



AusNet Electricity Services Pty Ltd

Electricity Distribution Price Review 2022-26

Appendix 7A: Distribution Demand Forecasting Review

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PUBLIC





FINAL REPORT

Review of AusNet's electricity maximum demand forecasting methodology

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AusNet Services
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CANBERRA

Centre for International Economics
Ground Floor, 11 Lancaster Place
Majura Park

Canberra ACT 2609
GPO Box 2203
Canberra ACT Australia 2601

Telephone +61 2 6245 7800
Facsimile +61 2 6245 7888
Email cie@TheCIE.com.au
Website www.TheCIE.com.au

SYDNEY

Centre for International Economics
Level 7, 8 Spring Street
Sydney NSW 2000

Telephone +61 2 9250 0800
Email ciesyd@TheCIE.com.au
Website www.TheCIE.com.au

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Executive summary

The CIE has been asked by AusNet to review their electricity maximum demand forecast methodology.

The review has considered:

- the overall structure of the methodology, including:
 - specification of the forecasting model
 - the appropriateness of the key drivers included in the model
 - the steps in implementing demand forecasts
 - the model logic and whether forecasts are likely to be accurate and unbiased
- the input data, including:
 - the electricity demand data used
 - the demand drive data used, including considering whether the most recent and consistent inputs have been used
- the spatial disaggregation of the model and mapping for demand drivers to spatial localities
- the approach used to account for variability in weather and other demand drivers (including those which are unobserved)
- the model logic and whether forecasts are likely to be accurate and unbiased
- the overall transparency and replicability of AusNet's forecasting methodology.

Note the review has focused on the methodology as opposed to the implementation of the methodology, which has not been reviewed by the CIE.

AusNet's methodology

AusNet estimates maximum demand in four steps.

- **Step 1:** Collect half hourly customer level residential, commercial and industrial electricity demand data.
- **Step 2:** Collect data on the drivers of electricity demand.
- **Step 3:** Estimate the relationship between maximum demand per residential customer and temperature (cooling degree days) for a given area.

This relationship is used to estimate the starting point for PoE10 and PoE50 forecasts, by applying the estimated scaling factor to observed maximum residential demand for the previous summer. Note that no temperature relationship is estimated for commercial or industrial demand.

- **Step 4:** Forecast maximum demand. This step combines unitised demand estimated in step 3 together with projected customer numbers.

AusNet's approach deviates from the standard top-down models to estimate maximum demand, which is enabled by the availability of customer level data. Changes in demand over time are primarily driven by changes in the number of customers.

Findings

We believe the methodology proposed by AusNet is a reasonable approach to forecasting maximum electricity demand.

The detailed findings of the review are summarised in table 1.

1 Summary of key findings

Number	Item	Discussion	Materiality
1	Demand drivers	Electricity prices are not incorporated into demand forecasts. (AEMO incorporate this indirectly, by reconciling connection point forecasts to network wide forecasts which account for these factors).	AusNet's approach would broadly be expected to have overstated demand from 2000 through to 2019, and over the forecast horizon is likely to understate demand slightly (assuming a negative elasticity) based on AEMO price forecasts.
2	Demand drivers	Economic growth is not incorporated into demand forecasts (AEMO incorporate this indirectly, by reconciling connection point forecasts to network wide forecasts which account for these factors).	Small impact as: <ul style="list-style-type: none"> ▪ the impact of economic growth will largely be accounted for by population and dwelling growth, and ▪ economic activity is difficult to forecast at the feeder or terminal station level.
3	Demand drivers	The methodology does not include adjustments for solar PV, batteries or other technological changes.	Small impacts as: <ul style="list-style-type: none"> ▪ solar PV generally has a small impact on demand during peak periods, which occur later in the day ▪ the other technologies are not expected to be prominent over the regulatory forecast horizon.
4	Estimation of relationship with demand drivers	CDD is the only weather variable used to estimate the relationship between temperature and demand.	This is a standard measure of energy demand and is likely to account for a large amount of variation in demand, however including additional variables may improve performance of the model. This may include other temperature measures or calendar effects.
6	Estimation of relationship with demand drivers	Around 30 data points are used to measure the temperature relationship for a given year. This may result in the model overfitting the data and outliers having a proportionally larger impact on estimated results.	The impact is likely small, however using a greater number of observations would provide greater certainty around the validity of the model parameters.

Number	Item	Discussion	Materiality
7	Estimation of relationship with demand drivers	The model is estimated for one summer. This may result in changes from year-to-year in this relationship.	The impact is likely small, however if it is a particularly hot or mild summer, the parameters may not be representative of the relationship with CDD and maximum demand. The relationship may change from year-to-year, because of the small set of data used.
8	Estimation of forecast starting point	The scaling factor used to estimate the starting point for the previous summer only reflects the relationship between thermal loads and maximum demand assuming representative non-thermal other factors. These idiosyncratic factors which have been filtered out will not be reflected in scaling factor which is used to determine the starting point of PoE estimates.	The starting point is likely to be sensitive to the data cleaning or curation process. This will affect the level of the starting point for forecasts.

Source: CIE.

2 *Scope of the review*

The CIE has been asked by AusNet to review their electricity maximum demand forecasts.

The review has considered:

- the overall structure of the methodology. This includes consideration of the specification of forecasting models (i.e. the variables included and how they enter the model) as well as the steps in implementing demand forecasts
- the input data, which includes the electricity demand data and the input demand drivers which are used to explain variation in demand over time
- the spatial disaggregation of the model. Forecasts of demand at the connection point level will often rely upon demand drivers forecast at the state or LGA level; how these forecasts are attributed to connection points can have an impact on the validity of the forecasts
- simulation of weather and residuals. Observed demand reflects, underlying demand drivers (e.g. prices and population), weather outcomes and a residual. To forecast maximum demand, the weather process and residuals should be accounted for in the methodology
- the overall presentation and clarity of AusNet's forecasting methodology documentation.

Coverage of review

We have been provided with the following documents for review.

- Demand Forecasting Methodology – Electricity Distribution Network, issue number 2.0, 13 September 2019.
- “180702 Demand forecasting Methodology.pptx”
- “180703 Demand Forecast Algorithm Explanation.docx”
- “181108 Overview of Demand Forecasts for CustForum – FINAL.pptx”
- “181116 AusNet Services_Distribution Annual Planning Report 2018_2022_Final kl sect4.1.docx”
- “190213 Winter Demand Forecasting.pptx”

This review is primarily based on the demand forecasting methodology document, as of 13 September 2019, as well as personal correspondence and consultations with AusNet.

Note we have not been provided with forecast spreadsheets or code and hence can only verify our understanding of the methodology, rather than that this is faithfully implemented in the model.

