5.07

2017 electricity demand forecasts report

Ausgrid

Executive Summary

Ausgrid serves 1.7 million customers across 22,000 square kilometres of ‘poles and wires’ that stretch from Sydney, through the Central Coast and up to the Hunter Valley. Ausgrid’s electricity network includes 181 zone substations and 33 sub-transmission substations; with separate summer and winter demand forecasts produced for each substation.

The electricity demand forecasts are a key input into the network planning process and are important in the development of Ausgrid’s capital expenditure forecasts. For details on Ausgrid’s capital expenditure requirements, please refer to the capex chapter of the revenue proposal or Ausgrid’s 2017 Distribution Annual Planning Report.

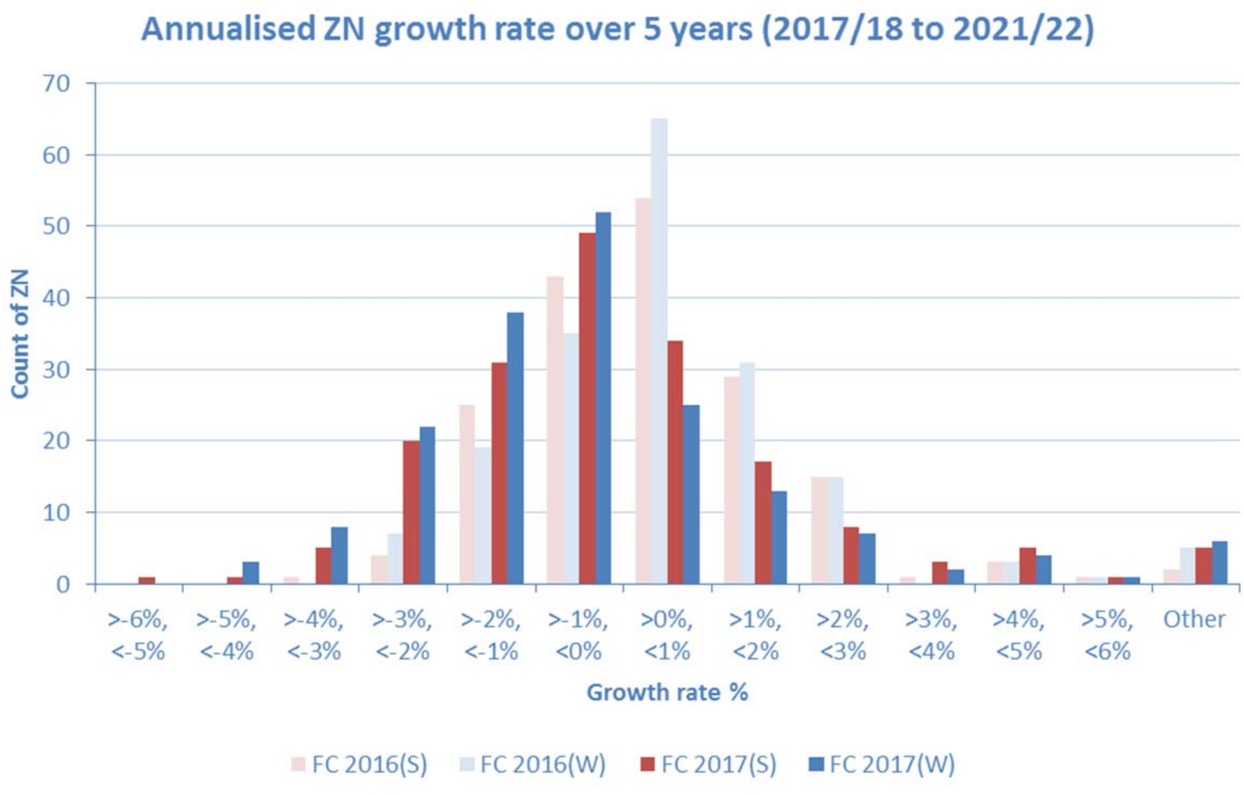
The forecasts are produced for 50% Probability of Exceedance (50 POE), 90% Probability of Exceedance (90 POE) and 10% Probability of Exceedance (10 POE) levels. The central forecasts used as part of the assessment of options for an identified need are the 50 POE forecasts. The 10 POE forecasts and 90 POE forecasts are used as part of an assessment of ‘reasonable’ scenarios which are designed to test alternate sets of key assumptions and whether they affect identification of the preferred option. Within this report, we have presented the results of the 50 POE forecasts.

As a core business function, the annual production of maximum electricity demand forecasts consolidates the input of external forecasting and subject matter experts with Ausgrid’s expertise and detailed customer energy demand and connection data. Ausgrid regularly seeks expert external advice on the forecasts methodology and following completion of the 2017 electricity demand forecasts engaged GHD Advisory to provide an external expert review. Please refer to Attachment 5.08 of the revenue proposal, ‘GHD Review of 2017 demand and customer connection forecasts’ for their report.

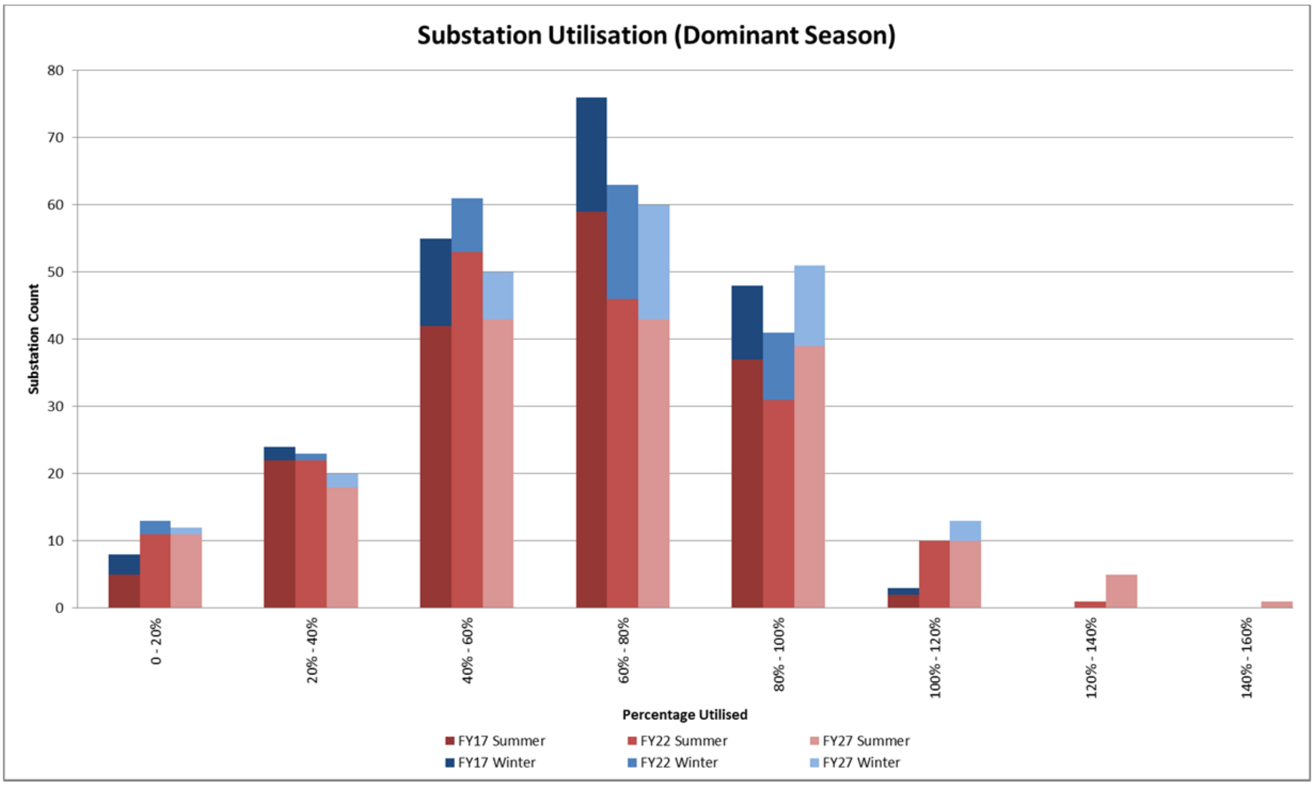
2017 Forecasts Results

The Ausgrid 2017 electricity demand forecasts for zone substations and sub-transmission substations are broadly similar to the result from the 2016 forecasts at a network whole of system level. Underlying this broad similarity, however, there have been significant updates to block loads and electricity price projections in this year’s forecast which has resulted in some modification at a spatial level.

At the spatial level, around 40% of zones in summer and 30% of zones in winter are expected to experience growth in maximum demand over the next 5 years based on the 2017 forecast. This is down from 60% of zones in summer and 66% of zones in winter expected to experience growth over 5 years in the 2016 forecast; mainly due to the forecast effects of customer’s response to electricity price rises. These lower rates of growth will suppress the need for network augmentation investment and be reflected in the capital expenditure requirements. A comparison of the growth rates for Ausgrid’s zone substations in the 2016 and 2017 forecasts is shown below.



The low rates of growth result in a relatively modest increase in substation utilisation across the period from 2017 to 2027 with 5% of zone substations forecast to exceed the substation rating in 2022 and 7.5% in 2027. Forecast substation utilisation[1] for the dominant peak season is displayed for 2017, 2022 and 2027 in the following chart.

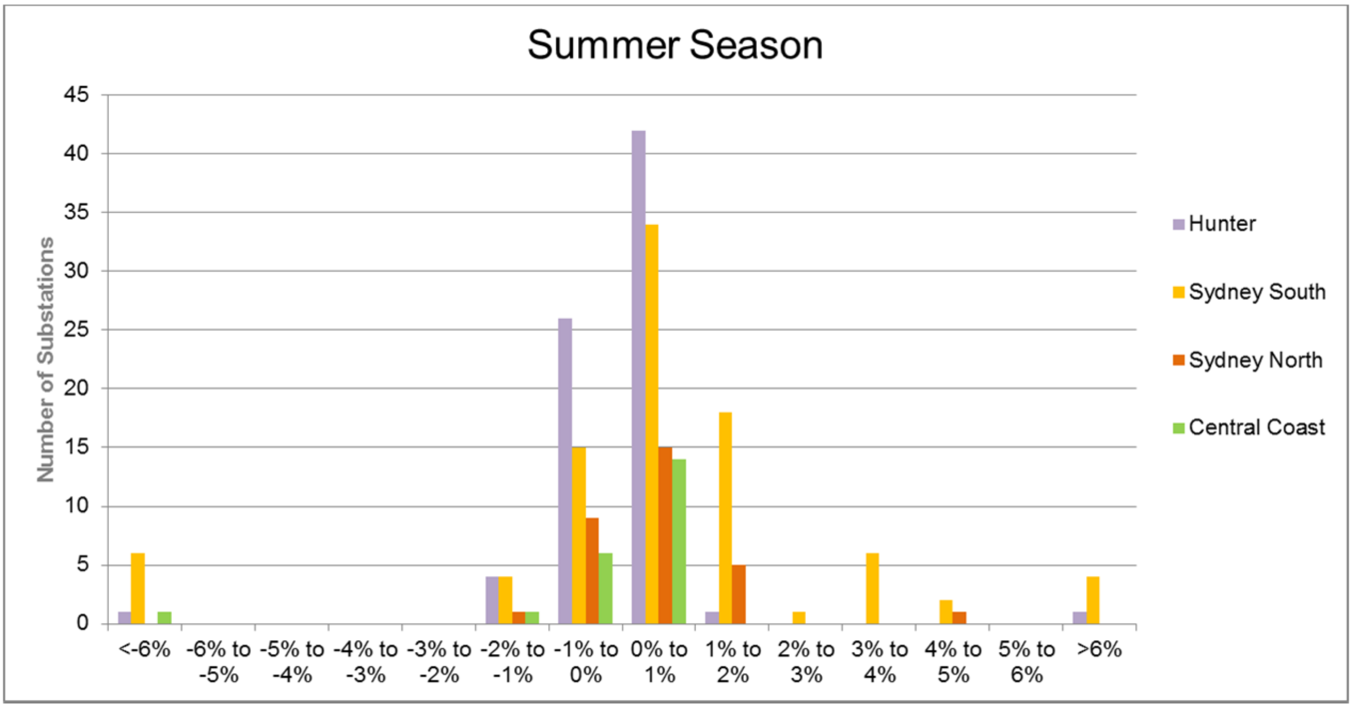


A total of 15 of the 181 zone substations have a 5 year average growth rate greater than +3.0%. These substations typically have a high number of new large customer connections (block loads) in the first 5 forecast years. While comprising only 8% of zone substations and 10% of total system demand, 43% of all new forecast load from large 11kV customer connections is situated in these areas.

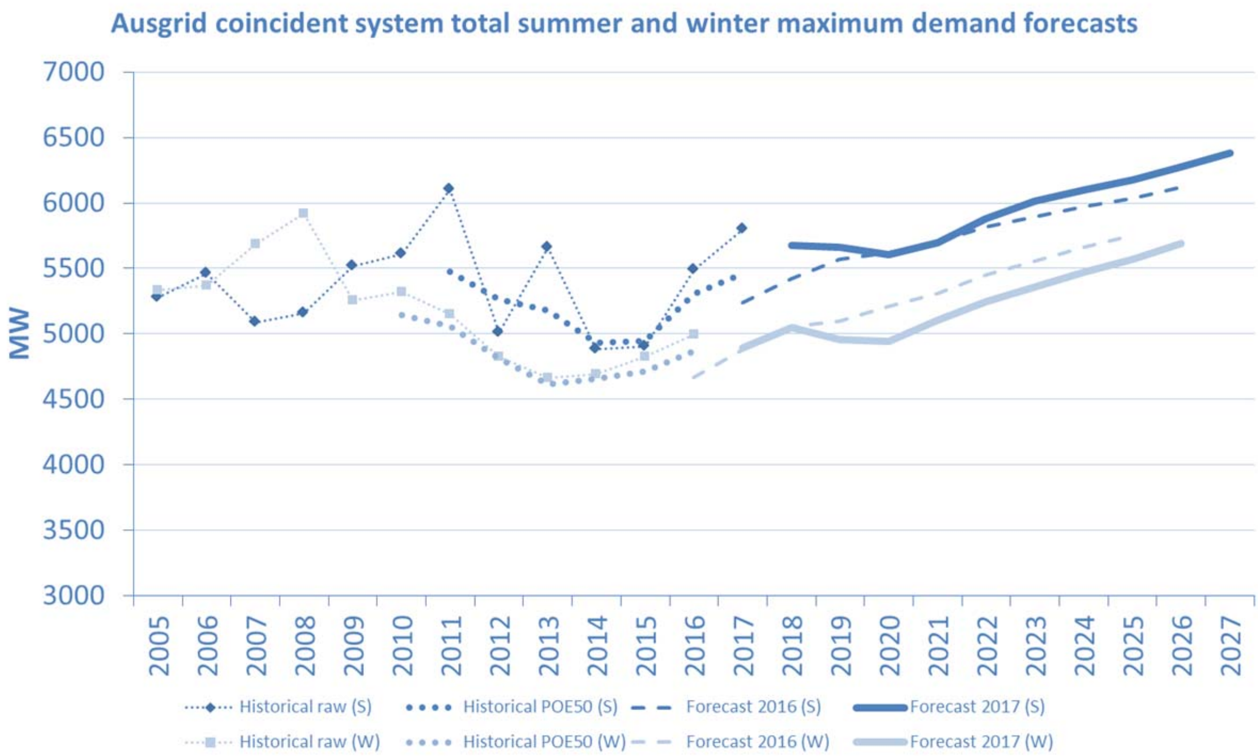
Rank	Growth pa	Zone Substation
1	9.90%	Camperdown 33/11kV
2	9.54%	Port Botany 33/11kV
3	8.61%	Macquarie Park 132/11kV
4	7.96%	Arncliffe 33/11kV
5	6.62%	Mascot 33/11kV
6	5.84%	Crows Nest 33/11kV
7	5.14%	Somersby 132/11kV
8	4.75%	Homebush Bay 132/11kV
9	4.67%	Darling Harbour 132/11kV
10	4.62%	Leichhardt 33/11kV
11	4.54%	Mayfield West 132/11kV
12	4.09%	Surry Hills 33/11kV
13	4.02%	Green Square 132/11kV
14	3.60%	Lidcombe 33/11kV
15	3.00%	Zetland 132/11kV

This spatial variation in forecast demand can be seen in the regional breakdown of growth rates with a greater number of zone substations in the Sydney South region experiencing higher rates of annual growth. See below histogram charts summarising the summer 50 POE forecast growth rates for each of Ausgrid's regional areas.

[1] *Note that results are based on forecast load without planned load transfers. Rating referred to in this diagram is the substation rating and does not take into account sub-transmission feeder limitations.*



The 2017 Ausgrid coincident system total summer and winter maximum demand forecast are shown in the chart below. Compared to the 2016 forecast, the 2017 forecast is broadly similar over the long term with a significant increase in new large customer connections (block loads) largely offset by the forecast customer response to the recent and near term electricity price rises.



Contents

1 Introduction

1.1 Background

Maximum demand forecasts are a key input into the network planning process and are important in the development of Ausgrid's capital expenditure forecasts. As a core business function, the annual production of maximum electricity demand forecasts (the forecasts) consolidates the input of external forecasting and subject matter experts with Ausgrid's expertise and detailed customer energy demand and connection data. The forecast models are regularly audited and reviewed by external forecast specialists with assumptions and methods tested annually to refine and improve methods. Please refer to Attachment 5.08, 'GHD Review of 2017 demand and customer connection forecasts' for a review of Ausgrid's electricity demand forecasts methodology.

The forecasts of maximum demand are prepared for winter and summer at 181 zone substations and 33 sub-transmission substations. The forecasts are produced annually at the end of the summer season and use the latest summer and winter actual electricity demand data.

Forecasts are produced for 50% Probability of Exceedance (50 POE), 90% Probability of Exceedance (90 POE) and 10% Probability of Exceedance (10 POE) levels. The central forecasts used as part of the assessment of options for an identified need are the 50 POE forecasts. The 10 POE forecasts and 90 POE forecasts are used as part of an assessment of 'reasonable' scenarios which are designed to test alternate sets of key assumptions and whether they affect identification of the preferred option. Within this report, we have principally presented the results of the 50 POE forecasts.

The forecasts for each substation are constructed from two primary components; a near term forecast that is based on the statistically derived trend line of the weather corrected historical customer electricity demand for the substation, and a medium to long term forecast that is based on a system level econometric model. This recognises the need for the forecast model to consider both the short term trend and long term macro econometric factors. Both components include post model adjustments to address out of trend impacts.

