Forecast Accuracy Report 2018

December 2018

For the 2017 Electricity Statement of Opportunities

Important notice

PURPOSE

This Forecast Accuracy Report has been prepared for the purposes of clause 3.13.3(u) of the National Electricity Rules. It reports on the accuracy of demand forecasts to date in the 2017 Electricity Statement of Opportunities (ESOO) for the National Electricity Market (NEM) and improvements made to the forecasting process for the 2018 ESOO.

This publication has been prepared by AEMO using information available at 31 August 2018.

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VERSION CONTROL

Version	Release date	Changes
1	21/12/2018	Initial release

Executive Summary

Each year, AEMO assesses the accuracy of its electricity demand and consumption forecasts to help inform its continuous improvement program and build confidence in the forecasts produced. The 2018 *Forecast Accuracy Report* assesses the accuracy of the annual operational consumption and maximum and minimum operational demand forecasts in AEMO's 2017 Electricity Statement of Opportunities (ESOO), for each region in the National Electricity Market (NEM)[1].

Maximum and minimum demand forecasts are probabilistic forecasts that are sensitive to prevailing weather conditions and other, sometimes unobservable, factors. This makes measuring the accuracy of maximum and minimum demand forecasts difficult. In seeking to improve forecasts it is also critical to provide more data on the estimation variance, noting that the variability of supply and demand and the rate of change in the industry will naturally reflect in wider bounds on likely outcomes.

To establish more transparency around AEMO's demand forecasts several quantitative and qualitative forecast performance metrics are used in this report, including:

- Measuring the percentage difference between actual and forecast consumption values.
- Testing how well the model is able to predict historical data (goodness-of-fit).
- Backcasting the top 15 demand periods in each region, using the actual weather conditions observed.
- Comparing actual maximum demand to the forecast distribution (noting that maximum demand is a probabilistic forecast) and qualitatively explaining the differences.
- Assessing the accuracy of key forecast input drivers.

AEMO is continuing to work with industry and researchers to establish other performance metrics, and develop a forecast performance monitoring dashboard, which will provide more frequent updates to forecast accuracy through an online portal and allow stakeholders to perform their own assessments of AEMO's forecasting performance.

The assessment of AEMO's 2017-18 demand and consumption forecast performance highlights that:

- Actual NEM operational consumption (sent-out) in 2017-18 was 1.3% below forecast. On a regional basis, the largest differences were observed in Queensland and Victoria, where consumption was over-estimated by nearly 3%. The other three regions all had actuals within 1% of forecast consumption.
- In all regions except Tasmania, maximum demand in 2017-18 was within the forecast range between 10% probability of exceedance (10POE) and 90% POE. In Tasmania, maximum demand was below the forecast distribution range due to expected industrial load growth not eventuating.
- In most regions, the forecast decline in minimum demand was more aggressive than actually observed.
- There were some material differences between inputs used in developing the forecast, and actual realisation of these input drivers. For example, residential connections growth in Victoria was higher than forecast, and rooftop photovoltaic (PV) uptake was more rapid than forecast. Other input assumptions were reasonably well aligned with actuals.

Some of the observed differences between actuals and forecasts have affirmed changes already made to the forecast methodology for the 2018 ESOO. Other differences have helped steer the direction for future improvements to be implemented for the 2019 ESOO. These future improvements are outlined in the body of this report.

[1] AEMO. *2017 Electricity Statement of Opportunities for the National Electricity Market*, June 2017. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2017-NEM-ESOO.

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1. Introduction

The Australian Energy Market Operator (AEMO) produces a Forecast Accuracy Report for its *Electricity Statement of Opportunities* (ESOO) each year.

This 2018 *Forecast Accuracy Report* assesses the accuracy of the annual operational consumption and maximum and minimum operational demand forecasts in AEMO's 2017 ESOO, for each region in the National Electricity Market (NEM)[2].

The 2017 ESOO provided AEMO's independent 10-year electricity consumption forecasts for each NEM region. It was based on the methodology outlined in the *2016 Forecasting Methodology Information Paper*[3]. Forecast data by region is available on AEMO's forecasting portal[4], and is updated regularly as material new information is made available to AEMO.

Compared to previous Forecast Accuracy Reports, this year's report has been expanded as part of AEMO's commitment to work collaboratively with market bodies and industry to strengthen AEMO's accountability and transparency and the accuracy of forecasts it produces. As alluded to in the 2017 *Forecast Accuracy Report*, this includes the implementation of a forecast performance monitoring system, which will provide more frequent updates to forecast accuracy through an online portal and allow stakeholders to perform their own assessments of AEMO's forecasting performance. In parallel, AEMO is continuing to develop metrics for assessing performance of probabilistic forecasts, and has been consulting extensively on how this may best be evaluated. A proposed approach is due to be finalised by the end of this year, and the metrics will be included in both the performance monitoring system and future Forecast Accuracy Reports.

Future reports will also provide broader coverage and deeper insights into the forecast accuracy overall for forecast operational consumption and maximum/minimum operational demand, and also where possible for individual segments and key input forecasts.

Supply assumptions will also be assessed against actual outcomes in recognition of the importance of these assumptions in assessing supply adequacy.

In this 2018 *Forecast Accuracy Report*, the accuracy is measured as the forecast values compared against actuals for the financial year 2017-18, and depends on AEMO's forecast models and the veracity of the inputs. Many of these inputs are provided by third parties, including economic forecasts.

The *Forecast Accuracy Report* also includes details of any improvements that will be applied to the energy and demand forecasting process for future ESOOs.

1.1 Definitions

In this report, all forecasts are reported on a "sent out" basis[5] unless otherwise noted. Terms used in this report are defined in the glossary. To assess forecasting performance, historical demand "as generated" is converted to "sent-out" based on estimates of auxiliary load.

For consistency, data and methodologies of actuals are the same as those used for the corresponding forecasts in the 2017 ESOO. This means:

- The assessment of operational consumption is done for the period 1 July 2017 to 30 June 2018.

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[2] AEMO. *2017 Electricity Statement of Opportunities for the National Electricity Market*, June 2017. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities/2017-NEM-ESOO.

[3] AEMO. *Forecasting Methodology Information Paper: 2016 National Electricity Forecasting Report*, July 2016. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

[4] At http://forecasting.aemo.com.au/.

[5] For the difference between sent out and as generated demand, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/EFI/2018/Operational-Consumption-definition---2018-update.pdf.

- Maximum and minimum operational demand is compared for the period 1 September 2017 to 31 August 2018.
- The following definitions of seasons have been used:
  - Summer is defined as November to March inclusive for all NEM regions, except Tasmania where summer is defined as December to February inclusive.
  - Winter is defined as June to August inclusive for all NEM regions.
  - AEMO reports on the accuracy of maximum and minimum operational demand for either summer or winter periods consistent with the 2017 ESOO. Shoulder periods are not assessed since they were not directly forecast in 2017 ESOO forecasts.
- This report uses an auxiliary load definition similar to that used in the 2017 ESOO forecast to approximate actual auxiliary load. Since the 2017 ESOO, AEMO has revised the way it estimates historical auxiliary load, so actual operational sent-out consumption, maximum and minimum demand values (in some instances including the timing of maximum and minimum demand) vary from estimates published more recently in the 2018 electricity forecasting process.

1.2 Methodology

1.2.1 Annual consumption forecast

AEMO assessed annual consumption forecast accuracy by measuring the percentage difference between actual and forecast values of the published forecasts.

The accuracy metric used is Percentage Error (PE), calculated using the formula below:

$$percentage\ error = \frac{actual_{FYE18} - forecast_{FYE18}}{actual_{FYE18}} \times 100$$

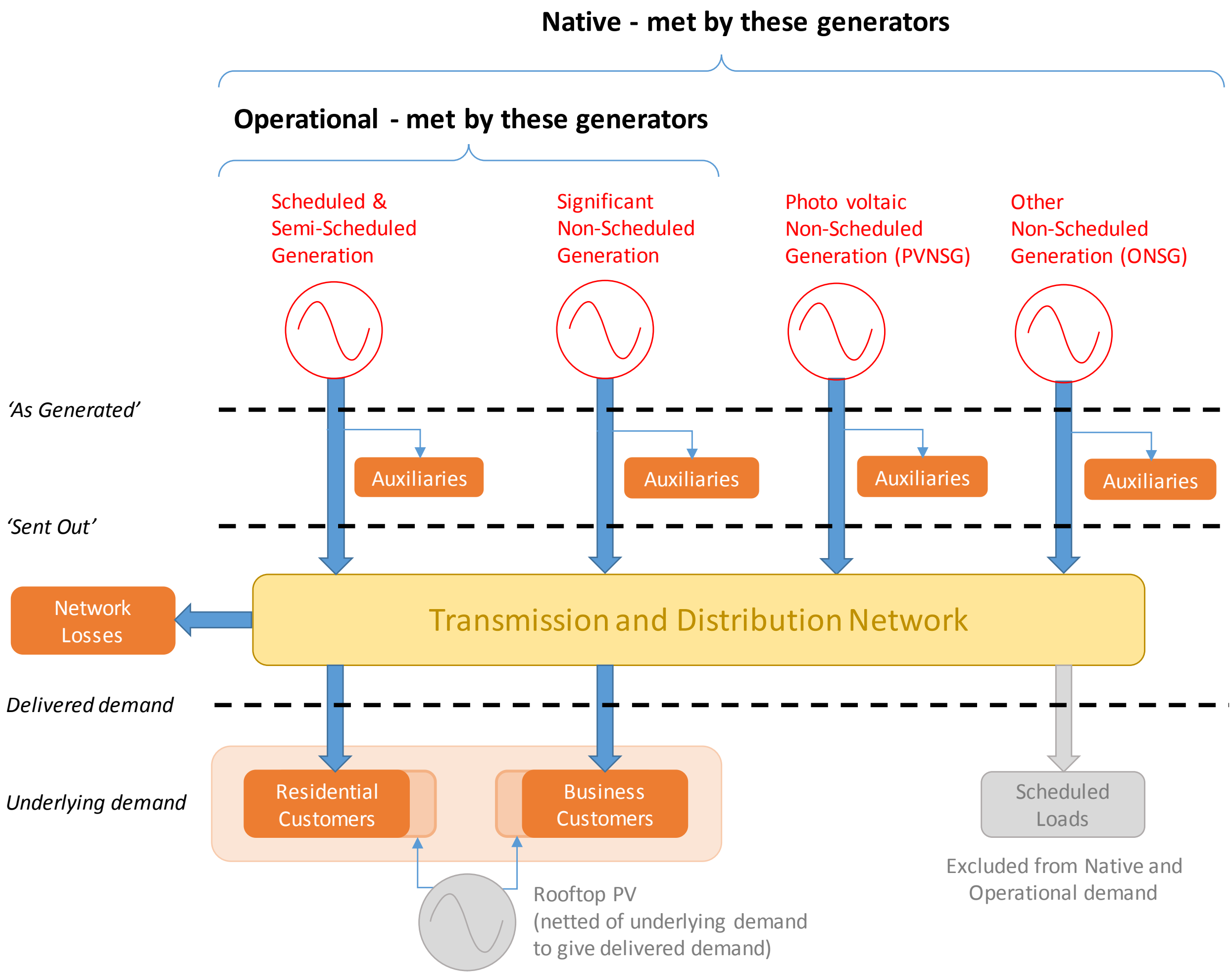
In the formula, FYE18 refers to the financial year 1 July 2017 to 30 June 2018.

Actual and forecast values are presented by different demand definitions:

- Operational – sent out.
- Operational – as generated.
- Native – as generated.

Figure 1 shows the demand definitions used in this document.

Figure 1 Demand definitions used in this document



Also, actual and forecast values are presented for a number of subcomponents to the extent possible, including:

- Transmission losses.
- Rooftop PV generation.
- Non-scheduled generation (both PV non-scheduled and other non-scheduled generation).
- Auxiliary load.

Breakdown of actuals into residential and business sectors is not possible until the split for the financial year 2017-18 is published by the Australian Energy Regulator (AER)[6]. The AER normally publishes this information 18 months after the fact. At the time of publishing this report, the breakdown for the financial year 2016-17 is available and has been compared to AEMO's split used to develop the 2016-17 annual consumption to check for major discrepancies or changing assumption trends.

Differences in weather

Forecast values were based on forecast weather outcomes defined by heating degree days and cooling degree days (HDD and CDD) of a median weather year.

Table 1 shows the temperature threshold used to calculate the HDD and CDD both for actual weather and the median weather years..

[6] From the network performance reporting to AER, at https://www.aer.gov.au/networks-pipelines/network-performance?f%5B0%5D=field_accc_aer_report_type%3A1495.

Table 1 HDD and CDD degree day thresholds

	NSW		QLD		TAS		SA		VIC	
Base temperature (°C)	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD
	19.5	17.0	20.0	17.0	20.0	16.0	19.0	16.5	18.0	16.5

Actual consumption values were not weather-corrected (adjusted to represent a median weather year). The comparison of actual and forecast HDD and CDD helps readers understand differences in inputs that drive the different forecast outcomes.

Differences in input forecasts

This 2018 *Forecast Accuracy Report*, also reports on the performance of some of the key input forecasts:

- Number of residential connections.
- Installed rooftop PV capacity.
- Economic forecast of gross state product.

These are discussed in Section 2.2, and help to understand the reason for any deviations, specifically if driven by variations in input assumption changes, model fit or forecast error.

1.2.2 Minimum and maximum demand forecast

Unlike the consumption forecast, which is a point forecast (single value), the minimum or maximum demand forecast is represented by a distribution of possible outcomes and probabilities.

The distribution of possible minimum or maximum demand outcomes is represented by the published 10%, 50%, and 90% probability of exceedance (or POE) forecasts.

To understand the characteristics of a maximum and a minimum demand outcome, the forecasting approach is summarised below.

Forecast methodology summary

The forecast of maximum and minimum demand is made up of two main components:

1. Explanatory variables (x variables) that drive demand,
2. The stochastic volatility[7] (ε) which is a feature of all regression models.

The model for underlying[8] demand generally takes the form:

$$Underlying_{hh} = f(x_{hh}) + \varepsilon_{hh}$$

where x_{hh} are the x variables detailed in Table 2 below. The model specification varies by region and hour – for instance, for the overnight hours Weekend and Public holiday is insignificant. Therefore, 24 separate models are developed for every region – one for every hour. Also, some models either use half-hourly temperature, or the three-hour rolling average of temperatures, but not both, as they are multicollinear[9].

Table 2 List of variables included in the minimum/maximum demand model – 2017 NEM ESOO

Variable	Description
Public holiday	Dummy flag for public holiday

[7] This represents the observed variability that exists beyond what is captured by the explanatory variables above.

[8] Underlying demand is consumers' total demand for electricity from all sources, regardless whether suppled from the grid or distributed resources such as rooftop PV. This is shown on Figure 1.

[9] Multicollnear variables are correlated with one another. If both are included in a regression model, they can adversely impact the predictive power.

Variable	Description
Weekend dummy	Dummy flag for weekend
Month factor	A factor variable with values for each month of the year
Dry temperature CD	Half-hourly dry temperature with a CD cut off
Dry temperature HD	Half-hourly dry temperature with a HD cut off
Dry temperature 3-hour rolling average CD	Three-hour rolling average of dry temperate with a CD cut off
Dry temperature 3-hour rolling average HD	Three-hour rolling average of dry temperate with a HD cut off
Dry temperature 3-day rolling average CD	Three-day rolling average of dry temperate with a CD cut off
Dry temperature 3-day rolling average HD	Three-day rolling average of dry temperate with a HD cut off

The model goodness-of-fit statistics are presented in Table 3 for the three hours most important to operational maximum demand (5 pm to 7 pm). These are not the only goodness-of-fit statistics assessed, but the R-squared[10] and the model sigma[11] presented below are generally well understood by industry. The other statistics considered are used to compare models, and are not interpretable as standalone metrics.

Table 3 Minimum/maximum demand model goodness-of-fit statistics

Region	Hour	R-squared	model sigma (MW)
NSW	5 pm	0.81	483.84
NSW	6 pm	0.84	435.07
NSW	7 pm	0.84	392.82
QLD	5 pm	0.85	217.30
QLD	6 pm	0.80	203.74
QLD	7 pm	0.87	173.33
SA	5 pm	0.78	142.15
SA	6 pm	0.80	131.32
SA	7 pm	0.82	114.69
TAS	5 pm	0.83	54.66
TAS	6 pm	0.84	55.58
TAS	7 pm	0.89	42.75
VIC	5 pm	0.80	355.18
VIC	6 pm	0.81	332.50
VIC	7 pm	0.80	309.25

[10] Coefficient of determination (or R-squared) is the proportion of the explained variance relative to the total variance of demand, generally an R-squared close to one is preferred but it is possible to over-fit the model to get a good R-squared and still have poor predictive power.

[11] Sigma is the standard deviation of the model, generally a lower sigma is preferable. The sigma is relative to the size of the market so regions with higher demand have a higher model sigma.

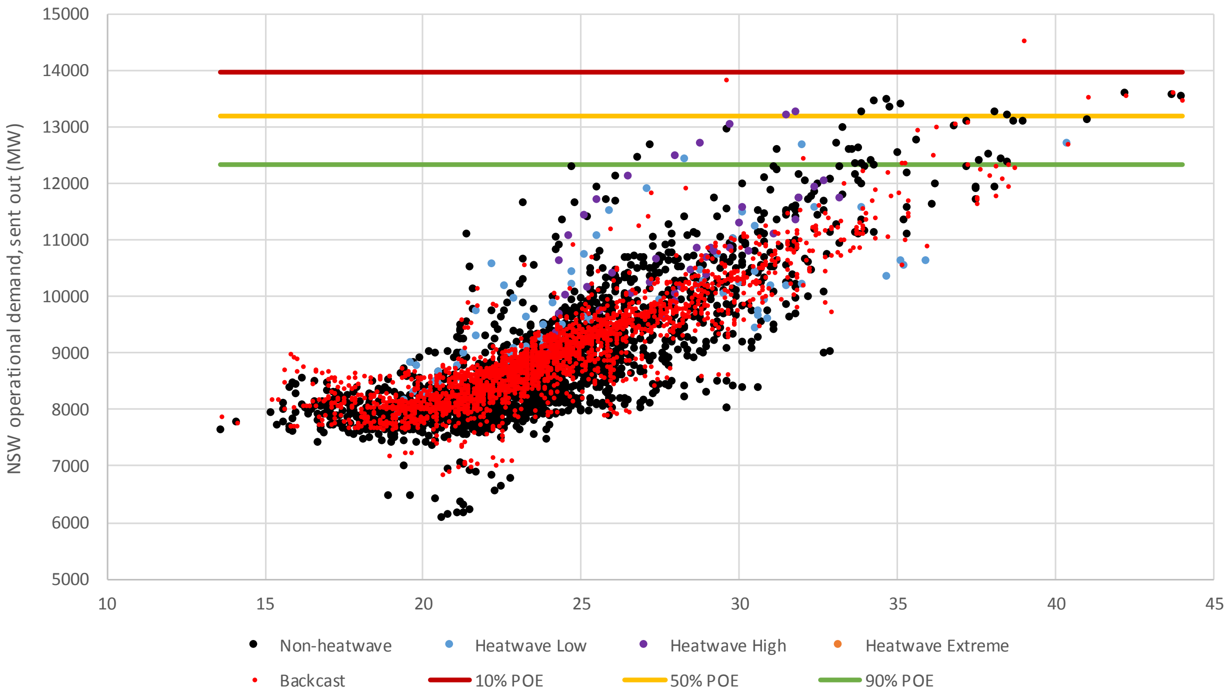
The goodness-of-fit can also be observed by comparing forecast outcomes based on historical drivers for every halfhour against actual outcomes, a process called backcasting. For example, Figure 2 compares the actual underlying demand for New South Wales in the last two summers, against model outcomes predicted by the explanatory variables alone (ignoring stochastic volatility):

$$Underlying_{hh} = f(x_{hh})$$

Each of the underlying demand backcast points were subsequently converted into operational demand by adjusting for network losses and subtracting rooftop PV (historical for the given halfhour) and non-scheduled generation.