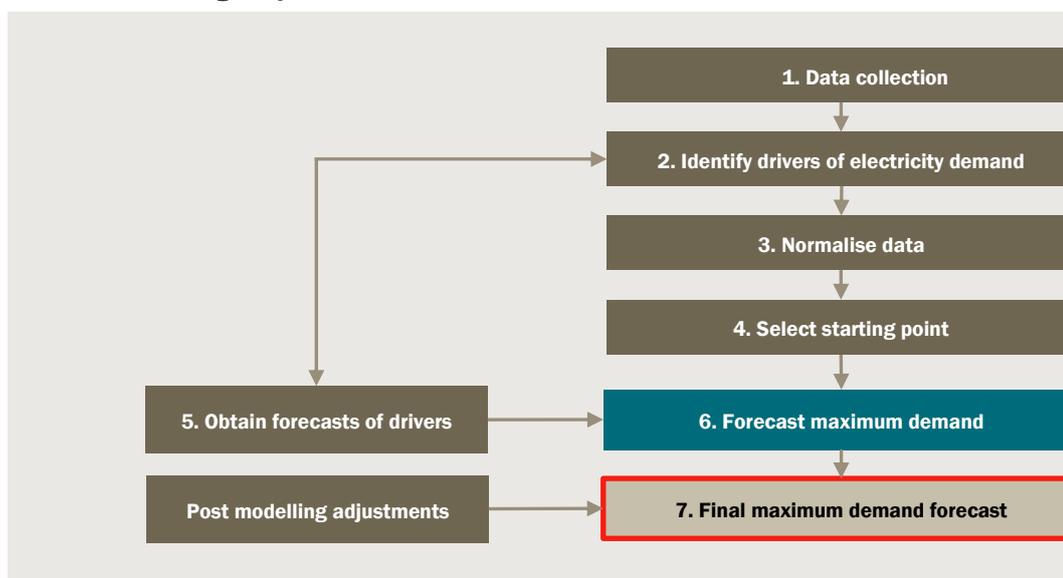
In the review we focus on maximum demand estimates for summer. We understand the same approach is used to measure winter maximum demand, however using HDD instead of CDD to measure the temperature relationship.

Overview of typical maximum demand forecast

The structure of a typical demand forecasting process is outlined in chart 2.1 and consists of:¹

- 1 Data collection, where the relevant electricity, weather and demand driver information is collected and mapped to substations or connection points
- 2 Identify relevant drivers of electricity demand to be included in the model
- 3 Normalise data by estimating relationships with demand drivers, which allows consideration of demand under normalised weather conditions
- 4 Select the starting point for the forecast
- 5 Obtain forecasts of drivers
- 6 Forecast maximum demand from the chosen starting point
- 7 Produce final forecasts including post modelling adjustments.

2.1 Forecasting steps



Data source: CIE based on ACIL Allen.

¹ Based on ACIL Allen Consulting 2013, "Connection Point Forecasting: A nationally consistent methodology for forecasting maximum electricity demand", prepared for AEMO.

Principles of forecasting

Forecasting is an inherently imprecise science. In arriving at demand forecasts for a regulatory determination:

- it is important that forecasts are unbiased. That is, projections do not systematically understate or overstate demand, and
- it is important that forecasts are as accurate as is possible. The less accurate the forecast the greater the risks to the regulated business.

Forecasts can be inaccurate but unbiased if over a sufficiently long period of time the forecast error is zero or in expectation the forecast error is zero. This would be the case for climatic conditions for example which are inherently uncertain.

There are many possible areas where forecast errors can arise. They have been detailed in technical terms by Hendry and Clements 2001 (shown in table 2.2). In plain English, the main areas of forecast error in electricity forecasting are likely to be:

- uncertainty around drivers of peak demand, such as
 - climatic conditions
 - population
- uncertainty around the impact that past drivers of electricity demand will have in the future, such as:
 - weather impacts remaining similar to those experienced in the past
 - trends in demand uptake rates remaining similar to those experienced in the past;
 - the ratio of commercial demand to residential demand remaining similar to those of the past
- impacts of additional policies or factors, such the increased uptake for rooftop solar PV.

2.2 Forecast error taxonomy

1 Shifts in the coefficients of stochastic terms	2 Shifts in the coefficients of stochastic terms
3 Misspecification of deterministic trends	4 Misspecification of stochastic terms
5 Misestimation of the coefficients of deterministic terms	6 Misestimation of the coefficients of stochastic terms
7 Mismeasurement of the data	8 Changes in the variances of the errors
9 Errors cumulating over the forecast horizon	

Source: Hendry, D. and M. Clements (2001), "Economic forecasting: some lessons from recent research", *Economic modelling*, vol. 20(2), (March, pp. 301–29).

In the remainder of this document we set out and review Ausnet's maximum demand forecasting methodology.

For the purpose of this review, we have drawn on AEMO's connection point and demand forecasting methodologies which are documented in:

- AEMO 2019, "Electricity demand forecasting Methodology Information Paper"
- AEMO 2016, "AEMO Connection Point Forecasting Methodology".

3 Overview of the AusNet methodology

AusNet estimates maximum demand in four steps.

- **Step 1:** Collect customer level residential, commercial and industrial electricity demand data. This is half hourly data on demand for individual customers.
- **Step 2:** Collect data on the drivers of electricity demand, including:
 - weather data, from which cooling degree days (CDD) is calculated
 - residential, commercial and industrial customer numbers, both actual and projections
- **Step 3:** Estimate the relationship between residential demand and the above demand drivers. This consists of estimating a scaling factor of the ratio of PoE10 and PoE50 respectively to maximum demand per customer, for each half hour of the day.

$$\text{Scaling factor estimate} = \frac{\widehat{PoE10}}{\widehat{MD}}$$

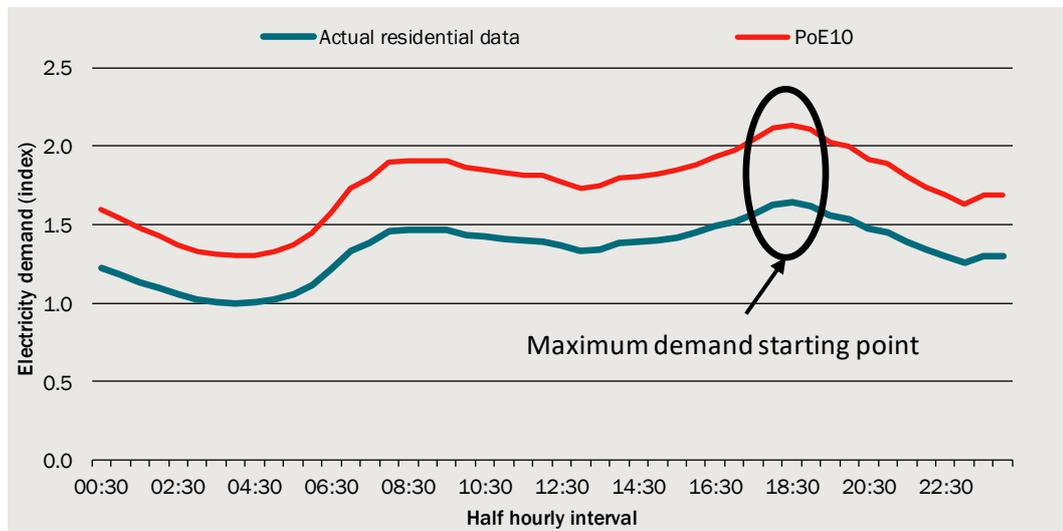
$\frac{\widehat{PoE10}}{\widehat{MD}}$ is estimated as a function of CDD (this is discussed in further detail in chapter 5). The PoE10 estimate of the scaling factor inputs the CDD consistent with PoE10 demand. This is applied to the actual residential demand for the maximum demand day in summer 2017/18, to get the starting point for PoE10 (or PoE50) unitised maximum demand forecast (or maximum demand per customer). The starting point is the maximum demand across the day (chart 3.1).

For example, suppose maximum demand occurred on 16 February, and this was a 30 degree day. Suppose the peak demand per residential customer on this day was 1 kW at 5.30 to 6pm. If a PoE 10 day had a temperature of 38 degrees, then the 1kW would be adjusted upwards by the estimated impact of a higher temperature. This would then give the starting point for the forecasts.

Note that no temperature relationship is estimated for commercial or industrial demand, so there is no PoE10 (or PoE50) estimate for either of these.