1.2 Purpose

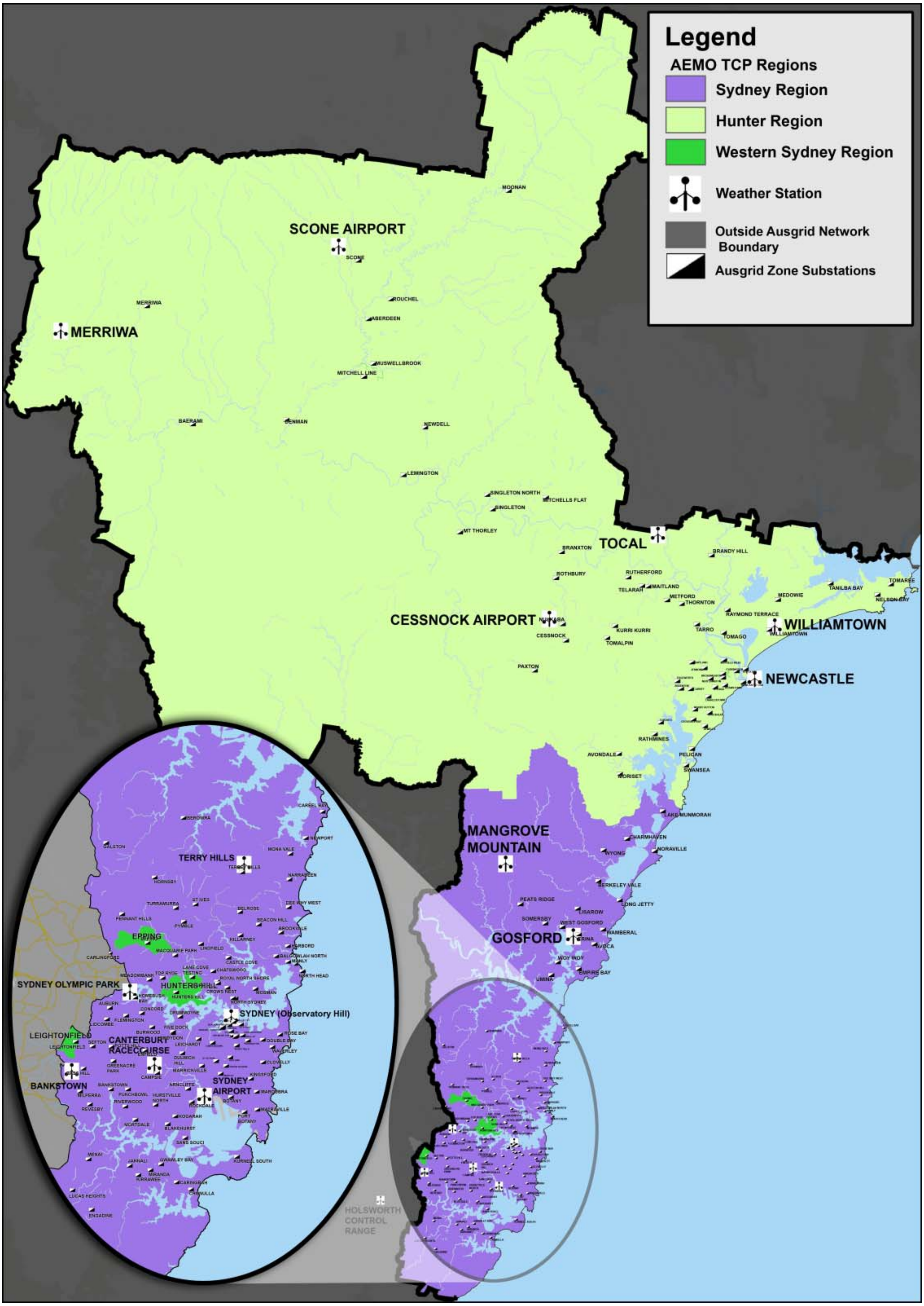
The purpose of this document is to detail the methodology and assumptions used to develop each of the zone and sub-transmission substation forecasts, and present the results of the 2017 forecasts. This includes details on how Ausgrid forecasts the impacts from emerging technologies such as solar power systems, storage batteries and electric vehicles.

1.3 Ausgid's Electricity Distribution Network Area

Ausgrid serves 1.7 million customers across 22,000 square kilometres of 'poles and wires' that stretch from Sydney, through the Central Coast and up to the Hunter Valley. The map following identifies the Ausgrid network boundary and the 181 Ausgrid zone substations for which we produce maximum electricity demand forecasts. Ausgrid's zone substation forecasts serve an average of about 9,500 customers per forecast.

Also shown are the two regions for which the Australian Energy Market Operator (AEMO) produces a transmission connection point (TCP) forecast. The AEMO regions in the Ausgrid network area are the Sydney region, serving 1.43 million customers and 121 zone substations, and the Hunter region, serving 300,000 customers and 60 zone substations.   In contrast to elsewhere in Australia, AEMO have not prepared TCP forecasts for local areas due principally to the mesh transmission network in place in Sydney and the Hunter. In preparing their TCP forecasts, AEMO have applied a 5% threshold to screen block loads for inclusion or exclusion in their forecasts, resulting in thresholds of over 200 MW and 50 MW for the Sydney and Hunter regions, which have underlying maximum demands of over 4000 MW and over 1000 MW, respectively. Since AEMO's methodology screens block loads on an individual basis against these thresholds, Ausgrid's block loads are not included in AEMO's TCP forecasts for Ausgrid's area.

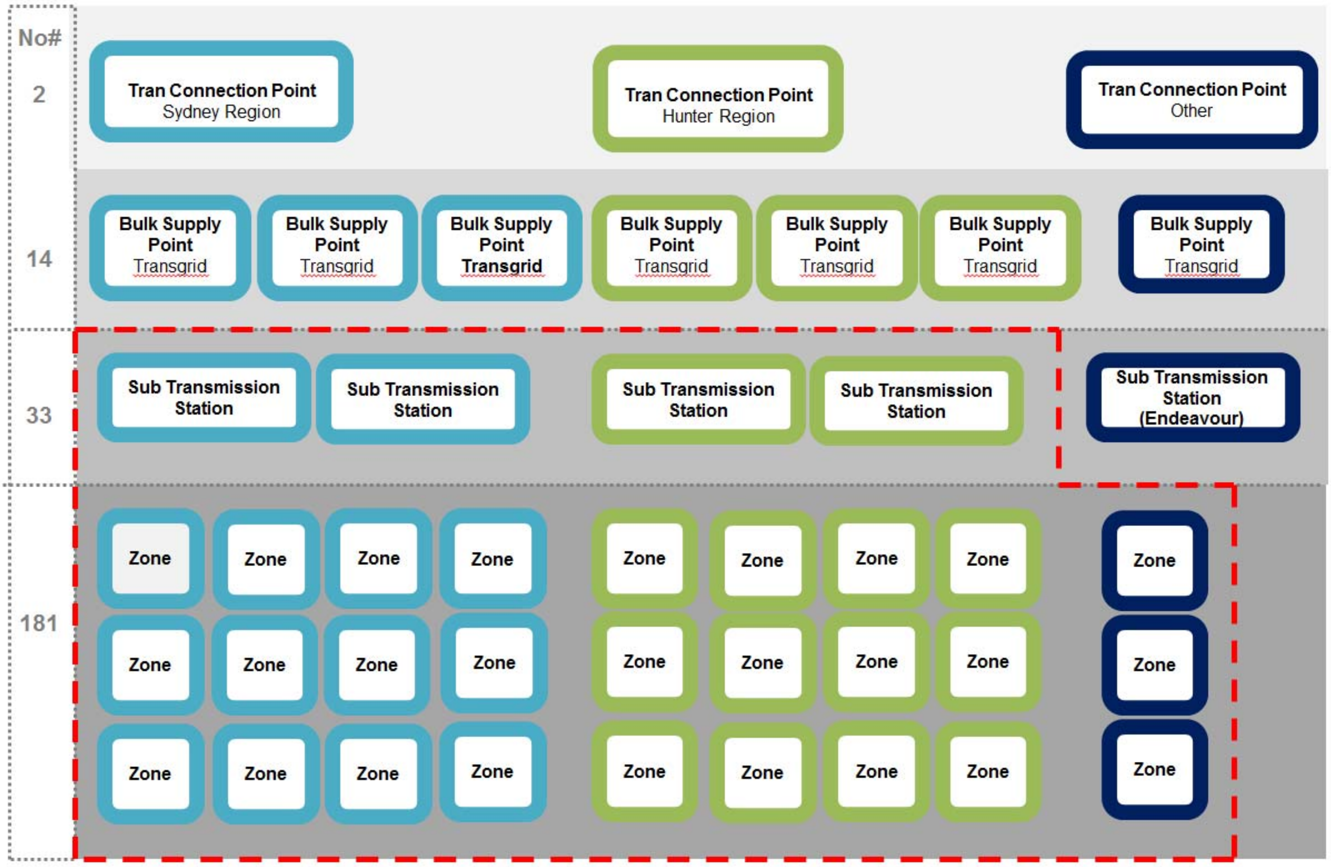
Note also that there are three Ausgrid zone substations identified in green which are included in AEMO's Western Sydney region. These three zone substations are supplied from an Endeavour Energy sub-transmission substation. AEMO's Wester Sydney region principally serves customer in the Endeavour Energy network area.


Legend
AEMO TCP Regions
Sydney Region
Hunter Region
Western Sydney Region
Weather Station
Outside Ausgrid Network Boundary
Ausgrid Zone Substations
SCONE AIRPORT
MERRIWA
TOCAL
CESSNOCK AIRPORT
WILLIAMTOWN
NEWCASTLE
MANGROVE MOUNTAIN
GOSFORD
TERRY HILLS
EPPING
SYDNEY OLYMPIC PARK
HUNTERS HILL
SYDNEY (Observatory Hill)
LEIGHTONFIELD
CANTERBURY RACECOURSE
BANKSTOWN
SYDNEY AIRPORT
HOLSWORTH CONTROL RANGE

1.4 Ausgrid's Electricity Distribution Network Hierarchy

Described below is the distribution network hierarchy for Ausgrid's network area. As noted above, there are principally two AEMO connection point forecast regions in Ausgrid's network area, for which Ausgrid produces separate winter and summer forecasts for each of our 181 zone substations and 33 sub-transmission substations.

The red dotted line indicates the asset level forecasts that are included in the Electricity Demand Forecasts.



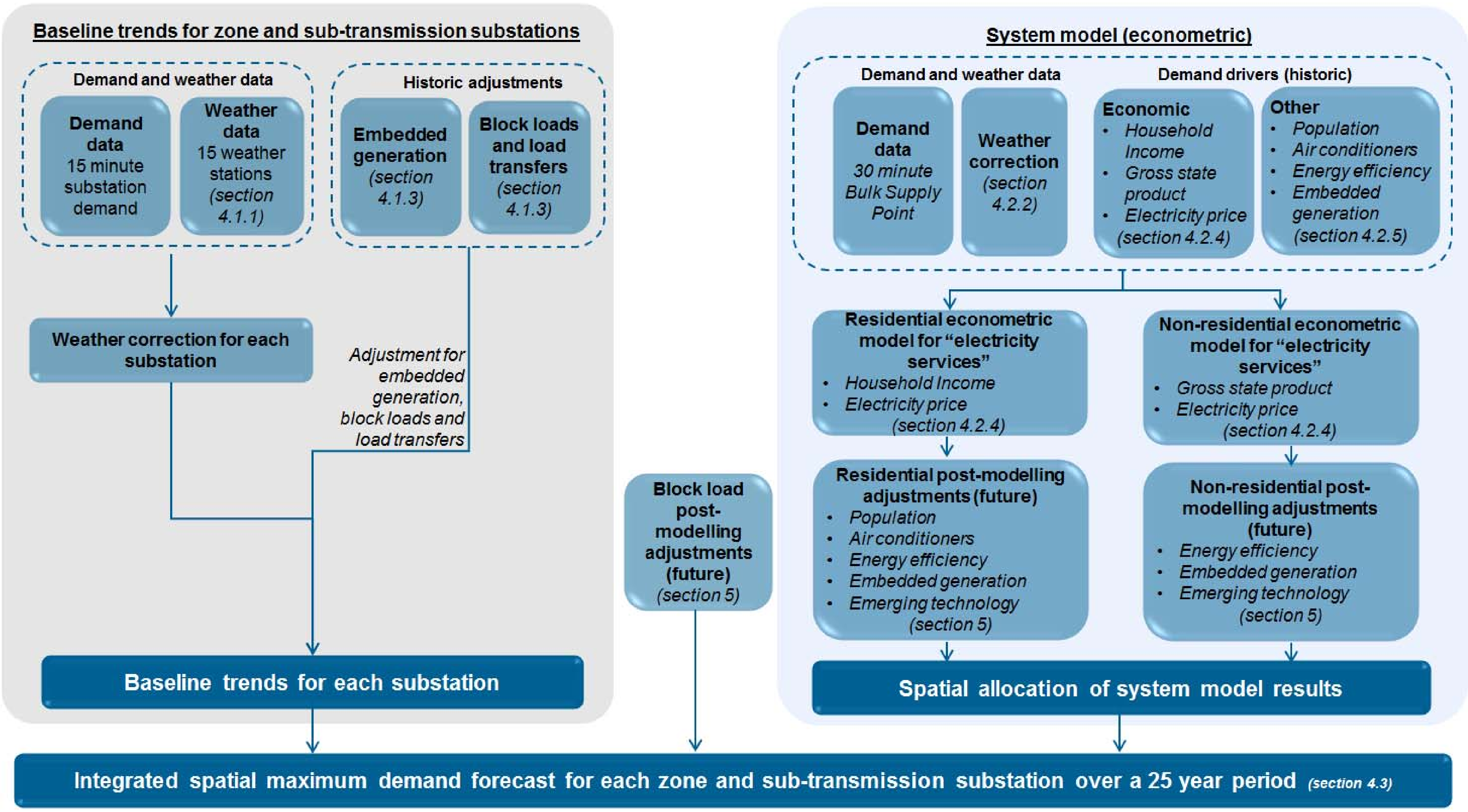
Note: red dotted lines show STS and zones included in Ausgrid's Spatial Demand Forecast 2017

1.5 Methodology Overview

The electricity demand forecast consists of integrating two forecast components:

- A baseline trend for each zone and sub-transmission substation calculated using historic 15-minute demand data, weather data for the closest Bureau of Methodology weather station and adjustments based on historic information for embedded generation, block loads and load transfers.
- A system level econometric model taking into account historical information on the main demand drivers of household income, gross state product and electricity price. Further post-modelling adjustments are also applied for energy efficiency, embedded generation, emerging technologies (batteries and electric vehicles), customer growth and increasing air conditioner penetration.

The methodology and process which guides Ausgrid's maximum demand forecasting for its zone and sub-transmission stations is shown below. Details on the methodology are found in Section 4 and 5.


Baseline trends for zone and sub-transmission substations
Demand and weather data
Demand data 15 minute substation demand
Weather data 15 weather stations (section 4.1.1)
Historic adjustments
Embedded generation (section 4.1.3)
Block loads and load transfers (section 4.1.3)
Weather correction for each substation
Adjustment for embedded generation, block loads and load transfers
Baseline trends for each substation
Block load post-modelling adjustments (future) (section 5)
System model (econometric)
Demand and weather data
Demand drivers (historic)
Demand data 30 minute Bulk Supply Point
Weather correction (section 4.2.2)
Economic
• Household Income
• Gross state product
• Electricity price
(section 4.2.4)
Other
• Population
• Air conditioners
• Energy efficiency
• Embedded generation
(section 4.2.5)
Residential econometric model for "electricity services"
• Household Income
• Electricity price
(section 4.2.4)
Non-residential econometric model for "electricity services"
• Gross state product
• Electricity price
(section 4.2.4)
Residential post-modelling adjustments (future)
• Population
• Air conditioners
• Energy efficiency
• Embedded generation
• Emerging technology
(section 5)
Non-residential post-modelling adjustments (future)
• Energy efficiency
• Embedded generation
• Emerging technology
(section 5)
Spatial allocation of system model results
Integrated spatial maximum demand forecast for each zone and sub-transmission substation over a 25 year period (section 4.3)

1.6 Report Structure

The report is comprised of the following sections:

- Section 2 details the results of Ausgrid's 2017 Electricity Demand Forecasts for each of the 181 zone substations and 33 sub-transmission substations.
- Section 3 outlines the drivers of demand that impact the forecasts.
- Section 4 details the methodology and processes used to derive the forecasts.
- Section 5 provides detailed information about the post model adjustments introduced to account for out of trend effects such as emerging or disruptive technologies and block loads.

1.7 Definitions

The following are definitions of terms which are used in this report:

Definition	
Block load	An identified step change in demand due to a new large customer connection or disconnection
CAGR	Compounded Annual Growth Rate
Demand	Instantaneous energy flow at a given point of measurement in MW
Probability of Exceedance (POE)	The likelihood that a given level of maximum demand will be exceeded. 10 POE maximum demand is the level of maximum demand that is expected to be exceeded for every one year in ten. 50 POE maximum demand is the level of maximum demand that is expected to be exceeded for every five years in ten. 90 POE maximum demand is the level of maximum demand that is expected to be exceeded for every nine years in ten.
Summer	For the purpose of the forecast, the period from Nov 1 to Mar 15 is the summer period.
Winter	For the purpose of the forecast, the period from May 1 to Aug 31 is the winter period.

