2016–2020 Price Reset

Appendix C
Demand, energy and customer forecasts

April 2015

Powercor
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Powercor
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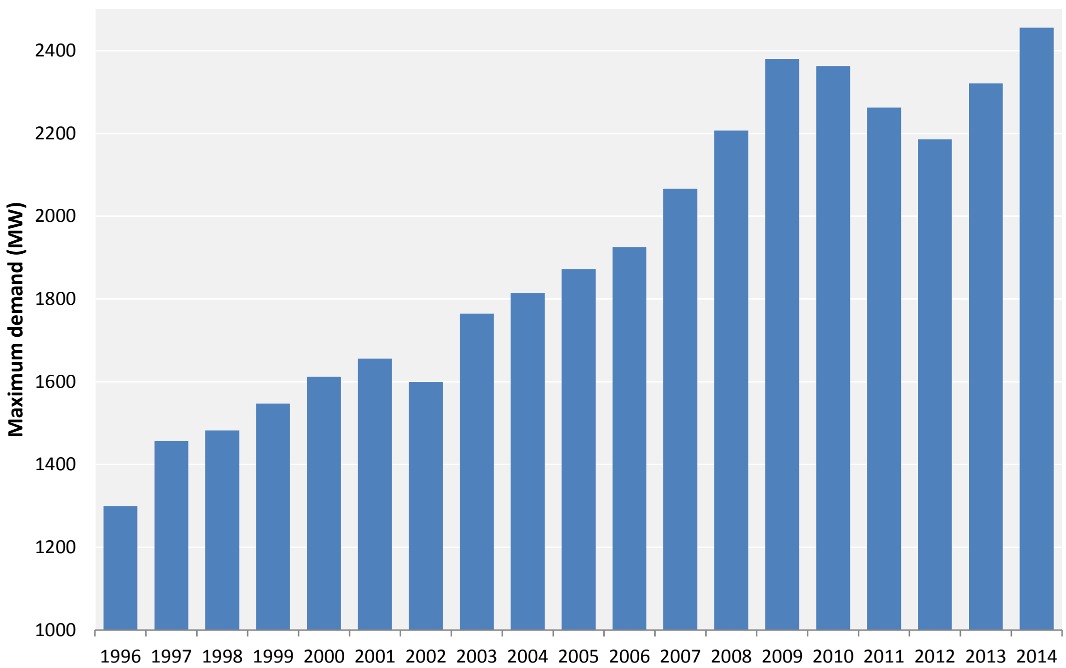
1 Overview

> The highest demand for electricity usually occurs on hot summer days, when temperature sensitive demand, such as air-conditioners and irrigation systems, drive a spike in demand.
>
> When demand is forecast to be greater than the capacity of the network in a particular area, then Powercor must invest in the network or implement demand management solutions to ensure that its network can continue to match the demand required by its customers.
>
> The forecasts indicate that demand is increasing, even though energy usage has been declining. It is demand, however, that drives investment.
>
> Powercor's demand forecasts have been prepared using a robust process that combines its own detailed local knowledge with independent economic analysis.

Powercor experienced its highest ever peak of demand on Tuesday 14 January 2014, during a four day period where temperatures exceeded 41 degrees Celsius each day. The network peak of 2,432MW was reached at 5.00pm, even though this period fell inside the holiday season, when some businesses and industry had not returned to their full electricity usage.

The upward trend in 'raw' demand (i.e. data that is not temperature corrected) is shown in figure 1.1.

Figure 1.1 Increasing 'raw' level of demand



Source: Powercor

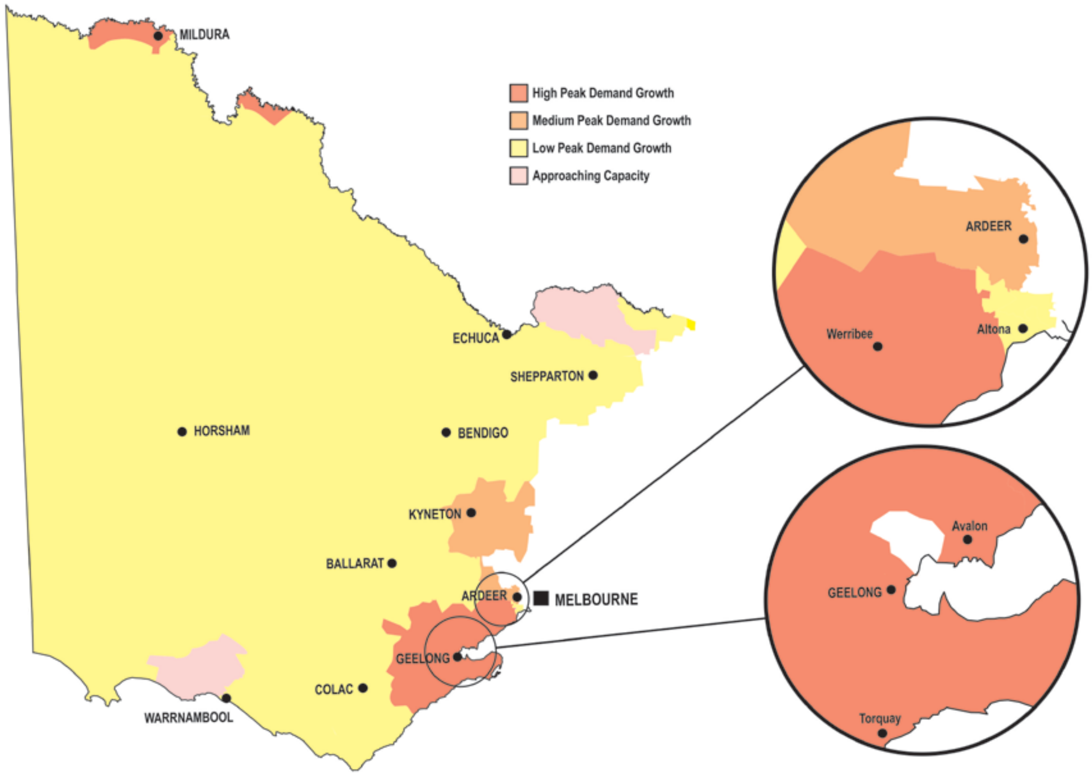
The use of air-conditioners by commercial and residential households was a key driver to the network peak, as the community sought respite from the prolonged heat. Increases in the frequency and duration of heatwaves[1] will be a significant contributor to a new network record peak being recorded in the future.

Over the 2016–2020 regulatory control period, Powercor expects demand to increase in specific areas of its network. In addition to the impact of temperatures, the increase in demand will be driven by:

- population (and customer) growth in the western suburbs of Melbourne and the Greater Geelong region; and
- expansion and additional capacity required in the agricultural and dairy sectors, particularly in the Warrnambool and Murray River regions.

Figure 1.2 provides a map of the areas of higher demand growth in the network together with areas approaching capacity.

Figure 1.2 Powercor peak demand forecasts



Source: Powercor

The methodology and evidence underpinning Powercor's forecasts for demand, energy and customer growth are discussed in more detail below. This document also considers the demand forecasts published by the Australian Energy Market Operator (**AEMO**) at the terminal station level,

[1] Climate Council, *Heatwaves: Hotter, Longer, More Often*, 2014. Available from: http://www.climatecouncil.org.au/uploads/9901f6614a2cac7b2b888f55b4dff9cc.pdf

and it is explained why those forecasts are unable to be reconciled to Powercor's forecasts, and thus why they should not be relied upon.

2 Growth in the distribution area

Powercor's stakeholders have commented on the expected growth in particular regions, and the need for new infrastructure investment to support and enable further growth.

Consistent with Powercor's expectation of population growth in the Geelong and Surf Coast regions, the City of Greater Geelong submitted in response to the Directions and Priorities paper that:[2]

> *Areas to the City's south are also anticipating strong growth such as Waurn Ponds, Wandana Heights and particularly Armstrong Creek a major new suburb currently underway and which will see 22,000 homes upon completion.*

In terms of expansion in the dairy industry, the United Dairyfarmers of Victoria (a commodity group of the Victorian Farmers Federation), submitted that:[3]

> *The lack of capacity in the delivery network in some regional areas is restricting the potential for growth at some major Australian dairy farms and processing sites. A significant investment to upgrade the infrastructure is required to enable farm and manufacturing growth.*

The Mildura Development Corporation (**MDC**) also responded to the Directions and Priorities consultation, imploring Powercor to further expand its local power network capacity. Mildura is dominated by the horticultural and dryland agricultural sectors, and according to MDC provides:

- 98 per cent of Australia's dried vine fruit;
- 75 per cent of Australia's table grapes;
- 68 per cent of Australia's almonds; and
- sheep, grain and cattle farming.

In addition, MDC notes that there is significant interest in solar developments, notably: [4]

> *…in late 2014, there has been an upsurge in interest in solar plant developments in the Mildura region, with a number of solar companies currently looking at 30MW, 50MW and other larger solar facilities. There has also been interest to establish other biomass plants in the Mildura region.*

MDC seek further investment from Powercor in the region:[5]

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2 Email from City of Greater Geelong to Powercor, Response to Directions and Priorities Consultation Paper, 4 November 2014

3 United Dairyfarmers of Victoria, *CitiPower and Powercor Directions and Priorities Consultation Paper*, 5 November 2014, p. 3.