A relationship is also estimated between dwelling age and demand, to reflect changes in the energy consumption depending on the composition and age of the housing stock.

3.1 Actual data and PoE10 estimate



Data source: CIE.

- Step 4:** Forecasting maximum demand. This step combines unitised demand estimated in step 3 together with projected customer numbers. It multiplies the maximum demand per customer by projected customer numbers to forecast maximum demand for each customer type. These profiles are added together to estimate maximum demand. The customer types allow for the changing composition and average age of the housing stock. Further adjustments are made to allow for losses and unmetered customers which are not captured in customer level demand. This process is repeated separately to generate estimates at the feeder, substation and terminal station level.

This approach does not make any allowance for solar PV (AusNet has indicated that peaks generally occur in the evening when there is no solar PV supply) or changes in energy efficiency (beyond changes in the housing stock). Given the structure of the forecasts, these adjustments could be incorporated into future iterations of the model. Adjustments for industrial loads and load transfers are made by planners after maximum demand forecasting.

- AusNet's approach deviates from the standard top-down models to estimate maximum demand, which is enabled by the availability of customer level data.**
- Changes in demand over time are primarily driven by changes in the number of customers. This greatly simplifies the estimation process, however, is likely to understate maximum demand where electricity prices are falling and economic growth is increasing, or vice versa.**

4 *Electricity demand data*

The AusNet methodology uses half hourly interval data for residential, commercial and industrial customers and is collected at the customer level. Residential, commercial and industrial data is collected from:

- Customer meter data from AMI and non-AMI meters. This measures demand at the customer level.
- Network operational data which measures demand at the feeder level.² For some commercial and industrial customers, individual customers can be identified using network operational data points.

The AusNet customer level data covers almost the entire network (only around 2 000 customers do not have meters which capture half-hourly customer level data)³. This data is only available for the past few years. For each customer, the following customer attributes are available:

- customer classification (residential, commercial or industrial)
- the feeder or zone substation supplying the customer, and
- whether the customer has rooftop solar PV installed.

Historically customer level data has not been widely available; and as a result, best practice approaches have previously focused on forecasting demand at the connection point level. This richer data set enables the implementation of alternative forecasting methodologies.

Measuring demand at the customer level allows for greater disaggregation of demand into residential, commercial and industrial, and sub-groups within these categories, and allows for demand to be forecast separately for each group. This may result in better forecasting outcomes, as:

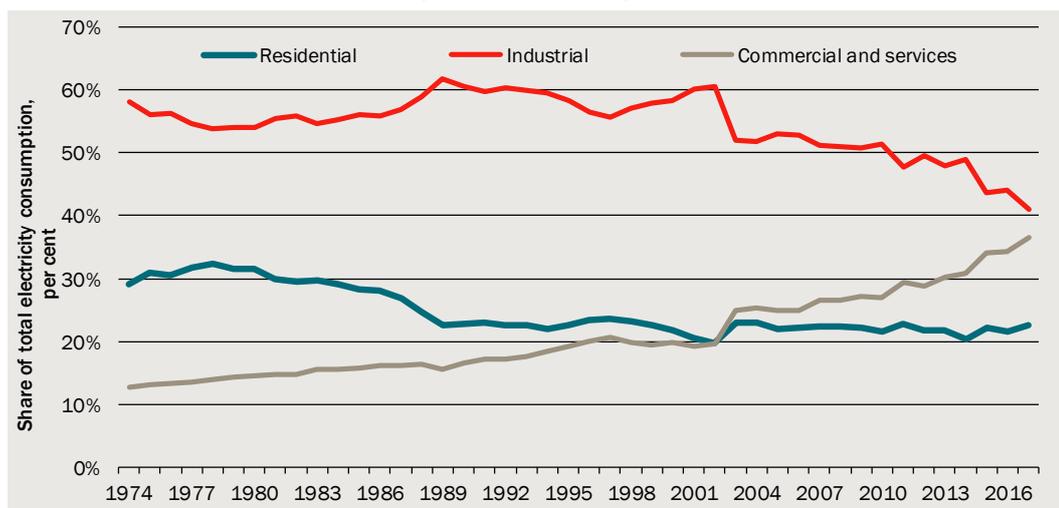
- different relationships between demand and demand drivers can be estimated – residential demand may not have the same relationship with temperature as commercial and industrial demand
- there may be significant divergences in the growth of the number of different customers and energy use per customer. Over the past 30 years the electricity consumption share of industrial sectors has been decreasing, while commercial and services has been increasing. This likely reflects changes in the number of customers in each of these sectors along with relative changes in energy consumption patterns (chart 4.1). The AusNet data allows for the change in the number of customers by each category to be accounted for in forecasts

² Network data is also referred to as OSIPi and SCADA data in AusNet documentation.

³ Workshop with AusNet, 16 October 2019.

- changes in electricity use for new versus existing customers can be easily accounted for
- different modelling specifications can be used for different customer types
- it may be easier to diagnose modelling irregularities, and
- allows demand to be formulated at any level in the network hierarchy.

4.1 Share of Victorian electricity consumption by sector



Note: Commercial and services includes ANZSIC divisions F, G, H, J, K, L, M, N, O, P, Q, R and S. Industrial includes ANSIC divisions A, B, C, D, E and I.

Data source: Australian Energy Updated 2018, Department of Environment and Energy, CIE.

Customer level and feeder level data can be aggregated up to terminal station level, by summing together the relevant components. There are likely to be differences between meter data and terminal station data due to a range of factors including system losses, unmetered supply and HV customers. These differences are also likely to vary across time (i.e. across different times or the day and between weekdays and the weekends). These differences can be material — on average they are around:

- 16 per cent of demand at the feeder level
- 10 per cent of demand at the zone substation level

To account for this difference and map customer level demand to the terminal station level, the AusNet methodology makes an adjustment for the difference between customer and network operations data during peak periods. There are also some known differences due to large customers, which are assumed to not be temperature sensitive, however these are left out the analysis to avoid complexity.

A number of adjustments are also made at the terminal station level to account for; planned and unplanned feeder reconfigurations (corrections are made to remove step changes in demand due to reconfiguration of the network); and large embedded generators (generation exports are added back to terminal station demand data).

- **Residential, commercial and industrial customer level demand, which has previously not being available, is likely to improve the quality of forecasts, by**

allowing different forecasting approaches to be implemented for different customer types.

- AusNet customer level data has almost complete coverage of the network.
- The difference between customer level data and feeder and zone substation data (due to unmetered demand, and losses) is accounted for by the AusNet methodology.

5 Demand drivers

The AusNet Methodology includes the following electricity demand drivers.

- Dwelling projections mapped to substations, which are used to project the number of residential customers by substation in year.
- Commercial and industrial customers are assumed to grow in proportion with residential customers. Adjustments are made based on detailed analysis at the feeder level to account for locational variability related to the development of embedded networks. At this level, adjustments are made based on observed trends, where it is deemed appropriate.
- Temperature – dry bulb half hourly temperature data is used to calculate CDD (dry ambient temperatures is the standard data used to forecast demand). This is then used to determine the PoE levels for maximum demand. Further detail on how this relationship is estimated is provided in chapter 5.
- Dwelling build year, which is used along with the estimated demand per dwelling to allow demand to respond to the changing average age of the building stock. In general customers in newer dwellings tend to use less electricity. This reflects building standard changes, as well as changes in the type of dwellings (such as the increase in higher-density dwellings). Further information on how this relationship is estimated is provided in chapter 5.

No other drivers are directly included in the model.