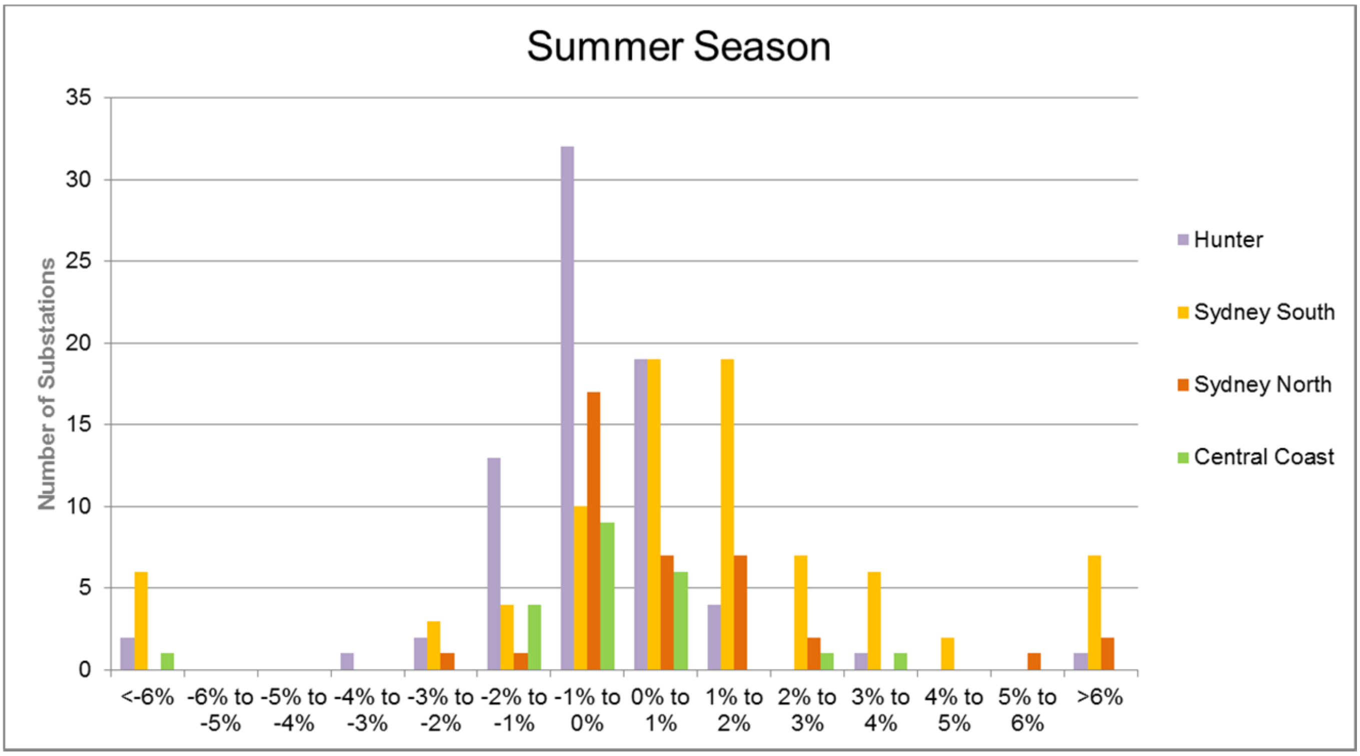
2 Demand Forecasts

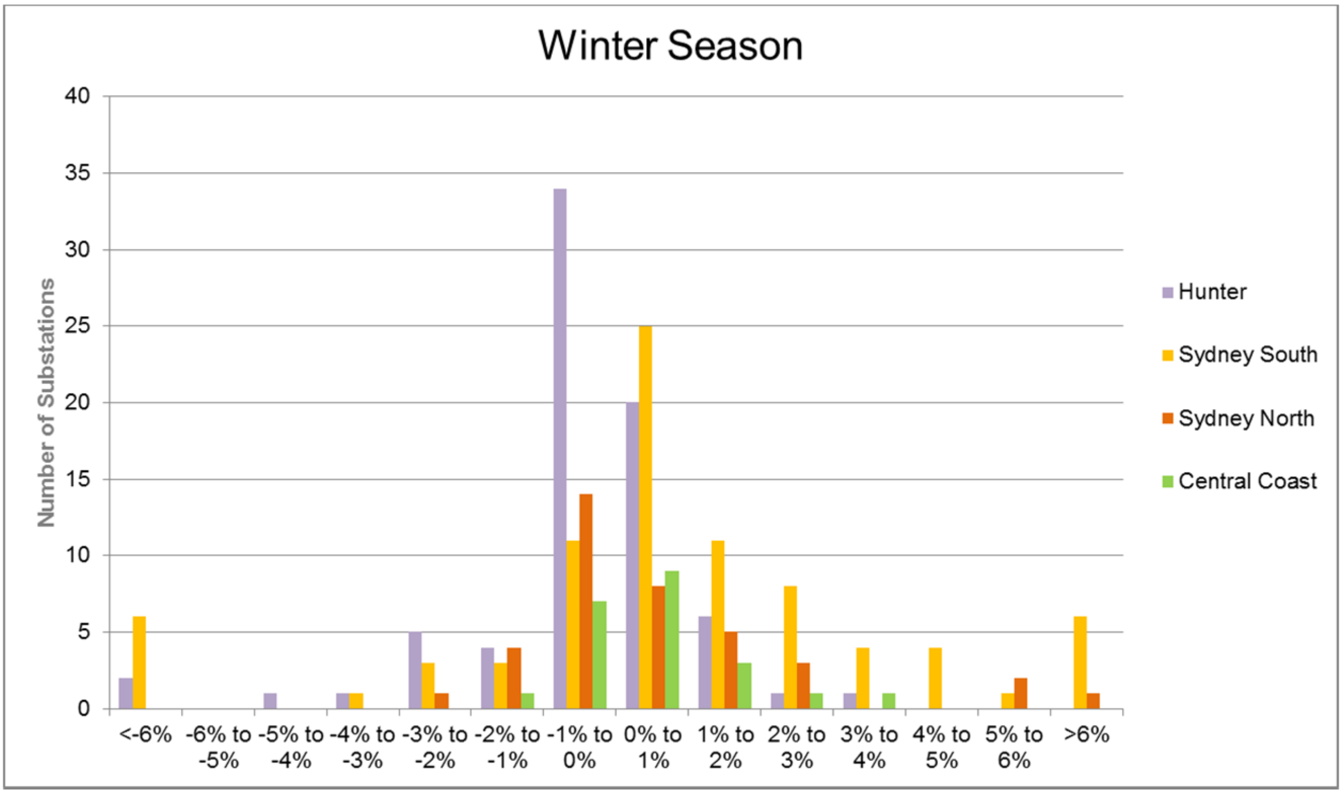
This section details the results of Ausgrid's 2017 Electricity Demand Forecasts for each of the 181 zone substations and 33 sub-transmission substations. The individual summer and winter maximum electricity demand forecasts have been summarized for four broad regional areas – Sydney South, Sydney North, Central Coast and the Hunter.

Each forecast is comprised of elements from the baseline trend forecast and the local allocation of impacts from the system level econometric model. Post model adjustments for energy efficiency, rooftop photovoltaics, emerging technologies (batteries and electric vehicles) and out of trend large customer connections are included where appropriate. Details on the methodology and the treatment of post model adjustments are in Sections 4 and 5.

Forecasts are produced for 50% Probability of Exceedance (50 POE), 90% Probability of Exceedance (90 POE) and 10% Probability of Exceedance (10 POE) levels. The central forecasts used as part of the assessment of options for an identified need are the 50 POE forecasts. The 10 POE forecasts and 90 POE forecasts are used as part of an assessment of 'reasonable' scenarios which are designed to test alternate sets of key assumptions and whether they affect identification of the preferred option. Within this report, we have presented the results of the 50 POE forecasts.

The following histogram charts summarise the resultant summer and winter 50 POE forecast growth rates for each of Ausgrid's network broad regional areas. The charts display the count of substation numbers for growth rate ranges using the 7 year compounded annual growth rate (CAGR). The diversity of growth within and between different regions reflects the variation in customer activity at a spatial level.



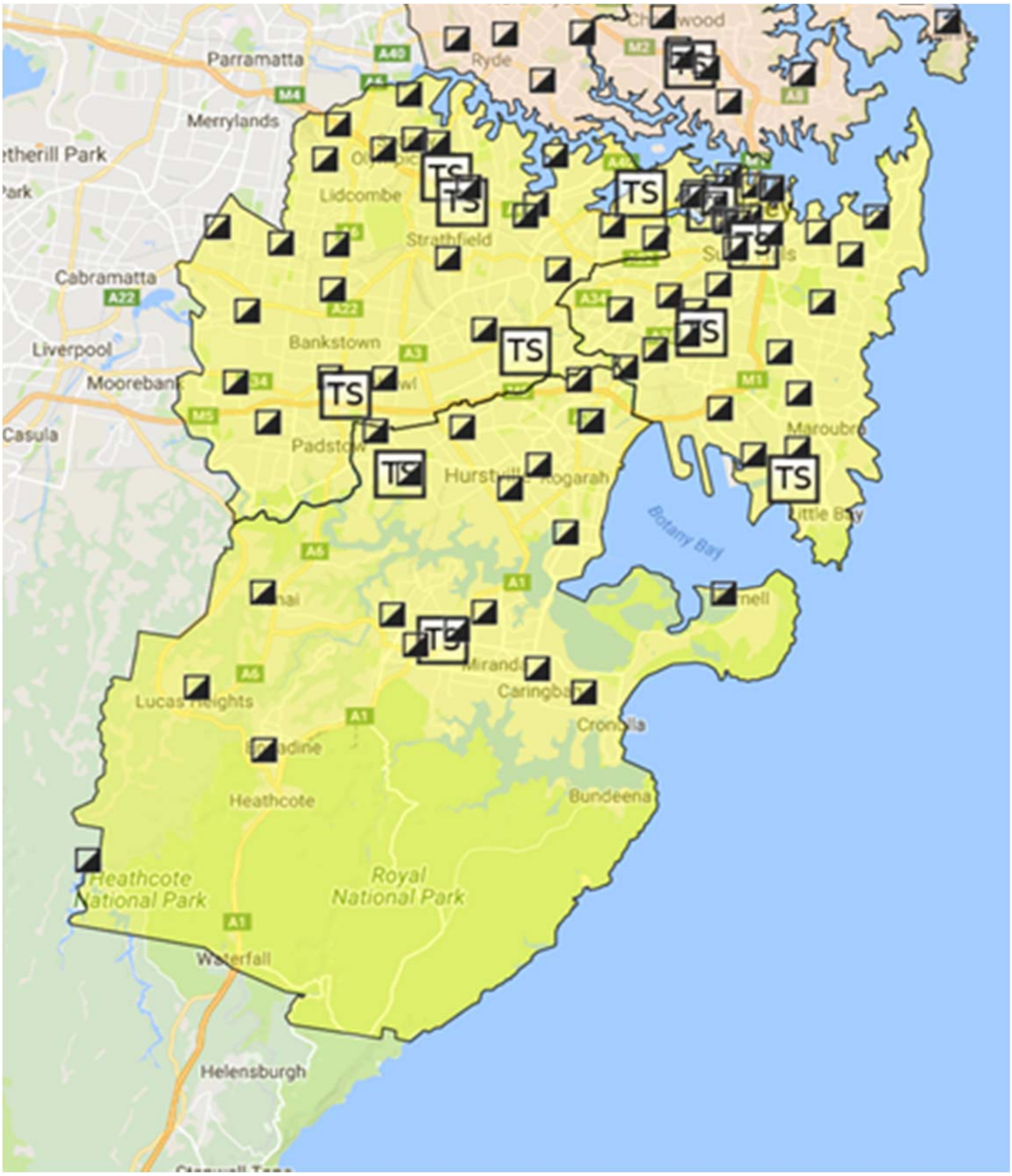


Winter Season
Number of Substations
40
35
30
25
20
15
10
5
0
<-6%
-6% to -5%
-5% to -4%
-4% to -3%
-3% to -2%
-2% to -1%
-1% to 0%
0% to 1%
1% to 2%
2% to 3%
3% to 4%
4% to 5%
5% to 6%
>6%
Hunter
Sydney South
Sydney North
Central Coast

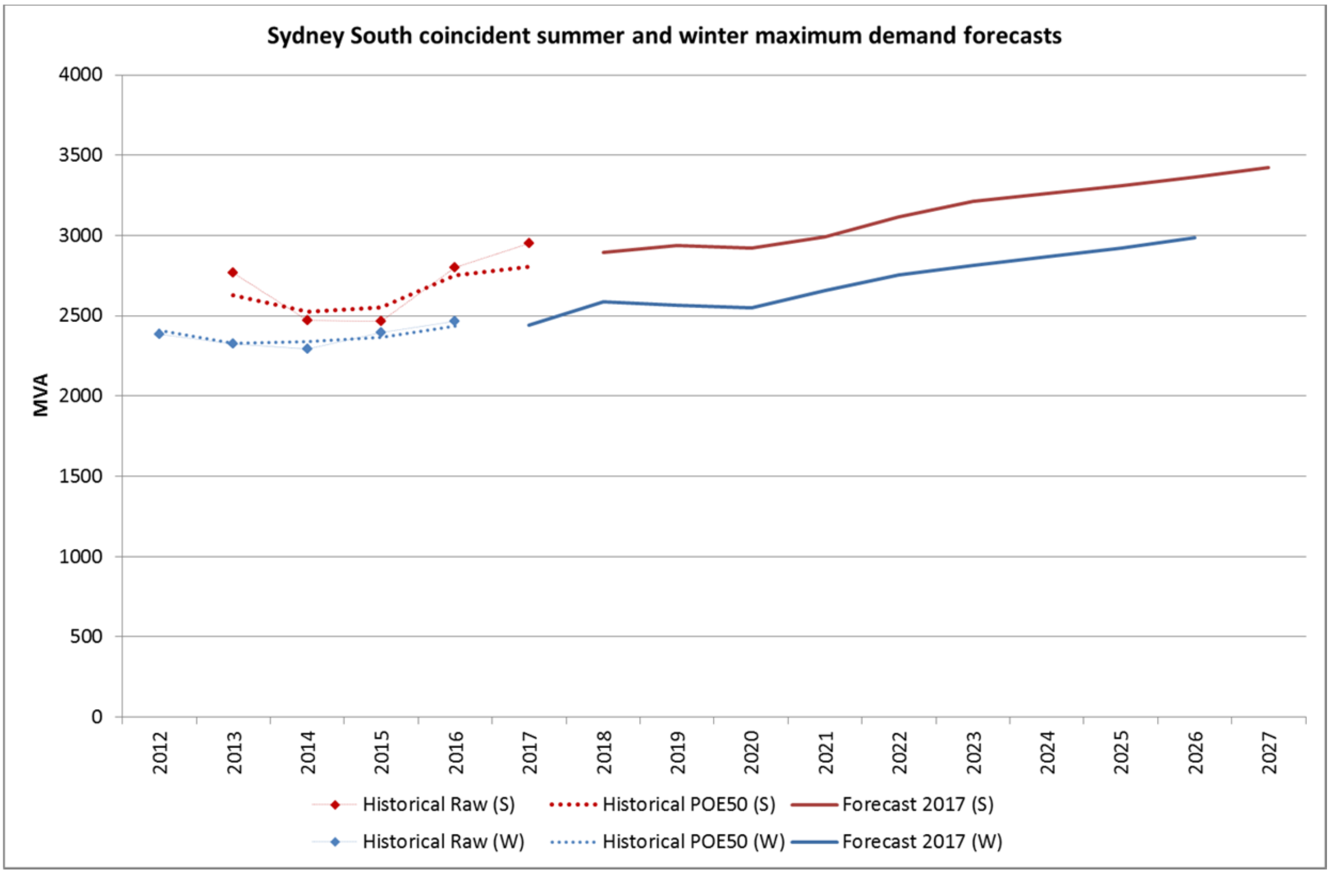
2.1 Sydney South Region

The Sydney South region of Ausgrid's network serves a total of 866,000 customers from 69 zone substations and 11 sub-transmission substations. The figure on the following page shows the Sydney South region and location of the zones and sub transmission stations within the region. The Sydney South region includes the Sydney CBD, key industrial areas such as Port Botany, Sydney airport and is home to about 1.8 million people.

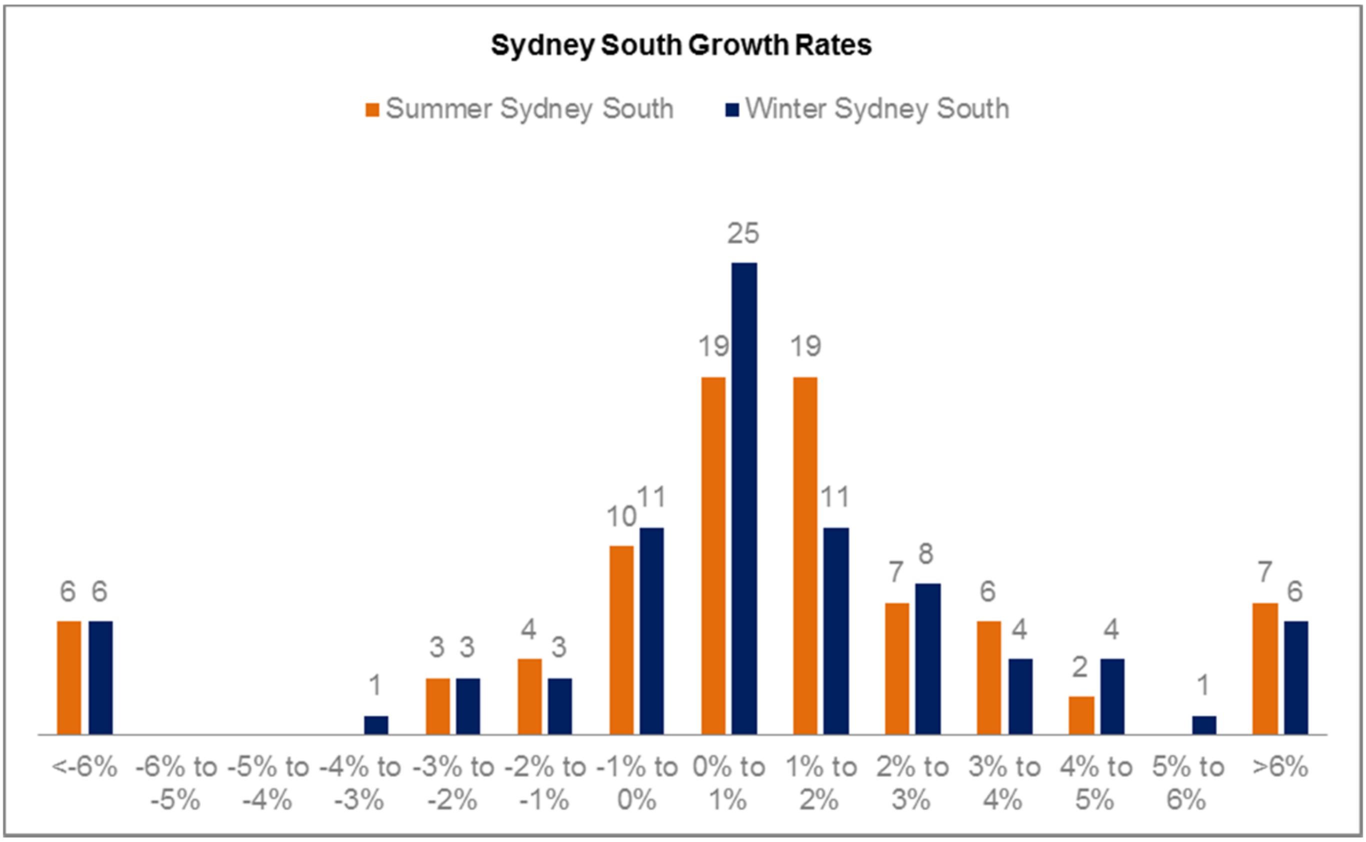
Sydney South Region:



The 2017 Sydney South region coincident system total summer and winter maximum demand forecast are shown in the chart below. The 7 year compounded annual growth rate (CAGR) for the region is 2.2% in summer and 2.1% in winter. Note that the higher growth is due to a significant number of new large customer connections. The underlying growth rate, excluding large customer connections, is -0.5% in summer and -0.9% in winter.



The histogram chart below for the Sydney South Zone region shows the count of substation numbers for 50 POE forecast growth rate ranges using the 7 year compounded annual growth rate (CAGR). While a majority of zones have forecast average annual growth rates of -1% to +2%, there is a broad range of growth rates at the local spatial level.



