, on average, one year in 10, while 50% and 90% POE projections are expected to be exceeded, on average, five years in 10 and nine years in 10 respectively.

2.1 Queensland

The summer maximum demand in 2014–15 was 8,831 MW on 5 March 2015.[18] This occurred on a Thursday when the maximum temperature reached 36.1°C in Brisbane. It was the seventh day in a row when Brisbane's maximum temperature had exceeded 30°C.

The 10% POE maximum demand is forecast to reach 10,282 MW in the 2017–18 summer, driven by the increase in load from LNG projects and a recovery in residential and commercial maximum demand. This is an increase of 591 MW from the 2015–16 10% POE.

Over the past five years, maximum demand has occurred between 14:00 and 17:00. Maximum demand is expected to shift to later in the day due to demand being offset by rooftop PV generation. This results in a decreasing load factor[19], due to the greater impact of rooftop PV on annual operational consumption.

2.2 New South Wales

The summer maximum demand in 2014–15 was 11,883 MW on 21 November 2014. The 2014–15 summer was characterised by warm average temperatures, but relatively few days with a maximum temperature over 30°C. The 2014–15 maximum demand occurred on a Friday when the temperature reached a maximum of 33.9°C in Sydney, which is relatively low for a maximum demand day.

The 10% POE maximum demand is forecast to reach 14,083 MW in the 2017–18 summer, driven by increasing GSP and population. This is an increase of 289 MW from the 2015–16 10% POE.

Over the past five years, maximum demand has occurred between 15:30 and 16:30. Maximum demand is not forecast to shift noticeably in New South Wales, because the increase in rooftop PV generation is not enough to push demand back to later in the day. Load factors are forecast to remain relatively flat, because rooftop PV consumption is a relatively small proportion of the total load.

2.3 South Australia

The summer maximum demand in 2014–15 was 2,872 MW on 7 January 2015. The 2014–15 maximum demand occurred on a Wednesday when Adelaide reached a maximum temperature of 42.2°C. This was the sixth day in a row with temperatures over 30°C (ranging from 30.5°C to 44.1°C).

The 10% POE maximum demand is forecast to reach 3,218 MW in the 2017–18 summer. Demand is relatively flat over the short term, with this demand representing a 14 MW decrease from the 2015–16 10% POE maximum demand.

Over the past five years, maximum demand has occurred between 15:30 and 18:30. Maximum demand is expected to continue to shift to later in the day, due to demand being offset by rooftop PV generation. This results in a large decrease in load factors due to the amount of rooftop PV generation during the middle of the day, but not at time of maximum demand.

2.4 Victoria

The summer maximum demand in 2014–15 was 8,626 MW on 22 January 2015. This occurred on a Thursday when the maximum temperature in Melbourne reached 35.8°C. This was the third day in a row with temperatures over 30°C, with maximum temperatures of 30.4 °C and 33.1 °C in the two preceding days.

[18] Summer is defined as October to March for maximum demand.
[19] The load factor is the ratio of average demand to maximum demand. See Glossary for more details. A lower load factor means a bigger difference between average and maximum demand.

The 10% POE maximum demand is forecast to reach 10,011 MW in the 2017–18 summer, driven by increasing GSP and population. This is an increase of 228 MW from the 2015–16 10% POE.

Over the past five years, maximum demand has occurred between 12:30 and 16:30. Maximum demand is expected to shift to later in the day, due to demand being offset by rooftop PV generation. This results in a decreasing load factor, due to PV having a greater impact on annual consumption than on maximum demand.

2.5 Tasmania

The winter maximum demand in 2014[20] was 1,656 MW on 30 June 2014. This occurred on a Monday when Hobart had a maximum temperature of 11.2°C and a minimum temperature of 4.7°C.

The 10% POE maximum demand is forecast to reach 1,769 MW, driven by increasing population and GSP. This is an increase of 14 MW from the 2015 10% POE.