Figure 2 shows that the explanatory variables such as temperature, type of day and month of year explain a large proportion of the variation in demand in New South Wales, but there is still some "noise" or variation in demand not captured by these factors. In the forecasting process ε_{hh} is added as stochastic volatility through the simulation process of 500 synthetic years, creating a spread similar to the one shown by the actual values.

Figure 2 Observed summer operational demand in New South Wales 2016-2018 as a function of temperature



Once the relationship between temperature and demand is found (using the last 3 years of actual data) then demand is simulated for different synthetic weather years (derived from history). The models simulate through every half-hour[12] in the year, assessing:

- underlying demand driven by temperature (and heatwaves[13])
- rooftop PV generation, based on historical solar radiation in that half-hour, which is used to convert underlying demand to operational demand sent-out
- the demand uncertainty – which is randomly generated based on the sigma calculated through the goodness-of-fit statistics, and added to the demand value calculated from the regression model.

[12] In the simulation, each hourly model is simulated twice to model temperature and PV correctly at half-hourly level.

[13] Consecutive days with temperatures well above average for the season.

This produces operational maximum demand by each half-hour, and incorporates an element of known stochastic volatility inherent in the underlying data. The maximum value across the year is saved, and the process is repeated for each region 500 times with different synthetic weather data. Based on the 500 observed maximum demand values obtained, the POE for maximum operational demand is derived.

Historical relationship between temperature, heatwaves, and maximum demand

Maximum demand is driven by high temperatures in all regions except for Tasmania (driven by cold temperatures in winter), and generally occurs on weekdays.

Figure 3 to Figure 7 outline the spread of demand at times of high temperatures on weekdays between the hours of 4:00 pm and 8:00 pm when maximum operational demand usually occurs. Heatwaves generally drive up demand relative to other periods for a similar temperature without a heatwaves. This is also depicted using colour to indicate heatwave extremity. Overlaid on these figures is the 2017-18 maximum demand forecast POE distribution for the region.

Figure 3 New South Wales summer temperature vs demand 2016-18, weekdays between 4 pm – 8 pm

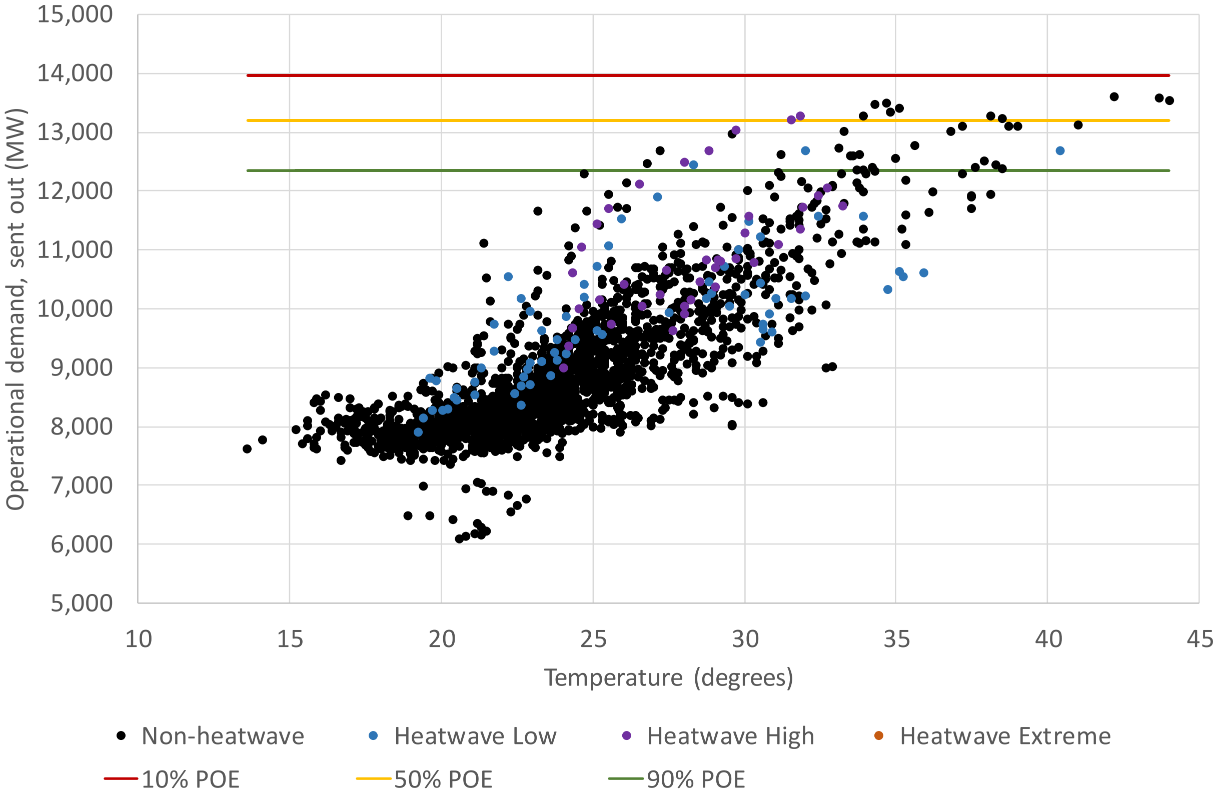


Figure 4 Queenland summer temperature vs demand 2016-2018, weekdays between 4 pm – 8 pm

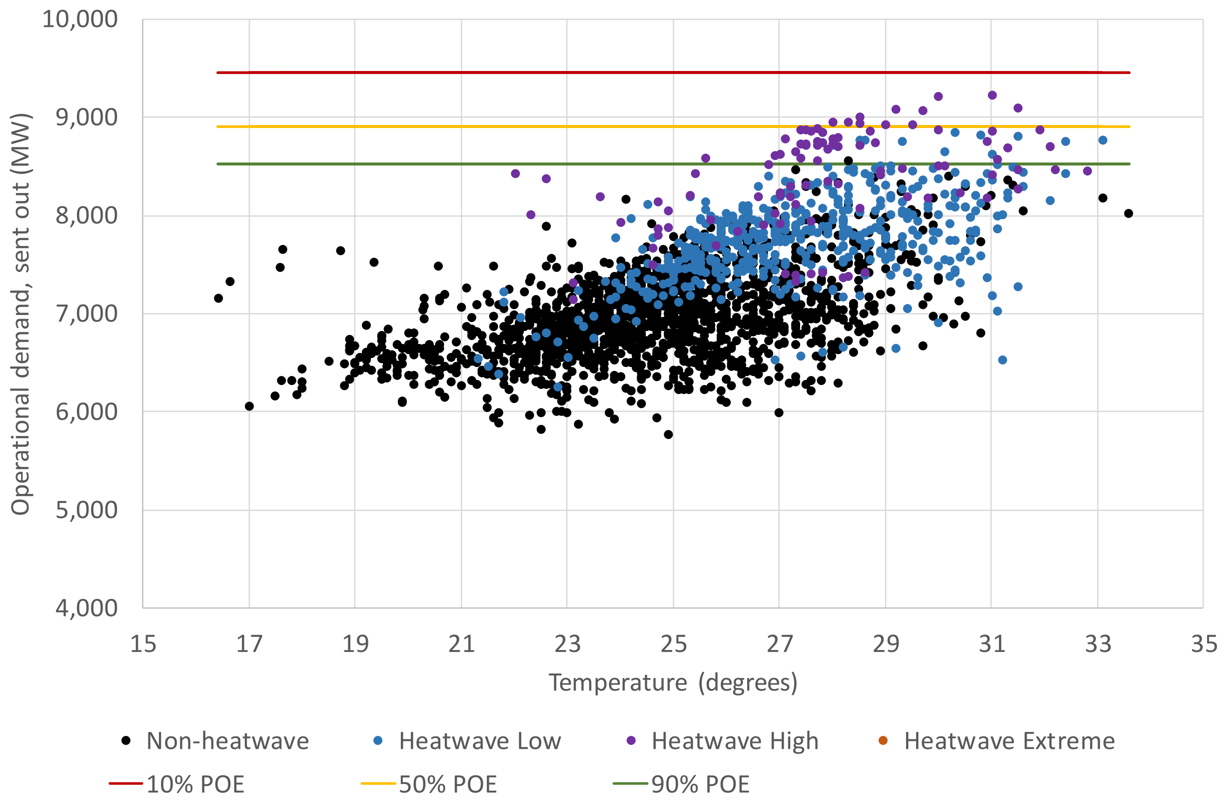


Figure 5 South Australia summer temperature vs demand 2016-2018, weekdays between 4 pm – 8 pm

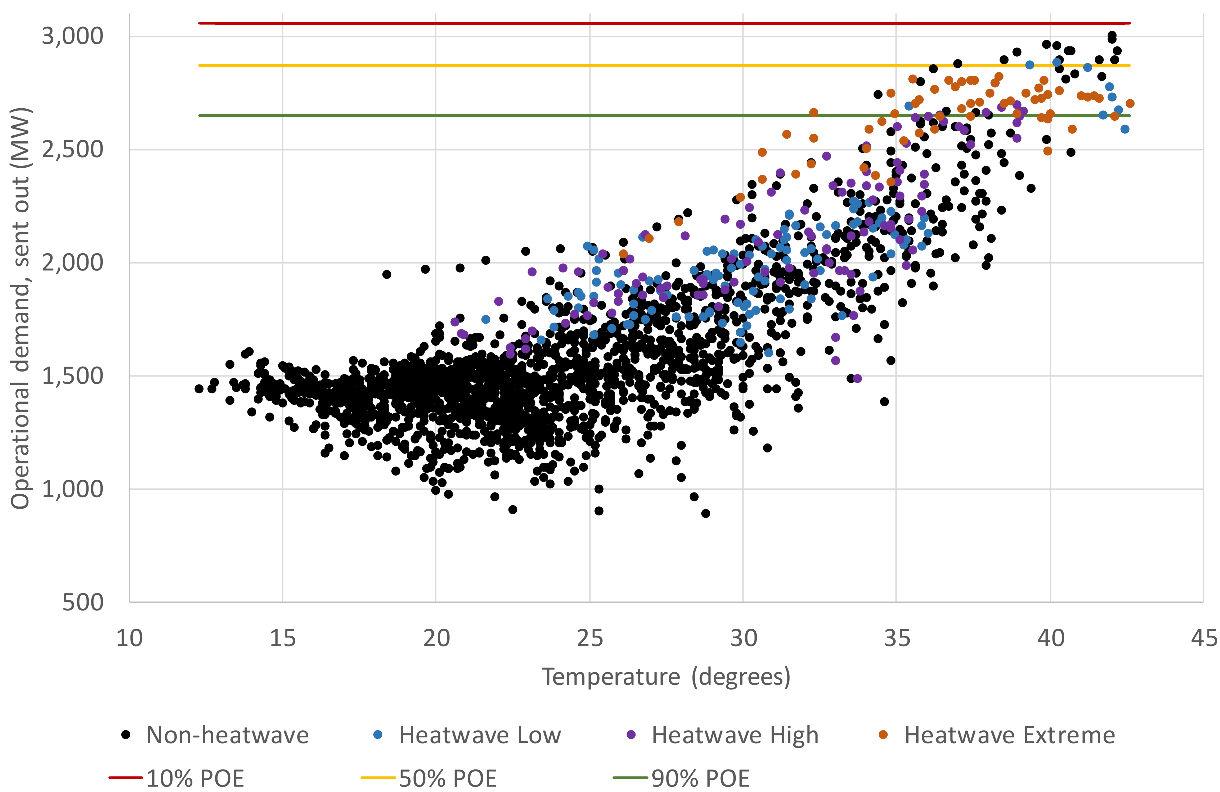


Figure 6 Tasmania winter temperature vs demand 2016-2018, weekdays between 4 pm – 8 pm

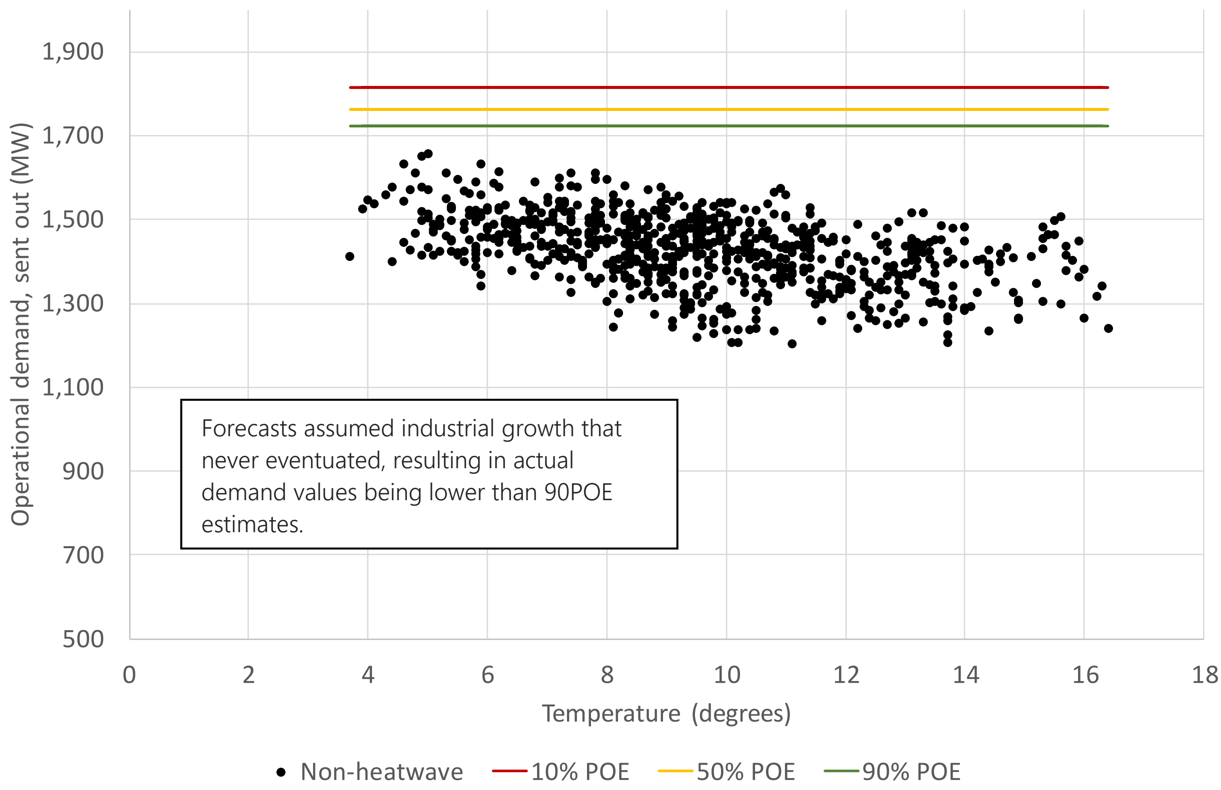
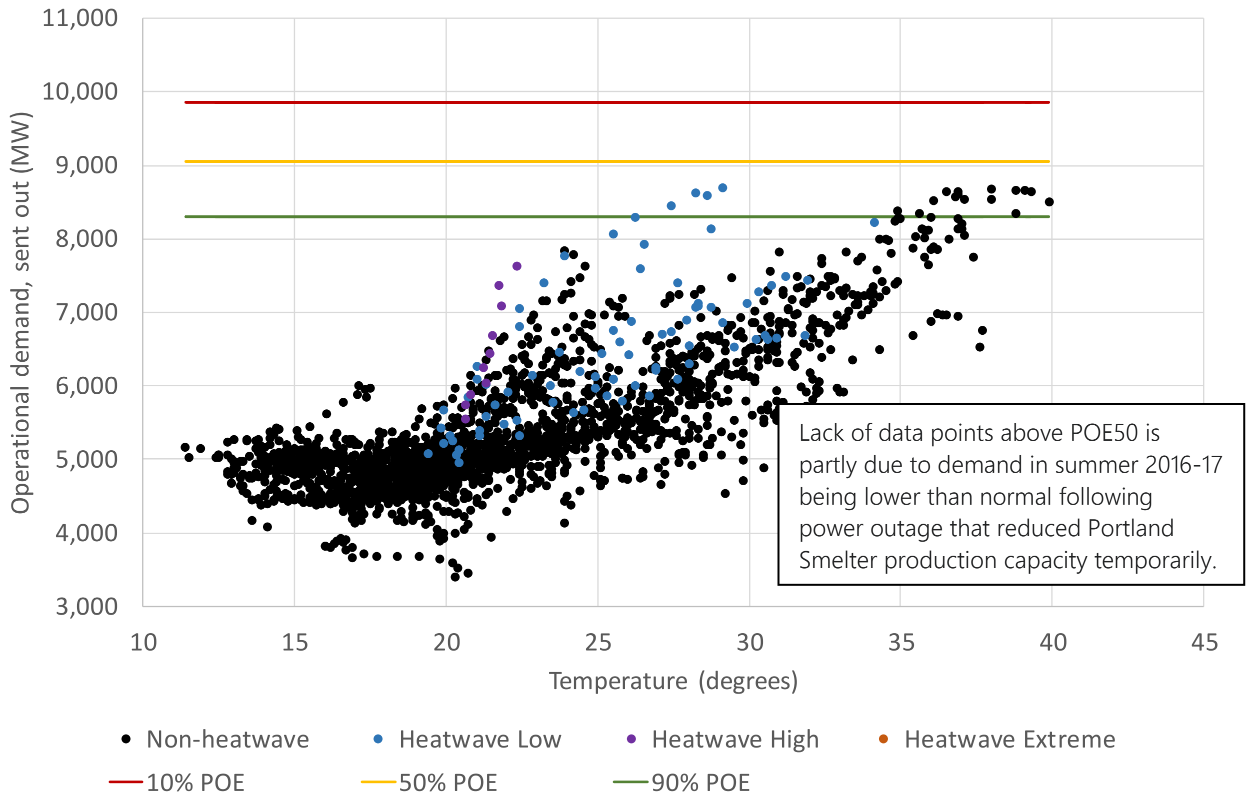


Figure 7 Victoria summer temperature vs demand 2016-2018, weekdays between 4 pm – 8 pm



Forecast performance assessment

AEMO assesses the performance of probabilistic forecasts qualitatively - comparing the actual minimum or maximum demand to these POE forecasts.