Drivers typically included in demand forecasts include:⁴

- Economic growth. AusNet has identified that population growth and the increase in dwellings will implicitly reflect the impact of economic growth related to population growth. This overlooks other components of economic growth, such as productivity, which may affect electricity demand. When economic growth per capita is positive, AusNet's approach will underestimate demand. This impact is likely to be small and is not likely to impact the geographical distribution of demand growth given the limited economic growth forecasts available. Reliable forecasts for Gross State Product (GSP) are only available at the state level so that using these in a forecast model requires assuming economic growth is even across the regions of Victoria, which is unlikely to be the case. Because regional variation is likely to be important, focusing on population and dwellings, which can more effectively be forecast at the local level, may reduce forecasting errors compared to also incorporating economic growth.

⁴ ACIL Allen Consulting 2013, "Connection Point Forecasting: A nationally consistent methodology for forecasting maximum electricity demand", prepared for AEMO.

The AEMO connection point forecast methodology does not directly include economic growth in PoE estimates, but rather reconciles connection point forecasts to operational demand forecasts which include population growth, economic and demographic outlook, electricity prices, energy efficiency and performance, and small-scale embedded technologies.⁵

- Electricity prices. Models of demand typically include an electricity price variable, consistent with economic theory that lower prices lead to higher consumption and higher prices lead to lower consumption. AEMO's residential annual consumption forecasts use a price elasticity of -0.1 for heating and cooling load, which means a 10 per cent increase in prices results in a 1 per cent decrease in demand.⁶ Higher elasticities have been estimated in the economic demand literature and used by AEMO in the past; but there is uncertainty around the appropriate elasticity to use and whether they are significantly different from zero during peak periods.

In private correspondence, AusNet has provided evidence that elasticities during peak periods were close to zero in a trial of customer rebates. While we expect that the result could be different if the price change was an increase in price as opposed to a rebate, we recognise the elasticity during peak periods may differ from average demand elasticities estimated and used by AEMO. This may occur as the peak to average ratio of demand may change as prices change. The AEMO connection point forecast methodology does not directly include electricity prices in PoE estimates, but rather reconciles these forecasts to operational demand forecasts which do include electricity prices.⁷ This implicitly assumes that the peak of average ratio remains constant.

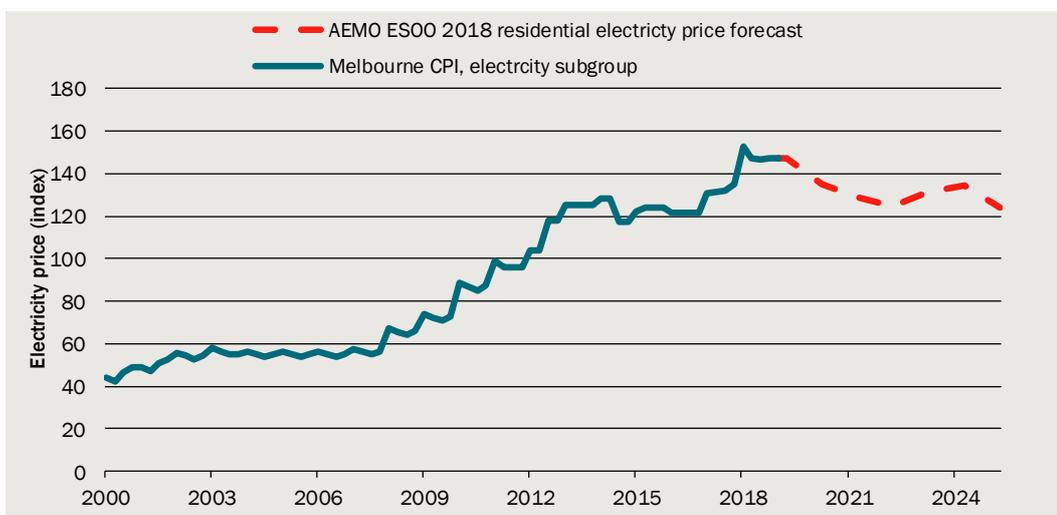
By not including prices as a demand driver (and assuming a negative elasticities significantly different from zero) AusNet's approach would broadly be expected to have overstated demand from 2000 through to 2019, and over the forecast horizon is likely to understate demand based on AEMO price forecasts (chart 5.1). This approach could be tested by estimating PoE, based on the forecast model, for previous years; if prices are an important driver, we would expect forecast PoE to lie above actual maximums. We understand that this is not possible due to customer level data limitations for earlier years but could be revisited in future years.

5 AEMO 2016, "AEMO Connection Point Forecasting Methodology", available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/TCPF/2016/AEMO-Transmission-Connection-Point-Forecasting-Methodology.pdf

6 AEMO 2019, "Electricity demand forecasting Methodology Information Paper", p. 25

7 AEMO 2016, "AEMO Connection Point Forecasting Methodology", available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/TCPF/2016/AEMO-Transmission-Connection-Point-Forecasting-Methodology.pdf

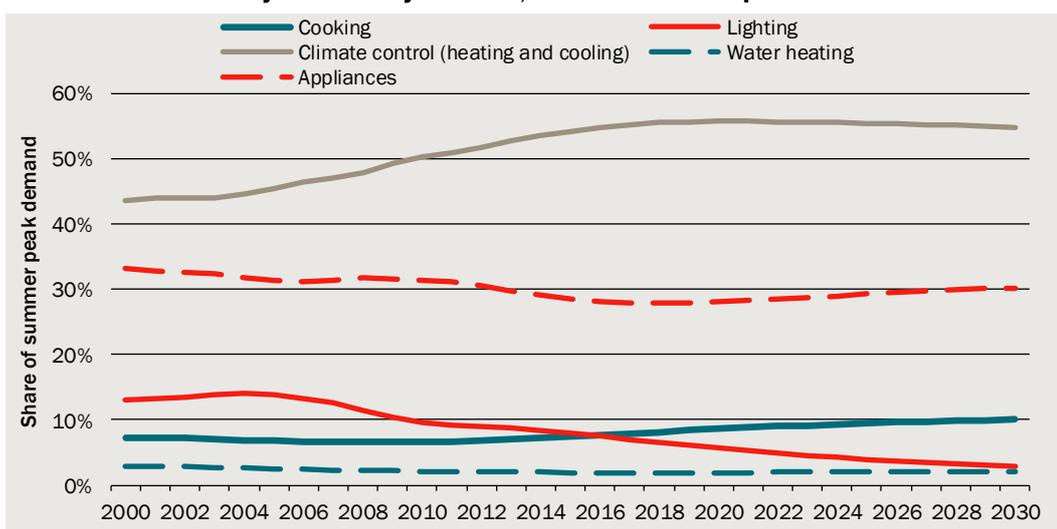
5.1 Electricity price index



Data source: AEMO ESOO 2018, ABS 6401.0 Consumer price Index, Australia March 2019, CIE.

- Growth in the number of air conditioning systems and heating systems. This may have an impact on demand forecasts, but potentially more limited than historically as peak summer electricity demand for heating and cooling is expected to flatten out (chart 5.2). The growth in the stock of air conditioning systems is expected to slow due to market saturation – in Victoria 59 per cent of dwellings have one air conditioner, 15 per cent have two or more air conditioners and 26 per cent have no air conditioners.⁸ The impact of changes in air-conditioning may be captured to some extent by the adjustment for the age of the dwelling stock.

5.2 Peak electricity demand by end use, Victoria summer peak



Data source: Energy Consult (2015) prepared for Department of Industry and Science, CIE.