2.1.1 Sydney South Region Zone Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each zone substation. Separate tables have been compiled for zone substations supplied at 132 kV and 33 kV.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Sydney South Zone Substation Summer 50 POE Forecasts (132 kV)

Sydney South Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Bankstown 132_11kV	25.8	25.9	23.2	23.4	37.4	42.9	48.7	50.9	51.8	51.9	52.4	53.0	53.7	54.3	1.6%
Belmore Park 132_11kV								0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Burwood 132_11kV	79.1	75.8	73.4	65.1	69.5	73.8	80.1	88.2	89.9	80.9	82.3	83.8	85.5	87.1	1.2%
Campbell St 132_11kV	31.8	30.1	42.3	39.5	39.3	40.6	43.2	44.4	49.5	48.5	45.2	46.0	46.7	47.6	1.4%
City Central 132_11kV						118.3	114.1	109.3	116.4	115.0	114.9	116.8	119.1	121.2	0.9%
City North 132_11kV						71.1	76.6	103.2	128.8	129.1	128.9	130.7	132.9	134.8	8.4%
City South 132_11kV						131.5	132.4	119.8	115.1	116.0	115.9	117.8	120.0	122.0	-1.2%
Clovelly 132_11kV	64.9	64.0	57.6	52.0	53.0	54.9	56.2	57.8	56.7	56.5	57.6	58.7	60.0	61.3	1.2%
Cronulla 132_11kV	45.9	47.7	41.9	39.5	40.3	44.8	48.3	49.3	49.9	50.3	51.4	52.2	53.1	53.9	1.6%
Croydon 132_11kV								38.9	38.2	34.8	35.3	36.0	36.8	37.5	-0.6%
Dalley St 132_11kV						106.1	100.2	52.1	15.8	16.1	16.1	16.4	16.7	17.0	-22.4%
Darling Harbour 132_11k	56.4	57.1	56.5	51.4	52.4	52.9	56.7	73.0	76.1	95.6	97.3	98.4	99.6	100.7	8.6%
Double Bay 132_11kV	65.1	58.2	55.4	54.6	57.6	60.6	60.9	61.6	60.8	60.1	60.9	62.0	63.1	64.3	0.8%
Drummoyne 132_11kV	52.5	50.3	46.1	44.0	43.0	50.4	52.4	50.3	50.7	51.2	52.4	53.5	54.7	55.8	0.9%
Engadine 132_11kV							29.5	30.1	30.5	31.0	31.6	32.0	32.4	32.8	1.5%
Flemington 132_11kV	85.9	83.8	82.3	81.2	82.4	84.3	84.0	87.5	86.0	83.7	84.5	85.9	87.6	89.2	0.9%
Green Square 132_11kV	34.4	35.8	33.0	38.9	42.4	48.3	55.0	64.0	63.4	63.8	64.7	65.4	66.2	66.9	2.8%
Greenacre Park 132_11k	86.6	78.4	76.2	74.7	57.5	63.1	64.5	66.4	66.1	65.5	66.3	67.3	68.5	69.5	1.1%
Gwawley Bay 132_11kV			28.4	27.2	28.1	31.7	33.8	33.6	33.0	32.6	32.8	33.1	33.5	33.9	0.0%
Homebush Bay 132_11k	47.9	45.0	44.1	43.9	47.4	48.5	51.5	62.2	64.1	62.7	64.2	64.9	65.8	66.5	3.7%
Hurstville North 132_11kV					23.7	24.8	23.2	22.7	22.6	22.4	22.7	23.1	23.5	23.9	0.4%
Kingsford 132_11kV	37.7	37.5	35.5	37.9	40.2	43.0	46.1	49.6	49.9	50.4	51.7	52.6	53.7	54.7	2.5%
Kirrawee 132_11kV	34.5	31.2	30.3	29.4	30.5	33.5	36.3	36.3	34.7	33.9	34.0	34.6	35.1	35.7	-0.2%
Kogarah 132_11kV	73.6	73.7	68.3	66.4	65.2	69.4	75.8	82.6	82.7	82.8	84.1	85.5	87.0	88.5	2.2%
Kurnell South 132_11kV						6.5	6.8	6.3	5.6	5.1	5.2	5.4	5.6	5.8	-2.1%
Leichhardt 132_11kV								0.0	24.6	24.0	24.2	24.6	25.1	25.6	0.8%
Maroubra 132_11kV	54.9	49.5	44.8	45.7	46.8	45.0	44.9	44.3	42.8	41.6	42.0	42.9	44.0	45.0	0.0%
Marrickville 132_11kV	54.3	53.0	47.9	47.8	48.5	48.9	53.7	55.7	55.9	56.0	56.8	57.3	58.0	58.6	1.3%
Menai 132_11kV	43.8	43.0	39.6	39.8	38.9	41.8	43.5	42.9	42.8	42.9	43.5	43.9	44.4	44.9	0.4%
Milperra 132_11kV	54.2	52.3	47.6	46.4	45.0	46.7	49.0	47.2	44.8	43.4	43.4	43.8	44.4	45.0	-1.2%
Olympic Park 132_11kV								1.0	1.4	1.6	1.7	1.7	1.7	1.7	9.7%
Potts Hill 132_11kV				11.2	40.9	41.5	41.8	46.1	47.5	47.6	48.4	49.0	49.8	50.5	2.7%
Revesby 132_11kV	41.6	38.8	37.9	36.6	38.3	44.9	43.3	44.5	44.7	45.2	46.1	46.9	47.7	48.6	1.6%
Rockdale 132_11kV								0.0	25.2	25.1	25.3	25.6	26.0	26.4	0.9%
Rose Bay 132_11kV					27.6	32.1	31.1	31.6	31.3	31.3	31.9	32.4	33.0	33.6	1.1%
Sefton 132_11kV	69.6	69.2	64.9	53.5	43.1	44.8	49.6	50.2	50.1	50.4	51.2	52.1	52.9	53.8	1.2%
St Peters 132_11kV	65.9	68.8	64.5	63.7	60.3	62.0	63.8	69.0	66.0	62.7	58.4	59.5	60.9	62.1	-0.4%
Waverley 132_11kV					20.6	22.2	22.2	21.7	21.7	21.5	21.9	22.3	22.8	23.3	0.7%
Zetland 132_11kV	79.8	71.0	67.2	62.4	62.5	62.0	65.9	79.6	79.5	78.8	78.7	79.9	81.2	82.5	3.3%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney South Zone Substation Summer 50 POE Forecasts (33 kV)

Sydney South Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Arncliffe 33_11kV	20.2	18.6	18.6	14.6	15.1	17.2	20.1	19.3	21.4	23.0	24.2	24.6	25.1	25.6	3.5%
Auburn 33_11kV	27.4	31.4	27.5	26.9	26.9	27.6	28.7	28.1	27.6	27.3	27.5	27.9	28.2	28.6	-0.1%
Bass Hill 33_11kV	27.3	24.5	23.3	23.8	25.0	29.6	24.9	25.3	25.1	25.2	25.6	26.0	26.4	26.8	1.0%
Blackwattle Bay 33_5kV	26.1	26.4	21.3	20.8	21.0	20.0	19.6	18.6	17.1	9.3	9.4	9.8	10.2	10.7	-8.3%
Blakehurst 33_11kV	23.3	17.9	17.5	16.9	16.0	18.5	20.2	19.6	20.0	19.7	19.9	20.3	20.7	21.1	0.6%
Botany 33_11kV	33.4	34.2	28.6	27.4	23.9	24.7	25.8	26.6	26.3	25.8	26.1	26.5	27.0	27.5	0.9%
Camperdown 33_11kV					5.3	13.7	15.3	20.5	31.4	37.4	39.0	39.4	39.9	40.3	14.9%
Camperdown 33_5kV	38.9	31.9	22.6	19.8	18.5	12.1	10.7	0.9	0.0	0.0	0.0	0.0	0.0	0.0	-100.0%
Campsie 33_11kV	56.8	58.0	57.6	53.8	55.3	63.5	66.5	74.6	76.3	73.0	74.7	76.1	77.6	79.0	2.5%
Caringbah 33_11kV	26.8	21.8	21.0	20.6	21.3	21.8	20.9	22.5	21.5	21.0	21.1	21.4	21.8	22.1	0.8%
City East 33_11kV						39.6	39.2	36.8	34.5	33.2	33.1	33.6	34.2	34.7	-1.7%
Concord 33_11kV	44.0	39.6	39.4	39.7	37.2	41.7	44.6	46.2	46.1	46.3	47.0	47.7	48.4	49.2	1.4%
Darlinghurst 33_11kV	52.7	49.9	47.2	44.5	45.1	44.9	44.6	44.0	41.1	39.6	39.8	40.7	41.8	42.8	-0.6%
Dulwich Hill 33_11kV	42.4	37.7	36.0	34.6	34.2	37.1	38.7	43.6	43.8	44.2	45.2	46.0	46.9	47.8	3.1%
Enfield 33_11kV	37.4	20.7	19.9	19.4	17.2	20.5	20.6	21.8	21.1	20.8	21.1	21.5	21.9	22.4	1.2%
Jannali 33_11kV	29.0	26.0	23.5	23.0	21.4	28.9	29.7	29.5	29.7	30.0	30.5	30.9	31.3	31.7	0.9%
Leichhardt 33_11kV	28.2	31.1	31.0	31.1	31.5	30.1	22.8	22.9	0.0	0.0	0.0	0.0	0.0	0.0	-100.0%
Leightonfield 33_11kV	24.2	21.5	21.6	21.7	22.5	23.5	24.4	24.4	23.5	23.0	23.1	23.4	23.8	24.1	-0.2%
Lidcombe 33_11kV	28.7	29.6	20.9	20.5	20.8	21.9	21.2	23.4	22.8	23.5	24.2	24.6	25.1	25.5	2.7%
Lucas Heights 33_11kV	7.1	7.4	7.1	7.4	7.9	8.5	8.6	8.3	7.8	7.6	7.6	7.7	7.9	8.0	-1.1%
Mascot 33_11kV	55.3	52.3	49.1	46.4	45.0	46.3	49.2	59.0	63.0	64.2	65.8	66.6	67.5	68.3	4.8%
Matraville 33_11kV	42.6	39.9	39.3	35.2	35.9	36.7	38.3	40.9	38.4	36.8	37.1	38.1	39.3	40.4	0.8%
Miranda 33_11kV	32.7	29.5	29.4	27.1	27.8	31.5	36.7	35.0	34.7	34.7	35.0	35.4	35.9	36.3	-0.2%
Mortdale 33_11kV	46.8	40.3	39.4	42.1	36.7	42.2	45.0	44.0	43.1	42.7	43.3	44.0	44.8	45.5	0.2%
Paddington 33_11kV	32.2	30.0	27.6	26.8	29.1	30.0	33.6	34.0	33.5	33.5	34.2	35.0	35.9	36.8	1.3%
Port Botany 33_11kV	2.7	3.3	2.8	3.0	6.9	6.7	7.5	11.6	11.9	11.8	11.8	11.9	12.0	12.0	6.9%
Punchbowl 33_11kV	55.7	52.2	50.6	49.1	37.1	35.9	33.6	35.3	33.8	33.1	33.4	34.3	35.3	36.2	1.1%
Riverwood 33_11kV	28.3	26.8	25.5	23.5	24.5	23.4	27.6	25.7	25.2	25.0	25.4	25.9	26.3	26.8	-0.4%
Rockdale 33_11kV	14.9	14.9	14.5	16.7	16.6	17.2	17.8	17.2	0.0	0.0	0.0	0.0	0.0	0.0	-100.0%
Sans Souci 33_11kV	14.4	13.9	12.6	11.5	12.6	15.1	14.9	15.7	15.2	15.1	15.3	15.6	15.9	16.2	1.2%
Surry Hills 33_11kV	60.5	59.5	42.8	43.2	45.4	46.4	37.6	40.6	41.2	40.8	41.5	42.3	43.4	44.3	2.4%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney South Zone Substation Winter 50 POE Forecasts (132kV)

Sydney South Zone Locations Winter Forecast	2010 MVA	2011 MVA	2012 MVA	2013 MVA	2014 MVA	2015 MVA	2016 MVA	2017 MVA	2018 MVA	2019 MVA	2020 MVA	2021 MVA	2022 MVA	2023 MVA	CAGR %
Bankstown 132_11kV		22.9	22.5	21.8	32.3	35.1	39.4	38.5	38.3	37.5	36.9	37.8	38.8	40.1	0.3%
Belmore Park 132_11kV								0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Burwood 132_11kV	60.4	67.1	62.2	58.6	57.6	59.8	61.5	67.7	75.4	73.1	65.2	66.8	69.0	71.1	2.1%
Campbell St 132_11kV	24.5	24.0	33.6	32.6	31.1	33.1	31.5	32.6	39.8	39.4	35.1	35.7	36.4	37.3	2.5%
City Central 132_11kV	109.8	104.0	103.4	101.4	96.6	84.7	83.8	91.2	98.7	95.3	92.4	92.9	94.3	96.1	2.0%
City North 132_11kV	18.7	23.8	39.6	47.7	45.9	53.1	55.3	84.0	107.0	105.2	102.3	102.7	104.1	105.8	9.7%
City South 132_11kV	116.6	112.9	103.9	105.2	102.6	95.3	94.9	96.9	95.7	94.4	91.7	92.3	93.8	95.6	0.1%
Clovelly 132_11kV	88.9	87.1	82.9	73.7	74.2	74.3	73.3	72.5	74.2	71.7	70.5	71.4	72.7	74.3	0.2%
Cronulla 132_11kV	59.7	58.2	58.7	56.4	57.6	57.6	57.5	58.7	59.1	57.5	56.8	57.6	58.7	59.9	0.6%
Croydon 132_11kV								0.0	43.8	43.6	40.6	41.3	42.2	43.2	-0.3%
Dalley St 132_11kV	117.5	115.5	108.3	90.9	84.5	83.1	72.0	40.4	11.6	11.6	11.2	11.2	11.4	11.6	-22.9%
Darling Harbour 132_11kV	46.1	40.0	40.7	43.2	40.4	41.6	44.6	43.5	60.4	79.7	79.1	79.7	80.8	82.1	9.1%
Double Bay 132_11kV	68.9	67.5	64.3	61.5	62.3	62.7	61.5	60.6	60.0	57.0	55.6	56.2	57.3	58.7	-0.7%
Drummoyne 132_11kV	63.3	61.9	60.7	57.0	58.1	59.6	59.4	59.4	60.4	59.1	58.7	59.6	60.8	62.4	0.7%
Engadine 132_11kV								29.6	30.1	29.8	29.7	30.1	30.6	31.2	0.9%
Flemington 132_11kV	67.4	62.7	65.3	63.2	63.2	63.9	63.0	67.0	68.7	65.8	63.6	64.6	66.1	68.0	1.1%
Green Square 132_11kV	25.2	28.1	28.4	29.3	31.4	38.1	39.5	44.7	54.6	51.5	50.8	51.1	51.8	52.5	4.2%
Greenacre Park 132_11kV	67.6	58.7	57.6	55.8	42.3	41.7	47.2	45.5	48.1	46.0	45.1	45.9	47.0	48.4	0.4%
Gwawley Bay 132_11kV				25.4	25.8	26.7	27.0	27.2	27.5	26.7	26.3	26.6	27.1	27.7	0.4%
Homebush Bay 132_11kV	40.2	41.6	34.4	36.7	36.7	39.1	38.5	45.8	46.9	42.3	42.7	43.2	44.1	45.1	2.3%
Hurstville North 132_11kV						17.2	18.9	21.1	21.6	21.3	21.1	21.4	21.9	22.4	2.5%
Kingsford 132_11kV	48.1	47.6	48.5	52.8	53.2	55.9	54.4	56.1	57.7	56.2	55.6	56.4	57.5	58.8	1.1%
Kirrawee 132_11kV	37.2	41.2	38.8	37.8	38.6	39.3	39.8	43.8	43.4	42.3	41.9	42.4	43.1	44.0	1.4%
Kogarah 132_11kV	60.7	70.4	67.7	67.8	68.2	65.8	65.2	73.0	74.0	71.2	70.1	71.6	73.6	75.7	2.1%
Kurnell South 132_11kV						7.2	6.8	6.7	6.3	5.7	5.4	5.4	5.6	5.8	-2.2%
Leichhardt 132_11kV								0.0	29.9	28.8	28.4	28.8	29.4	30.1	0.2%
Maroubra 132_11kV	57.0	53.8	50.2	45.8	49.4	49.3	46.3	44.8	45.3	42.7	41.7	42.2	43.3	44.4	-0.6%
Marrickville 132_11kV	56.7	53.2	55.0	49.9	50.6	52.1	55.4	54.0	54.9	54.0	53.6	54.5	55.8	57.1	0.4%
Menai 132_11kV	42.2	42.5	37.9	38.6	45.0	39.3	40.4	41.1	41.1	40.4	40.1	40.6	41.3	42.1	0.6%
Milperra 132_11kV	48.0	46.9	46.3	42.8	40.4	41.6	38.9	37.5	35.5	33.3	32.3	32.8	33.5	34.5	-1.7%
Olympic Park 132_11kV								0.0	1.4	1.6	1.7	1.7	1.7	1.7	4.9%
Potts Hill 132_11kV				1.2	34.2	32.7	33.1	35.6	39.6	38.8	38.5	39.1	40.0	41.1	3.1%
Revesby 132_11kV	40.8	41.1	39.3	36.7	36.4	39.6	41.8	41.6	43.4	42.9	42.8	43.6	44.7	45.8	1.3%
Rockdale 132_11kV								0.0	0.0	23.4	23.2	23.6	24.0	24.6	1.2%
Rose Bay 132_11kV						41.0	40.3	39.9	39.2	37.7	37.0	37.5	38.2	39.0	-0.5%
Sefton 132_11kV	57.6	60.7	60.7	54.4	33.6	34.8	40.7	38.0	38.0	37.2	37.0	37.9	39.0	40.3	-0.1%
St Peters 132_11kV	53.5	53.4	54.4	53.3	51.0	51.1	50.8	54.2	58.5	55.5	48.7	49.6	51.1	52.7	0.5%
Waverley 132_11kV						28.7	29.3	29.3	29.5	28.8	28.4	28.8	29.3	29.9	0.3%
Zetland 132_11kV	64.2	62.6	56.6	51.8	55.1	53.2	51.7	57.8	68.9	67.5	66.0	67.1	68.7	70.3	4.5%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney South Zone Substation Winter 50 POE Forecasts (33kV)