For the first time, in this year's report, AEMO has also attempted some level of backcasting to demonstrate the maximum demand the model would have forecast if the explanatory variables were known with certainty in advance. However, as highlighted in the above discussion and figures, there remains uncertainty in the minimum and maximum demand, with quite large variations in demand observed historically, even for the same temperature, heatwave conditions, time of day and day of week. This uncertainty, while not necessarily unexplainable, is difficult to observe and measure explicitly. For example, maximum demand can also be driven by a number of other unobservable events such as the finale of a hit TV show or sports game, or the scaling probability of residential customers arriving home simultaneously rather than staggered, which is why it is represented as a probabilistic forecast.

Therefore, measuring the accuracy of the forecasts through backcasting is challenging, as these unobservable events are known to impact maximum demand (positively or negatively), and are included in AEMO's forecasts, but are not easily measureable in any backcasting approach.

AEMO is currently working with industry to develop other metrics to help improve assessment of forecast accuracy and model performance where dealing with probabilistic forecasts.

This report is the first time AEMO has assessed the accuracy of its minimum demand forecast. The forecast accuracy is assessed similarly to the maximum demand forecast (see Section 1.2.2), although no backcasting has been performed. Minimum demand is largely driven by the lack of heating or cooling on mild days and, increasingly, the peak solar generation period mid-day in regions with high rooftop PV penetration. Uptake of behind-the-meter energy storage systems will further influence minimum demand levels. Demand is generally low on weekends and public holidays, increasing the chance of minimum demand occurring on those days.

2. Forecast accuracy

Measuring and improving forecast accuracy is vital for AEMO to provide independent, reliable, and accurate advice to NEM stakeholders.

Internally, AEMO assesses forecast accuracy as part of a continued improvement process to measure actual performance against forecasts, identify and eliminate systemic bias, incorporate new sources of relevant information that add explanatory power, and develop innovative methods to improve the accuracy of both the data collation and forecasting model process.

2.1 Consumption forecast accuracy summary

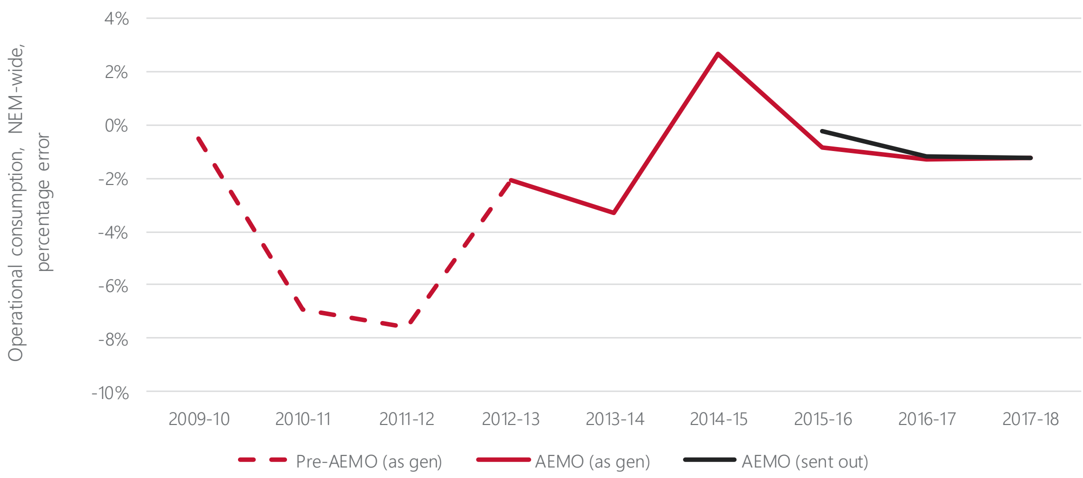
The accuracy of AEMO's 2017-18 annual operational consumption forecast (sent out), measured as the percentage error (PE), is summarised for each region, and the NEM in aggregate, in Table 4 below.

Table 4 Percentage error (PE) by region for annual operational consumption – sent out

NEM region	PE	Comment
New South Wales	0.1%	Good alignment with forecast.
Queensland	-2.8%	Difference mainly driven by lower consumption by CSG sector than forecast.
South Australia	0.8%	Good alignment with forecast.
Tasmania	0.1%	Good alignment with forecast.
Victoria	-2.5%	Difference driven by lower consumption by residential and smaller industrial/commercial users.
NEM total	-1.3%	Reasonable alignment with forecast. Difference driven by variations in Queensland and Victoria.

Figure 8 shows the performance of AEMO's NEM consumption forecasts over time (for numbers see Appendix B). Note that there has been a change in reporting, so the first six years only reported consumption on an as generated basis, while the more recent years reported sent out, however the PE is relatively insensitive to whether consumption is compared on a sent out or as generated basis. Overall, it can be seen that forecast errors in recent years are generally lower than earlier forecasts.

Figure 8 Trend in percentage error for operational consumption forecast, NEM-wide



Differences between actual and forecast consumption may be attributable to differences in input assumptions, rather than forecast error per se. A discussion of three of the key input forecasts is provided below, followed in Sections 2.4 to 2.8 by a detailed discussion of forecast performance (including for maximum and minimum demands) for each of the NEM regions.

As explained in the introduction, data for the split between actual residential and business consumption is not yet available, which limits AEMO's ability to interrogate forecasting performance by customer segment for 2017-18.

2.2 Key input forecasts

A number of key input forecasts provide some visibility on factors that can explain differences between forecast and actual demand.

The following discusses three of the key inputs into the forecast.

2.2.1 Residential number of connections

Table 5 shows actuals and forecast growth rate of residential connections, informed by HIA projections of dwelling construction. Growth in connections translates into growth in both consumption and maximum/minimum demand. Connections were generally forecast reasonably well, with the exception of Victoria, where the observed growth in residential meters grew noticeably faster than forecast, and much faster than any other state. Consequently, the 2018 forecast connections, used for the 2018 ESOO, were adjusted to better reflect connections growth drivers (dwelling construction in particular) observed in the last year.

Table 5 Actual vs 2017 ESOO forecast growth in number of residential connections

NEM region	NSW	QLD	SA	TAS	VIC
Forecast connections growth (FY 2017-2018)	0.97%	1.42%	0.82%	0.75%	1.14%
Actual connections growth (FY 2017-2018)	1.22%	1.36%	0.77%	0.98%	2.63%
Difference (Actual - Forecast)	0.25%	-0.06%	-0.05%	0.23%	1.50%

2.2.2 Installed rooftop PV capacity

Table 6 shows actual versus forecast installed rooftop PV capacity (up to 100 kW). The forecast was provided by Jacobs for the 2017 ESOO forecast[14]. It correctly projected an increase in the installation rate, but did underestimate the magnitude of the increase. Growth in PV installations will lead to a greater offset of operational consumption (making it lower). Also, maximum and minimum demand levels may also decrease depending on the time of day these occur.

Excluding any consideration of the the number of sunshine hours in the last year, this leads to PV generation being underestimated in all mainland regions and in Queensland and South Australia in particular, with differences exceeding 10%. The 2018 forecasts of installed capacity have been recalibrated to reflect latest installation figures from the Clean Energy Regulator and recent growth trends.

Table 6 Actual vs 2017 ESOO forecast installed rooftop PV capacity (for systems up to 100 kW)

NEM region	NSW	QLD	SA	TAS	VIC
Forecast MW of capacity (as of 30 June 2018)	1,675	1,971	818	129	1,314
Actual MW of capacity (as of 30 June 2018)	1,727	2,212	930	130	1,364
Difference (Actual - Forecast)	52	241	112	1	50
Difference (%)	3.0%	10.9%	12.0%	0.7%	3.6%

2.2.3 Gross State Product growth

Table 7 shows actual versus forecast growth in Gross State Product (GSP). This is the key driver of growth in the manufacturing sector. Forecast performance is measured based on growth rate (actual versus forecast). Since the 2017 forecast, ABS has made revisions to the annual national accounts for the entire historical time series data, resulting in estimated actuals having changed. Hence, a comparison with actual values is not possible.

GSP growth is highly correlated with population. The 2012-census-based ABS forecast population growth rates were used in the economic outlook and generally higher in Queensland and South Australia (compared to recent trends). The economic forecast therefore overestimated the economic growth in these states. The opposite was the case for Tasmania and Victoria. It should also be noted that Queensland had less revenue from liquefied natural gas (LNG) exports than forecast.

Table 7 Actual vs 2017 ESOO forecast growth in Gross State Product

NEM region	NSW	QLD	SA	TAS	VIC
Forecast GSP growth (FY 2017-2018)	2.5%	4.6%	2.3%	1.7%	3.0%
Actual GSP growth (FY 2017-2018)	2.6%	3.4%	2.0%	3.3%	3.5%

[14] See Jacobs (June 2017), *Projections of uptake of small-scale systems*, available at https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-WEM-ESOO-Methodology-Report---Projections-of-Uptake-of-Small-scale-Systems.pdf.

NEM region	NSW	QLD	SA	TAS	VIC
Difference (Actual - Forecast)	0.2%	-1.2%	-0.3%	1.6%	0.5%

2.3 Maximum and minimum demand

As explained in Section 1.2.2, the actual minimum or maximum demand is highly dependent on a number of factors, in particular temperature, heatwaves, cloud cover, and the type of day (weekday or weekend). In qualitatively assessing the accuracy of the maximum and minimum demand forecasts, actual values are reported alongside weather observations at the time. Temperatures are based on measurements from the capital city of each region along with other statistics shown in Table 2.

Reference temperatures are also provided for the POE forecasts, but these should be interpreted as indicative only. High demand can be due to very high temperatures on a sunny day (with rooftop PV generation offsetting demand from the grid), but similar demand can arise from lower temperatures with cloud cover reducing the rooftop PV generation. Prolonged periods of high temperatures (heatwaves) also tend to lead to higher demand than otherwise, and are measured through a rolling three-day average of cooling degrees.

What is currently less discoverable, but potentially still impactful on maximum demand, is the energy efficiency and behind-the-meter battery contributions that would reduce maximum demand observed on the grid, and/or increase minimum demand. Further work is ongoing, to be able to better assess what this impact may have been in any historical demand period. This includes inferring the impact through meter data analysis and customer behavioural surveys.

In the figures accompanying the discussion of maximum and minimum demand by region, the shown POE forecast values vary substantially year on year due to the randomness from the simulation process. The 2018 forecast process has increased the number of simulations to reduce the noise over that seen in the 2017 ESOO forecast.

Minimum demand forecasts for all regions look to be low compared to actual observed minimum demand, most noticeably in Victoria and South Australia. As a consequence, AEMO will be embarking on work to improve the performance of its minimum demand forecasts. Again, this may include inferring the impact on demand of consumer behavioural change, demand management, and behind-the-meter battery installations.

2.4 New South Wales

Annual consumption

Table 8 Accuracy of New South Wales 2017 ESOO annual consumption forecast for 2017-18

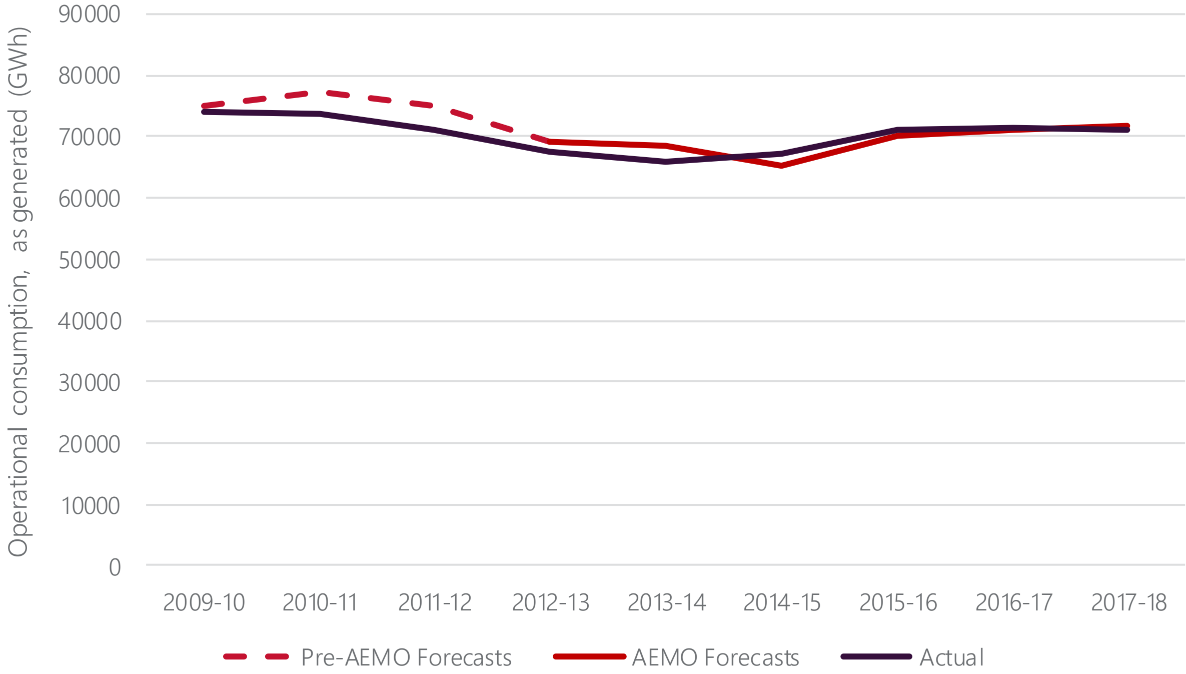
Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	67,819	67,899	80	0.1
Auxiliary load (GWh)	3,996	3,105	-891	-28.7
Operational consumption – as generated (GWh)	71,815	71,004	-811	-1.1
Non-scheduled generation* (GWh)	1,652	2,070	418	20.2

Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Native consumption – as generated (GWh)	73,467	73,074	-393	-0.5
Significant input forecasts				
Transmission losses (GWh)	872	1,556	684	43.9
Rooftop PV generation offset (GWh)	-1,991	-2,068	-77	3.7%
Weather factors – annual				
Heating degree days (HDD)	618	640	22	3.4%
Cooling degree days (CDD)	449	577	128	22.2%

* This excludes any non-scheduled generation part of operational consumption (significant non-scheduled).

- Actual New South Wales operational consumption (sent out) in the 2017-18 financial year was 0.1% above the 2017 ESOO forecast.
  - The 2017-18 financial year was significantly warmer than normal, resulting in more cooling degree days in New South Wales. This would have led to higher consumption for cooling services than forecast.
  - During the 2018 electricity forecasting process, AEMO discovered an error in the loss factor used for New South Wales transmission loss calculation. This has been corrected for the 2018 ESOO, but the impact can be seen in the 2017 forecast, which was 43.9% lower than actual.
  - Actual rooftop PV generation was broadly in line with forecast (3.7% higher).
  - Non-scheduled generation was significantly above forecast, exceeding forecasts by 418 GWh (20.2%), primarily driven by higher than forecast non-scheduled PV generation.
- Actual as generated operational consumption for the 2017-18 financial year was 1.1% below forecast. The performance of the as generated consumption forecast in recent years is shown in Figure 9.
- Actual native demand (as generated) was 0.5% below forecast. This is less than the difference seen in operational (as generated) due to small non-scheduled generation being 20.2% above forecast. As in other regions, underforecasting non-scheduled PV generation was the key reason for differences in non-scheduled generation.

Figure 9 Historical performance of operational (as generated) forecasts for New South Wales produced by AEMO (2012 onwards) and TNSPs (pre-2012)



Maximum and minimum demand

Table 9 Accuracy of New South Wales 2017 ESOO maximum and minimum demand forecasts for 2017-18

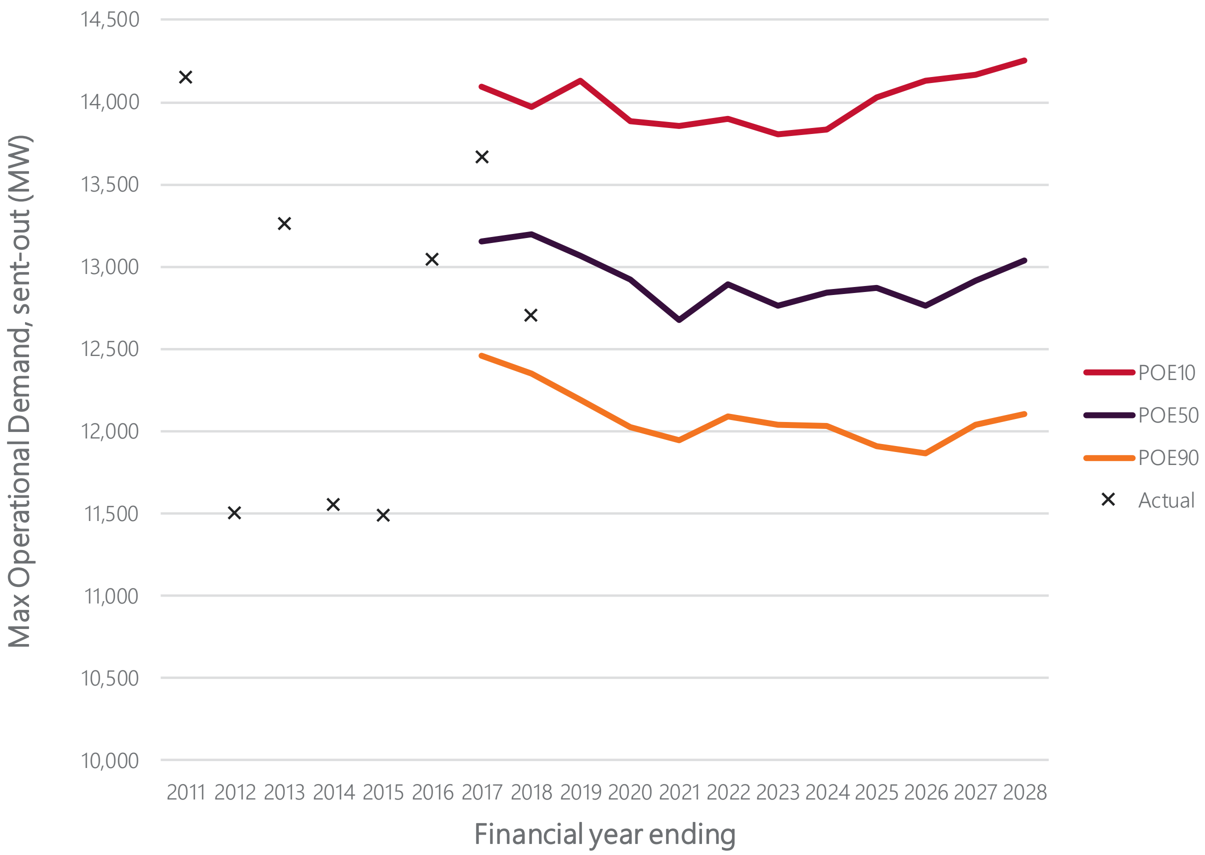
Operational maximum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Maximum demand – sent out (MW)	12,709	13,970	13,194	12,353
Rooftop PV at time of operational max demand (MW)	461	354 to 392		
Weather – at time of operational maximum demand				
Temperature (°C)	33.6	39.5	37.4	33.7
Dry temperature rolling 3-day cooling degrees	5*	n/a	n/a	n/a
Characteristics of peak demand day				
Time (local)	5:00 pm	5:00 pm to 5:30 pm		
Weekend	No			
Public holiday	No			
School holiday	Yes			

* In New South Wales, the 95 percentile is 6.32, the 97 percentile is 6.43 and the 99 percentile is 7.46 cooling degree hours. A value of 7.46 means the three-day rolling average half-hourly temperature was 7.46 degrees above the base CDD temperature threshold. The three-day rolling average is much lower than daily maxima because it averages all half-hours over the last three days.