4 Mildura Development Corporation, *Submission – CitiPower and Powercor Australia Directions and Priorities Consultation Paper*, 3 November 2014, p. 5.

5 Mildura Development Corporation, *Submission – CitiPower and Powercor Australia Directions and Priorities Consultation Paper*, 3 November 2014, p. 6.

> *MDC … calls for further support for an even more significant expansion in local power network capacity, not only recognising the many food processors and solar energy plants with high energy demands establishing themselves in the region, but also recognising the needs of those companies considering establishing themselves in the region ….*

Powercor's customers' views on growth and expansion is supported by Victorian Government projections of growth.

2.1 Population growth

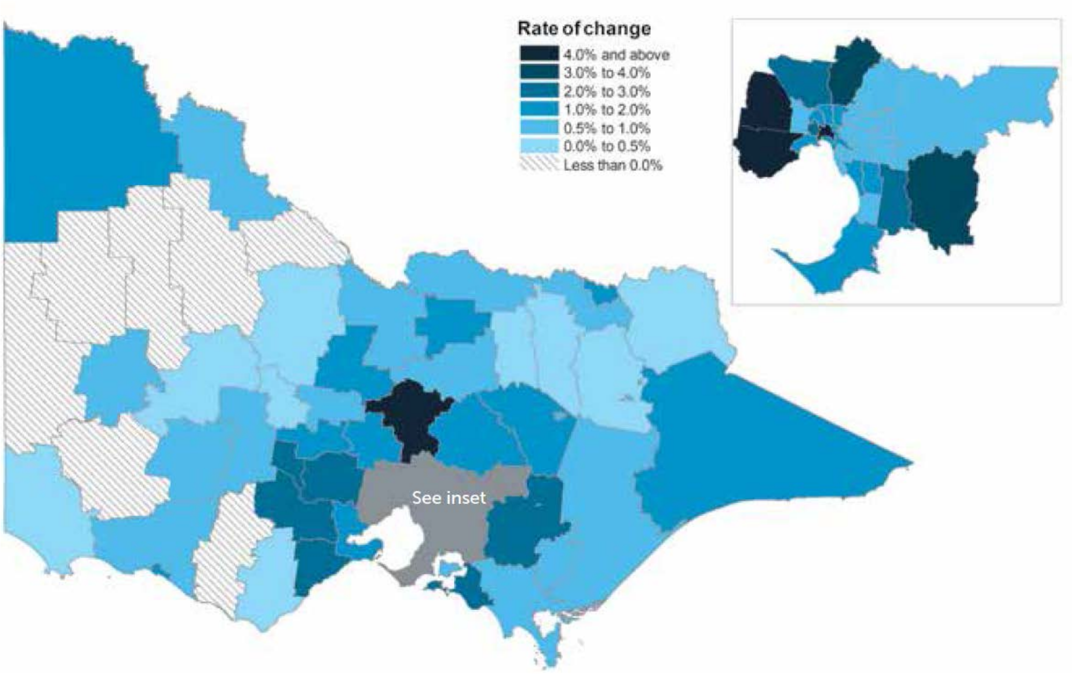
In terms of population growth, the Victorian Government has forecast that the Greater Melbourne region will grow the fastest, but that there will also be growth in the regional areas. The areas of strongest growth are generally in the Powercor area. The Government has noted that:[6]

> *Within Greater Melbourne, the areas with the greatest capacity for dwelling growth are the outer growth areas and the inner city…*
>
> *In Victoria's regions the largest numbers of projected extra dwellings, and thus largest concentrations of population growth, are in the major regional cities and in areas close to Melbourne. Between 2011 and 2031, the three largest LGAs by population (Greater Geelong, Greater Bendigo and Ballarat) are projected to account for 44 per cent of the population growth in Victoria's regions.*

The Victorian Government's projections for annual population growth are shown in figure 2.1 and reinforce Powercor's expectations of strong population growth in the western corridor of Melbourne, as well as the Surf Coast region encompassing Torquay, Anglesea and Lorne.

[6] Department of Transport, Planning and Local Infrastructure, *Victorian In Future 2014 – population and household projections to 2051*, May 2014, p. 5.

Figure 2.1 Rate of projected annual population change by Local Government Area, 2011 to 2031



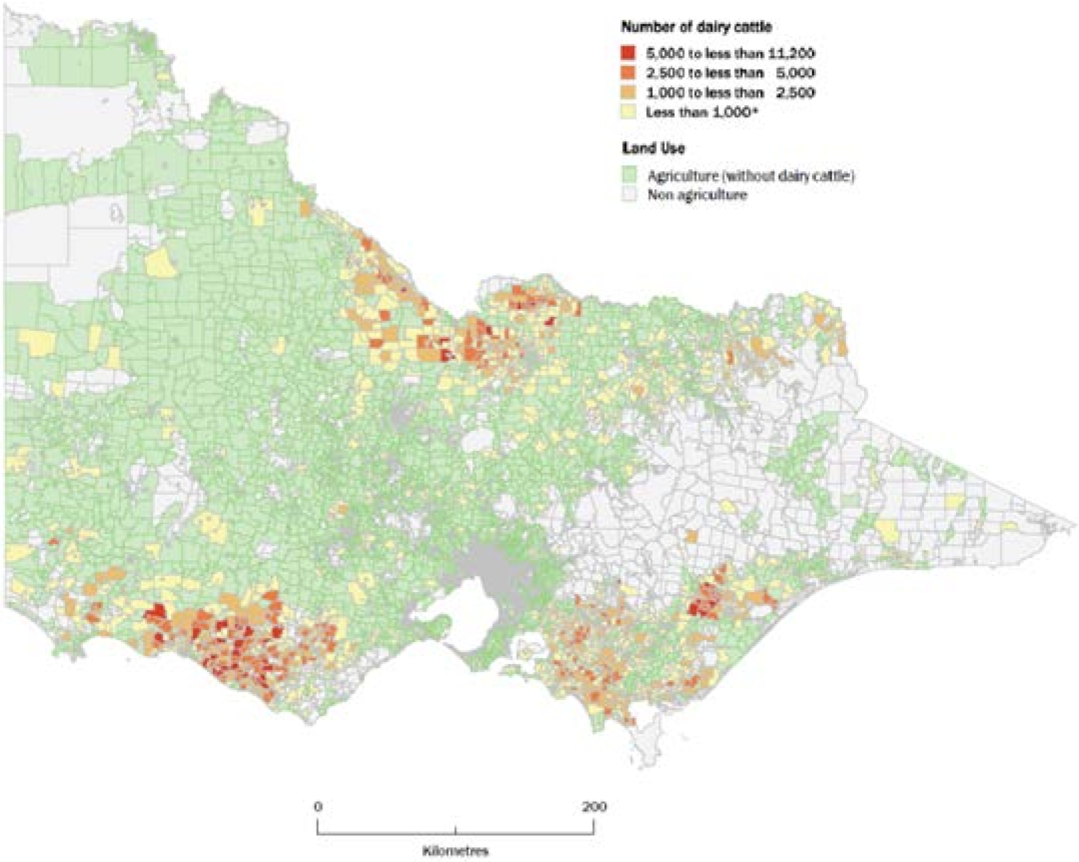
Source: Department of Transport, Planning and Local Infrastructure, *Victorian In Future 2014 – population and household projections to 2051*, May 2014, p. 6.

2.2 Expansion of agricultural industry

Growth in demand is also expected to be driven by requirements in the agricultural and dairy sectors. The dairy industry is Victoria's largest rural industry[7] and is currently expanding production. Victoria's dairy farms are predominately located in the north, south and Gippsland regions, as shown in figure 2.2. The northern region is dominated by irrigated farms, while in the south-west region, such as near Warrnambool, the farms are mainly dry land farms.

[7] Department of Environment and Primary Industries, *Dairy Industry Profile*, January 2013 available from http://www.depi.vic.gov.au/agriculture-and-food/dairy/dairy-industry-profile.

Figure 2.2 Victoria's milk production regions[8]



Source: Department of Environment and Primary Industries, *Dairy Industry Profile*, December 2014, p. 2..

Other agricultural sectors, such as almonds and olive orchards, and vegetable farming, rely heavily on irrigation in the northern regions of Victoria along the Murray River, such as Mildura. This is also driving expected increases in demand.

