

Maximum demand and customer numbers

CP APP03 - Maximum demand and customers -
Jan2020 - Public

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1 Overview

This document summarises our approach to forecasting maximum demand growth and customer number growth. We forecast maximum demand and customer numbers as drivers of the size of the network.

1.1 Maximum demand

Maximum (or peak) electricity demand is the highest demand, measured in megawatts (**MW**), experienced by the network in any 30-minute interval. This is in contrast to average demand that represents the average demand per customer generally over a 12 month period. Maximum demand is an important measure of the required capacity of the network, as the network needs to be able to accommodate at least the maximum demand at any given 30-minute interval.

Our total maximum demand for the network can be:

- coincident—a particular 30-minute interval where the summated demand across each terminal or zone substation is the highest
- non-coincident—a sum of the highest demands at each terminal or zone substation, regardless of which 30-minute interval each maximum demand occurs.

The non-coincident maximum demand forecasts are the most relevant in planning the network's capacity, as we need to examine each network area considering the characteristics of that part of our network. We also use the sum of all non-coincident terminal station level maximum demand in our rate of change calculation for forecasting operating expenditure, as a measure of the change in scale of output.

We engaged the Centre of International Economics (**CIE**) to develop top-down maximum demand forecasts at terminal station level, using our actual Advanced Metering Infrastructure (**AMI**) data. We then forecast a bottom-up maximum demand forecast at zone substation level for each terminal station, also using our AMI data and network knowledge. We reconciled the two approaches to develop the final maximum demand forecasts. The network level forecasts, calculated as a sum of non-coincident demand at each terminal station, are shown in table 1.

Table 1 Maximum demand forecasts, non-coincident weather adjusted 50% POE

	2021/22	2022/23	2023/24	2024/25	2025/26
CitiPower	1,735	1,887	1,725	1,750	1,775

Source: CP MOD 9.04 - Maximum demand forecasts - Jan2020 - Public

Our demand growth is expected to remain relatively subdued over the five year period ending in 2025/26. For more details on growth areas refer to our regulatory proposal augmentation chapter.

1.2 Customer numbers

Our customers range by type, including residential, commercial and unmetered supplies (e.g. telecommunications box). We provide electricity supply and various other services to each customer type. As our customer base grows we must expand our services to meet each customer's needs. We therefore use customer number forecasts in the rate of change calculation for forecasting operating expenditure, as a measure of the change in scale of output.

We engaged CIE to develop independent customer number forecasts by customer type¹. Table 2 summarises their forecasts for the 2021–2026 regulatory period.

Table 2 Forecast customer number per customer type for the 2021–2026 regulatory period

	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	297,495	301,059	304,417	307,592	310,592
Non-residential	48,454	49,256	50,057	50,859	51,661
Low voltage	9,094	9,163	9,232	9,302	9,371
High voltage	101	101	101	101	101
Unmetered	5,490	5,740	5,990	6,240	6,490
Other	-	-	-	-	-
Other customers	360,635	365,319	369,798	374,094	378,215

Source: CP MOD 9.03 - CIE customer number forecast - Jan2020 - Public

¹ Customer types is as per the Australian Energy Regulator's Economic Benchmarking Regulatory Information Notice template, 3.4 Operational data.

2 Maximum demand forecasts

Our maximum demand forecast approach includes two steps:

- develop top-down economically derived independent maximum demand forecasts at terminal stations, including 'post-model' adjustments (e.g. block loads, embedded generation) from independent sources
- align bottom-up zone substation forecasts with top-down independent terminal station forecasts.

2.1 Top-down maximum demand forecasts at terminal stations

We engaged CIE to forecast maximum electricity demand at each terminal station. 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 the Australian Energy Market Operator (AEMO) for connection point forecasting.²

We summarise the CIE approach below. For a complete explanation of their approach, refer to attachment CP ATT022 - CIE - Maximum demand forecasting - Mar2019 - Public.

CIE used a two-step process:

1. modelling average demand with a statistical model
2. estimating a model of distributional maximum demand, dependent on calendar effects (time of day and week) and climatic effects.