Operational minimum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Minimum demand – sent out (MW)	5,177	5,188	5,040	4,840
Rooftop PV at time of operational min demand (MW)	0	29 to 108		
Weather – at time of operational minimum demand				
Temperature (°C)	19.7	18.2	18.8	18.8
Characteristics of minimum demand day				
Time (local)	4:30 am	6:30 am	6:30 am	6:30 am

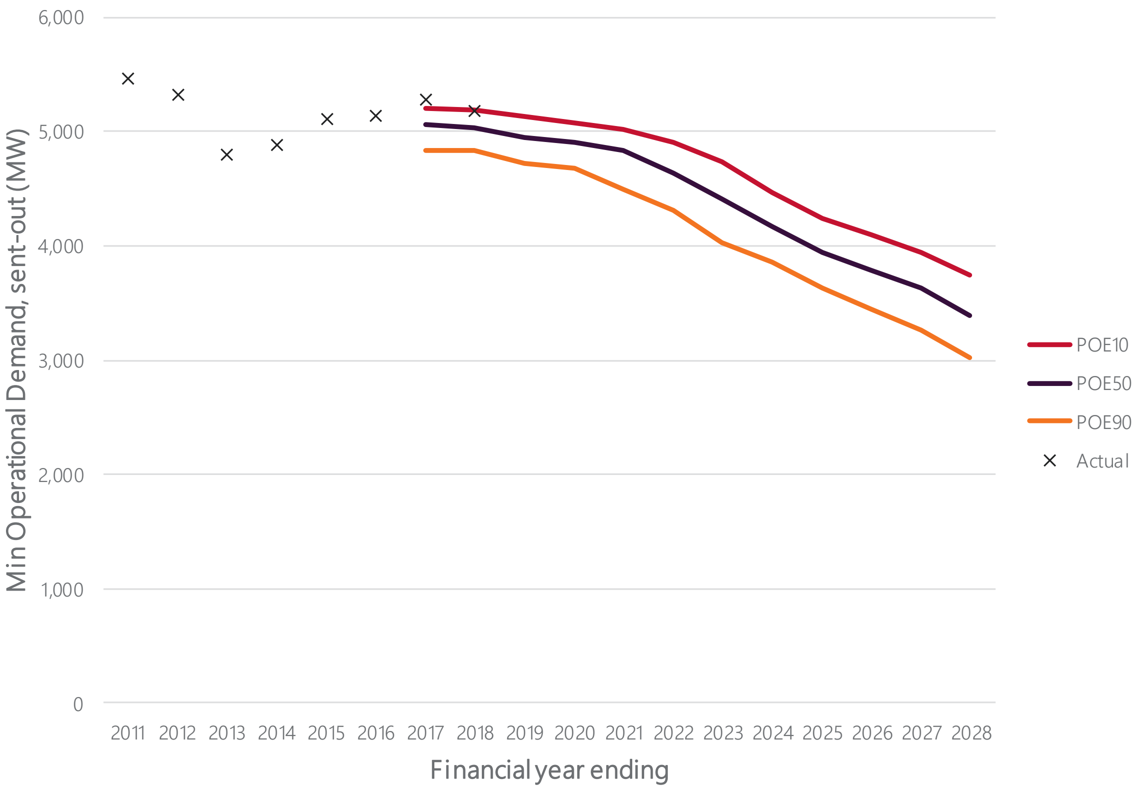
- Actual maximum demand occurred in summer on Tuesday 19 December 2017. At the time of maximum demand, temperature at Bankstown was 33.6°C with an earlier daily maximum of 37.3°C.
  - For a weekday peak just inside the school holiday season, the actual being between a 50% and 90% POE is therefore explainable, but based on temperature alone, the model would have predicted a lower maximum demand, closer to 90% POE.
  - The rooftop PV generation at time of maximum demand was higher than expected, reflecting more rapid uptake than anticipated. Had this PV capacity uptake been anticipated, the model would have forecast even lower maximum demand.
  - The model underestimate may be attributable to energy efficiency impacts being over-estimated in the 2017-18 maximum demand forecasts, as evidenced through data analytics performed in 2018, or purely due to natural stochastic variation.
  - As shown on Figure 10, the 90% POE maximum demand forecast is higher than a number of recent actual maximum demand outcomes. The 2018 forecast process used more simulations and improved model selection, resulting in a lower 90% POE forecast, more in line with the historical spread observed.

Figure 10 Historical actual and 2017 ESOO forecast maximum demand for New South Wales (summer season)



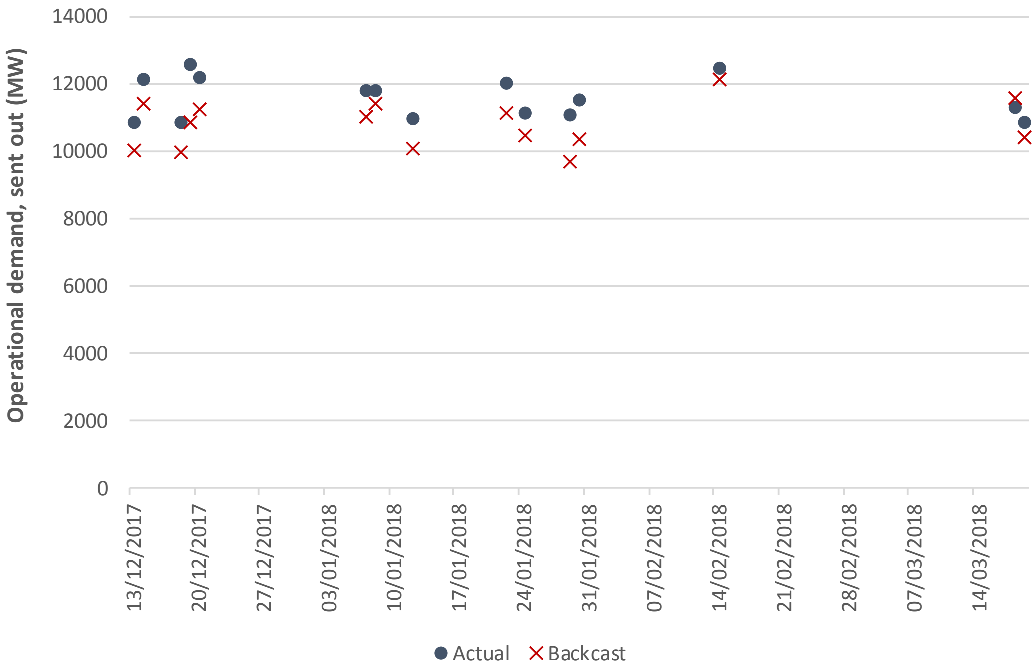
- Actual minimum demand occurred in summer on Tuesday 26 December 2017 at 4:30 am local time when the temperature was 19.7°C.
  - This is hotter than the 10% to 90% POE temperature range, suggesting some cooling load at the time (evidenced by the data).
  - For regions such as New South Wales, where rooftop PV generation has not yet pushed minimum demand to the middle of the day, the minimum generally occurs early morning during public holidays or weekends, where industrial demand is lower.

Figure 11 Historical actual and 2017 ESOO forecast minimum demand for New South Wales



- Figure 12 shows backcast results of the highest half-hour in the top 15 highest demand days observed in New South Wales over last summer, using actual weather observations. Appendix A provides deeper insights into the extent by which the explanatory variables (weather, day type and month) were predicted to impact demand in a sample of these backcast periods, along with the component parts essential to convert underlying maximum demand to operational sent out maximum demand. As the discussion around Figure 2, the backcast points presented in Figure 12 and Appendix A excludes any stochastic volatility.
- As expected, and consistent with other regions, the models underestimate maximum demand, if known stochastic volatility is ignored. A varying degree of this uncertainty is incorporated in our forecasts when simulating, leading to the forecast 90POE, 50POE and 10POE forecasts being well above the backcast values. What is unclear, is whether the difference between backcast and actuals is within normal statistical probabilities, after accounting for stochastic volatility, or is indicating a systematic bias. From 2019 onwards, AEMO will save and store more 'model fit' parameters from each of the models to allow calculation of the statistical significance of the mean absolute error.
- AEMO will continue to explore alternate model specifications, testing the best balance between bias and variance, to see whether the range of uncertainty in the maximum demand forecasts can be narrowed. In the case of New South Wales, the changes already made to energy efficiency impacts are expected to improve future maximum demand forecasts. This is discussed in more detail in Section 3.

Figure 12 Actual versus backcast max demand half-hour for top 15 highest demand days in New South Wales



2.5 Queensland

Annual consumption

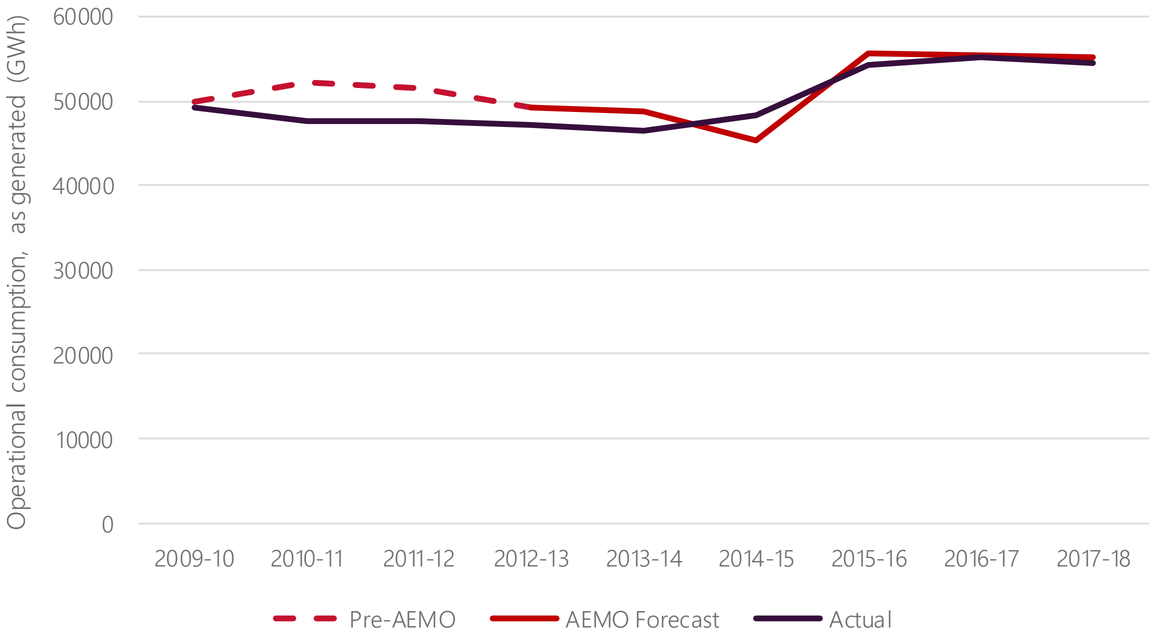
Table 10 Accuracy of Queensland 2017 ESOO annual consumption forecast for 2017-18

Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	51,870	50,443	-1,427	-2.8
Auxiliary load (GWh)	3,276	4,095	819	20.0
Operational consumption – as generated (GWh)	55,147	54,538	-609	-1.1
Non-scheduled generation* (GWh)	1,993	2,132	139	6.5
Native consumption – as generated (GWh)	57,140	56,669	-471	-0.8
Significant input forecasts				
Coal seam gas (GWh)	6,393	5,855	-538	-9.2
Transmission losses (GWh)	1,525	1,269	-256	-20.1
Rooftop PV generation offset (GWh)	-2,649	-2,900	-251	8.7
Weather factors – annual				
Heating degree days (HDD)	215	210	-5	-2.4
Cooling degree days (CDD)	733	762	29	3.8

* This excludes any non-scheduled generation part of operational consumption (significant non-scheduled).

- Actual Queensland operational consumption (sent out) in the 2017-18 financial year was 2.8% below the 2017 ESOO forecast.
  - Weather was close to normal conditions for both heating and cooling, with a very small impact expected on annual consumption overall.
  - The forecast overestimated electricity consumption by the Queensland coal seam gas (CSG) sector (actual 9.2% lower than forecast), about a third of the difference.
  - Another 251 GWh is explained by actual generation from rooftop PV, which reduces operational consumption, being higher than forecast, driven by larger than forecast growth in installed capacity (see Table 6).
  - Non-scheduled generation reduced operational demand by 139 GWh more than forecast. This was particularly driven by higher than expected non-scheduled PV generation.
  - Remainder of variation may be explained by differences in the residential connections and GSP input assumptions, which were lower than forecast.
- Actual as generated operational consumption for the 2017-18 financial year was 1.1% below forecast, as auxiliary load was 20% above forecast. The alignment between actual and forecast consumption in recent years has been close, as shown in Figure 13.
- Actual native demand (as generated) was 0.8% below forecast. This is smaller than the difference seen in operational consumption (as generated) due to small non-scheduled generation being 8.7% above forecast.

Figure 13 Historical performance of operational (as generated) forecasts for Queensland produced by AEMO (2012 onwards) and transmission network service providers (TNSPs, pre-2012)



Maximum and minimum demand

Table 11 Accuracy of Queensland 2017 ESOO maximum and minimum demand forecasts for 2017-18

Operational maximum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Maximum demand – sent out (MW)	9,335	9,456	8,902	8,527

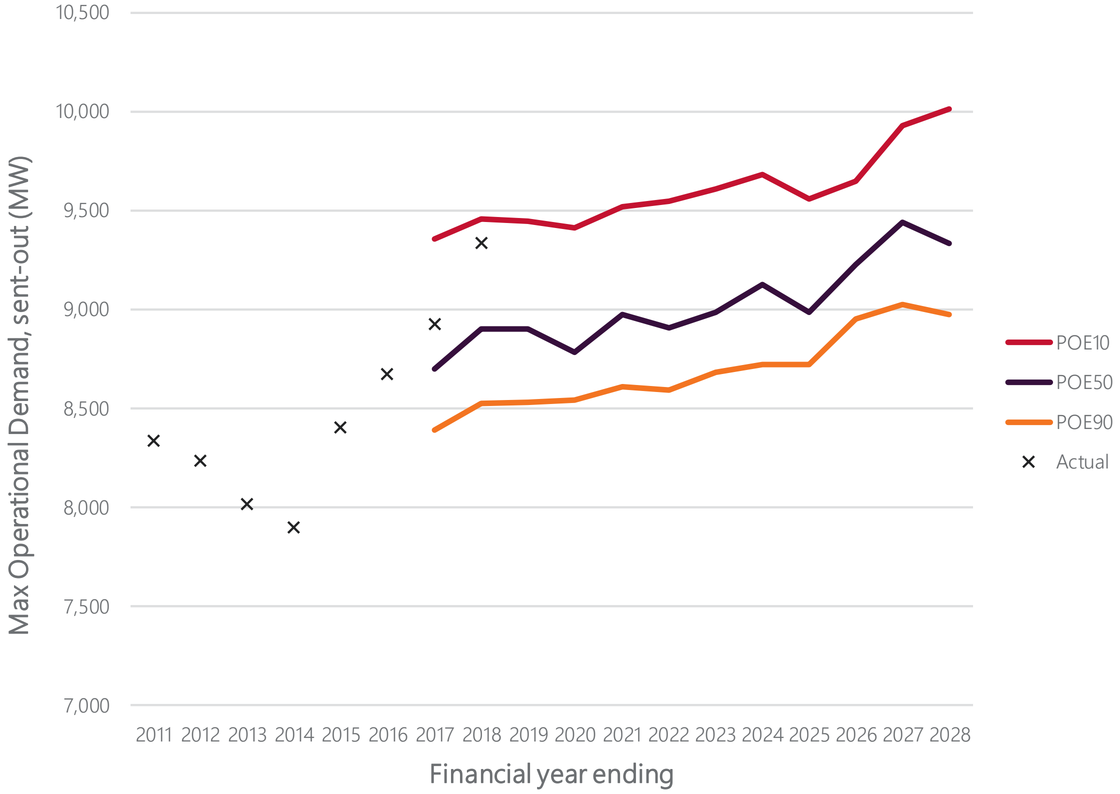
Operational maximum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Rooftop PV at time of operational max demand (MW)	369	298 to 399		
Weather – at time of operational max demand				
Temperature (°C)	31.5	37.1	32.6	31.0
Dry temperature rolling 3-day cooling degrees	7.14*			
Characteristics of peak demand day				
Time (local)	5:00 pm	3:30 pm to 4:30 pm		
Weekend	No			
Public holiday	No			
School holiday	No			

* In Queensland, the 95 percentile is 7.12, the 97 percentile is 7.53 and the 99 percentile is 7.88 cooling degrees.