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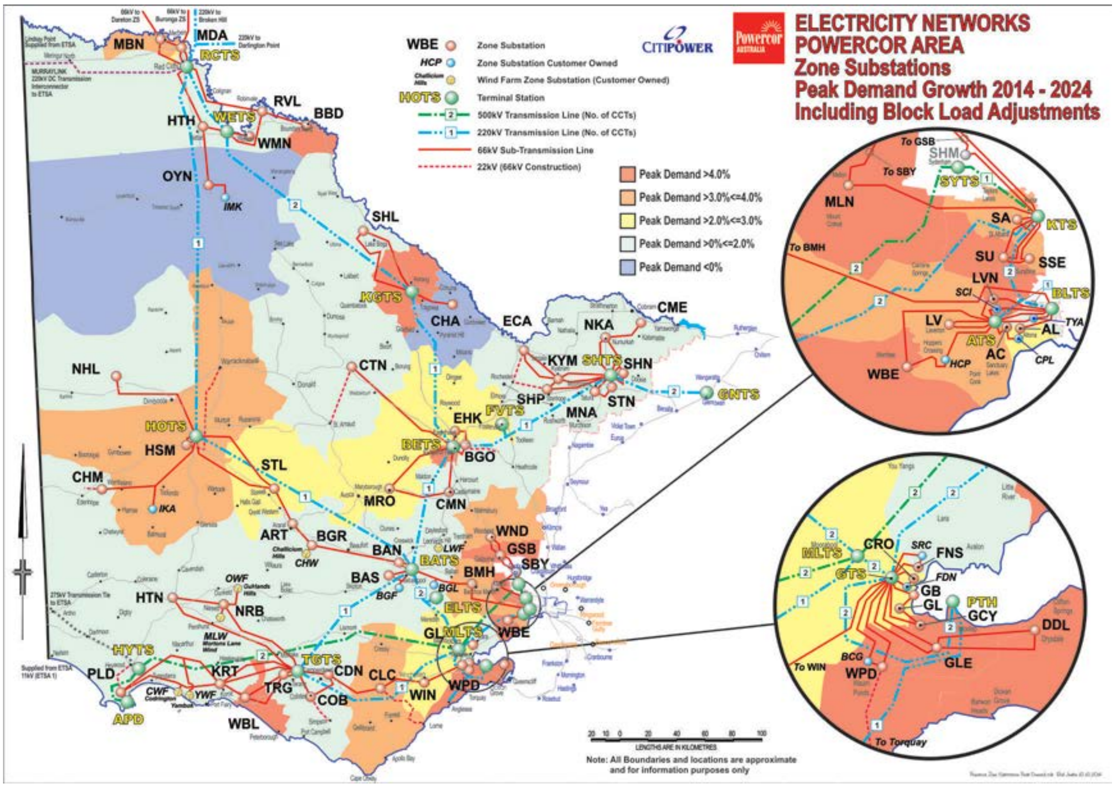
[8] Department of Environment and Primary Industries, *Dairy Industry Profile*, December 2014, p. 2, available from http://www.depi.vic.gov.au/agriculture-and-food/food-and-fibre-industries/industry-profiles#dairy, accessed 14 April 2015.

3 Approach to peak demand forecasting

Overall, Powercor is forecasting an increase in demand in particular areas in its distribution area, as shown in figure 3.1.

The forecasts take into account the expected continued growth in embedded generation and the take-up of energy efficient devices in households. In addition, the forecasts take into account the expected use of Time of Use tariffs.

Figure 3.1 Forecasts of peak demand growth by zone substation



Source: Powercor

The demand forecasts have been prepared using a robust process by an independent economic forecaster that draws upon analysis of economic and environmental factors at each terminal station. A key objective of Powercor's demand forecasting process was to align its econometric modelling with that used by AEMO.

Powercor uses its demand forecasts as the basis for calculating the forecast load at each zone substation, on each sub-transmission line and on each feeder. These forecasts are necessary to establish whether additional capacity is required at any location, and then to assess augmentation options to address the forecast network constraints.

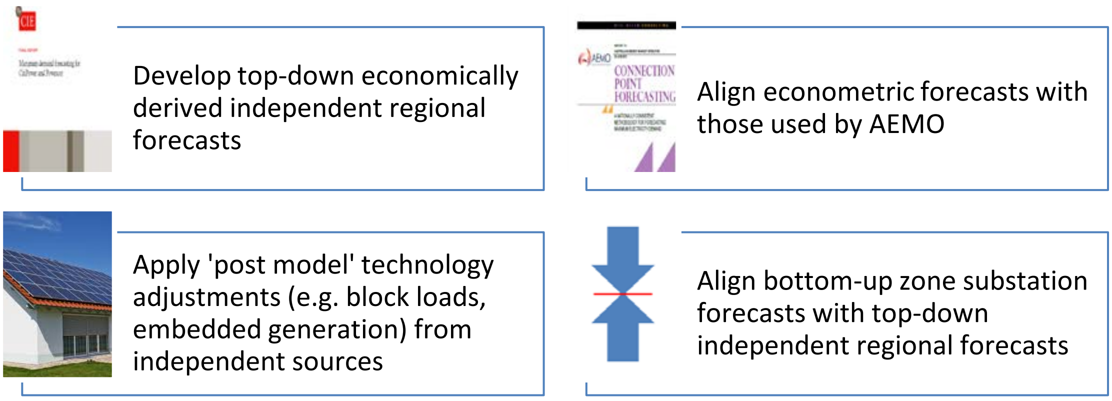
Use of demand forecasts

Since the late 1990s, a risk based approach to network planning has been used in Victoria. The approach is supported by the AER's Regulatory Investment Test for Distribution (**RIT-D**), where an augmentation is only undertaken where it provides a net economic benefit to consumers. That is, there is no risk of overinvestment under this framework.

The RIT-D takes into account the level of risk from increasing peak demand forecasts for an asset (i.e. number of hours and amount of energy at risk). The energy at risk is multiplied by the most recent AEMO value of customer reliability (**VCR**) to determine a $ value associated with the risk. This $ value is then fed into a financial model and compared against the cost of various options to address this risk. The analysis considers both network and non-network solutions, as per Powercor's demand side engagement strategy. The option with the highest net economic benefit to consumers is selected as the preferred solution to address any forecast network constraints.

The key elements in Powercor's forecasting process are shown in figure 3.2.

Figure 3.2 Key elements of Powercor's forecasting process



At all levels, terminal stations, zone substations and high voltage (**HV**) feeders, the constant steady state of demand associated with industrial loads is taken into account, i.e. a growth rate is not applied to large industrial loads. They are only adjusted upon advice from the customer regarding an increase in load or by applying local knowledge in respect to a known closure of a plant or industrial type load.

These steps are discussed below.

3.1 Top-down forecasts

Powercor engaged the Centre for International Economics (**CIE**) to develop models to forecast maximum electricity demand at each terminal station, along with maximum demand at the Powercor network level. The forecasts include both residential and non-residential demand.

The overall approach that CIE used for forecasting maximum electricity demand for terminal stations was consistent with the best practice methodology described by ACIL Allen in their 2013 report to AEMO for connection point forecasting.[9]

CIE used a two-step process:

- forecasts were produced for actual demand for the terminal station area, which included demand served through the terminal station and demand served by major embedded generators; and
- forecasts were then also produced for demand served by the terminals stations, which removed the demand that could be served by major embedded generators and changes in the amount of small-scale solar embedded generation.

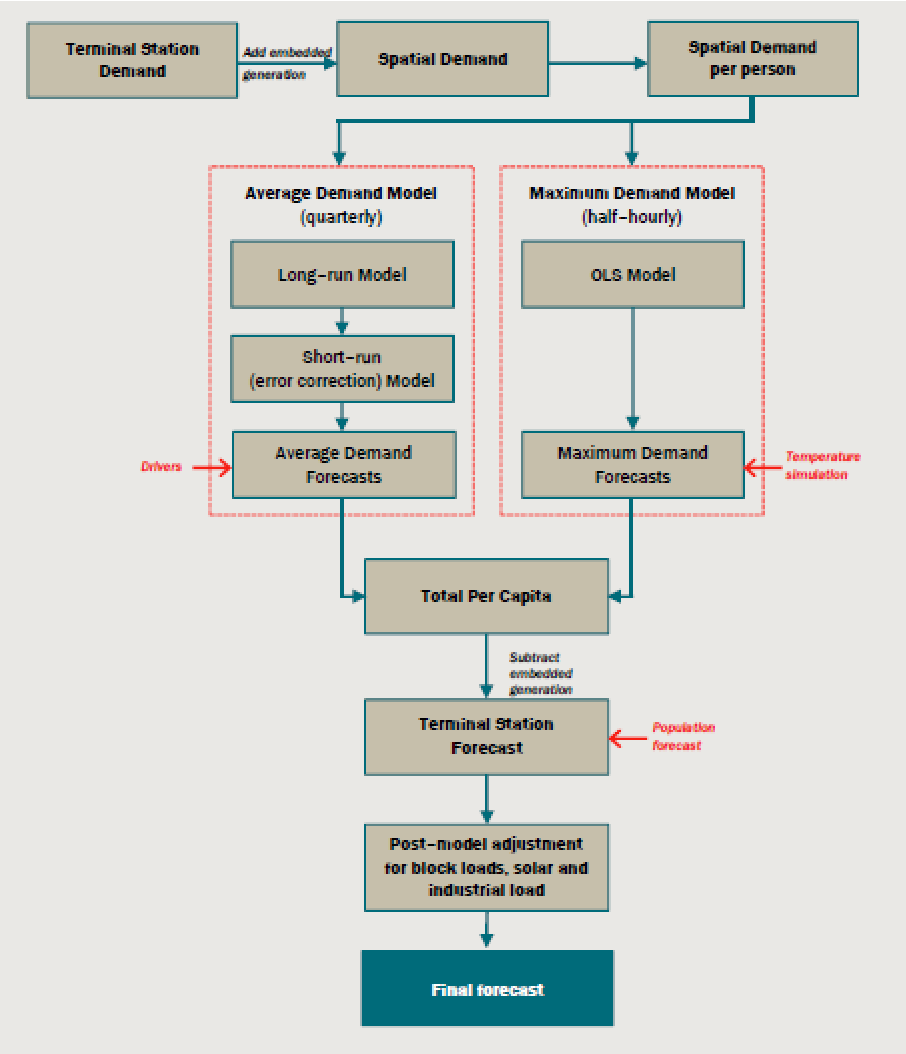
CIE's approach to forecasting maximum electricity demand for terminal stations was broadly consistent with the two-step approach used by AEMO in its preparation of the 2013 National Electricity Market electricity forecasts. The first step was a model of average demand and the second step was a model of the distribution of demand.