This approach is similar to the approach used by AEMO to produce the 2018 National Energy Forecast Insights and Electricity Statement of Opportunities, and is consistent with the AER-approved approach for our maximum demand forecasts for the 2016-2020 regulatory period.³

CIE forecasts are based on statistical modelling that estimates the historic relationship between demand drivers; for example, the relationship between income and electricity prices in the average demand model and the relationship of these drivers with temperature in the maximum demand model. The projected driver variables are then used to estimate demand based on the historical relationships. To ensure robustness of the modelling, each terminal station model incorporates ten years of our historical 30-minute wholesale metering data up to the 2017/18 summer.

Figure 1 summarises the key drivers of average demand for electricity.

² CP ATT023 - ACIL Allen - Connection point forecasting - Jun2013 - Public. This is a nationally consistent methodology for forecasting maximum electricity demand

³ CP ATT095: AER, Final Decision CitiPower distribution determination 2016 to 2020, Attachment 6 – Capital expenditure, May 2016, p.84; p.94

Figure 1 Average demand drivers

Variable	Data	Spatial disaggregation
Population	<ul style="list-style-type: none"> Resident population 	<ul style="list-style-type: none"> Local Government Area
Real income per capita	<ul style="list-style-type: none"> Average nominal personal income per capita CPI 	<ul style="list-style-type: none"> Local Government Area Capital city (Melbourne)
Real electricity prices	<ul style="list-style-type: none"> Origin retail tariff prices (average, marginal and time of use) CPI Share of customers on time of use tariffs Share of demand by customer type 	<ul style="list-style-type: none"> Part of state (Victoria) Capital city (Melbourne) Terminal station area Terminal station area
Temperature	<ul style="list-style-type: none"> CDDs (Cooling degree days) HDDs (Heating degree days) 	<ul style="list-style-type: none"> Weather station area
Air conditioning index	<ul style="list-style-type: none"> Penetration rate 	<ul style="list-style-type: none"> State (Victoria)
Solar PV capacity	<ul style="list-style-type: none"> Solar PV capacity 	<ul style="list-style-type: none"> Terminal station area

Source: CP ATT022 - CIE - Maximum demand forecasting - Mar2019 - Public, p.10.

The main difference between the 2015 model and the 2018 model is the inclusion of installed solar photovoltaic (PV) capacity as a variable in average demand model. This is to account for a growing residual between estimated and observed average demand since 2015. Including solar PV capacity significantly improves performance of the model and reduces the residuals.

2.1.1 Forecasting summer and winter maximum demand

Maximum demand can occur during the summer season or the winter season, depending on the terminal station. CIE use 96 separate half-hourly models (48 each for summer and winter) to predict demand at different times of the day in each season. This allows for relationships between the temperature and calendar variables to vary throughout the day and between seasons.

As weather patterns cannot be accurately forecasted over the time horizon required, CIE simulated future weather, using historical weather data, to obtain predicted maximum demand for 1,000 summers and winters for each forecast year.

The results of the simulation are combined with the average electricity demand forecasts to give a distribution of maximum demand for each year of the forecast period. From the distribution of weather outcomes for a given year, CIE then predict maximum demand through Probability of Exceedance (POE) forecasts.

2.1.2 Post-model adjustments

Once maximum demand is estimated at each terminal station, the result is adjusted for the following factors:

- block loads

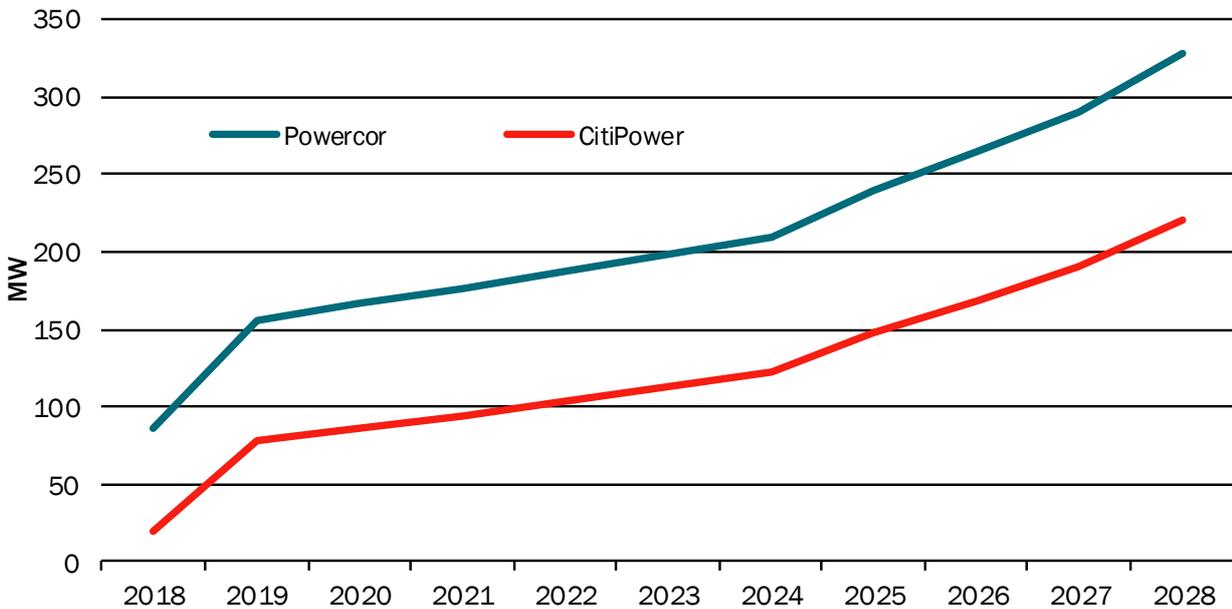
- rooftop solar PV
- electric vehicles
- battery storage
- other forms of distributed generation (excluding PV).

This is consistent with the approach taken for the 2015 model that the AER approved. We provided block load estimates to CIE, based on known planned changes, including new industrial load, existing industrial loads being removed and transfers between terminal stations.

As with the 2015 model, CIE engaged Oakley Greenwood to develop the forecasts for new technologies on the network. Attachment CP ATT024 - OGW - Adjustments for terminal station - Dec2018 - Public details Oakley Greenwood's forecasting approach and CP MOD 9.05 - OGW new technologies - Jan2020 - Public provides the detailed forecasts of each category.

The largest post-model adjustment for new technologies is the impact of new solar PV on the network. The adjustments include estimates of solar PV resulting from the Victorian Government 'Solar Homes' policy, overlaid onto the initial AEMO solar forecasts.

Figure 2 Post-modelling adjustment for solar PV generation



Source: CP ATT022 - CIE - Maximum demand forecasting - Mar2019 - Public, p.47

CIE did not make post-model adjustments for electric vehicles, battery storage and other forms of distributed generation as CIE considered that the impact of these technologies was small and more uncertain over the period up to 2026. Oakley Greenwood also forecast energy efficiency; however, there is no adjustment for energy efficiency as any trend is captured through historical energy demand data.

2.1.3 Comparison to AEMO terminal station maximum demand forecasting methodology

We sought CIE's independent forecasts, rather than using AEMO's 2018 terminal station connection point forecasts, for the following reasons:

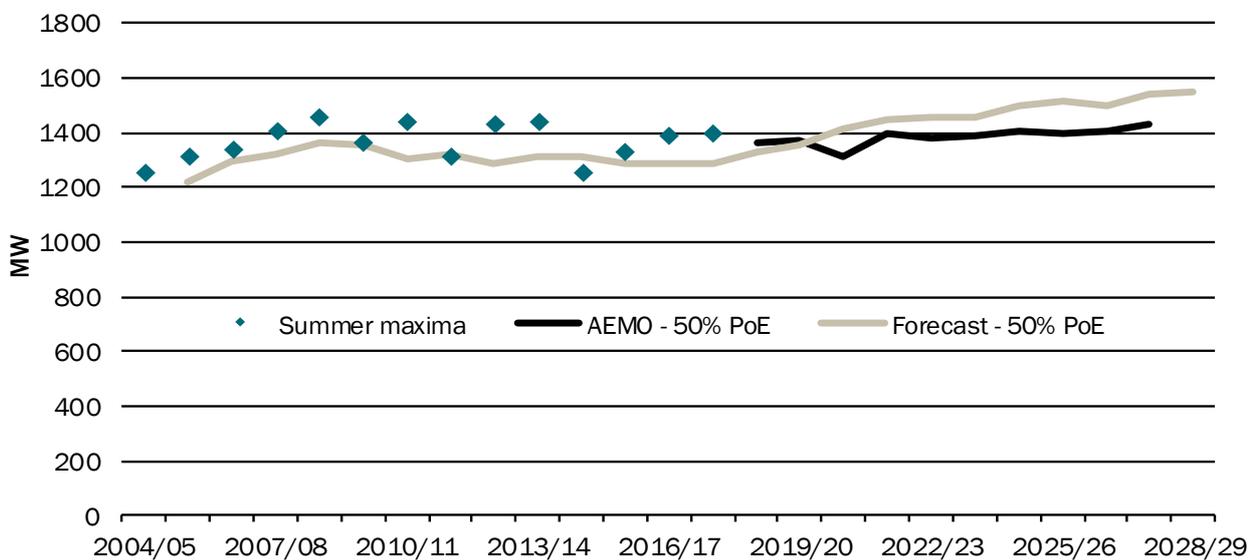
- CIE forecasts measure changes in drivers of electricity demand at each terminal station, allowing for any changes in drivers to be captured (e.g. areas where houses are replaced with apartment blocks)
- CIE forecasts use our AMI data and our own mapping of customers to terminal stations, whereas AEMO's mapping of each network's assets to terminal stations differs. The AER has previously acknowledged and noted the range of differences in the datasets used by AEMO and has noted that the AEMO forecasts were not 'tailor-made' for each distributor.⁴

The main difference between CIE's and AEMO's forecasting approach is that CIE estimate demand based on forecast drivers across each terminal station, whereas AEMO's approach is to forecast demand based on observed trends in the data at a terminal station level, which is then reconciled to regional forecasts. In short, CIE's forecasts measure if there are changes in trends at each terminal station while AEMO's forecast assume historical trends at each terminal station are indicators of future trends at the same station. As demand patterns can change at each terminal station based on the demographic changes in those areas, we consider CIE's approach will more correctly capture those changes.

Additionally, CIE's methodology allows for maximum and average demand to grow at different rates, which is consistent with the observed historical relationship on our network. However, AEMO does not give statistical significance to this diverging relationship, which is inconsistent with the observed trends.

CIE have compared their forecasts to AEMO's with the results shown in **Error! Reference source not found.** and figure 3. While CIE have provided commentary on the size of the difference, they have not been able to identify the reasons behind the difference. The starting points for CIE's and AEMO's forecasts of CitiPower's coincident demand are similar, while CIE forecasts a higher growth rate.

Figure 3 Total annual coincident maximum demand forecasts compared to AEMO's forecasts



Source: CP ATT022 - CIE - Maximum demand forecasting - Mar2019 - Public, p 153.

⁴ For example, see CP ATT221: AER, Draft Decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 6: capital expenditure, November 2014, p. 6-90.

2.1.4 Top-down maximum demand forecasts

Table 3 indicates the final network level maximum demand for CitiPower, as a sum of non-coincident maximum demand at each terminal station.

Table 3 Network level maximum demand forecasts, non-coincident weather adjusted 50% POE

	2021/22	2022/23	2023/24	2024/25	2025/26
CitiPower	1,513.5	1,544.4	1,578.4	1,640.3	1,667.3

Source: CP MOD 9.04 - Maximum demand forecasts - Jan2020 - Public

2.2 Bottom-up zone substation forecasts

We conduct bottom-up zone substation forecasts using an in-house forecasting tool that relies on actual AMI 30-minute data and trends observed at each zone substation, taking into account diversification factors. This gives us confidence that the differences between the zone substations at one terminal station are appropriately captured, while the summation of the zone substations aligns with the top-down independent forecasts for the terminal station.