Sydney South Zone Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Arncliffe 33_11kV	21.4	20.3	19.9	17.0	16.6	19.8	19.6	15.9	20.2	21.1	21.8	22.3	23.0	23.7	2.7%
Auburn 33_11kV	18.9	21.5	24.2	22.2	22.4	21.7	19.6	19.9	19.2	18.2	17.7	17.9	18.2	18.7	-0.7%
Bass Hill 33_11kV	24.1	23.8	21.3	21.3	21.3	22.6	19.6	20.3	20.1	19.4	19.2	19.5	20.0	20.6	0.7%
Blackwattle Bay 33_5kV	23.9	25.2	23.3	18.4	17.3	17.7	17.6	16.5	15.4	10.4	10.0	10.3	10.9	11.4	-6.1%
Blakehurst 33_11kV	22.2	19.8	19.1	18.5	19.1	20.3	19.4	19.8	20.1	20.3	20.1	20.5	21.0	21.6	1.5%
Botany 33_11kV	29.0	29.8	27.9	27.5	22.5	21.2	22.0	22.3	23.1	21.9	21.5	22.1	22.9	23.5	1.0%
Camperdown 33_11kV						7.7	12.1	12.5	28.5	34.0	34.9	35.4	36.0	36.7	17.1%
Camperdown 33_5kV	38.6	34.1	23.8	18.2	15.5	14.3	10.2	7.1	0.0	0.0	0.0	0.0	0.0	0.0	-100.0%
Campsie 33_11kV	57.1	64.2	61.8	58.4	58.5	60.8	66.7	72.2	74.1	73.5	68.9	70.4	72.2	74.3	1.6%
Caringbah 33_11kV	22.0	22.7	18.9	18.4	18.7	19.1	21.0	21.9	22.0	21.4	21.2	21.3	21.7	22.1	0.8%
City East 33_11kV	31.8	37.2	34.5	33.2	31.1	28.4	27.1	30.0	28.6	27.0	26.2	26.3	26.6	27.0	0.0%
Concord 33_11kV	32.7	32.3	31.3	30.9	29.6	30.3	31.4	34.9	36.0	35.4	35.2	35.6	36.2	37.1	2.4%
Darlinghurst 33_11kV	43.4	41.7	38.7	38.0	37.1	37.9	37.3	36.2	35.8	33.8	33.0	33.7	34.8	36.0	-0.5%
Dulwich Hill 33_11kV	48.6	46.0	45.4	43.0	42.7	44.2	47.4	49.1	53.0	52.6	52.7	53.5	54.7	55.9	2.4%
Enfield 33_11kV	39.6	22.1	20.9	19.8	20.4	19.4	20.8	21.8	21.5	20.8	20.6	21.1	21.8	22.4	1.1%
Jannali 33_11kV	33.0	31.8	32.2	29.7	29.7	32.3	34.3	33.7	33.9	33.5	33.4	33.8	34.4	35.1	0.3%
Leichhardt 33_11kV	30.5	30.7	39.4	38.9	40.4	34.8	25.6	29.6	0.0	0.0	0.0	0.0	0.0	0.0	-100.0%
Leightonfield 33_11kV	21.1	19.7	19.9	19.1	19.4	20.9	20.0	20.3	19.4	18.4	17.9	18.1	18.5	19.0	-0.8%
Lidcombe 33_11kV	24.6	22.7	19.8	14.9	14.3	15.9	15.5	15.4	16.7	17.2	17.6	18.0	18.5	19.1	3.0%
Lucas Heights 33_11kV	6.3	6.3	6.3	6.2	6.5	7.3	7.3	7.2	7.0	6.6	6.4	6.4	6.5	6.6	-1.6%
Mascot 33_11kV	43.4	41.3	40.0	38.4	36.8	38.4	38.9	38.6	50.4	50.6	50.8	51.6	52.7	53.7	4.7%
Matraville 33_11kV	46.9	47.5	44.1	43.1	42.1	42.6	42.4	46.4	47.1	44.8	43.6	44.1	45.1	46.3	1.2%
Miranda 33_11kV	34.5	30.2	28.8	26.7	26.0	28.2	29.8	30.2	30.5	29.7	29.2	29.5	30.0	30.6	0.4%
Mortdale 33_11kV	46.9	45.4	44.2	42.6	42.2	42.3	43.6	44.7	43.6	42.0	41.4	42.3	43.4	44.5	0.3%
Paddington 33_11kV	31.5	31.3	32.5	29.1	28.4	30.6	31.1	32.1	32.4	31.4	31.2	31.9	33.0	34.0	1.3%
Port Botany 33_11kV		2.8	2.5	2.5	5.3	6.1	6.1	8.6	8.9	8.8	8.7	8.8	8.9	9.0	5.7%
Punchbowl 33_11kV	54.3	52.5	49.6	47.4	36.1	35.9	33.5	33.5	33.6	32.4	32.1	33.0	34.2	35.5	0.8%
Riverwood 33_11kV	26.5	25.8	24.4	23.5	24.0	24.5	26.3	26.0	26.0	25.5	25.4	25.9	26.5	27.2	0.5%
Rockdale 33_11kV	22.2	13.7	13.3	16.1	15.3	15.9	20.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	-100.0%
Sans Souci 33_11kV	18.4	16.0	16.1	14.7	15.0	15.5	15.7	15.5	15.2	14.8	14.7	15.1	15.6	16.1	0.4%
Surry Hills 33_11kV	47.7	47.4	36.1	35.4	36.2	38.0	39.0	30.9	33.9	33.6	32.9	33.5	34.5	35.5	-1.3%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

2.1.2 Sydney South Region Sub-transmisson Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each sub-transmission substation.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Sydney South Sub-transmission Substation Summer 50 POE Forecasts (132 kV)

Sydney South STS Locations	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	CAGR
Summer Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Alexandria 132_33kV								10.3	40.3	50.4	76.1	76.1	106.0	106.0	47.4%
Bankstown 132_33kV	92.6	86.0	78.6	79.0	73.0	70.9	63.1	65.3	63.7	63.1	63.9	65.1	66.3	67.6	1.0%
Bunnerong North 132_33kV	232.0	228.0	220.9	205.6	202.3	203.1	211.2	213.5	212.5	211.3	213.3	215.3	217.7	219.8	0.6%
Canterbury 132_33kV	143.9	136.8	119.7	124.3	126.1	130.6	136.0	144.8	145.9	142.6	145.4	173.0	175.8	178.5	4.0%
Homebush 132_33kV	131.6	122.6	108.8	120.8	120.1	120.0	120.0	108.5	107.5	114.3	131.5	132.8	134.3	135.8	1.8%
Peakhurst 132_33kV	156.6	151.5	138.1	132.3	112.1	125.8	140.0	132.3	116.4	112.3	112.6	114.8	117.2	119.5	-2.2%
Port Hacking 132_33kV	125.6	112.1	76.4	76.7	74.5	122.2	98.7	102.3	102.3	102.6	103.7	104.5	105.4	106.3	1.1%
Pyrmont 132_33kV	99.6	101.4	75.0	72.1	75.5	88.4	99.1	107.6	130.5	116.1	120.6	124.5	128.5	133.2	4.3%
Rozelle 132_33kV	11.8	16.1	10.0	10.9	10.5	10.5		13.2	13.2	13.2	13.2	36.9	57.2	57.2	27.7%
Strathfield 132_33kV	45.3	46.2	49.9	52.8	54.9	58.1	51.7	52.5	30.0	29.8	29.6	29.6	29.6	29.6	-7.6%
Surry Hills 132_33kV	231.6	235.5	202.1	193.8	170.9	157.4	153.1	154.3	151.5	148.5	150.3	188.9	192.7	196.2	3.6%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney South Sub-transmission Substation Winter 50 POE Forecasts (132 kV)

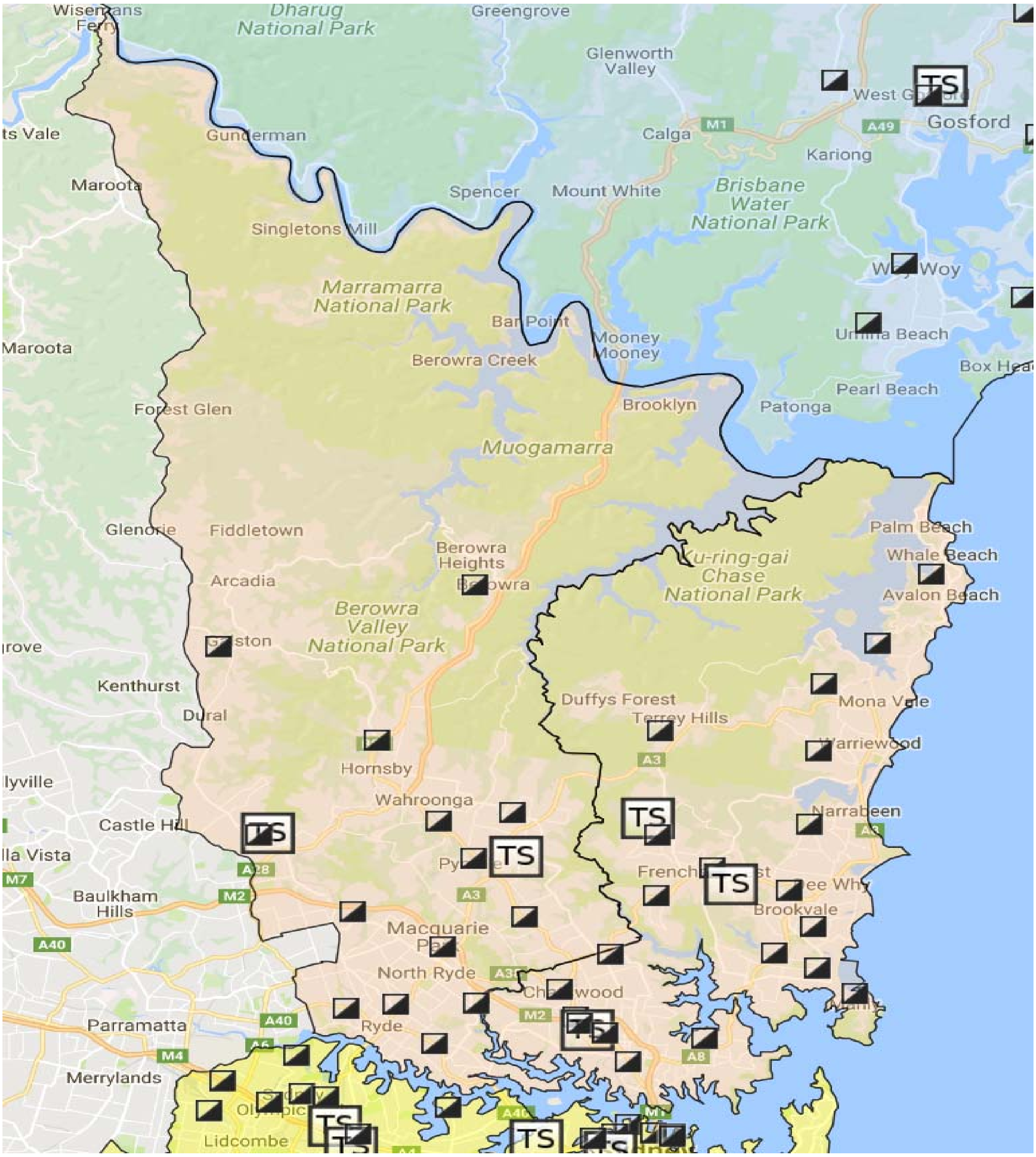
Sydney South STS Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Alexandria 132_33kV								0.0	15.0	42.5	69.5	69.5	98.4	98.4	45.6%
Bankstown 132_33kV	103.2	84.2	78.7	75.7	63.9	64.4	61.3	61.8	61.7	59.9	59.4	60.6	62.2	64.1	0.6%
Bunnerong North 132_33kV	221.0	214.4	187.4	194.4	187.6	186.2	192.9	192.1	199.4	195.8	194.5	196.2	198.8	201.3	0.6%
Canterbury 132_33kV	164.5	151.8	133.2	134.1	131.0	132.1	139.1	148.0	147.8	146.2	141.6	168.5	172.0	175.9	3.4%
Homebush 132_33kV	119.7	102.9	95.7	98.1	87.5	91.8	95.4	105.2	72.0	83.0	97.9	98.8	100.1	101.9	0.9%
Peakhurst 132_33kV	178.3	158.9	152.0	149.4	144.4	132.6	135.8	127.9	138.9	111.7	108.6	111.2	114.4	117.7	-2.0%
Port Hacking 132_33kV	143.5	127.6	121.1	84.0	83.8	98.9	125.7	95.2	95.6	94.2	93.5	94.2	95.3	96.6	-3.7%
Pyrmont 132_33kV	88.5	92.1	75.7	64.9	69.0	74.3	75.4	90.2	122.4	108.5	112.6	114.9	117.4	120.0	6.9%
Rozelle 132_33kV	16.1	15.0	19.4	13.9	14.1	15.5		12.0	12.0	12.0	12.0	32.7	50.5	50.5	27.0%
Strathfield 132_33kV	40.2	43.9	56.8	51.6	53.3	48.5	54.0	51.3	24.6	25.1	25.4	25.4	25.4	25.4	-10.2%
Surry Hills 132_33kV	211.4	210.5	208.6	188.7	197.3	131.6	129.3	121.8	126.7	122.2	120.4	157.0	160.8	164.7	3.5%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

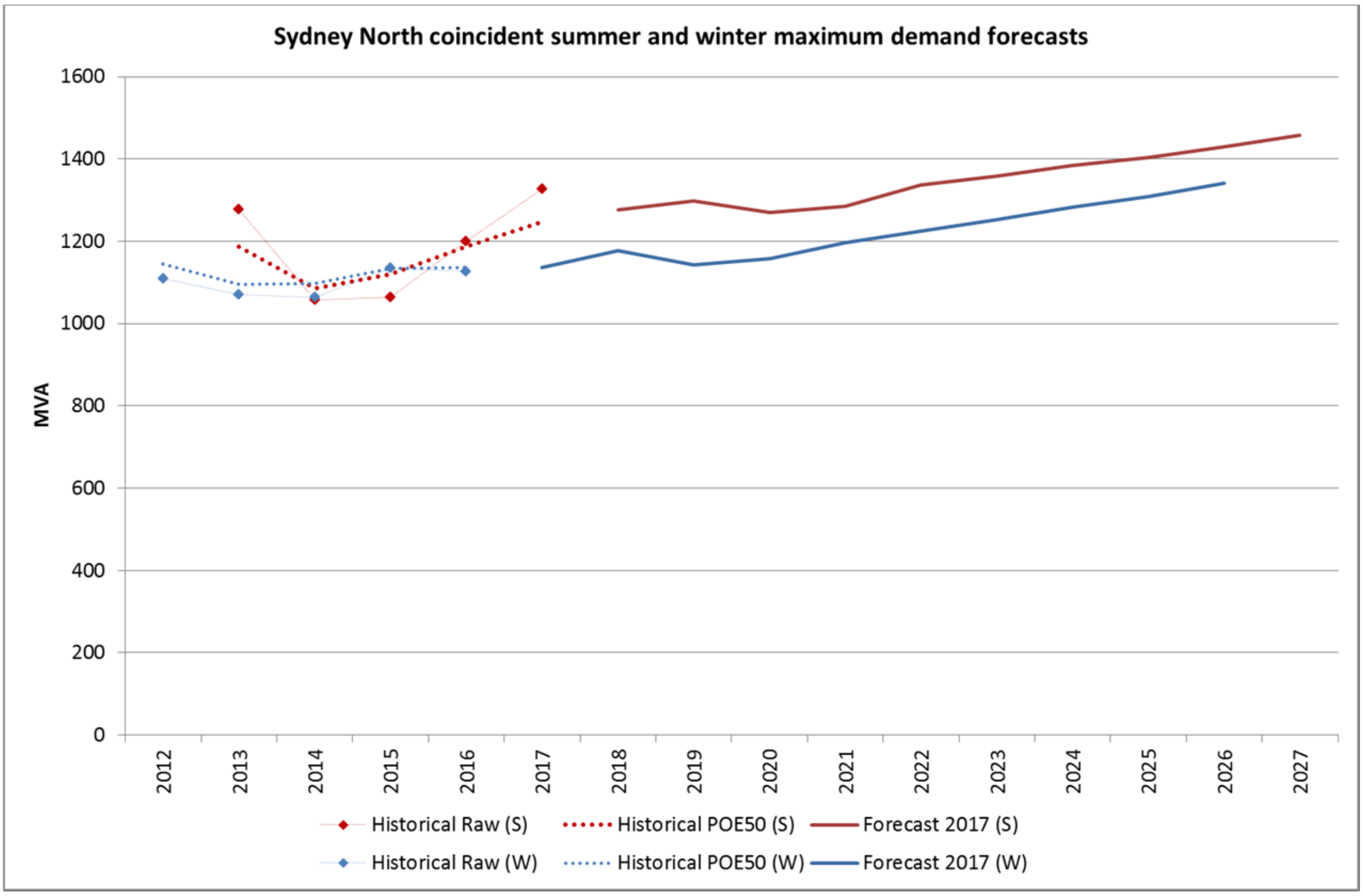
2.2 Sydney North Region

The Sydney North region of Ausgrid's network serves a total of 396,000 customers from 34 zone substations and 4 sub-transmission substations. The following figure shows the Sydney North region and location of the zones and sub transmission stations within the region. The Sydney North region includes the North Sydney, Chatswood and Macquarie CBD commercial and retail precincts and is home to about 800,000 people.

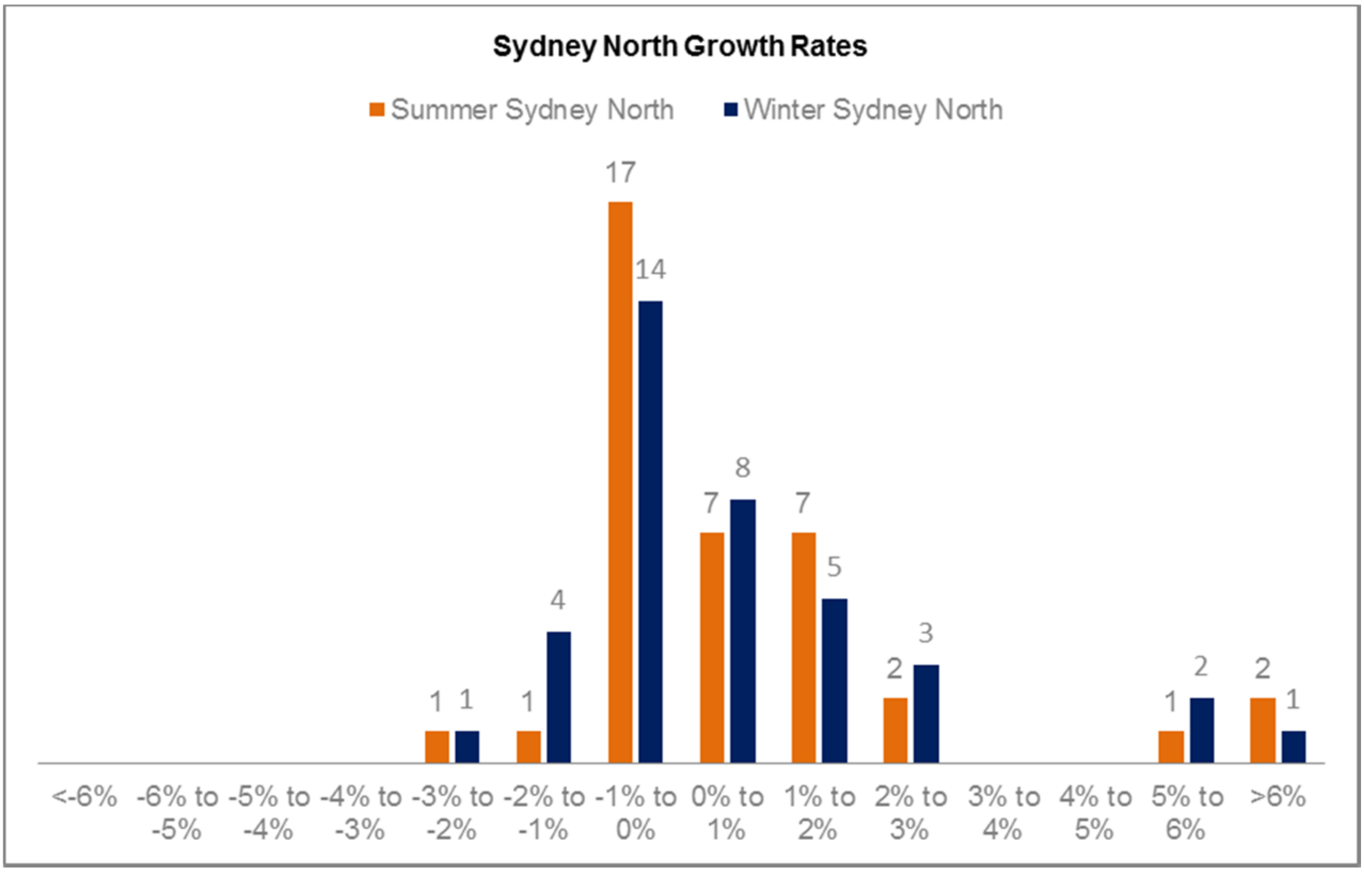
Sydney North Region:



The 2017 Sydney North region coincident system total summer and winter maximum demand forecast are shown in the chart below. The 7 year compounded annual growth rate (CAGR) for the region is 1.5% in summer and 1.4% in winter. Note that the higher growth is due to a significant number of new large customer connections. The underlying growth rate, excluding large customer connections, is -0.5% in summer and -0.8% in winter.