- Calendar effects, such as seasonality, public holidays, day of week and month and time of summer. Maximum demand tends to have strong dependency with these variables. Given AusNet’s methodology only forecasts demand for the maximum

⁸ ABS 2012, “4602.2 - Household Water and Energy Use, Victoria, October 2011”

demand day, calendar effects will be incorporated into the starting point of the forecasts (i.e. summer 2017/18 maximum demand).

- Solar PV uptake and other technologies, such as batteries and electric vehicles. By construction, the demand data used reflects the current penetration rate for these technologies such that forecasts implicitly assume penetration rates remain constant.

AusNet has indicated that including solar PV is not relevant as the distribution area generally has evening peaks. AusNet has provided analysis of customer data which shows the impact of solar PV is very small during peak periods (median impact on feeder maximum demand is around 1.2 per cent), which is not material in terms of maximum demand or for network planning.⁹

Into the future, solar PV will become more relevant with the uptake of batteries. Similarly, electric vehicles may have a large impact on future demand and can be incorporated into the methodology. AusNet expects the impact of these technologies to be negligible over the regulatory forecast period.

The methodology removes the impact of larger embedded generation, such as windfarms, from network data to identify underlying network demand.

Energy efficiency has not been adjusted for as analysis by AusNet of energy consumption of the same dwellings through time showed no reduction in the amount of electricity consumed at peak demand times.

- **In the absence of spatial economic activity projects, it is reasonable to assume that commercial and industrial demand will be driven by population growth.**
- **Economic growth is not incorporated into demand forecasts (AEMO incorporate this indirectly, by reconciling connection point forecasts to network wide forecasts which account for these factors). This approach is reasonable as a large part of the impact of economic growth will already be accounted for by population and dwelling growth. Also, economic activity is difficult to forecast at the feeder or terminal station level.**
- **Electricity prices are not incorporated into demand forecasts. Not including prices as a demand driver (and assuming a negative elasticities significantly different from zero) AusNet's approach would broadly be expected to have overstated demand from 2000 through to 2019, and over the forecast horizon is likely to understate demand based on AEMO price forecasts.**
- **The methodology does not include adjustments for solar PV, batteries, electric cars or other technological changes. AusNet analysis indicates this is not likely to have a material impact on forecasts over the regulatory period.**

⁹ This analysis consisted of data for 28 customers with solar PV across a range of consumption levels, with different demographics and roof orientations to provide a representative sample.

Data and sources

The sources of demand drivers are summarised in table 5.3.

5.3 Demand driver data sources

Data	Sources	CIE comment
Dwelling projections	<ul style="list-style-type: none"> ▪ Victorian Government dwelling projections (Victoria in the Future 2016) VIFSA areas ▪ ABS, 3101.0 Australian Demographic statistics 	<p>VIF is the standard data sources for spatially disaggregated dwelling projections.</p> <p>Recent VIF dwelling/population growth has been lower than ABS actuals, which AusNet adjusts for in their forecasts.</p>
Dry bulb half hourly temperature data	Bureau of Meteorology	This is the standard data source for temperature data.
Dwelling build year	AusNet new customer connections	The age of dwellings is inferred from the when a connection was established.

Source: CIE.

- **AusNet has used standard data sources for dwelling projections and temperature.**

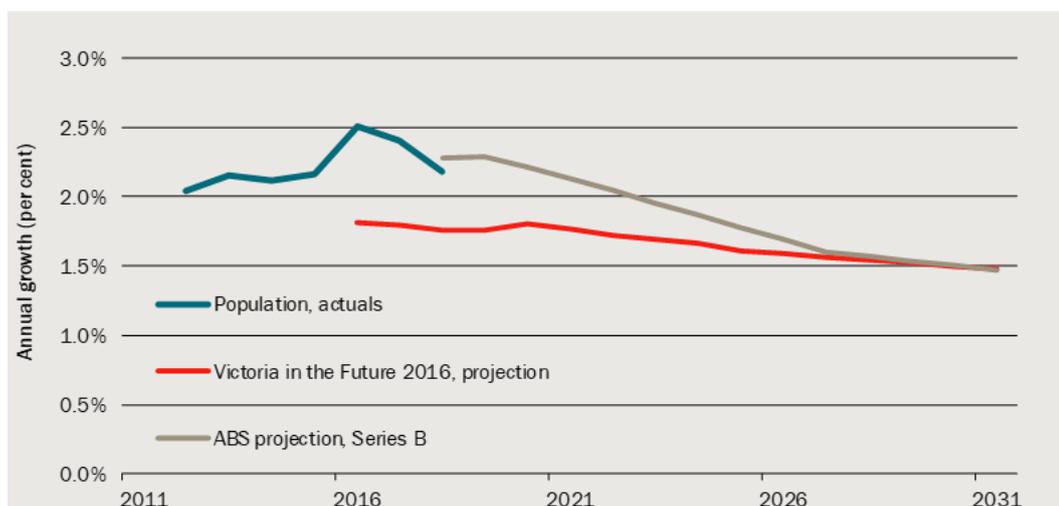
Dwelling projection data

VIF dwelling and population projections are the official state government projection of population and households across Victoria. This was last updated in 2016¹⁰ and has under-estimated population growth and dwelling growth in recent years (chart 5.4). VIFSA data is mapped to the relevant terminal station area.

To account for this AusNet's dwelling forecasts are based on the recent rate of change in state level population growth, disaggregating this to VIFSA areas based on growth patterns in the VIF. Future projected growth is then based on the projected growth in the VIF, rebased to actual dwelling numbers inferred from ABS data. The approach is prudent given the recent under estimation of population and dwellings in the VIF.

¹⁰ The updated VIF 2019 was released in July 2019, which accounts for recent population and dwelling growth. Using the new population projections will remove the need to project growth based on recent population and dwelling growth.

5.4 Actual population growth compared to population projections



Data source: Victoria in the future 2016, ABS 3222.0 - Population Projections, Australia, 2017 (base) - 2066, ABS 3101.0 - Australian Demographic Statistics, Jun 2018, CIE.

- **Standard data sources are used for dwelling projections, with prudent adjustments to VIF which has forecast lower growth than actuals over the past few years.**

Dry bulb half hourly temperature data

AusNet uses standard dry bulb temperature data, which is consistent with the data used in AEMO's forecasts.¹¹

From this CDD and HDD are calculated as follows:

$$CDD = \max(0, \text{Average daily temp} - CT_{sum})$$

$$HDD = \max(0, CT_{win} - \text{Average daily temp})$$

Where T is the temperature for a given half hour and $CT_{sum} = 21^{\circ}\text{C}$ is the temperature cut-off for summer and $CT_{win} = 18^{\circ}\text{C}$. This is the same as the calculation used by AEMO¹², although AusNet's summer and winter critical temperatures are greater than that those used for Victoria by AEMO (18°C and 16.5°C respectively).¹³ These small differences will not have a material impact on results. Temperature data is collected for a 10-year period.

For AusNet's 3 regions they use data from the following weather stations:

- Central: Scoresby Weather station (86104), back-up Moorabbin weather station (86077)
- East: East Sale (85072), back-up Bairnsdale Airport Weather station (85279)
- North: Wangaratta Weather station (82138), back-up Benalla (82170)

¹¹ AEMO 2019, "Electricity demand forecasting Methodology Information Paper", p. 35-36.

¹² Note CDD is incorrectly defined in AEMO 2019, "Electricity demand forecasting Methodology Information Paper", p. 44.

¹³ AEMO 2019, "Electricity demand forecasting Methodology Information Paper", p. 44.

Specific weather stations are mapped to substations based on proximity.