To ensure robustness, each terminal station model incorporated ten years of historical 30 minute demand data, in addition to weather, economic and post model adjustments.

Figure 3.3 illustrates the forecasting process, highlighting the combination of the average demand model and maximum demand model in producing per capital forecasts of electricity demand for a terminal station.

9 ACIL Allen Consulting, *Connection point forecasting – a nationally consistent methodology for forecasting maximum electricity demand*, Report to Australian Energy Market Operator, 26 June 2013.

Figure 3.3 CIE's approach to maximum demand forecasting



Source: CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014, p. 2.

In forecasting average demand, the forecasting approach used by CIE had two components:

- establishing quantitative, historical relationships between demand drivers and demand; and
- projecting the driver variables and calculating estimates of demand based on the historical relationships.

CIE's forecasts for average demand growth took into account the following demand drivers:

- price-electricity prices are projected using forecasts of the real electricity residential price index, including assumptions about use of time of use tariffs;
- income-projections based on the growth rate in Gross State Product per capita in each quarter;
- population-annual forecasts of population in local government areas; and
- weather-the effect of temperature on demand largely due to air-conditioner and heater usage.

It is noted that the price, income and population inputs were consistent with AEMO's demand forecasting model at that time.

To forecast summer, winter and annual maximum demand, CIE used 96 separate half hourly models to predict demand at different times of the day. This allowed for the relationship between the temperature and calendar variables to vary through the day and between seasons. The CIE then projected the variables used in the models of historical demand into the future. This follows the approach of Hyndman and Fan that is used by AEMO to deliver its forecasts.

The results of the economic simulation and other factors were combined with the forecasts of average quarterly electricity demand to obtain a distribution of maximum demand for each year of the forecast period. A detailed description of the process that CIE used is provided in their report.[10] The output of the CIE model is provided in the attached *CIE forecasts results model.*

CIE undertook post modelling adjustment to take into account known changes in block loads, i.e. negative adjustments for industry shutdowns such as car manufacturing, positive adjustments for load increases such as in the dairy industry. The block load information was provided to CIE by Powercor, however it is noted that:

- forecast block load additions were only included where the customer had accepted an offer to connect, or where the Powercor offer to connect had not yet been accepted by the customer but was still valid, and Powercor considered that the probability of a project proceeding was very high; and
- Powercor had ensured that there was no double-counting of block loads, by taking into account the magnitude of the block load and the forecast growth rate. For example, Urban Residential Developments (**URDs**) are generally not included as block loads but are considered as part of the underlying growth rates.

No future transfers or switching were assumed by CIE in the forecasting process.

CIE's forecasts also took into account the demand from major embedded generators, notably wind farms in the Powercor area. The CIE made post-model adjustments for wind farms and solar rooftop photovoltaic (**PV**) generation. These adjustments were based on information contained in a report by Oakley Greenwood which summarised the impact of technology changes on terminal station demand.[11]

[10] CIE, *Maximum demand forecasting for CitiPower and Powercor*, Final report, July 2014.

[11] Oakley Greenwood, *Summary and documentation of the terminal station impacts of five technology trends*, May 2014.

Figure 3.4 Level of deployment of the five technology trends

Technology trend	Level of deployment	Summary of rationale
Rooftop solar PV	Medium	Take-up of rooftop solar PV systems has remained similar to previous years despite removal of a significant proportion of the available subsidies. Decreasing system costs, increasing system efficiencies and emerging business models that will increase penetration in the non-residential sectors also indicate that take-up will continue at moderate levels.
Electric vehicles	Low	Current penetration is extremely low in Australia and the current price differential between EVs and conventional vehicles in Australia is $30,000. Absent material policy incentives (i.e., subsidies) take-up is expected to remain low by global standards until price parity is approached which is not expected until about 2025.
Battery storage	Low	Recent technology advances and external trends such as increased uptake of EVs have caused battery costs to drop substantially, from approximately $1,700/kW in 2000 to approximately $800/kW today, but they are still not cost effective for either end-user or distribution system deployment. Given that take-up by end-users requires that the purchase be justified solely on the benefits that can be provided with regard to the charging elements within the customer's tariff structure, and the projected structure and level of electricity prices in the Reference Case, it is most likely that take-up will conform to the low case over the study period.
Distributed generation	Low	The low level of take-up to date and the significant increase in gas price as compared to electricity price makes take-up of distributed generation less attractive over the study period than in the past.
Energy efficiency	Medium	A decade of government information and subsidy programs have activated a strong market for the delivery of energy efficiency technologies. The fact that government subsidies are likely to reduce somewhat in the near term and electricity price increases are forecast to moderate in the Reference Case will tend to reduce uptake from its recent high to more moderate levels over the study period. Environmental concerns and lingering concerns about the absolute level of power prices if not continued double-digit increases along with the activated industry will tend to provide a floor for take-up.

Source: Oakley Greenwood, *Summary and documentation of the terminal station impacts of five technology trends*, prepared for the Centre of International Economics, May 2014, p. 6.

Post model adjustments were not made for energy efficiency as they are included in the forecasts to the extent that they reflect historical changes in polices. Adjustments were also not made for electric vehicles, battery storage and other forms of distributed generation as CIE considered that the impact of these technologies was small and somewhat more uncertain.[12]

CIE provided models and forecasts for each terminal station connected to the Powercor distribution network. At the total network level, CIE forecasts the following maximum demand forecasts for Powercor.

12 CIE, *Maximum demand forecasting for CitiPower and Powercor*, Final report, July 2014, p. 32.

Figure 3.5 CIE aggregate maximum demand forecasts for Powercor including post-modelling adjustments

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Summer Maxima										
90% PoE	2300.8	2397.4	2453.8	2511.6	2565.0	2622.3	2662.0	2704.9	2827.3	2847.5
50% PoE	2521.7	2634.9	2719.4	2756.1	2859.0	2922.6	2975.6	3032.9	3162.4	3227.3
10% PoE	2820.0	2953.8	3116.1	3183.5	3266.7	3345.3	3448.3	3560.7	3693.6	3856.3
Winter Maxima										
90% PoE	1815.2	1809.6	1848.6	1854.5	1885.9	1895.6	1884.9	1877.9	1885.6	1884.1
50% PoE	1849.3	1837.6	1881.1	1889.7	1919.9	1929.2	1918.7	1912.4	1918.4	1920.9
10% PoE	1892.3	1877.5	1923.8	1931.2	1965.0	1971.0	1963.0	1958.6	1961.8	1971.9
Annual Maxima										
90% PoE	2300.8	2395.0	2453.2	2510.8	2564.7	2622.0	2661.9	2704.9	2827.3	2847.5
50% PoE	2521.7	2634.2	2719.4	2756.1	2859.0	2922.6	2975.6	3032.9	3162.4	3227.3
10% PoE	2820.0	2953.8	3116.1	3183.5	3266.7	3345.3	3448.3	3560.7	3693.6	3856.3

Note: All forecasts are in MW.

Source: CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014, pp. 37-38.

Using the above figures, the annual change in coincident maximum demand at the network level, in Megawatts (MW), is shown in figure 3.6.

Figure 3.6 Coincident annual maximum demand at terminal stations annual growth rate (per cent)

	2016	2017	2018	2019	2020
50% PoE	4.5	3.2	1.3	3.7	2.2
10% PoE	4.7	5.5	2.2	2.6	2.4

Source: CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014, p. 38.

