2016–2020 Price Reset

Appendix C
Demand, energy and customer forecasts

April 2015

CitiPower
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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, drive a spike in demand

When demand is forecast to be greater than the capacity of the network in a particular area, then CitiPower 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.

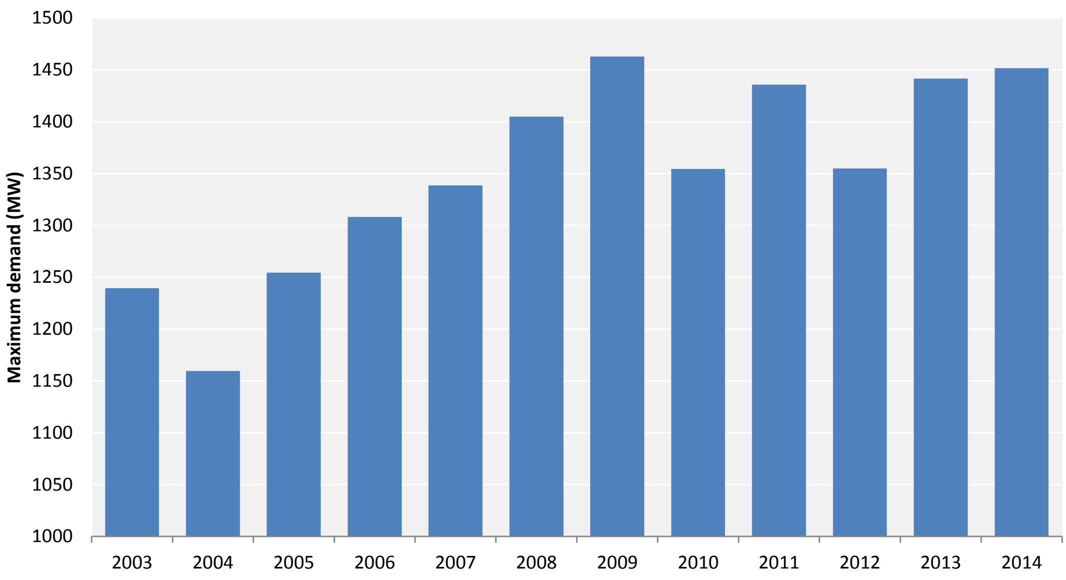
The forecasts indicate that demand is increasing, even though usage energy has been declining. It is demand, however, that drives investment.

CitiPower's demand forecasts have been prepared using a robust process that combines its own detailed local knowledge with independent economic analysis.

CitiPower experienced a near network peak on 12 March 2013 of 1442MW, just shy of its highest ever peak of 1463MW reached on 29 January 2009. The peak in 2013 was recorded at 3.30pm, reflecting the large amount of commercial demand.

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

Figure 1.1 Increasing 'raw' level of peak demand



Source: CitiPower

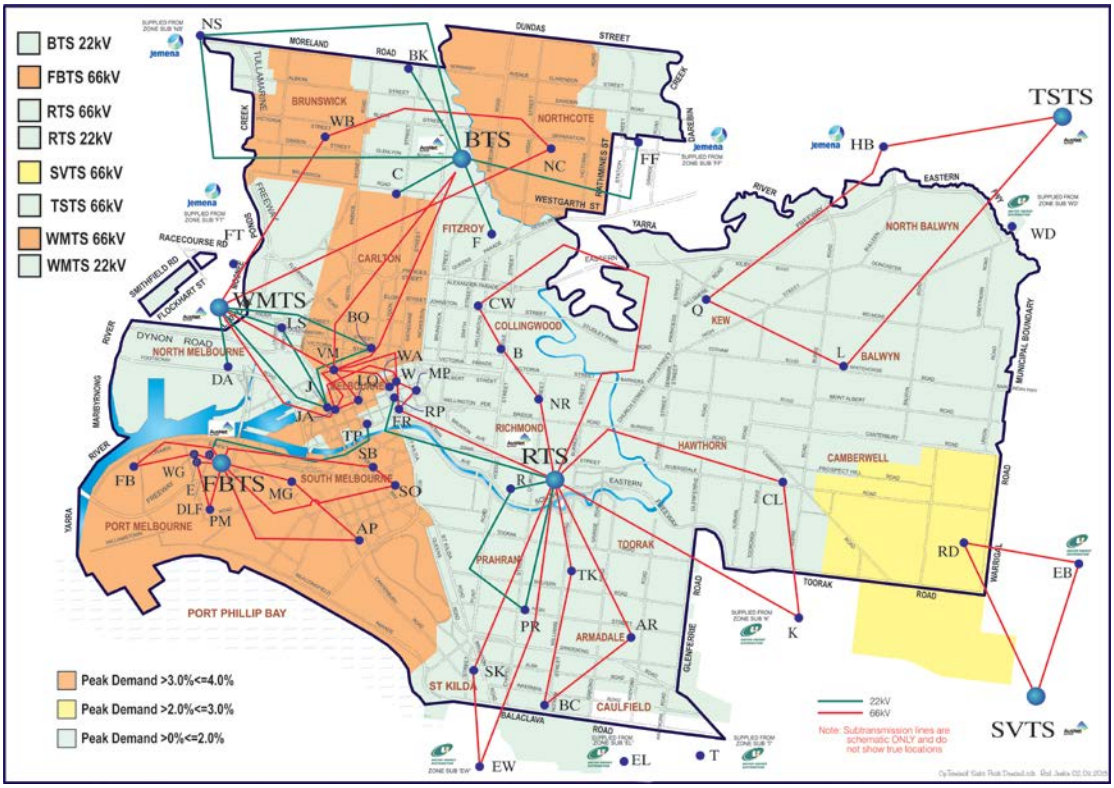
The use of air-conditioners by commercial and residential households was a key driver to the network peak, as it was during a ten day heatwave in Melbourne. Increases in the frequency and duration of heatwaves[1] will be a significant contributor to a new record peak occurring in the future.