- **AusNet use standard data sources and formula to calculate CDD. The difference in temperature thresholds compared to AEMO are unlikely affect results.**

6 Estimation of relationship with demand drivers

Estimating the relationship between unitised demand and CDD

The impact of CDD on demand is only estimated for residential customers — other customer types are assumed to not be temperature sensitive.¹⁴ The estimation process consists of estimating a scaling factor of the ratio of PoE10 and PoE50 respectively to maximum demand per customer, for the day's peak demand:

$$\text{Scaling factor estimate} = \frac{\widehat{PoE10}}{\widehat{MD}}$$

Where \widehat{MD} and $\widehat{PoE10}$ are functions of CDD; \widehat{MD} uses the CDD value for the maximum demand day in 2017/18 and $\widehat{PoE10}$ uses the PoE10 CDD from the past 10 years of data. The function used to estimate these is:

$$\begin{aligned} \text{Maximum daily demand per customer} &= F(CDD_t) \\ &= f(CDD_t) + f(F(CDD_{t-1}) - f(CDD_{t-1})) + adj \end{aligned}$$

Where $f(x)$ is a polynomial function of x , *Avg dem per customer* is also referred to as unitised demand and *adj* is an additional adjustment which is included to account for the remaining residual for the top 5 demands. The CIE has found in previous work a similar pattern where residuals differ from average at very high levels of demand and we agree with an additional adjustment if this leads to more sensible results.

The model is estimated in two steps:

- 1 Estimate the relationship for the previous period $F(CDD_{t-1}) = f(CDD_{t-1})$
- 2 Include the residual of this estimate in the final equation $F(CDD_t)$

This effectively includes a lagged variable of *CDD* in the final specification. The standard approach would be to estimate the equation in one step by including a lag of *CDD* (and would ultimately give the same result). In this case the $F(CDD_t)$ would be:

$$F(CDD_t) = f(CDD_t) + f(CDD_{t-1}) + adj$$

The function is estimated for the maximum of a given day, such that $F(CDD_t)$ is the maximum unitised demand on day t . The relationship is estimated using data from the most recent summer period data for weekdays¹⁵ with a maximum temperature greater

¹⁴ In this section we focus on discussing the approach used to measure the summer relationship. The same approach is used to estimate the winter temperature relationship, however using HDD instead of CDD.

¹⁵ Weekend data is also used in some network areas where maximums typically occur on these days.

than 30°C. This leaves around 30 data points, in most cases, to estimate the relationship. This may result in the following issues:

- Few data points are used to estimate the temperature relationship. This may result in the model overfitting the data and outliers having a proportionally larger impact on estimated results.
- The model is estimated for one summer. If it is a particularly hot or mild summer, the parameters may not be representative of the relationship with CDD and maximum demand. This may lead to changes from year-to-year in the forecasts, because of changes in the estimated weather relationships.

The relationships are estimated individually for feeders, zone substations and terminal stations as they have different customer makeups and geographic impacts.

From the estimated unitised demand relationship, the components of the scaling factor are recovered as follows:

Substituting in CDD associated with PoE10, PoE50 and MD gives the following fitted values:

$$\widehat{PoE10} = F(CDD_t^{PoE10}) = f(CDD_t^{PoE10}) + f(F(CDD_{t-1}^{PoE10}) - f(CDD_{t-1}^{PoE10})) + adj$$

$$\widehat{PoE50} = F(CDD_t^{PoE50}) = f(CDD_t^{PoE50}) + f(F(CDD_{t-1}^{PoE50}) - f(CDD_{t-1}^{PoE50})) + adj$$

$$\widehat{MD} = F(CDD_t^{MD}) = f(CDD_t^{MD}) + f(F(CDD_{t-1}^{MD}) - f(CDD_{t-1}^{MD})) + adj$$

Where:

- CDD_t^{PoE10} is the PoE10 (i.e. the 90th percentile) CDD from 11 years of CDD data for summer
- CDD_t^{PoE50} is the PoE50 (i.e. median) CDD from 11 years of CDD data for summer
- CDD_t^{MD} is the CDD from the “curated” maximum demand day in 2017/18 summer. If $CDD_t^{MD} = CDD_t^{PoE10}$, meaning that the summer was a PoE10 event, the scaling factor from MD to PoE10 will be 1. The value of CDD to estimate \widehat{MD} is curated, or chosen, to exclude observations which are affected by non-thermal impacts.¹⁶ The intent of this appears to be to only measure the thermal impact on demand during periods of representative idiosyncratic factors. This means the CDD used to estimate \widehat{MD} may not be from the observed maximum demand day if that maximum was caused primarily by non-thermal factors but will be for a high demand day.

Given that \widehat{MD} , $\widehat{PoE10}$ and $\widehat{PoE50}$ as estimated using this function, the scaling factors adjust to reflect the strength of the 2017/18 summer.

The respective scaling factors are applied to actual residential demand for the maximum demand day in summer 2017/18 for each half hour. CDD and peak day temperatures were reviewed for 2017/18 by AusNet and considered reasonable for scaling as they did not represent a cool year. Based on my understanding this wouldn't matter if 2017/18

¹⁶ This approach sees maximums driven by the following factors being excluded: peaks at night (hot water related), non-thermally driven loads from public events, temporary load transfers, network outages instances where larger customers are included/not included and CPD tariff event days. This process is undertaken at the feeder and substation level.

was a cold or warm summer, as the \widehat{MD} component of the scaling factor would control for this. Earlier years were not used due to incomplete data sets as metering was progressively introduced.

This gives the starting points for PoE10 and PoE50 unitised maximum demand forecast (or maximum demand per customer). The starting point is the maximum half hourly demand across the day (chart 3.1).

Note that no temperature relationship is estimated for commercial or industrial demand, so there is no PoE10 or PoE50 estimate for either of these customer type; as peak demand does not respond to temperature in the AusNet distribution area.¹⁷

- **AusNet uses a novel approach to estimate PoE10 and PoE50 demand levels based on temperature data. The process is relatively simple, which allows for a high level of transparency in presenting forecast results.**
- **Around 30 data points are used to measure the temperature relationship. This may result in the model overfitting the data and outliers having a proportionally larger impact on estimated results.**
- **The model is estimated for one summer. If it is a particularly hot or mild summer, the parameters may not be representative of the relationship with CDD and maximum demand.**
- **The model only measures the relationship between thermal loads and maximum demand. CDD is the only weather variables used to estimate the relationship between temperature and demand. This is a standard measure of energy demand and is likely to account for a large amount of variation in demand, however including additional variables (such as other temperature measures or calendar effects) may improve performance of the model.**
- **The \widehat{MD} term in the scaling factor only reflects the relationship between thermal load and demand. These idiosyncratic factors which have been filtered out will not be reflected in scaling factor which is used to determine the starting point of PoE estimates. The starting point of forecasts will be sensitive to the filtering process.**

Estimating the relationship between unitised demand and dwelling age

A relationship is also estimated between dwelling age and demand, to reflect changes in the energy demand depending on the composition and age of the housing stock. This follows observation that newer dwellings tend to use less electricity due to:

- improvements in insulation and construction techniques
- changes in the average floor space of new dwellings

¹⁷ Demand Forecasting Methodology – Electricity Distribution Network, issue number 2.0, 13 September 2019, p. 16.

- the use of new domestic appliances, including air conditioners, with lower electricity consumption, and
- the change in the composition of new dwellings — over the past 10 years there has been an increase in the share of higher density dwellings in total building approvals which tend to have lower energy consumption.