Operational minimum demand	Actual (winter)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Minimum demand – sent out (MW)	4,328	4,025	3,877	3,690
Rooftop PV at time of operational min demand (MW)	1,437	1,133 to 1,192		
Weather – at time of operational min demand				
Temperature (°C)	22.9	21.0	20.7	21.4
Characteristics of minimum demand day				
Time (local)	1:00 pm	11:30 am	12:00 pm	12:00 pm

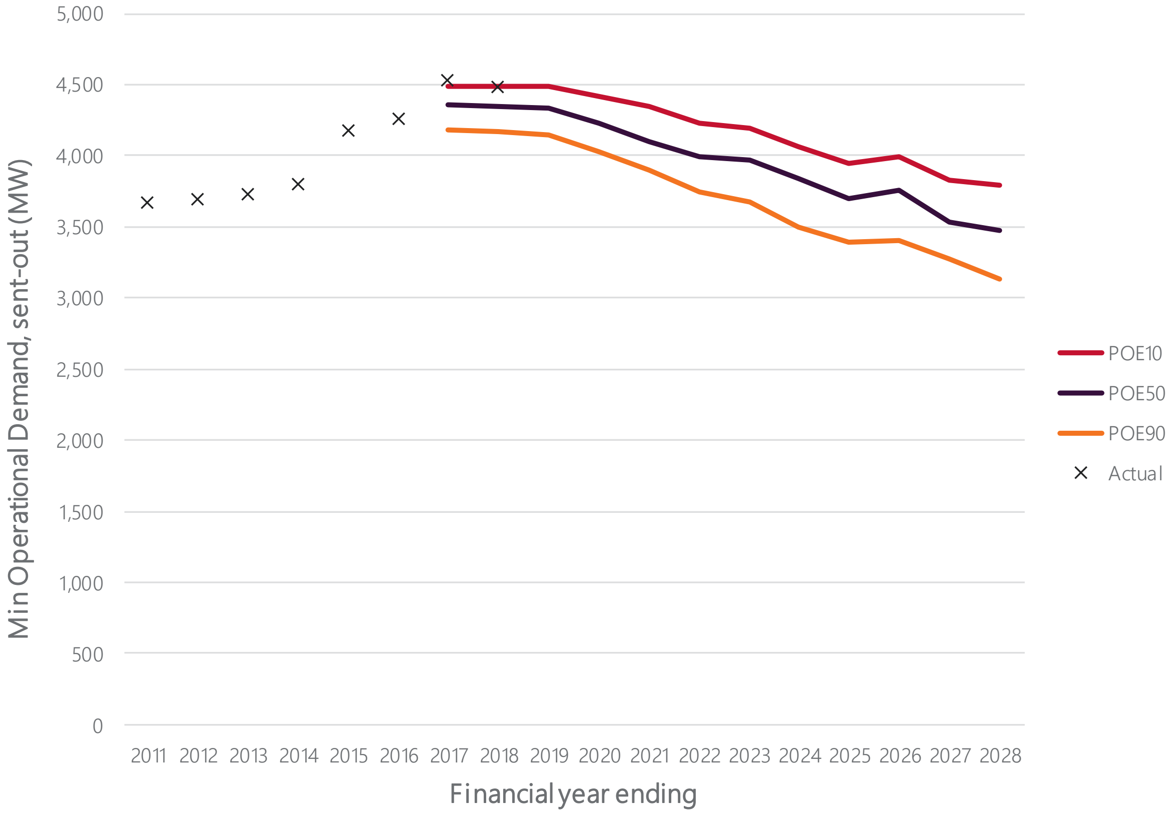
- Actual maximum demand occurred in summer on Wednesday 14 February 2018, when the temperature was 31.5°C.
  - The maximum demand falls between the 10% POE and 50% POE maximum demand values, and the temperature aligns between the 50% POE and 90% POE temperature values.
  - The observed maximum demand came after three consecutive hot days state-wide, with extreme temperatures in central/north Queensland, on a weekday and outside the school holiday season. It was also unusually humid in South East Queensland. The combination of these factors rarely happens and generally leads to outcomes in the high end of the forecast distribution. Therefore, while temperature was well below the indicative 10% POE temperature, the combination of factors resulted in maximum demand that AEMO considers to be close to a one-in-10-year expectation.
  - Figure 14 shows how close the actual came to the 10% POE forecast. The CSG sector ended up consuming less than forecast (approximately 60 MW on average). Considering this, the actual is even closer to a 10% POE outcome. Note that there was a large increase in CSG sector demand in the 2014-18 period supporting the LNG export industry, explaining the rapid growth of observed actual maximum demand those years.

Figure 14 Historical actual and 2017 ESOO forecast maximum demand for Queensland (summer season)



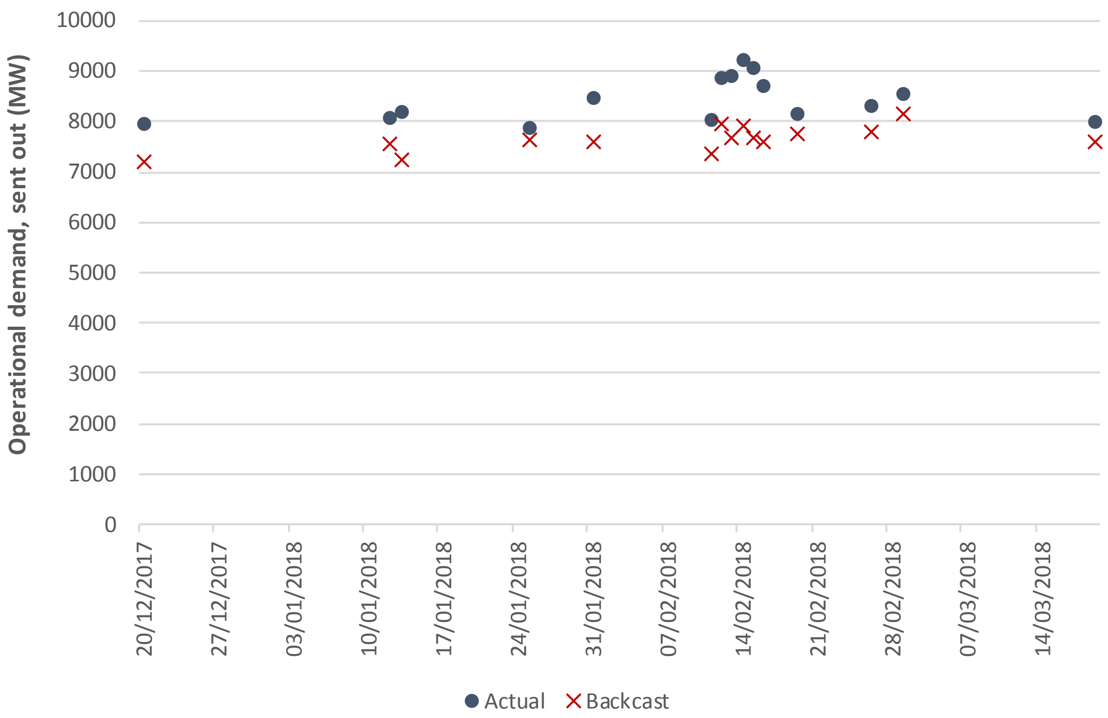
- Actual minimum demand occurred in winter on Saturday 19 August 2017, when the temperature was 22.9°C during the middle of the day.
  - This is the first time minimum demand has occurred mid-day in Queensland. With the growth in rooftop PV capacity, future years are most likely to see mid-day annual minimum demand occurrences, which as rooftop PV capacity expands, will lead to minimum demand declining rapidly, a break from the recent increasing trend driven by growth in CSG sector demand, as illustrated in Figure 15.
  - Actual PV generation at time of minimum demand was higher than forecast, reflecting the faster than anticipated uptake of rooftop PV capacity.

Figure 15 Historical actual and 2017 ESOO forecast minimum demand for Queensland



- Figure 16 shows backcast results of the highest half-hour in the top 15 highest demand days observed in Queensland over last summer, using actual weather observations. As expected, and consistent with other regions, the models would underestimate maximum demand, if known stochastic volatility is ignored.
- For the actual maximum demand day, and those either side of it, the backcast is furthest from the actual, suggesting that events like extreme temperatures outside the Brisbane region (not currently explanatory variables in the regression model) played a significant role in lifting demand. This is currently captured implicitly as part of the model uncertainty, but the model formulation could be refined to reduce this uncertainty. For example, more than one weather station could be used to represent the relationship between temperature and demand, provided that multicollinearity is avoided.

Figure 16 Actual vs. backcast maximum demand half-hours for top 15 highest demand days in Queensland



2.6 South Australia

Annual consumption

Table 12 Accuracy of South Australia 2017 ESOO annual consumption forecast for 2017-18

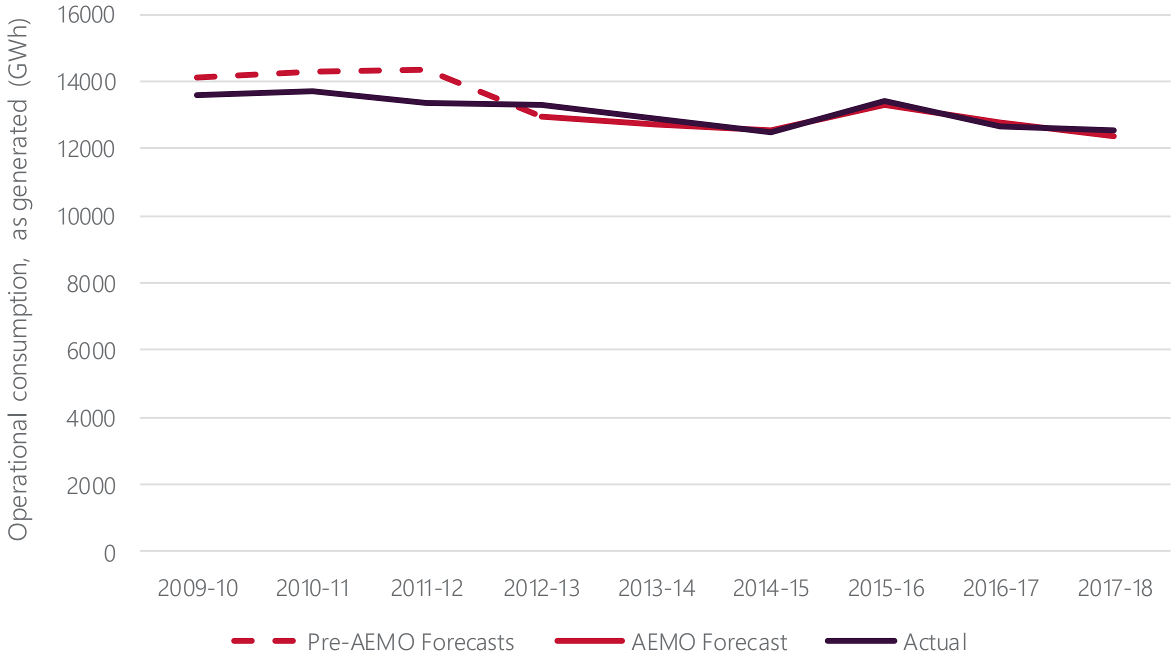
Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	12,144	12,238	94	0.8%
Auxiliary load (GWh)	209	317	108	34.1%
Operational consumption – as generated (GWh)	12,352	12,555	203	1.6%
Non-scheduled generation* (GWh)	96	177	81	45.8%
Native consumption – as generated (GWh)	12,448	12,732	284	2.2%
Significant input forecasts				
Transmission losses (GWh)	303	399	96	24.1%
Rooftop PV generation offset (GWh)	-1,098	-1,160	-62	5.3%

Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Weather factors – annual				
Heating degree days (HDD)	638	616	-22	-3.7%
Cooling degree days (CDD)	446	561	115	20.5%

* This excludes any non-scheduled generation part of operational consumption (significant non-scheduled).

- Actual South Australian operational consumption (sent out) in the 2017-18 financial year was 0.8% above the 2017 ESOO forecast.
  - Actual weather, while close to a normal year for heating, resulted in a higher need for cooling than forecast.
  - Estimated transmission losses were significantly higher than forecast. The 2017 ESOO transmission loss forecast was based on the average of the transmission loss percentages for the previous five years. These were quite a bit lower in the first three years, causing losses to be underestimated compared to the most recent trend. The change in trend is likely to reflect the change in generation mix in South Australia and Victoria, and the corresponding change in transmission flows. In 2017-18, for the first time in over nine years, South Australia was a net exporter of electricity.
  - Rooftop PV generation (accounting both for actual installed capacity and insolation across the year) was higher than forecast, driven mainly by more installations than forecast (see Table 6) offsetting operational consumption 62 GWh more than forecast.
  - Non-scheduled generation, in particular driven by PV, was also significantly above forecast, offsetting operational consumption by 81 GWh more than forecast.
- Actual as generated operational consumption for the 2017-18 financial year was 1.6% below forecast, as auxiliary load was 34.1% above forecast. The performance of the as generated forecast in recent years is shown in Figure 17.
- Actual native demand (as generated) was 2.2% above forecast. This is due to small non-scheduled generation being 45.8% above forecast. This is a very small component and additional capacity, such as the unexpected growth in non-scheduled PV capacity, can lead to large percentage errors.

Figure 17 Historical performance of Operational (as generated) forecasts for South Australia produced by AEMO (2012 onwards) and TNSPs (pre-2012)



Maximum and minimum demand

Table 13 Accuracy of South Australia 2017 ESOO maximum and minimum demand forecasts for 2017-18

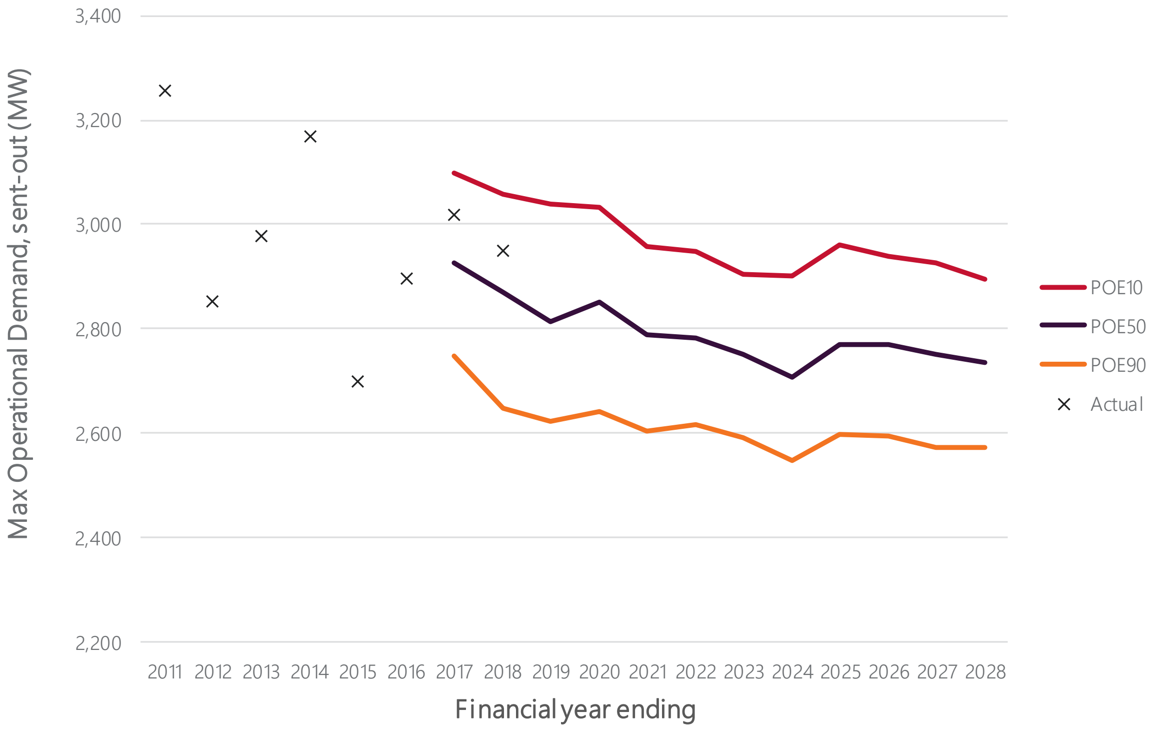
Operational maximum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Maximum demand – sent out (MW)	2,947	3,057	2,870	2,647
Rooftop PV at time of operational max demand (MW)	82	179 to 221		
Weather – at time of operational maximum demand				
Dry temperature (°C)	39.3	39.8	39.1	35.6
Dry temperature rolling 3-day cooling degrees	4.91*	n/a	n/a	n/a
Characteristics of peak demand day				
Time (local)	7:30 pm	5:30 pm		
Weekend	No			
Public holiday	No			
School holiday	Yes			

* In South Australia, the 95 percentile is 10.16, the 97 percentile is 11.26 and the 99 percentile is 12.81 cooling degrees.

Operational minimum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Minimum demand – sent out (MW)	645	552	498	387
Rooftop PV at time of operational min demand (MW)	645	589 to 631		
Weather – at time of operational minimum demand				
Dry temperature (°C)	23.2	20.3	20.0	21.3
Characteristics of minimum demand day				
Time (local)	2:00 pm	2:00 pm	2:00 pm	1:00 pm

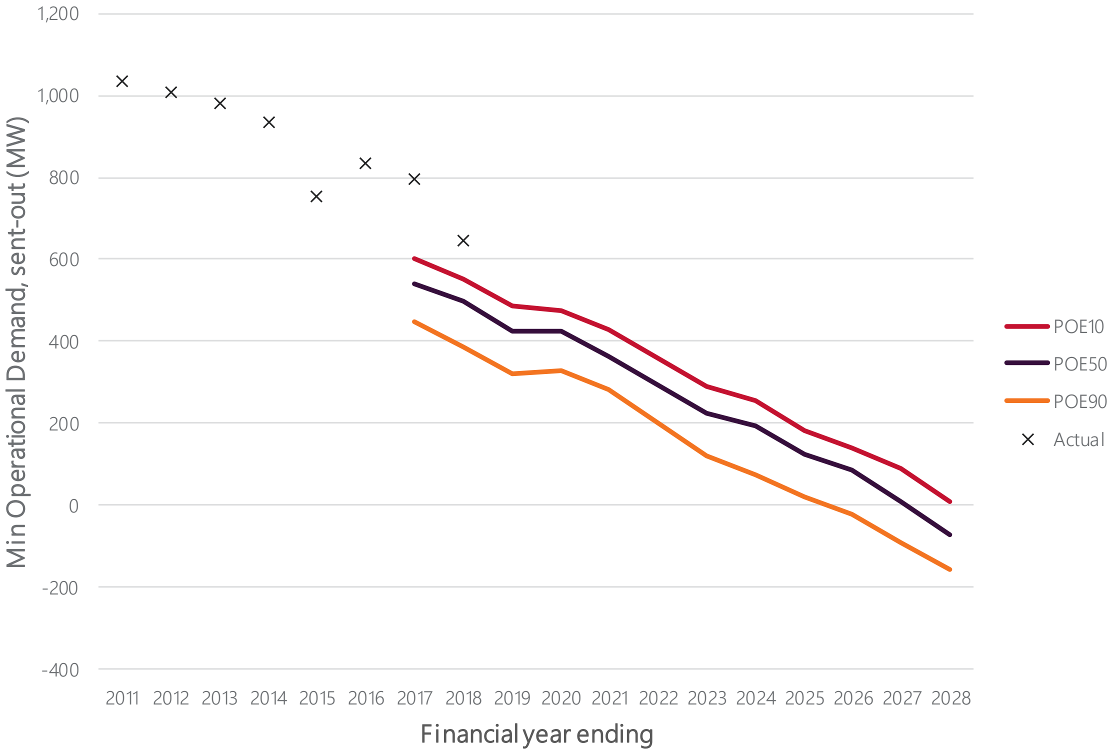
- Actual maximum demand occurred in summer on Thursday 18 January 2018, when temperatures reached 39.3°C.
  - While most industry would be back at full production following the Christmas break, the fact that maximum demand occurred during the school holiday suggests it could have been even higher, for same conditions happening a few weeks later.
  - Even though in school holidays, the actual demand was higher than forecast for temperatures near 50% POE. This may be a symptom of the over-estimation of energy efficiency impacts already discussed, or natural stochastic variation.
  - Maximum demand also occurred later in the day, at 7.30 pm, resulting in lower than expected rooftop PV generation at time of maximum demand, despite more rapid rooftop PV uptake than forecast.
  - Figure 18 shows the three POE forecasts.