It is noted that Professor Rob Hyndman (Monash University) reviewed the CIE methodology and his comments were taken into account in the final CIE forecasts.[13]

3.1.1 Amendments to the top-down forecasts

Powercor has not simply taken the output of the econometric analysis at each terminal station to derive its forecasts. Rather, Powercor has revised the CIE forecasts in two specific situations:

- where CIE used "off the line" forecasting, referring to the a regression line fitted to the weather normalised history of data, Powercor amended the observations to "off the point" (i.e. the most recently observed weather normalised demand) in a small number of cases where the line and the point were far from each other; and

13 CIE, *Maximum demand forecasting for CitiPower and Powercor*, Final report, July 2014, p. 4.

- where the baseline forecasts were inconsistent with the judgement of expert planning engineers with strong local area knowledge.

In a small number of situations, Powercor has revised down the CIE forecasts. This is consistent with the process outlined by ACIL Allen in its report *Connection Point Forecasting* which discusses the role of judgement and local experts in forecasting process.[14]

> *In any of these situations, and possibly others, growth rates that are derived using econometric analysis, which is based on historical relationships, may lead to the wrong answers. The forecaster needs to consider the likely future of an area before blindly applying the calculated growth rates to each CP [connection point].*
>
> *The process of determining growth rates at each CP is not a simple mechanical one. It requires the forecaster to exercise their own judgement as well as the expert knowledge of planning engineers with strong local area knowledge.*

This approach to forecasting in the report is considered industry "best practice". As such, Powercor has amended the starting point or applied local knowledge to the forecasts prepared by CIE before reconciling those forecasts to the bottom-up forecasts.

The CIE terminal station forecasts, with these minor reductions, were used as Powercor's 'top-down' forecasts for the purposes of reconciling with the 'bottom-up' forecasts.

3.2 Bottom-up forecasts

Powercor had prepared bottom up, rolling ten year summer and winter 50 per cent Probability of Exceedance (**PoE 50**) maximum demand[15] forecast for each terminal station, and minimum six year forecasts for zone substations and sub-transmission lines. Powercor undertook the following three steps.

First, Powercor adjusted the most recent actual load data by:

- weather normalising the most recent actual summer and winter maximum load at the zone substation level, to obtain the PoE 50 maximum loads; and
- scaling the zone substation PoE 50 maximum loads according to the historic weather normalised summer and winter load growth for each zone substation area.

Secondly, Powercor adjusted the forecasts for known changes in load:

- known major customer load increases and decreases. These are factored into the forecast at the respective distribution feeder and zone substation levels in the year that they are planned to occur; and

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[14] ACIL Allen Consulting, *Connection point forecasting – a nationally consistent methodology for forecasting maximum electricity demand*, Report to Australian Energy Market Operator, 26 June 2013, p. 33.

[15] PoE 50 means for a given season projected maximum demand is expected to be met or exceeded on average, five years in ten years.

- known load transfers caused by approved upcoming network re-configuration projects, such as transfer of load from a distribution feeder or zone substation that is at capacity to an adjacent distribution feeder or zone substation with spare capacity.

Third, Powercor aggregated the maximum demand forecasts at each asset level, taking into account the diversity and power factor.[16]

3.3 Reconciliation

As a final step, Powercor reconciled the internally developed maximum demand forecast at the zone substation level against the maximum demand forecast at the terminal station level. This was done by adjusting the feeder level growth rate so that bottom-up forecasts closely matched the top-down forecasts.

Powercor has had the reconciliation process independently reviewed by ACIL Allen, and their attached report entitled *Demand Forecasts Reconciliation Review*. ACIL Allen noted that:[17]

> *Bottom up and top down forecasts have their own strengths and weaknesses. The purpose of reconciliation is to capture the 'best of both worlds' and develop forecasts that have the strengths of both techniques.*

ACIL Allen identified some minor areas for improvement in Powercor's reconciliation process, mostly related to the weather corrected forecasts at the 10 per cent probability of exceedance level (10% PoE) for extremely hot summer days.[18] These improvements will be incorporated in future reconciliation processes but have had no impact on augmentation expenditure requirements.

3.4 Use of forecasts

The reconciled demand forecasts were used by Powercor in the preparation of its 2014 Distribution Annual Planning Report as well as the 2014 Transmission Connection Planning Report for the purpose of joint planning.

The forecasts have been consistently applied for the purposes of this regulatory proposal.

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16 The maximum demand forecasts are not necessarily identical at each asset level. This is because of diversity resulting from different customers demanding electricity at different times during the day. For example, commercial loads' peak demand usually peak in the early afternoon, whilst residential loads usually peak in the early evening. As a consequence to successfully aggregate the maximum demand forecasts at each asset level a power and diversity factor must be applied.

17 ACIL Allen, *Demand forecasts – reconciliation review*, 27 January 2015, p. ii.

18 ACIL Allen, *Demand forecasts – reconciliation review*, 27 January 2015, p. iii.

4 AEMO forecasts for peak demand

AEMO has produced two sets of forecasts in Victoria:

- top-down Victorian system level forecasts; and
- forecast at each transmission connection point.

Separate forecast of some elements, such as future energy efficiency savings and rooftop PV generation are separately modelled and used to adjust the core model.

In September 2014, AEMO produced its first electricity demand forecasting report of maximum demand (**MD**) at transmission connection point level for Victoria. Powercor has worked with AEMO to discuss their methodology, as well as providing historical data and demand forecasts. However, as discussed below, AEMO has assumed aggressive assumptions associated with solar PV penetration and energy efficiency that Powercor has been unable to verify, and as a result it has been unable to align its forecasts with those of AEMO at the transmission connection point level.

In its draft decision for the NSW distributors, the AER noted the range of differences in the datasets used by AEMO and the distributors to derive the forecasts, including different treatment of high voltage (**HV**) customers and embedded generation (including rooftop solar PV), energy efficiency, different timing of data and different levels of coincidence. The AER was satisfied with the explanation of some of the differences between the forecasts, and noted that the AEMO forecasts were not 'tailor-made' for each distributor.[19] As a result, the AER considered that AEMO's forecasts provided a useful reference point for assessing the distributors' demand forecasts. The AER did not rely upon AEMO's forecasts.

Powercor will continue to work with AEMO as they continue to develop and refine their forecasts. However, given the concerns with AEMO's forecasts, Powercor considers it appropriate that the AER relies upon Powercor's own demand forecasts rather than those of AEMO.

System level forecasts

AEMO produces Victorian system level forecasts of peak demand in its National Electricity Forecast Report (**NEFR**). Since the first NEFR report in 2012, AEMO has reduced its summer 10% PoE forecasts for Victoria for the period to 2018/19 by 25 per cent, with the ten year growth rate falling from 1.6 per cent to 0.1 per cent per annum.[20] The change in forecast is shown in figure 4.1.

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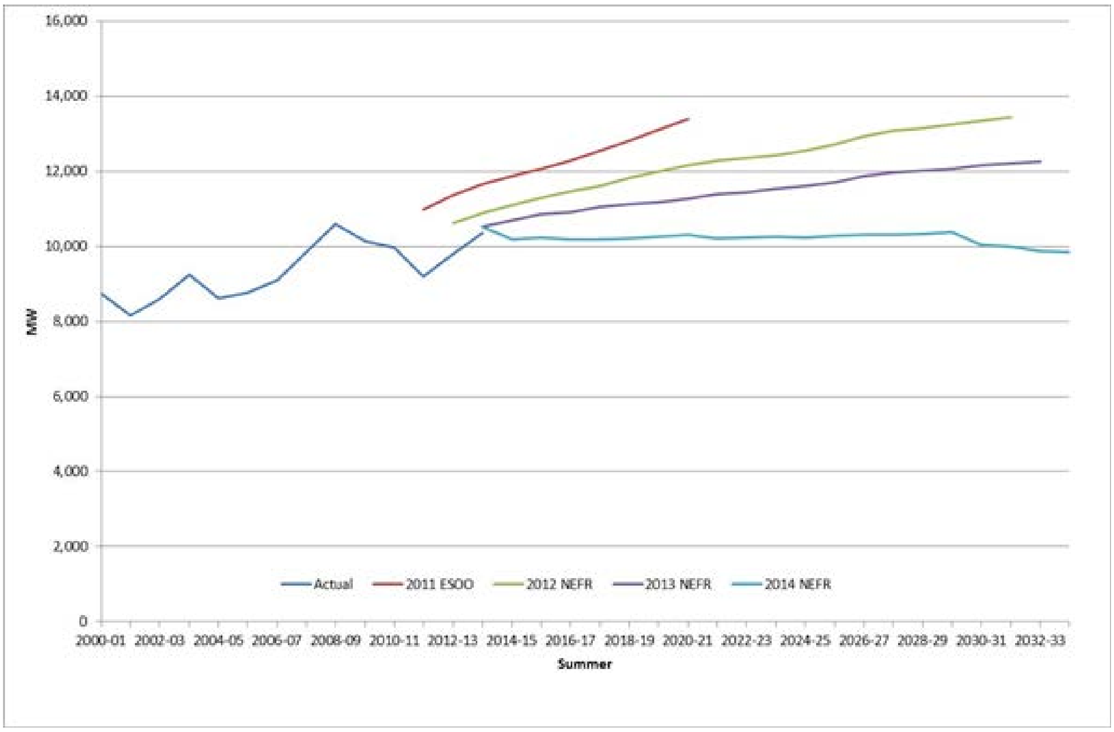
[19] For example, see AER, *Draft Decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 6: capital expenditure*, November 2014, pp. 6-85 to 6-90.