The histogram chart for the Sydney North Zone region shows the count of substation numbers for 50 POE forecast growth rate ranges using the 7 year compounded annual growth rate (CAGR). While a majority of zones have forecast average annual growth rates of -1% to +1%, there is a broad range of growth rates at the local spatial level.



2.2.1 Sydney North Region Zone Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each zone substation. Separate tables have been compiled for zone substations supplied at 132 kV and 33/66 kV.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Sydney North Zone Substation Summer 50 POE Forecast (132kV)

Sydney North Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Balgowlah North 132_11kV		20.2	24.8	22.6	23.3	25.6	26.9	26.7	26.5	26.5	27.0	27.4	28.0	28.5	0.8%
Berowra 132_11kV	23.8	21.3	21.4	19.9	21.3	21.6	23.4	20.8	20.7	20.9	21.5	22.0	22.6	23.1	-0.2%
Castle Cove 132_11kV	75.8	69.2	65.4	61.9	62.7	65.1	67.9	63.3	58.4	55.7	55.3	56.2	57.3	58.3	-2.2%
Crows Nest 132_11kV							23.5	36.3	34.7	33.9	34.2	34.8	35.6	36.3	6.4%
Galston 132_11kV	6.3	6.9	8.5	9.9	10.6	10.9	11.7	11.5	11.1	11.0	11.0	11.1	11.2	11.4	-0.4%
Hornsby 132_11kV	78.4	63.0	64.7	62.1	64.4	69.1	74.0	73.6	79.3	76.0	77.8	79.0	80.3	81.6	1.4%
Macquarie Park 132_11kV	75.1	70.0	68.2	64.3	71.0	76.5	84.3	104.7	107.3	114.4	119.2	127.9	130.8	137.3	7.2%
Meadowbank 132_11kV	75.5	67.3	64.5	65.7	67.1	73.3	77.7	81.9	82.4	82.9	84.6	86.3	88.2	90.0	2.1%
Mosman 132_11kV	68.6	62.7	57.4	53.1	53.9	60.3	61.0	57.8	54.4	52.7	53.1	54.3	55.6	56.9	-1.0%
North Sydney 132_11kV						50.3	73.5	77.7	74.5	71.6	71.9	73.1	74.5	75.7	0.4%
Pennant Hills 132_11kV	86.4	76.3	75.4	72.3	73.2	80.0	85.6	84.9	92.5	76.3	76.6	77.7	78.9	80.0	-1.0%
RNS Hospital 132_11kV		7.2	12.4	11.3	11.3	12.1	13.3	12.9	12.6	12.5	12.6	12.7	13.0	13.1	-0.2%
Top Ryde 132_11kV		46.9	52.6	48.5	48.6	50.1	57.0	54.7	52.3	51.1	51.3	52.2	53.2	54.1	-0.7%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney North Zone Substation Summer 50 POE Forecast (33/66kV)

Sydney North Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Beacon Hill 33_11kV	24.0	25.3	21.9	19.7	20.1	20.7	21.2	18.3	18.6	18.0	18.1	18.3	18.6	18.8	-1.7%
Belrose 33_11kV	23.7	23.8	23.3	22.8	22.1	26.3	26.3	26.7	25.8	25.3	25.4	25.7	26.0	26.3	0.0%
Brookvale 33_11kV	47.3	46.1	42.9	40.6	39.8	40.3	43.3	43.4	43.1	43.1	43.7	44.1	44.6	45.1	0.6%
Careel Bay 33_11kV	10.6	10.4	10.6	9.5	9.8	9.7	10.5	9.8	9.5	9.3	9.4	9.6	9.8	10.1	-0.6%
Chatswood 33_11kV	45.7	42.4	39.6	38.6	38.5	42.1	48.8	51.1	49.4	45.6	46.0	46.8	47.8	48.7	0.0%
Dee Why West 33_11kV	37.1	31.8	32.5	28.4	29.8	34.3	33.5	33.5	32.2	31.6	31.9	32.6	33.2	33.9	0.2%
Epping 66_11kV	62.8	60.8	58.2	56.4	58.5	61.0	61.1	58.7	59.0	58.7	59.5	60.5	61.7	62.8	0.4%
Gore Hill 33_11kV	81.9	72.7	64.5	59.4	60.2	60.4	60.2	58.6	56.6	54.4	54.4	55.4	56.7	57.8	-0.6%
Harbord 33_11kV	26.4	24.6	15.6	14.5	14.8	15.6	15.7	16.3	16.5	16.3	16.5	16.9	17.2	17.5	1.6%
Hunters Hill 66_11kV	62.2	58.6	44.3	43.5	46.3	50.7	41.9	44.3	44.5	45.0	46.0	46.7	47.5	48.3	2.1%
Killarney 33_11kV	15.6	15.9	12.3	11.5	11.5	13.8	13.7	13.3	12.8	12.5	12.6	12.7	12.9	13.1	-0.6%
Lindfield 33_11kV	31.9	32.0	27.6	25.7	27.6	28.9	30.4	31.9	31.7	31.7	32.2	32.8	33.4	34.0	1.6%
Manly 33_11kV	17.9	16.8	16.4	15.8	15.8	15.8	16.0	15.3	14.5	14.0	14.1	14.5	14.9	15.2	-0.7%
Mona Vale 33_11kV	34.4	30.5	31.1	27.6	27.5	33.2	34.6	33.8	32.8	32.3	32.5	32.9	33.4	33.9	-0.3%
Narrabeen 33_11kV	10.7	9.4	9.9	9.3	11.2	10.6	11.3	12.3	12.2	12.2	12.3	12.5	12.7	12.9	1.9%
Newport 33_11kV	12.3	11.0	11.3	11.0	10.9	10.7	11.3	10.8	10.4	10.2	10.3	10.5	10.7	11.0	-0.5%
North Head 33_11kV	20.6	21.4	20.3	21.2	19.5	20.3	20.0	19.7	19.2	18.9	19.0	19.2	19.4	19.5	-0.3%
Pymble 33_11kV	39.6	33.7	30.0	30.3	30.7	33.5	34.5	35.2	35.6	35.8	36.5	37.0	37.6	38.1	1.4%
St Ives 33_11kV	51.6	49.1	42.2	38.4	41.9	43.6	46.9	47.8	48.1	48.5	49.4	50.0	50.7	51.4	1.3%
Terrey Hills 33_11kV	16.7	15.3	15.4	14.9	16.3	16.8	17.3	17.4	16.8	16.5	16.6	16.7	16.9	17.0	-0.2%
Turramurra 33_11kV	34.2	30.7	30.3	28.9	30.3	32.8	36.4	35.6	35.6	35.7	36.4	36.9	37.5	38.2	0.7%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney North Zone Substation Winter 50 POE Forecast (132kV)

Sydney North Zone Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Balgowlah North 132_11kV			33.9	32.7	33.1	34.0	33.8	34.1	33.6	32.7	32.3	32.8	33.4	34.2	0.2%
Berowra 132_11kV	25.0	23.6	22.2	21.3	20.6	21.2	22.2	20.4	20.3	19.5	19.2	19.6	20.2	20.9	-0.8%
Castle Cove 132_11kV	66.5	63.4	60.0	54.8	54.4	54.0	54.9	51.2	52.7	50.4	49.3	49.8	50.8	52.1	-0.8%
Crows Nest 132_11kV							26.6	23.4	38.5	36.4	35.5	36.1	36.9	37.9	5.2%
Galston 132_11kV		2.9	8.4	9.3	9.0	9.6	9.6	9.4	8.9	8.5	8.3	8.4	8.6	8.8	-1.2%
Hornsby 132_11kV	76.7	72.7	66.5	61.8	62.2	66.2	65.4	67.5	72.2	66.3	65.9	67.0	68.6	70.4	1.0%
Macquarie Park 132_11kV	55.3	56.1	55.3	54.2	54.1	54.1	59.8	68.8	87.3	89.5	96.2	100.2	108.6	111.2	9.3%
Meadowbank 132_11kV	64.2	63.1	58.4	56.0	58.2	60.3	62.5	62.3	67.9	66.1	65.8	67.4	69.6	72.0	2.0%
Mosman 132_11kV	88.6	87.1	84.0	79.5	83.0	80.6	80.2	80.0	79.0	76.5	75.5	76.7	78.3	80.2	0.0%
North Sydney 132_11kV							41.2	56.4	60.9	58.0	56.0	56.6	57.7	59.0	5.3%
Pennant Hills 132_11kV	79.7	77.0	71.5	62.8	62.4	64.2	65.6	69.9	78.0	60.5	59.4	60.6	62.1	63.8	-0.4%
RNS Hospital 132_11kV			7.4	9.1	9.3	9.6	9.5	9.4	9.3	9.0	8.8	8.8	8.9	9.1	-0.6%
Top Ryde 132_11kV			43.1	41.4	39.1	39.2	39.5	44.8	45.9	44.7	44.4	45.3	46.5	47.7	2.7%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Sydney North Zone Substation Winter 50 POE Forecast (33-66kV)

Sydney North Zone Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Beacon Hill 33_11kV	21.8	20.5	22.8	20.2	20.2	21.0	20.8	20.1	20.8	20.2	19.9	20.1	20.4	20.8	0.0%
Belrose 33_11kV	25.8	24.5	24.0	26.0	26.4	27.1	27.3	29.3	28.1	27.1	26.6	27.0	27.4	27.9	0.4%
Brookvale 33_11kV	39.3	38.7	36.4	35.2	34.7	36.9	34.6	37.9	38.5	37.6	37.2	37.4	38.0	38.6	1.6%
Careel Bay 33_11kV	14.2	13.8	13.5	12.8	12.8	13.9	13.5	13.7	13.6	13.2	13.1	13.3	13.6	13.9	0.4%
Chatswood 33_11kV	45.0	42.4	43.8	44.6	40.9	43.0	45.0	47.1	50.0	47.7	45.2	46.0	47.0	48.2	1.0%
Dee Why West 33_11kV	51.2	47.9	43.9	41.1	41.5	42.1	45.4	43.1	42.0	40.3	39.5	40.1	40.8	41.8	-1.2%
Epping 66_11kV	56.4	53.0	49.3	46.5	46.3	48.4	50.2	50.0	54.1	52.7	52.2	53.0	54.2	55.5	1.5%
Gore Hill 33_11kV	67.6	67.3	60.6	54.7	51.9	52.4	51.0	48.8	46.6	44.4	42.7	43.0	43.8	44.9	-1.8%
Harbord 33_11kV	38.0	34.8	23.7	25.0	23.3	24.1	23.2	23.9	24.7	24.0	23.8	24.1	24.5	25.0	1.1%
Hunters Hill 66_11kV	59.6	58.4	47.0	43.4	43.6	45.1	46.0	36.5	36.3	35.1	34.7	35.3	36.3	37.4	-2.9%
Killarney 33_11kV	17.6	16.5	15.1	13.7	13.8	14.2	14.4	14.8	14.8	14.5	14.4	14.6	14.9	15.2	0.7%
Lindfield 33_11kV	36.4	33.1	32.6	30.7	31.6	32.4	31.3	31.6	32.8	31.6	31.1	31.7	32.4	33.3	0.9%
Manly 33_11kV	23.3	21.9	21.8	20.9	19.9	20.4	19.9	19.3	18.4	17.4	17.0	17.2	17.6	18.1	-1.4%
Mona Vale 33_11kV	30.7	34.1	32.7	31.6	31.1	33.1	32.9	33.5	33.3	32.2	31.7	32.0	32.6	33.3	0.2%
Narrabeen 33_11kV	13.0	12.6	12.1	11.6	12.2	13.1	12.5	13.8	13.7	13.4	13.3	13.4	13.7	13.9	1.6%
Newport 33_11kV	22.5	16.0	15.4	14.8	14.2	15.2	14.9	14.9	14.6	14.1	13.9	14.2	14.5	14.8	-0.1%
North Head 33_11kV	21.9	23.4	21.2	21.5	20.9	16.4	21.3	21.2	21.0	20.5	20.3	20.4	20.6	20.7	-0.4%
Pymble 33_11kV	36.2	35.9	32.7	30.2	31.0	33.6	33.4	32.8	32.6	31.4	30.9	31.4	32.1	32.9	-0.2%
St Ives 33_11kV	53.4	52.6	48.8	44.7	44.7	44.7	43.7	43.0	42.9	41.2	40.5	41.2	42.3	43.4	-0.1%
Terrey Hills 33_11kV	13.2	12.6	13.3	12.6	13.1	13.6	13.6	13.5	13.3	12.8	12.6	12.7	12.8	13.1	-0.5%
Turramurra 33_11kV	35.7	34.4	33.7	33.4	33.7	34.2	34.5	32.8	32.3	30.8	30.2	30.7	31.5	32.3	-0.9%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

2.2.2 Sydney North Region Sub-transmisson Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each sub-transmission substation.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Sydney North Sub-transmission Substation Summer 50 POE Forecasts (132 kV)

Sydney North STS Locations	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	CAGR
Summer Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Kuring-gai 132_33kV	171.0	133.9	133.9	119.8	124.7	144.8	149.3	153.2	153.8	154.7	157.4	159.7	162.1	164.5	1.4%
Sydney East 132_33kV	77.3	73.2	71.0	63.0	62.5	72.7	71.1	69.1	66.9	65.8	66.4	67.4	68.6	69.7	-0.3%
Warringah 132_33kV	186.5	163.3	146.3	138.1	138.2	152.1	150.2	150.0	147.4	145.2	146.6	148.9	151.4	153.9	0.3%
Willoughby 132_33kV	310.6	253.4	237.0	215.1	210.4	173.9	135.3	146.6	170.4	165.9	166.3	191.9	194.0	195.9	5.4%

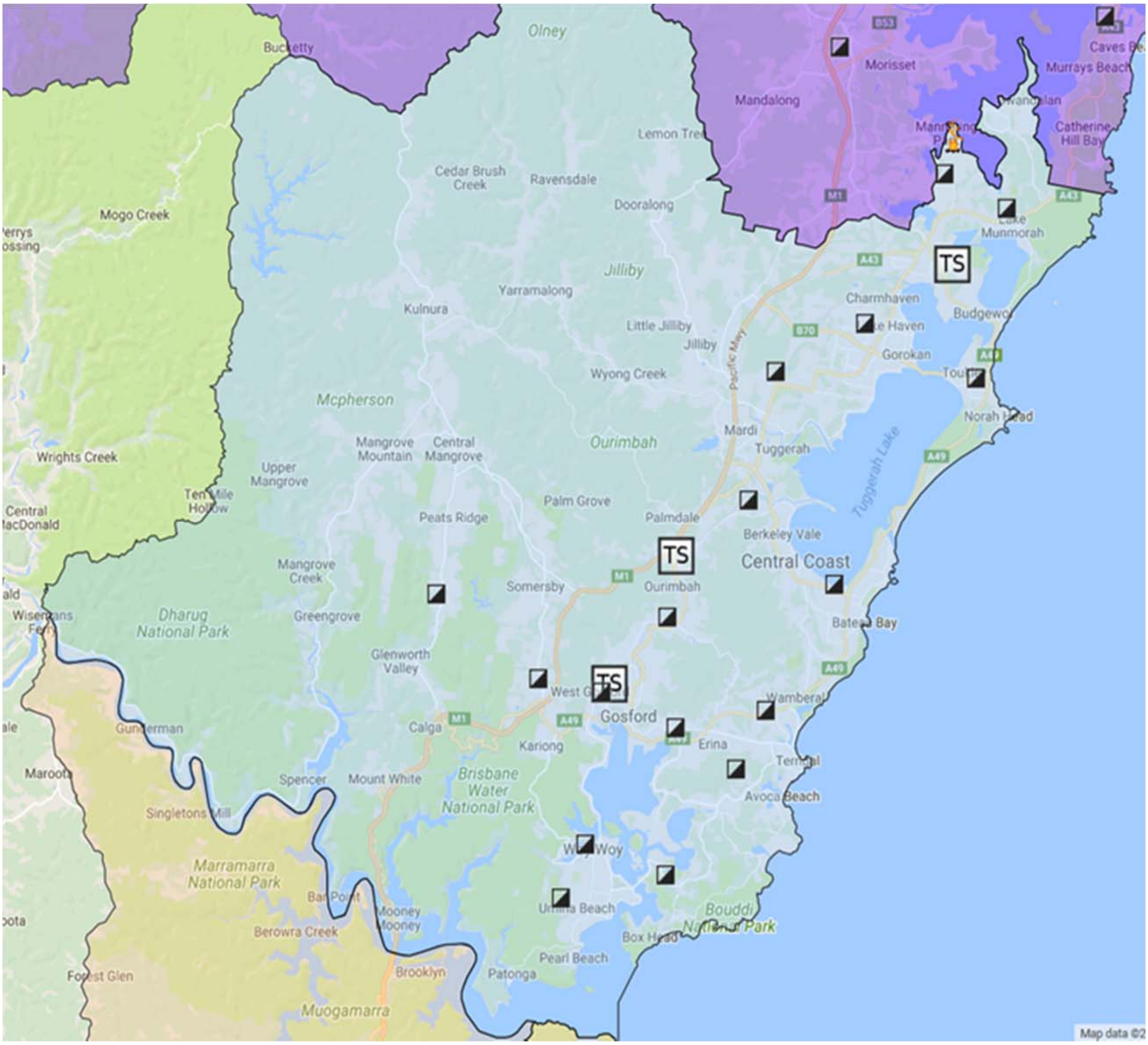
Sydney North Sub-transmission Substation Winter 50 POE Forecasts (132 kV)