Over the 2016–2020 regulatory control period, CitiPower expects peak demand to increase in specific areas of its network. The increase in peak demand will be driven by:

- transfer of load around the network given the program to retire the 22kV sub-transmission network;
- population expansion, particularly along established and proposed transport corridors driven by changes in zoning; and
- block load additions from specific projects.

Figure 1.2 highlights the areas of the network where increases in demand are expected.

Figure 1.2 Peak demand forecasts by zone substation



Source: CitiPower

The methodology and evidence underpinning CitiPower'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 CitiPower's forecasts, and thus why they should not be relied upon.

2 Growth in the distribution area

The areas that CitiPower has identified for the continued growth in peak demand is supported by a range of evidence from government and sectorial information that is publicly available.

In its response to the Directions and Priorities Consultation Paper, the City of Melbourne noted that:[2]

> *... the electrical network will need to facilitate significant growth within the central city and surrounds. Plan Melbourne, the Victorian Government's Metropolitan Planning Strategy released in 2014, predicts there will be an additional 310,000 dwellings in the central city and surrounds. This area referred to as the Central Subregion in Plan Melbourne, is projected to grow from 485,000 residents in 2013 to 765,000 residents by 2031. This will help support Melbourne's central city as Australia's largest business centre with a growth from 435,000 jobs in 2011 to almost 900,000 jobs by 2051. As part of the Central Subregion, the City of Melbourne is growing quickly and will continue to do so. In 2013, the City of Melbourne was the fastest growing local government area in Australia with over 11,000 new residents.*
>
> *By 2021, the residential population of the municipality is estimated to be over 150,000 residents living in 92,000 homes, increasing to over 190,000 residents living in over 115,000 homes by 2031. The majority of our new housing will occur in our growth areas, which offer significant development opportunities as they transition from predominately industrial or commercial uses to a mix of uses, including high density housing. These areas include City North and Arden-Macaulay to the north of the city, the Hoddle Grid, Southbank, Fishermans Bend, Docklands and E-gate. Fishermans Bend, in both the City of Melbourne and City of Port Phillip, is the largest urban renewal area covering 250 hectares and expected to accommodate 40,000 new jobs and 80,000 new residents by 2051.*

The Victorian Government's projections for annual population growth reinforce CitiPower's expectations of strong population growth in inner Melbourne. The Government has noted that:[3]

> *Population growth and change are not evenly distributed across Victoria. Greater Melbourne attracts the bulk of Victoria's overseas migrants, and due to its large share of the population (76 per cent in 2013) also accounts for the majority of the natural increase. These trends are likely to continue and Greater Melbourne is projected to have more than 80 per cent of the state's growth up to 2051.*
>
> *…*
>
> *Within Greater Melbourne, the areas with the greatest capacity for dwelling growth are the outer growth areas and the inner city. This is reflected in projected population growth. While the middle suburbs are expected to regenerate and increase steadily in population, the designated growth areas (52 per cent) and the five inner LGAs (15 per cent) are expected to account for two thirds of population growth to 2031.*