[20] GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, p. 12.

Figure 4.1 Victorian summer 10% PoE peak demand forecasts



Source: GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 12.

According to GHD, the reductions in long term growth forecasts appear to reflect methodological changes to the core model, as well as other elements of the forecasts outside of the core model such as increasing estimates of future rooftop PV generation.

Transmission connection point forecasts

In September 2014, AEMO produced its first electricity demand forecasting report of MD at transmission connection point level for Victoria.

The connection point forecasts are initially prepared on an individual basis and in the final reconciliation process are scaled so that their sum is equivalent to the system level peak demand for Victoria.

AEMO's description of the key steps in its forecasting methodology is shown in table 4.1.

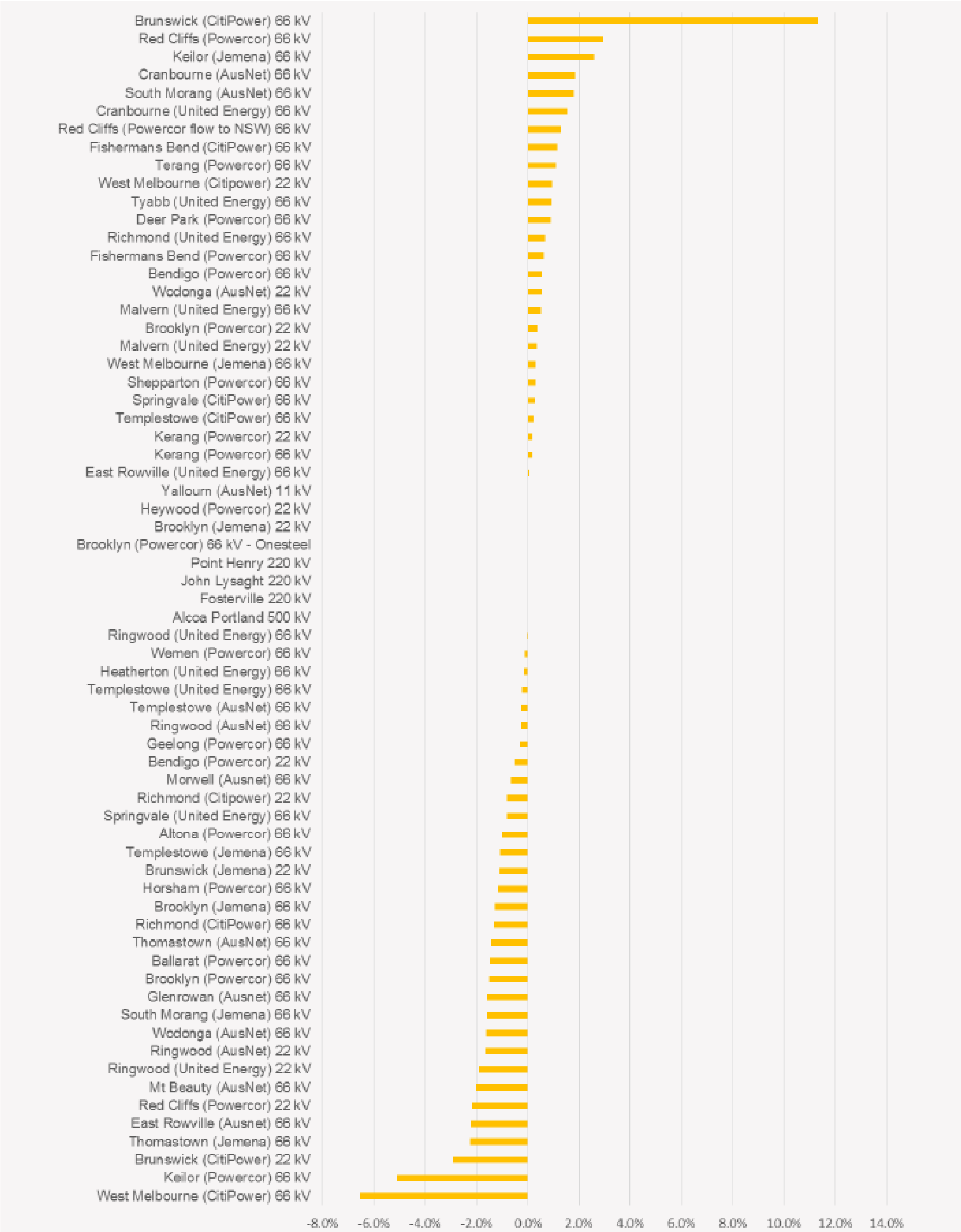
Table 4.1 AEMO's key steps in forecasting methodology

Step	Description
1. Prepare data	Obtain and clean demand and weather data. Determine demand profile and demand mix.[10]
2. Weather normalise	Determine weather sensitivity at each connection point.
3. Select starting point	Determine where the forecasts should start from: last historical point or time trend line.
4. Select growth rate	Determine a growth rate to forecast future demand.
5. Baseline forecasts	Apply growth rate to selected starting point.
6. Apply post model adjustments	Adjust for rooftop PV and energy efficiency. The amount of rooftop PV and energy efficiency adjustments were derived from the 2014 NEFR.
7. Reconcile to system forecasts	Make the forecasts consistent with the 2014 NEFR thereby applying regional-level economic and demographic growth drivers at the connection point level. The regional forecasts were taken directly from the 2014 NEFR.[11]

Source: AEMO, AEMO Transmission Connection Point Forecasting Report for Victoria, September 2014, p 9.

AEMO's forecast for annual growth at each connection point is shown in figure 4.2. These forecasts include load transfers between terminal stations, for example transfers from Keilor to Deer Park.

Figure 4.2 AEMO's 10% PoE summer 10-year average annual growth rates, 2014-15 to 2023-24 (includes the impact of load transfers between terminal stations)



Source: AEMO, AEMO Transmission Connection Point Forecasting Report for Victoria, September 2014, p 16.

In its report, AEMO noted that it consulted widely with stakeholders in developing these connection point forecasts, and in particular with the relevant distributors. AEMO indicated that this involved sharing local knowledge about the network, understanding differences in forecasting methodologies, and exchanging data.[21]

AEMO's report noted that its forecasts are much lower than those produced by the Victorian distributors. AEMO publishes the Victorian Terminal Station Demand Forecast (**TSDF**) which is compiled by AEMO from forecasts provided by Victorian distributors and direct-connect customers, and reflects participant expectations of future demand. AEMO noted that:[22]

> *The Victorian connection point forecast is > 2000 megawatts (MW) lower than the Victorian TSDF at end of 10 year outlook period*

The next sections explain AEMO's approach to forecasting and explain the variance between AEMO's forecasts and those of distributors. The Victorian distributors are continuing to work with AEMO to understand the approaches and assumptions behind the AEMO forecasts.

4.1 Comments on AEMO's approach

Powercor understands that AEMO's terminal station maximum demand forecasts consist of four different forecasts:

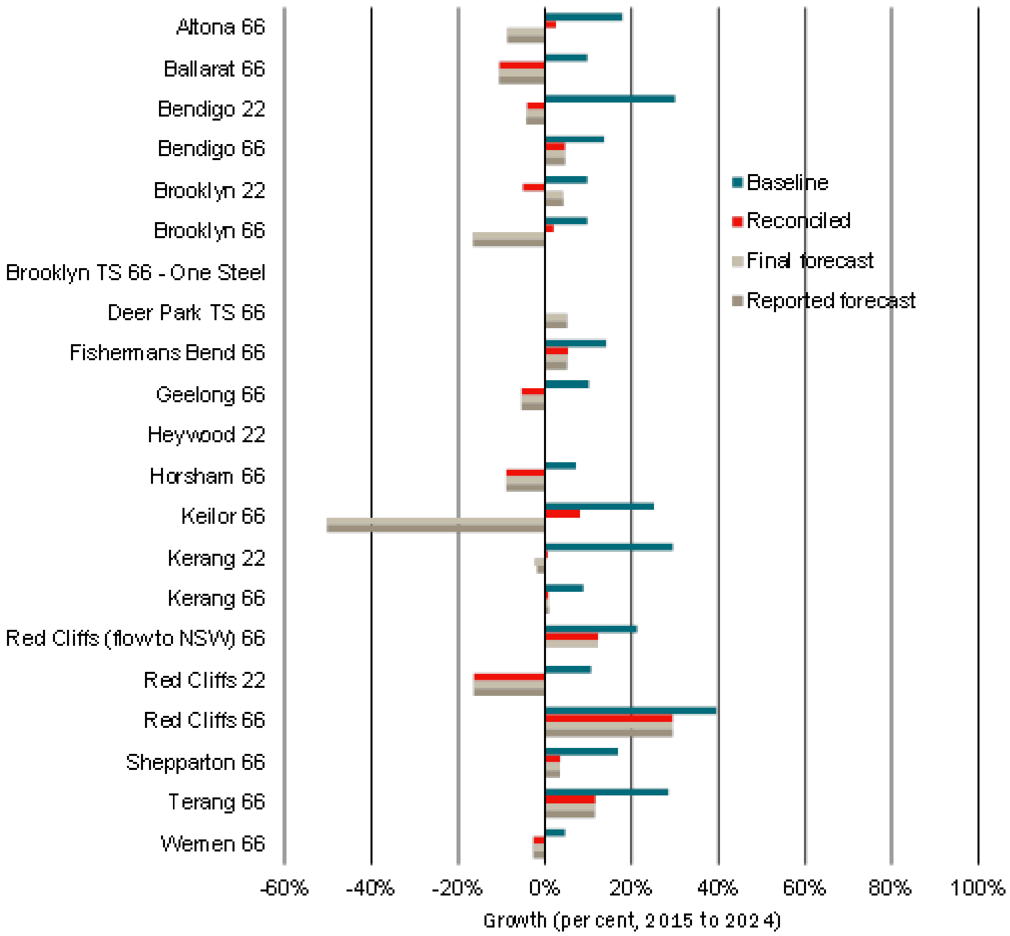
- baseline forecast which are extrapolated from historical trend;
- reconciled forecasts which are the baseline forecasts adjusted for solar PV and energy efficiency to then reconciled to the state wide forecasts;
- final forecast which is further adjusted by block loads and known load transfers between terminal stations; and
- report forecast, which is made publicly available.

