DETAILED SUMMARY OF 2015 ELECTRICITY FORECASTS

2015 NATIONAL ELECTRICITY FORECASTING REPORT

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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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CHAPTER 1. ABOUT THE 2015 NATIONAL ELECTRICITY FORECASTING REPORT

1.1 National electricity forecasting

The National Electricity Forecasting Report (NEFR) provides independent electricity consumption forecasts for each National Electricity Market (NEM) region over a 20-year outlook period (2014–15 to 2034–35).

The forecasts explore a range of scenarios across low, medium, and high consumption outlooks (see Table 1 below). The medium scenario is considered the most likely.

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

Resource	Description	Available
2015 National Electricity Forecasting Report Overview	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	This document. A detailed summary of forecasts for the NEM and each individual NEM region for the 20-year outlook period for the medium scenario, and comparisons 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 Information	Consultant reports related to the NEFR and additional information.	From June 2015

This detailed summary also includes commentary and data regarding low, medium and high scenarios, in the short-term (2014–15 to 2017–18), medium-term (2017–18 to 2024–25), and long-term (2024–25 to 2034–35) outlook periods.

Comparisons between the 2014 and 2015 NEFR forecasts refer to the equivalent periods.

AEMO makes data available on its Forecasting Dynamic Interface, including all operational data as well as native data, so users can undertake their own comparative analysis of the forecasts. Where necessary for confidentiality, industrial data is aggregated.

While both operational and native forecasts are developed, the published NEFR reports on operational data only.

As some data was not available at the time the report was developed:

- The 2014–15 estimate for residential and commercial (including small industrial) load is based on nine months of actual data from July 2014 to March 2015, and three months of forecast data, from April to June 2015.
- The rooftop photovoltaic (PV) 2014–15 estimate is based on six months of actual data, from July 2014 to December 2014, because data for January to June 2015 was not available from the Clean Energy Regulator (CER).
- For large industrial load, the 2014–15 estimate is based on nine months of actual data, from July 2014 to March 2015, and three months of forecast data, from April to June 2015.

- The liquefied natural gas (LNG) 2014–15 estimate, developed by Lewis Grey Consultants, is based on seven months of actual data, from July 2014 to 31 January 2015, and five months of forecast data, from February to June 2015.

1.2 Forecast scenarios

AEMO develops annual operational consumption and maximum demand forecasts using three forecast scenarios – low, medium and high consumption. The terms "low", "medium" and "high" are used throughout the 2015 NEFR documents to identify the three scenarios.

AEMO develops stretching scenarios for consumption in partnership with market participants, industry groups, and academics, and reviews scenarios every two years so they reflect real-world trends, the current regulatory environment and changes in consumer behaviour. The scenarios used for the 2015 NEFR are the same as those in the 2014 NEFR, and will be updated in 2016.

The scenarios represent low, medium, and high operational consumption for electricity from a centralised source (the national electricity transmission grid). See AEMO's 2014 Scenarios Descriptions for more information.[1]

Table 1 shows how the key variables that affect the forecast – operational consumption, customer type, economic activity, and the uptake of rooftop PV and energy efficiency measures – relate to each scenario.

Table 1 Scenarios for national electricity forecasting

	Low energy consumption from centralised sources[a]	Medium energy consumption from centralised sources	High energy consumption from centralised sources
Energy consumption	Low	Medium	High
Type of consumer[b]	High engagement	High engagement	Low engagement
Economic activity	Low	Medium	High
Rooftop PV	High uptake	Medium uptake	Low uptake
Energy efficiency	High uptake	Medium uptake	Low uptake

a) A centralised source refers to the national electricity transmission grid for electricity.
b) "Engagement" refers to the extent to which consumers proactively exercise choice of energy sources and usage patterns.

In addition to conducting research to explore impacts under the three scenarios, AEMO seeks guidance about future consumption changes directly from Transmission Network Service Providers (TNSPs) and large industrial customers.

[1] Available at:http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx.

1.3 Definitions

The following terms and definitions relating to electricity supply and consumption are critical to understanding the forecasts in the 2015 NEFR. There is also a full glossary of terms at the end of this document.

Consumption

Operational consumption includes all electricity used by residential and commercial[2] consumers, and large industrial loads drawn from the national electricity grid, including transmission losses supplied by scheduled, semi-scheduled and significant non-scheduled generating units.

Underlying residential and commercial consumption includes all consumption by residential and commercial premises, whether or not drawn from the national electricity grid.

Native consumption is calculated as operational consumption plus the contribution from small non-scheduled generation (SNSG), which generally includes units with less than 30 megawatts (MW) capacity.

Per capita consumption is the annual consumption for a typical residential and commercial customer. Population is a key driver of operational consumption in the residential and commercial sector. A population rise, all other factors being equal, leads to a rise in consumption. To analyse the impact of other drivers on consumption, and hence underlying consumption patterns, AEMO removes the effect of population by focussing on per capita consumption.

Operational consumption is measured by metering supply to the network rather than consumption at the point of use. Measuring consumption this way accounts for electricity used by customers, energy lost during transportation (transmission losses), and the energy used to generate the electricity (auxiliary loads).

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

[2] Throughout the NEFR residential and commercial includes light industrial consumption.

Electricity (energy) supplied by generators can be measured in two ways:

- **Supply "as-generated"** is measured at generator terminals, and represents a generator's entire output.
- **Supply "sent-out"** is measured at the generator connection point, and represents only the electricity supplied to the market, excluding generator auxiliary loads.

In the 2015 NEFR, AEMO presents:

- Annual operational consumption on a sent-out basis.
- Maximum demand on an as-generated basis. The forecast includes actual demand-side participation (DSP), but does not include additional forecast DSP (this is available on the NEFR website[3]).

Transmission losses and auxiliary loads

Transmission losses are calculated as a percentage of large industrial and residential and commercial consumption.

Auxiliary loads are calculated as a percentage of the energy produced at each plant.

Small non-scheduled generation

SNSG forecasts are constructed by developing profiles of existing generators and future developments based on publicly available information. Limited information is available about SNSG projects in the medium to long term, so SNSG profiles for annual operational consumption and their contribution to maximum demand display little variation over the long-term forecast.

Maximum demand

Maximum demand is the highest level of instantaneous operational demand during summer and winter each year, averaged over a 30-minute period.

Minimum demand

Minimum demand is the lowest level of instantaneous operational demand during summer and winter each year, averaged over a 30-minute period.

[3] http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

Probability of exceedance

A **probability of exceedance (POE)** refers to the likelihood that a maximum demand or minimum demand forecast will be met or exceeded. The various probabilities (generally 90%, 50%, and 10% POE) provide a range of possibilities for analysts to determine a realistic range of power system and market outcomes.

Maximum demand in any year will be affected by weather conditions, and an increasing proportion of residential and commercial consumption is sensitive to temperature and humidity. AEMO's model considers heating degree days (HDD) and cooling degree days (CDD), which reflect the average temperature over summer or winter. This provides a better representation of the POE distribution, by allowing for additional temperature-related variations in maximum demand caused by consistently hotter or colder summers and/or winters.

For any given season:

- A 10% POE maximum demand projection is expected to be exceeded, on average, one year in 10.
- A 50% POE maximum demand projection is expected to be exceeded, on average, five years in 10 (or one year in two).
- A 90% POE maximum demand projection is expected to be exceeded, on average, nine years in 10.

The 2015 NEFR presents maximum demand data based on 10% POE maximum demand projections, as did the 2014 NEFR.

Minimum demand forecasts, included in the 2015 NEFR for the first time, are based on a 90% POE. For minimum demand, a 90% POE means actual demand is expected to be below the projected minimum only one year in 10, making this the equivalent of a 10% POE maximum demand forecast in its level of expected reliability.

1.4 Improvements to the 2015 NEFR

AEMO consistently evaluates its forecasting performance and methodologies, and conducts both internal and external peer reviews to identify opportunities for improvement. Opportunities identified after the 2014 NEFR was published in November 2014 are outlined in the 2015 NEFR Action Plan.[4]

A number of improvements to the 2015 NEFR were based on this reviewer feedback. AEMO has also made additional improvements to better meet stakeholders' needs.

See the 2015 Forecasting Methodology Information Paper, to be published in July 2015, for details.

Improvements to residential and commercial consumption calculations

The econometric model was changed for the 2015 NEFR, to provide better analysis of the decline in electricity prices in some regions in recent years. This reflects the greater importance being placed on recent consumption patterns in forecasting future trends.

In the 2014 NEFR, AEMO used the same underlying model for each NEM region. For the 2015 NEFR, given changing trends and drivers in each NEM region, AEMO adjusted the underlying model to be more sensitive to region-specific trends. Where there was enough historical data, the model incorporated asymmetric price effects, allowing the forecasts to capture the different consumer behaviour linked to price increases and price decreases.

Large industrial load methodology improvements

AEMO increased the sample size of large industrial customers that it contacted directly for information, from 93 customers in 2014 to 115 in 2015, and included customers with a maximum demand greater than 10 MW. This change captured additional data, and provided a more representative sample of distribution-connected and transmission-connected customers.

Customers were asked for information on their likely load under the three scenarios (low, medium, and high), and their own estimates were used in the forecasts where provided.

For the medium to long-term outlook, AEMO applied an economic sectoral approach.

Improvements to maximum demand calculations

In the 2014 NEFR, AEMO modelled industrial and non-industrial load separately for maximum demand calculations. In the 2015 NEFR, AEMO explicitly incorporated industrial load in the maximum demand model.

The model was also modified to include temperature and day-of-week interactions by modelling the demand for workdays and non-workdays separately. To further optimise variables, mornings, afternoons and evenings each had separate models fitted. This allowed variable selection to vary with time of day.

The maximum demand model was also more efficiently aligned to annual operational consumption, and AEMO changed the methodology for energy efficiency calculations (see below).

[4] Available at: http://aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/planning/NEFR/2014/2014%20Updates/2015%20NEFR%20Action%20Plan%20V2.ashx

Improvements to energy efficiency estimates

AEMO analysed the impact of energy efficiency in various sectors, particularly the impact of appliance and building energy efficiency measures in commercial and residential settings.

The annual operational consumption forecast included energy efficiency calculated at the average historical uptake rate. In the last two years, an additional post-model adjustment was added, to account for the impacts of future energy efficiency programs.

The 2015 energy efficiency analysis is based on recent, comprehensive data for federal Government energy efficiency programs targeting electrical appliances, as well as both existing and new building stock, and data from New South Wales Government programs. For more details see the 2015 Forecasting Methodology Information Paper, to be published in July 2015.

In the 2015 NEFR, AEMO excluded the future industrial energy efficiency savings that had been included in the 2014 NEFR, as the Energy Efficiency Opportunities program was scrapped in the 2013–14 federal budget.

All three scenarios in the 2015 NEFR used different energy efficiency uptake rates for operational consumption and maximum demand. However, the methodology for applying the energy efficiency contribution to maximum demand has been improved since 2014, to account for varying appliance efficiency levels at different temperatures and loads. AEMO assessed appliances targeted by future Minimum Energy Performance Standards (MEPS) programs, to determine what impact could be expected for the 10%, 50% and 90% POEs. For more details, refer to the 2015 Forecasting Methodology Information Paper.

Rooftop PV methodology improvements

For the first time, AEMO modelled residential and commercial PV separately, to reflect the different drivers in each sector. Previously, all systems under 100 kilowatts (kW) were treated as residential installations, and no systems above 100 kW were included.

In the 2015 NEFR, systems less than 10 kW were assumed to be residential, while anything above 10 kW was classified as commercial.

This methodology accounts for the different investment decisions made by households and businesses, as well as the impact of policy on uptake. AEMO based residential uptake on typical payback (as it has in previous NEFRs). Commercial uptake was based on a Net Present Value (NPV) analysis, considered a more likely driver for business investment.

The database of historical PV installations was extended to include projects above 100 kW and primarily installed to offset self-consumption (that is, solar farms and community projects designed to sell electricity into the market were excluded).

Improvement to transmission loss calculations

AEMO revised the maximum demand model for transmission losses, to reflect recent trends and to improve robustness. The summer and winter maximum demand contribution factors were calculated using historical transmission losses in the top 10 highest operational demand intervals over the past five years.

Demand-side participation

AEMO revised its demand-side participation (DSP) methodology to include SNSG as an offset to demand at the various price triggers. For further detail refer to the DSP Supplement.

1.5 Operational minimum demand

For the first time, AEMO developed operational minimum demand forecasts for South Australia.

Operational minimum demand forecasts are becoming increasingly important for AEMO and network service providers. Where there are high levels of renewable penetration, minimum demand periods are an important operational and planning consideration.

AEMO selected South Australia for its first minimum demand forecasts, as it is the NEM region with the highest rooftop PV penetration. AEMO intends to develop minimum demand forecasts for the other NEM regions.

1.6 Emerging technologies supplement

AEMO recognises emerging technologies as a critical element of long-term forecasting.

For the first time in the 2015 NEFR, AEMO has modelled the potential impact of emerging technologies and trends (battery storage, electric vehicles and fuel switching) on operational consumption and maximum demand in the NEM.

This set of forecasts and user tools is published in the Emerging Technologies Information Paper.

1.7 Forecasting dynamic interface

AEMO has developed a dynamic interface so users can access information, review data and add their own filters. This web-based portal can be accessed at http://forecasting.aemo.com.au/.

1.8 Content and structure of this report

Forecasts in this detailed summary report focus mainly on the medium consumption (most likely) scenario. It also provides further information the about low and high scenarios and associated forecasts.

The sections of this report summarise AEMO's forecasts for the whole NEM, and for each individual NEM region.[5] Each section is intended to stand alone, and covers:

- Consumption in the residential and commercial sector.
- Consumption in the industrial sector.
- Rooftop PV in both the residential and commercial sectors.
- Maximum demand.
- Minimum demand (for South Australia only).
- Changes in forecasts from the 2014 NEFR to the 2015 NEFR, and the reasons for these changes.

[5] New South Wales includes the Australian Capital Territory.

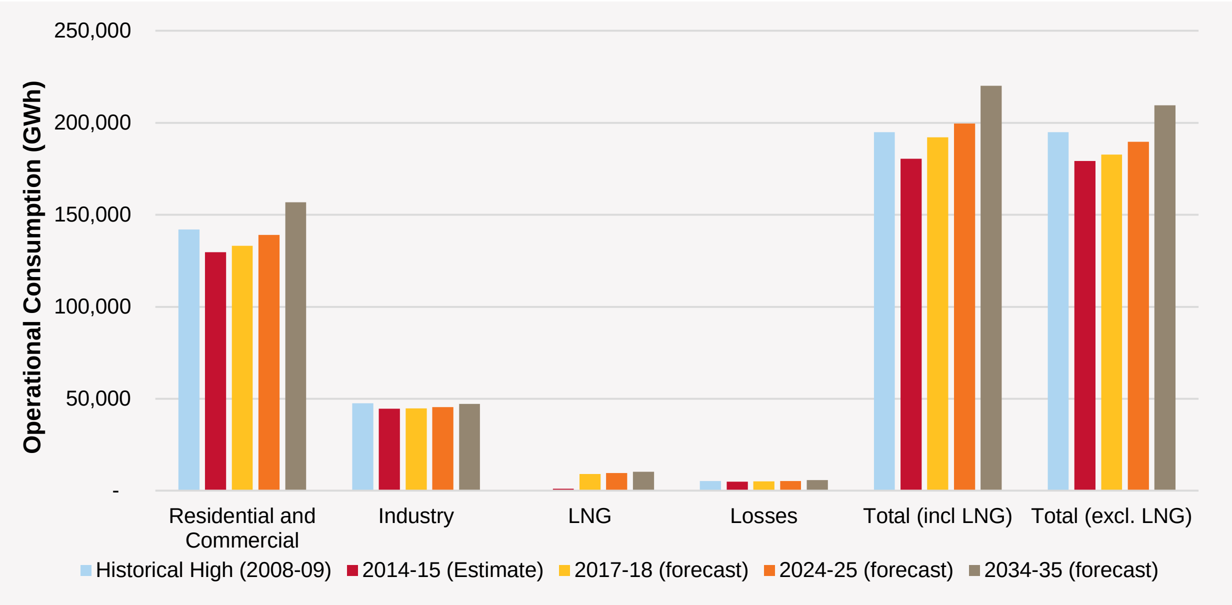
CHAPTER 2. NATIONAL ELECTRICITY MARKET

2.1 Key points

Key points for the NEM overall are:

- The decline in operational consumption seen in recent years has slowed, with operational consumption expected[6] to be flat in 2014–15.
- Overall operational consumption in the short-term (2014–15 to 2017–18) is forecast to recover from 180,390 gigawatt hours (GWh) to 192,131 GWh, an average annual increase of 2.1%.
- Consumption in the industrial sector is forecast to increase at an average annual rate of 5.6% in the short term, attributable to Queensland liquefied natural gas (LNG) projects.[7] Excluding LNG, industrial consumption is forecast to be flat in the short term (see Figure 2).
- In the medium and long-term outlooks, there is little net change in industrial consumption (see Figure 2).
- Consumption in the residential and commercial sector is forecast to recover over the short to medium term, but per capita consumption continues to decline, indicating that any recovery in consumption is mainly due to population growth.
- Residential and commercial consumption is not expected to recover to its historical high[8] until 2026–27. From 2014–15 to this time, population is forecast to increase by 3.9 million (see Figure 1).

Figure 1 Comparison of NEM historical and forecast operational consumption



[6] The 2014–15 value is based on nine months of actual demand data from 1 July 2014 to 31 March 2015, and one quarter of forecast data from 1 April to 30 June 2015, which is not available at the time of publication. Rooftop PV contribution is based on six months of forecast data.

[7] 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 consume electricity from the grid. See Lewis Grey Advisory, Projections of Gas and Electricity Used in LNG, 15 April 2015, for more details.

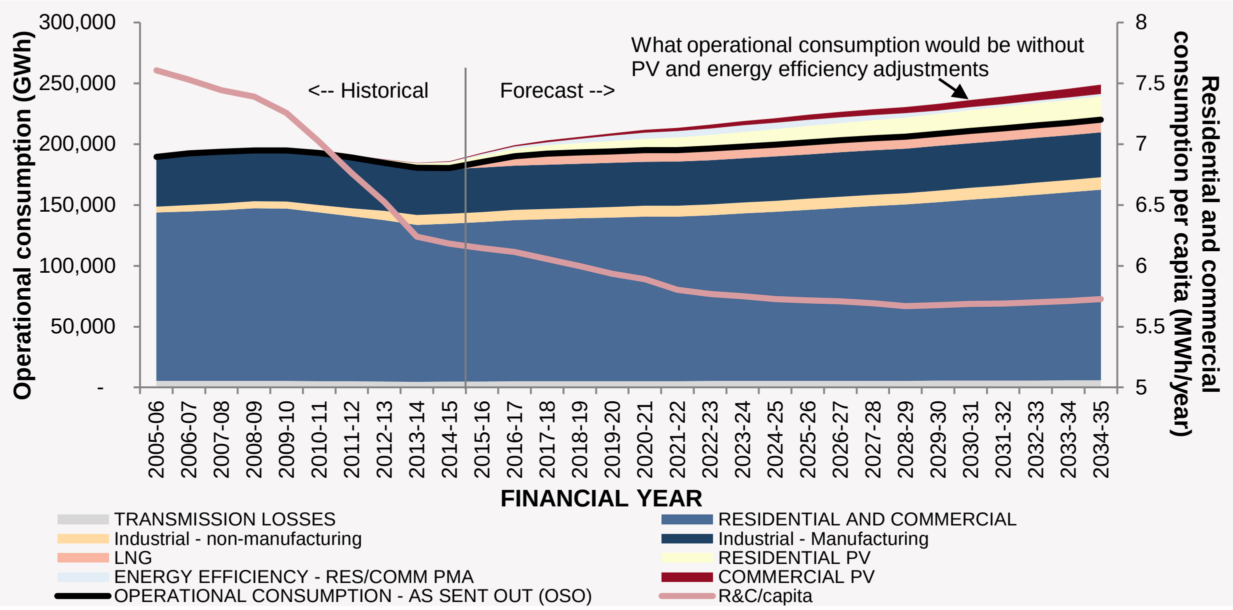
[8] The historical high for consumption in the residential and commercial sector in the NEM was 142,076 GWh, reached in 2008–09.

2.2 Annual operational consumption

2.2.1 Overview of historical operational consumption

As shown in Figure 2, in the five years to 2014–15, operational consumption in the NEM has been declining at an average annual rate of 1.5%.

Figure 2 NEM operational consumption by key component to 2034-35



Consumption in the residential and commercial sector decreased in this period, due to factors including:

- Rapidly increasing 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 energy savings through the replacement of aging appliances.
- Greater customer awareness of electricity usage, and changes in behaviour.

The impact of these factors is clearly evident in the strong decline in per capita residential and commercial consumption during this period (see Figure 2).

From 2010–11, industrial consumption has been declining overall, with some sectors experiencing increases and others decreases.

Increased consumption from the non-manufacturing sector (see Figure 2) was primarily driven by:

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

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.

Changes over the last year (2013–14 to 2014–15)

The decline in operational consumption across the NEM was highest between 2011–12 and 2012–13. Since then it has slowed, and is flat in the last year, with consumption expected to decrease by just 264 GWh (0.1%) from 2013–14 to 2014–15. This is despite a decrease in industrial consumption of 1,258 GWh.

Consumption in the residential and commercial sector is expected to recover for the first time since 2008–09, with an additional 751 GWh expected in 2014–15 compared to the previous year. Drivers for the changing trend in this sector include:

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

In the residential and commercial sector, the slowing of the historical decline in operational consumption, and the expected recovery in the last year, can also be noted in the sharp change in the trend of per capita consumption in 2012–13 (shown in Figure 2). This is largely attributable to the slowdown in rooftop PV uptake, as generous state feed-in-tariff schemes ended.

There is, however, also a possibility that consumers are 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 *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”. [9]

2.2.2 Forecasts

AEMO forecasts a continued decline in per capita consumption over the short to medium outlook period, although the rate of decline is much lower than the historical average.

Table 2 provides a summary of the forecasts under the medium scenario, and drivers for these results, while Figure 2 above illustrates the forecasts by key components.

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

Table 2 Summary of operational consumption in the short, medium and long-term

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short-term (2014–15 to 2017–18)	180,390 to 192,131	2.1%	The recovery in operational consumption is driven by the ramp-up of all three LNG projects in Queensland, which are projected to reach operational capacity in 2017–18.
Medium -term (2017–18 to 2024–25)	192,131 to 199,602	0.5%	Recovery in operational consumption is driven largely by the residential and commercial sector. Underlying consumption recovery is based on relatively lower electricity prices compared with recent history, and population growth. This increase is partially moderated by rooftop PV and energy efficiency measures.
Long-term (2024–25 to 2034–35)	199,602 to 220,044	1.0%	

The impact of LNG on operational consumption is clearly evident in Figure 2, with the ramp-up occurring until 2017–18 and then plateauing for the remainder of the period. The historical increase and then decline in residential and commercial consumption is also evident. The black line indicates overall operational consumption, while the top of the graph indicates what operational consumption would be if it was not reduced by rooftop PV and energy efficiency measures.

But for the impact of LNG, operational consumption would not have been expected to recover to the historical high of 194,971 GWh (in 2008-09) until 2027–28. This is despite a projected increase in population of 4.2 million between now and 2027–28.

Residential and commercial consumption

Underlying consumption refers to the electricity used by the residential and commercial sector, whether drawn from the electricity grid or not. It is forecast over a 20-year horizon, with the key modelled drivers being population, income, weather and electricity prices.

In this long-term methodology, residential and commercial consumers are modelled as responding to increases or decreases in average prices, as well as the average income measured by Gross State Product (GSP). In general, consumption increases if income increases, and decreases if electricity prices increase. For further detail, see the Forecasting Methodology Information Paper.

AEMO models residential and commercial consumption in two stages:

1. It forecasts per capita consumption, to capture underlying usage trends by removing the impact of population growth. This is why per capita consumption is the key metric in analysing the forecasts.
2. It then uses population growth forecasts to calculate overall underlying consumption.

The underlying consumption is then offset by forecast rooftop PV generation (which reduces electricity drawn from the grid) and adjustments to account for energy efficiency impacts not already captured in the underlying trends.

In all NEM regions, consumption in the residential and commercial sector recovers, with the strongest recovery in Victoria and New South Wales. Table 3 summarises forecast annual residential and commercial consumption over the short, medium and long-term, and explains the key drivers.

Table 3 Consumption in the residential and commercial sector in the short, medium and long term

Timeframe	Forecast (GWh)	Average annual change	Consumption per capita (MWh/yr)	Drivers
Short term (2014–15 to 2017–18)	129,743 to 133,163	0.9%	6.2 to 6.1	Continued uptake of rooftop PV and energy efficiency measures provide a partial offset of consumption, but overall there is a slight recovery in consumption, largely attributable to recovery in Victoria and New South Wales. Per capita consumption continues to decline, suggesting that population growth is a key driver of the increase.
Medium-term (2017–18 to 2024–25)	133,163 to 139,071	0.6%	6.1 to 5.7	Recovery in underlying consumption is moderated, and rooftop PV offsets an increasing proportion of the load.
Long-term (2024–25 to 2034–35)	139,071 to 156,747	1.2%	5.7 to 5.7	Population growth drives the increase in consumption in this period, as evidenced by the stable per capita consumption.

Rooftop PV forecasts

The 2015 NEFR is the first time AEMO has modelled residential and commercial PV separately. Systems less than 10 kW were classified as residential, while commercial systems were categorised as either small (less than 100 kW) or large (greater than 100 kW):

- Residential PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability of rooftop PV. The programs that incentivised the historical uptake have helped to establish a local industry and drive a reduction in PV technology and installation costs.
- Uptake in the commercial sector has been more recent, driven by a combination of programs like the Clean Technology Investment Fund and SRES, as well as 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.

Table 4 shows the cumulative capacity and generation of installations by segment for the medium scenario. Uptake in residential PV installations continues over the short-term to medium-term outlook, and then slows as it begins to reach saturation levels. Commercial PV continues to increase across the entire forecast period, with small commercial installations displaying the strongest increase.

Table 4 Cumulative rooftop PV installed (MW) and forecast generation (GWh)

	Commercial PV		Residential PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014–15	497	535	3,700	4,518	**4,196**	**5,052**
2017–18	1,149	1,363	5,550	6,949	**6,698**	**8,311**
2024–25	2,942	3,690	9,919	12,736	**12,861**	**16,427**
2034–35	5,808	7,398	15,083	19,504	**20,890**	**26,902**

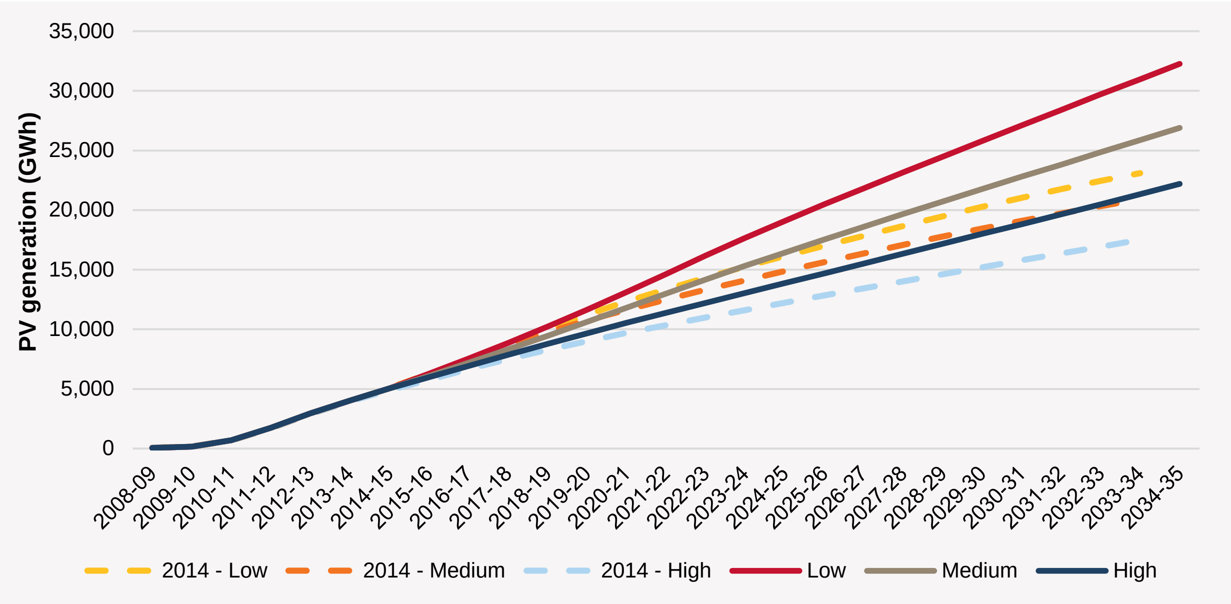
Figure 3 shows rooftop PV forecasts for the three scenarios, and those of the 2014 NEFR. The differences in the 2015 NEFR are mainly due to separate modelling of residential and commercial PV.

When comparing the scenarios, it is useful to remember that they refer to levels of consumption from the national electricity grid. So, in the low scenario, large localised generation is assumed and this means the highest level of uptake of rooftop PV, and vice versa for the high scenario.

In the 2014 NEFR, saturation rates were imposed on the forecasts, based on the projected number of residential dwellings. Modelling the commercial market separately means there is an increased number of rooftops on which PV can be installed, allowing for greater growth over the outlook period. Only in some NEM regions is saturation reached in the commercial PV sector.

The long term 2015 NEFR projections see commercial PV dominating the overall growth, and result in higher forecasts than in the 2014 NEFR.

Figure 3 Comparison of rooftop PV forecasts



The level of forecast uptake in each NEM region depends on the economic viability of PV systems, which varies widely between regions due to significant differences in solar resources and electricity prices.

Table 5 shows the forecast proportion of rooftop PV generation, relative to total residential and commercial consumption, for each region.

Table 5 Proportion of rooftop PV relative to residential and commercial underlying consumption

	Queensland	New South Wales	South Australia	Victoria	Tasmania
2014–15	5.7%	2.4%	8.4%	2.7%	3.0%
2017–18	9.1%	3.7%	11.9%	4.4%	4.9%
2024–25	16.0%	6.3%	22.1%	8.6%	11.0%
2034–35	20.2%	9.3%	28.5%	13.7%	17.4%

Despite Victoria and New South Wales having the second and third highest installed rooftop PV capacity respectively in 2034–35, they have the lowest relative proportion of all the NEM regions. This means PV generation offsets a much smaller proportion of their underlying consumption (see regional forecasts).

Energy efficiency

AEMO adjusts its forecasts based on additional energy efficiency savings that are not already captured in the residential and commercial consumption. These are based on data from existing and planned future government programs.

In the medium scenario, the energy efficiency adjustments applied to the forecasts were:

- Short term – the adjustment increased from 486 GWh in 2014–15 to 2,601 GWh in 2017–18.
- Medium term – the adjustment increased from 2,601 GWh in 2017–18 to 5,391 GWh in 2024–25.
- Long term – the adjustment decreased from 5,391 GWh in 2024–25 to 1,892 GWh in 2034–35.

The adjustment decreases in the long term, because the forecast already includes a larger proportion of the impacts of energy efficiency savings.

Industrial consumption

Industrial loads are defined as loads with typical demand greater than 10 MW.[10] 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:[11]

- Manufacturing loads are those classified under Division C of the ANZSIC code. This includes primary and fabricated metal, petroleum, basic chemical, pulp and paper, non-metallic mineral, transport equipment, wood, and food product manufacturing.
- All loads not captured under Division C are defined as 'other'. This includes coal and metal ore mining, water supply services and defence services.

Forecasts for the industrial loads have been developed based on sectoral outlooks for each industry, and in consultation with individual industrial customers. For more information refer to the 2015 Forecasting Methodology Report.

Over recent years, increased consumption from the non-manufacturing sector has been offset by a decline in manufacturing consumption.

In the medium scenario, AEMO has assumed that all aluminium smelters remain in operation. No further closure announcements have been made, and the depreciation of the Australian dollar should have reduced the cost exposure of Australian smelters compared to last year.

Table 6 summarises industrial consumption over the short, medium and long-term, and explains key drivers.

Table 6 Industrial consumption in the short, medium and long term

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	45,737 to 53,811	5.6%	The growth in consumption is driven by the three LNG projects in Queensland. Excluding LNG, industrial consumption remains flat.
Medium term (2017–18 to 2024–25)	53,811 to 55,188	0.4%	LNG projects reach operational capacity in 2017–18 and so their consumption plateaus in the medium-term. There are no net trends in industrial consumption for the remainder of the outlook period, with small declines in some sectors offsetting increases in others.
Long term (2024–25 to 2034–35)	55,188 to 57,421	0.4%	

10 This refers to customers whose demand is greater than 10 MW for at least 10% of the previous year.
11 For more information on ANZSIC code classifications, refer to the ABS website, http://www.abs.gov.au/ausstats/abs@.nsf/Previousproducts/20C5B5A4F46DF95BCA25711F00146D75?opendocument

Differences between the low, medium and high consumption scenarios

Figure 4 shows the annual operational consumption trend from 2008–09 to 2014–15, and forecast operational consumption over the medium-term (10 years) outlook under low, medium and high scenarios, in the 2015 NEFR. It also shows the 2014 NEFR forecasts for comparison.

The differences between the low, medium and high consumption scenarios are driven by differences in economic variables such as electricity price, GSP forecasts, industrial sector outlooks, population growth and assumptions on rooftop PV and energy efficiency uptake.

The scenarios also include explicit assumptions related to specific industrial sectors.