Rooftop PV generation is forecast to have minimal impact on winter maximum demand, due to the time that peaks are expected to occur. Over the past five years, winter maximum demand has occurred in both morning and evening periods. As rooftop PV penetration continues to increase, a small amount of PV generation is expected to offset demand in the morning, but not the evening. As a result, time of maximum demand is expected to shift more often to the evening. This results in a decreasing load factor, due to rooftop PV offsetting demand during the day, but not at time of peak.

[20] As the maximum demand occurs in winter, results for Tasmania are presented in calendar year.

CHAPTER 3. OPERATIONAL MINIMUM DEMAND – SOUTH AUSTRALIA

AEMO has forecast minimum demand for the first time, to investigate the impact of rooftop PV on the daily load profile. This provides useful information on network usage, which can inform further studies to evaluate operational implications.

AEMO has developed this forecast for South Australia initially, as it has the largest concentration of rooftop PV in the NEM. AEMO plans to develop minimum demand forecasts for the other NEM regions.

The 90% POE is used as the representative measure of the minimum demand forecasts, with a probability of only one year in ten being below this value.

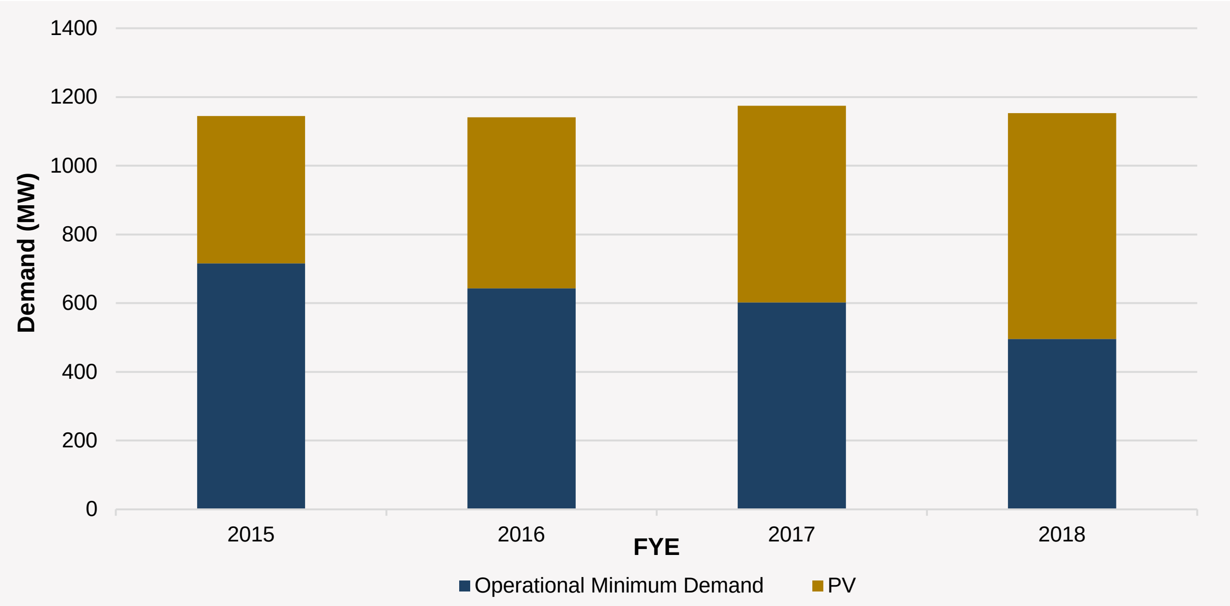
Minimum demand can occur in summer or winter, but in the outlook period is expected to increasingly occur in summer, due to the impact of increased uptake of rooftop PV, which generates more in summer than winter.

Before rooftop PV generation began to impact on minimum demand, minimum demand consistently occurred in the morning. The last time minimum demand occurred in the morning was 26 December 2011 at 5:00. Since then, due to rooftop PV generation, minimum demand has occurred in the middle of the day for both summer and winter.