This ensures our zone substation forecasts reflect local drivers and do not simply reflect an allocation of the terminal station forecast derived from econometric analysis.

Before conducting the reconciliation of top-down and bottom-up forecasts, we review and revise the top-down forecasts where necessary and appropriate. We revised the top-down forecast in two specific situations:

- where CIE used 'off the line' forecasting, referring to the regression line fitted to the weather normalised history of data, we 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
- where the baseline forecasts were inconsistent with the judgement of expert planning engineers with strong local area knowledge.

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.⁵ Growth rates that are derived using econometric analysis, which is based on historical relationships, may lead to the wrong answers. Equally, the process of determining growth rates at each terminal station requires the forecaster to exercise their own judgement as well as the expert knowledge of planning engineers with strong local area knowledge.

As a result, we have 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 top-down forecasts for the purposes of reconciling with the bottom-up forecasts.

Table 4 indicates the revised network level non-coincident maximum demand forecast. The largest difference is a step up in our maximum demand forecast starting in 2021/22, which accounts for an adjustment to transfers of load between terminal stations which occur approximately every 4-5 years. More specifically, the following transfers are expected in 2021/22:

⁵ CP ATT023 - ACIL Allen - Connection point forecasting - Jun2013 - Public. This is a nationally consistent methodology for forecasting maximum electricity demand.

- ~35MW transfer of zone substation from West Melbourne terminal station (**WMTS**) 22kV to Brunswick terminal station 66kV. This transfer is being driven by the project to decommission CitiPower’s ageing 22kV zone substations supplied from AusNet Transmission's WMTS. AusNet Transmission are also decommissioning the 220/22kV switchyard in WMTS
- ~40MW transfer of McIlwraith Place (**MP**) zone substation from Richmond terminal station (**RTS**) 66kV to Brunswick terminal station (**BTS**) 66kV. This transfer is being driven by the BTS augmentation project. The MP zone substation will be reconnected away from RTS and on to the augmented BTS 66kV supply.

Table 4 Revised network level maximum demand forecasts, non-coincident weather adjusted 50% POE

	2021/22	2022/23	2023/24	2024/25	2025/26
CitiPower	1,735	1,887	1,725	1,750	1,775

Source: CIE and CitiPower

To perform the reconciliation, the bottom-up forecast for each zone substation was scaled by the ratio between the top-down and the bottom-up forecasts at terminal station level for each year of the forecast period.

3 Customer number forecasts

We engaged CIE to develop our customer number forecasts for 2019–2029 period. Figure 4 summarises CIE's approach to forecasting growth in each customer type, while Table 2 summarises customer number forecasts for the 2021–2026 regulatory period.

Figure 4 Forecast approach for each customer type

Tariff category	Forecast approach
Residential	Forecast using projected dwelling growth, adjusted for CitiPower to reflect historically lower growth of customers than dwellings
Non-residential	Continuation of historical time trend observed from 2006 through 2016, from most recent data point (2018) The final two years of historical data were excluded from the trend calculation because small commercial customers using more than 60MWh and less than 120MWh have been reclassified from non-residential customers not on demand tariff to low voltage demand tariff, resulting in a structural break in 2017
Low voltage	Continuation of historical time trend observed from 2006 through 2016, from most recent data point (2018) The final two years of historical data were excluded from the trend calculation because small commercial customers using more than 60MWh and less than 120MWh have been reclassified from non-residential customers not on demand tariff to low voltage demand tariff, resulting in a structural break in 2017
High voltage	Zero growth from most recent data point
Un-metered	Assumed to increase by 500 customers and 250 customers for Powercor and CitiPower areas respectively. This is based on expected increase in customers in 2019 due to the installation of telecommunication infrastructure. Data is not available for future years; growth is assumed to continue due to the continued roll out of the NBN the expected future transition from 4G to 5G network
Other customers	Assumed to remain at zero

Source: CP MOD 9.03 - CIE customer number forecast - Jan2020 - Public

For more information on their approach, refer to attachment CP ATT019 - CIE - Customer number forecasts - May2019 - Public and CP MOD 9.03 - CIE customer number forecast - Jan2020 - Public.