The relationship between demand and house age is determined using data from the actual half hour maximum demand in summer 2017/18; peak demand by build year is compared across different build years for each substation. This covers dwellings constructed between 2001 and 2016 (later years are not included as recently completed dwellings may not yet be occupied). The trend in average demand by build year is used to forecast average electricity demand at the peak for dwellings built in 2017 and 2018. For future years, average demand by build year is held constant at 2018 levels.

Changes in population average values are achieved through the replacement of buildings over time. No adjustment was made for increasing efficiency for existing dwellings, from behavioural change and new appliances, due to data limitations. Having only one year of data limits analysis of this, data overtime is required to assess whether efficiency for dwellings constructed in a given year is changing.

- **The approach used to measure the change in peak demand by dwelling age is an effective approach to account for the changes in building types, quality and energy efficiency overtime.**
- **Adjustments for electricity consumption for new buildings will likely capture changes in energy efficiency. There may be additional efficiency from behavioural change and the adoption of new appliances by existing dwellings, however this is difficult to quantify.**

Commercial customer load forecast

The number of new commercial customers is forecast proportional to residential customers. Following consultation with AusNet, this approach is sound as:

- new commercial customer loads are developed at the feeder and zone substation level as opposed to an average across the network
- new customers tend to have similar loads to existing commercial customers in a given areas. AusNet reviews this assumption at the zone substation level; where the existing commercial demand is deemed to not be representative, a typical commercial load for new customers for that substation is chosen (this approach is used for around representative demand is used for about 25 per cent of zone substations).

7 Forecasting maximum demand

Select the starting point

The residential unitised demand starting point of is calculated as:

$$PoE10 \text{ starting point} = 2017/18 \text{ Max demand} \times \frac{\widehat{PoE10}}{\widehat{MD}}$$

$$PoE50 \text{ starting point} = 2017/18 \text{ Max demand} \times \frac{\widehat{PoE50}}{\widehat{MD}}$$

This is added to the unitised demand for commercial and industrial customers.

This is known as starting the forecast off the point (taking weather corrected PoE values for the last available year as the starting point). This implicitly assumes that the last year is the best indicator of maximum demand, and information on prior years is discarded. The alternative, of starting the forecast 'off the line', gives weight to prior years. There is sometimes a concern this may force a step change in demand between the last actual year and the first forecast year, however for AusNet's methodology which is largely driven by customer growth this is not relevant.¹⁸

The methodology uses a curation process to select the maximum demand day used to scale demand. This process is undertaken by a subject matter expert at the feeder and zone substation level and considers the maximum temperature, temperature profile, maximum load, load profile shape and calendar effects. This seeks to select a day which contains a representative non-thermal factor which affects demand. This is intended to reduce the variability of the PoE starting point from year to year (if a non-thermal driven peak were used as the maximum demand, this would overstate the PoE10 level as the temperature relationship does not directly account for other factors). Data cleaning can be subjective; there is a risk that the observation chosen could differ from year to year or depending on who undertakes the curation or data cleaning.

The above process implicitly means that the forecast is for a typical demand on a day where the temperature reaches a PoE10 level. This is not quite the same as a PoE10 demand, because the latter accounts for both temperature variation and idiosyncratic variation. If idiosyncratic variation is large, then the PoE10 levels that result from AusNet's approach may be too low. If idiosyncratic variation is small relative to temperature variation then this will be less of an issue. The key test will be if there are more than 10 per cent of actuals above the PoE10 level over a long period. It is not

¹⁸ ACIL Allen Consulting 2013, "Connection Point Forecasting: A nationally consistent methodology for forecasting maximum electricity demand", prepared for AEMO, p. xvii – xviii.

possible to backcast to test historically that there are the right number of actual maxima above the PoE10 level with the forecasting approach.

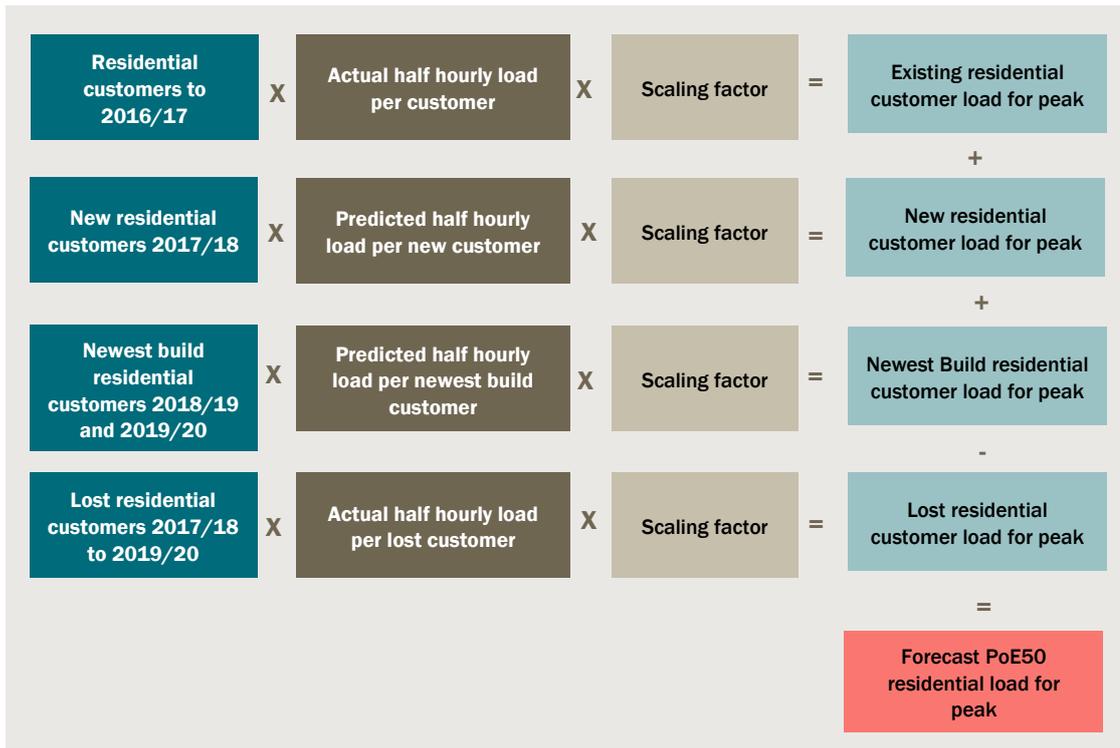
Forecasting maximum demand

Charts 7.1 through 7.4 lay out the AusNet maximum demand forecasting methodology.

Essentially the forecasting methodology multiplies the estimated unitised demand from 2017/18 (i.e. the last summer) for residential, commercial and industrial customers by the respective number of customers, and by the scaling factor to recover PoE10 and PoE50 estimates. Existing, new and lost customers are treated differently, allowing them to have different unitised demand.

Next the sum of the residential, commercial and industrial forecast is taken for the relevant half hour of the day. Adjustments are made to allow for differences between meter and network data, which then give the maximum demand forecast for the year.

7.1 Residential forecasting approach –PoE50, 2019/20 estimate



Source: AusNet, CIE.