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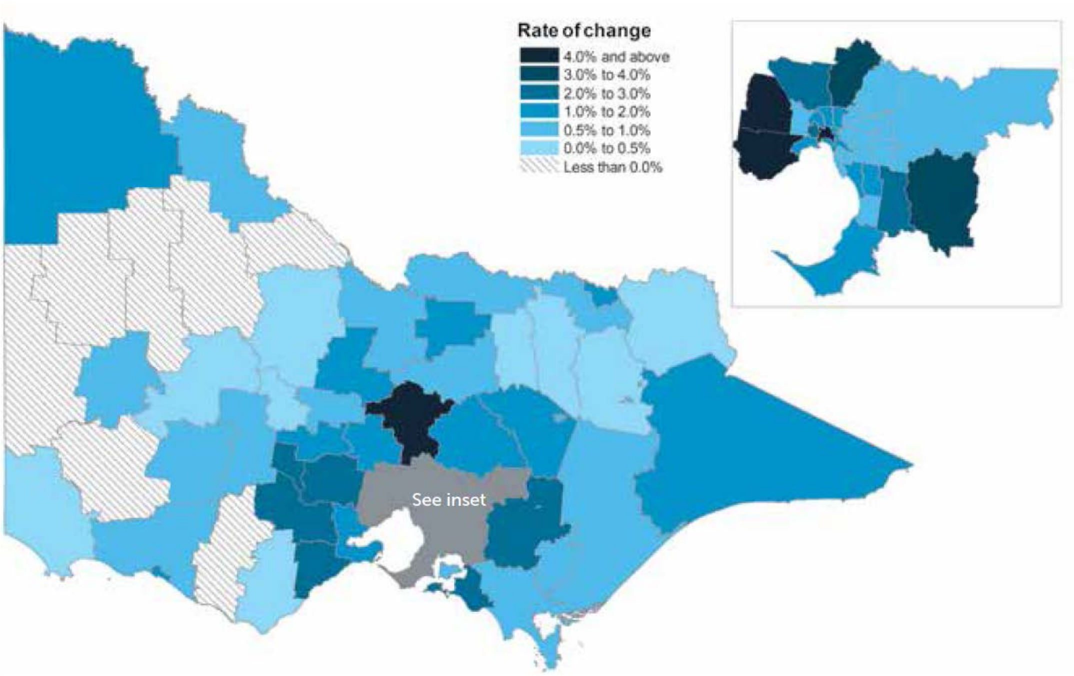
[2] City of Melbourne, *Feedback to the Directions and Priorities Consultation Paper*, October 2014, pp. 6-7.

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

The Victorian Government's projections for annual population growth are shown in Figure 2.1.

Figure 2.1 Rate of projected annual population change by Local Government Area, 2011 to 2031[4]



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

[4] Department of Transport, Planning and Local Infrastructure, *Victorian In Future 2014 – population and household projections to 2051*, May 2014, page 6. Available from: http://www.dpcd.vic.gov.au/__data/assets/pdf_file/0015/171240/VIF-2014-WEB.pdf

3 Approach to peak demand forecasting

Overall, CitiPower is forecasting an increase in demand in particular areas in its distribution area. 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.

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 CitiPower's demand forecasting process was to align its econometric modelling with that used by Australian Energy Market Operator (**AEMO**).

CitiPower 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.

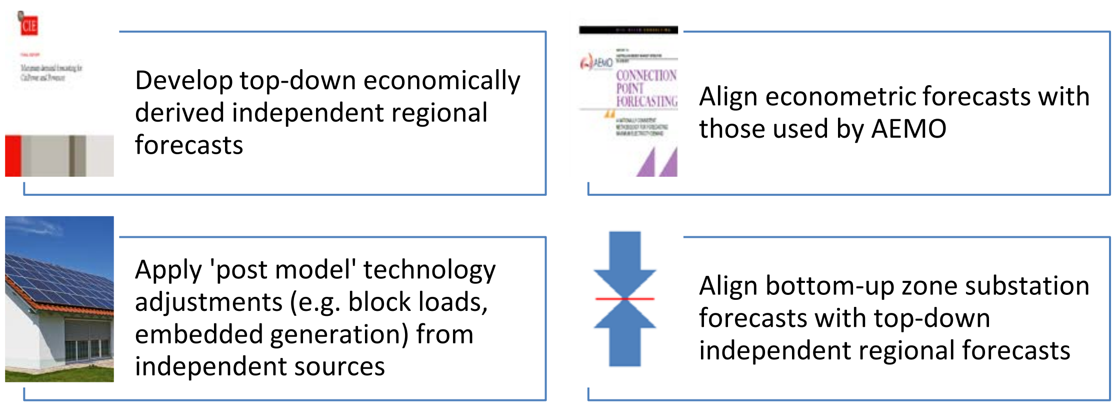
Use of demand forecasts

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 will consider both network and non-network solutions, as per CitiPower'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 CitiPower's forecasting process are shown in the figure below.

Figure 3.1 Key elements of CitiPower'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

CitiPower 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 CitiPower 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.[5]

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.