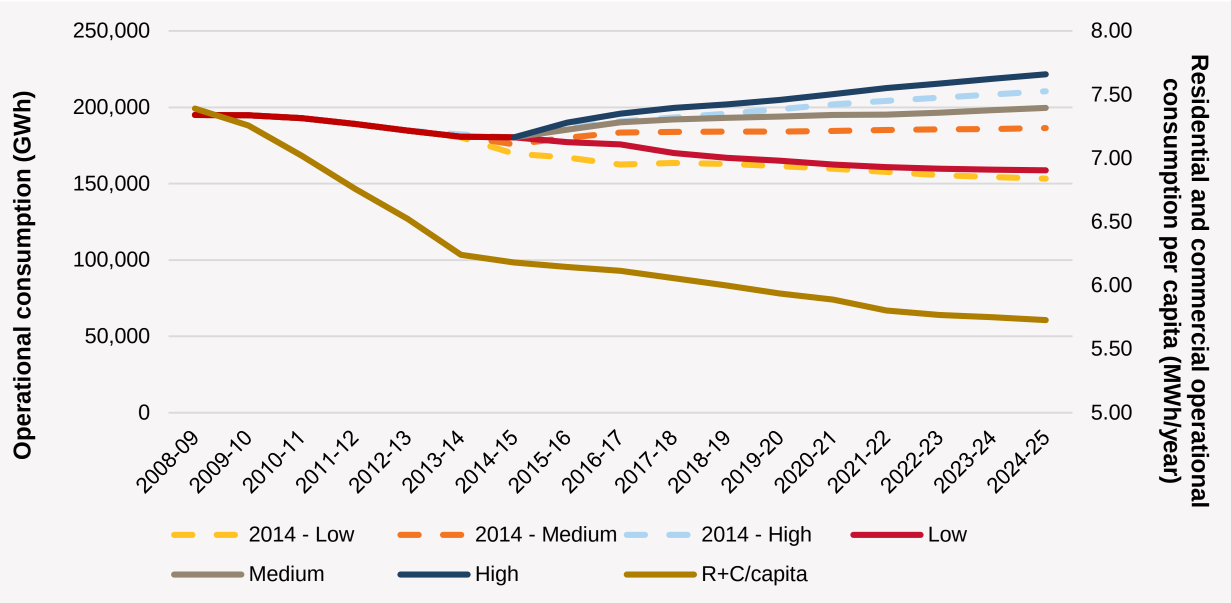
The low consumption scenario in the 2015 NEFR assumes:

- All aluminium smelters will close.
- Desalination plants will run in care and maintenance mode.
- The LNG trains operate 15% below contract.
- There will be a general decline in electricity consumption in the manufacturing sector.

The high consumption scenario assumes there will be growth in consumption from both the manufacturing and mining sectors, and also assumes:

- Desalination plants operating at full capacity.
- LNG trains operating at boilerplate capacity and the commissioning of a seventh LNG train.
- Expansion at Olympic Dam in South Australia.
- The development of Rex Minerals' Hillside mine in South Australia.

Figure 4 Comparison of low, medium and high consumption scenarios to 2024–25



In 2024–25, compared to the medium scenario, forecast operational consumption is 20% lower in the low scenario, and 11% higher in the high scenario.

Comparison to the 2014 NEFR

As shown in Figure 4 above, the 2015 NEFR forecast for operational consumption in the short term is higher than the published 2014 NEFR forecast, based on the medium scenario, and is close to the 2014 NEFR high consumption scenario.

The changes in the 2015 NEFR 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 recent past, 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 MWh/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.[12] (The volume of exports remains the same.)
- Recovery in industrial consumption in some sectors, due to factors including the fall in the Australian dollar.

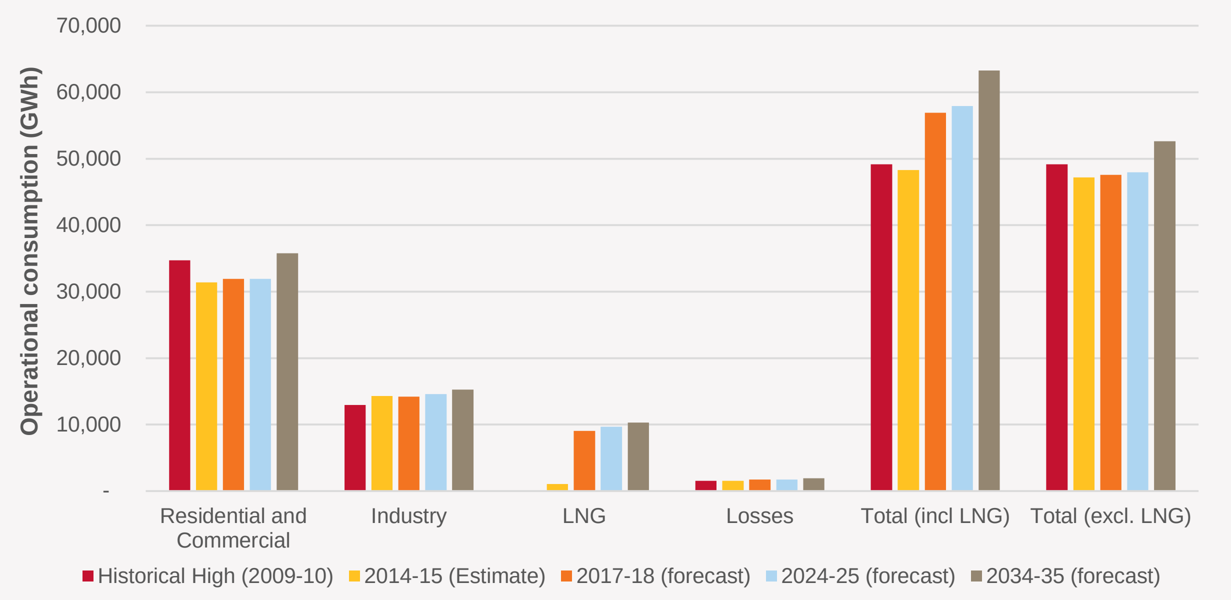
[12] Lewis Grey Advisory, Projections of Gas and Electricity Used in LNG, 15 April 2015.

CHAPTER 3. QUEENSLAND

3.1 Key points for Queensland

- Operational consumption in the short term (2014–15 to 2017–18) is driven by LNG.[13]
- Consumption by LNG projects will see Queensland exceed its historic operational consumption record[14] in 2015–16. Excluding LNG, operational consumption would not be expected to return to this level until 2028–29, driven by recovery in both industrial and residential/commercial consumption (see Figure 5).
- Excluding LNG, industrial consumption is expected to remain relatively flat in the short term and increase slightly in the longer term.
- Although there is an overall increase in consumption from the residential and commercial sector, consumption per capita continues to decline over the 20-year outlook period (see Figure 6).
- There is continued uptake of rooftop PV in the residential and commercial sectors over the 20-year outlook period (see Table 10), and energy efficiency measures.
- Maximum demand is forecast to exceed its historical high for the whole outlook period, because of LNG projects.

Figure 5 Comparison of actual and forecast operational consumption in Queensland



[13] 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 consume electricity from the grid. See Lewis Grey Advisory, Projections of Gas and Electricity Used in LNG, 15 April 2015, for more details.

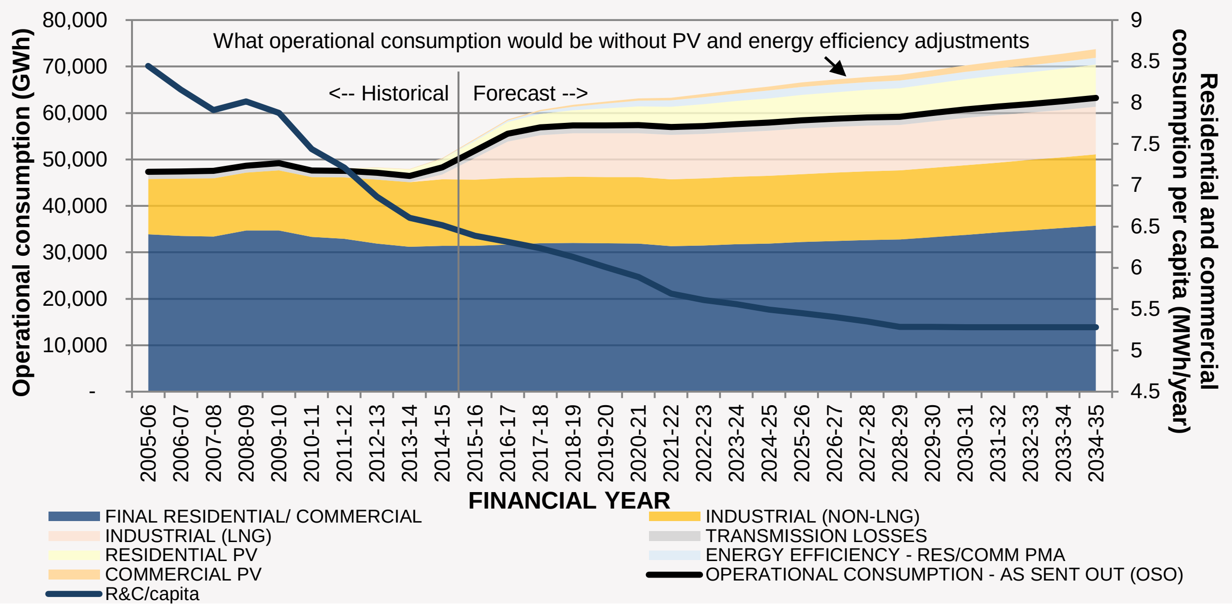
[14] Queensland recorded its previous highest level of operational consumption of 49,175 GWh in 2009–10.

3.2 Annual operational consumption in Queensland

In the ten years to 2014–15, operational consumption has remained relatively flat, with the decline in residential and commercial consumption offset by increases in industrial consumption (see Figure 6).

AEMO forecasts recovery in operational consumption in the short term, driven by the ramp-up of LNG projects. Excluding LNG, operational consumption would increase by only 381 GWh in this outlook period.

Figure 6 Operational consumption by key component in Queensland



Medium and long term forecasts indicate slightly increased operational consumption, driven primarily by increases in the industrial sector. Residential and commercial consumption is forecast to continue to decline per capita.

Table 7 provides a summary of forecasts under the medium scenario, and drivers for these results, while Figure 6 illustrates the forecasts by key components.

Table 7 Operational consumption in Queensland over the short, medium and long term

Timeframe		Forecast (GWh)	Average annual change	Drivers
Short-term (2014–15 to 2017–18)	Inc. LNG	48,289 to 56,932	5.6%	LNG drives the recovery in operational consumption over the short term. Excluding LNG, operational consumption increases only slightly due to a recovery in the residential and commercial sector driven by population growth.
	Ex. LNG	47,193 to 47,574	0.3%	
Medium term (2017–18 to 2024–25)	Inc. LNG	56,932 to 57,919	0.2%	LNG is forecast to reach operational capacity in 2017–18, so consumption in this sector remains flat for the remainder of the forecast period. Operational consumption in the medium term is flat, increasing by only 987 GWh over the seven years.
Long term (2024–25 to 2034–35)	Inc. LNG	57,919 to 63,259	0.9%	In the long term, the increase in operational consumption is driven by the residential and commercial sector. Income per capita grows over this period, encouraging greater underlying consumption. The offset by PV slows over the period, as the number of installations reach saturation levels, and it only partially meets the increase in consumption due to population growth.

The impact of LNG on operational consumption is clearly evident in Figure 6, with the ramp-up occurring until 2017–18 and then plateauing for the remainder of the 20-year outlook period. Figure 6 also shows the historical increase and then decline in residential and commercial consumption. The black line indicates overall operational consumption, while the top of the graph indicates what the operational consumption would be if it was not reduced by rooftop PV and energy efficiency measures.

Despite the forecast increase in operational consumption, excluding LNG Queensland would not be projected to recover to its historical high of 49,175 GWh[15] until 2028–29, despite a projected increase in population of 1.4 million from 2014–15 to 2028–29.

3.2.1 Residential and commercial consumption in Queensland

Methodology Overview

Underlying consumption refers to the electricity used by the residential and commercial sector whether drawn from the electricity grid or not. It is forecast over a 20-year horizon, with the key modelled drivers being population, income, weather and electricity prices.

In this long-term methodology, residential and commercial consumers are modelled as responding to increases or decreases in average prices, as well as the average income measured by Gross State Product (GSP). In general, consumption increases if income increases, and decreases if electricity prices increase. For further detail refer to the 2015 Forecasting Methodology Information Paper.

AEMO models this in two stages:

1. It forecasts per capita consumption, to capture underlying usage trends by removing the impact of population growth. This is why per capita consumption is the key metric in analysing the forecasts.
2. It then uses population growth forecasts to calculate overall underlying consumption.

The underlying consumption is then offset by forecast rooftop PV generation (which reduces electricity drawn from the grid) and adjustments to account for energy efficiency impacts not already captured in the underlying trends.

15 Queensland experienced its historical peak operational consumption in 2009–10.

Forecasts

Historically, residential and commercial consumption in Queensland has been declining from 2009–10 to 2014–15, with consumption per capita decreasing from 7.9 MWh/year to 6.5 MWh/year, due to a rapid increase in electricity prices, uptake of rooftop PV, and greater customer engagement in reducing electricity consumption.

This decline in per capita consumption has slowed over recent years, and consumption recovered slightly last year, from 31,189 GWh in 2013–14 to 31,414 GWh in 2014–15. This is despite an increasing number of rooftop PV installations, which offset consumption drawn from the grid. Queensland did, however, experience a longer and warmer summer than average.

The consumption forecast relies on the forecast economic and demographic variables shown in Figure 7. Key points in the variables are:

- Population growth continues, although the rate of growth slows over the forecast period.
- GSP grows in real terms.
- The increase in electricity prices is moderated from 2013–14, increasing at a much slower rate in real terms until 2029–30, when there is an estimated decrease due to the end of the Renewable Energy Target (RET).

Figure 7 Key drivers for underlying residential and commercial consumption in Queensland

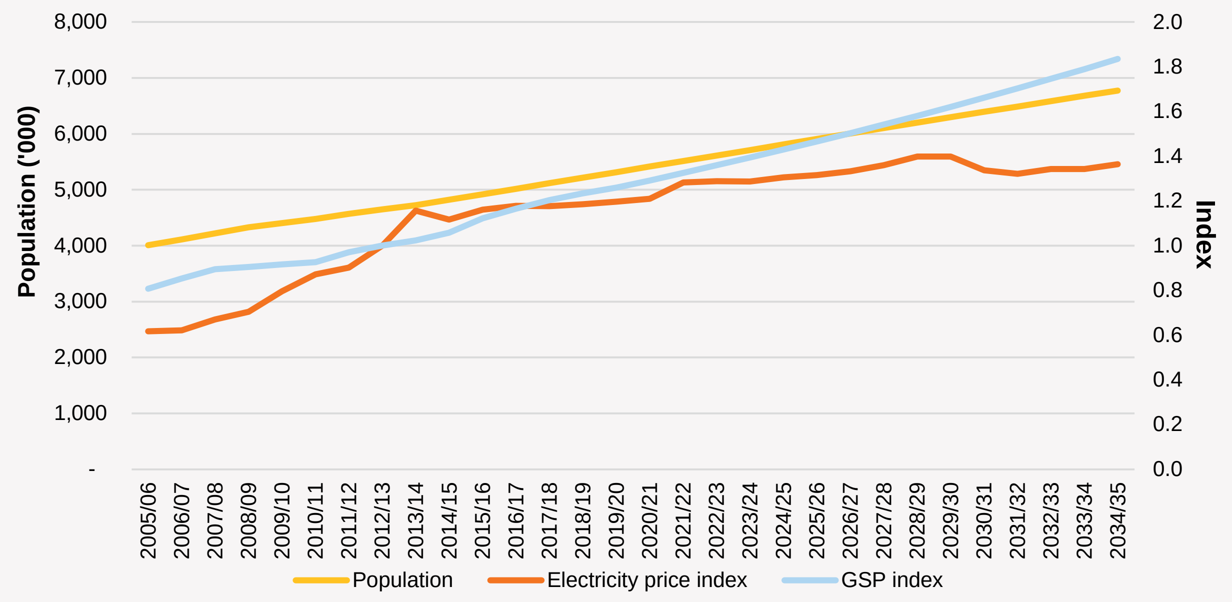


Table 8 summarises forecast consumption in the residential and commercial sector over the short, medium and long term, and explains key drivers.

Table 8 Consumption in the residential and commercial sector over the short, medium and long term in Queensland

Timeframe	Forecast (GWh)	Average annual change	Consumption per capita (MWh/yr)	Drivers
Short term (2014–15 to 2017–18)	31,414 to 31,920	0.5%	6.5 to 6.2	Underlying consumption recovers, driven by population and income growth. This is moderated by continued uptake of rooftop PV and energy efficiency. Because per capita consumption decreases, the 506 GWh increase is attributable mainly to population growth.
Medium term (2017-18 to 2024-25)	31,920 to 31,915	0.0%	6.2 to 5.5	Recovery in underlying consumption slows, due largely to a decline in income per capita. The increase due to population growth is offset by uptake of rooftop PV, which continues particularly in the small commercial sector, and further energy efficiency improvements. Per capita consumption decreases significantly in this period.
Long term (2024–25 to 2034–35)	31,915 to 35,769	1.1%	5.5 to 5.3	Income per capita grows over the long term, driving a recovery in underlying consumption. Over this period uptake of rooftop PV continues although at a slower rate, and so only partially offsets the underlying consumption. Per capita consumption continues to decline, but at a slower rate, indicating both income and population drive the increase in consumption in this period.

Although residential and commercial consumption recovers over the short and long term, this increase is primarily driven by population growth, because average consumption per capita continues to decline. Consumption in this sector is not forecast to recover to Queensland's historical high until 2032–33.

Differences between low, medium and high scenarios for Queensland

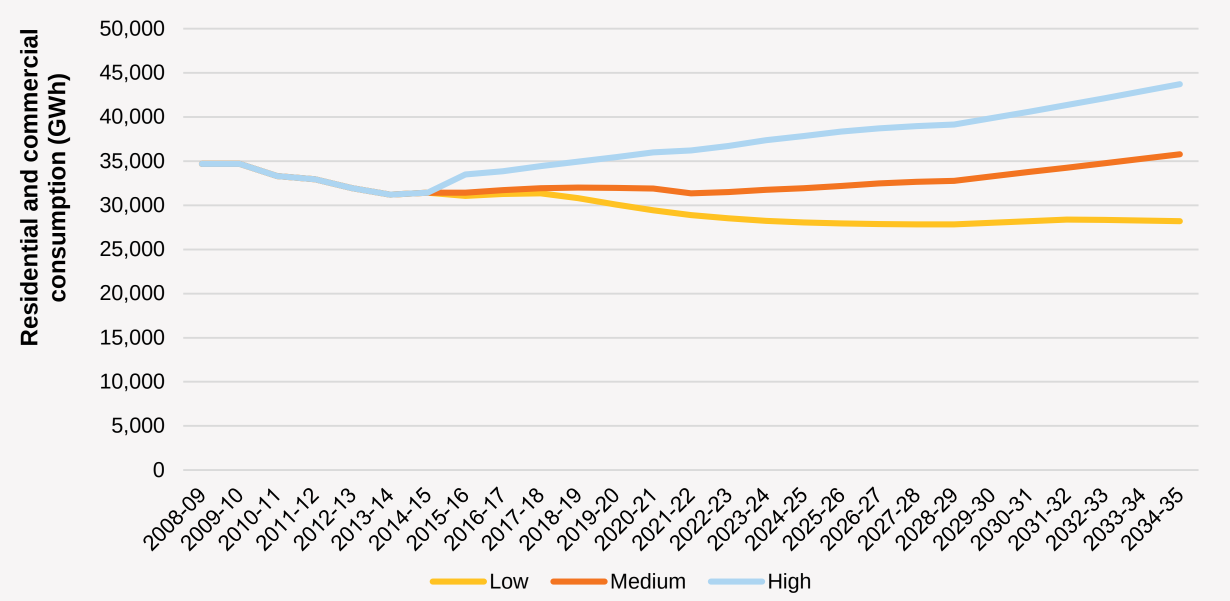
The differences between the low, medium and high consumption scenarios in this sector are driven by differences in the electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 9, and the forecasts are given in Figure 8.

Table 9 Average annual rates of change for the low, medium and high consumption scenarios in Queensland

	Low	Medium	High
Short term (2014–15 to 2017–18)	-0.1%	0.5%	3.1%
Medium term (2017–18 to 2024–25)	-1.6%	0.0%	1.4%
Long term (2024–25 to 2034–35)	0.1%	1.1%	1.5%

Figure 8 Comparison of low, medium and high residential and commercial forecasts for Queensland



In 2024–25, compared to the medium scenario, forecast consumption is 12% lower in the low scenario, and 19% higher in the high scenario.

Queensland residential and commercial consumption comparison to the 2014 NEFR

To keep improving the NEFR, AEMO often reclassifies loads from the residential and commercial segment to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

The 2014 NEFR estimated an average annual decrease of 0.9% over the period 2014–15 to 2017–18, compared with the average annual increase of 0.5% forecast in the 2015 NEFR. The reasons are:

- In 2014, AEMO applied an intercept correction to the forecasts to avoid an upward bias.[16] However, over the last year consumption has been higher than projected by the 2014 NEFR. AEMO removed the intercept correction in 2015, and this contributes to a relative increase in the forecasts.
- Since 2014, rooftop PV forecasts have been revised downwards, meaning there is a smaller offset from PV in the 2015 NEFR. Further detail on the rooftop PV forecasts is given in Section 3.2.2 below.

Over the medium and longer term, the average annual growth rates for the 2014 and 2015 NEFRs are comparable.

16 Refer to the 2014 Forecasting Methodology Information paper for more details available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/~/media/Files/Other/planning/NEFR/2014/2014%20Supplementary/2014_Forecasting_methodology_information_paper_NEW.ashx

3.2.2 Rooftop PV forecasts for Queensland

The 2015 NEFR is the first time AEMO has modelled residential and commercial PV separately. Systems less than 10 kW were classified as residential, while commercial systems were categorised as either small (less than 100 kW) or large (greater than 100 kW).

- Residential PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability of rooftop PV. The programs that incentivised the historical uptake have helped to establish a local industry and drive a reduction in PV technology and installation costs.
- Uptake in the commercial sector has been more recent, driven by a combination of programs such as the Clean Technology Investment Fund and SRES, as well as 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.

Table 10 shows the cumulative capacity and generation of installations by segment for the medium scenario. Uptake of residential PV installations continues over the short to medium term, then slows as it begins to reach saturation levels. Commercial PV continues to grow across the entire forecast period, with small commercial installations displaying the strongest growth.

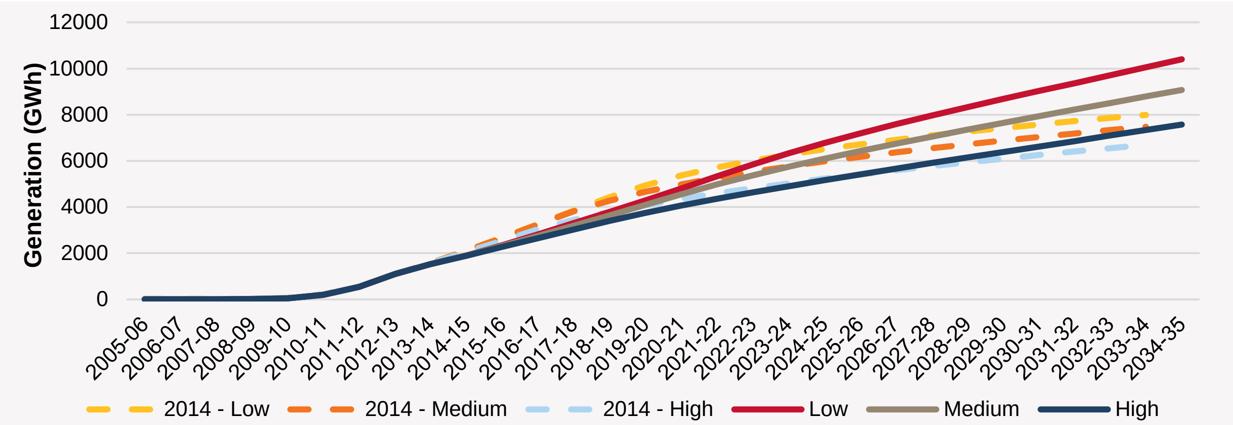
Table 10 Rooftop PV forecasts for Queensland

	Commercial PV		Residential PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014–15	102	115	1,415	1,779	**1,517**	**1,894**
2017–18	241	299	2,233	2,892	**2,474**	**3,191**
2024–25	647	846	3,900	5,243	**4,546**	**6,090**
2034–35	1,430	1,905	5,275	7,173	**6,705**	**9,078**

Figure 9 shows rooftop PV forecasts for the low, medium and high scenarios, and from the 2014 NEFR. The differences in the 2015 NEFR in the short term are due to less uptake over the last year than forecast in 2014, and in the medium to long term are mainly due to separate modelling of residential and commercial PV.

In the 2014 NEFR, because rooftop PV installations were all treated as residential, saturation levels were forecast to be reached from 2017–18, as indicated by the curve in the forecasts. The 2015 NEFR projections over the longer term see commercial PV dominating the overall growth, resulting in higher forecasts than the previous NEFR.

Figure 9 Queensland rooftop PV forecasts for low, medium and high consumption scenarios



Energy efficiency

AEMO adjusts its forecasts based on additional energy efficiency savings that are not already captured in the residential and commercial consumption. These are based on data from existing and planned future government programs.

In the medium scenario, the energy efficiency adjustments applied to the forecasts were:

- Short term – the adjustment increased from 91 GWh in 2014–15 to 551 GWh in 2017–18.
- Medium term – the adjustment increased from 551 GWh in 2017–18 to 1,686 GWh in 2024–25.
- Long term – the adjustment decreased from 1,686 GWh in 2024–25 to 1,436 GWh in 2034–35.

The adjustment decreases in the long term, because a larger proportion of the impacts of energy efficiency savings are already included in the forecast.

3.2.3 Industrial consumption for Queensland

Methodology Overview

Industrial loads are defined as loads with typical demand greater than 10 MW.[17] 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:[18]

- Manufacturing loads are those classified under Division C of the ANZSIC code. This includes primary and fabricated metal, petroleum, basic chemical, pulp and paper, non-metallic mineral, transport equipment, wood, and food product manufacturing.
- All loads not captured under Division C are defined as 'other'. In Queensland, this includes coal and metal ore mining.

Forecasts for industrial loads have been developed based on sectoral outlooks for each industry, and in consultation with individual industrial customers. For further details refer to the 2015 Forecasting Methodology Information Paper.

Forecasts

Historically, industrial consumption in Queensland has increased incrementally since 2006, mainly due to the expansion of coal mining. There has been some growth in consumption from the manufacturing sector, mostly because of the development of the Yarwun alumina refinery, which opened in 2005. The increase in consumption between 2013–14 and 2014–15 is largely due to the start of LNG production at one project, complemented by small increases from large manufacturers due to plant improvements.

For confidentiality reasons, the 2013–14 value for LNG is aggregated into the 'other' industrial category. From 2014–15, these projects are considered as a separate industry category.

Table 11 summarises industrial consumption in Queensland over the short, medium and long term, and explains key drivers.

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

[18] For more information on ANZSIC code classifications, refer to the ABS website, http://www.abs.gov.au/ausstats/abs@.nsf/Previousproducts/20C5B5A4F46DF95BCA25711F00146D75?opendocument

Table 11 Industrial consumption over the short, medium and long term for Queensland

Timeframe		Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)		15,345 to 23,292	14.9%	The short-term growth 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.
Medium term (2017–18 to 2024–25)	Inc. LNG	23,292 to 24,254	0.6%	Growth in the medium term is due to the final ramp-up of LNG manufacturing and continued growth in coal mining, though overall it is relatively small.
	Ex. LNG	14,217 to 14,582	0.4%	
Long-term (2024–25 to 2034–35)	Inc. LNG	24,254 to 25,579	0.5%	There are no changes from the medium term trends over this period.
	Ex. LNG	14,582 to 15,289	0.5%	

Differences between low, medium and high consumption scenarios for Queensland

For the low consumption scenario, AEMO assumed less favourable economic conditions resulting in:

- A general decline in the manufacturing sector.
- A 50% reduction in operations at the Boyne Island aluminium smelter in 2016–17 and final closure in 2028–29.
- The six LNG trains operating 15% below contract (approximately 20 Mtpa), with a slower ramp-up.

In the high consumption scenario, AEMO has assumed better economic conditions resulting in:

- A higher level of electricity consumption from the manufacturing sector.
- Stronger growth in coal mining.
- The six LNG trains operate at boilerplate capacity (above contract) with a faster ramp-up, plus a seventh train of 4.2 Mtpa capacity.

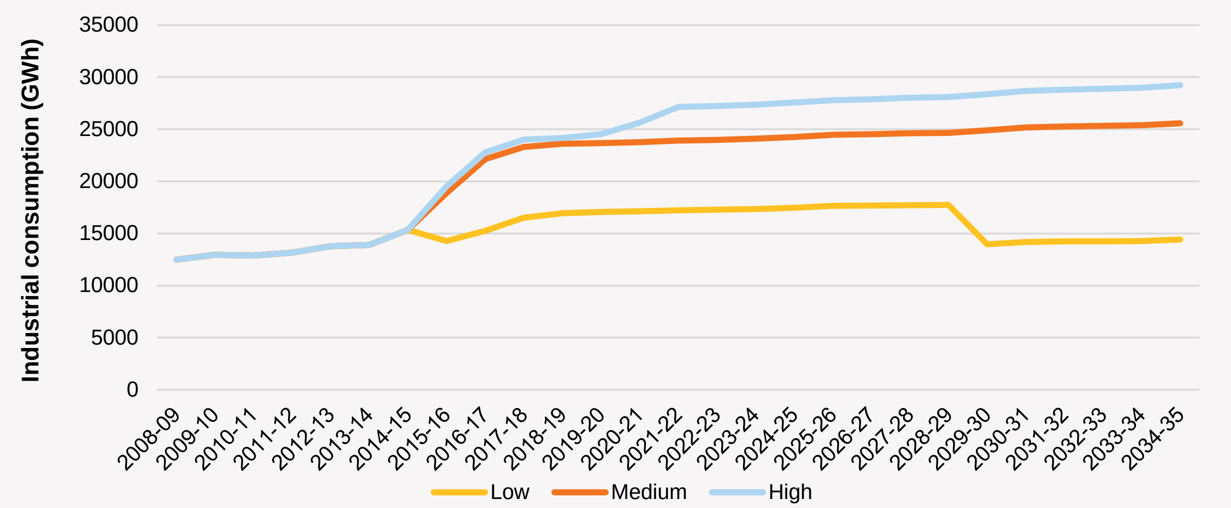
The average annual rates of change for the industrial sector for the low, medium and high scenarios in each outlook period are shown in Table 12, and the forecasts are shown in Figure 10.

Table 12 Average annual rates of change for the low, medium and high scenarios for Queensland

	Including LNG			Excluding LNG		
	Low	Medium	High	Low	Medium	High
Short term (2014–15 to 2017–18)	2.5%	14.9%	16.1%	-13.7%	-0.2%	1.2%
Medium term (2017–18 to 2024–25)	0.8%	0.6%	2.0%	0.3%	0.4%	0.5%
Long term (2024–25 to 2034–35)	-1.9%	0.5%	0.6%	-4.8%	0.5%	0.7%

In 2024–25, compared to the medium scenario, forecast industrial consumption is 28% lower in the low scenario, and 14% higher in the high scenario.

Figure 10 Comparison of low, medium and high industrial forecasts for Queensland



Queensland industrial consumption comparison to the 2014 NEFR

The 2015 NEFR has higher electricity usage projections in LNG production compared to 2014, because estimates of electricity used per TJ of gas produced have been revised upwards, based on actual meter data.

Underlying base case scenario assumptions of total LNG exports remain very similar, with limited changes to public information on project start-up timing and contracted volumes. There are more significant differences in the low and high scenario assumptions (the low scenario assumes exports are 15% lower than previously, due to lower contract take-or-pay levels, and the high scenario assumes that the seventh train comes in two years later).

Excluding LNG, industrial consumption in the 2014 NEFR was forecast to decline by an annual average of 0.1% annually, in the short term. The 2015 NEFR forecasts an average annual decline of 0.2%.

Including LNG, the 2014 NEFR forecast an average annual increase in consumption of 16.3% between 2014–15 and 2017–18. The 2015 NEFR forecasts an average annual increase of 14.9%.
The lower forecast growth rate in the 2015 NEFR is due to changes in consumption of electricity for LNG export. Although the forecast for electricity usage for LNG is higher than in the 2014 NEFR, the annual rate of growth is slower. The level of consumption in 2014–15 is higher than the 2014 NEFR predicted, which means a portion of the growth forecast in the 2014 NEFR has already been achieved.

In the 2015 NEFR, AEMO surveyed more Queensland industrial customers (31, compared to 24 last year). As a result, AEMO removed approximately 700 GWh[19] of energy from the residential and commercial segment, and added it to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

In the medium term, the 2015 NEFR forecasts average annual growth of 0.6%, compared to 0.3% forecast in 2014. This higher rate of growth is mostly due to larger growth in consumption from LNG, and also to changes in the non-LNG industrial load methodology.

In the 2015 NEFR, AEMO used economic sectoral forecasts, rather than survey information, to forecast medium-term and long-term industrial consumption. See the 2015 Forecasting Methodology Information Paper for more detail.

[19] Based on consumption levels in 2013–14.

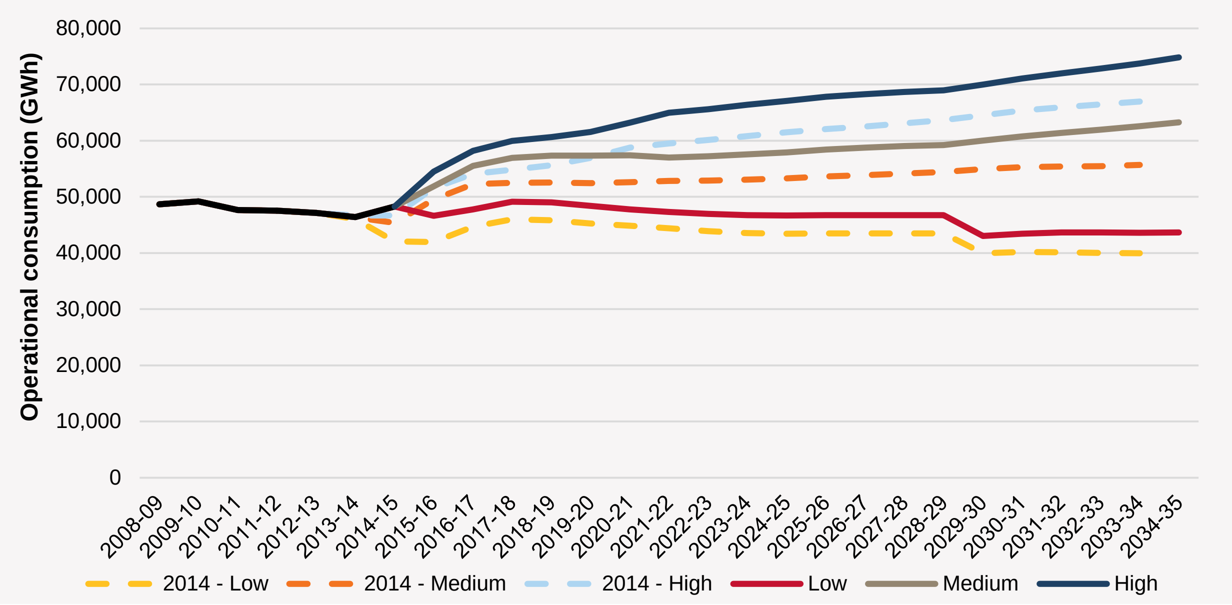
3.2.4 Differences between low, medium and high consumption scenarios for Queensland

Figure 11 compares the scenarios over the forecast period.