There are substantial reductions in the growth rates for Powercor as a result of moving from baseline to reconciled forecasts, as shown in figure 4.3.

[21] AEMO, *AEMO Transmission Connection Point Forecasting Report for Victoria*, September 2014, p 5.

[22] AEMO, *AEMO Transmission Connection Point Forecasting Report for Victoria*, September 2014, p 2.

Figure 4.3 AEMO changing forecasts for terminal stations



Source: CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, 16 January 2015, p. 5.

The baseline forecasts that AEMO produces up to step 5 of its process are not significantly dissimilar from those produced by Powercor. That said, GHD has identified areas for further focus and investigation of the AEMO forecasting methodology up to step 5, which Powercor is currently discussing with AEMO.

The main variation in results is driven by AEMO's adjustments at the final step 6 for:

- rooftop solar PV, and
- energy efficiency.

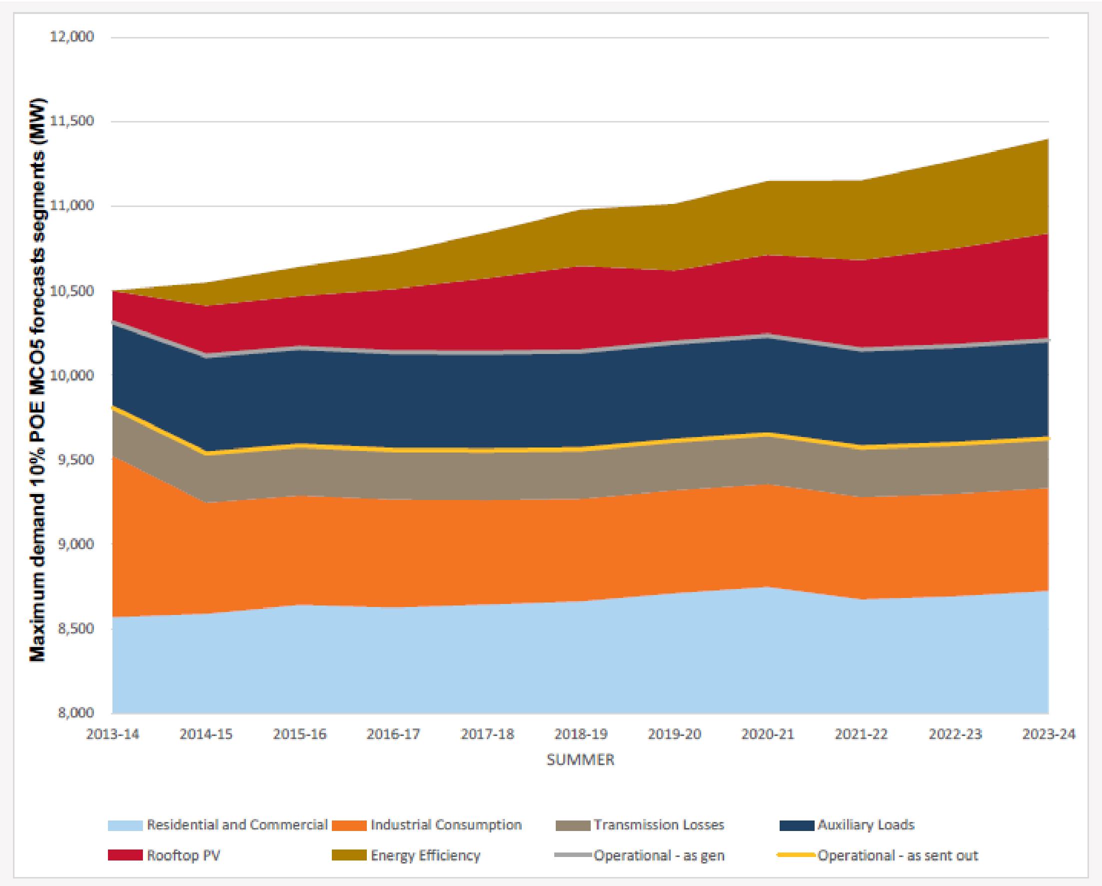
AEMO obtained the rooftop solar PV and energy efficiency aspects of the forecasts from its NEFR report. That report notes that for Victoria, its short term forecast key drivers include:[23]

[23] AEMO, *National Electricity Forecasting Report for the National Electricity Market*, June 2014, p. 6-1.

- increased residential and commercial consumption forecasts driven by the strongest population and income growth of all NEM regions. The increase is moderated by increased forecasts for rooftop PV penetration and energy efficiency offsets;
  - Victoria's strong growth in rooftop PV is the second highest in the NEM. PV growth results from the fall in PV system costs while financial incentives stay the same;
  - energy efficiency growth is forecast to increase year on year driven by Federal Government programs; and
- PV is also causing MD to shift to later in the day. This long-term trend is seen in the short term, but to a much lesser extent. Victorian MD is expected to shift back to later in the day by 30 minutes in the short term.

The impact of rooftop PV and energy efficiency within AEMO's Victorian forecasts for maximum demand is shown in figure 4.4.

Figure 4.4 AEMO 10% PoE maximum demand forecast segments for Victoria



Source: AEMO, National Electricity Forecasting Report for the National Electricity Market, June 2014, p. 6-5.

The AEMO assumptions relating to rooftop solar PV and energy efficiency are discussed in turn below.

4.1.1 Rooftop solar PV

AEMO has forecast a significant contribution from rooftop solar PV to meeting peak demand.

AEMO's own analysis from the Victorian heatwave of January 2014 showed that at the state wide system peak recorded at 4.30pm on 16 January 2014, embedded solar generation contributed 1.04 per cent to the peak operational demand.[24]

Figure 4.5 AEMO statistics on the percentage contribution to peak operational demand by generation source for Victoria

Victoria 2014	13/1/14	14/1/14	15/1/14	16/1/14	17/1/14
Peak operational demand (MW)	8,262	10,151	10,126	10,307	10,263
Brown Coal Generation (%)	70.4	52.6	53.5	54.9	57.7
Gas generation (%)	10.6	19.4	19.8	18.1	15.7
Hydro generation (%)	6.7	16.5	17.2	18.9	15.7
Interconnector imports (%)	11.3	9.9	8.8	7.6	5.2
Wind generation (%)	0.93	1.6	0.61	0.32	2.27
Embedded solar generation (%)	0.74	1.17	1.46	1.04	1.6

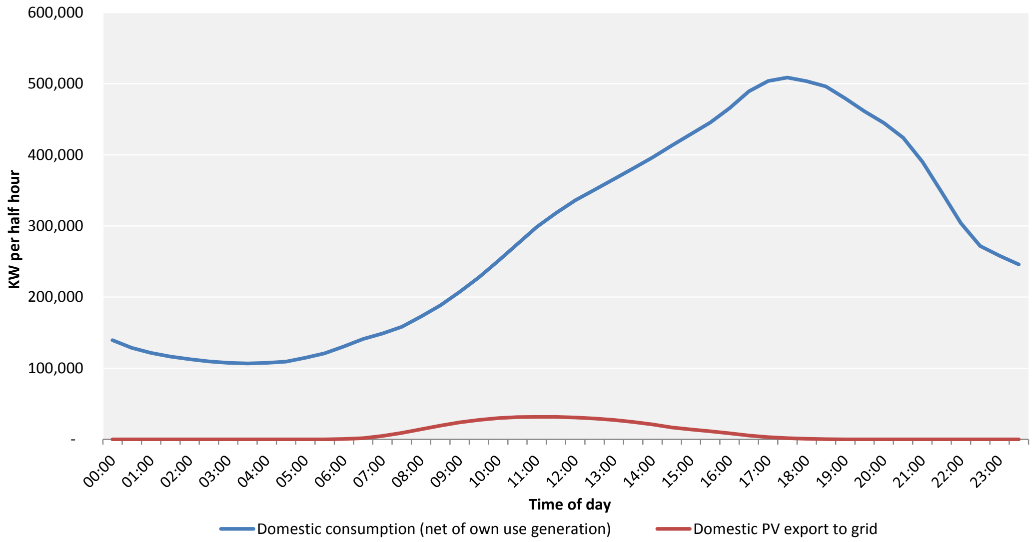
Source: AEMO, *Heatwave 13-17 January 2014*, 26 January 2014, p. 6.