In chart 7.1 note:

- “Scaling factor” = $\frac{PoE50}{MD}$
- “New residential customers” are customers connected in the years after 2016, but not in the year preceding the forecast (i.e. for a 2019/20 forecast this is the new customers in 2017/18). These are new dwellings which have reached their full load.
- “Predicted half hourly load per new customer” is the average load per new dwelling which has reach its full load capacity. This is calculated as:

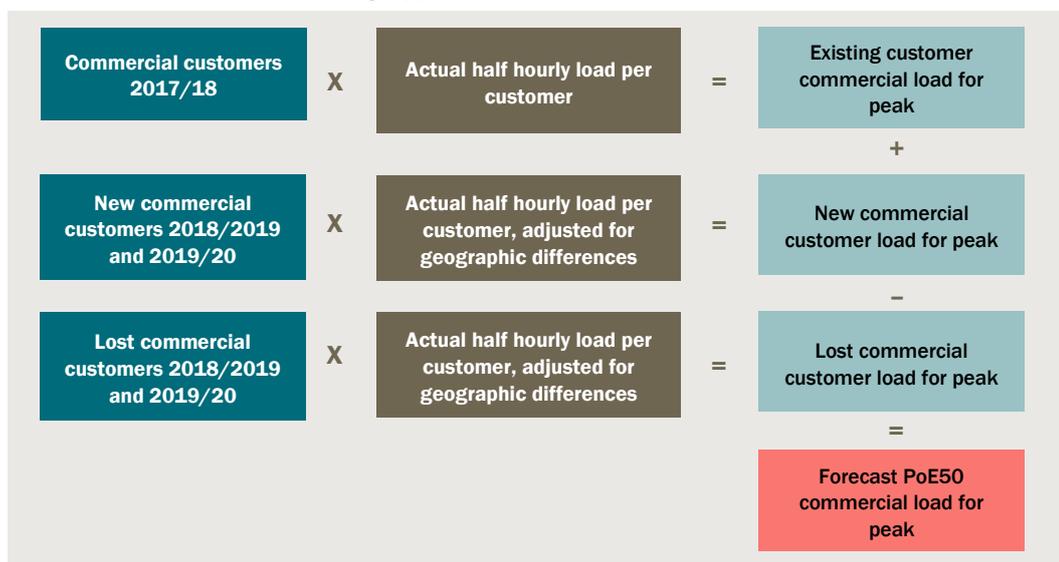
$$\begin{aligned} \text{Predicted half hourly load per new customer} \\ = \text{Actual half hourly load per customer} \times \text{new customer scalar} \end{aligned}$$

- The “new customer scalar” weights the actual average load per customer to be consistent with the load of new customers. How this relationship between build year and electricity load is discussed in chapter 5.
- “Newest build residential customers” are new customers from the preceding year, who’s electricity demand has not ramped up to its full load.
- “Predicted half hourly load per newest build customer” is calculated as:

$$\begin{aligned} \text{Predicted half hourly load per newest buildcustomer} \\ = \text{Predicted half hourly load per new customer} \\ \times \text{newest build scalar} \end{aligned}$$

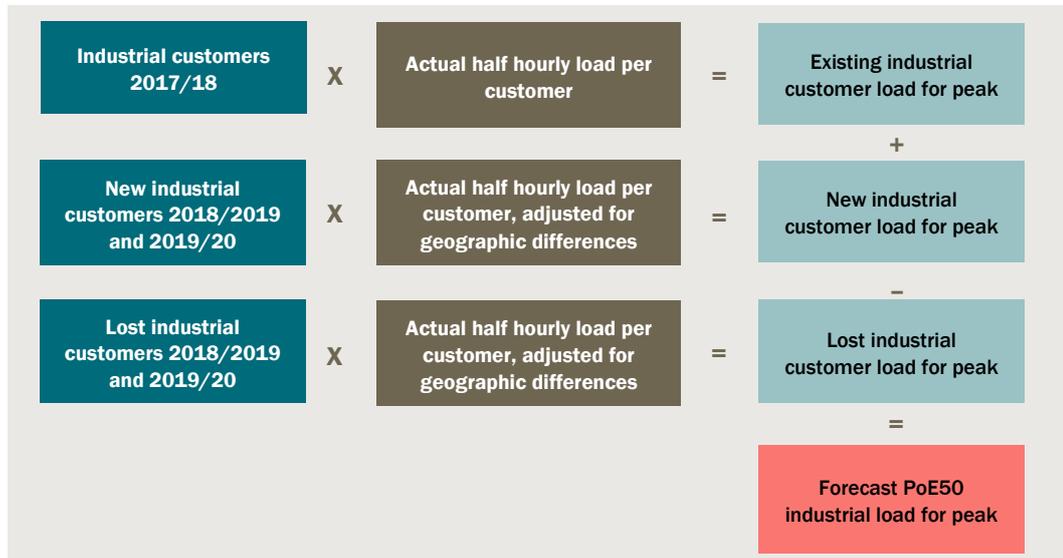
- The approach does not allow for climate change to increase temperatures overtime as temperatures changes are expected to be small over the regulatory forecast horizon.

7.2 Commercial forecasting approach – PoE50, 2019/20 estimate



Source: AusNet, CIE.

7.3 Industrial forecasting approach – PoE50, 2019/20 estimate

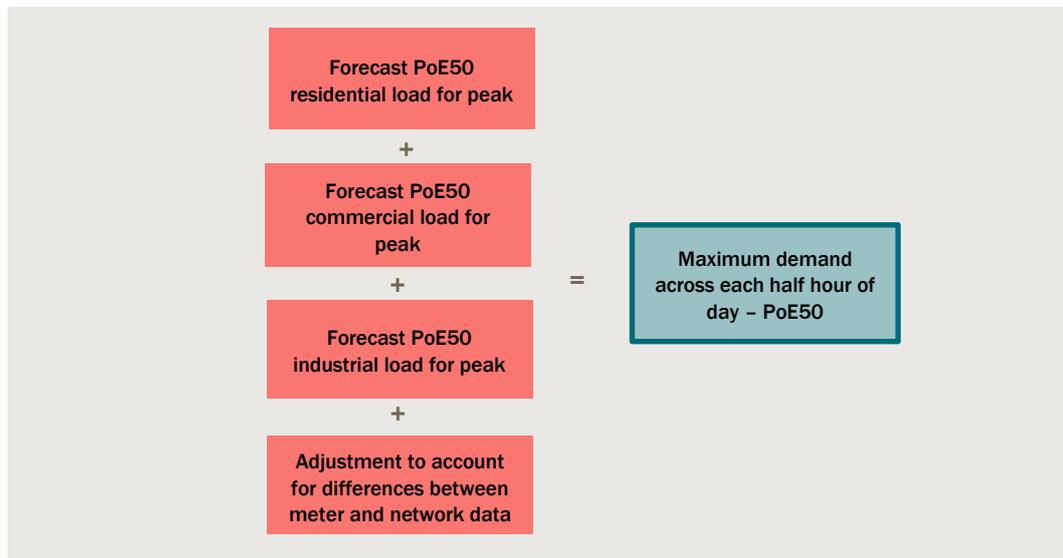


Source: AusNet, CIE.

In charts 7.2 and 7.3 note that unitised demand for new commercial and industrial customers is determined on recent customers joining the network. AusNet has indicated that this approach will underestimate large developments.

Terminal station maximum demand is forecast for each year by taking the maximum across the half hours of the day for the given connection point (chart 7.4).

7.4 Putting it all together – Maximum demand PoE50 estimate, 2019/20



Note: Maximum demand is calculated as the maximum half hour (*h*) total electricity load across the daily demand profile.

Source: AusNet, CIE.

Adjustments are made to final forecasts by planners for load transfers between substations and new large customers (industrial or commercial).

- **Non-thermal factors are allowed for through the curation, or data cleaning process, but some variation is removed. The maximum demand CDD is chosen to reflect what maximum demand would be, given representative non-thermal factors, such that the starting point from which demand is scaled, is not necessarily the actual maximum. The result being:**
 - **the starting point is sensitive to the curation process.**
 - **the methodology does not allow maximums to be driven by non-thermal factors, which may mean maximum demand is underestimated, particularly if non-thermal variation is large.**



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