Operational consumption in the low scenario is 14%, 19% and 31% lower than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

Operational consumption in the high scenario is 5%, 16% and 18% higher than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

Figure 11 Comparison of the low, medium and high consumption scenarios for Queensland



3.3 Maximum demand in Queensland

3.3.1 Maximum demand in Queensland in 2014–15

Queensland's 2014–15 summer maximum demand was 8,831 MW, on 5 March 2015.[20] This was 210 MW above the 2014 NEFR 10% probability of exceedance (POE) forecast.[21] In other words, the maximum demand last year exceeded the demand that was expected to be the maximum one year out of ten. It was also the highest maximum demand recorded for Queensland since its previous record of 8,897 MW was set in 2009–10.

The 2014–15 maximum demand was 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 exceeded 30°C.

Brisbane's maximum temperature for the summer period was 38.9°C on 16 November 2014. Demand on this day reached 8,016 MW, and was probably lower because it was a Sunday rather than a weekday.

3.3.2 Methodology Overview

Maximum demand is driven by demand from the residential and commercial sector. It is therefore driven by the same variables as residential and commercial consumption, namely population, GSP, electricity prices, and weather. Weather has a significant impact, with cooling loads increasing on high temperature days, resulting in high demand.

Rooftop PV generation offsets demand, but less so in the later parts of the day. As installed capacity increases and demand is offset, the peak shifts to later in the day. Once this shift occurs, rooftop PV generation will have a smaller impact on maximum demand.

Unlike residential load, industrial load remains relatively flat during high temperature days. Industrial load is more likely to respond to price signals than temperature. AEMO investigates the impact of prices on industrial demand with an analysis of demand side participation (DSP), to be published separately.

3.3.3 Key points for Queensland maximum demand forecasts

- The 10% POE maximum demand is forecast to increase at an annual average rate of 2.8% over the short term (2014–15 to 2017–18). This is primarily driven by increased LNG demand.
- Rooftop PV generation is expected to shift the time of maximum demand from 17:00 to 19:30 over the forecast period.
- Load factors[22] in Queensland are expected to decrease due to increasing penetration of rooftop PV. Rooftop PV is expected to have a greater impact on annual consumption and average demand than on maximum demand in Queensland over the forecast period. This is because Queensland does not adopt daylight savings, so rooftop PV does not offset much of the evening peak after the initial shift.

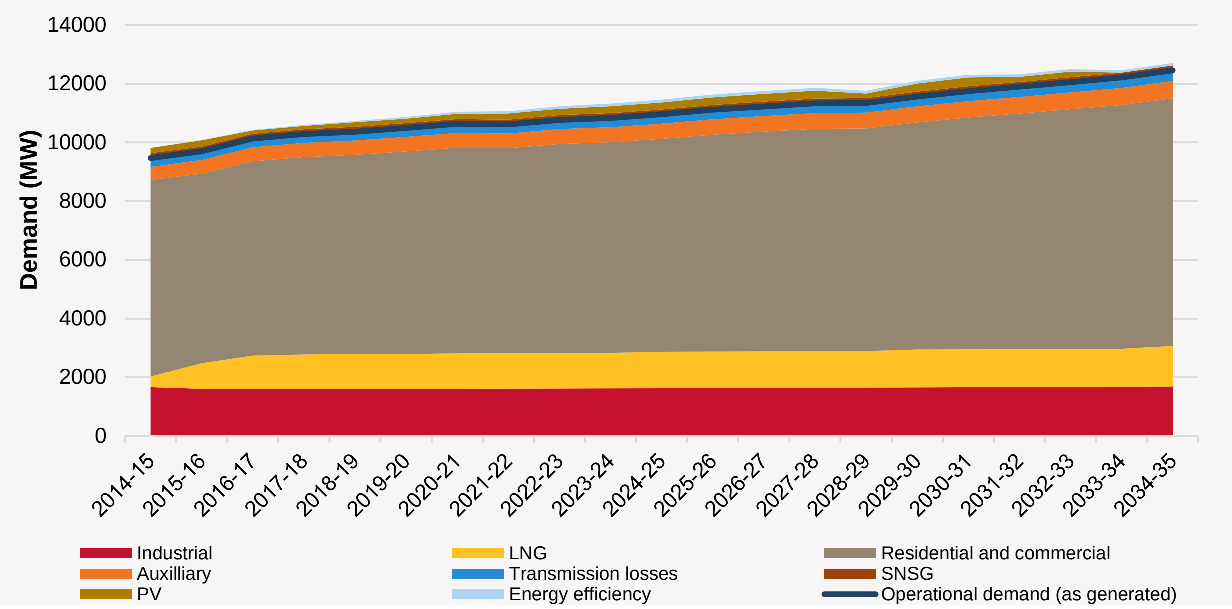
Table 13 summarises Queensland's summer 10% POE maximum demand forecasts and key drivers, while Figure 12 shows the breakdown by key components.

[20] Queensland summer is defined as October to March for maximum demand.
[21] See Section 1.3 for definitions of probability of exceedance (POE).
[22] 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.

Table 13 Summer 10% POE maximum demand and key drivers for Queensland

Timeframe	Forecast (MW)	Average annual change	Drivers
Short-term (2014–15 to 2017–18)	9,465 to 10,282	2.8%	The ramp-up of the three LNG projects to 2017–18 increases the demand from the industrial sector.
Medium term (2017–18 to 2024–25)	10,282 to 10,956	0.9%	Continued recovery in residential and commercial demand, due to population growth. The offset provided by rooftop PV declines over the later years as the time of maximum demand shifts to later in the evening.
Long term (2024–25 to 2034-35)	10,956 to 12,455	1.3%	

Figure 12 Summer 10% POE maximum demand forecast by key components for Queensland

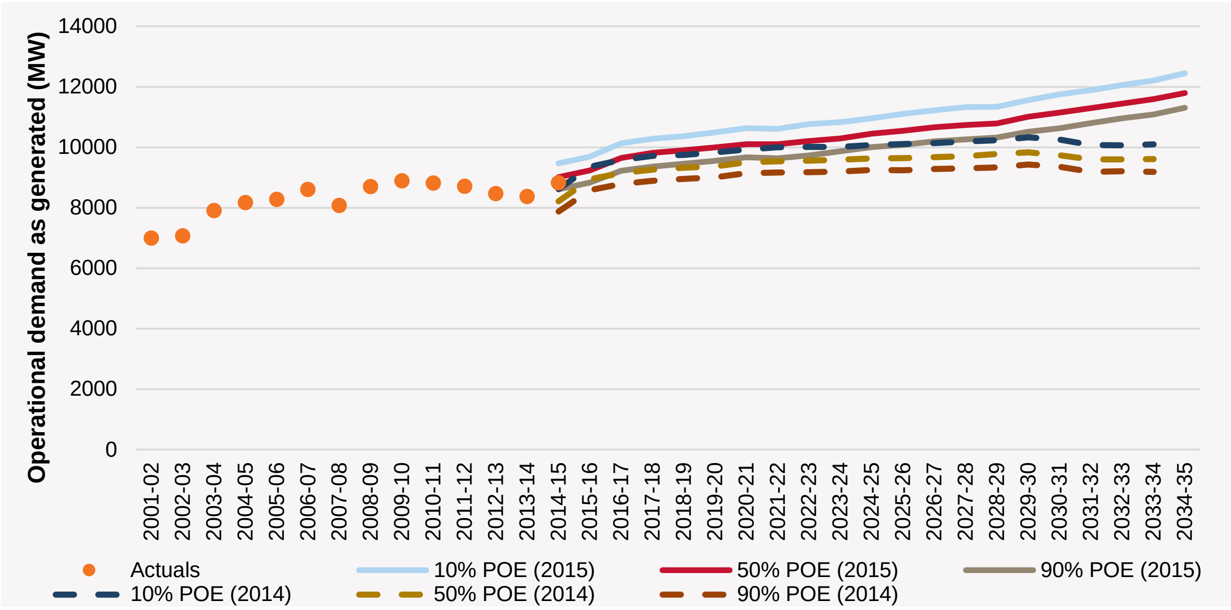


A comparison of the summer 90%, 50% and 10% POE forecasts, for the 2014 NEFR and 2015 NEFR, is given in Figure 13.

The 2015 NEFR forecasts for operational maximum demand are higher than in the 2014 NEFR, mainly because:

- Rooftop PV installed capacity forecasts have been revised downwards in the medium term, resulting in higher residential and commercial demand.
- Forecast LNG demand has increased, primarily due to revised forecasts based on actual demand data.
- If high demand events occur, the maximum demand model will produce a greater spread between the 10%, 50% and 90% POEs to better reflect these peaks. High actual maximum demand in the 2014–15 summer has resulted in an increased residential and commercial 10% POE forecast.
- Population forecasts are higher in the 2015 NEFR compared to the 2014 NEFR.
- Electricity prices are projected to fall in 2030 when the Renewable Energy Target (RET) ends, resulting in increased demand from the residential and commercial sector.
- Reconciliation of maximum demand forecasts with annual consumption forecasts is more sophisticated in the 2015 NEFR.

Figure 13 Summer 90%, 50% and 10% POE maximum demand forecasts for Queensland

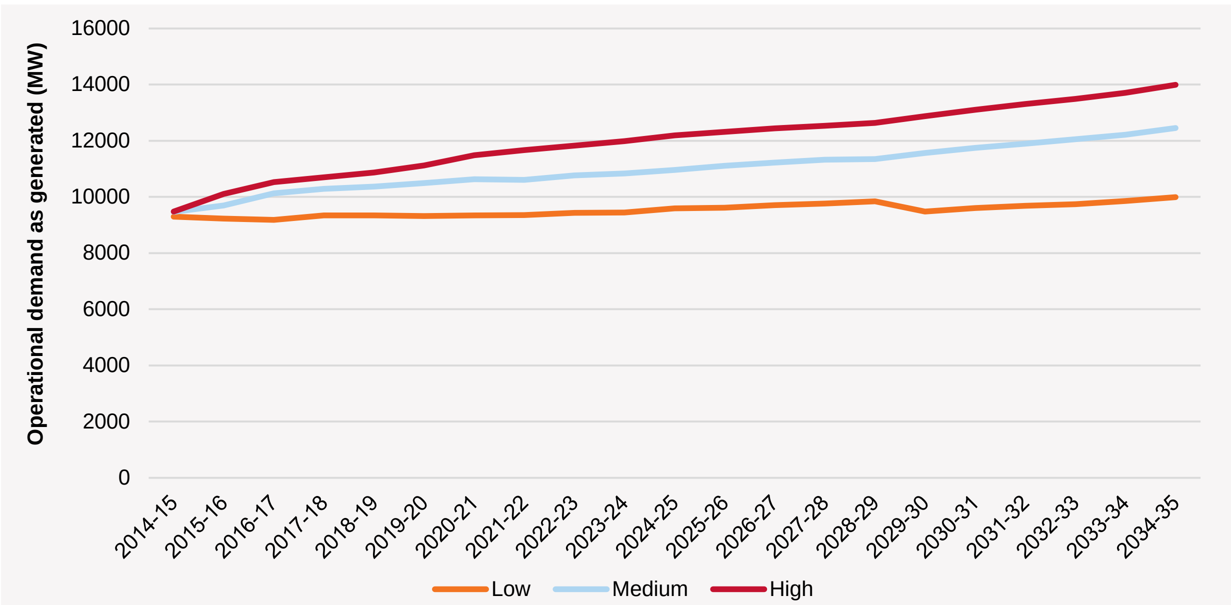


Differences between low, medium, and high consumption scenario forecasts for Queensland maximum demand

As maximum demand is driven by the residential and commercial sector, as with annual consumption, the differences between the low, medium and high maximum demand scenarios are driven by differences in the electricity price, population and GSP forecasts,
as well as the assumptions on rooftop PV and energy efficiency uptake.

Figure 14 shows a comparison of the 10% POE forecasts across the three maximum demand scenarios.

Figure 14 Summer 10% POE forecast scenarios for Queensland

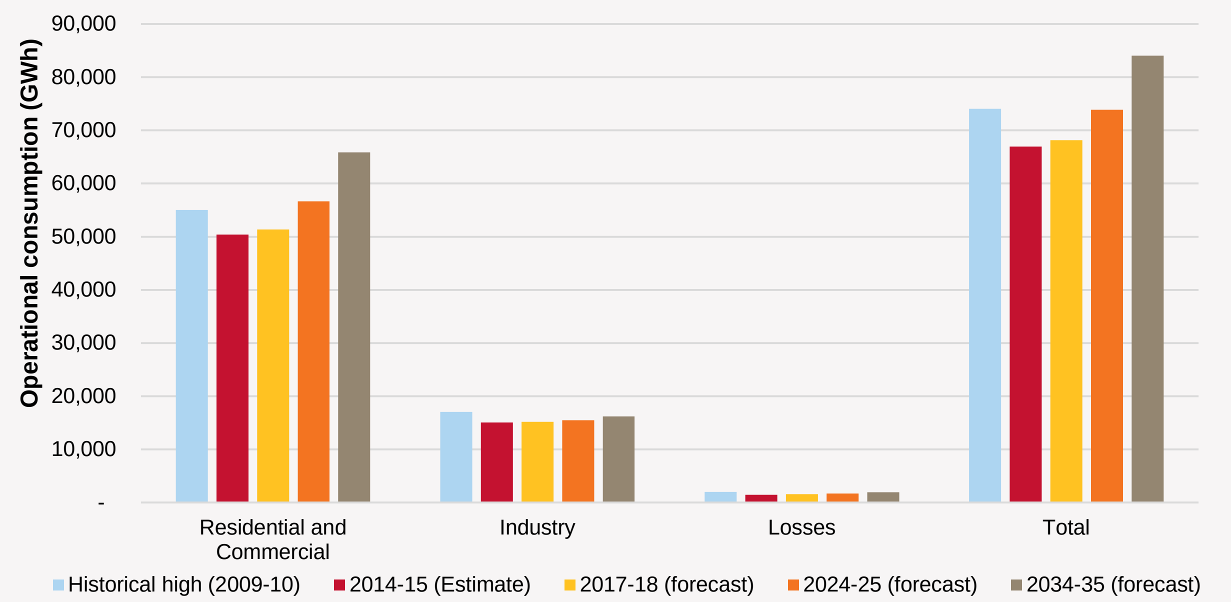


CHAPTER 4. NEW SOUTH WALES (INCLUDING THE AUSTRALIAN CAPITAL TERRITORY)

4.1 Key points for New South Wales

- Overall consumption in the New South Wales region (including the ACT) is driven largely by the residential and commercial sector, which represents the largest proportion of the New South Wales load.
- New South Wales will not recover to its historic operational consumption record[23] until 2025–26 (see Figure 15), when population is forecast to be 1.2 million higher than in 2014–15.
- The recovery in residential and commercial consumption is driven by population growth, and a decline in electricity prices which slows the continuing decline in per capita consumption to 2020–21, from which point per capita consumption increases (see Figure 16).
- There is a continued uptake of rooftop PV in the residential and commercial sectors (see Table 17) and energy efficiency measures.
- Maximum demand is forecast to decrease slightly in the short term, and recover slowly as population and Gross State Product increases in the medium and long term (see Table 20).

Figure 15 Comparison of actual and forecast operational consumption



4.2 Annual operational consumption in New South Wales

From 2006-07 to 2010–11, operational consumption in New South Wales remained relatively flat, with the decline in residential and commercial consumption from 2009–10 offset by increases in industrial consumption (see Figure 16).

From 2010–11 to 2014–15, there were closures and production curtailment in the industrial sector, and total operational consumption fell in this period.

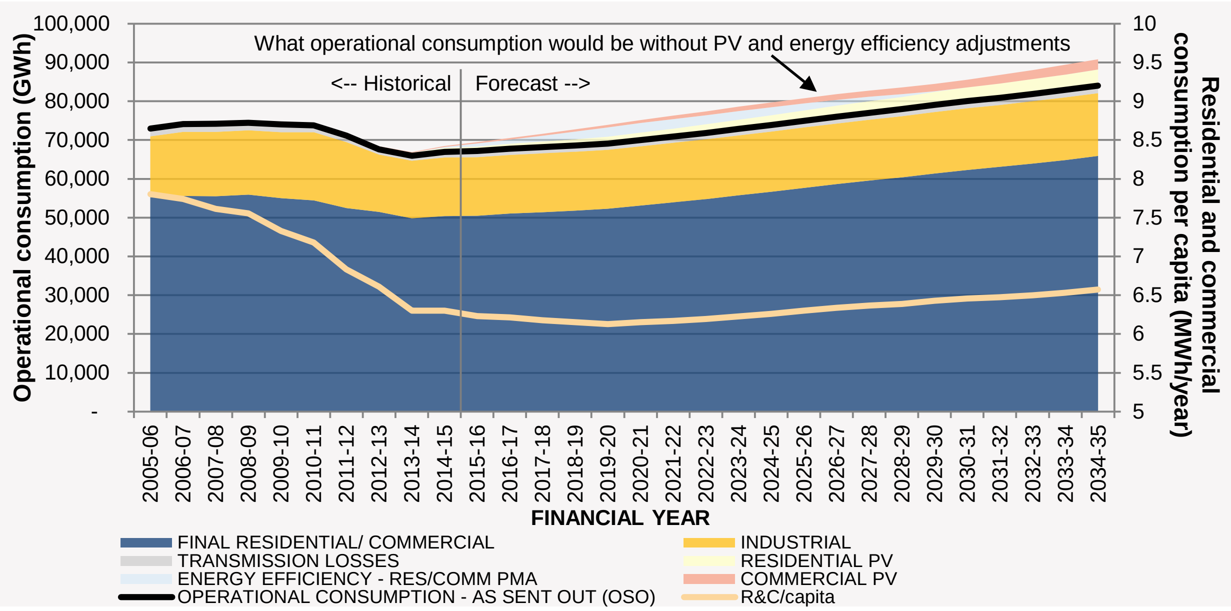
In the short term (2014–15 to 2017–18), AEMO forecasts a recovery in operational consumption, driven by the residential and commercial sector, which represents the largest proportion of the total state load.

[23] New South Wales recorded its highest historical level of operational consumption of 74,414 GWh in 2008–09.

Medium and long term forecasts indicate a stronger recovery in operational consumption, again driven primarily by the residential and commercial sector. New South Wales is the only NEM region to have a slight increase in per capita consumption, driven by a relative fall in electricity prices and increase in average income. New South Wales also has the lowest proportion of rooftop PV of all the NEM regions, so it has a lower impact of rooftop PV offsetting consumption from the grid.

Figure 16 illustrates the forecasts by key components, and Table 14 summarises forecasts under the medium scenario, and drivers for these results.

Figure 16 Operational forecasts by key component in New South Wales



The historical decline in operational consumption is evident in Figure 16, as is the forecast increase in residential and commercial consumption. The black line indicates operational consumption, while the top of the graph indicates what the operational consumption would be if it was not reduced by rooftop PV and energy efficiency measures.

Table 14 Operational consumption over the short, medium and long term in New South Wales

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	66,935 to 68,151	0.6%	Forecast recovery in operational consumption is driven by the residential and commercial sector. A recent fall in electricity prices, combined with increased average income results in a recovery in underlying consumption which is only partially offset by rooftop PV and energy efficiency. New South Wales has the smallest proportion of PV generation relative to its load.
Medium term (2017–18 to 2024–25)	68,151 to 73,878	1.2%	
Long term (2024–25 to 2034–35)	73,878 to 84,030	1.3%	

Despite the forecast increase, operational consumption is not projected to recover to the historical high of 74,414 GWh[24] until 2025–26. This is despite a projected increase in population of 1.2 million between 2014–15 and 2025-26.

[24] New South Wales experienced its historical high for operational consumption in 2008-09.

4.2.1 Residential and commercial consumption in New South Wales

Methodology Overview

Underlying consumption refers to the electricity used by the residential and commercial sector, whether it is drawn from the electricity grid or not. It is forecast over a 20-year horizon, with the key modelled drivers being population, income, weather, and electricity prices.

In this long-term methodology, residential and commercial consumers are modelled as responding to increases or decreases in average prices, as well as the average income measured by Gross State Product (GSP). In general, consumption increases if income increases, and decreases if electricity prices increase. For further detail, see the 2015 Forecasting Methodology Information Paper.

AEMO models residential and commercial consumption in two stages:

1. It forecasts per capita consumption, to capture underlying usage trends by removing the impact of population growth. This is why per capita consumption is the key metric in analysing the forecasts.
2. It then uses population growth forecasts to calculate overall underlying consumption.

The underlying consumption is then offset by forecast rooftop PV generation (which reduces electricity drawn from the grid) and adjustments to account for energy efficiency impacts not already captured in the underlying trends.

Forecasts

Historically, residential and commercial consumption in New South Wales has been declining from 2009–10 to 2014–15, with consumption per capita decreasing from 7.3 MWh/year to 6.3 MWh/year, due to a rapid increase in electricity prices as well as the uptake of rooftop PV and energy efficiency measures.

This decline in per capita consumption has slowed over recent years, and consumption recovered slightly last year, from 49,797 GWh in 2013–14 to 50,414 GWh in 2014–15. This recovery is despite an increasing number of rooftop PV installations, which offset consumption drawn from the grid, and a summer with relatively few extreme weather days.

The consumption forecast relies on the forecast economic and demographic variables shown in Figure 17.

Key points in the variables are:

- Population growth continues, although the rate of growth slows over the forecast period.
- Gross State Product (GSP) grows in real terms.
- The electricity price is forecast to fall substantially over the next few years, based on the draft revenue determination by the Australian Energy Regulator (AER) for the New South Wales distribution businesses.[25] After the initial fall, prices are forecast to rise again in real terms, but at a much slower rate, until 2029–30, when there is an estimated decrease due to the end of the Renewable Energy Target (RET).

[25] The electricity forecasts were based on the draft determination. 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.

Figure 17 Key drivers of residential and commercial underlying consumption in New South Wales

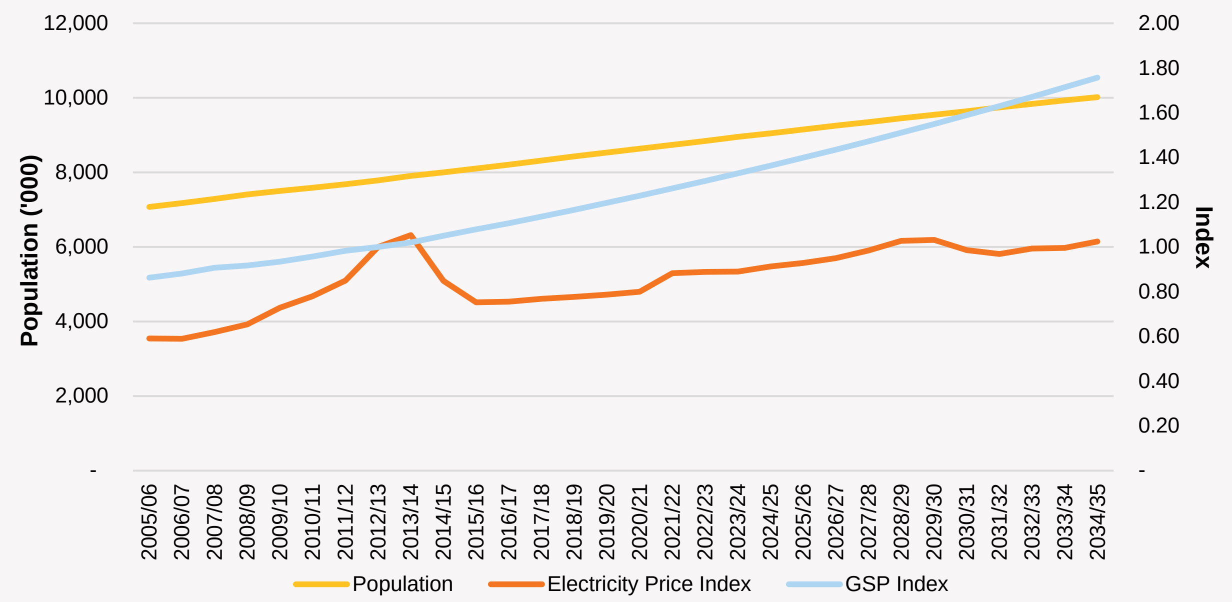


Table 15 summarises the forecast annual residential and commercial consumption over the short, medium and long term, with drivers. In the short term, the primary driver is the relatively lower electricity prices, and over the longer term, recovery is driven by income per capita (indicated by the increase in per capita consumption during this period) as well as population growth.

Table 15 Consumption in the residential and commercial sector over the short, medium and long term in New South Wales

Timeframe	Forecast (GWh)	Average annual change	Consumption per capita (MWh/yr)	Drivers
Short term (2014–15 to 2017–18)	50,414 to 51,390	0.6%	6.3 to 6.2	Underlying consumption recovers, driven by a combination of population and income growth, and the relatively lower electricity prices. This is moderated by growth in PV and energy efficiency, which offsets 70% of underlying consumption growth.
Medium term (2017–18 to 2024–25)	51,390 to 56,676	1.4%	6.2 to 6.3	Recovery in underlying consumption continues at a similar rate, driven by income and population. This recovery outpaces the uptake of rooftop PV and energy efficiency, with these only offsetting around 30% of underlying consumption.
Long term (2024–25 to 2034–35)	56,676 to 65,868	1.5%	6.3 to 6.6	Income per capita grows over the long term, driving an increase in underlying consumption. Over this period, uptake of rooftop PV still continues, although at a slower rate.

Although there is continued uptake of rooftop PV in New South Wales, it still represents the lowest proportion of total load of all the NEM regions (see Table 5), and thus provides a smaller relative offset to underlying increases in consumption.

Differences between low, medium and high consumption scenarios in New South Wales

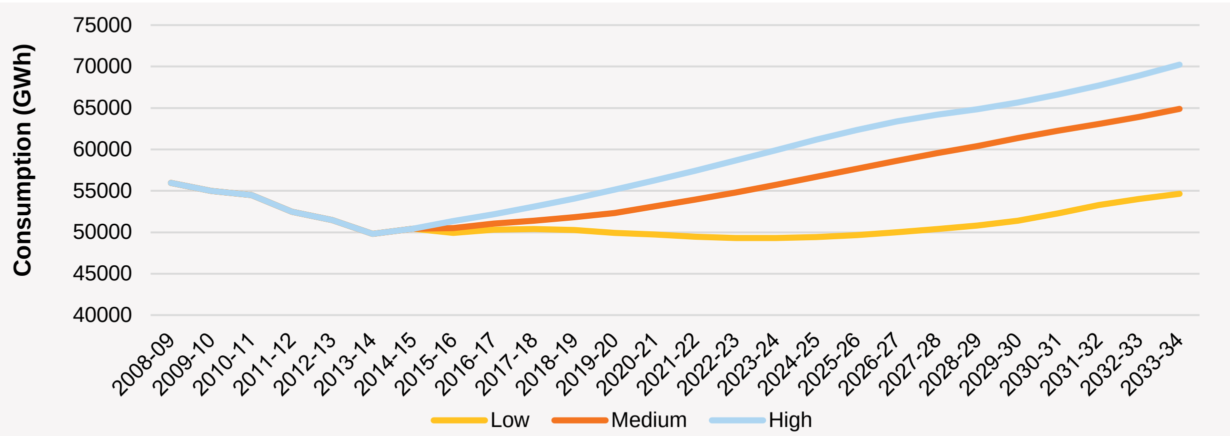
The differences between the low, medium and high consumption scenarios are driven by differences in electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 16, and the forecasts are shown in Figure 18.

Table 16 Average annual rates of change for the low, medium and high consumption scenarios in New South Wales

	Low	Medium	High
Short term (2014–15 to 2017–18)	0.0%	0.6%	1.7%
Medium term (2017–18 to 2024–25)	-0.3%	1.4%	2.0%
Long term (2024–25 to 2034–35)	1.1%	1.5%	1.6%

Figure 18 Comparison of low, medium and high residential and commercial scenarios for New South Wales



In 2024–25, compared to the medium scenario, forecast residential and commercial consumption is 13% lower in the low scenario, and 8% higher in the high scenario.

New South Wales residential and commercial consumption comparison to 2014 NEFR

To keep improving the NEFR, AEMO often reclassifies loads from the residential and commercial segment to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

The 2015 forecasts are higher than those developed in the 2014 NEFR, largely due to lower electricity prices and projected higher income, which are expected to increase underlying consumption. This outpaces the relative increase in rooftop PV in the 2015 NEFR.

Consumption growth rates in the medium scenario for the 2014 NEFR were 0.5%, 0.5% and 0.7% respectively for the short, medium and long term periods. While the short-term rates are similar to the 2015 forecasts, Table 16 illustrates higher growth rates in the medium to long term.

Per capita consumption in the 2015 NEFR increases from 6.2 to 6.6 MWh/year from 2017–18 to 2034–35 (New South Wales is the only region to have a forecast per capita consumption increase). In the 2014 NEFR, per capita consumption continued to decline over this period, from 6.3 to 5.9 MWh/year.

4.2.2 Rooftop PV forecasts for New South Wales

The 2015 NEFR is the first time AEMO has modelled residential and commercial PV separately. Systems less than 10 kW were classified as residential, while commercial systems were categorised as either small (less than 100 kW) or large (greater than 100 kW).

- Residential PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability rooftop PV. The programs that incentivised the historical uptake have helped to establish a local industry and drive a reduction in PV technology and installation costs.
- Uptake in the commercial sector has been more recent, driven by a combination of programs such as the Clean Technology Investment Fund and SRES, as well as 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.

Table 17 shows the cumulative capacity and generation of installations by segment for the medium scenario. New South Wales has had the highest historical growth in uptake of commercial PV of the NEM regions. Both residential and commercial PV continue to grow across the entire forecast period, with small commercial installations displaying the strongest growth, and in 2034–35, New South Wales is forecast to have the highest installed capacity of commercial PV of the NEM regions. The estimated PV generation remains, however, a relatively low proportion of the region's total consumption.

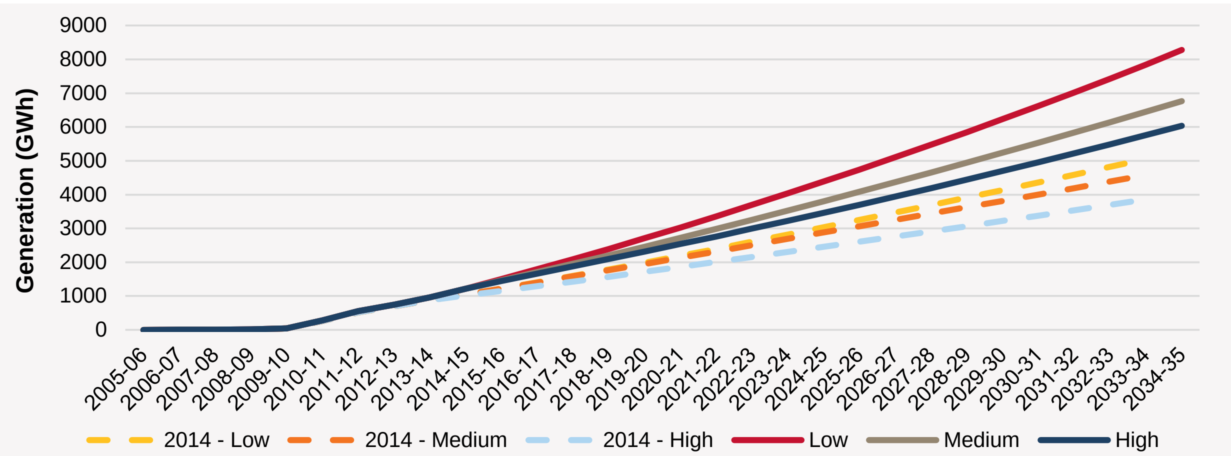
Table 17 Rooftop PV forecasts for New South Wales

	Commercial PV		Residential PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014–15	193	204	855	1,012	**1,048**	**1,216**
2017–18	422	490	1,203	1,464	**1,625**	**1,954**
2024–25	1,039	1,267	2,047	2,536	**3,086**	**3,803**
2034–35	2,123	2,633	3300	4,131	**5,424**	**6,764**

A comparison of rooftop PV forecasts for the low, medium and high scenarios, and from the 2014 NEFR, is given in Figure 19. The differences in the 2015 NEFR are mainly due to separate modelling of residential and commercial PV.

All 2015 NEFR scenario forecasts for New South Wales are greater than the 2014 low scenario forecasts. This difference is attributable to growth in the commercial sector.

Figure 19 Rooftop PV forecasts for low, medium and high consumption scenarios in New South Wales



Energy efficiency

AEMO adjusts its forecasts based on additional energy efficiency savings that are not already captured in the residential and commercial consumption. These are based on data from existing and planned future government programs.

In 2015, AEMO received additional data from the New South Wales Office of Environment and Heritage on several of its energy efficiency schemes targeting small businesses.

In the medium scenario, the energy efficiency adjustments applied to the forecasts were:

- Short term – the adjustment increased from 300 GWh in 2014–15 to 1,527 GWh in 2017–18.
- Medium term – the adjustment increased from 1,527 GWh in 2017–18 to 2,022 GWh in 2024–25.
- Long term – the adjustment decreased from 2,022 GWh in 2024–25 to 0 GWh in 2034–35.