Powercor's experience is that solar PV makes a very small contribution to peak demand on its network. While the state wide peak occurred on 16 January 2014, the time of the state wide peak at 4.00pm on 14 January 2014 is more relevant for Powercor. The Powercor network reached its peak for residential customers at 5.30pm on 14 January 2014, solar PV contributed around 0.46 per cent of that demand, as shown in figure 4.6.

The use of embedded solar generation at times of the state wide peak are not relevant to the contribution of embedded solar generation to the Powercor network peak, which for residential customers on 14 January 2014 occurred 1 ½ hours later in the afternoon after the state wide peak.

[24] AEMO, *Heatwave 13-17 January 2014*, 26 January 2014, page 6, which is available from: http://www.aemo.com.au/News-and-Events/News/2014-Media-Releases/Heatwave-13-to-17-January-2014

Figure 4.6 Domestic consumption of electricity on 14 January 2014



Source: Powercor

It should also be noted that the generation output of solar rooftop PV on any particular day depends on cloud conditions on the day. Therefore the extent to which solar PV contributes to addressing peak demand on a given day cannot be guaranteed.

In the period from 2009 to 2013, the Powercor network peak occurred between 4.00pm and 5.00pm in four out of the five years.[25] It is clear that even if the amount of embedded generation in the network continues to rise, this will have minimal impact on addressing peak demand.

In reviewing the AEMO post model adjustments for solar PV, CIE and Oakley Greenwood identified four material assumptions in AEMO's payback model, all of which in our opinion, would place downward pressure on the installed capacity of solar PV forecasts:[26]

- assuming that 50 per cent of all energy that is produced will be exported is too high unless large increases in the penetration of solar PV on commercial rooftops is assumed (which it does not appear to given comments in the NEFR);
- methodology makes no allowance for the possibility that tariff structures (as opposed to tariff levels) will be adjusted in response to National Electricity Rules (**Rules**) changes requiring a move to cost-reflective tariffs and competitive pressure placed on distributors;
- methodology makes no allowance for the removal of feed-in-tariffs and the consequential longer payback period; and
- forecasts do not appear to have taken into account the risk that current incentives for purchases of solar PV will decline in the future.

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[25] Refer Table 5.3.1 of the 2013 Category Analysis RIN for Powercor.

[26] CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, 16 January 2015, pp. 21–22.

A further review of the connection point forecasting process used by the AEMO was undertaken by GHD. In relation to solar rooftop PV forecasts of Victorian distributors and AEMO, GHD noted that the difference "could reflect over-optimistic assumptions about generation from a given installed capacity by AEMO".[27] GHD's report, *Review of AEMO Demand Forecasting Methodology* is attached.

4.1.2 Energy efficiency programs

AEMO states that energy efficient savings are derived from three broad categories:

- appliances;
- buildings; and
- industrial.

In reviewing the AEMO post model adjustments for energy efficiency, CIE and Oakley Greenwood found that the forecasts for appliances were based on an unpublished report. While they were unable to comment on the input assumptions, they noted that load factors were applied uniformly across different appliances rather than split by appliance type. Such a split would be appropriate, for example, if a higher proportion of the improvements in energy efficiency are forecast to come from hot water systems and lighting, which is likely, then there would only be a small contribution to peak demand in comparison to air-conditioners.[28]

Secondly, CIE and Oakley Greenwood commented on the inappropriate assumption of the same load factors being applied to building energy savings for residential and commercial premises. This is because if the system peak is outside of business hours, then many of the businesses may not be operating at that time.[29]

Finally, in relation to industrial efficiency, CIE and Oakley Greenwood found that the AEMO assumption that energy efficiency programs would be implemented by industry irrespective of the fact that the funding program has been scrapped by the Federal Government is unlikely to be reasonable.[30]

GHD noted in their review of the AEMO forecasts that "the energy efficiency assumptions made by AEMO are at the high end of a wide range of uncertainty".[31]

27 GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, p. 20.

28 CIE and Oakley Greenwood, *Review of transmission connection point forecasts*, 16 January 2015, pp. 28-30.

29 CIE and Oakley Greenwood, *Review of transmission connection point forecasts*, 16 January 2015, pp. 30-33.

30 CIE and Oakley Greenwood, *Review of transmission connection point forecasts*, 16 January 2015, pp. 33-34.

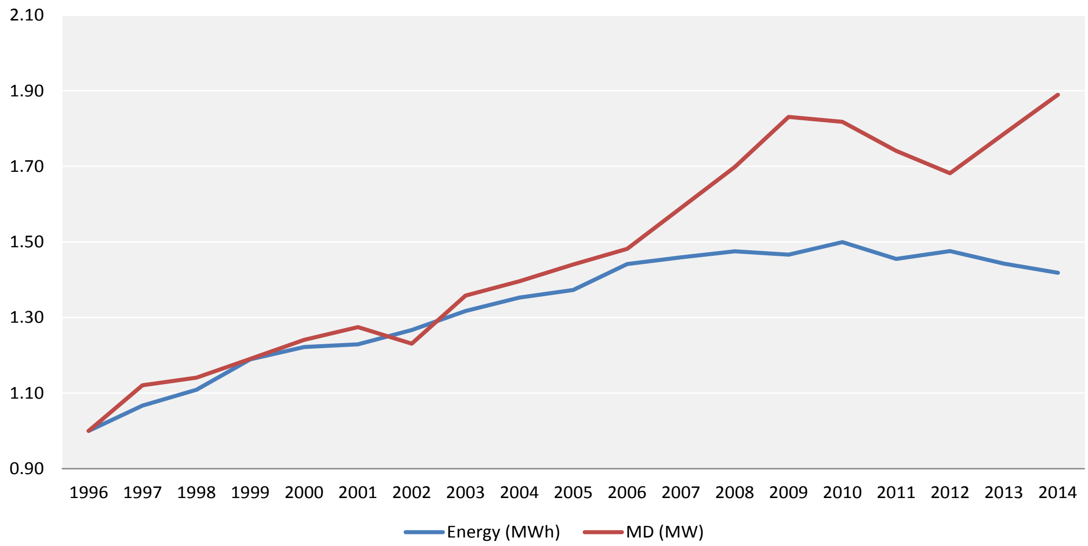
31 GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, p. 17.

5 Energy forecasts

Energy refers to the amount of consumption of electricity over a period of time, as opposed to peak demand which refers to the maximum consumption of electricity at a specific point in time.

While peak demand has been increasing historically for Powercor, energy has not. The relationship between energy and demand is shown in table 5.1, where the data has been indexed to 1996 and the cumulative growth rate since 1996.

Table 5.1 Powercor growth in energy and maximum demand



Source: Powercor

Powercor engaged CIE to develop its energy volume forecasts for the 2016-2020 regulatory control period. CIE forecast growth rates in energy volumes for residential, commercial and industrial customers, taking into consideration factors that drive demand for a particular tariff class and factors that contribute to network wide demand growth, including:

- historical trends in energy usage;
- projections of customer numbers by tariff class;
- block-load forecasts; and
- economic conditions such as incomes and electricity prices.

CIE's report, *Tariff volume forecasts,* is attached.

Table 5.2 sets out the forecast growth in energy volumes for the 2016-2020 regulatory control period.

Table 5.2 Energy volume growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Energy growth rates	2.06	1.25	1.01	1.35	1.35	1.24

Source: CIE, *Tariff volume forecasts*, February 2015, p. 16.

6 Customer forecasts

Powercor engaged CIE to develop its customer number forecasts for the 2016-2020 regulatory control period. CIE forecast the growth rate in customer numbers for residential, commercial and industrial customers as follows:

- residential customers—based on the forecast growth in dwelling numbers by Local Government Area (**LGA**) produced by the Victorian Planning and Local Infrastructure. CIE mapped the relevant LGAs to Powercor's network area;
- commercial customers—based on a time trend from the most recent data point (2013); and
- industrial customers—assumed zero growth from the most recent data point (2013).

CIE's report, *Tariff volume forecasts,* is attached.

Table 6.1 sets out the forecast growth in customer numbers for the 2016-2020 regulatory control period.

Table 6.1 Customer number growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Customer number rates	1.75	1.75	1.81	1.82	1.82	1.82

Source: CIE, *Tariff volume forecasts*, February 2015, p. 7.