Figure 18 Historical actual and 2017 ESOO forecast maximum demand for South Australia (summer season)



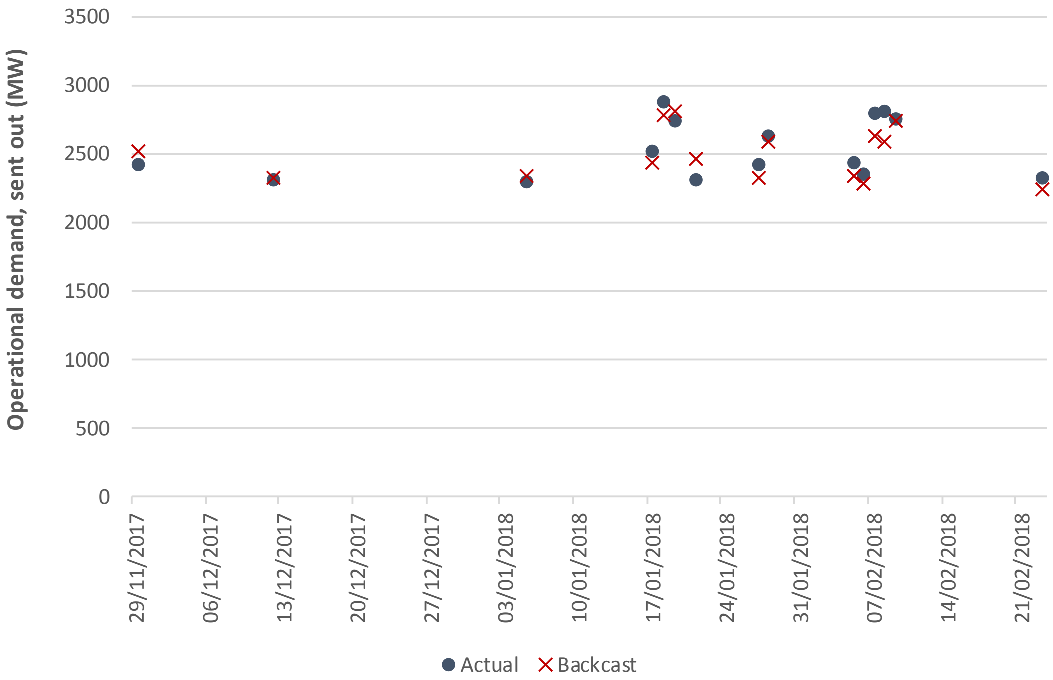
- Actual minimum demand occurred in "summer" on Sunday 5 November 2017, in the early afternoon, when the temperature was 23.2°C.
  - This temperature is higher than the range within which minimum demand is projected to fall suggesting there may have been some cooling load increasing minimum demand.
  - South Australian minimum demand has been occurring mid-day for a number of years with minimum demand reducing year on year in response to growth in installed rooftop PV capacity.
  - PV generation was higher than forecast at time of minimum demand due to higher installed capacity.

Figure 19 Historical actual and 2017 ESOO forecast minimum demand for South Australia



- Figure 20 shows backcast results of the highest half-hour in the top 15 highest demand days observed in South Australia over last summer, using actual weather observations. Unlike the other summer peaking regions, the is only a slight backcast model bias to underestimate forecasts if known stochastic volatility is ignored in South Australia, and in some instances the backcast model over-estimated maximum demand. This may indicate a stronger relationship between temperature and maximum demand in South Australia than in other regions, with less variation being attributable to stochastic factors. Further information is required, and will be collected in future, to assess whether the magnitude of the underestimation is statistically significant, once stochastic factors are represented in the backcast.

Figure 20 Actual versus backcast maximum demand half-hour for top 15 highest demand days in South Australia



AEMO will also continue to explore alternate model specifications, testing the best balance between bias and variance, to see whether the range of uncertainty in the maximum demand forecasts can be narrowed. In regions where maximum demand is now occurring late in the day, when additional rooftop PV has less of a time-shifting impact, as is the case in South Australia, alternative models applying extreme value theory will be explored to complement current approaches. Additionally, improvements to the current model specification to combine the 24 hourly models into a single model with time as an explanatory variable, may also help the model refine the relationship between temperature and demand based on recent history. This is discussed in more detail in Section 3.

2.7 Tasmania

Annual consumption

Table 14 Accuracy of Tasmania 2017 ESOO annual consumption forecast for 2017-18

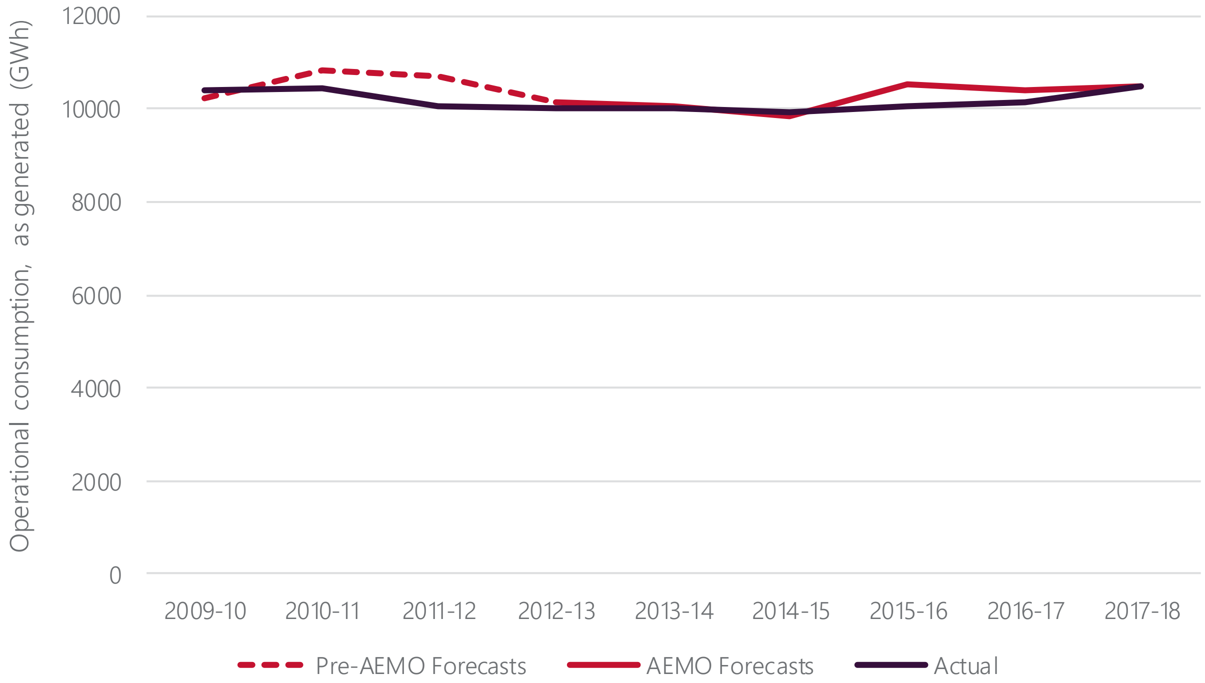
Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	10,372	10,385	13	0.1%
Auxiliary load (GWh)	102	122	20	16.3%
Operational consumption – as generated (GWh)	10,474	10,507	33	0.3%
Non-scheduled generation* (GWh)	423	436	13	3.1%
Native consumption – as generated (GWh)	10,897	10,943	46	0.4%

Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Significant input forecasts				
Transmission losses (GWh)	269	312	43	13.8%
Rooftop PV generation offset (GWh)	-142	-140	2	-1.4%
Weather factors – annual				
Heating degree days (HDD)	1,275	1,303	28	2.1%
Cooling degree days (CDD)	39	45	6	13.3%

* This excludes any non-scheduled generation part of operational consumption (significant non-scheduled).

- Actual Tasmanian operational consumption (sent out) in the 2017-18 financial year was 0.1% above the 2017 ESOO forecast.
  - Weather was close to normal conditions for both heating and cooling, with a very small impact expected on annual consumption overall.
  - Actual estimated rooftop PV and non-scheduled generation were both close to forecast, the former being 2 GWh below and the latter 13 GWh above forecast.
  - Estimated transmission losses were 43 GWh above forecast.
  - Large industrial consumption was approximately 220 GWh lower than forecast, mainly due to as assumed expansion in this sector did not eventuate. Offsetting this is other consumption (residential and commercial), which is likely to have been greater than forecast, with both growth in number of residential connections and GSP being higher than forecast (no break down of actual consumption is available to verify).
- Actual as generated operational consumption for the 2017-18 financial year was 0.3% above forecast as auxiliary load was 16.3% higher than projected. The auxiliary load in Tasmania is generally very small and a high percentage error does not reflect any significant contribution to forecast inaccuracy. The performance of the as generated forecast in recent years is shown in Figure 21.
- Actual native demand (as generated) was 0.4% above forecast. This is slightly higher than the difference seen in operational (as generated) due to small non-scheduled generation being 3.1% above forecast.

Figure 21 Historical performance of Operational (as generated) forecasts for Tasmania produced by AEMO (2012 onwards) and TNSPs (pre-2012)



Maximum and minimum demand

Table 15 Accuracy of Tasmania 2017 ESOO maximum and minimum demand forecasts for 2017-18

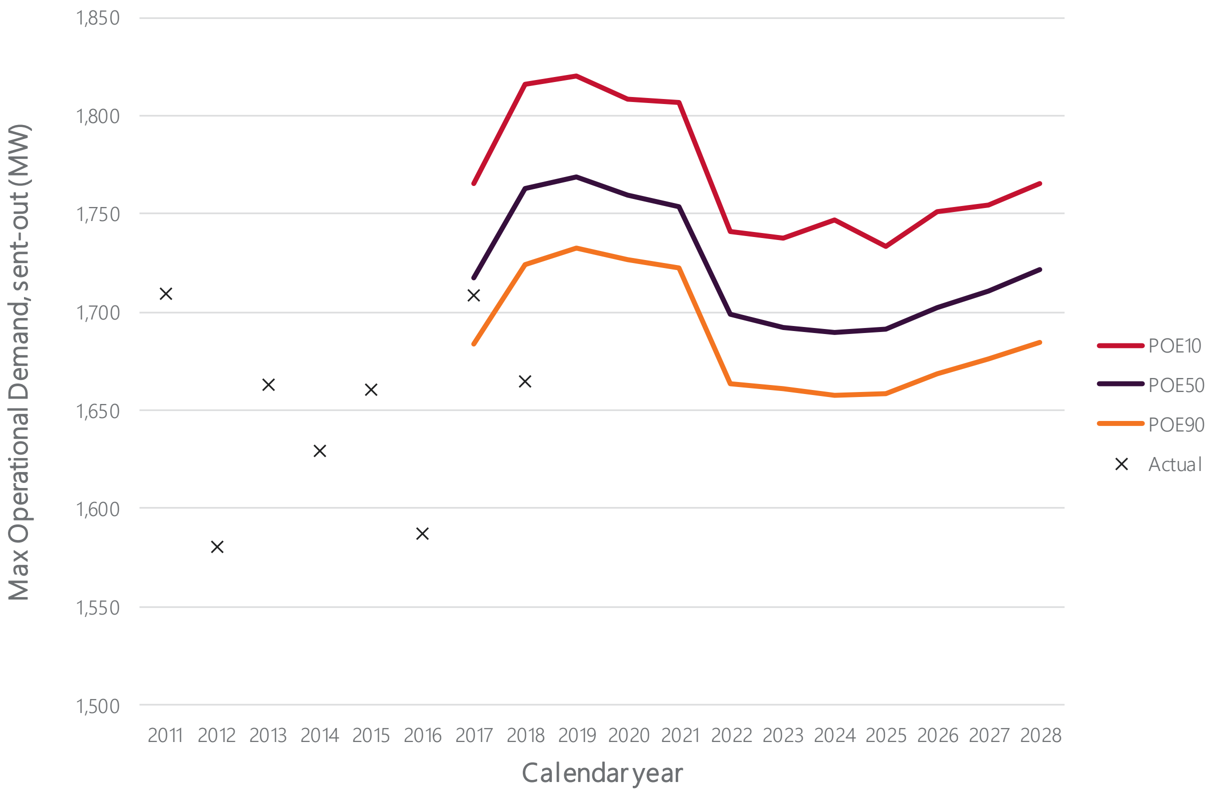
Operational maximum demand	**Actual (winter)**	**Forecast 10% POE**	**Forecast 50% POE**	**Forecast 90% POE**
Maximum demand – sent out (MW)	1,664	1,816	1,763	1,725
Rooftop PV at time of operational max demand (MW)	6	0 to 1		
Weather – at time of operational max demand				
Dry temperature (°C)	4.4	5.6	6.0	6.2
Characteristics of peak demand day				
Time (local)	9:00 am	6:30 pm		
Weekend	No			
Public holiday	No			
School holiday	No			

Operational minimum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Minimum demand – sent out (MW)	830	890	870	840
Rooftop PV at time of operational min demand (MW)	83	11 to 12		
Weather – at time of operational minimum demand				

Operational minimum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Dry temperature (°C)	20.6	17.4	17.8	16.8
Characteristics of minimum demand day				
Time (local)	11:30 am	2:30 am	7:30 am	7:30 am

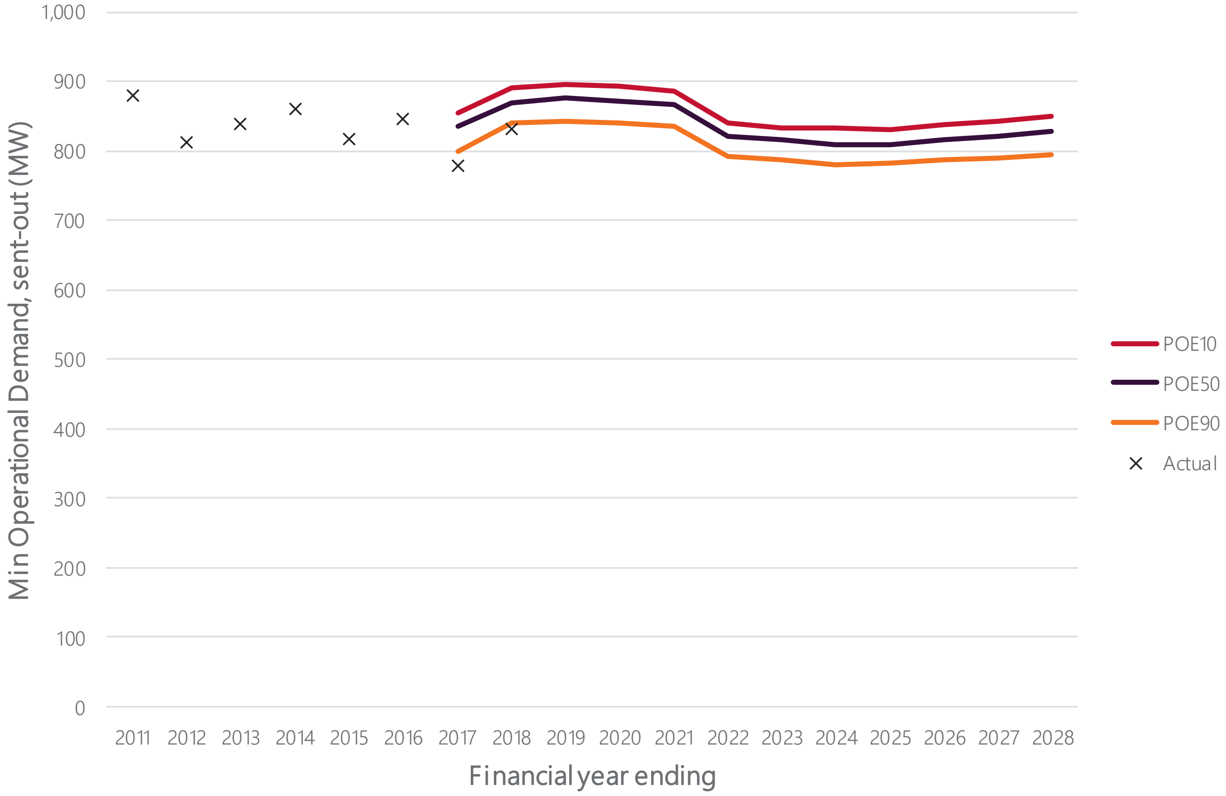
- Actual maximum demand occurred in winter on Monday 20 August 2018, with a temperature of 4.4°C at 9.00 am.
  - While it was one of the coldest days of the year (minimum temperature was 2.3°C), the temperature at time of maximum demand had warmed up from the minimum temperature for that day.
  - The forecast distribution of maximum demand values was comparatively high, due to assumptions on industrial growth that did not eventuate. This is particular clear when looking at the forecasts in Figure 22. As result, observed maximum demand was below the 90% POE.

Figure 22 Historical actual and 2017 ESOO forecast maximum demand for Tasmania (Winter season)



- Actual minimum demand occurred in summer on Tuesday 12 December 2017, in the late morning, when the temperature was 20.6°C.
  - The forecast distribution of minimum demand values was comparatively high, due to assumptions on industrial growth that did not eventuate.

Figure 23 Historical actual and 2017 ESOO forecast minimum demand for Tasmania



- Backcasting for Tasmania winter 2018 is not currently available, as some key data is yet to be updated beyond the 2017-18 financial year. AEMO will endeavour to source this information for subsequent forecasting accuracy reports.

2.8 Victoria

Annual consumption

Table 16 Accuracy of Victoria 2017 ESOO annual consumption forecast for 2017-18

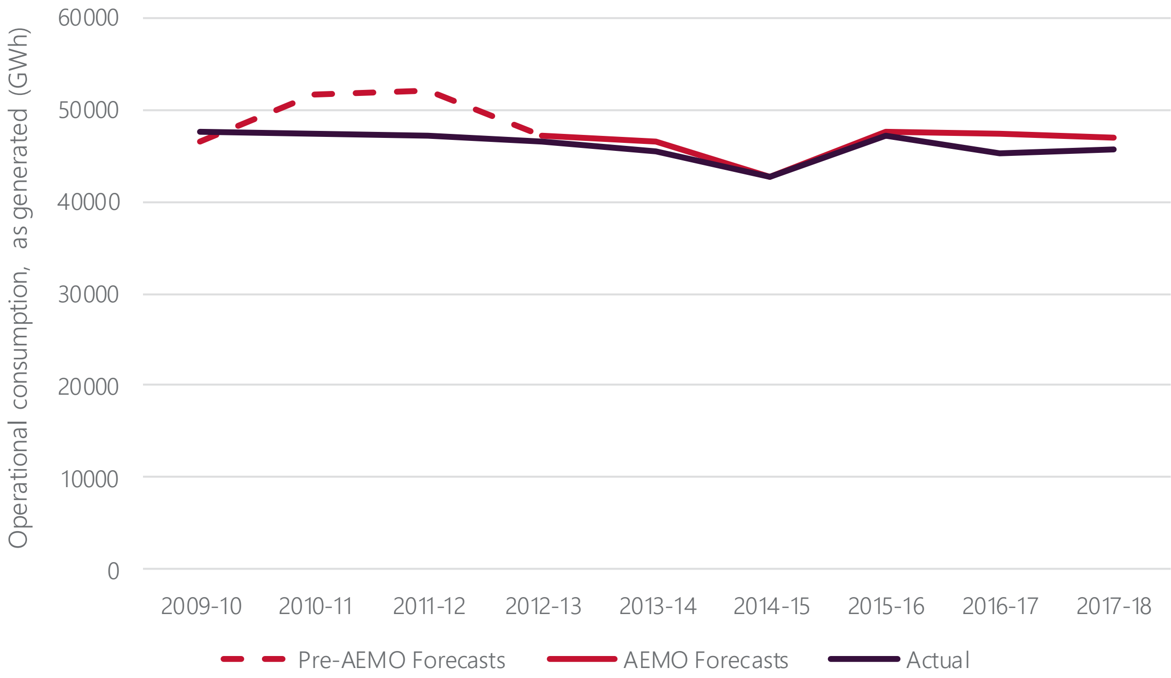
Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Operational consumption – sent out (GWh)	43,541	42,471	-1,070	-2.5
Auxiliary load (GWh)	3,302	3,146	-156	-5.0
Operational consumption - as generated (GWh)	46,843	45,617	-1,226	-2.7
Non-scheduled generation* (GWh)	890	1085	195	18.0
Native consumption – as generated (GWh)	47,733	46,702	-1,031	-2.2
Significant input forecasts				
Transmission losses (GWh)	1,126	1,111	-15	-1.3
Rooftop PV generation offset (GWh)	-1,512	-1,539	-27	1.8

Annual consumption	2017 ESOO forecast	Actual	Difference	Difference (%)
Weather factors – annual				
Heating degree days (HDD)	716	869	153	17.6
Cooling degree days (CDD)	442	470	28	6.0

* This excludes any non-scheduled generation part of operational consumption (significant non-scheduled).