The adjustment decreases in the long term, because a larger proportion of the impacts of energy efficiency savings are already included in the forecast.

4.2.3 Industrial consumption in New South Wales

Methodology Overview

Industrial loads are defined as loads with typical demand greater than 10 MW.[26] 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:[27]

- Manufacturing loads are those classified under Division C of the ANZSIC code. In New South Wales this includes primary and fabricated metal, petroleum, basic chemical, pulp and paper, non-metallic mineral, wood, and food product manufacturing.
- All loads not captured under Division C are defined as 'other'. In New South Wales, this includes coal and metal ore mining.

Forecasts for industrial loads have been developed based on sectoral outlooks for each industry and in consultation with individual customers. For further detail refer to the 2015 Forecasting Methodology Information Paper.

Forecasts

The highest level of industrial consumption in NSW occurred in 2010–11. From 2011–12, consumption decreased due to the curtailment of steel-making capacity, and then consumption further decreased in 2012–13 following the closure of the Kurri Kurri aluminium smelter.

Over the last two years consumption has recovered, primarily due to increased consumption in the coal mining and paper and pulp manufacturing sectors.

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

[27] For more information on ANZSIC code classifications, refer to the ABS website, http://www.abs.gov.au/ausstats/abs@.nsf/Previousproducts/20C5B5A4F46DF95BCA25711F00146D75?opendocument

Table 18 shows the forecasts and key drivers in the short, medium and long term.

Table 18 Industrial consumption over the short, medium and long term in New South Wales

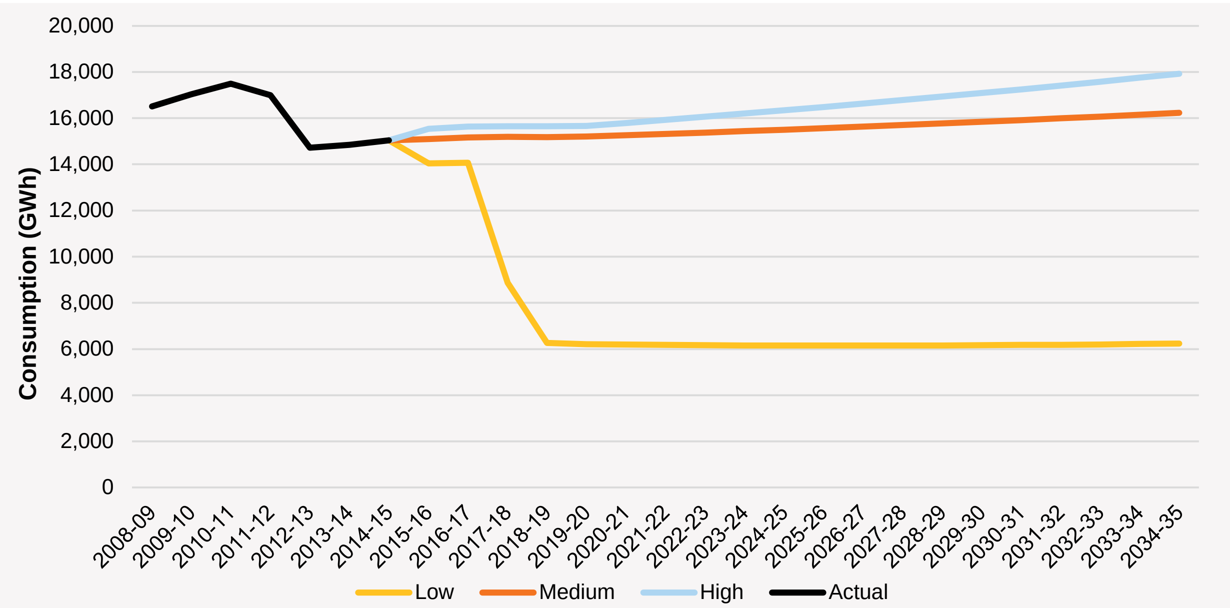
Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	15,045 to 15,191	0.3%	Expansion in ore mining offsets any decline due to the closure of the Kurnell refinery in 2015.
Medium term (2017–18 to 2024–25)	15,191 to 15,499	0.3%	This is primarily driven by growth in coal mining as a number of projects reach full production, and an increase in the production of building materials, such as steel and cement, to support growth in the residential construction sector.
Long term (2024–25 to 2034–35)	15,499 to 16,225	0.5%	

Differences between low, medium and high scenarios for New South Wales

The scenario forecasts are shown in Figure 20. The low consumption scenario assumes a decline in the manufacturing sector and the closure of the Tomago aluminium smelter from 2016-17.

The high consumption scenario assumes that there will be growth in consumption in both the manufacturing and mining sectors.

Figure 20 Comparison of low, medium and high consumption scenarios for industrial load



The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 19.

Table 19 Average annual rates of change for the low, medium and high consumption scenarios

	Low	Medium	High
Short term (2014–15 to 2017–18)	-16.1%	0.3%	1.3%
Medium term (2017–18 to 2024–25)	-5.1%	0.3%	0.6%
Long term (2024–25 to 2034–35)	0.1%	0.5%	0.9%

In 2024–25, compared to the medium scenario, forecast industrial consumption is 60% lower in the low scenario, and 5% higher in the high scenario.

New South Wales industrial consumption comparison to 2014 NEFR

To keep improving the NEFR, AEMO often reclassifies loads from the residential and commercial segment to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

The 2014 NEFR forecast an average annual increase of 0.8% between 2014–15 and 2017–18. In the 2015 NEFR, AEMO has forecast an average annual increase of 0.3% over the same period. Both forecasts estimate fairly flat consumption beyond 2015–16. In the 2014 NEFR, AEMO forecast a temporary decline in consumption in 2014–15 (due to projected softness in steel and metals production) and a subsequent rebound in consumption in the following year. This decline did not eventuate, so the 2015 NEFR has a higher value for consumption in 2014–15, and a lower annual rate of change over the long term.

In the medium term, the 2014 NEFR forecast an average annual decline of 0.6%, and the 2015 NEFR forecasts an average annual change of 0.3%. Both forecasts represent fairly flat consumption, and the difference in the direction of the growth is due to changes in methodology. In the 2015 NEFR, AEMO used economic sectoral forecasts, rather than survey information, to forecast medium and long term industrial consumption. See the 2015 Forecasting Methodology Information Paper for more detail.

4.2.4 Differences between low, medium, and high consumption scenario forecasts for New South Wales

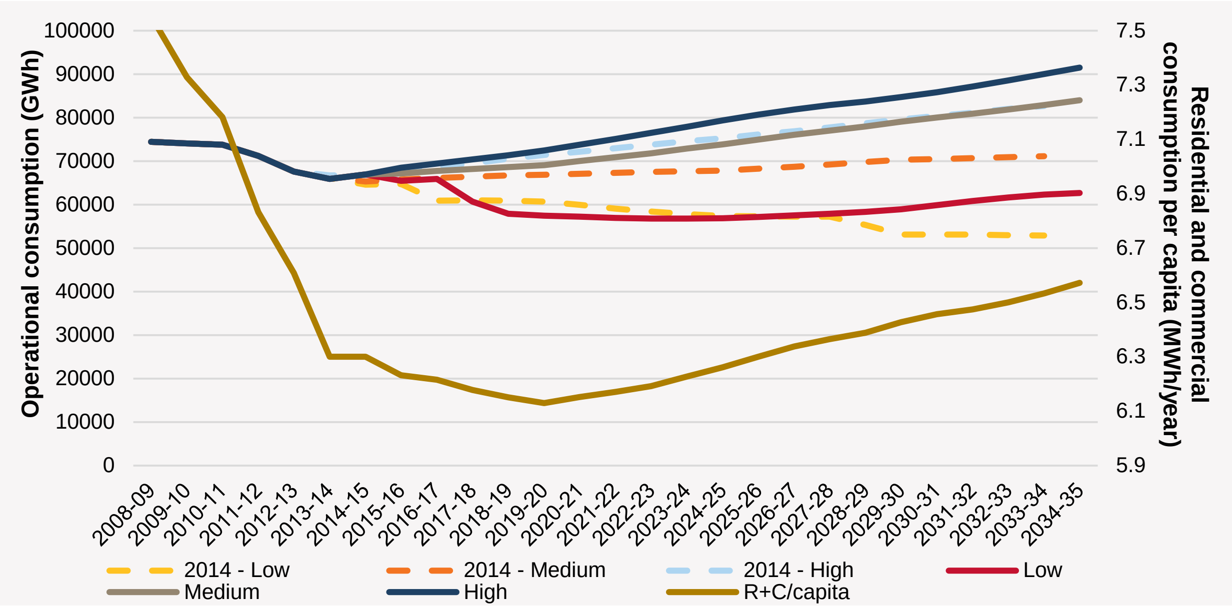
Figure 21 compares the scenarios over the forecast period.

Operational consumption in the low scenario is 11%, 23% and 25% lower than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

Operational consumption in the high scenario is 3%, 7% and 9% higher than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

The 2015 forecasts are higher than those of the 2014 NEFR, for the reasons outlined above in the industrial and residential and commercial sectors. Operational consumption in 2014–15 was 2.4% higher than was forecast in the 2014 NEFR, and is forecast to remain 2.6% higher in 2017–18 than the 2014 NEFR forecast.

Figure 21 Comparison of low, medium and high operational consumption for New South Wales



4.3 Maximum demand for New South Wales

4.3.1 Maximum demand in New South Wales 2014–15

New South Wales' 2014–15 summer maximum demand was 11,883 MW, on 21 November 2014.[28] This was 427 MW below the 2014 NEFR 50% probability of exceedance (POE) forecast.[29] In other words, maximum demand last year was average, being closest to the demand that was expected to be the maximum in one out of every two years.

The 2014–15 summer was characterised by warm average temperatures, but relatively few days with maximum temperature over 30°C. The 2014–15 maximum demand fell 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 hottest four days over the summer period occurred on weekends, when demand is generally lower. For example, Sydney's maximum temperature for the summer period was 36.5°C on 1 November 2014, when demand reached 9,485 MW.

4.3.2 Methodology Overview

Maximum demand is driven by demand from the residential and commercial sector. It is therefore driven by the same variables as residential and commercial consumption, namely population, GSP, electricity prices, and weather. Weather has a significant impact, with cooling loads increasing on high temperature days, resulting in high demand.

Rooftop PV generation offsets maximum demand in New South Wales. As the installed capacity increases, maximum demand continues to be offset.

Unlike residential load, industrial load remains relatively flat during high temperature days. Industrial load is more likely to respond to price signals than temperature. AEMO investigates the impact of prices on industrial demand with an analysis of demand side participation (DSP) to be published separately.

4.3.3 Key points for New South Wales maximum demand forecasts

- The 10% POE maximum demand is forecast to decrease at an annual average rate of 0.4% over the short term (2014–15 to 2017–18). This is primarily because the warm average temperatures in the 2014–15 summer pushed up average demand, and demand is only expected to recover slowly to the level of that summer as population and GSP increase over time.
- Load factors[30] are expected to remain relatively flat in New South Wales compared to other NEM regions.
- Expected time of maximum demand is not expected to shift, as it will in other NEM regions, due to the low proportion of rooftop PV in New South Wales.

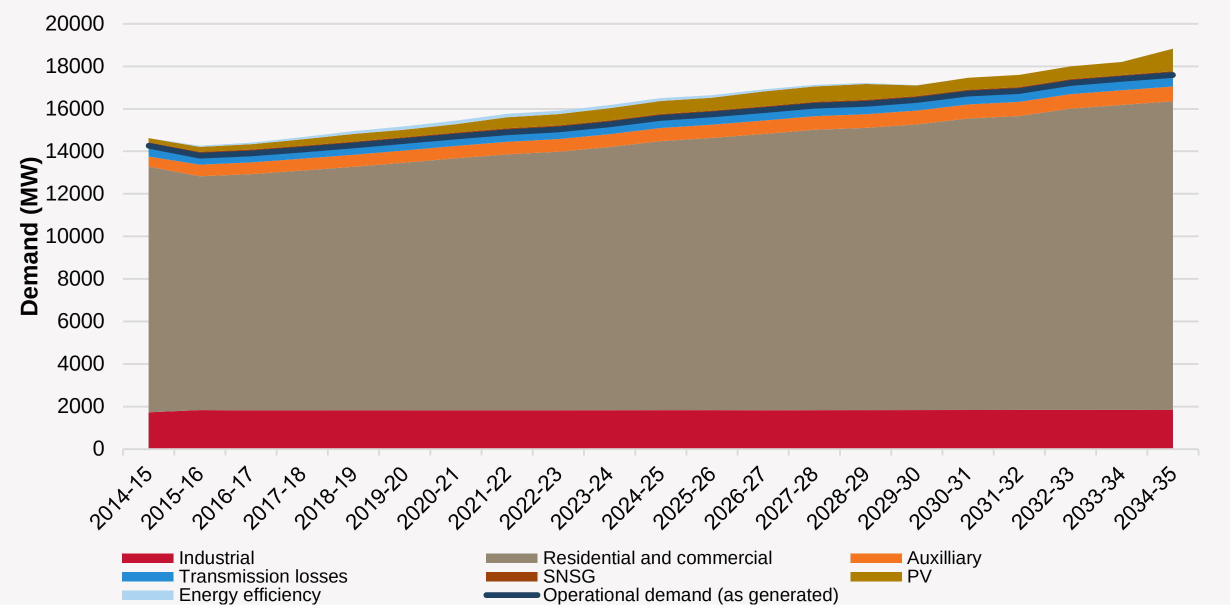
[28] NSW summer is defined as October to March for maximum demand.
[29] See Section 1.3 for definitions of probability of exceedance (POE).
[30] The load factor is the ratio of average demand to maximum demand. See Glossary for more details. A lower load factor means a bigger difference between average and maximum demand.

Table 20 summarises the summer 10% POE forecasts and key drivers, and Figure 22 shows the breakdown by key components.

Table 20 Summer 10% POE maximum demand and key drivers

Timeframe	Forecast (MW)	Average annual change	Drivers
Short-term (2014–15 to 2017–18)	14,265 to 14,083	-0.4%	Warm average temperatures in the 2014–15 summer pushed up average demand, and demand is only expected to recover slowly to that level as population and GSP increase over time.
Medium term (2017–18 to 2024–25)	14,083 to 15,572	1.4%	Increasing population and GSP drives recovery in residential and commercial maximum demand.
Long term (2024–25 to 2034–35)	15,572 to 17,585	1.2%	

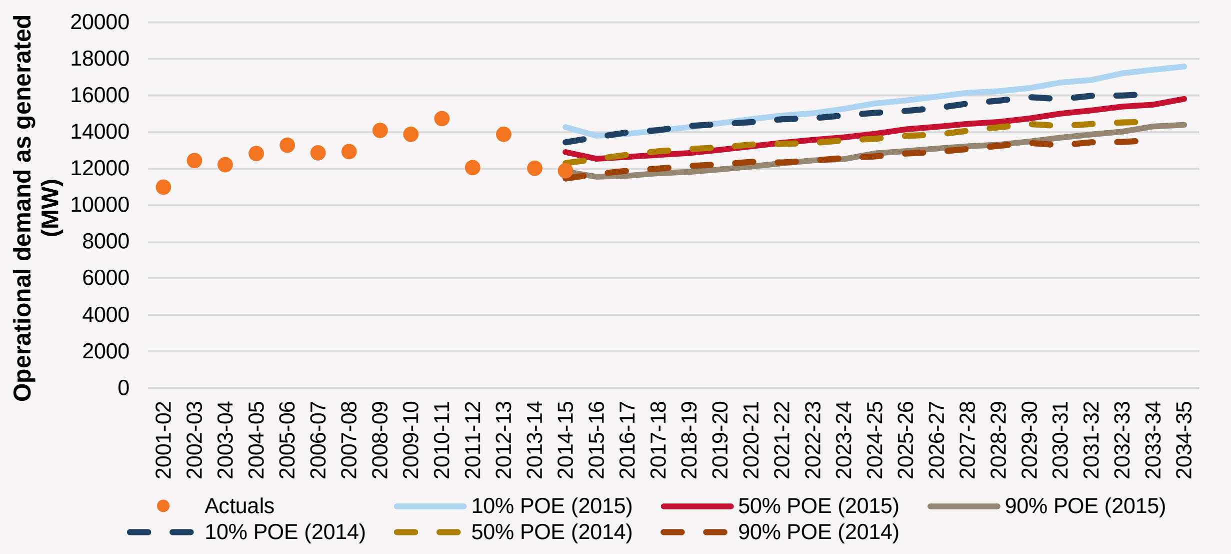
Figure 22 Summer 10% POE maximum demand forecast segments for New South Wales



A comparison of the summer 90%, 50% and 10% POE forecasts, for the 2014 NEFR and 2015 NEFR, is given in Figure 23. The two forecasts are close in the short term, although in the medium term the 2015 NEFR forecasts are higher, mainly due to:

- Population and GSP forecasts being higher in the 2015 NEFR compared to the 2014 NEFR.
- Relatively lower electricity prices.
- More sophisticated reconciliation of maximum demand forecasts with annual consumption forecasts.

Figure 23 Summer 90%, 50% and 10% POE maximum demand forecasts for New South Wales



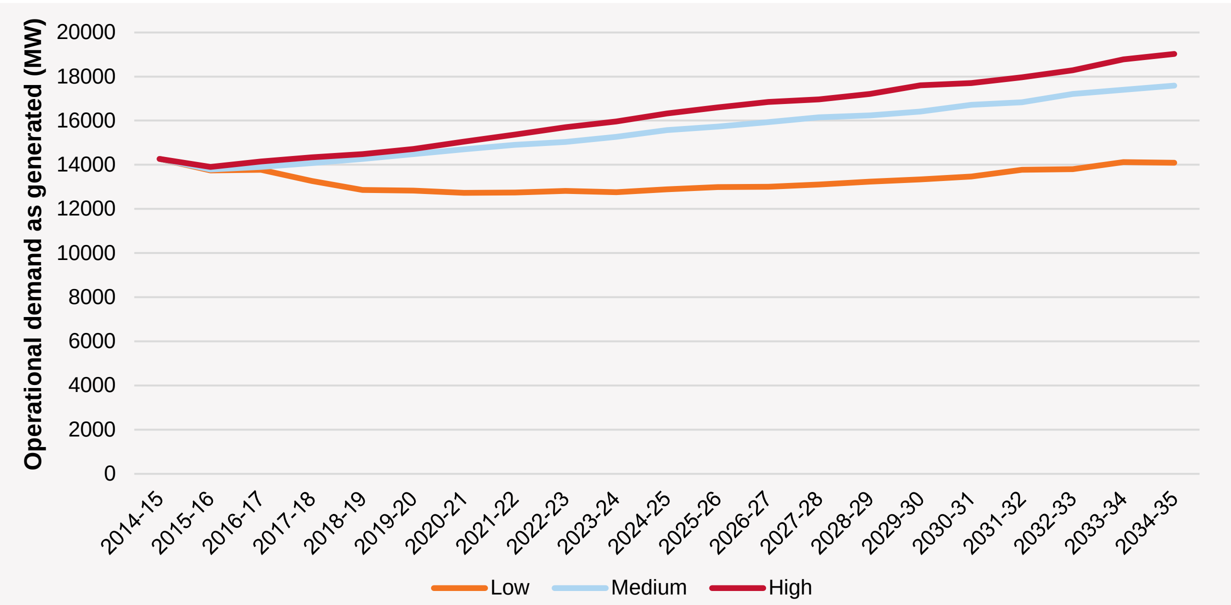
Differences between low, medium, and high consumption scenarios for New South Wales maximum demand

As maximum demand is driven by the residential and commercial sector, as with annual consumption, the differences between the low, medium and high demand scenarios are driven by differences in the electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

Figure 24 shows a comparison of the 10% POE forecasts across the three demand scenarios.

The difference between the medium and high scenarios is smaller than between the medium and low scenarios, because there is only a small difference between the medium and high scenario electricity price forecasts. In the low scenario, forecast electricity prices are significantly higher.

Figure 24 Summer 10% POE forecast scenarios for New South Wales

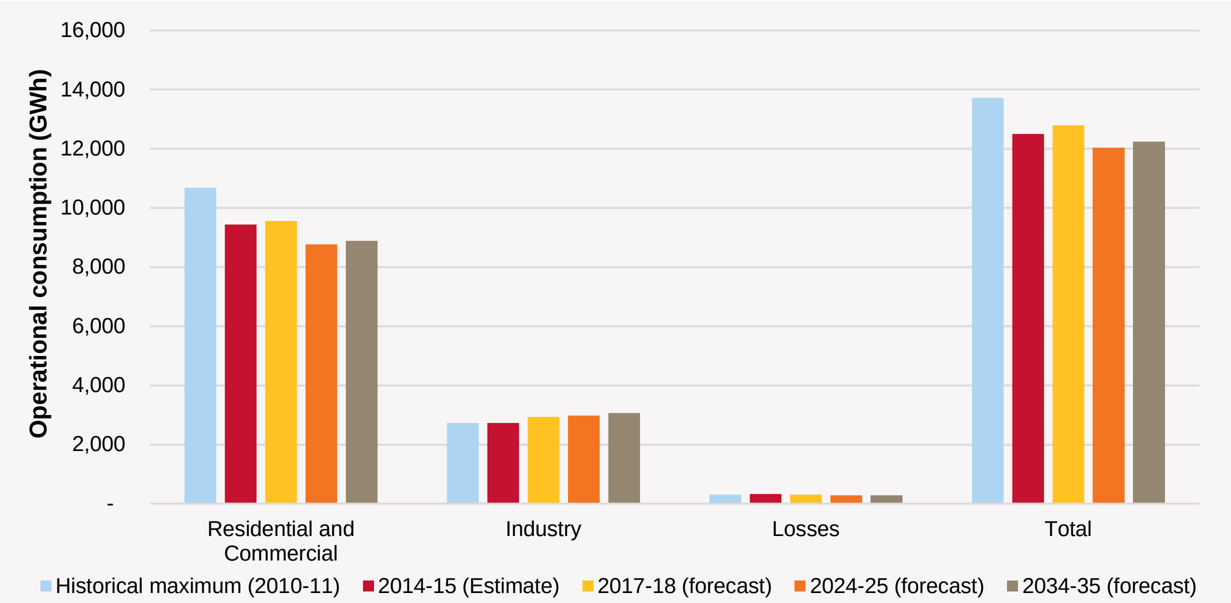


CHAPTER 5. SOUTH AUSTRALIA

5.1 Key points for South Australia

- South Australia is not expected to recover to its historical highest level of operational consumption[31] over the forecast period (see Figure 25).
- Residential and commercial consumption recovers slightly in the short term (2014–15 to 2017–18) but declines in the longer term (see Figure 25).
- Consumption per capita continues to decline over the period (see Figure 26).
- There is continued uptake of rooftop PV in the residential and commercial sectors (see Table 24) and energy efficiency measures.
- Over the short term there is an increase in industrial consumption, but this then remains flat over the remainder of the forecast period.
- Maximum demand is forecast to increase, but the high penetration of rooftop PV results in the difference between average demand and maximum demand continuing to grow.

Figure 25 Comparison of actual and forecast operational consumption in South Australia



5.2 Annual operational consumption in South Australia

In the four years to 2014–15, operational consumption has declined steadily. This has been driven by reductions in residential and commercial consumption, due to rising electricity prices and the uptake of rooftop PV and energy efficiency, which reduces consumption from the grid (see Figure 26).

AEMO forecasts recovery in operational consumption in the short term (2014–15 to 2017–18), driven by an increase in industrial consumption, mainly due to Port Pirie smelter returning to pre-2014 levels of consumption following redevelopment of the facility.

In the medium term, operational consumption is forecast to decline, due to the decline in residential and commercial consumption, with rooftop PV uptake outpacing any growth in underlying residential and

31 South Australia experienced its highest level of operational consumption of 13,723 GWh in 2010-11.

commercial consumption. Per capita consumption is forecast to continue to decline, with population growth keeping operational consumption relatively flat throughout the long term outlook periods.

Table 21 summarises forecasts under the medium scenario, and drivers for these results, and Figure 26 illustrates the forecasts by key components.

Figure 26 shows the historical increase and then decline in residential and commercial consumption. The black line indicates operational consumption, while the top of the graph indicates what the operational consumption would be if it was not reduced by rooftop PV and energy efficiency measures. This highlights the large component of consumption in South Australia that is supplied by rooftop PV, and Chapter 6 focuses on the impact of this high rooftop PV penetration on the network.

Figure 26 Summary of operational consumption by key component in South Australia

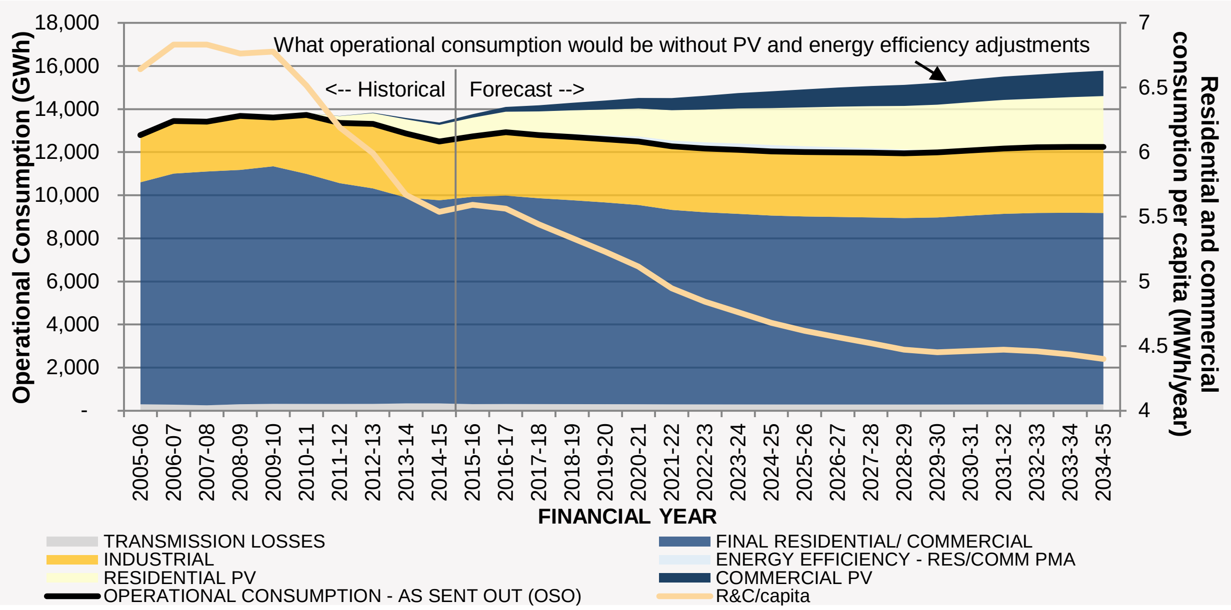


Table 21 Summary of operational consumption over the short, medium and long term in South Australia

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	12,498 to 12,797	0.8%	Recovery in the short term is driven by the industrial sector with the return to pre-2014 levels of consumption at Port Pirie following redevelopment of the facility.
Medium term (2017–18 to 2024–25)	12,797 to 12,034	-0.9%	The decrease in operational consumption in the medium term is due to a decline of 786 GWh in the residential and commercial sector, where continued uptake of rooftop PV outpaces increases in underlying consumption due to population growth.
Long term (2024–25 to 2034–35)	12,034 to 12,240	0.2%	There is little net change over the long term as the uptake of rooftop PV slows, and provides only a partial offset of the increase in consumption due to population growth.

5.2.1 Residential and commercial consumption in South Australia

Methodology overview

Underlying consumption refers to the electricity used by the residential and commercial sector, whether it is drawn from the electricity grid or not. It is forecast over a 20-year horizon, with the key modelled drivers being population, income, weather, and electricity prices.

In this long-term methodology, residential and commercial consumers are modelled as responding to increases or decreases in average prices, as well as the average income measured by Gross State Product (GSP). In general, consumption increases if income increases, and decreases if electricity prices increase. For further detail refer to the 2015 Forecasting Methodology Information Paper.

AEMO models this in two stages:

1. It forecasts per capita consumption to capture underlying usage trends by removing the impact of population growth. This is why per capita consumption is the key metric in analysing the forecasts.
2. It then uses population growth forecasts to calculate overall underlying consumption.

The underlying consumption is then offset by forecast rooftop PV generation (which reduces electricity drawn from the grid) and adjustments to account for energy efficiency impacts not already captured in the underlying trends.

Forecasts

Historically, residential and commercial consumption in South Australia has been declining since 2009–10, with consumption per capita decreasing from 6.8 MWh/year to 5.5 MWh/year in this period. The decline is due to a rapid increase in electricity prices, as well as the uptake of rooftop PV and energy efficiency measures.

This decline in consumption has slowed over the last year despite population growth, decreasing only slightly over the last year from 9,557 GWh in 2013–14 to 9,436 GWh in 2014–15. This is because uptake in the number of rooftop PV installations has slowed, so rooftop PV is offsetting a smaller proportion of consumption increases due to population growth.

The consumption forecast relies on the forecast economic and demographic variables shown in Figure 27.

Key points in the variables are:

- Population growth continues, although the rate of growth slows over the forecast period.
- Gross State Product (GSP) grows in real terms.
- Electricity prices have declined since 2013–14 and are projected to continue declining until 2018–19. Prices are then forecast to increase at a slower rate than historical rises until 2029–30, when there is an estimated decrease due to the end of the Renewable Energy Target (RET).

Figure 27 Key drivers of underlying residential and commercial consumption in South Australia

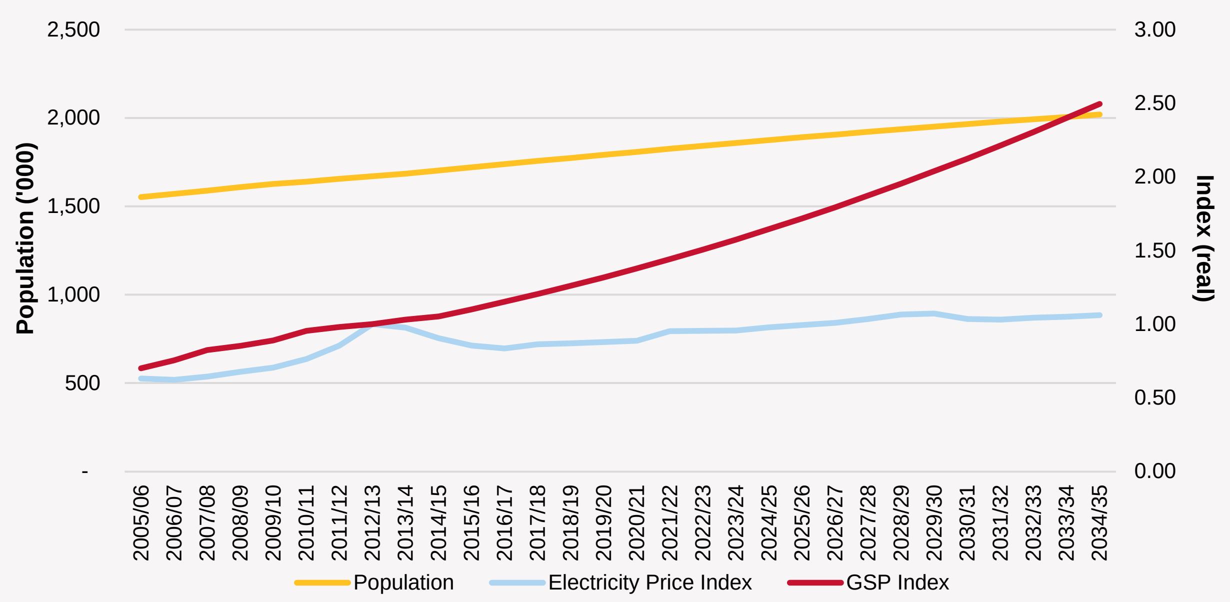


Table 22 summarises the forecast annual residential and commercial consumption over the short, medium and long term.

Table 22 Consumption in the residential and commercial sector over the short, medium and long term in South Australia

Timeframe	Forecast (GWh)	Average annual change	Consumption per capita (MWh/yr)	Drivers
Short term (2014–15 to 2017–18)	9,436 to 9,559	0.4%	5.5 to 5.4	Growth in income and declining prices lead to strong recovery in underlying consumption, which is offset by continued uptake of rooftop PV and energy efficiency, tempering any net change in consumption.
Medium term (2017–18 to 2024–25)	9,559 to 8,773	-1.2%	5.4 to 4.7	Recovery in underlying consumption slows a little in response to a forecast increase in electricity prices. This recovery is outpaced by the uptake of rooftop PV and energy efficiency, which reduce overall consumption from the grid.
Long term (2024–25 to 2034–35)	8,773 to 8,888	0.1%	4.7 to 4.4	Underlying consumption continues to grow as income per capita increases in the long term, and population grows. Residential and small commercial PV slows as it starts to reach saturation levels, but still offsets the growth in the underlying consumption.

Any recovery in underlying consumption, driven by economic factors, is offset by continued uptake of rooftop PV and energy efficiency in the short to medium term, with an overall decline in consumption in the latter period. In the longer term, consumption is relatively flat. Consumption per capita continues to decline over the entire forecast period.