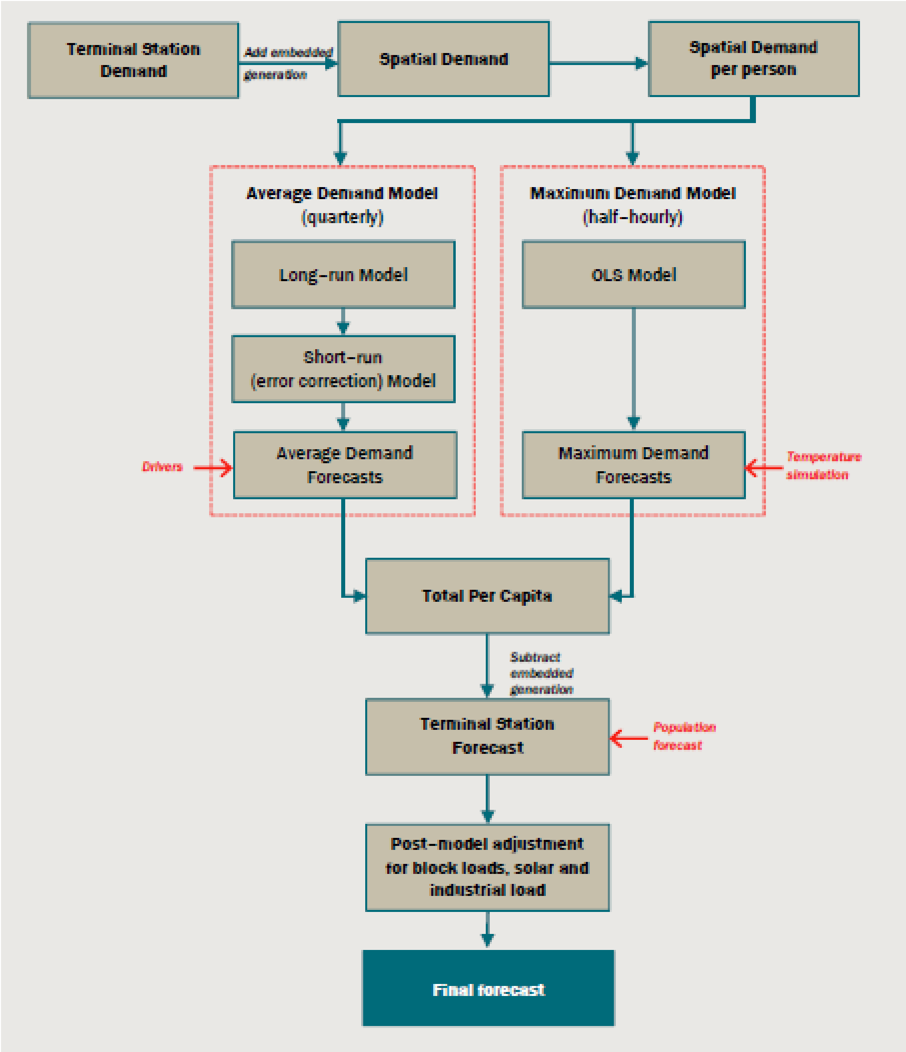
CIE's approach to forecasting maximum electricity demand for terminal stations was broadly consistent with the two-step approach used by AEMO in its preparation of the 2013 National Electricity Market electricity forecasts. The first step was a model of average demand and the second step was a model 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 3.2 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.

[5] 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 3.2 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.[6] 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 CitiPower, however it is noted that:

- forecast block load additions were only included where the customer had accepted an offer to connect, or where the CitiPower offer to connect had not yet been accepted by the customer but was still valid, and CitiPower considered that the probability of a project proceeding was very high;
- CitiPower 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 in the CitiPower area. The CIE made post-model adjustments for solar photovoltaic (**PV**) rooftop 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.[7]

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

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

Figure 3.3 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.[8]

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

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

Figure 3.4 CIE aggregate maximum demand forecasts for CitiPower including post-modelling adjustments

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Summer Maxima										
90% PoE	1396.8	1485.3	1529.9	1569.0	1592.6	1597.7	1611.0	1617.7	1605.9	1606.0
50% PoE	1497.7	1581.2	1641.6	1679.9	1712.2	1712.7	1732.2	1741.3	1748.7	1756.6
10% PoE	1598.3	1686.8	1752.1	1802.3	1846.8	1837.3	1877.2	1901.3	1939.1	1975.4
Winter Maxima										
90% PoE	1078.5	1138.9	1162.9	1181.5	1182.3	1179.6	1173.9	1160.6	1146.3	1123.6
50% PoE	1101.9	1162.1	1188.5	1204.8	1206.1	1203.7	1199.1	1185.8	1171.0	1153.1
10% PoE	1135.6	1193.3	1221.8	1237.0	1240.1	1234.5	1232.3	1219.4	1203.0	1209.3
Annual Maxima										
90% PoE	1396.8	1485.3	1529.9	1569.0	1592.6	1597.7	1611.0	1617.7	1605.9	1606.0
50% PoE	1497.7	1581.2	1641.6	1679.9	1712.2	1712.7	1732.2	1741.3	1748.7	1756.6
10% PoE	1598.3	1686.8	1752.1	1802.3	1846.8	1837.3	1877.2	1901.3	1939.1	1975.4

Note: All forecasts are in MW.

Source: CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014, pp. 129-130.

Using the above figures, the annual change in coincident maximum demand at the network level, in Megawatts (MW), is shown in figure 3.5.