- Actual Victorian operational consumption (sent out) in the 2017-18 financial year was 2.5% below the 2017 ESOO forecast.
  - There were slightly more heating degree days and cooling degree days than average, likely leading to higher actual consumption for heating and cooling services compared with forecast.
  - Actual rooftop PV generation was broadly in line with forecast (actual 1.8% above forecast).
  - Non-scheduled generation was significantly above forecast, exceeding forecasts by 195 GWh (18.0%), primarily driven by higher than forecast non-scheduled PV generation.
  - Actual growth in residential connections was above forecast (see Table 5), suggesting residential consumption would be above forecast (but no breakdown of actual consumption is available to verify).
  - Remainder of variation is assumed to be from lower than forecast consumption by industrial and commercial users.
- Actual as generated operational consumption for the 2017-18 financial year was 2.7% below forecast. This is a slightly larger difference than sent out consumption, due to auxiliary load being lower than forecast. The performance of the as generated consumption forecast in recent years is shown in Figure 24. In the last few years the actuals have generally been below the forecast. In 2016-17 that was largely attributable to the outage of capacity of the Portland smelter.
- Actual native demand (as generated) was 2.2% below forecast. This is less than the difference seen in operational (as generated) due to small non-scheduled generation being 18% above forecast. As in other regions, underforecasting non-scheduled PV generation was the key reason for differences in non-scheduled generation.

Figure 24 Historical performance of operational (as generated) forecasts for Victoria produced by AEMO (2012 onwards) and TNSPs (pre-2012)



Maximum and minimum demand

Table 17 Accuracy of Victoria 2017 ESOO maximum and minimum demand forecasts for 2017-18

Operational maximum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Maximum demand – sent out (MW)	8,770	9,859	9,062	8,299
Rooftop PV at time of operational max demand (MW)	101	296 to 324		
Weather – at time of operational maximum demand				
Dry temperature (°C)	36.6	41.9	39.4	36.5
Dry temperature rolling 3-day cooling degrees	3.10*			
Characteristics of peak demand day				
Time (local)	7:30 pm	5:30 pm		
Weekend	Yes			
Public holiday	No			
School holiday	Yes			

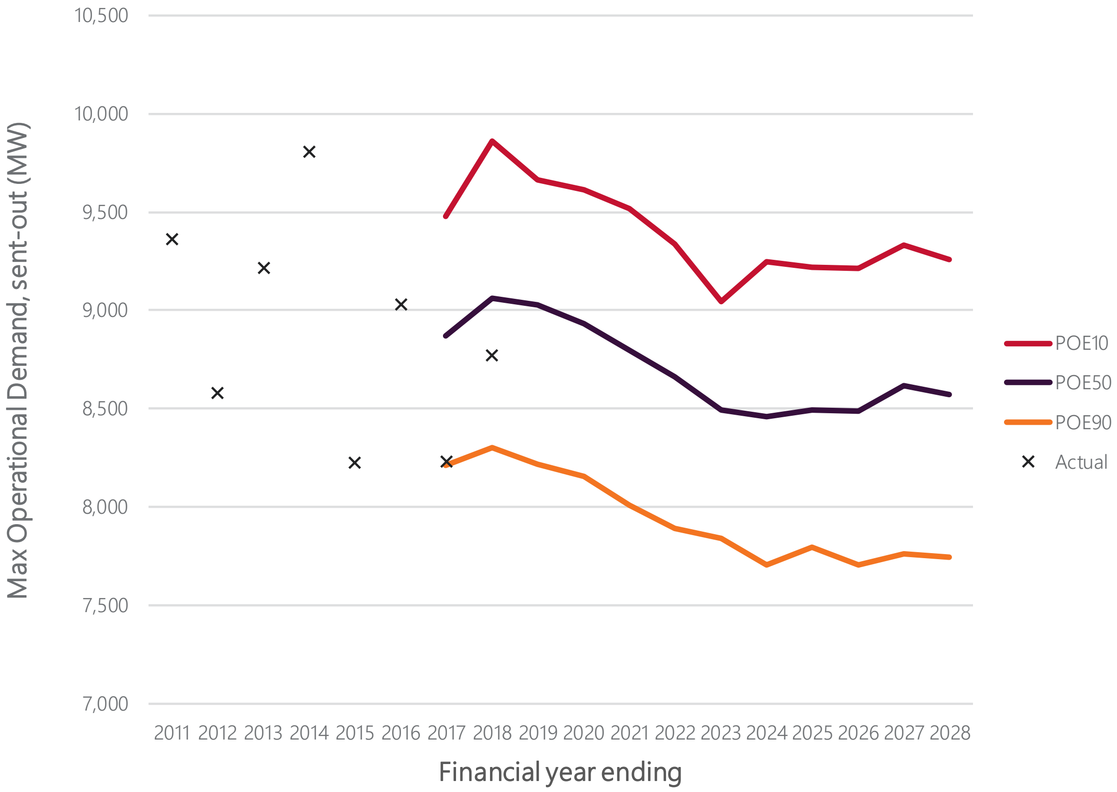
* In Victoria, the 95 percentile is 5.14, the 97 percentile is 6.13 and the 99 percentile is 7.03 cooling degree hours.

Operational minimum demand	Actual (summer)	Forecast 10% POE	Forecast 50% POE	Forecast 90% POE
Minimum demand – sent out (MW)	2,935	2,647	2,492	2,237
Rooftop PV at time of operational min demand (MW)	21	519 to 768		
Weather – at time of operational minimum demand				
Dry temperature (°C)	15.5	18.1	18.6	19.1
Characteristics of minimum demand day				
Time (local)	7:00 am	3:00 pm	2:00 pm	2:00 pm

- Actual operational (sent out) maximum demand occurred in summer, on Sunday 28 January 2018[15].
  - Since it was observed during a weekend, maximum demand would have been in the lower range of the forecast distribution if it were not for other factors increasing demand relative to the forecast. Had the same weather conditions occurred on a weekday, all else being equal, the demand could have been substantially higher.
  - It also occurred later in the day, at 7.30 pm, resulting in lower than expected rooftop PV generation at time of maximum demand.
  - Figure 25 shows how forecast maximum demand for 2017-18 financial year increased after the return to full service of Portland smelter from its outage. The spread of POE forecasts captures the observed variability of actual maximum demand values.

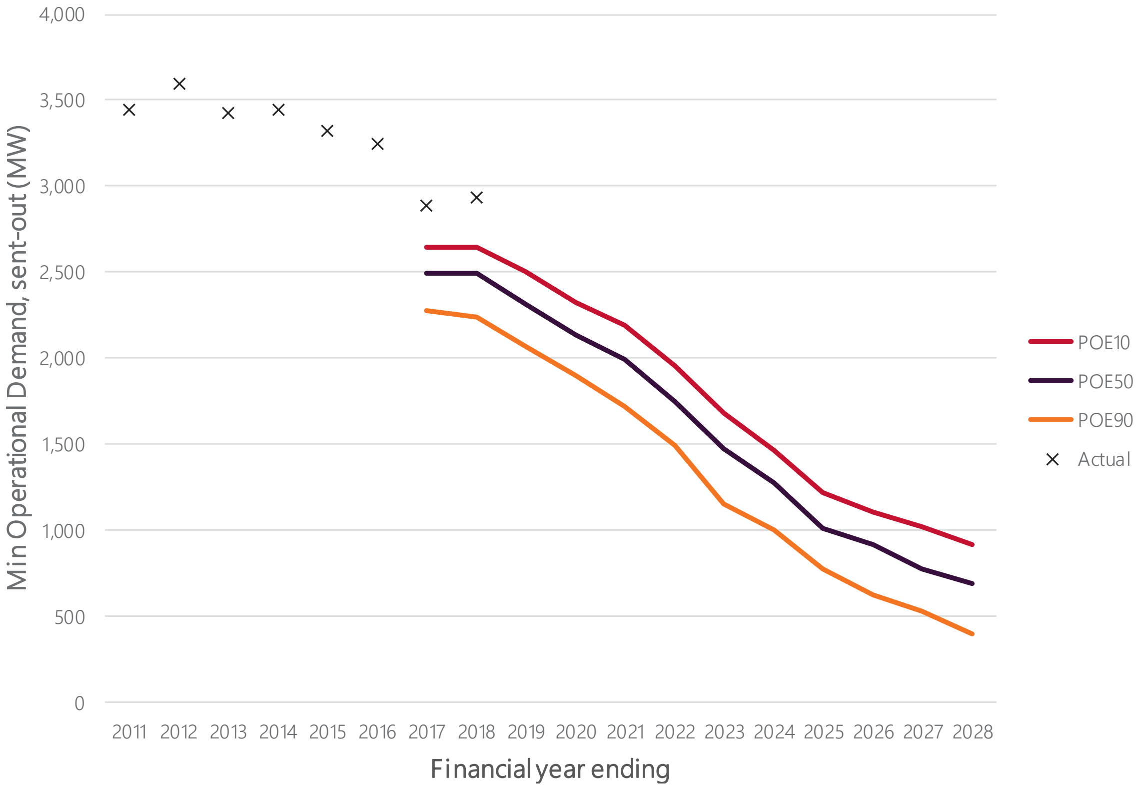
[15] Note that on a as generated basis, the maximum demand occurred 19 January 2019 due to higher estimated auxiliary load that day.

Figure 25 Historical actual and 2017 ESOO forecast maximum demand for Victoria (Summer season)



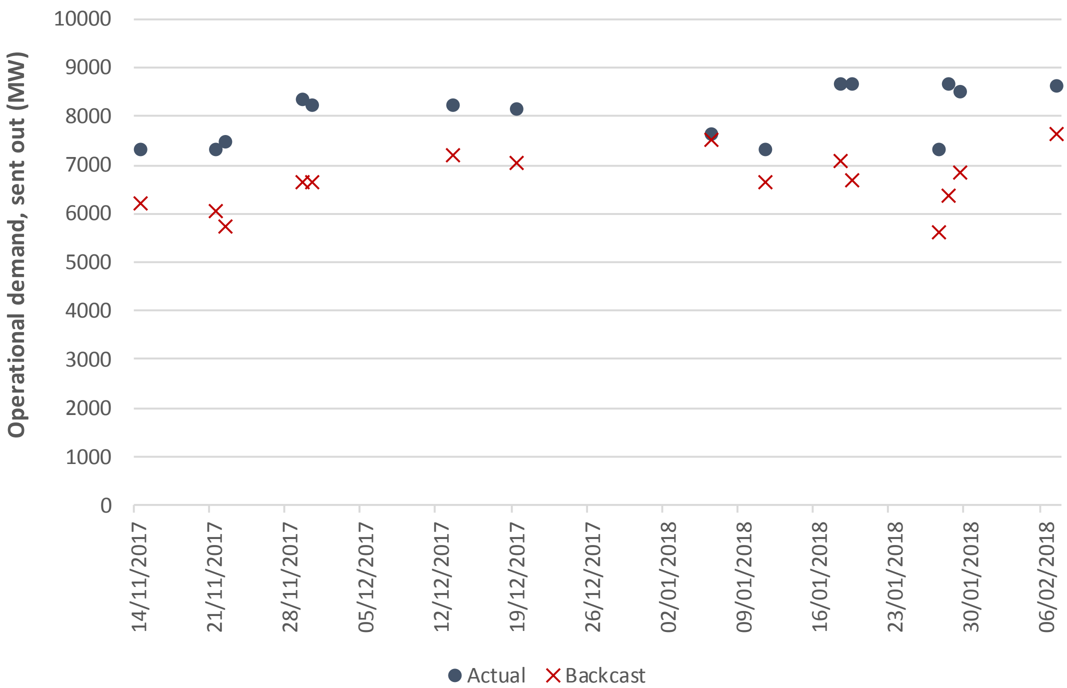
- Actual minimum demand occurred in "summer", on Sunday 12 November 2017, at 7:00 am local time when the temperature was 15.5°C.
  - For regions such as Victoria, where rooftop PV generation has not yet pushed minimum operational demand to the middle of the day, the minimum generally occurs early morning during public holidays or weekends, when industrial demand is lower.
  - For this minimum demand occurrence, there may have been some rooftop PV generation as sun rose at 6:03 am in Melbourne. Further, there may have been some heating load as temperature was lower than the minimum demand temperature range.

Figure 26 Historical actual and 2017 ESOO forecast minimum demand for Victoria



- Figure 27 shows backcast results of the highest half-hour in the top 15 highest demand days observed in Victoria over last summer, using actual weather observations. As expected, and consistent with other regions, the models would underestimate maximum demand, if known stochastic volatility is ignored. Further information is required, and will be collected in future, to assess whether the magnitude of the underestimation is statistically significant, once stochastic volatility is included in the backcast.

Figure 27 Actual vs. backcast max demand half-hour for top 15 highest demand days in Victoria



AEMO will also continue to explore alternate model specifications, testing the best balance between bias and variance, to see whether the range of uncertainty in the maximum demand forecasts can be narrowed. In regions where maximum demand is now occurring late in the day, when additional rooftop PV has less of a time-shifting impact, as is the case in Victoria, alternative models applying extreme value theory will be explored to complement current approaches.

Additionally, improvements to the current model specification to combine the 24-hourly models into a single model, with time as an explanatory variable, may also help the model refine the relationship between temperature and demand based on recent history. Further work to better understand the relationship between new connections, appliance penetration and consumption may also improve the maximum and minimum demand forecasts. This is discussed in more detail in Section 3.

3. Improvements to the forecasting process

This year's *Forecast Accuracy Report* has been expanded to reflect the importance of forecast accuracy to industry decision making and to improve transparency around areas where AEMO is focusing efforts to improve forecasts. The reporting here is part of a continuous improvement process, which will be enhanced as AEMO moves towards more regular forecast performance monitoring and reporting.

The process has three key steps:

1. Monitor – track performance of key forecasts and their input drivers against actuals.
2. Evaluate – for any major differences, seek to understand whether the reason behind the discrepancy is due to forecast input deviations (actual inputs differed from forecast inputs) or a forecast model error (the model incorrectly translates input into consumption or maximum/minimum demand).
3. Action – seek to improve input data quality or forecast model formulation where issues have been identified prioritising actions based on materiality and time/cost to correct.

The following section:

- Summarises key observations on the performance of the 2017 NEM ESOO demand forecasts from this year's *Forecast Accuracy Report.*
- Discusses improvements made in the 2018 forecasts (as per the 2018 NEM ESOO forecast) that may already help improve accuracy in areas needing focus.
- Presents a high-level action plan for 2019, including the ongoing development of a forecasting monitoring dashboard and general forecast improvements.

3.1 2017 NEM ESOO forecast – summary of findings

The annual operational consumption (sent out) forecasts were well aligned with actuals in New South Wales and South Australia and Tasmania. In Queensland, the -2.8% percentage error is mostly explained by lower than forecast demand from the CSG sector and higher than forecast uptake of PV capacity (both rooftop and non-scheduled). The -2.5% percentage error in Victoria requires more investigation, in particular on the back of higher than forecast growth in residential connections and the economy overall. Seen over time however, the consumption forecasts generally track well compared to actuals across all regions.

It is acknowledged that the performance of probabilistic forecasts such as AEMO's maximum and minimum demand forecasts is harder to assess. AEMO is working on improving the ability to explain these forecasts, and reasons for variations from backcast. This, along with investigation into weather variable choice and minimum demand improvements in general are the highest priority for the coming year.

Section 2 highlighted reasonable alignment between maximum demand forecasts and actual observations, with most deviations explainable, but also flagged several areas warranting further investigation. These are summarised in the table below, along with the actions taken in 2018 or planned for 2019 that should help improve accuracy in these areas.

Table 18 List of forecast improvements undertaken in 2018 or planned for 2019

Observations	Action already taken in 2018	Actions to be taken in 2019
Maximum demand		
Improve ability to explain forecast differences	Increased information provided in this Forecast Accuracy Report, and consulted with industry on new performance metrics that could be used to measure accuracy of probabilistic forecasts.	Retain more modelling data so POE outcomes can be explained for a number of variables beyond temperature. This includes the impact of heatwaves, months and type of day.
Forecast values fluctuate between forecast years	Doubled simulations to smooth forecasts between years.	Same as 2018 or even more simulations.
Need to better understand interaction of multiple weather variables, including subregional weather	Improved modelling of climate change - particularly extreme temperature and heatwave trends.	Further improvements to model formulation, considering other combinations of weather variables, enabled by greater access to climate and weather data.
Poor distribution alignment in New South Wales and Tasmania	Reformulated model – POE spread now more representative of historical values.	Continuous review of model formulation.
Minimum demand		
Minimum demand forecasts too low across all regions, particularly Victoria and South Australia	Started forecast performance monitoring of minimum demand. Reviewed forecasts of rooftop PV and PVNSG.	Further improvement to model formulation with emphasis on minimum demand periods. Meter data analysis to glean any behavioural change impacts.
Only checks for minimum demand summer and winter	No change.	Check for occurance of minimum demand in forecast shoulder months.
Consumption		
Lack of timely insight into split between residential, commercial and industrial consumption to measure performance of components	No improvements.	Review ability to separate out large industrial consumers specifically.
Consumption over-estimated in Victoria despite key inputs such as connections and economic growth being higher than expected		Further investigation and fine-tuning of econometric models used in Victoria.
Underforecast PVNSG	Specific forecast of this segment by CSIRO	Similar approach as 2018 updated with latest uptake trends and installation cost data.
Auxiliary loads under or over-estimated	Forecast values estimated based on updated modelling of future generation mix. Historical values re-estimated based on auxiliary load factors.	Estimated based on updated modelling of future generation mix. Auxiliary load factors to be reviewed.
Input forecasts		
Residential connections growth in Victoria much higher than forecast	Used updated housing projections to inform 2018 ESOO forecast's short term trend.	Will update housing projections again. Will use new ABS 2017 census population projections as longer term trend.
Rooftop PV installations growth underforecast in particular for Queensland and South Australia	New forecast better reflecting current uptake (as per Clearn Energy Regulator) relative to cost of PV systems and electricity retail prices.	Similar approach as 2018 updated with latest uptake trends and installation cost data.