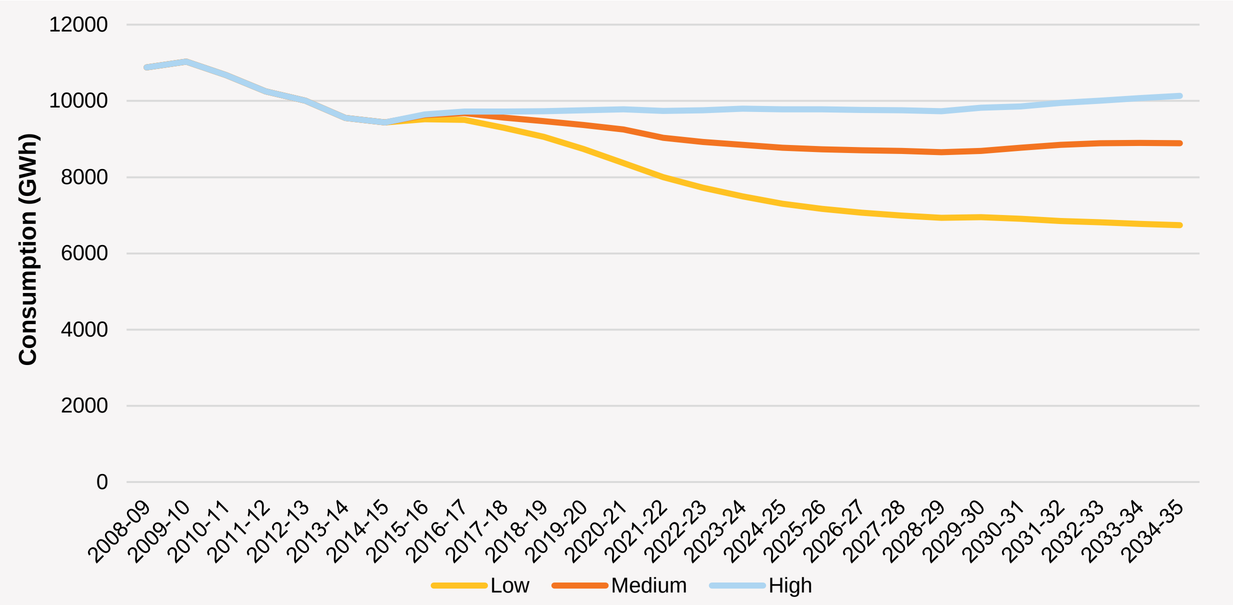
Differences between low, medium and high consumption scenarios in South Australia

The differences between the low, medium and high consumption scenarios are driven by differences in the electricity price, population, and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake. The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 23 and the forecasts are shown in Figure 28.

Table 23 Average annual rates of change for the low, medium and high consumption scenarios in South Australia

	Low	Medium	High
Short term (2014–15 to 2017–18)	-0.5%	0.4%	1.0%
Medium term (2017–18 to 2024–25)	-3.4%	-1.2%	0.1%
Long term (2024–25 to 2034–35)	-0.8%	0.1%	0.4%

Figure 28 Comparison of the low, medium and high residential and commercial forecasts in South Australia



In 2024–25, compared to the medium scenario, forecast residential and commercial consumption is 17% lower in the low scenario, and 12% higher in the high scenario.

South Australia residential and commercial consumption comparison to 2014 NEFR

To keep improving the NEFR, AEMO often reclassifies loads from the residential and commercial segment to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

Growth rates for the 2014 NEFR medium scenario were -0.9%, -0.5% and 0.2% respectively over the short, medium and long terms. Over the short term, the growth in the 2015 forecasts is largely due to the relative decrease in electricity prices, which is expected to increase underlying consumption.

In the short term, the 2015 forecasts sit between the medium and high 2014 NEFR forecasts. Over the medium and long term, the low and high forecasts for 2015 are lower than those projected in 2014 due to differences in forecast GSP and electricity prices, and also more sophisticated modelling, incorporating different price elasticities for South Australia to account for different behaviour in response to price increases and decreases.

5.2.2 Rooftop PV forecasts for South Australia

The 2015 NEFR is the first time AEMO has modelled residential and commercial PV separately. Residential systems were considered to be those less than 10 kW, while commercial systems were categorised as either small (less than 100 kW) or large (greater than 100 kW).

- Residential rooftop PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability of rooftop PV. The programs that incentivised the historical uptake have helped to establish a local industry and drive a reduction in PV technology and installation costs.
- Uptake in the commercial sector has been more recent, driven by a combination of programs such as the Clean Technology Investment Fund and SRES, as well as 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.

Table 24 shows the cumulative capacity and generation of installations by segment for the medium scenario. Both residential and small commercial PV installations continue to increases and start to reach saturation levels in the longer term.

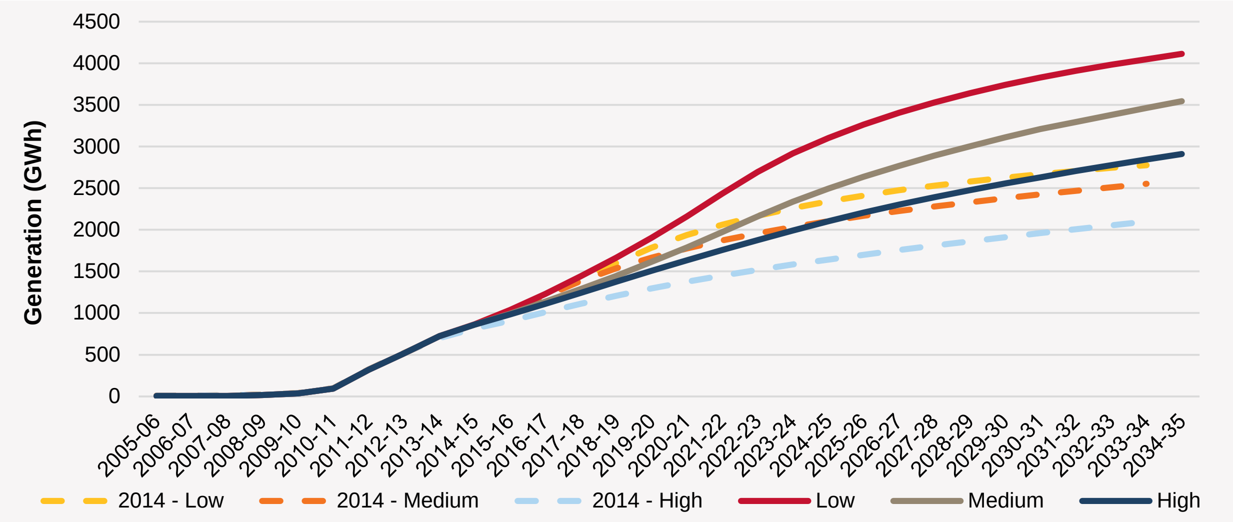
Table 24 Rooftop PV forecasts for South Australia

	Small commercial PV		Residential PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014–15	96	109	575	753	**671**	**862**
2017–18	228	284	761	1,005	**989**	**1,289**
2024–25	587	780	1,276	1,715	**1,864**	**2,495**
2034–35	866	1,177	1,738	2,366	**2,603**	**3,544**

A comparison of rooftop PV forecasts for the three scenarios, and for the 2014 NEFR and 2015 NEFR, is in Figure 29.

The differences in the 2015 NEFR are mainly due to separate modelling of residential and commercial PV. The 2015 forecasts are slightly lower than the 2014 NEFR in the short term, but higher in the medium to long term. In the 2014 NEFR, as all installations were treated as residential, saturation was reached earlier, while the new methodology employed in 2015 allows for growth in the commercial sector.

Figure 29 Rooftop PV forecasts for low, medium and high consumption scenarios in South Australia



Overall, South Australia has the highest proportion of rooftop PV, relative to its total load, of all the NEM regions (see Table 5). The implications of this level of uptake are discussed in Chapter 6.

Energy efficiency

AEMO adjusts its forecasts based on additional energy efficiency savings that are not already captured in the residential and commercial consumption. These are based on data from existing and planned future government programs.

In the medium scenario, the energy efficiency adjustments applied to the forecasts were:

- Short term – the adjustment increased from 18 GWh in 2014–15 to 93 GWh in 2017–18.
- Medium term – the adjustment increased from 93 GWh in 2017–18 to 299 GWh in 2024–25.
- Long term – the adjustment decreased from 299 GWh in 2024–25 to 0 GWh in 2034–35.

The adjustment decreases in the long term, because a larger proportion of the impacts of energy efficiency savings are already included in the forecast.

5.2.3 Industrial consumption in South Australia

Industrial loads are defined as those loads with typical demand greater than 10 MW[32]. 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:[33]

- Manufacturing loads are those classified under Division C of the ANZSIC code. In South Australia this includes primary and fabricated metal, basic chemical, pulp and paper and non-metallic mineral product manufacturing.
- All loads not captured under Division C are defined as 'other'. In South Australia, this includes coal and metal ore mining, defence services and water supply services.

Forecasts for industrial loads have been developed based on sectoral outlooks for each industry and in consultation with individual customers. For further detail refer to the 2015 Forecasting Methodology Information Paper.

Despite a decline in consumption from the manufacturing sector, total industrial consumption in South Australia has increased since 2007-08. The increase is mostly attributable to continued growth in metal ore mining. The decline in consumption in the manufacturing sector reflects both a decline in production operations by some customers, and the installation of some on-site generation.

The decrease in electricity consumption between 2012-13 and 2014-15 is due to operational changes at the desalination plant and the Port Pirie smelter.

Table 25 shows the forecasts and key drivers in the short, medium and long term.

Table 25 Industrial consumption over the short, medium and long term in South Australia

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	2,728 to 2,934	2.5%	Return of Port Pirie smelter to pre-2014 levels of consumption post redevelopment of the facility.
Medium term (2017–18 to 2024–25)	2,934 to 2,976	0.2%	There is little change in the industrial sector over the medium to long term.
Long term (2024–25 to 2034–35)	2,976 to 3,062	0.3%	

32 This refers to customers whose demand is greater than 10 MW for at least 10% of the previous year

33 For more information on ANZSIC code classifications, refer to the ABS website, http://www.abs.gov.au/ausstats/abs@.nsf/Previousproducts/20C5B5A4F46DF95BCA25711F00146D75?opendocument

Differences between the low, medium and high scenarios for South Australia

In the low consumption scenario, AEMO has assumed that the desalination plant will be in care and maintenance mode and that there will be a decline in consumption from both mining and manufacturing sectors.

In the high consumption scenario, AEMO has assumed:

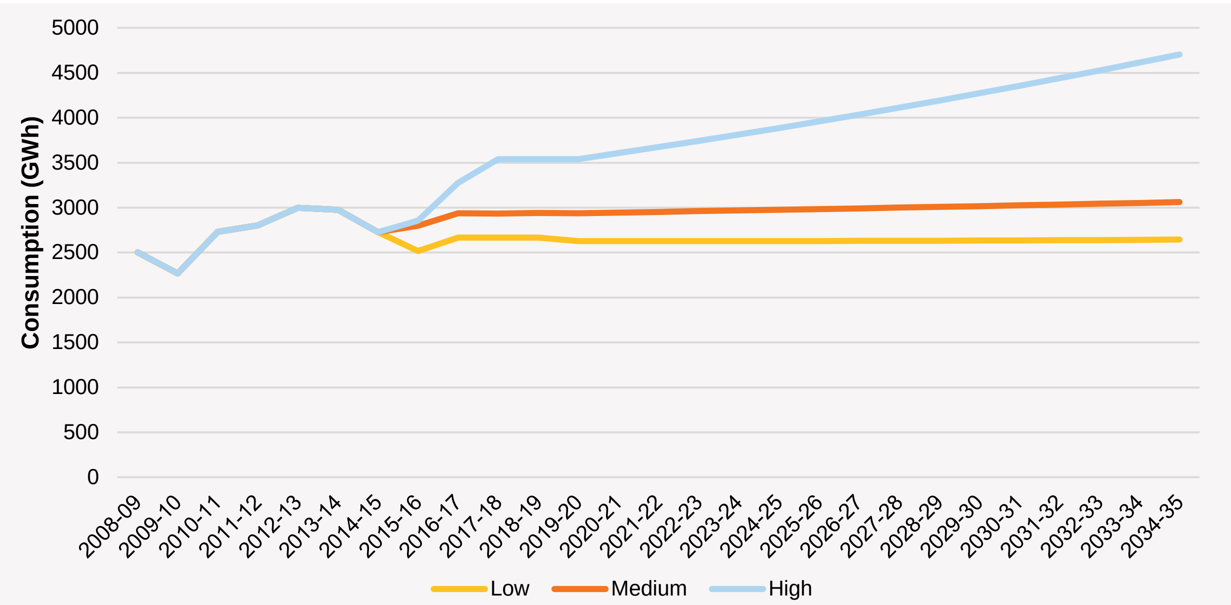
- There will be growth in electricity consumption from both the manufacturing and mining sectors. Growth in mining is the largest contributor to increased consumption and is based on the expansion of operations at Olympic Dam and the commissioning of Rex Minerals' Hillside copper mine.

The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 26, and the forecasts are shown in Figure 30.

Table 26 Average annual rates of change for the low, medium and high consumption scenarios in South Australia

	Low	Medium	High
Short term (2014–15 to 2017–18)	-0.8%	2.5%	9.1%
Medium term (2017–18 to 2024–25)	-0.2%	0.2%	1.3%
Long term (2024–25 to 2034–35)	0.1%	0.3%	1.9%

Figure 30 Comparison of low, medium and high industrial forecasts for South Australia



In 2024–25, compared to the medium scenario, forecast industrial consumption is 12% lower in the low scenario, and 31% higher in the high scenario.

South Australia industrial consumption comparison to 2014 NEFR

In the 2015 NEFR, AEMO increased the number of industrial customers surveyed in South Australia from 16 to 18.[34] As a result, approximately 40 GWh[35] of energy has been removed from the residential and commercial segment and added to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

The 2014 NEFR forecast an average annual decrease of 1.0% between 2014–15 and 2017–18. In the 2015 NEFR, AEMO forecasts an average annual increase of 2.5% over the same period. The rate of growth is higher in the 2015 NEFR because it captures the return to pre-2014 consumption levels by the Port Pirie smelter following redevelopment of the facility (this was not included in the 2014 NEFR).

In the medium term, the 2014 NEFR forecast average annual decline of 0.03%, and the 2015 NEFR forecasts growth of 0.2%. The increase is due to changes in methodology. In the 2015 NEFR AEMO used economic sectoral forecasts, rather than survey information, to forecast medium and long term industrial consumption. Refer to the 2015 Forecasting Methodology Information Paper for more detail.

5.2.4 Differences between the low, medium and high consumption scenarios in South Australia

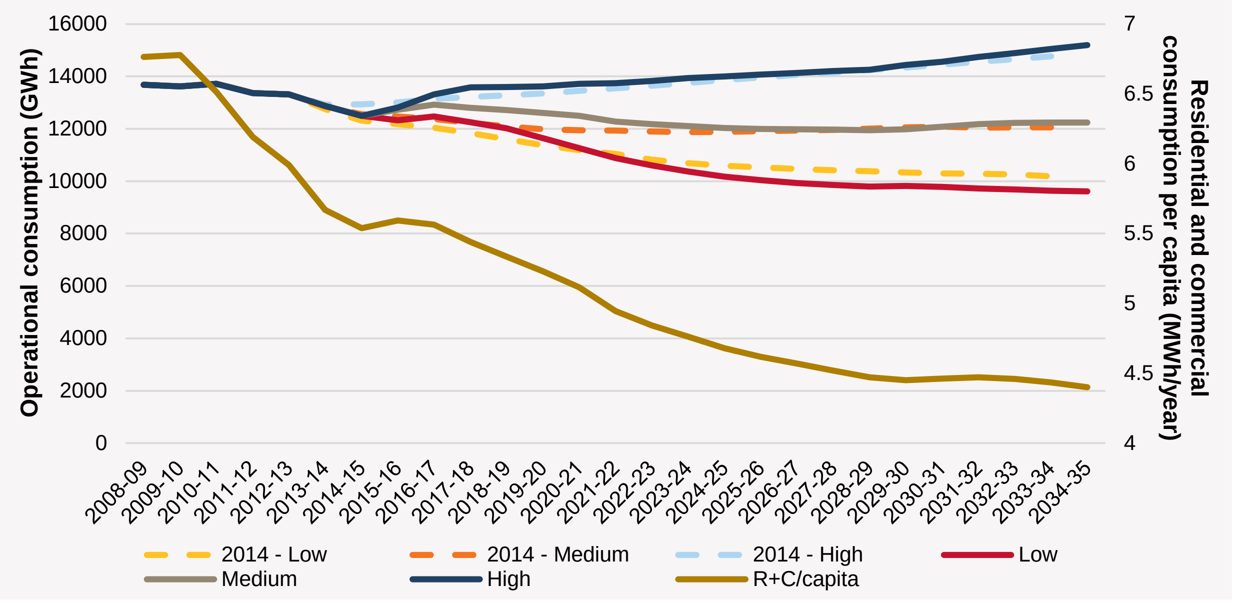
Figure 31 compares the scenarios over the forecast period.

Operational consumption in the low scenario is 4%, 15% and 21% lower than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

Operational consumption in the high scenario is 6%, 16% and 24% higher than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

The 2015 forecasts are slightly higher than the 2014 NEFR in the short term for the reasons outlined above in the industrial and residential and commercial sectors. Over the medium to long term, the forecasts track closely to the 2014 projections.

Figure 31 Comparison of low, medium and high forecasts for South Australia



[34] One of these is the Rex Minerals Hillside project, which is only included in the high case.
[35] Based on consumption levels in 2013–14.

5.3 Maximum demand for South Australia

5.3.1 Maximum demand in South Australia in 2014–15

South Australia's 2014–15 summer maximum demand was 2,872 MW on 7 January 2015. This was 94 MW below the 2014 NEFR 50% probability of exceedance (POE) forecast.[36] In other words, maximum demand last year was average, being closest to the demand that was expected to occur one out of every two years.

The 2014–15 maximum demand fell 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, with temperatures ranging from 30.5°C to 44.1°C in the preceding days.

Adelaide's maximum temperature for summer 2014–15 was 44.1°C on Friday 2 January 2015. Demand on this day reached 2,669 MW, and was probably relatively lower than expected for this temperature because it was in the Christmas and New Year holiday period.

5.3.2 Methodology Overview

Maximum demand is driven by demand from the residential and commercial sector. It is therefore driven by the same variables as residential and commercial consumption, namely population, GSP, electricity prices, and weather. Weather has a significant impact, with cooling loads increasing on high temperature days, resulting in high demand.

Rooftop PV generation offsets demand, but less so in the later parts of the day. As installed capacity increases and demand is offset, the peak shifts to later in the day. Once this shift occurs, rooftop PV generation will have a smaller impact on maximum demand.

Unlike residential load, industrial load remains relatively flat during high temperature days. Industrial load is more likely to respond to price signals than temperature. AEMO investigates the impact of prices on industrial demand with an analysis of demand side participation (DSP) to be published separately.

5.3.3 Key points for South Australia maximum demand forecasts

- The 10% POE maximum demand is forecast to increase at an annual average rate of 0.4% over the short term (2014–15 to 2017–18). This is primarily driven by increasing population and GSP.
- Rooftop PV generation has already shifted the expected maximum demand time to 18:30. As rooftop PV generation increases, the time of maximum demand shifts later, to 19:30 by the end of the forecast period.
- Load factors[37] in South Australia are expected to decrease due to the high penetration of rooftop PV. This is because rooftop PV will be offsetting a large amount of demand during the middle of the day, but not at time of maximum demand.

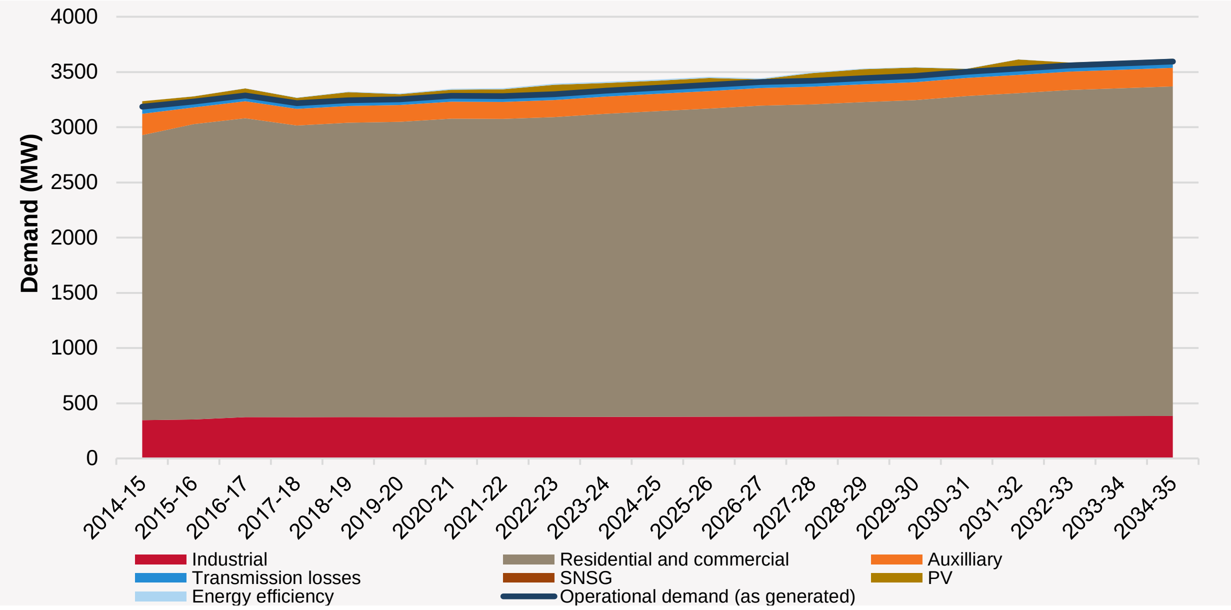
Table 27 summarises the summer 10% POE forecasts and key drivers, and Figure 32 shows the breakdown by key components. The PV values in the plot represent the amount of rooftop PV generation at time of maximum demand. Drops that can be seen in PV are caused by the time of maximum demand shifting to later in the day when there is less PV generation.[38]

[36] See Section 1.3 for definitions of probability of exceedance (POE).
[37] 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.
[38] Since modelling is done at a half-hourly resolution, the PV values do not show a smooth transition when time of peak demand time shifts to a different half-hourly period.

Table 27 Summary of summer 10% POE maximum demand and key drivers

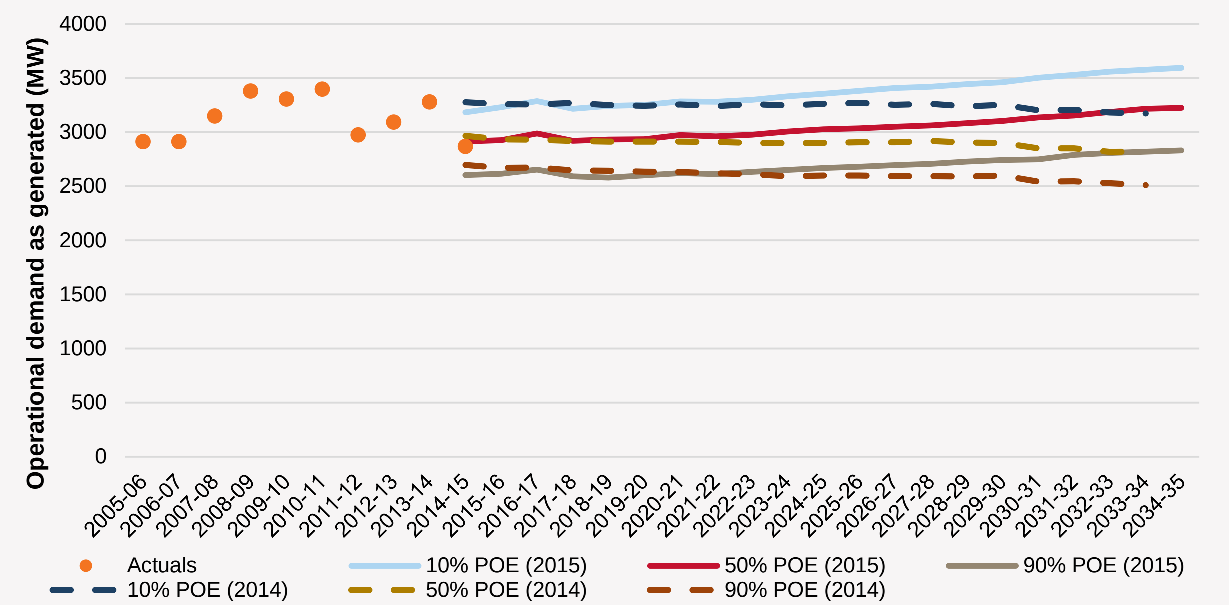
Timeframe	Forecast (MW)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	3,185 to 3,218	0.4%	Increasing population and GSP drives recovery in residential and commercial demand. Due to the expected time of maximum demand, there is a reduced impact of rooftop PV generation to offset demand.
Medium term (2017–18 to 2024–25)	3,218 to 3,357	0.6%	
Long term (2024–25 to 2034–35)	3,357 to 3,596	0.7%	

Figure 32 Summer 10% POE maximum demand forecast segments for South Australia



A comparison of the summer 90%, 50% and 10% POE forecasts, and the 2014 NEFR and 2015 NEFR, is given in Figure 33. Both forecasts are closely aligned, although the 2015 NEFR forecasts begin to show an increase towards the end of the medium-term outlook. The main driver behind this increase is a more sophisticated reconciliation of maximum demand forecasts with annual consumption forecasts.

Figure 33   Summer 90%, 50% and 10% POE maximum demand forecasts for South Australia

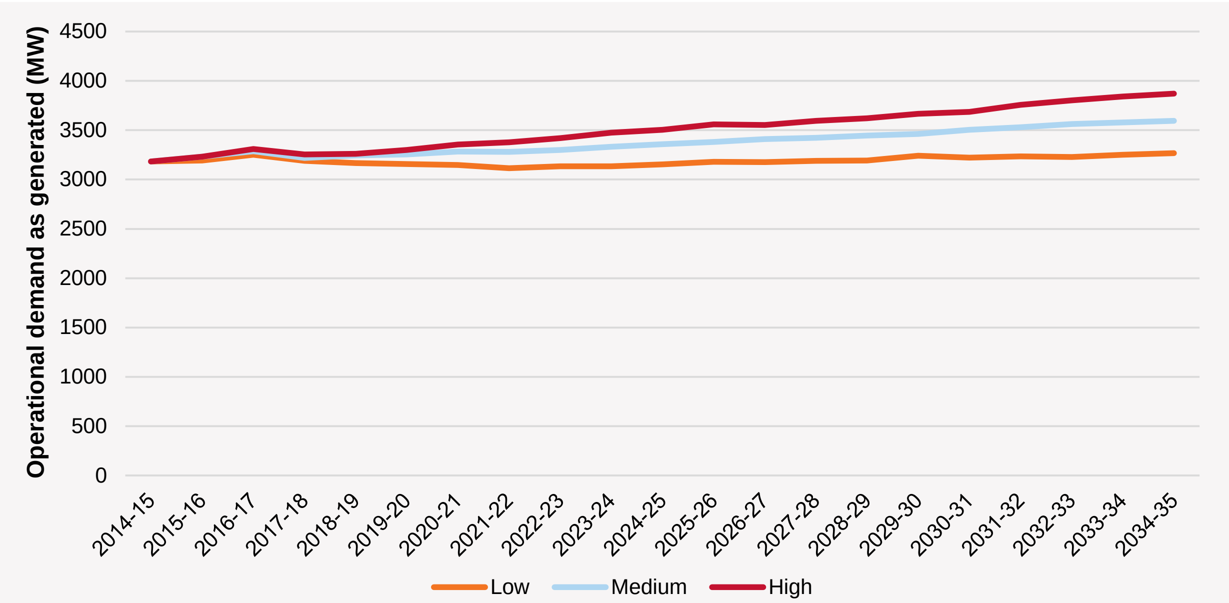


Differences between low, medium, and high consumption scenarios for South Australia maximum demand

As maximum demand is driven by the residential and commercial sector, as with annual consumption, the differences between the low, medium and high demand scenarios are driven by differences in the electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

Figure 34 shows a comparison of the 10% POE forecasts across the three demand scenarios.

Figure 34   Summer 10% POE forecast scenarios for South Australia



CHAPTER 6. MINIMUM DEMAND – SOUTH AUSTRALIA

6.1 Key points for South Australia

- In 2014–15, South Australia's minimum operational demand was 790 MW, comprising 1,235 MW of end user demand, offset by 445 MW generated by rooftop PV.
- In the short term (2014–15 to 2017–18), rooftop PV is expected to offset demand by 658 MW, resulting in forecast operational minimum demand of 496 MW.
- Towards the end of the medium-term outlook, in 2023–24, continued uptake of rooftop PV is forecast to offset 100% of demand in South Australia, resulting in South Australia distribution customers in aggregate being net generators to the grid on 90% POE minimum demand days (falls below one year out of ten).[39]
- Prior to the rapid uptake of rooftop PV generation, minimum demand occurred during the morning. In the 2012–13 summer, the expected time of minimum demand shifted from morning to midday, due to rooftop PV generation offsetting demand during the middle of the day. Continued penetration of rooftop PV installations will further reduce demand during the middle of the day, causing operational minimum demand to decrease.

6.2 Minimum demand forecasts for 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 other 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.

In 2014–15, the operational 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 35 shows the short-term forecast operational minimum demand in South Australia, and the amount of residential and commercial rooftop PV offsetting demand.

As Figure 36 shows, the impact of rooftop PV on minimum demand is more dramatic in the medium term. Due to the continued uptake of rooftop PV, consumer demand is expected to be completely met by rooftop PV generation by 2023–24 on 90% POE minimum demand days.

[39] See Section 1.3 for definitions of minimum demand and probability of exceedance (POE).

Figure 35 Summer 90% POE minimum demand forecasts and the offset from rooftop PV over the short term

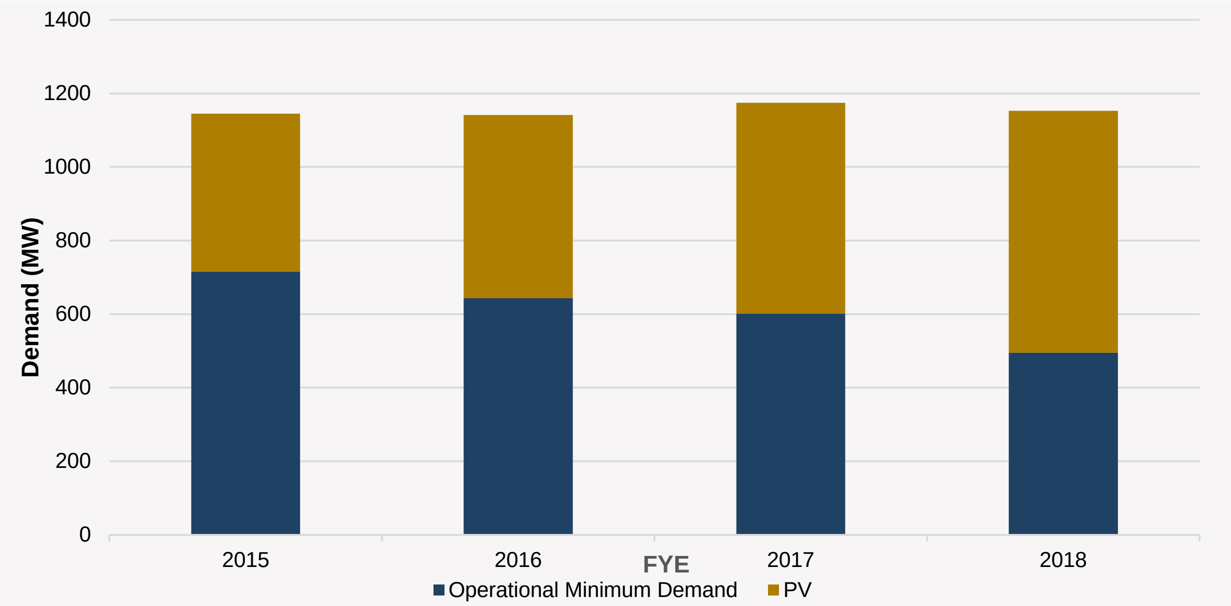
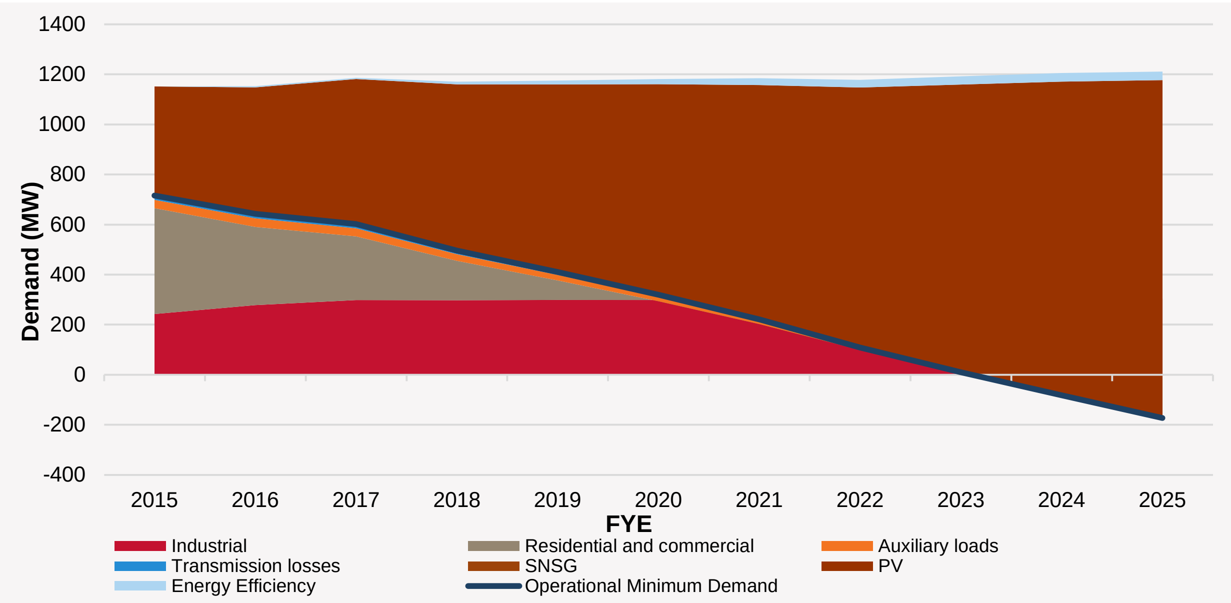


Figure 36 Summer 90% POE minimum demand forecast by key component



Load profiles in South Australia

Rooftop PV generation has been gradually changing the shape of South Australia's load profiles. As installed capacity has increased, more demand has been offset during the middle of the day, resulting in the minimum demand time shifting from morning to midday.

Figure 37 shows the 90% POE load profile for summer in 2011–12, which was the last year when minimum demand occurred during the morning. As this shows, rooftop PV generation was already having a large impact on midday demand, but not enough to change the expected time of minimum demand.