Figure 3.5 Coincident annual maximum demand at terminal stations annual growth rate

	2016	2017	2018	2019	2020
50% PoE	5.6	3.8	2.3	1.9	0.0
10% PoE	5.5	3.9	2.9	2.5	-0.5

Source: CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014, p. 130.

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.[9]

3.1.1 Amendments to the top-down forecasts

CitiPower has not simply taken the output of the econometric analysis at each terminal station to derive its forecasts. Rather, CitiPower 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, CitiPower 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

[9] 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 these situations, CitiPower 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.[10]

> *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, CitiPower 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 CitiPower's 'top-down' forecasts for the purposes of reconciling with the 'bottom-up' forecasts.

3.2 Bottom-up forecasts

CitiPower had prepared bottom up, rolling ten year summer and winter 50 per cent Probability of Exceedance (**PoE 50**) maximum demand[11] forecast for each terminal station, and minimum six year forecasts for zone-substations and sub-transmission lines. CitiPower undertook the following three steps.

First, CitiPower 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, CitiPower 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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[10] 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.

[11] 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, CitiPower aggregated the maximum demand forecasts at each asset level, taking into account the diversity and power factor.[12]

3.3 Reconciliation

As a final step, CitiPower 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.

CitiPower has had the reconciliation process independently reviewed by ACIL Allen, and their report entitled *Demand Forecasts Reconciliation Review* is attached. ACIL Allen noted that:[13]

> *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 CitiPower'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.[14].

These improvements will be incorporated in future reconciliation processes but have had no impact on augmentation requirements.

3.4 Use of forecasts

The reconciled demand forecasts were used by CitiPower 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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[12] The maximum demand forecasts are 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.

[13] ACIL Allen, *Demand forecasts – reconciliation review*, 27 January 2015, p. ii.

[14] 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
- bottom-up 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.

CitiPower 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 CitiPower 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 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.[15] 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.

CitiPower will continue to work with AEMO as they continue to develop and refine their forecasts. However, given the concerns with AEMO’s forecasts, CitiPower considers it appropriate that the AER relies upon CitiPower’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.[16] The change in forecast is shown in figure 4.1.

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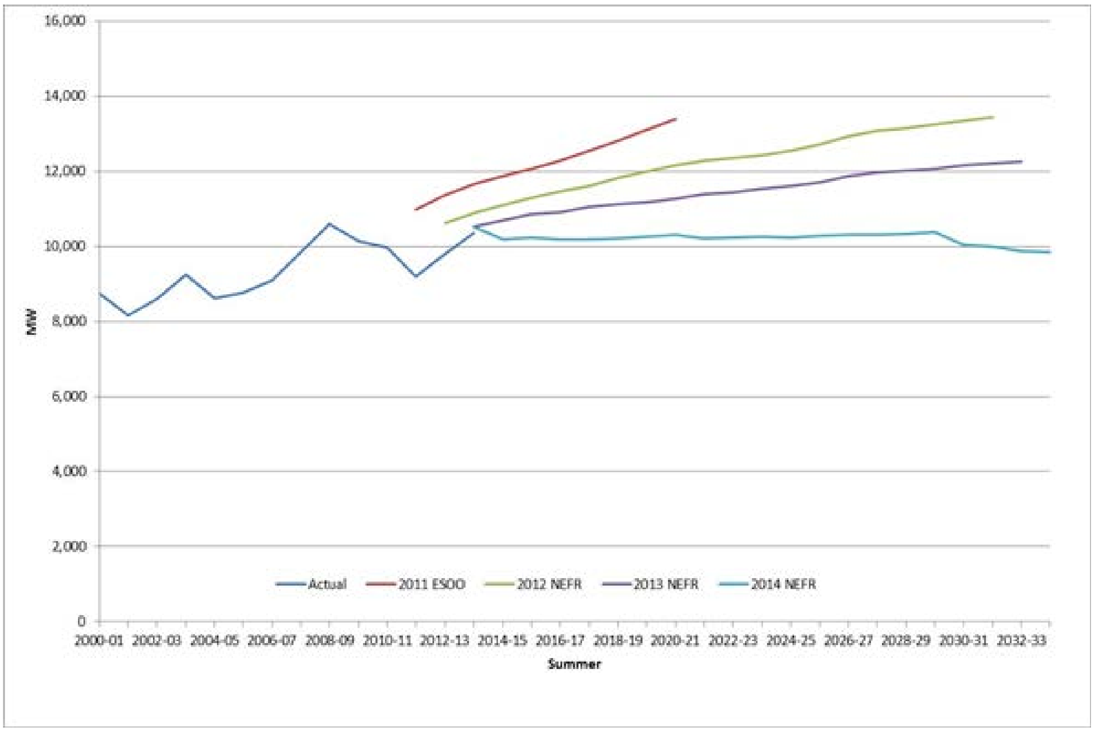
15 For example, see AER, *Draft Decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 6: capital expenditure*, November 2014, pp. 6-85 to 6-90.