Observations	Action already taken in 2018	Actions to be taken in 2019
Economic growth reliance on older population trends	Same methodology.	Will use new 2017 census based population growth, more in line with recent trends.
Losses	Corrected error in NSW losses. Changed methodology to project forward based on the most recent losses as historical losses prior to Northern and Hazelwood closures were inaccurate to inform forecasts.	Same as 2018.
Coal Seam Gas consumption overforecast in Queensland	Used updated CSG consumption forecast rebased to recent trends.	Will be based on updated forecast from AEMO's 2019 Gas Statement of Opportunities.
Impact of emerging technologies such as electric vehicles and energy storage systems	Used updated forecasts based on recent cost trends.	Work with industry to Identify lead and lag indicators to monitor uptake rate and charge/discharge profiles for these emerging technologies.

3.2 2018 demand forecasting improvements

To improve consumption and maximum demand forecasts for the 2018 ESOO, AEMO implemented the following new methodologies:

- Improvements to AEMO's short-term (2-3 years) business and residential forecast models – AEMO constructed the short-term consumption model using the latest meter data for residential and business consumers up to 30 June 2018 (working on such a large dataset has previously not been practical). These models improved estimates of weather-sensitive load components. The energy efficiency forecasts have been mapped directly to these datasets to improve the allocation of energy efficiency savings from cooling and heating, and the effect on maximum demand forecasts. Compared to the previously used allocations this has resulted in lower impact of energy efficiency at time of maximum demand. AEMO will seek to verify the impact through further studies of meter data in 2019.
- Weather and climate impacts – AEMO has enhanced the methodology that more dynamically identifies when climate change impacts are likely to drive greater increases in high/extreme temperature (and maximum demand) than average temperature.
- PV non-scheduled generation (PVNSG) – for this fast-growing segment covering solar PV installations between 100 kW and 30 MW, AEMO last year assumed the same growth rate as commercial-scale PV (10 kW to 100 kW). This year, AEMO engaged with CSIRO to derive a dedicated forecast of installed capacity for PVNSG. For the year analysed, the forecast was based on available information about likely PVNSG project completion, so it is unlikely it contributed to any significant differences observed, but over the forecast 20 year period, the new forecast is vastly different.
- Emerging developments in energy storage systems as well as electric vehicle charging profiles – these are expected to alter demand in more dynamic ways. Using recently available meter data, AEMO has improved the forecast methodology related to battery and electric vehicle charging to better reflect the growing sophistication in the demand profiles of these activities, technological development and consumer tariff offerings in relation to the evolution of developments observed in the NEM.
- Improvement in the way AEMO estimates historical auxiliary loads – AEMO implemented a new process to calculate actual auxiliary loads for generators where AEMO had the data available. For the remaining generators, AEMO used the auxiliary factors by generation type from ACIL Allen's 2014 Fuel and Technology Cost Review Report[16].

[16] See https://www.aemo.com.au/media/Fuel_and_Technology_Cost_Review_Report_ACIL_Allen.pdf.

- Increase in number of simulations in maximum/minimum demand model – doubled the number of simulations to create a more stable forecast year on year.

3.3 2019 demand forecasting improvements

As in previous years, AEMO will consult on further forecasting methodology improvements via the Forecasting Reference Group (FRG). Focus areas include:

3.3.1 Transparancy, accountability and accuracy

AEMO is committed to producing quality forecasts that support informed decision-making. For decision-makers to act on our forecasts, the forecasts must be credible and dependable.

To achieve this, AEMO's forecasting team has three main objectives:

- Transparency – to ensure our inputs and forecast methodologies are well understood.
- Accountability – to measure forecasting performance, refine and improve where issues are detected.
- Accuracy – to adopt best-practice methodologies and monitor lead indicators of change.

This forecast accuracy report addresses the second and third points in measuring performance and committing to change to improve accuracy. This will be supported by the mid-2019 implementation of a dashboard that will provide stakeholders with a range of forecast accuracy data as tracked throughout the year.

The forecast metrics will build upon those presented in this report and be continuously refined based on stakeholder feedback. AEMO will also get an expert peer review of the proposed metrics before the implementation.

Transparency will be improved though increased stakeholder engagement at regular FRG meetings and workshops, and descriptive explanations of forecast methodology following the recently completed consultation of the effectiveness of AEMO's Demand Forecasting Methodology Information Paper.

3.3.2 Improvements to maximum and minimum demand forecasts

Improving explainability

AEMO is working on ways to improve the explainability of its maximum and minimum demand forecasts. Some improvements have been implemented as part of this forecast accuracy report, but work is ongoing, including:

- Building metrics to assess performance of probabilistic forecasts. This can include
  - Prediction interval coverage probability (PICP), also known as "coverage":
    - Percentage of observations that fall within a nominal Prediction Interval %.
  - Prediction interval normalised average width (PINAW):
    - PINAW measures the sharpness of a probabilistic forecast
- Develop visualisations that illustrate forecast performance at a glance.
- Improving backcasting capability by retaining more modelling data so POE outcomes can be explained for a number of variables beyond temperatures. This includes the impact of heatwaves, months and type of day. Methods will be developed to assess the statistical significance of any variance between backcast and actual observed values. Backcasting for Tasmania winter maximum demand will also be introduced.

Understand impact of changing consumer energy picture

In Queensland, New South Wales, and Victoria, temperatures at time of maximum demand were close to 90% POE indicative temperature, but actual maximum demand was closer to 50% POE (or in case of QLD, 10% POE). This might be attributable to the multiple weather variables at play, but might also be due to a change in energy consumption behaviour at times of maximum demand, where consumers may be increasingly valuing comfort over the cost of electricity use (in particular if self-generating electricity from rooftop PV).

Similarly, there may be a change in consumption behaviour from owners of rooftop PV systems shifting consumption to the middle of the day to limit consumption from the grid at other times. Also, they may increase consumption in general due to the perception that they are generating cheap or free energy. As a result, the models may systematically overestimate the impact of increasing rooftop PV capacity on minimum demand.

To understand this, and the consumer energy picture more generally, AEMO will look into:

- Tracking (and reporting on) lead indicators for new technologies such as EV and battery installations.
- Meter data analysis of technology use and behavioural economics.
- Forecasting minimum demand in shoulder seasons rather than just the summer and winter periods defined in this report.

Impact of extreme weather

AEMO will continue its work with the Bureau of Meteorology to understand impacts of climate change on extreme temperature outcomes and maximum demand.

3.3.3 Consumption drivers

To improve the consumption forecast, AEMO will:

- Investigate how to segment the consumption forecast into sectors that can be monitored in a more timely manner using available data, so deviations in customer segment trends can be detected early and forecast models adjusted accordingly. This may include separating out transmission-connected loads from the rest of the business sector.
- Conduct further work on the consumption aspects of the consumer energy picture (similar to the work explained in Section 3.3.2 above for maximum/minimum demand) to better understand the relationship between new connections, appliance uptake, tariff incentives and consumption behaviour.
- Continue to refine a number of key input forecasts (connections, rooftop PV uptake, PVNSG) and sub-models, such as auxiliary load and transmission losses.

These initivatives will generally also help to improve the maximum and minimum demand forecasts.

Measures and abbreviations

Units of measure

Abbreviation	Full name
GW	Gigawatt
GWh	Gigawatt hour/s
kW	Kilowatt
kWh	Kilowatt hour/s
MW	Megawatt
MWh	Megawatt hour/s
TWh	Terawatt hour/s

Abbreviations

Abbreviation	Full name
ABS	Australian Bureau of Statistics
BoM	Bureau of Meteorology
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
ESS	Electricity Storage System
ESOO	Electricity Statement of Opportunities
FRG	Forecasting Reference Group
NEM	National Electricity Market
NER	National Electricity Rules
POE	Probability of exceedance
PV	Photovoltaic
PVNSG	PV non-scheduled generation

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
auxiliary load	The load from equipment used by a generating system for ongoing operation. Auxiliary loads are located on the generating system's side of the connection point and include loads to operate generating systems co-located at coal mines.
cooling degree days (CDD)	A sum of the number of degrees that the ambient temperature is above the threshold temperature for each day of the year.
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
heating degree days (HDD)	A sum of the number of degrees that the ambient temperature is below the threshold temperature for each day of the year.
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 capacity installed at any given time.
large industrial load	There are a small number of large industrial loads – typically transmission-connected customers – that account for a large proportion of consumption in each 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 load occur when plants open, expand, close, or partially close.
maximum demand	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, year) either at a connection point or simultaneously at a defined set of connection points.
native electricity consumption	The electricity energy supplied by scheduled, semi-scheduled, significant non-scheduled, and small non-scheduled generation.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as a non-scheduled generating unit in accordance with NER Chapter 2.
operational electricity consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, a POE10 maximum demand for any given season is expected to be met or exceeded, on average, on year in 10 – in other words, there is a 10% probability that the projected maximum demand will be met or exceeded.
rooftop photovoltaic (PV)	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop to convert sunlight into electricity. The 2017 ESOO forecasts considered only rooftop systems (systems installed to generate electricity primarily for self-consumption by residential or commercial consumers). It did not consider PV installations above 100kW like solar farms or community projects which are designed to sell electricity into the market. These are part of the SNSG.
small non-scheduled generation	Small non-scheduled generation, generally representing generation projects up to 30 MW in size.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission network.

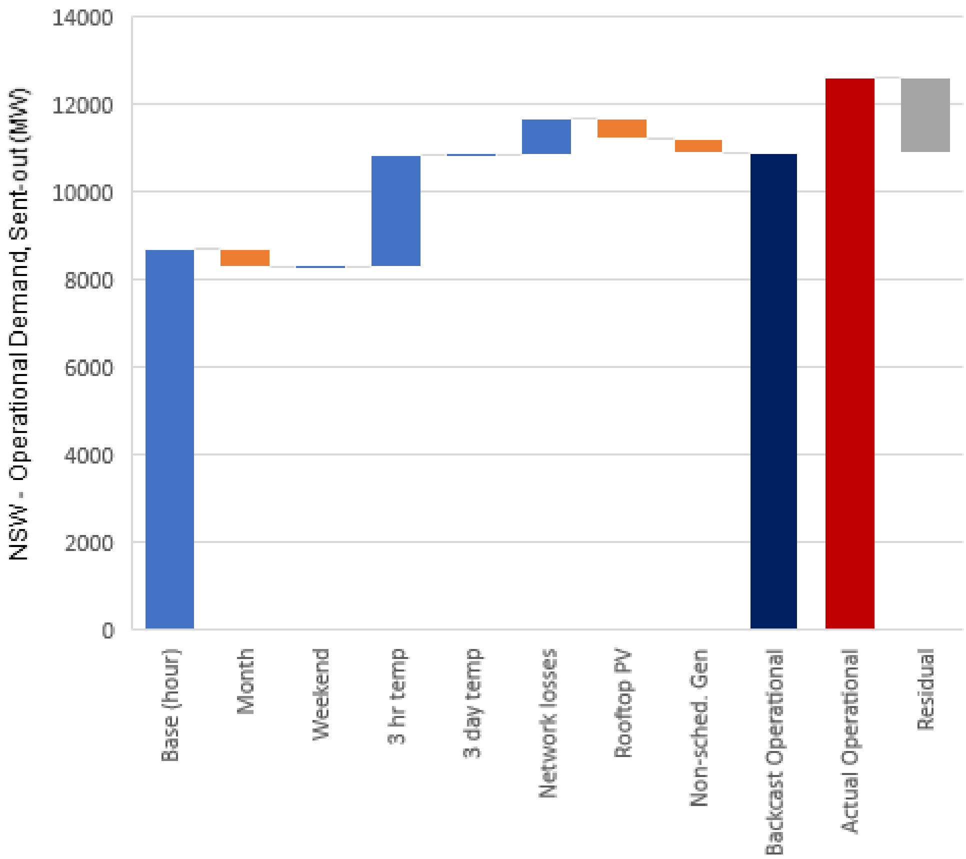
Appendix A: Building blocks of maximum demand forecasts

The operational sent-out maximum demand forecasts are derived by first forecasting underlying demand as a function of temperature, day type and month of year, and then adjusting to take account of network losses, rooftop PV and non-sheduled generation.

The component figures below show three examples of how the backcast values have been derived. The three periods selected were among the top 10 peak demand days in New South Wales in the last year and were selected to show the impact of different drivers (month, daytype, temperature) and the impact of PV when converting into operational consumption. They show the half-hour of the day with the highest operational consumption.

The first example was the highest demand period in New South Wales in 2017-18. Backcasting shows the key driver of demand in that period was the temperature on the day (rollng 3-hour average temperature). Being December, the demand was slightly lower than it would otherwise have been for the same weather conditions in January. As maximum demand occurred on a weekday, there was no offset from the weekend factor. Also, the rolling 3-day average temperature was not sufficient to trigger a 'heatwave' response.

Figure 28 Backcast example, breakdown by component, New South Wales 19 Dec 2017



The following two examples show:

- where the rolling 3-day average temperature exceeded the threshold to give a heatwave response of almost 1000 MW on top of the impact from the temperature on the day.
- a high demand occurring in a weekend, where the base value was lowered by approximately 450 MW from this factor alone. That day also had its peak demand relatively late in the day, around 6:30 pm, resulting in a relatively low offset by rooftop PV. This also reflects this day was in mid March where the sun sets earlier than January.

Figure 29 Backcast example, breakdown by component, New South Wales 8 Jan 2018

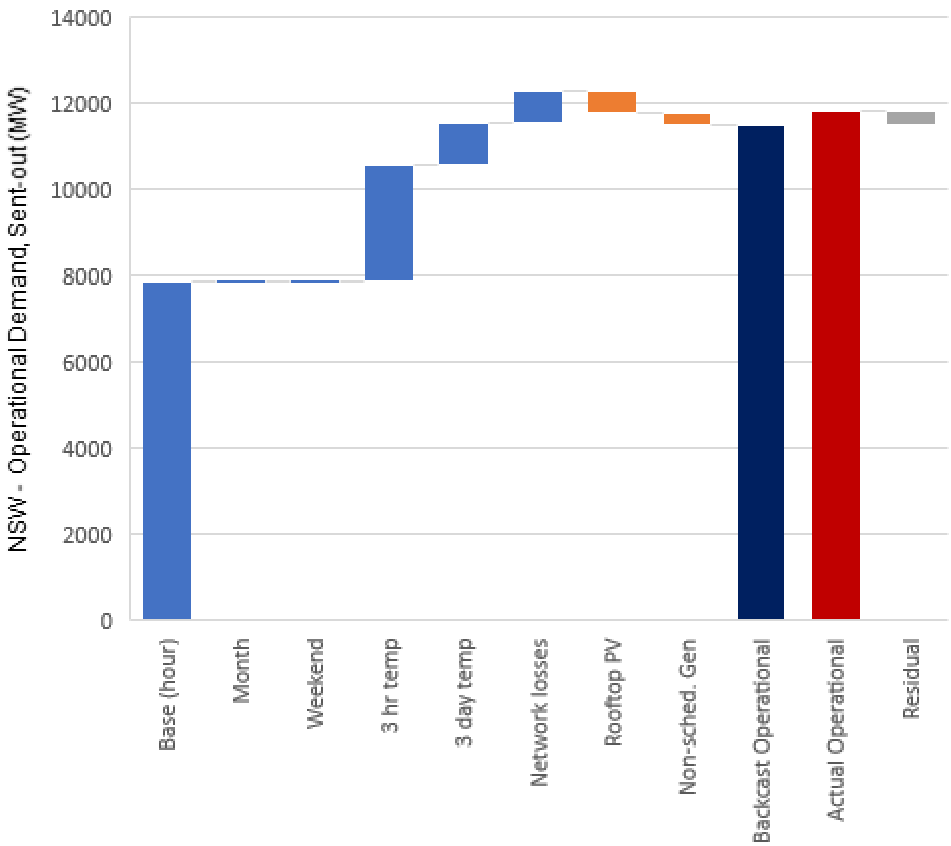
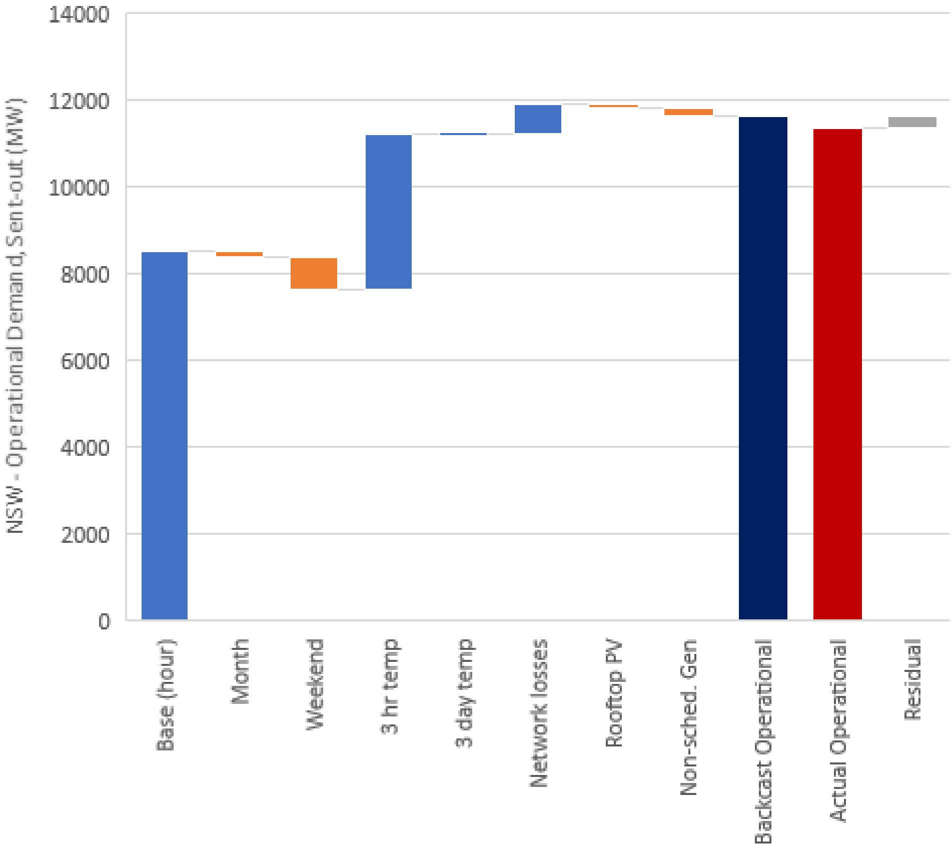


Figure 30 Backcast example, breakdown by component, New South Wales 18 March 2018



Appendix B: Accuracy of operational consumption forecast over time

Table 19 Development of operational consumption percentage error (PE) for the NEM region over time

	NEM region PE (as generated)	NEM region PE (sent out)
2009-10	-0.5%	
2010-11	-6.9%	
2011-12	-7.6%	
2012-13	-2.1%	
2013-14	-3.3%	
2014-15	2.6%	
2015-16	-0.8%	-0.3%
2016-17	-1.3%	-1.2%
2017-18	-1.2%	-1.3%