In the 2014–15 summer, rooftop PV penetration reached the point that minimum demand was clearly expected to take place during the middle of the day, as shown in Figure 38.

By the end of 2024–25, AEMO's installed capacity forecast for South Australia rooftop PV is forecast to reach 1,864 MW. The output from these installations is expected to exceed consumer demand between 12:30 pm and 2:30 pm on a minimum demand day, as shown in Figure 39.

Figure 37 2011-12 summer 90% POE minimum demand load profile for South Australia

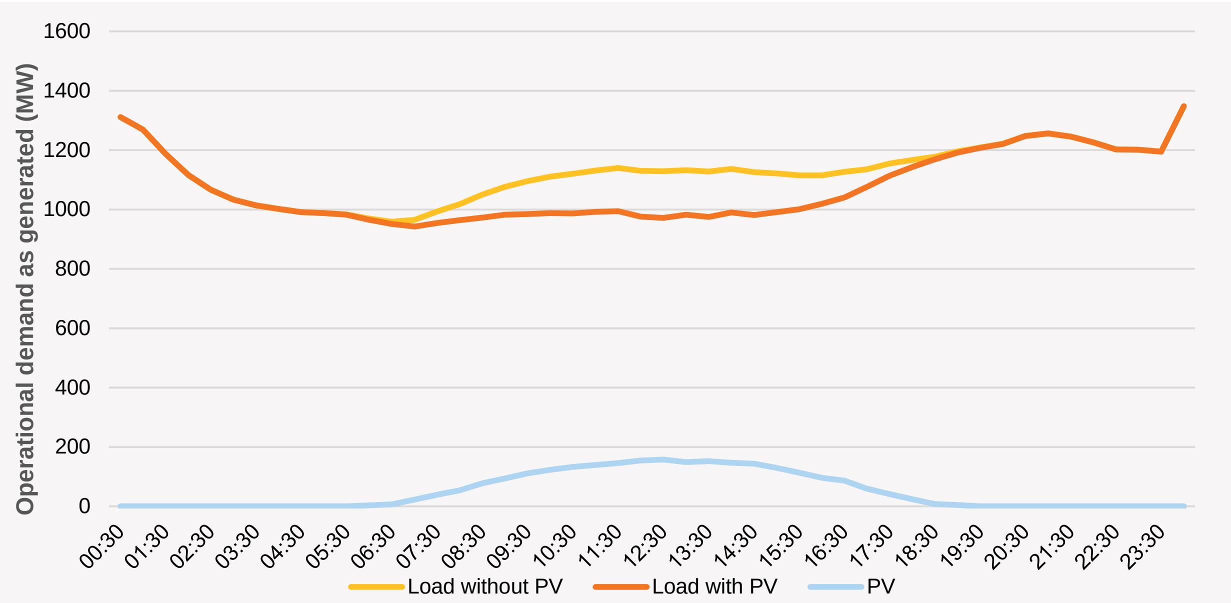


Figure 38 2014-15 summer 90% POE minimum demand load profile for South Australia

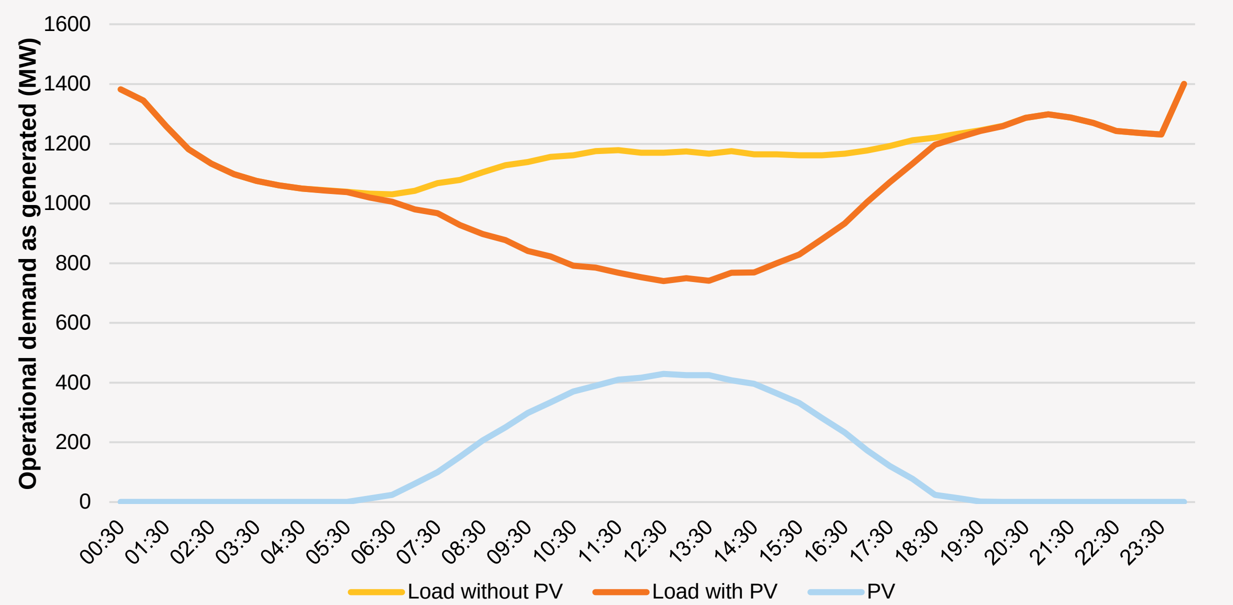
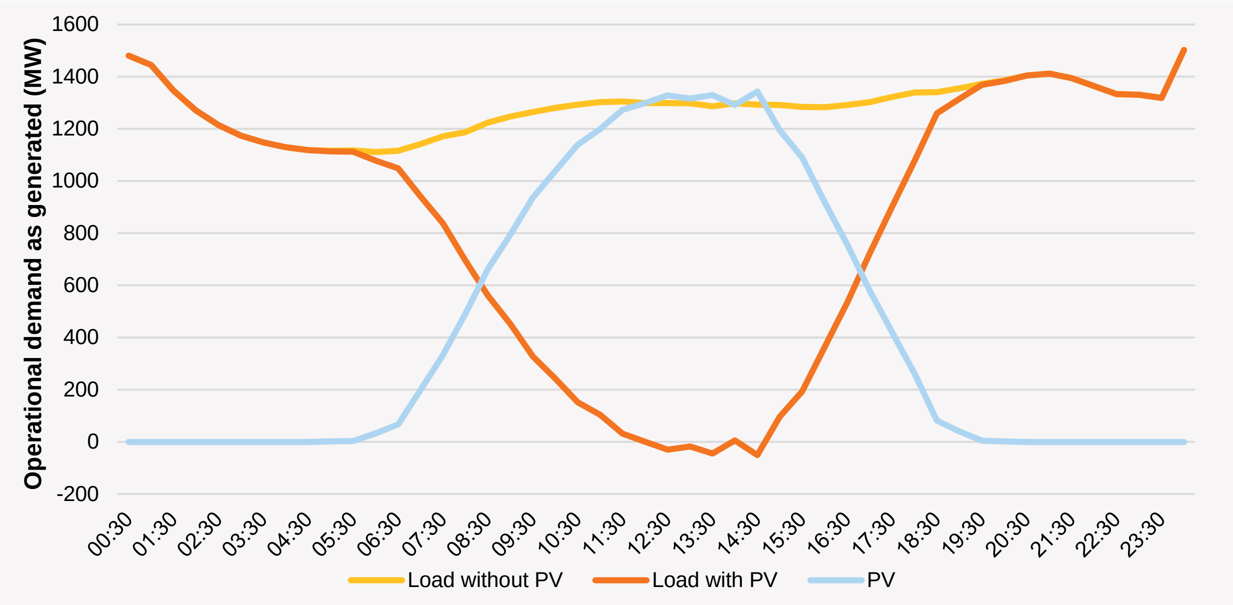


Figure 39 2024-25 summer 90% POE minimum demand load profile for South Australia



A similar outcome can be seen with the winter load profiles. Figure 40 shows only a minor impact from PV generation in 2011, when the minimum demand was expected to occur in the morning. Figure 41 shows that in the most recent winter the expected time of minimum demand had shifted to midday.[40] By the 2024 winter, rooftop PV generation is offsetting the bulk of demand during the middle of the day, as shown in Figure 42.

[40] The actual minimum demand fell to 931 MW on 21 September 2014 at 12:30.

Figure 40   2011 winter 90% POE minimum demand load profile for South Australia

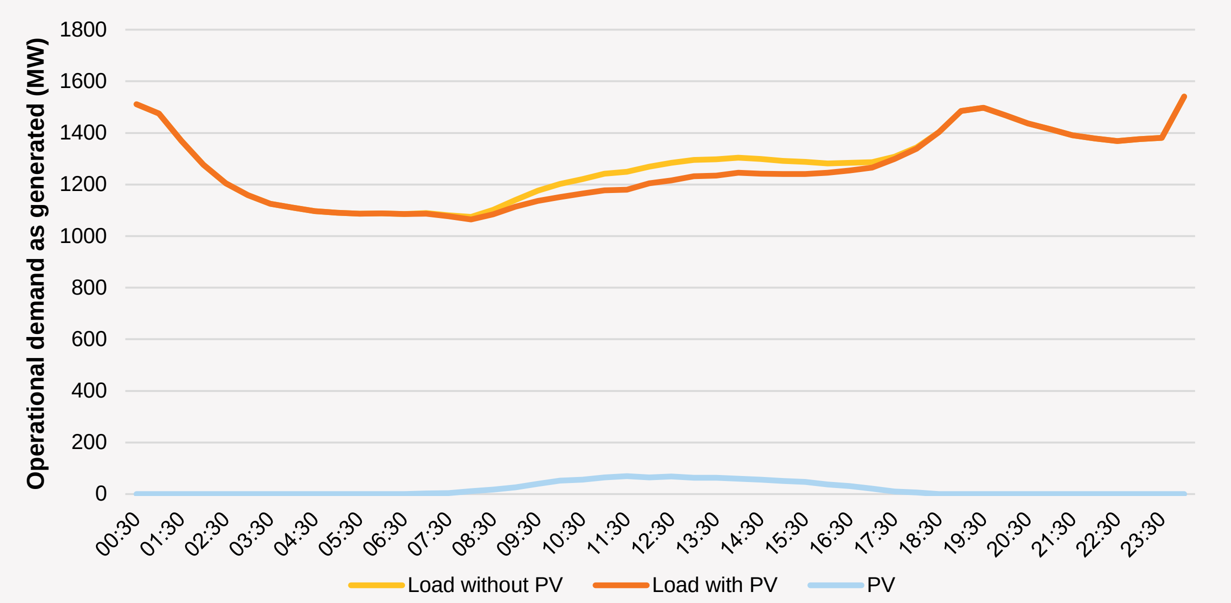


Figure 41   2014 winter 90% POE minimum demand load profile for South Australia

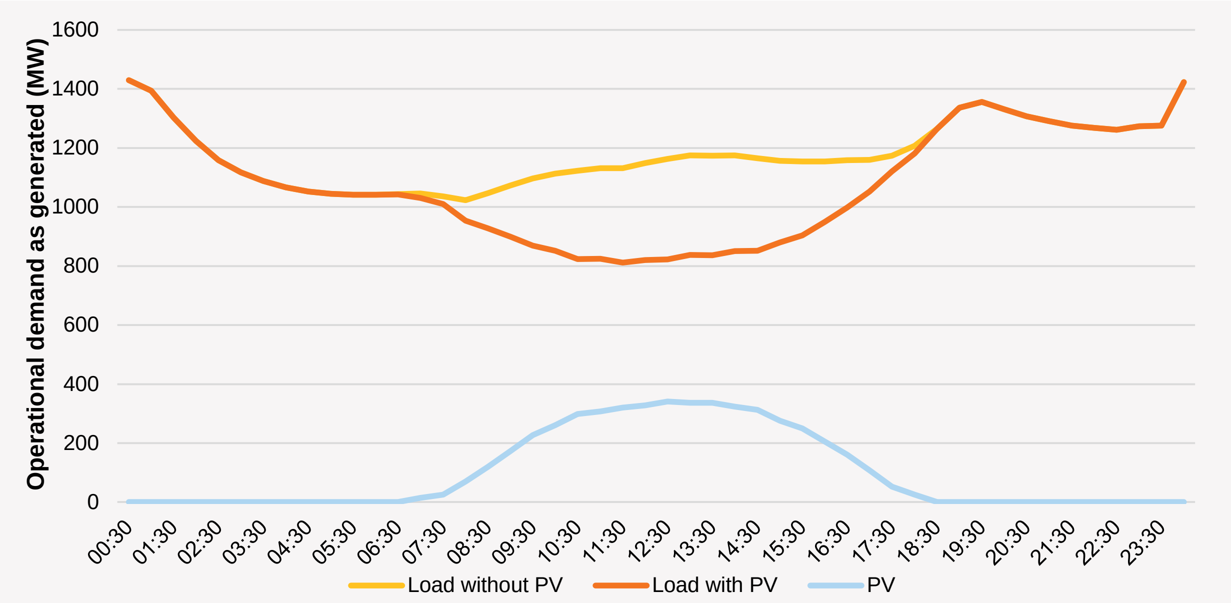
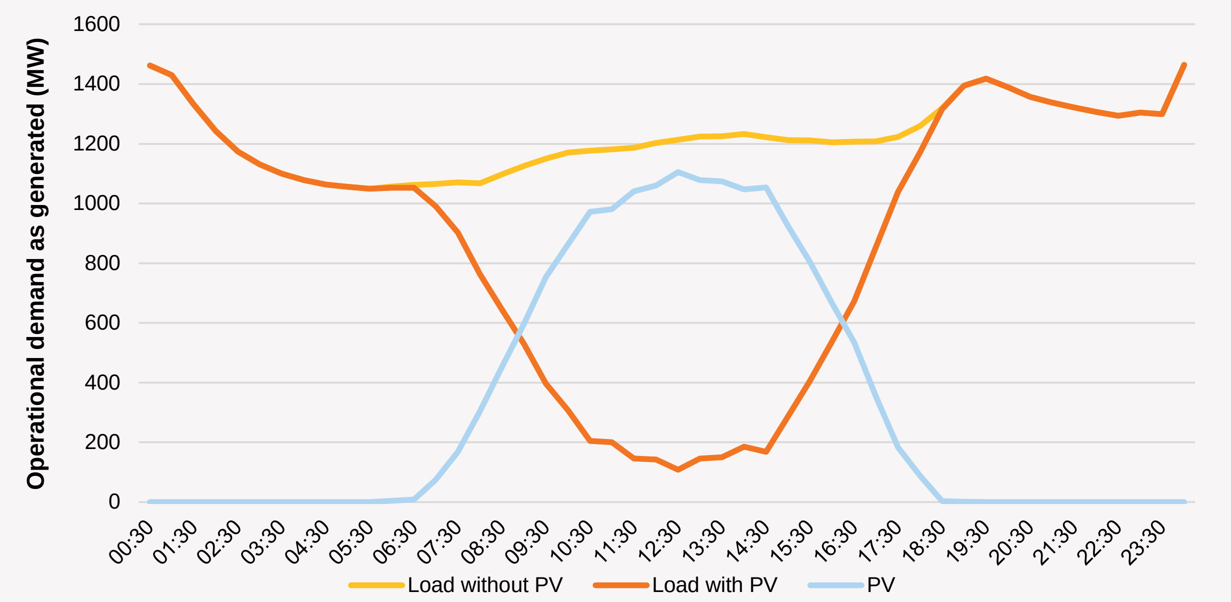


Figure 42 2024 winter 90% POE minimum demand load profile for South Australia



6.3 Modelling limitations for minimum demand

The primary purpose of the minimum demand modelling is to assess the impact that rooftop PV generation may have under current market conditions. The minimum demand model does not incorporate potential impacts of:

- Export restrictions on rooftop PV generation.
- Potential tariff reform.
- Battery storage.

Each of these has the potential to affect operational minimum demand, and AEMO plans to investigate these further in future NEFRs.

This analysis has focused on operational demand, so the impact of wind generation (excluding small non-scheduled generators) has not been considered. Minimum demand for scheduled demand may be affected by wind generation. AEMO plans to investigate the effect of wind generation on scheduled demand in future NEFRs.

It is important to note that AEMO has assumed no restrictions on the uptake of rooftop PV (whether regulatory, policy or technical), with these forecasts presenting an unconstrained observation of what may occur under the current environment.

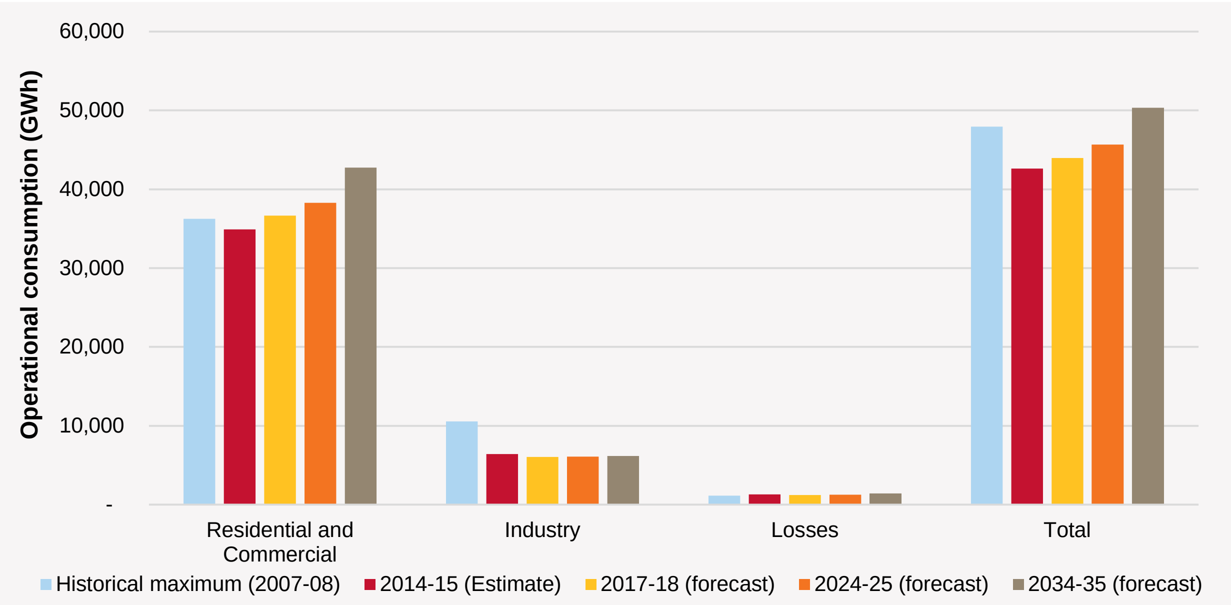
AEMO intends to continue its work on renewable integration studies in South Australia, and will assess potential impacts of lowered operational minimum demand in the upcoming National Transmission Network Development Plan (NTNDP). The impact of residential battery storage uptake on these forecasts is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

CHAPTER 7. VICTORIA

7.1 Key points for Victoria

- Operational consumption in Victoria is expected to recover, driven by the residential and commercial sector, which represents the largest proportion of Victorian load.
- Victoria does not recover to its historical high level of operational consumption[41] until 2030–31 (see Figure 43), when population is projected to be 1.7 million higher than in 2014–15.
- Although there is recovery in consumption from the residential and commercial sector, consumption per capita continues to decline (see Figure 44), indicating that population growth is a major driver of this recovery.
- There is continued uptake of rooftop PV in the residential and commercial sectors, however Victoria has the second lowest proportion of rooftop PV relative to its load of all the NEM regions (see Table 5). Energy efficiency measures also continue.
- Industrial consumption declines in the short term, due to the planned closure of vehicle manufacturing plants (see Figure 44).
- Maximum demand is forecast to decrease slightly in the short term, and then increase slightly across the medium term outlook.

Figure 43 Comparison of historical and forecast operational consumption in Victoria



[41] Victoria experienced its highest level of operational consumption of 47,935 GWh in 2007-08.

7.2 Annual operational consumption in Victoria

In the five years to 2014–15, operational consumption in Victoria has declined (see Figure 44). Consumption in the residential and commercial sector decreased, due to rising prices and the uptake of rooftop PV and energy efficiency, while decline in the manufacturing sector and major industrial closures have seen large decreases in industrial consumption in the last few years.

AEMO forecasts recovery in operational consumption in the short, medium and long term outlooks. This recovery is driven by the residential and commercial sector, which constitutes the majority of the Victorian load. Despite this recovery, consumption per capita is forecast to continue to decline, indicating that population growth is a major driver of this recovery.

Table 28 summarises forecasts under the medium scenario, and drivers for these results, while Figure 44 illustrates the forecasts by key components.

Figure 44 shows the historical decline and the forecast increase in residential and commercial consumption. The black line indicates operational consumption, while the top of the graph indicates what the operational consumption would be if it was not offset by rooftop PV and energy efficiency measures. This shows that, in Victoria, rooftop PV and energy efficiency offset only a small proportion of underlying consumption.

Figure 44 Operational consumption by key component in Victoria

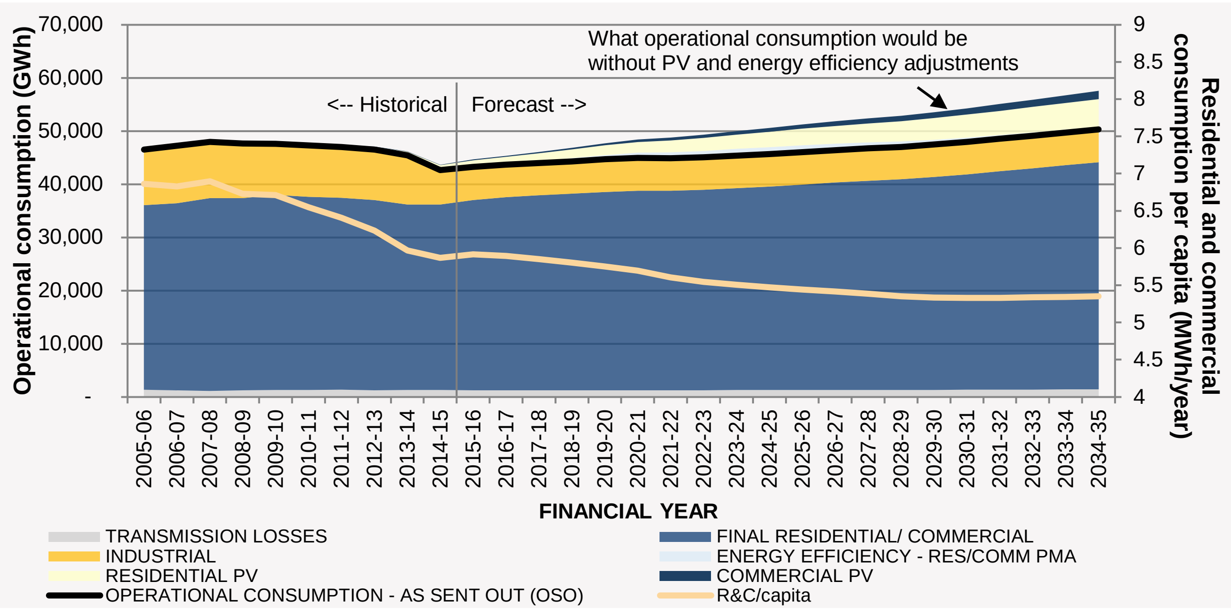


Table 28 Consumption over the short, medium and long term in Victoria

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	42,635 to 43,963	1.0%	A recent decline in average electricity prices due to the repeal of the carbon price drives recovery in average consumption, which offsets further decline in industrial consumption. Per capita consumption remains steady.
Medium term (2017–18 to 2024–25)	43,963 to 45,680	0.5%	Continued uptake of rooftop PV offsets a larger proportion of the residential and commercial underlying consumption, moderating recovery in this sector.
Long term (2024–25 to 2034–35)	45,680 to 50,315	1.0%	Population growth drives continued recovery in consumption from the residential and commercial sector, while per capita consumption remains flat.

Despite the forecast recovery in operational consumption, Victoria is not projected to reach its historical high until 2030–31.[42] This is despite a projected increase in population of 1.7 million in this period, compared to 2014–15.

7.2.1 Residential and commercial consumption in Victoria

Methodology overview

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 forecast over a 20-year horizon, with the key modelled drivers being population, income, weather, and electricity prices.

In this long-term methodology, residential and commercial consumers are modelled as responding to increases or decreases in average prices, as well as the average income measured by Gross State Product (GSP). In general, consumption increases if income increases, and decreases if electricity prices increase. For further detail refer to the 2015 Forecasting Methodology Information Paper.

AEMO models this in two stages:

1. It forecasts per capita consumption to capture underlying usage trends by removing the impact of population growth. This is why per capita consumption is the key metric in analysing the forecasts.
2. It then uses population growth forecasts to calculate overall underlying consumption.

Underlying consumption is then offset by forecast PV generation (which reduces electricity drawn from the grid) and adjustments to account for energy efficiency impacts not already captured in the underlying trends.

Forecasts

Historically, consumption in the residential and commercial sector in Victoria started to decline in 2008–09 as electricity prices increased alongside the uptake of rooftop PV and energy efficiency, with consumption per capita decreasing from 6.7 MWh/year in 2008–09 to an estimated 5.9 MWh/year in 2014–15.

This decline has slowed over the last year, with consumption expected to recover slightly, from 34,868 GWh in 2013–14 to an estimated 34,903 GWh in 2014–15. This is because underlying consumption has grown faster than rooftop PV installations, which would otherwise offset consumption.

The consumption forecast relies on the economic and demographic variables which are shown in Figure 45.

[42] Victoria reached its historic high of 47,935 GWh in 2007–08.

Key points in the variables are:

- Population is projected to grow steadily over the forecast period.
- Gross State Product (GSP) grows in real terms.
- Electricity prices are projected to fall from 2014–15 to 2015–16, then remain relatively stable until 2020–21, rising again until 2029–30, then falling due to the end of the Renewable Energy Target (RET).

Figure 45 Key drivers of underlying residential and commercial consumption in Victoria

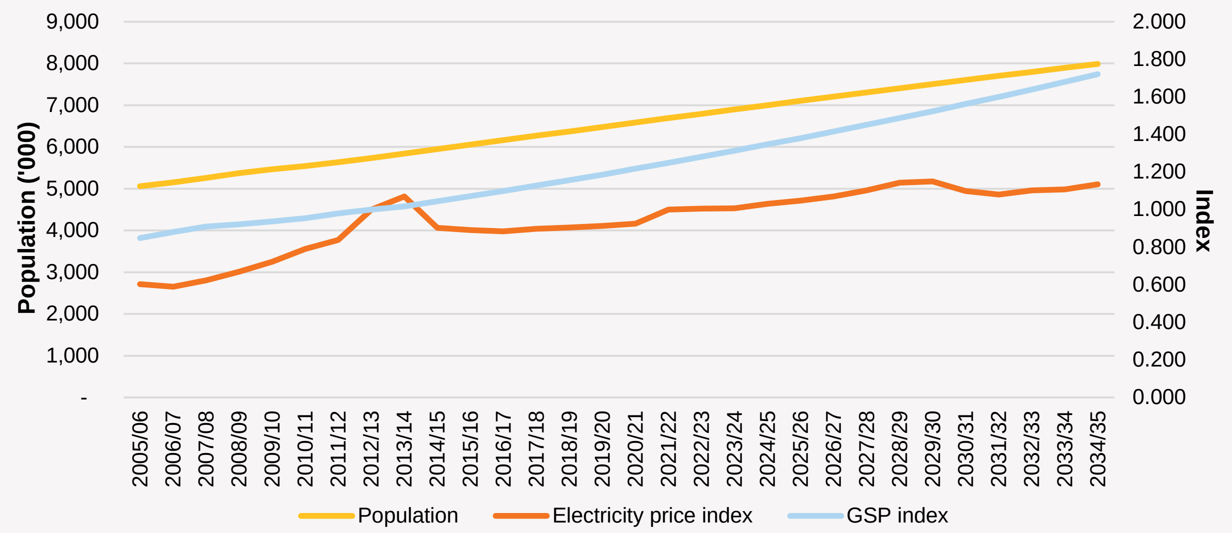


Table 29 summarises forecast annual residential and commercial consumption, and key drivers, over the short, medium and long term.

Table 29 Consumption in the residential and commercial sector over the short, medium and long term in Victoria

Timeframe	Forecast (GWh)	Average annual change	Consumption per capita (MWh/yr)	Drivers
Short term (2014–15 to 2017–18)	34,903 to 36,665	1.7%	5.87 to 5.85	A relative decline in electricity prices, coupled with population and income growth, lead to strong underlying recovery in consumption. This is partially offset by continued uptake of rooftop PV and energy efficiency.
Medium term (2017–18 to 2024–25)	36,665 to 38,283	0.6%	5.85 to 5.5	Recovery in underlying consumption slows as electricity prices are forecast to rise. This recovery is offset by the continued uptake of rooftop PV and energy efficiency, which reduce overall consumption from the grid.
Long term (2024–25 to 2034–35)	38,283 to 42,737	1.1%	5.5 to 5.4	Underlying consumption continues to recover, due to population growth and increasing income per capita. Uptake of rooftop PV continues but at a slower rate, and offsets less of the increase due to population growth.

The forecast increase in underlying residential and commercial consumption, driven by relatively lower electricity prices and population growth, is only partially offset by in the continued uptake of rooftop PV and energy efficiency. Of all the NEM regions, Victoria has the second lowest proportion of PV relative to its underlying consumption (see Table 5).

Over the short term, consumption per capita only decreases by 0.3%. This is slower than recent decreases, suggesting a change in behaviour of consumers compared with recent years.

Differences between low, medium and high scenarios

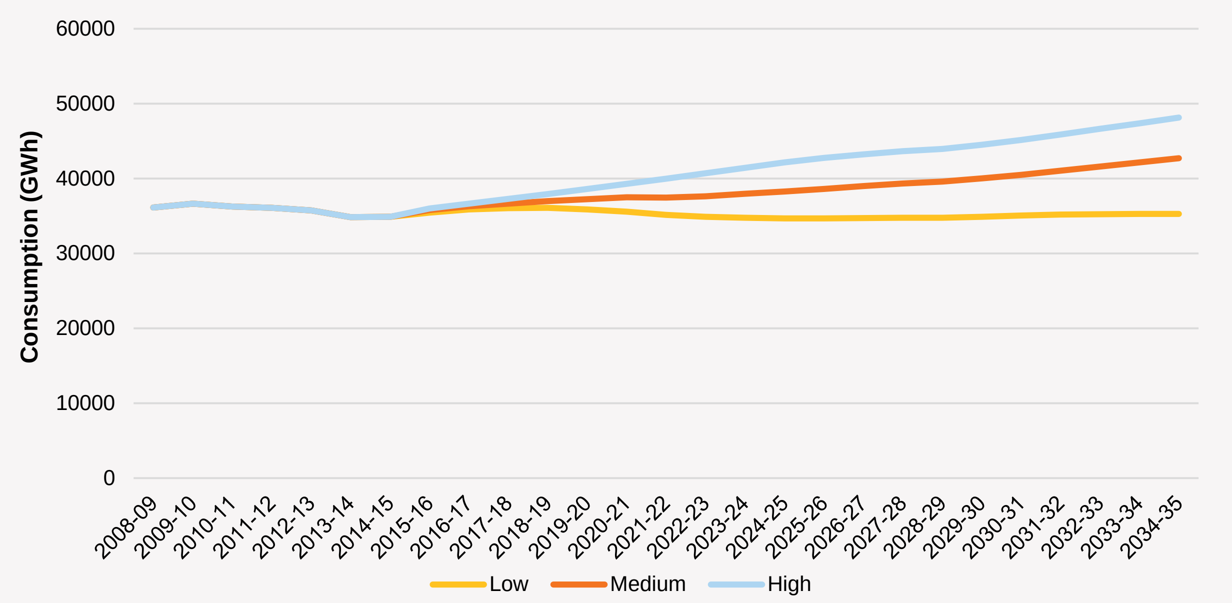
The differences between the low, medium and high consumption scenarios are driven by differences in the electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

Average annual rates of change across the scenarios for the short, medium and long term are in Table 30 and the forecasts are in Figure 46.

Table 30 Average annual rates of change for the low, medium and high consumption scenarios in Victoria

	Low	Medium	High
Short term (2014–15 to 2017–18)	1.1%	1.7%	2.2%
Medium term (2017–18 to 2024–25)	-0.6%	0.6%	1.8%
Long term (2024–25 to 2034–35)	0.2%	1.1%	1.3%

Figure 46 Comparison of low, medium and high residential and commercial forecasts for Victoria



In 2024–25, compared to the medium scenario, forecast residential and commercial consumption is 9% lower in the low scenario, and 10% higher in the high scenario.

Victoria residential and commercial consumption comparison to 2014 NEFR

The 2015 forecasts for Victoria are slightly higher than the 2014 NEFR, due to the recent fall in the average electricity price, which drives a recovery in underlying consumption.

To keep improving the NEFR, AEMO often reclassifies loads from the residential and commercial segment to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

Growth rates for the 2014 NEFR medium scenario were 0.7%, 0.4% and 0.4% respectively over the short, medium and long terms.

7.2.2 Rooftop PV forecasts for Victoria

The 2015 NEFR is the first time AEMO has modelled residential and commercial PV separately. Systems less than 10 kW were classified as residential, while commercial systems were categorised as either small (less than 100 kW) or large (greater than 100 kW).

- Residential rooftop PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability of rooftop PV. The programs that incentivised the historical uptake have helped to establish a local industry and drive a reduction in PV technology and installation costs.
- Uptake in the commercial sector has been more recent, driven by a combination of programs such as the Clean Technology Investment Fund and SRES, as well as 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.