16 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

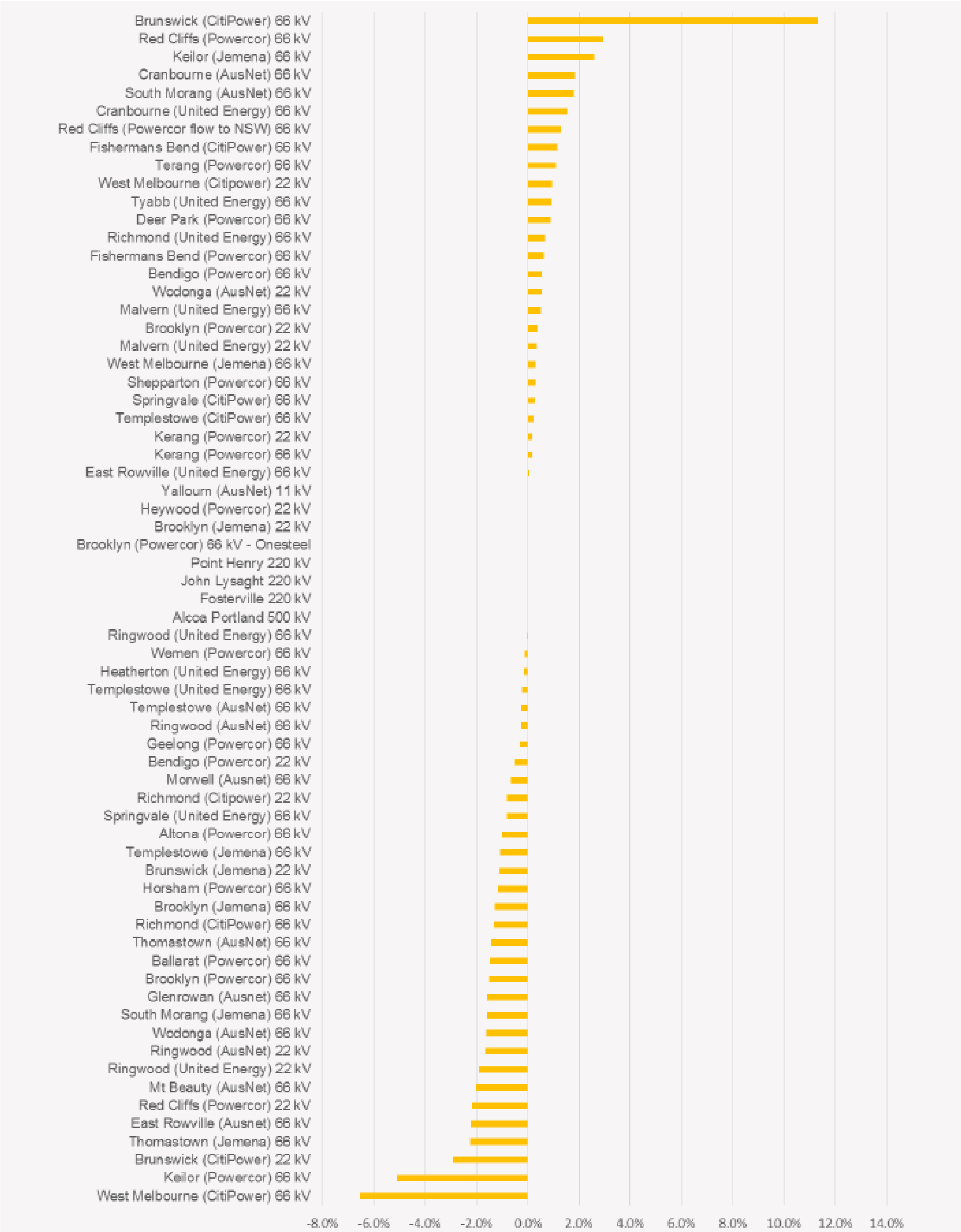
Step	Description
1. Prepare data	Obtain and clean demand and weather data. Determine demand profile and demand mix.[10]
2. Weather normalise	Determine weather sensitivity at each connection point.
3. Select starting point	Determine where the forecasts should start from: last historical point or time 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 West Melbourne 66kV to Brunswick 66kV.

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.[17]

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:[18]

> *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.

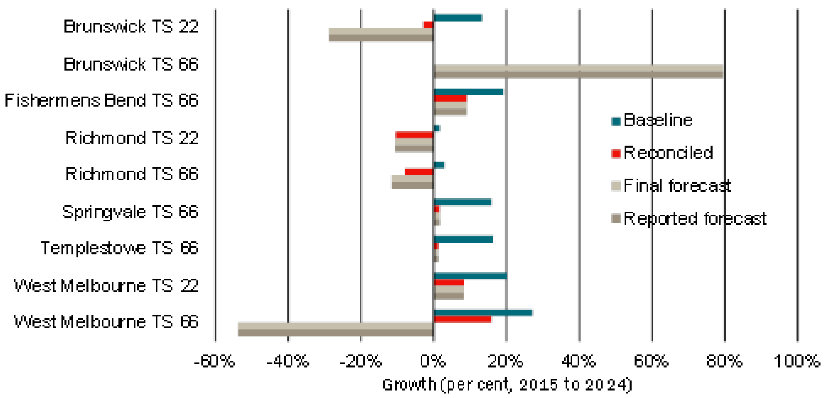
4.1 Comments on AEMO's approach

CitiPower 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 CitiPower as a result of moving from baseline to reconciled forecasts, as shown in figure 4.3.