Sydney North STS Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Kuring-gai 132_33kV	171.2	164.8	151.6	137.6	152.3	144.2	142.0	141.3	141.6	135.9	133.7	136.0	139.2	142.7	0.1%
Sydney East 132_33kV	90.1	83.0	83.0	72.1	73.5	75.0	76.7	76.0	75.1	72.7	71.6	72.5	74.0	75.7	-0.2%
Warringah 132_33kV	221.8	213.0	175.1	172.1	171.1	193.7	174.2	169.5	168.5	163.2	160.8	162.5	165.3	168.6	-0.5%
Willoughby 132_33kV	227.2	245.6	207.5	203.4	184.5	196.8	153.6	135.9	120.7	137.6	160.9	183.8	185.5	187.6	2.9%

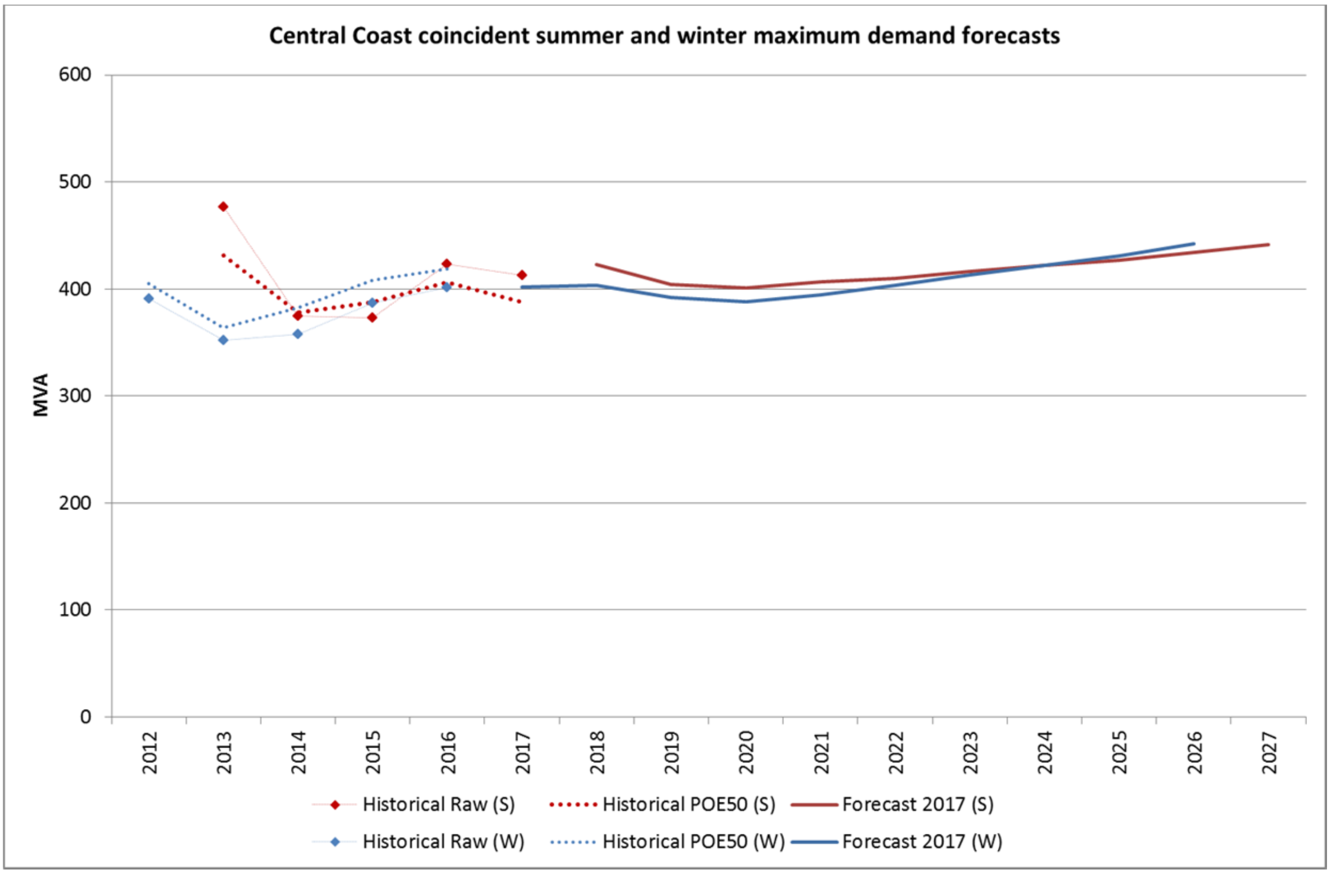
2.3 Central Coast Region

The Central Coast region of Ausgrid's network serves a total of 163,000 customers from 17 zone substations and 5 sub-transmission substations. The following figure shows the Central Coast region and location of the zones and sub transmission stations within the region. The Central Coast region is home to about 350,000 people.

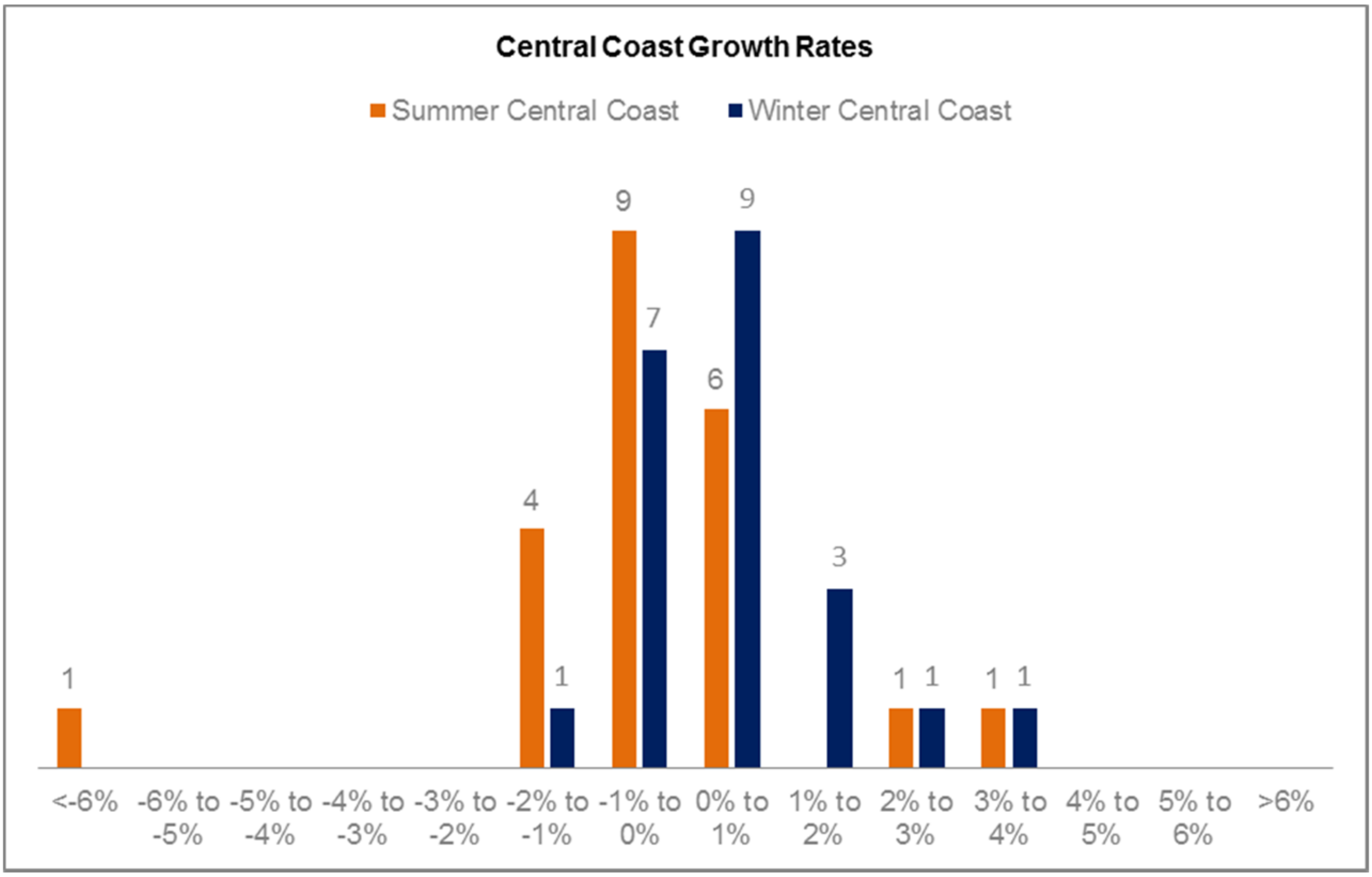
Central Coast Region



The 2017 Central Coast region coincident system total summer and winter maximum demand forecast are shown in the chart below. The 7 year compounded annual growth rate (CAGR) for the region is 1.2% in summer and -0.2% in winter. Note that the higher growth is due to a significant number of new large customer connections. The underlying growth rate, excluding large customer connections, is 1.0% in summer and -0.7% in winter.



The histogram chart for the Central Coast Zone region shows the count of substation numbers for 50 POE forecast growth rate ranges using the 7 year compounded annual growth rate (CAGR). A majority of zones have forecast average annual growth rates of -1% to +1% with limited variation across the region.



2.3.1 Central Coast Region Zone Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each zone substation. Separate tables have been compiled for zone substations supplied at 132 kV and 33/66 kV.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Central Coast Zone Substation Summer 50 POE Forecasts (132kV)

Central Coast Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Berkeley Vale 132_11kV	45.4	46.9	43.7	39.6	40.8	44.4	45.2	45.3	43.6	42.8	44.9	45.4	46.0	46.6	0.4%
Charmhaven 132_11kV	43.2	47.7	43.5	39.6	42.3	45.6	45.1	42.9	42.1	41.7	42.1	42.6	43.2	43.8	-0.4%
Lake Munmorah 132_11kV			17.0	14.8	15.6	19.1	18.3	18.5	17.9	17.6	17.7	17.9	18.2	18.4	0.1%
Somersby 132_11kV	18.9	17.6	17.0	16.2	16.0	17.4	18.9	24.5	24.2	24.0	24.1	24.3	24.5	24.6	3.9%
Wamberal 132_11kV	0.0	11.6	12.5	9.6	10.5	11.8	12.8	11.7	11.1	10.9	11.0	11.2	11.4	11.6	-1.3%
West Gosford 132_11kV	56.8	53.5	48.9	49.4	49.0	50.4	53.0	53.1	53.2	53.3	54.0	54.6	55.3	56.0	0.8%
Wyong 132_11kV	40.6	38.7	33.3	33.0	33.4	36.5	38.2	41.6	41.7	42.0	42.7	43.1	43.6	44.1	2.1%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Central Coast Zone Substation Summer 50 POE Forecasts (33/66kV)

Central Coast Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Avoca 66_11kV	39.8	33.7	35.3	28.8	30.3	31.8	33.5	32.4	31.9	31.7	32.2	32.8	33.4	34.0	0.2%
Empire Bay 66_11kV				4.4	6.9	10.4	11.0	10.8	10.5	10.4	10.5	10.6	10.8	11.0	-0.1%
Erina 66_11kV	37.1	35.5	33.2	30.8	32.0	33.1	34.2	33.2	32.4	32.1	32.3	32.6	33.0	33.4	-0.4%
Lisarow 33_11kV	23.8	24.7	22.5	19.8	21.0	22.9	24.7	23.5	23.4	23.4	23.8	24.1	24.5	24.9	0.1%
Long Jetty 66_11kV		36.6	38.6	31.5	34.1	36.5	37.4	36.1	34.9	34.4	34.8	35.5	36.3	37.0	-0.2%
Noraville 33_11kV	21.7	20.1	21.0	16.9	17.7	20.8	20.4	19.8	18.8	18.2	18.3	18.6	18.9	19.2	-0.9%
Peats Ridge 33_11kV	12.8	11.9	11.1	10.5	12.1	11.8	12.4	12.1	11.3	10.8	10.7	10.8	10.9	10.9	-1.8%
Umina 66_11kV	30.9	30.4	29.9	26.4	28.3	29.8	30.4	29.0	28.1	27.7	28.0	28.5	29.1	29.6	-0.4%
Vales Point 33_11kV	9.4	10.1	9.3	7.1	7.1	6.4	8.2	8.0	7.8	7.6	7.6	7.7	7.8	7.9	-0.6%
Woy Woy 66_11kV	26.3	27.0	27.1	19.0	18.1	18.5	18.7	17.2	16.4	15.9	16.0	16.3	16.6	16.9	-1.4%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Central Coast Zone Substation Winter 50 POE Forecasts (132kV)

Central Coast Zone Locations Winter Forecast	2010 MVA	2011 MVA	2012 MVA	2013 MVA	2014 MVA	2015 MVA	2016 MVA	2017 MVA	2018 MVA	2019 MVA	2020 MVA	2021 MVA	2022 MVA	2023 MVA	CAGR %
Berkeley Vale 132_11kV	34.4	33.5	35.0	35.2	33.6	36.4	35.5	36.9	35.8	34.2	34.3	34.7	35.4	36.2	0.3%
Charmhaven 132_11kV	35.7	35.6	34.8	33.5	34.9	37.4	37.6	38.0	37.8	36.8	36.5	37.1	37.9	38.9	0.5%
Lake Munmorah 132_11kV				15.6	16.7	18.1	18.4	19.1	19.3	19.2	19.2	19.5	19.9	20.4	1.5%
Somersby 132_11kV	17.8	17.2	16.7	16.7	16.0	17.3	17.4	17.4	21.9	21.2	20.8	20.9	21.2	21.5	3.1%
Wamberal 132_11kV	0.0	0.0	15.0	14.2	14.7	15.7	15.1	15.6	15.5	15.2	15.1	15.4	15.7	16.1	0.9%
West Gosford 132_11kV	43.9	41.9	40.0	40.3	39.6	42.2	40.4	40.6	41.9	40.7	40.1	40.8	41.7	42.7	0.8%
Wyong 132_11kV	34.1	32.4	32.5	27.8	28.5	29.2	29.6	29.5	30.1	29.2	28.8	29.3	30.0	30.8	0.6%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Central Coast Zone Substation Winter 50 POE Forecasts (33/66kV)

Central Coast Zone Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Avoca 66_11kV	44.0	43.8	44.1	37.2	38.9	38.8	38.5	36.7	35.8	34.4	33.9	34.6	35.5	36.5	-0.8%
Empire Bay 66_11kV				7.0	5.3	10.6	11.2	12.9	12.6	12.3	12.2	12.4	12.6	12.9	2.1%
Erina 66_11kV	31.2	28.1	25.6	23.0	24.5	25.9	25.6	26.3	26.2	25.6	25.3	25.7	26.3	26.9	0.7%
Lisarow 33_11kV	25.3	21.6	21.4	20.7	20.7	21.8	21.9	21.7	21.4	20.8	20.6	20.9	21.3	21.8	-0.1%
Long Jetty 66_11kV		43.4	40.7	40.8	42.7	44.0	43.6	45.3	45.4	44.7	44.6	45.4	46.5	47.6	1.3%
Noraville 33_11kV	23.7	23.4	24.6	21.9	23.0	23.8	23.9	23.8	24.0	23.3	23.1	23.6	24.1	24.7	0.5%
Peats Ridge 33_11kV	10.7	10.4	9.8	9.8	9.2	10.4	10.3	9.8	9.4	8.8	8.5	8.6	8.8	9.0	-2.0%
Umina 66_11kV	30.5	28.8	26.7	26.1	27.2	30.0	28.1	27.5	26.9	26.0	25.6	26.2	27.0	27.9	-0.1%
Vales Point 33_11kV	10.2	9.5	12.5	6.8	7.9	7.4	8.3	8.3	8.1	7.9	7.8	7.8	7.9	7.9	-0.7%
Woy Woy 66_11kV	26.7	25.9	26.7	21.0	19.1	18.7	18.1	17.1	16.6	15.9	15.7	16.0	16.4	16.9	-1.0%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

2.3.2 Central Coast Region Sub-transmisson Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each sub-transmission substation.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Central Coast Sub-transmission Substation Summer 50 POE Forecasts (132 kV)

Central Coast STS Locations	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	CAGR
Summer Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Gosford 132_33kV	25.3	26.2	24.8	19.8	21.3	23.1	24.2	23.4	23.2	23.3	23.6	24.0	24.4	24.7	0.3%
Gosford 132_66kV	141.4	136.2	130.8	107.3	116.2	124.6	127.6	118.6	115.8	114.4	115.6	117.1	119.0	120.8	-0.8%
Munmorah 132_33kV							26.6	26.8	12.8	12.3	12.4	12.7	13.0	13.3	-9.4%
Ourimbah 132_33kV	70.7	16.7	15.1	13.3	13.1	17.9	16.9	16.5	15.9	15.5	15.4	15.5	15.6	15.6	-1.1%
Ourimbah 132_66kV		46.2	51.6	38.7	41.3	41.9	43.3	41.9	40.9	40.4	40.8	41.5	42.1	42.8	-0.2%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Central Coast Sub-transmission Substation Winter 50 POE Forecasts (132kV)