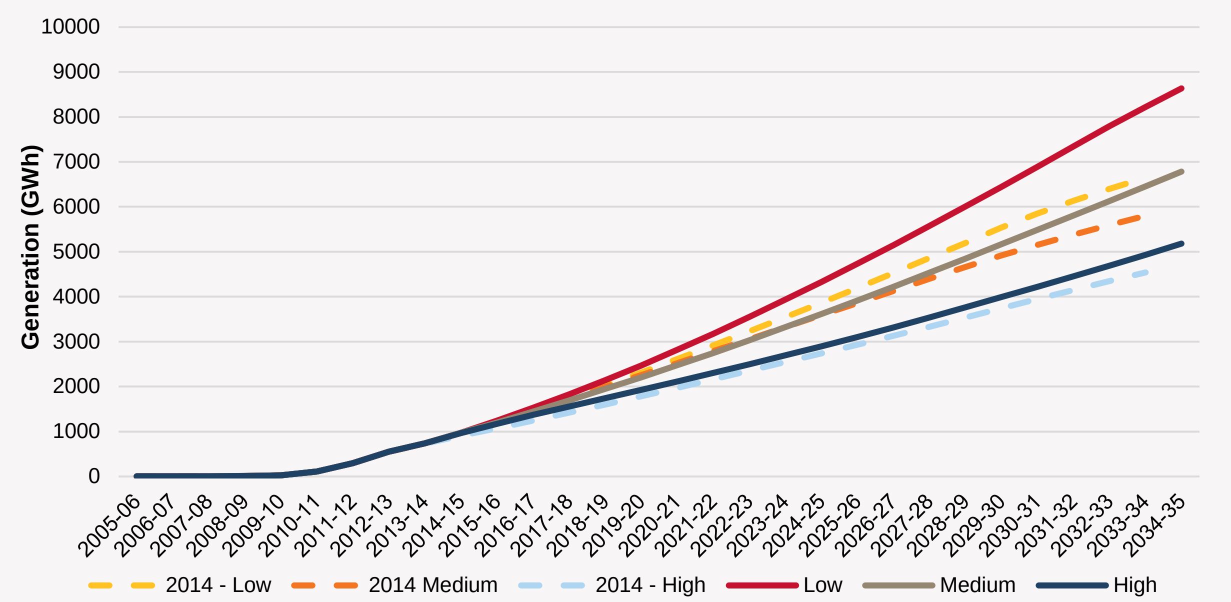
Table 31 shows the cumulative capacity and generation of installations by segment for the medium scenario. All sectors grow strongly and saturation is not reached in the forecast period. Despite this continued uptake, rooftop PV still only offsets a small proportion of total Victorian underlying consumption.

Table 31 Rooftop PV forecast for Victoria

	Commercial PV		Residential PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014–15	95	94	770	876	**866**	**970**
2017–18	234	263	1,220	1,429	**1,454**	**1,692**
2024–25	611	725	2,408	2,890	**3,018**	**3,615**
2034–35	1,278	1,545	4,296	5,238	**5,573**	**6,783**

A comparison of rooftop PV forecasts for the three scenarios, and for the 2014 NEFR and 2015 NEFR, is given in Figure 47. The differences in the 2015 NEFR are mainly due to separate modelling of residential and commercial PV. Both the medium and high scenario forecasts track closely with the 2014 projections, while the low scenario is higher in the 2015 NEFR, due to the different forecast electricity price trajectories.

Figure 47 Summary of rooftop PV forecasts for low, medium and high consumption scenarios in Victoria



Energy efficiency

AEMO adjusts its forecasts based on additional energy efficiency savings that are not already captured in the residential and commercial consumption. These are based on data from existing and planned future government programs.

In the medium scenario, the energy efficiency adjustments applied to the forecasts were:

- Short term – the adjustment increased from 72 GWh in 2014–15 to 408 GWh in 2017–18.
- Medium term – the adjustment increased from 408 GWh in 2017–18 to 1,303 GWh in 2024–25.
- Long term –the adjustment decreased from 1,303 GWh in 2024–25 to 457 GWh in 2034–35.

The adjustment decreases in the long term, because a larger proportion of the impacts of energy efficiency savings are already included in the forecast.

7.2.3 Industrial consumption in Victoria

Methodology overview

Industrial loads are defined as those loads with typical demand greater than 10 MW[43]. 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:[44]

- Manufacturing loads are those classified under Division C of the ANZSIC code. In Victoria, this includes primary and fabricated metal, petroleum, basic chemical, pulp and paper, non-metallic mineral, and transport equipment manufacturing.
- All loads not captured under Division C are defined as ‘other’. In Victoria, this includes metal ore mining and water supply services.

Forecasts for industrial loads have been developed based on sectoral outlooks for each industry and in consultation with individual customers. For further detail refer to the 2015 Forecasting Methodology Information Paper.

[43] This refers to customers whose demand is greater than 10 MW for at least 10% of the previous year
[44] For more information ABS information on ANZSIC code classifications, refer to the xxx

Forecasts

Industrial consumption has been declining since 2007–08, due to a gradual decline in consumption from the manufacturing sector, most notably in primary metals production and car manufacturing. A large decrease in consumption, of approximately 3,000 GWh, occurred between 2013–14 and 2014–15 with the closure of the Point Henry aluminium smelter in 2014.

Table 32 summarises the industrial consumption over the short, medium and long terms.

Table 32 Industrial consumption over the short, medium and long term in Victoria

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	6,432 to 6,061	- 2.0%	Falling consumption is driven by decline in manufacturing sector including closures of vehicle manufacturing plants and the final closure of Point Henry in July 2014
Medium term (2017–18 to 2024–25)	6,061 to 6,112	0.1%	No expected major changes to industrial consumption.
Long term (2024–25 to 2034–35)	6,112 to 6,162		

Differences between low, medium and high consumption scenarios in Victoria

The low scenario assumes:

- The closure of Portland aluminium smelter in 2016.
- A decline in consumption from the manufacturing sector.
- The Victorian Desalination Project operates in preservation mode only (without any knowledge of future government annual water orders).
- A gold mine closes when current reserves are depleted.

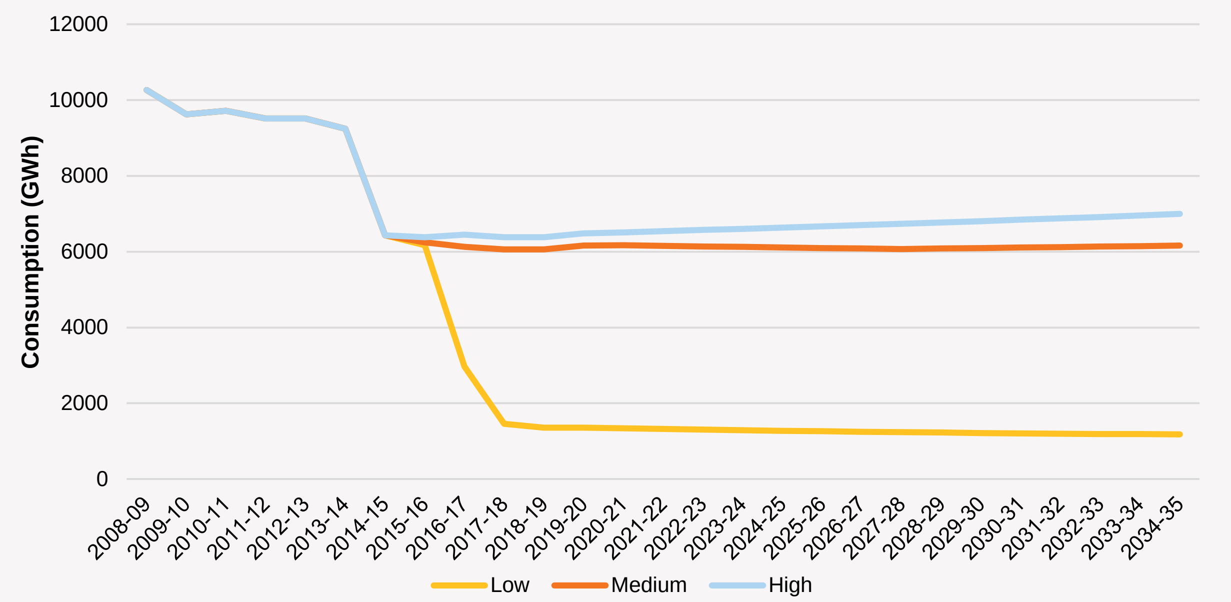
The high consumption scenario assumes there will be growth in electricity consumption from all remaining manufacturing sectors and (without any knowledge of future government annual water orders) that the Victorian Desalination Project will continue to operate at full capacity from 2020 onwards.

The average annual rates of change across the scenarios for the short, medium and long term are in Table 33 and the forecasts are shown in Figure 48.

Table 33 Average annual rates of change for the low, medium and high consumption scenario in Victoria

	Low	Medium	High
Short term (2014–15 to 2017–18)	-39.1%	-2.0%	-0.3%
Medium term (2017–18 to 2024–25)	-1.9%	0.1%	0.6%
Long term (2024–25 to 2034–35)	-0.8%	0.1%	0.5%

Figure 48 Comparison of the low, medium and high consumption industrial forecasts in Victoria



In 2024–25, compared to the medium scenario, forecast industrial consumption is 79% lower in the low scenario, and 9% higher in the high scenario.

Victoria industrial consumption comparison to 2014 NEFR

In the 2015 NEFR, AEMO increased the number of industrial customers surveyed in Victoria, from 14 to 17. As a result, approximately 300 GWh[45] of energy has been removed from the residential and commercial segment and added to the industrial segment. It is therefore more useful to compare growth rates, rather than levels of consumption, between the 2014 NEFR and 2015 NEFR forecasts.

The 2014 NEFR assumed an average annual decrease of 2.1% between 2014–15 and 2017–18. This is similar to the average annual decrease of 2.0% forecast in the 2015 NEFR.

In the medium term, the 2014 NEFR forecast an average annual decline of 0.2%, and the 2015 NEFR forecasts average annual growth of 0.1%. Both forecasts represent fairly flat consumption, and the difference in the direction of the growth is due to changes in methodology. In the 2015 NEFR, AEMO used economic sectoral forecasts, rather than survey information, to forecast medium and long term industrial consumption. See the 2015 Forecasting Methodology Information Paper for more information.

[45] Based on consumption levels in 2013–14.

7.2.4 Differences between low, medium, and high consumption scenarios in Victoria

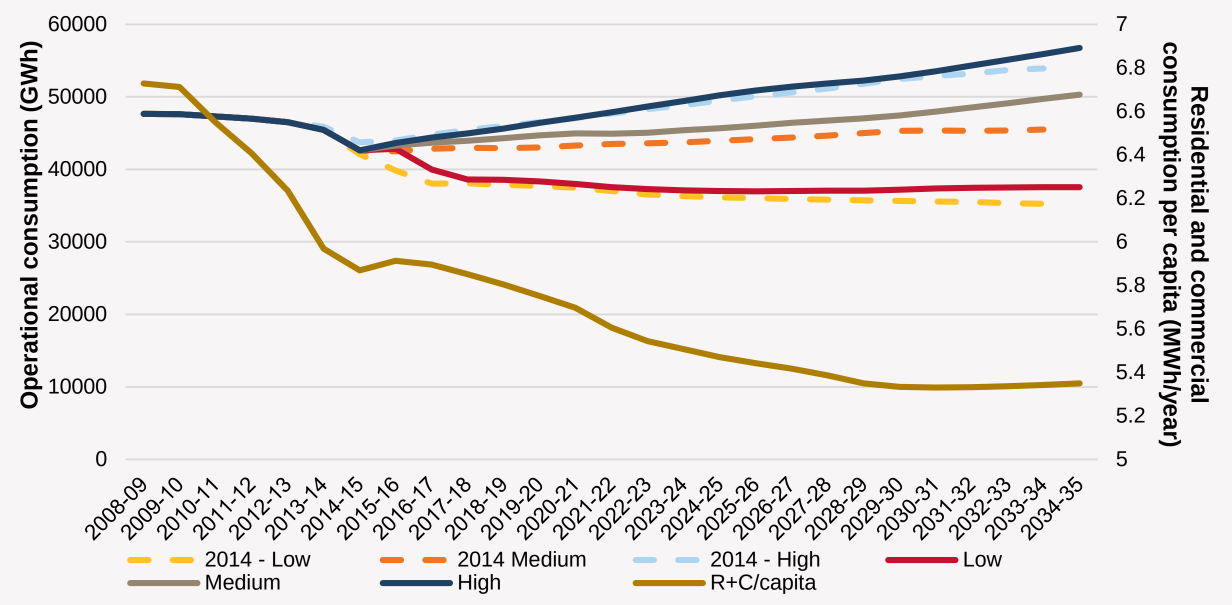
Figure 49 compares the scenarios over the forecast period.

Operational consumption in the low scenario is 12%, 19% and 25% lower than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

Operational consumption in the high scenario is 2%, 10% and 13% higher than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

The 2015 forecasts are similar to those of the 2014 NEFR in the short term, while in the longer term there is a relative increase in the medium scenario, due to more favourable economic projections.

Figure 49 Comparison of low, medium and high forecasts for Victoria



7.3 Maximum demand for Victoria

7.3.1 Maximum demand in Victoria in 2014–15

Victoria's 2014–15 summer maximum demand was 8,626 MW on 22 January 2014. This was 149 MW below the 2014 NEFR 50% probability of exceedance (POE).[46] In other words, maximum demand last year was average, being closest to the demand that was expected to be the maximum in one out of every two years.

The 2014–15 maximum demand was 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.

Melbourne's maximum temperature for summer 2014–15 was 38.8°C, which was reached on Friday 2 January 2015. Demand on this day reached 7,676 MW, probably lower than expected for this temperature because it was in the Christmas and New Year holiday period.

7.3.2 Methodology Overview

Maximum demand is driven by demand from the residential and commercial sector. It is therefore driven by the same variables as residential and commercial consumption, namely population, GSP, electricity prices, and weather. Weather has a significant impact, with cooling loads increasing on high temperature days, resulting in high demand.

Rooftop PV generation offsets demand, but less so in the later parts of the day. As installed capacity increases and demand is offset, the peak shifts to later in the day. Once this shift occurs, rooftop PV generation will have a smaller impact on maximum demand.

Unlike residential load, industrial load remains relatively flat during high temperature days. Industrial load is more likely to respond to price signals than temperature. AEMO investigates the impact of prices on industrial demand with an analysis of demand side participation (DSP) to be published separately.

7.3.3 Key points for Victoria maximum demand forecasts

- The 10% POE maximum demand is forecast to decrease at an average annual rate of 0.1%. This is primarily because the warm average temperatures in the 2014–15 summer pushed up demand. The medium term growth rate of 1.0% better reflects the expected recovery in maximum demand.
- Rooftop PV generation is expected to shift the time of maximum demand from 16:00 to 17:30 over the forecast period.
- Load factors[47] in Victoria are expected to decrease, due to increasing penetration of rooftop PV. Rooftop PV generation, which offsets consumption from the grid, is expected to have a greater impact on annual (average) consumption than maximum demand over the forecast period.

Table 34 summarises the summer 10% POE forecasts and key drivers, while Figure 50 shows the breakdown by key components.

[46] See Section 1.3 for definitions of probability of exceedance (POE).
[47] 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.

Table 34 Summary of summer 10% POE maximum demand and key drivers in Victoria

Timeframe	Forecast (MW)	Average annual growth	Drivers
Short term (2014–15 to 2017–18)	10,034 to 10,011	-0.1%	Warm average temperatures in the 2014–15 summer pushed up demand, and demand is only expected to recover slowly to that level as population and GSP increase over time.
Medium term (2017–18 to 2024–25)	10,011 to 10,761	1.0%	Increasing population and GSP drives recovery in residential and commercial maximum demand
Long term (2024–25 to 2034–35)	10,761 to 12,100	1.2%	Increasing population and GSP continues to drive recovery in maximum demand.

Figure 50 Summer 10% POE maximum demand forecast segments for Victoria

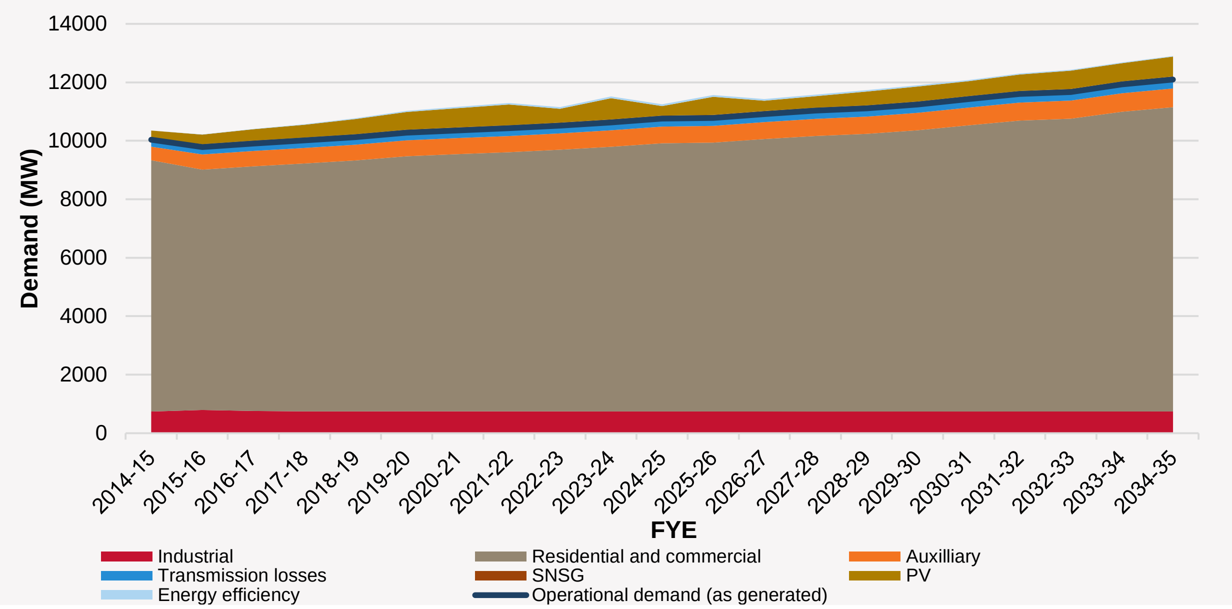
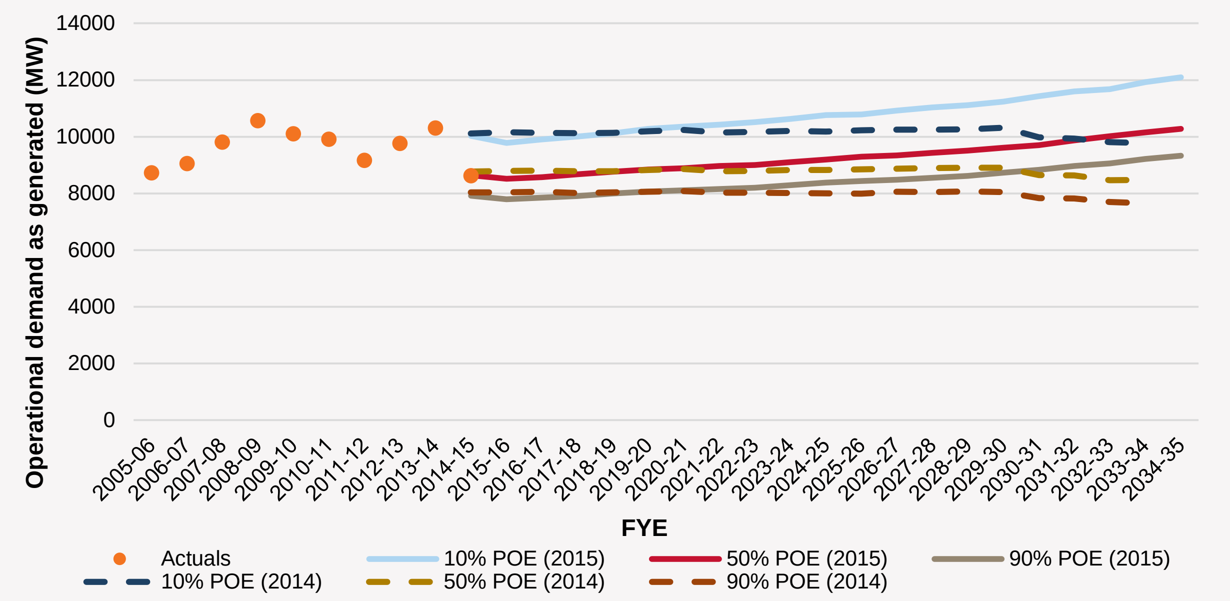


Figure 51 shows a comparison of the summer 90%, 50% and 10% POE forecasts, and the 2014 NEFR and the 2015 NEFR. The 2015 NEFR forecasts for operational demand are initially lower than in the 2014 NEFR, but increase due to a higher residential and commercial demand over the medium term period. The main drivers behind this increase are:

- Electricity price forecasts are lower in the 2015 NEFR compared to the 2014 NEFR.
- More sophisticated reconciliation of maximum demand forecasts with annual consumption forecasts.

Figure 51 Summer 90%, 50% and 10% POE maximum demand forecasts for Victoria

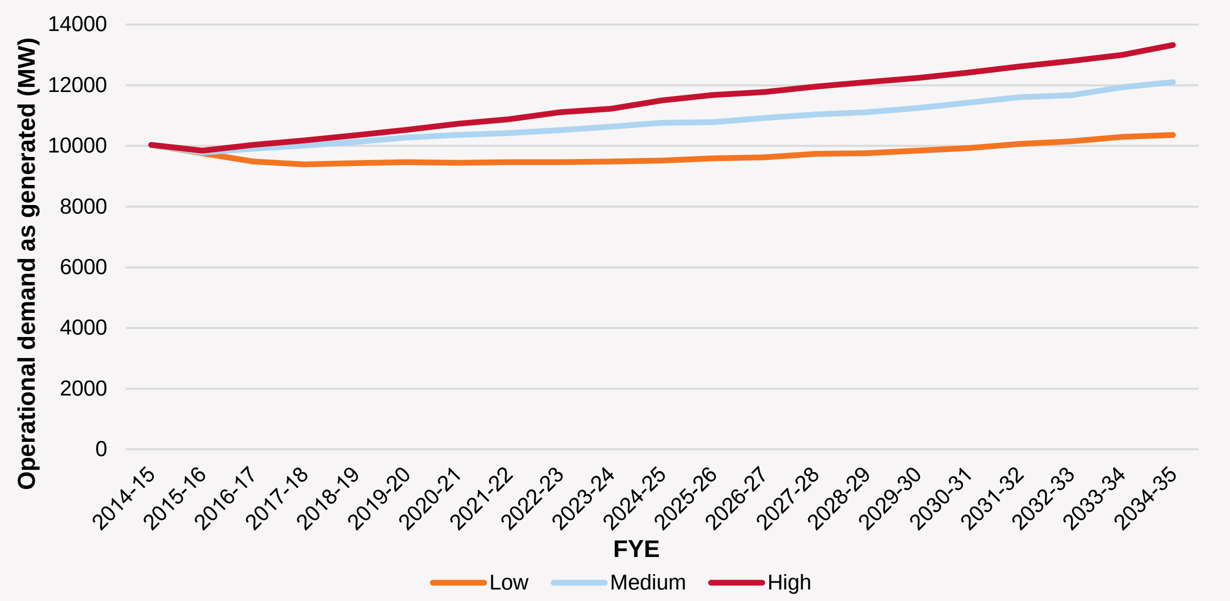


Differences between low, medium, and high scenarios in Victoria

As maximum demand is driven by the residential and commercial sector, as with annual consumption, the differences between the high, medium and low demand scenarios are driven by differences in the electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

Figure 52 shows a comparison of the 10% POE forecasts across the three demand scenarios.

Figure 52 Summer 10% POE maximum demand forecast segments for Victoria

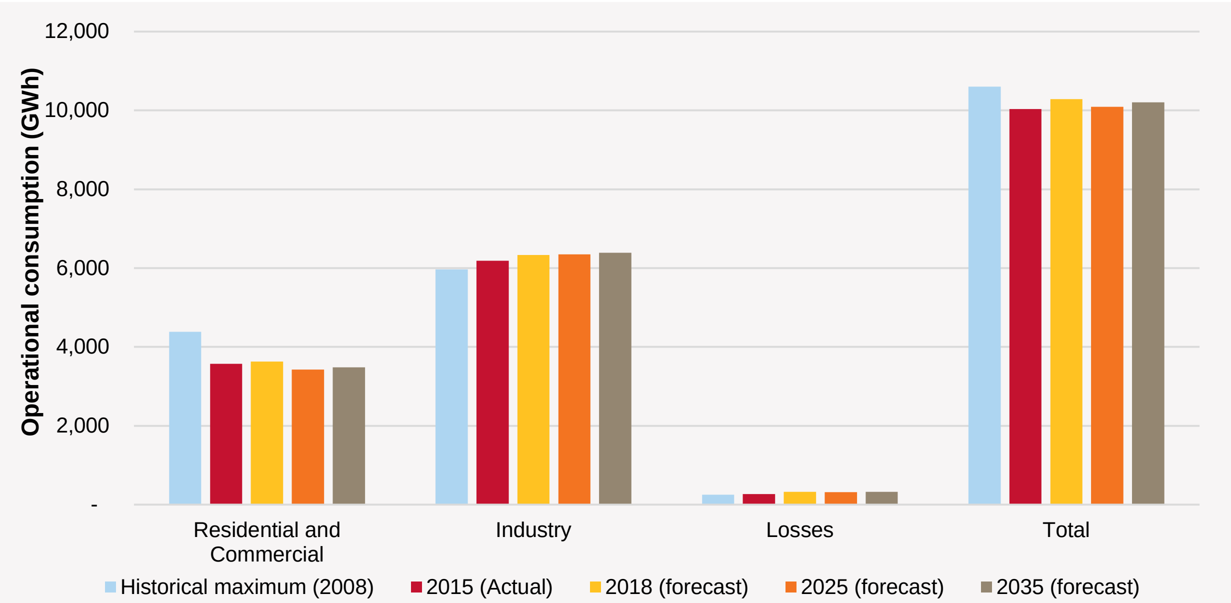


CHAPTER 8. TASMANIA

8.1 Key points for Tasmania

- Operational consumption in Tasmania remains relatively flat across the forecast period (see Figure 53).
- Tasmania is not expected to recover to its historical highest level of operational consumption[48] in the forecast period (see Figure 53).
- In the short term, there is a small increase in consumption from the residential and commercial sector, but over the longer term consumption is forecast to decline.
- There is continued uptake of rooftop PV in the residential and small commercial sectors (see Table 38) and energy efficiency measures.
- Consumption per capita continues to decline over the short to medium term, and plateaus in the long term (see Figure 54).
- Industrial consumption increases in the short term, due to greater plant utilisation and the announced increased consumption at Bell Bay aluminium smelter.[49] Over the medium to long term, it is forecast to remain flat (see Figure 54).
- Maximum demand is forecast to shift from morning to evenings, due to the impact of rooftop PV.

Figure 53 Comparison of actual and forecast operational consumption in Tasmania



[48] Tasmania experienced its highest level of operational consumption of 10,600 GWh in 2007–08.
[49] http://bellbayaluminium.com.au/client-assets/documents/Media%20Releases/070514-media-release-bell-bay-aluminium-announcement.pdf

8.2 Annual operational consumption in Tasmania

In the five years to 2014–15, operational consumption has been declining in Tasmania. The decline has been driven by a fall in residential and commercial consumption, largely in response to rising electricity prices and the uptake of rooftop PV and energy efficiency (see Figure 54).

AEMO forecasts a slight recovery in operational consumption in the short term (2014–15 to 2017–18), driven by an increase in industrial consumption. Medium and long term forecasts indicate a slight decrease, to flat operational consumption.

Consumption per capita continues to decline, with any increases in consumption due to population growth offset by continued uptake of rooftop PV and energy efficiency.

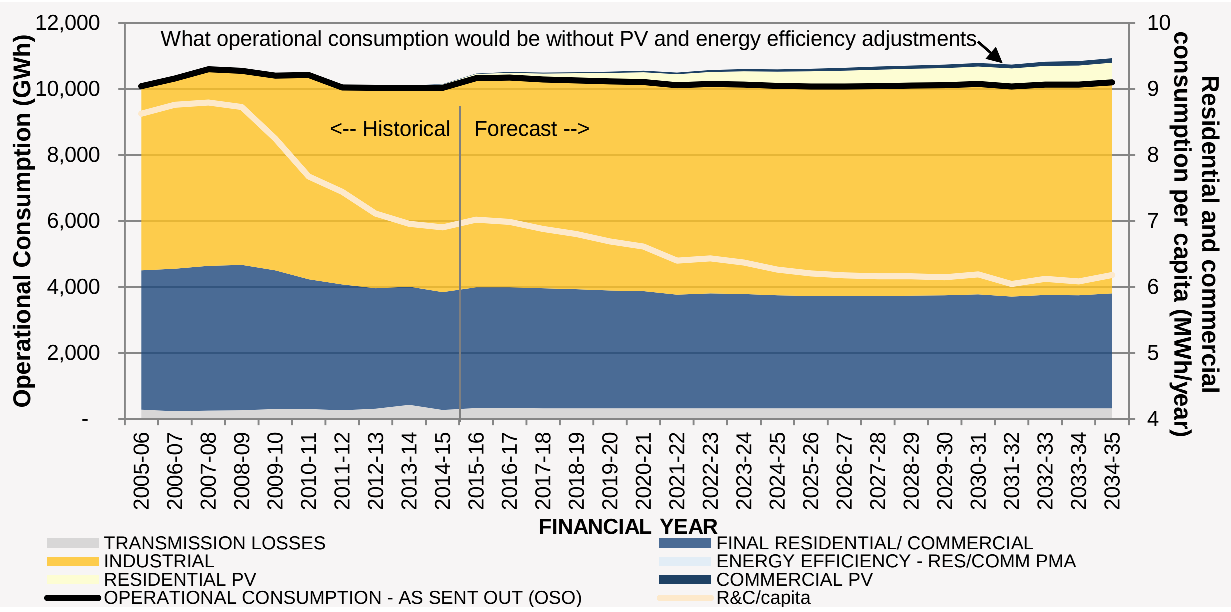
Table 35 summarises forecasts under the medium scenario, and drivers for these results, while Figure 54 illustrates the forecasts by key components.

Figure 54 shows the historical decline in residential and commercial consumption, and the short-term forecast increase in industrial consumption. The black line indicates the operational consumption, while the top of the graph indicates what the operational consumption would be, if it was not offset by rooftop PV and energy efficiency measures.

Table 35 Operational consumption over the short, medium and long term in Tasmania

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	10,034 to 10,289	0.8%	The increase of 255 GWh is driven by increases in the industrial sector, notably Bell Bay.
Medium term (2017–18 to 2024–25)	10,289 to 10,091	-0.3%	The decline in consumption is driven by reduced consumption from the residential and commercial sector as uptake of rooftop PV and energy efficiency outpaces increases in underlying consumption due to population growth.
Long term (2024–25 to 2034–35)	10,091 to 10,201	0.1%	Operational consumption is flat over the long term, with both industrial and residential and commercial consumption displaying little net change.

Figure 54 Operational consumption by key component in Tasmania



8.2.1 Residential and commercial consumption in Tasmania

Methodology overview

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 forecast over a 20-year horizon, with the key modelled drivers being population, income, weather and electricity prices.

In this long-term methodology, residential and commercial consumers are modelled as responding to increases or decreases in average prices, as well as the average income measured by Gross State Product (GSP). In general, consumption increases if income increases, and decreases if electricity prices increase. For further detail refer to the 2015 Forecasting Methodology Information Paper.

AEMO models this in two stages:

1. It forecasts per capita consumption to capture underlying usage trends by removing the impact of population growth. This is why per capita consumption is the key metric in analysing the forecasts.
2. It then uses population growth forecasts to calculate overall underlying consumption.

The underlying consumption is then offset by forecast rooftop PV generation (which reduces electricity drawn from the grid), and adjustments to account for energy efficiency impacts not already captured in the underlying trends.

Forecasts

Historically, residential and commercial consumption in Tasmania has been declining since 2008–09, as electricity prices have increased, with consumption per capita decreasing from 8.8 MWh/year to 6.9 MWh/year.

The decline in consumption has slowed over the last two years despite population growth, and is estimated to be flat over the last year (3,581 GWh in 2013–14 and an estimated 3,576 GWh in 2014–15). Continued uptake in rooftop PV installations has largely offset the small growth in underlying consumption due to population.

The consumption forecast relies on the economic and demographic variables shown in Figure 55.

Key points in the variables are:

- Population is projected to grow over the forecast period.
- Gross State Product (GSP) recovers from its recent plateau and grows in real terms.
- Electricity prices have declined since 2012–13, and are projected to continue declining until 2017–18, when they are forecast to increase at a slow rate for the remainder of the forecast period.

Figure 55   Key drivers of residential and commercial underlying consumption in Tasmania

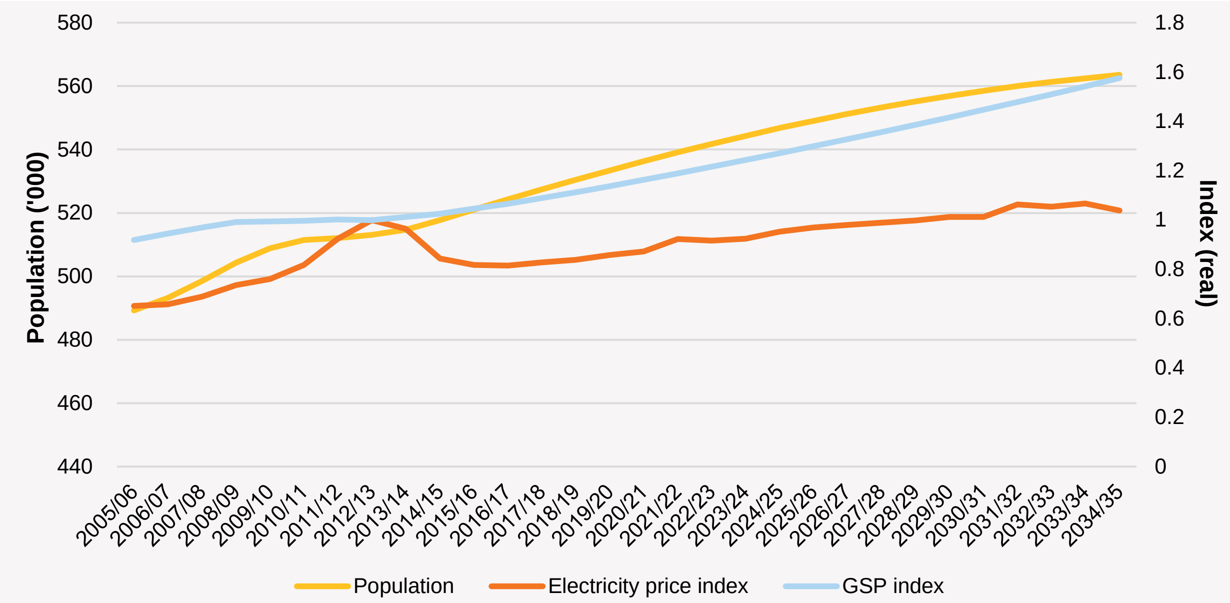


Table 36 summarises the forecast annual residential and commercial consumption over the short, medium and long term.