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. 4.

17 AEMO, *AEMO Transmission Connection Point Forecasting Report for Victoria*, September 2014, p 5.

18 AEMO, *AEMO Transmission Connection Point Forecasting Report for Victoria*, September 2014, p 2.

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

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

- rooftop solar PV, and
- energy efficiency.

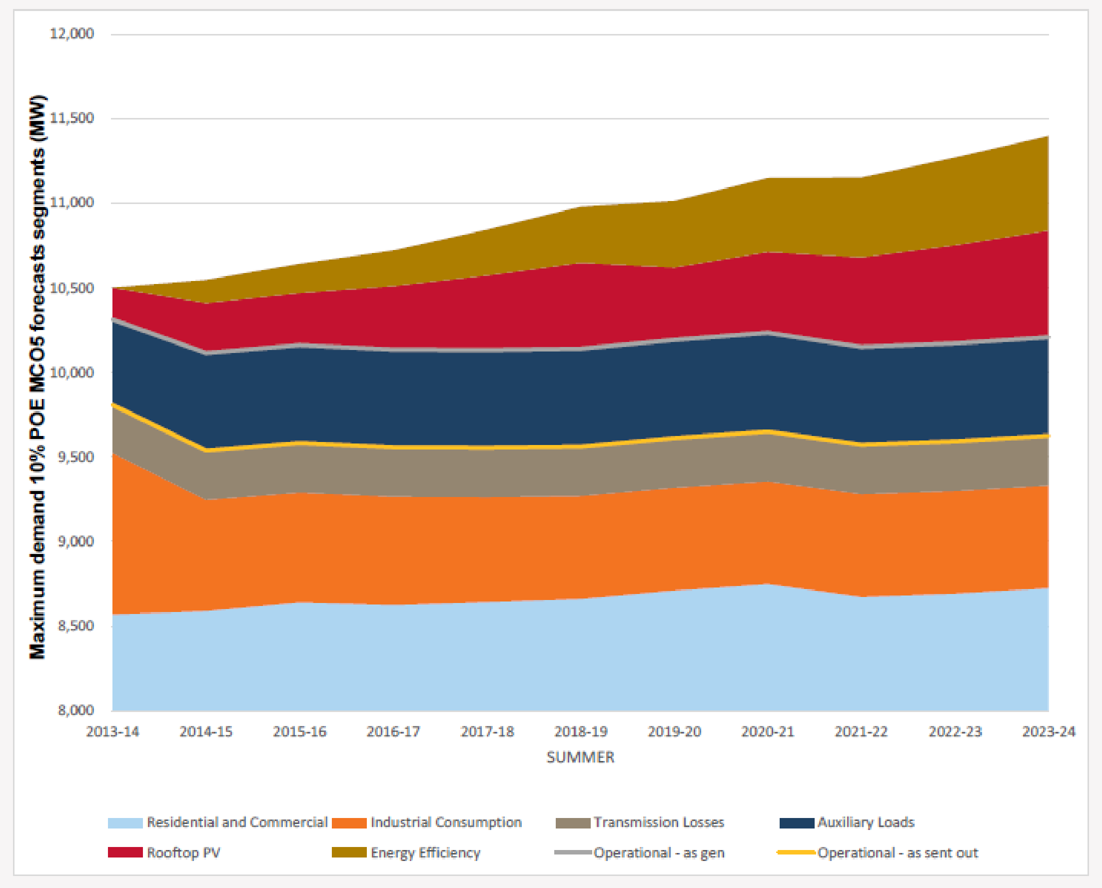
AEMO obtained the rooftop solar PV and energy efficiency aspects of the forecasts from its NEFR report. That report notes that for Victoria, its short term forecast key drivers include:[19]

- 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.