In 2014–15, the minimum demand in South Australia occurred in summer, on 26 December 2014 at 1:30 pm. The minimum operational demand was 790 MW, comprising 1,235 MW of end user demand, offset by 445 MW generated by PV. This is the lowest demand experienced in South Australia in ten years.

Figure 7 shows the short-term forecast minimum demand in South Australia, and the amount of residential and commercial PV offsetting demand.

Figure 7 Summer 90% POE minimum demand forecasts for South Australia and the offset from rooftop PV



The significance of these operational minimum demand forecasts becomes more apparent when assessing the longer term outlook. If the uptake of rooftop PV continues, the electricity it generates will eventually become sufficient, on some days, to meet the underlying consumption of the residential, commercial and industrial sectors during the middle of the day. At these times, instead of drawing electricity from the grid, excess PV generation will export a net supply of electricity to the grid.

Under current market settings, this is forecast to occur in 2023–24, when operational minimum demand is completely offset by rooftop PV generation. Further discussion of these forecasts is available in the Detailed Summary of 2015 Electricity Forecasts.

It is important to note here that these forecasts assume no restrictions on the uptake of rooftop PV (whether regulatory, policy or technical), so are an observation of what may occur if the current environment continues.

AEMO intends to continue its work on renewable integration studies in South Australia, and will assess potential impacts of lowered operational minimum demand in the upcoming National Transmission Network Development Plan (NTNDP). The impact of residential battery storage uptake on these forecasts is also explored in the Emerging Technologies Information Paper, to be released shortly.

GLOSSARY

The 2015 NEFR uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified. Other key terms used in the 2015 NEFR are listed below.

Term	Definition
as-generated	A measure of electricity demand or electrical energy at the terminals of a generating system. This measure includes electricity delivered to customers, transmission and distribution losses, and auxiliary load.
auxiliary load	The load from equipment used by a generating system for ongoing operation. Auxiliary loads are located on the generating system's side of the connection point, and include loads to operate generating systems co-located at coal mines.
electrical energy	The average electrical power over a time period, multiplied by the length of the time period.
electrical power	The instantaneous rate at which electrical energy is consumed, generated or transmitted.
electricity demand	The electrical power requirement met by generating units.
energy efficiency	Potential annual energy or maximum demand that is mitigated by the introduction of energy efficiency measures.
feed-in tariff	A tariff paid to consumers for electrical energy they export to the network, such as rooftop PV output that exceeds the consumers' load.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
large industrial load (annual energy or maximum demand)	There are a small number of large industrial loads – typically transmission-connected customers – that account for a large proportion of annual energy in each National Electricity Market (NEM) region. They generally maintain consistent levels of annual energy and maximum demand in the short term, and are weather insensitive. Significant changes in large industrial load occur when plants open, expand, close, or partially close.
load factor	The ratio of average demand to maximum demand. This is calculated by dividing average demand (MW) over the summer/winter period (Oct–Mar or Apr–Sep) by the maximum demand for the same period.
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
operational electricity consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, a 10% POE MD for any given season is expected to be met or exceeded, on average, one year in 10 – in other words, there is a 10% probability that the projected MD will be met or exceeded.
Renewable Energy Target (RET)	The national Renewable Energy Target (RET) scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • Small-scale Renewable Energy Scheme (SRES), which is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC). • Large-scale Renewable Energy Target (LRET), which is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.

Term	Definition
residential and commercial load (annual energy or maximum demand)	The annual energy or maximum demand relating to all consumers except large industrial load. This means consumption after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
rooftop photovoltaic (PV) systems	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop, to convert sunlight into electricity.
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
sent-out	A measure of demand or energy (in megawatts (MW) or megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
Small-scale Renewable Energy Scheme (SRES)	See 'Renewable Energy Target (RET)'.
summer	Unless otherwise specified, refers to the period 1 November – 31 March (for all regions except Tasmania), and 1 December – 28 February (for Tasmania only). For maximum demand in the 2015 NEFR, it refers to 1 October – 31 March.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission network.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).