Table 36   Consumption in the residential and commercial sector over the short, medium and long term in Tasmania

Timeframe	Forecast (GWh)	Average annual change	Consumption per capita (MWh/yr)	Drivers
Short term (2014–15 to 2017–18)	3,576 to 3,629	0.5%	6.90 to 6.88	Growth in income and declining electricity prices lead to recovery in underlying consumption, which is offset by continued uptake of rooftop PV, tempering any net change in consumption.
Medium term (2017–18 to 2024–25)	3,629 to 3,424	-0.8%	6.88 to 6.3	Recovery in underlying consumption slows as electricity prices rise. This recovery is outpaced by the continued uptake of rooftop PV and energy efficiency, which reduce overall consumption from the grid and consumption per capita.
Long term (2024–25 to 2034–35)	3,424 to 3,484	0.2%	6.3 to 6.2	Recovery in underlying consumption increases as income per capita increases in the long term. Residential and small commercial PV slows as it starts to reach saturation levels, but still largely offsets the recovery in underlying consumption.

Overall, consumption in the residential and commercial sector in Tasmania remains relatively flat across the forecast period. Underlying recovery is driven by falling electricity prices in the short term, and by population and income growth in the long term, but it is offset by growth in residential and small commercial PV, and energy efficiency measures. Consumption per capita continues to decline over the entire forecast period, and consumption never reaches the historical high of 4,402 GWh.[50]

Differences between low, medium and high consumption scenarios in Tasmania

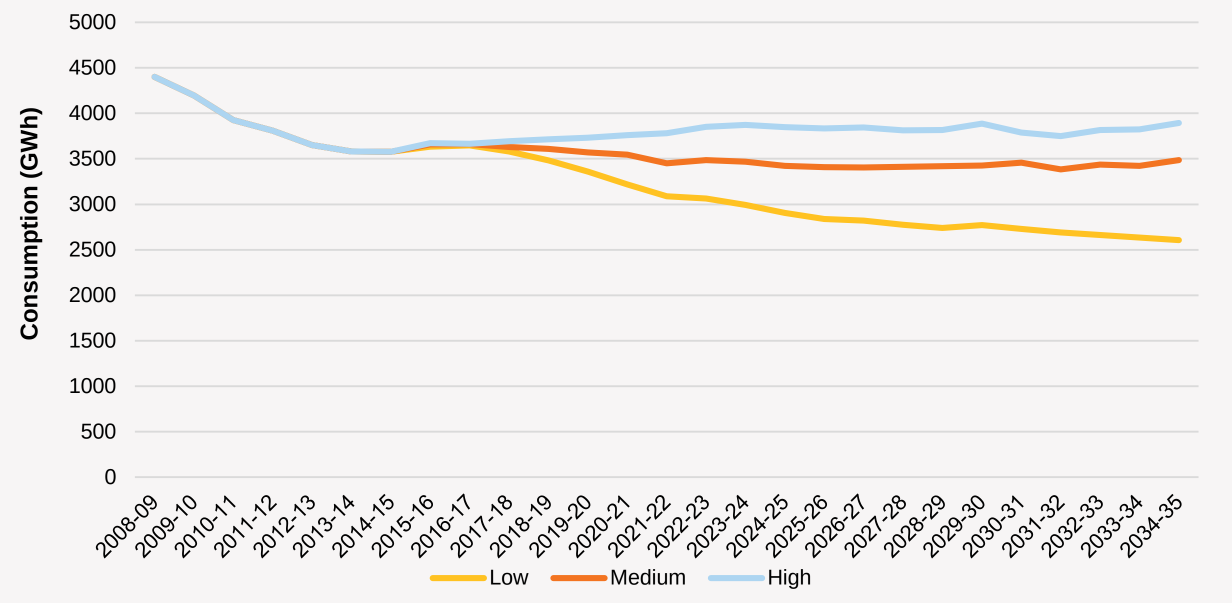
The differences between the low, medium and high consumption scenarios are driven by differences in electricity price, population and GSP forecasts, as well as the assumptions on rooftop PV and energy efficiency uptake.

The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 37 and the forecasts are shown in Figure 56.

Table 37 Average annual rates of change for the low, medium and high consumption scenarios in Tasmania

	Low	Medium	High
Short term (2014–15 to 2017–18)	0.1%	0.5%	1.1%
Medium term (2017–18 to 2024–25)	-3.0%	-0.8%	0.6%
Long term (2024–25 to 2034–35)	-1.1%	0.18%	0.12%

Figure 56 Comparison of low, medium and high residential and commercial forecasts



In 2024–25, compared to the medium scenario, residential and commercial consumption is 15% lower in the low scenario, and 12% higher in the high scenario.

[50] Residential and commercial consumption in Tasmania reached its historical high in 2008-09

Tasmania residential and commercial consumption comparison to 2014 NEFR

Overall, the medium and low scenario forecasts are very similar to the 2014 NEFR.

The high scenario in 2015 is higher than that forecast in 2014, due to higher forecast GSP and lower forecast electricity prices. The 2015 low forecasts are slightly higher than those in the 2014 NEFR, due to a recovery in income and population growth.

8.2.2 Rooftop PV forecasts for Tasmania

The 2015 NEFR is the first time AEMO has modelled residential and commercial PV separately. Systems less than 10 kW were classified as residential, while commercial systems were categorised as either small (less than 100 kW) or large (greater than 100 kW).

- Residential PV uptake continues to be driven by the federal Small-scale Renewable Energy Scheme (SRES) and the increasing economic viability of rooftop PV. The programs that incentivised the historical uptake have helped to establish a local industry and drive a reduction in PV technology and installation costs.
- Uptake in the commercial sector has been more recent, driven by a combination of programs such as the Clean Technology Investment Fund and SRES, as well as 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.

Table 38 shows the cumulative capacity and generation of rooftop PV installations by segment for the medium scenario. There is continued uptake in both residential and small commercial installations and both sectors start to reach saturation levels in the longer term. There is no forecast growth in the large commercial sector.

Despite having the lowest amount of installed rooftop PV capacity of all the NEM regions, Tasmania has the third highest proportion of PV relative to its residential and commercial load (see Table 5).

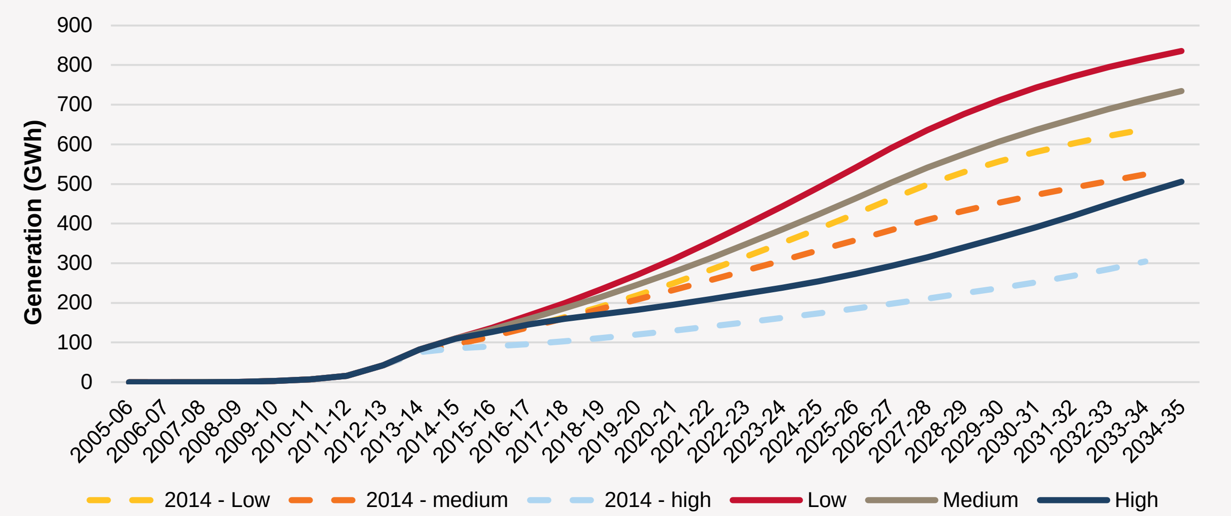
Table 38 Rooftop PV forecasts for Tasmania

	Commercial PV		Residential PV		Total	
	MW	GWh	MW	GWh	MW	GWh
2014–15	11	12	84	99	**95**	**110**
2017–18	24	28	133	159	**157**	**186**
2024–25	59	72	289	352	**347**	**423**
2034–35	111	138	475	596	**585**	**734**

A comparison of the rooftop PV forecasts for the three scenarios, and for the 2014 NEFR and 2015 NEFR, is given in Figure 57. The differences in the 2015 NEFR are mainly due to separate modelling of residential and commercial PV. Recent data also shows a stronger uptake of rooftop PV in the last year.

In the short term, the 2015 forecasts are close to the 2014 low and medium scenarios, but all other 2015 NEFR scenario forecasts are higher.

Figure 57 Rooftop PV forecasts for low, medium and high consumption scenarios in Tasmania



Energy efficiency

AEMO adjusts its forecasts based on additional energy efficiency savings that are not already captured in the residential and commercial consumption. These are based on data from existing and planned future government programs.

In the medium scenario, the energy efficiency adjustments applied to the forecasts were:

- Short term – the adjustment increased from 5 GWh in 2014–15 to 22 GWh in 2017–18.
- Medium term – the adjustment increased from 22 GWh in 2017–18 to 81 GWh in 2024–25.
- Long term – the adjustment decreased from 81 GWh in 2024–25 to 0 GWh in 2034–35.

The adjustment decreases in the long term, because a larger proportion of the impacts of energy efficiency savings are already included in the forecast.

8.2.3 Industrial consumption in Tasmania

Methodology overview

Industrial loads are defined as those loads with typical demand greater than 10 MW.[51] 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[52]:

- Manufacturing loads are those classified under Division C of the ANZSIC code. In Tasmania, this includes primary metal, pulp and paper, wood, and non-metallic mineral product manufacturing.
- All loads not captured under Division C are defined as ‘other’. In Tasmania, this includes metal ore mining.

Forecasts for the industrial loads have been developed based on sectoral outlooks for each industry and in consultation with individual customers. For further detail refer to the 2015 Forecasting Methodology Information Paper.

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

[52] For more information on ANZSIC code classifications, refer to the ABS website, http://www.abs.gov.au/ausstats/abs@.nsf/Previousproducts/20C5B5A4F46DF95BCA25711F00146D75?opendocument

Forecasts

Industrial consumption in Tasmania has increased incrementally since 2006, due to increased consumption from large manufacturers.

Table 39 summarises forecast consumption over the short, medium and long term.

Table 39 Industrial consumption over the short, medium and long term in Tasmania

Timeframe	Forecast (GWh)	Average annual change	Drivers
Short term (2014–15 to 2017–18)	6,187 to 6,333	0.8%	This growth is driven by full utilisation of plants by major customers to take advantage of recent plant improvements and/or the lower Australian dollar, and increased consumption at Bell Bay
Medium term (2017–18 to 2024–25)	6,333 to 6,346	0.03%	Consumption remains steady, based on the assumption that there are no plant expansions or closures.
Long term (2024–25 to 2034–35)	6,346 to 6,392	0.07%	

Differences between the low, medium and high consumption scenarios in Tasmania

The low consumption scenario reflects electricity consumption in Tasmania if two large customers closed. The modelled closure of Bell Bay and one other large customer reduces industrial consumption by approximately 3,500 GWh. These closures are assumed to be driven by plant age, high electricity prices and falling demand for products.[53]

The medium case includes the recent announcement by Bell Bay aluminium smelter of its intention to increase production.

The high consumption scenario assumes:

- Growth in both manufacturing and mining in Tasmania, and in the production of cement to support construction activities.
- The four largest customers make modifications to existing plants and operate at maximum capacity for the duration of the forecast.

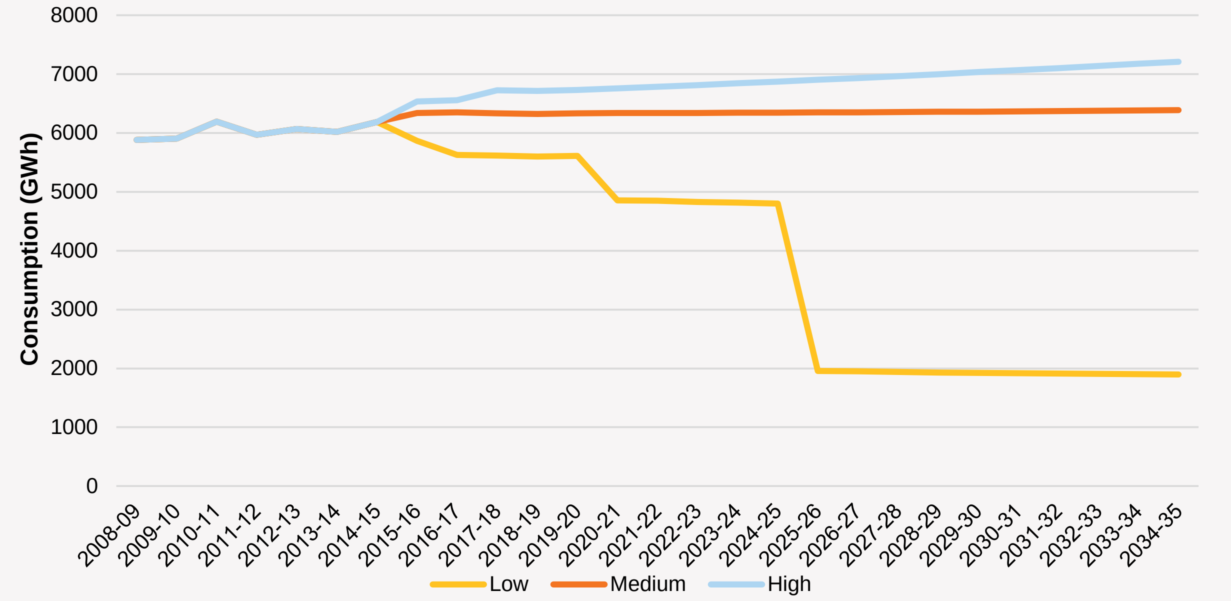
The average annual rates of change across the scenarios for the short, medium and long term are shown in Table 40, and the forecasts are shown in Figure 58.

Table 40 Average annual rates of change for the low, medium and high consumption scenarios in Tasmania

	Low	Medium	High
Short term (2014–15 to 2017–18)	-3.2%	0.8%	2.8%
Medium term (2017–18 to 2024–25)	-2.2%	0.03%	0.3%
Long term (2024–25 to 2034–35)	-8.9%	0.07%	0.5%

[53] Please note that these are AEMO's assumptions and they have been developed to provide an indication of a low consumption scenario for Tasmania. At the time of writing, no customer indicated their intentions to close.

Figure 58 Comparison of low, medium and high consumption industrial forecasts for Tasmania



In 2024–25, compared to the medium scenario, forecast industrial consumption is 24% lower in the low scenario, and 8% higher in the high scenario.

Tasmania industrial consumption comparison to 2014 NEFR

There has been no change in the number of customers surveyed as part of the NEFR in Tasmania. A total of 13 sites were surveyed.

The 2014 NEFR forecast an average annual increase of 0.6% between 2014–15 and 2017–18. In the 2015 NEFR, AEMO has forecast an average annual increase of 0.8% over the same period. The increase in growth is due to increased consumption from large customers, particularly Bell Bay aluminium smelter.

In the medium term, the 2014 NEFR forecast a decline of 0.1%, and the 2015 NEFR forecasts an average annual rate change of 0.0%. The small difference is due to methodology changes. In the 2015 NEFR, AEMO used economic sectoral forecasts, rather than survey information, to forecast medium and long term industrial consumption. Refer to the 2015 Forecasting Methodology Information Paper for more information.

8.2.4 Differences between low, medium, and high consumption scenario forecasts

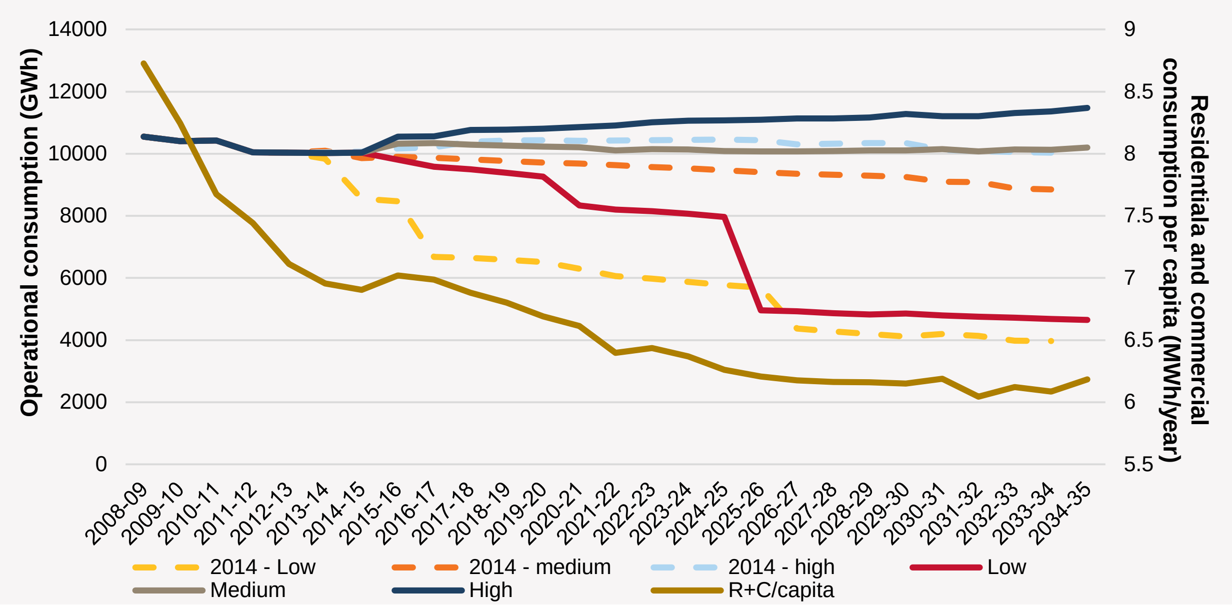
Figure 59 compares the scenarios over the forecast period.

Operational consumption in the low scenario is 8%, 21% and 54% lower than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

Operational consumption in the high scenario is 5%, 10% and 12% higher than the medium scenario in the years 2017–18, 2024–25 and 2034–35 respectively.

The 2015 forecasts are higher than those of the 2014 NEFR for the reasons outlined above in the industrial and residential and commercial sectors.

Figure 59 Comparison of the low, medium and high forecasts in Tasmania



8.3 Maximum demand for Tasmania

Unlike the other NEM regions, maximum demand in Tasmania occurs in winter. For this reason, maximum demand results are presented in calendar years.

8.3.1 Maximum demand in Tasmania 2014

In 2014, the maximum demand was 1,656 MW on 30 June 2014. This was 16 MW below the 2014 NEFR 50% probability of exceedance (POE) forecast. In other words, maximum demand last year was average, being closest to the demand that was expected to be the maximum in one out of every two years.

The 2014 maximum demand in Tasmania occurred on a Monday with a maximum temperature of 11.2°C in Hobart and a minimum temperature of 4.7°C.

Hobart's coldest day (on an average temperature basis) occurred on Monday 9 June 2014, with an average temperature of 5.1°C and an overnight minimum of 1.2°C. Demand on this day reached 1,518 MW.

8.3.2 Methodology Overview

Winter maximum demand is driven by demand from the residential and commercial sector. It is therefore driven by the same variables as residential and commercial consumption, namely population, GSP, electricity prices, and weather. Weather has a significant impact, with heating loads increasing on low temperature days, resulting in high demand.

Tasmania has its winter peak occur either in the morning or evening. As rooftop PV generation offsets demand throughout the middle of the day, there is only a small impact on the morning demand and none on the evening demand. As installed capacity increases, the morning peak is offset, resulting in the peak being more likely to occur in the evening.

Unlike residential load, industrial load remains relatively flat during low temperature days. Industrial load is more likely to respond to price signals than temperature. AEMO investigates the impact of prices on industrial demand with an analysis of demand side participation (DSP) to be published separately.

8.3.3 Key points for Tasmania maximum demand forecasts

- The 10% probability of exceedance (POE)[54] maximum demand is forecast to increase slightly, at an annual average rate of 0.3%, over the short term (2014 to 2017). This is primarily driven by increasing population and Gross State Product (GSP).
- As rooftop PV penetration continues to increase, there is expected to be a small amount of PV generation offsetting demand in the morning, but not the evening. As a result, time of maximum demand is expected to shift to 18:00 over the forecast period.[55]
- Load factors[56] are expected to decrease. As rooftop PV installations increase, there will be an increased impact on annual consumption, but no impact on maximum demand due to the evening peak time.

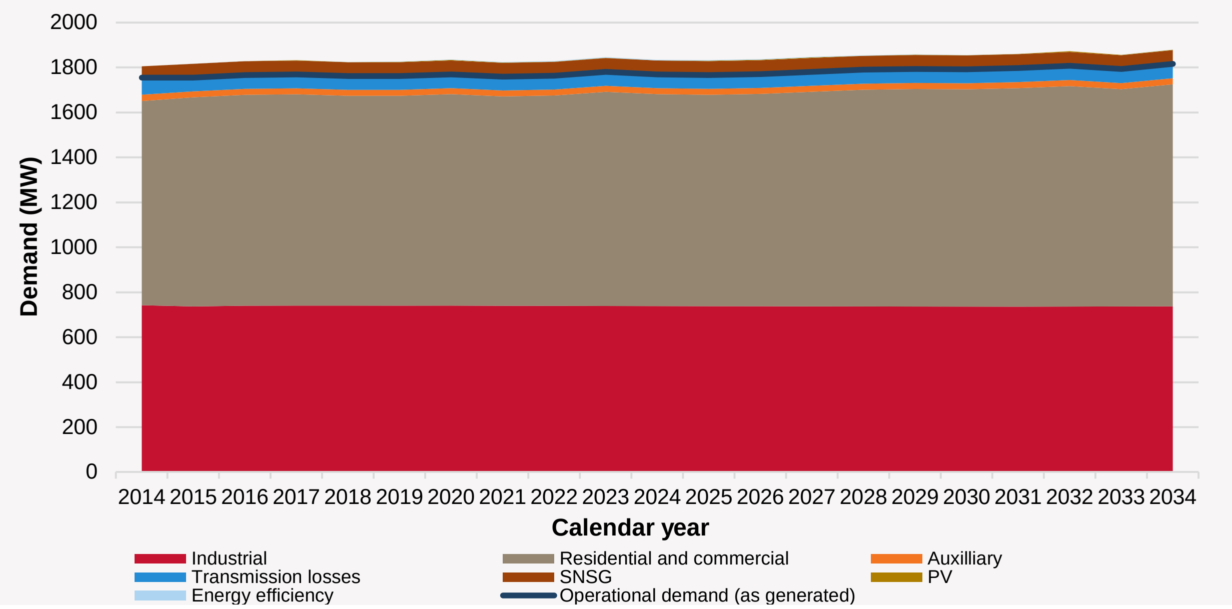
Table 41 provides a summary of the winter 10% POE forecasts and key drivers, while Figure 60 shows the breakdown by key components.

[54] See Section 1.3 for definitions of probability of exceedance (POE).
[55] Over the past five years, winter maximum demand has occurred either in the morning or evening. There is still a chance that maximum demand will occur in the morning, but it is more likely to occur in the evening.
[56] 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.

Table 41 Summary of winter 10% POE maximum demand and key drivers in Tasmania

Timeframe	Forecast (MW)	Average annual change	Drivers
Short term (2014 to 2017)	1,754 to 1,769	0.3%	Increasing population and GSP drives recovery in residential and commercial demand.
Medium term (2017 to 2024)	1,769 to 1,769	0%	Residential and commercial demand expected to remain flat due to increasing electricity prices offsetting recovery from population growth.
Long term (2024 to 2034)	1,769 to 1,815	0.3%	Electricity prices do not increase as much over this period allowing GSP and population growth to again drive demand.

Figure 60 Winter 10% POE maximum demand forecast segments for Tasmania

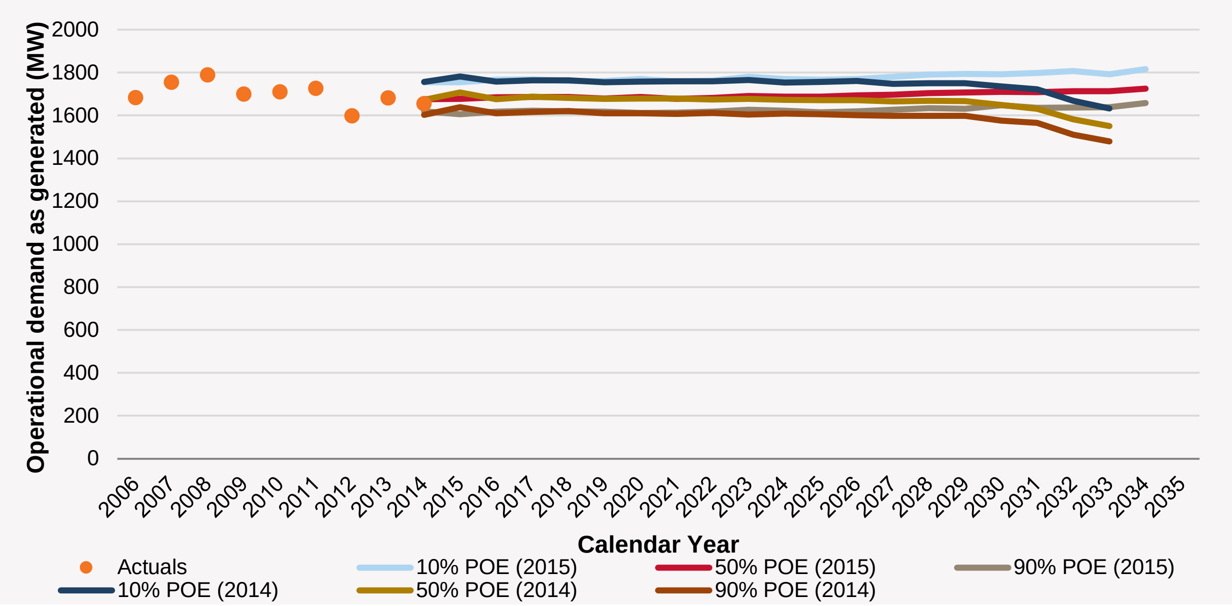


A comparison of the winter 90%, 50% and 10% POE forecasts, and the 2014 NEFR and 2015 NEFR, is given in Figure 61.

It shows the 2015 NEFR forecasts for operational demand closely align with the 2014 NEFR forecasts. There is a slight increase towards the end of the medium term, due to:

- Electricity prices being lower in the 2015 NEFR compared to the 2014 NEFR.
- More sophisticated reconciliation of maximum demand forecasts with annual consumption forecasts.

Figure 61 Winter 90%, 50% and 10% POE maximum demand forecasts for Tasmania



Differences between low, medium, and high consumption scenarios in Tasmania

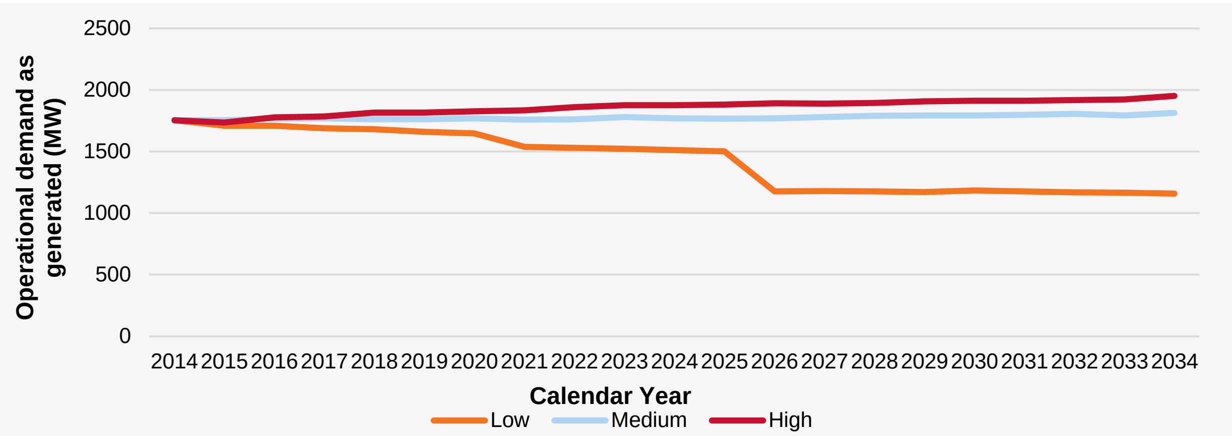
As maximum demand is driven by the residential and commercial sector, as with annual consumption, the differences between the high, medium and low demand scenarios are driven by differences in the electricity price, population and GSP forecasts, as well as assumptions on rooftop PV and energy efficiency uptake.

Figure 62 shows a comparison of the 10% POE forecasts across the three demand scenarios.

In 2015, there is a slight crossover between the high demand and medium demand scenarios, due to crossovers in electricity prices. The low price (high demand) forecast and medium price (medium demand) crossover occurs due to different assumptions around fuel prices, the carbon price and generation costs.

Long term, the population and GSP growth in the high scenario cause the supply-side effects to dominate, resulting in low prices and high demand. For further information please refer to the Frontier Economics report.[57]

Figure 62 Winter 10% POE maximum demand forecast segments for Tasmania



[57] Frontier Economics, Electricity market forecasts: 2015, April 2015.

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
CDD	Cooling degree days
DD	Degree days
EDD	Effective degree days
GWh	Gigawatt hours
HDD	Heating degree days
kV	Kilovolts
kWh	Kilowatt hours
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
$	Australian dollars
$/kWh	Australian dollars per kilowatt hour
$/MWh	Australian dollars per megawatt hour

Abbreviations

Abbreviation	Expanded name
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
APR	Annual planning report
AUX	Power station auxiliaries
BOM	Bureau of Meteorology
DNSP	Distribution network service provider
DSP	Demand-side participation
EE	Energy efficiency
ESOO	Electricity Statement of Opportunities
GFC	Global financial crisis
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MD	Maximum demand
NEM	National Electricity Market
NERF	National Electricity Repository for Forecasting
NIEIR	National Institute of Economic and Industry Research
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
POE	Probability of exceedance
PV	Photovoltaic

Abbreviation	Expanded name
QGC	Queensland Gas Company
QLD	Queensland
REC	Renewable Energy Certificate
RET	Renewable Energy Target - national Renewable Energy Target scheme
Rooftop PV	Rooftop photovoltaic
SA	South Australia
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
TAS	Tasmania
TNSP	Transmission network service provider
VAPR	Victorian Annual Planning Report
VIC	Victoria

GLOSSARY

Definitions

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 system co-located coal mines.
capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
contribution factor	The rooftop PV power generation (in MW) as a percentage of the total rooftop PV (MW) installed capacity.
cooling degree days	A sum of the products of: • The time that a region experiences ambient temperatures above its threshold temperature; and • The number of degrees that the ambient temperature is above the threshold temperature.
deeming period (of STCs)	STCs can be claimed in advance for the electricity the system will displace over a future period. This is called a deeming period. Rooftop PV STCs, for example, may be created annually or at the start of each five year deeming period, or for a single 15 year deeming period.
demand-side participation (DSP)	The situation where customers vary their electricity consumption in response to a change in market conditions, such as the price of electricity. This encompasses both voluntary/reactionary and coordinated responses.
diversity factor	Refers to the ratio of the maximum demand of a connection point/terminal station to the demand of that connection point at the time of system peak. This is sometimes referred to as the demand factor, and is always less than or equal to one. When the diversity factor equals one, the connection point peak coincides with the system peak.
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.
heating degree days (HDD)	A sum of the products of: • The time that a region experiences ambient temperatures below its threshold temperature; and • The number of degrees that the ambient temperature is below the threshold temperature.
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.

Term	Definition
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 calculate d by dividing average demand (MW) over the summer/winter period (Oct-Mar or Apr-Sep) 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.
native electrical consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled and small non-scheduled generating units.
operational electrical 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.
payback period	The time required for the return on an investment to equal the original investment amount.
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, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
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.
residential and commercial load (annual energy or maximum demand)	The annual energy or maximum demand relating to all consumers except large industrial load. Mass market load is the load on the network, after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
retail electricity price	The price paid by consumers to retailers for supplying them with electricity.
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.
saturation level	The estimated maximum rooftop PV capacity, reflecting the number of households, rooftop areas, and other siting factors.
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 non-scheduled generation (SNSG)	Non-scheduled generating systems that generally have capacity less than 30 MW.
Small-scale Renewable Energy Scheme (SRES)	See 'Renewable Energy Target (RET)'.
small-scale technology certificate (STC)	See 'Renewable Energy Target (RET)'.
Small-scale Technology Certificate (STC) multiplier	A mechanism that multiplied the number of STCs that rooftop PV systems would usually create under the RET scheme. The multiplier ceased (was reduced to one) from 1 January 2013.

Term	Definition
smart meter	An electricity meter that records electricity usage for discrete time intervals (such as for each 30-minute period) and automatically sends this data to the electricity supplier. Some smart meters have additional communications and load control functions.
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).
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission network.
wholesale electricity price	Wholesale trading in electricity is conducted as a spot market, and the wholesale price is the spot price. It is based on the price that generators receive for generating electricity and the price that retailers pay for electricity they purchase. The spot price is the price in a trading interval (a 30-minute period) for one megawatt hour (MWh) of electricity at a regional reference node.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).