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

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.[20]

[20] 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

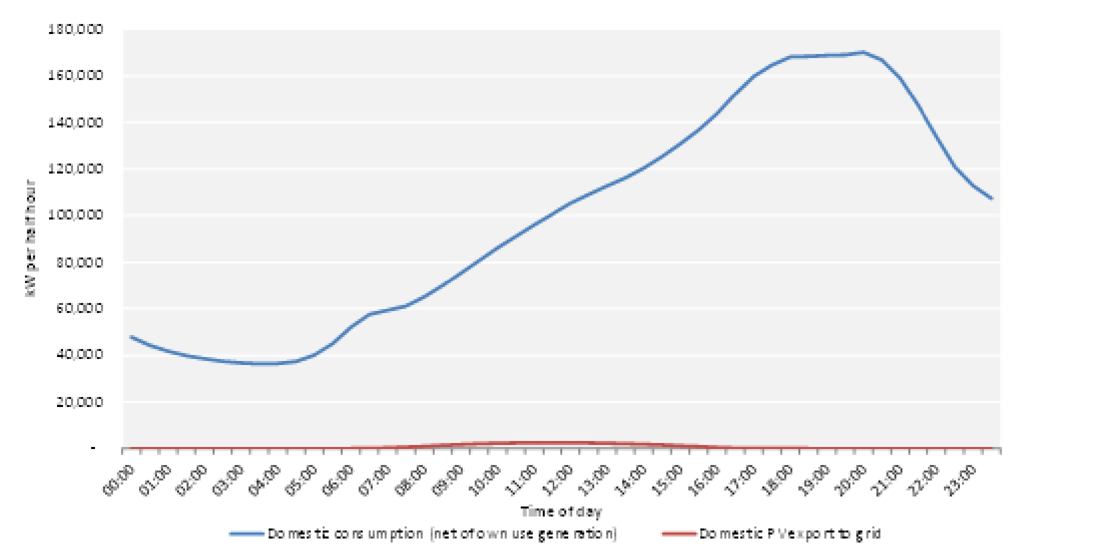
Figure 4.5 AEMO statistics on the percentage contribution to peak operational demand by generation source for Victoria

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.

CitiPower's experience is that solar PV makes a very small contribution, if any, to demand. For example, when CitiPower's network reached its peak for residential customers at 8.00pm on 14 January 2014, solar PV contributed around 0.007 per cent of that demand, as shown in figure 4.6.

Figure 4.6 Domestic consumption of electricity on 14 January 2014



Source: CitiPower

It should 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 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 installation forecasts:[21]

- 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 pay back 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.

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'.[22] 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 is 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.[23]

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.[24]

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

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

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

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

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.[25]

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'.[26]

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

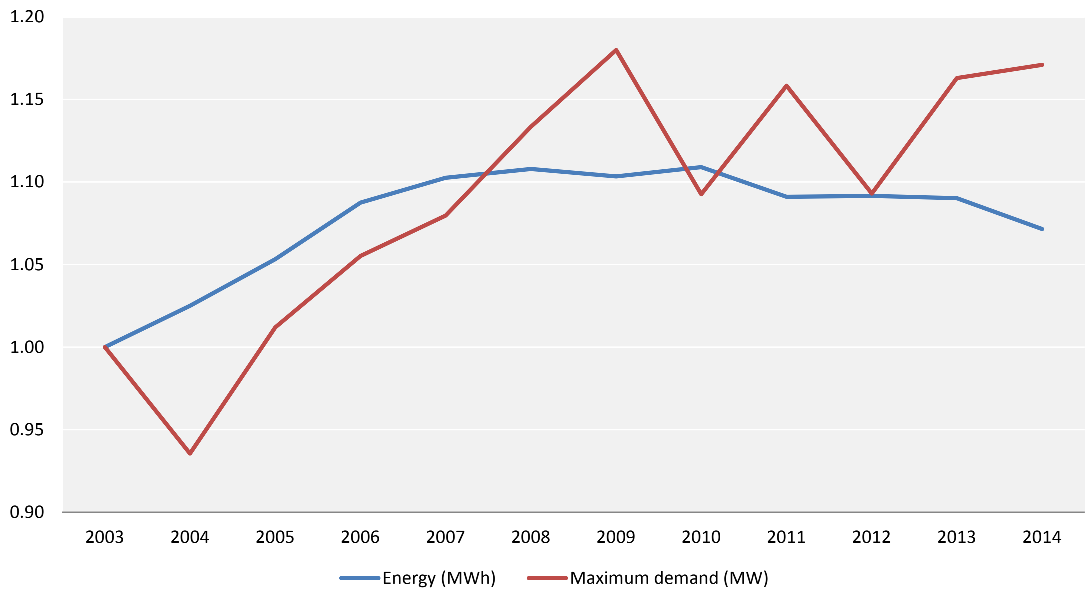
[26] GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, p. 17.

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 CitiPower, energy has not. The relationship between energy and demand is shown in table 5.1[27], where the data has been indexed to 1996 and the cumulative growth rate since 1996 shown in the figure below.

Table 5.1 CitiPower growth in energy and maximum demand



Source: CitiPower

CitiPower 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 income 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.

27 Demand is reflected as coincident demand at the terminal station (including embedded generation) and energy is the total energy at the terminal station. The data is not weather corrected.

Table 5.2 Energy volume growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Energy growth rates	3.06	3.05	2.43	1.80	1.39	1.24

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

6 Customer forecasts

CitiPower 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 CitiPower'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	1.98	1.97	1.60	1.60	1.59	1.58

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