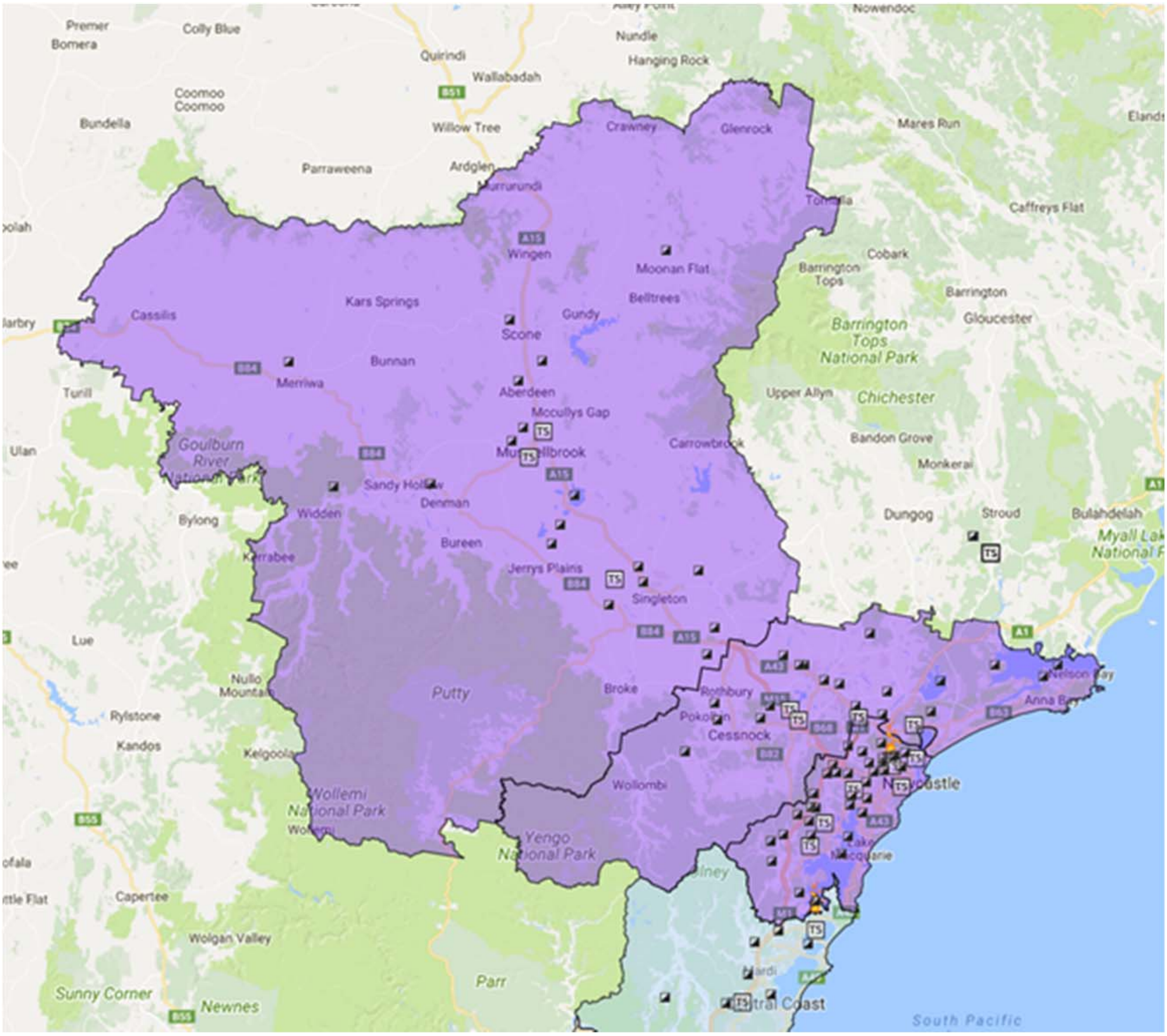
Central Coast STS Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Gosford 132_33kV	27.0	24.1	21.0	20.4	20.5	21.4	21.6	21.6	21.4	20.8	20.5	20.8	21.3	21.8	0.2%
Gosford 132_66kV	140.8	137.3	123.1	116.9	116.0	124.1	123.0	121.0	118.6	114.8	113.3	115.5	118.4	121.4	-0.2%
Munmorah 132_33kV								28.6	28.6	27.9	27.6	28.0	28.6	29.2	0.4%
Ourimbah 132_33kV	68.6	12.8	12.1	11.4	12.0	11.8	12.7	12.7	12.3	11.7	11.5	11.6	11.7	11.9	-1.0%
Ourimbah 132_66kV		49.3	54.6	49.2	49.6	52.1	50.0	52.3	52.5	51.8	51.7	52.5	53.6	54.7	1.3%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

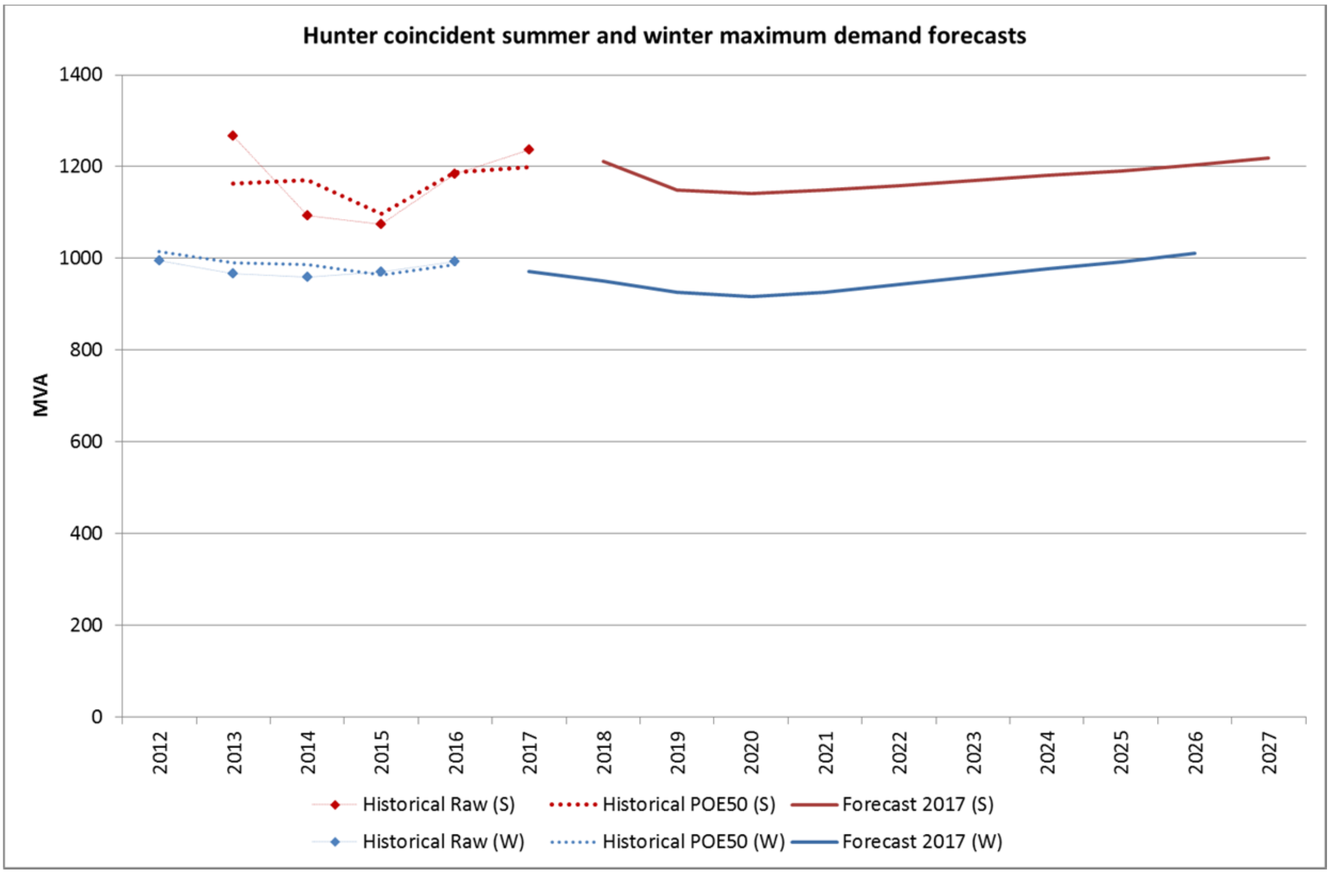
2.4 Hunter Region

The Hunter region of Ausgrid's network serves a total of 297,000 customers from 61 zone substations and 14 sub-transmission substations. The following figure shows the Hunter region and location of the zones and sub transmission stations within the region. The Hunter region includes the Newcastle CBD commercial, significant industrial areas in Newcastle, numerous coal mines throughout the Upper Hunter and is home to about 650,000 people.

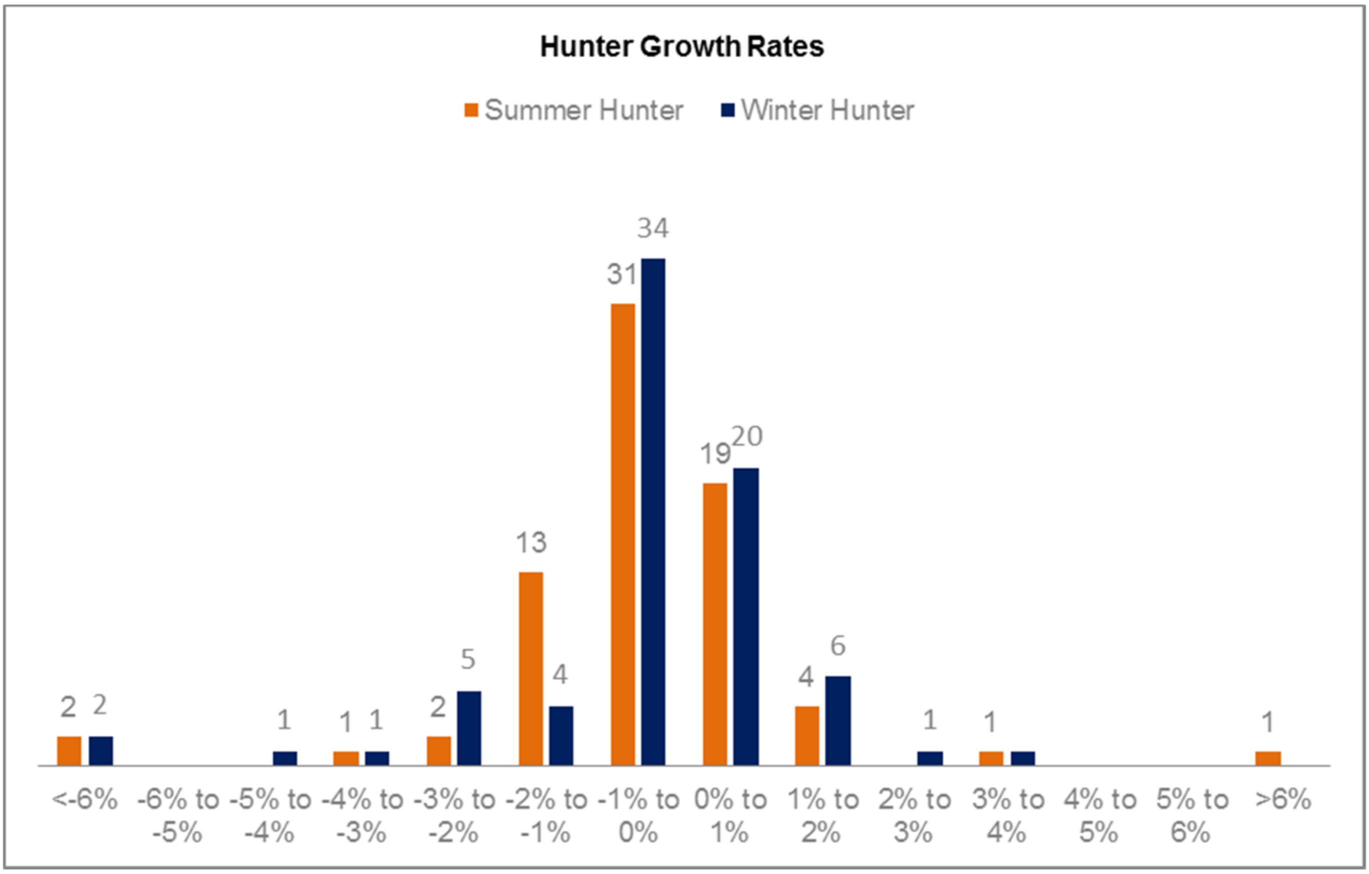
Hunter Region



The 2017 Hunter region coincident system total summer and winter maximum demand forecast are shown in the chart below. The 7 year compounded annual growth rate (CAGR) for the region is -0.2% in summer and -0.4% in winter. The underlying growth rate, excluding large customer connections, is -0.2% in summer and -0.5% in winter. Note that number of new large customer connections is significantly lower in the Hunter when compared to the rest of Ausgrid's network area resulting in the headline grow rate and underlying growth rate being broadly similar.



The histogram chart for the Hunter Zone region shows the count of substation numbers for 50 POE forecast growth rate ranges using the 7 year compounded annual growth rate (CAGR). A majority of zones have forecast average annual growth rates of -1% to +1%.



2.4.1 Hunter Region Zone Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each zone substation. Separate tables have been compiled for zone substations supplied at 132 kV and 33/66 kV.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Hunter Zone Substation Summer 50 POE Forecasts (132kV)

Hunter Zone Locations Summer Forecast	2010/11 MVA	2011/12 MVA	2012/13 MVA	2013/14 MVA	2014/15 MVA	2015/16 MVA	2016/17 MVA	2017/18 MVA	2018/19 MVA	2019/20 MVA	2020/21 MVA	2021/22 MVA	2022/23 MVA	2023/24 MVA	CAGR %
Adamstown 132_11kV	18.4	27.0	27.6	29.1	24.0	24.2	26.6	23.9	23.2	22.8	23.1	23.6	24.0	24.5	-1.2%
Argenton 132_11kV	31.8	36.4	33.2	34.0	31.0	32.5	37.1	30.6	29.3	28.6	28.6	28.9	29.2	29.5	-3.2%
Brandy Hill 132_11kV				2.2	7.7	8.9	9.3	9.2	8.9	8.8	8.8	8.9	8.9	9.0	-0.5%
Broadmeadow 132_11kV				0.0	11.5	26.3	29.6	29.8	29.6	29.6	29.9	30.0	30.3	30.5	0.4%
Charlestown 132_11kV			32.6	35.2	30.9	31.5	37.9	34.3	34.2	34.4	34.8	35.2	35.5	35.9	-0.8%
Jesmond 132_11kV	4.4	32.6	40.7	41.2	40.5	44.4	46.2	44.2	43.4	43.0	43.5	44.1	44.7	45.3	-0.3%
Kurri 132_11kV	31.2	30.0	25.9	27.1	27.1	30.0	30.7	29.5	29.0	28.8	29.0	29.3	29.7	30.0	-0.3%
Maryland 132_11kV	28.0	22.5	22.2	23.3	21.4	23.2	24.7	24.3	22.7	22.7	23.0	23.2	23.4	23.7	-0.6%
Mayfield West 132_11kV	22.2	26.3	24.5	21.7	21.7	24.1	25.9	34.0	32.9	32.2	32.1	32.3	32.5	32.7	3.4%
Morisset 132_11kV	20.2	18.3	17.6	18.5	19.4	22.2	22.2	21.8	21.0	20.6	20.6	20.9	21.1	21.3	-0.6%
Rathmines 132_11kV				14.2	12.8	16.4	16.4	14.5	14.4	14.4	14.6	14.8	15.0	15.1	-1.1%
Rothbury 132_11kV	11.5	10.4	10.0	10.4	10.0	9.8	11.4	11.0	10.5	10.2	10.2	10.2	10.3	10.3	-1.3%
Toronto West 132_11kV								21.8	21.3	21.0	21.1	21.3	21.4	21.6	-0.2%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Hunter Zone Substation Summer 50 POE Forecasts (33/66kV)

Hunter Zone Locations Summer Forecast	2010/ 11 MVA	2011/ 12 MVA	2012/ 13 MVA	2013/ 14 MVA	2014/ 15 MVA	2015/ 16 MVA	2016/ 17 MVA	2017/ 18 MVA	2018/ 19 MVA	2019/ 20 MVA	2020/ 21 MVA	2021/ 22 MVA	2022/ 23 MVA	2023/ 24 MVA	CAGR %
Aberdeen 66_11kV				0.9	5.7	5.9	6.2	6.1	5.9	5.9	5.9	6.0	6.0	6.1	-0.3%
Avondale 33_11kV	14.2	13.4	12.4	10.0	8.7	10.9	12.3	12.8	12.8	12.7	12.8	12.9	13.1	13.2	0.9%
Baerami 33_11kV	0.9	0.7	1.0	1.0	0.9	0.8	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	-0.3%
Branxton 66_11kV	13.2	12.7	13.0	13.6	13.1	13.0	14.3	13.7	13.7	13.8	14.0	14.1	14.3	14.4	0.1%
Cardiff 33_11kV	20.7	19.8	20.0	19.3	19.7	22.3	18.3	20.7	20.1	19.7	19.8	20.0	20.2	20.5	1.6%
Cessnock 33_11kV	24.1	22.8	22.2	21.8	21.4	22.0	22.4	21.6							
Cessnock South 33_11kV									20.7	20.5	20.6	20.8	21.1	21.3	0.6%
Croudace Bay 33_11kV	26.0	24.7	23.6	23.8	21.3	22.8	26.4	24.2	24.0	23.9	24.1	24.3	24.5	24.7	-0.9%
Denman 66_11kV	6.6	5.6	6.8	6.5	6.0	5.7	6.2	5.9	5.6	5.5	5.5	5.6	5.7	5.7	-1.1%
Edgeworth 33_11kV	16.7	20.3	20.5	20.6	22.8	24.0	25.3	26.0	26.3	26.6	26.9	27.1	27.3	27.5	1.2%
Gateshead 33_11kV	15.6	15.1	11.6	15.2	13.7	14.9	17.3	16.2	15.4	14.9	14.9	15.0	15.1	15.2	-1.9%
Jewells 33_11kV	17.1	15.9	14.2	14.6	13.2	14.2	15.4	14.7	14.5	14.5	14.6	14.8	15.0	15.2	-0.2%
Kotara 33_11kV	28.0	24.3	23.3	24.2	23.2	24.0	26.7	24.9	24.5	24.4	24.6	24.8	25.1	25.4	-0.7%
Lemington 66_11kV	3.1	2.4	2.9	3.0	2.9	2.5	2.7	2.6	2.5	2.4	2.4	2.5	2.5	2.5	-0.7%
Maitland 33_11kV				26.9	24.9	26.0	28.4	28.4	27.9	27.6	27.8	28.1	28.5	28.9	0.2%
Medowie 33_11kV					11.4	11.9	12.6	12.5	12.2	12.1	12.3	12.5	12.7	12.9	0.3%
Merriwa 33_11kV	3.7	3.7	3.6	3.8	3.5	3.3	3.6	3.4	3.2	3.1	3.1	3.1	3.2	3.2	-1.6%
Metford 33_11kV						35.0	36.5	36.1	36.3	36.5	37.0	37.2	37.4	37.6	0.4%
Mitchell Line 66_11kV	12.9	13.2	12.7	12.6	11.8	12.5	12.8	12.5	12.2	12.0	12.1	12.2	12.4	12.5	-0.4%
Mitchells Flat 66_11kV	1.4	1.3	1.3	1.3	1.2	1.3	1.6	1.4	1.4	1.4	1.4	1.4	1.4	1.5	-1.5%
Moonan 33_11kV	1.1	0.9	1.0	0.9	0.8	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	1.0	-0.5%
Mt Hutton 33_11kV	19.9	19.5	17.7	18.8	17.1	17.5	20.7	20.0	19.7	19.6	19.8	20.0	20.1	20.3	-0.2%
Mt Thorley 66_11kV	9.8	8.5	9.1	8.3	6.6	6.6	7.2	6.7	6.3	6.1	6.1	6.1	6.2	6.2	-2.2%
Muswellbrook 33_11kV	16.4	13.8	13.6	15.6	13.8	15.9	15.7	14.0	13.7	13.6	13.7	13.8	14.0	14.2	-1.5%
Nelson Bay 33_11kV	39.7	31.9	26.3	21.8	22.3	23.3	25.9	24.5	24.0	23.8	24.1	24.6	25.1	25.5	-0.2%
New Lambton 33_11kV	24.4	21.9	19.7	19.7	19.3	18.3	17.2	17.9	16.8	16.2	16.2	16.5	16.8	17.0	-0.1%
Newcastle CBD 33_11kV	48.6	47.7	44.1	44.0	43.0	43.7	45.0	44.2	42.5	41.5	41.6	42.2	42.8	43.4	-0.5%
Newdell 66_11kV	12.6	10.4	12.8	6.7	3.4	3.9	4.4	4.1	3.8	3.5	3.6	3.7	3.8	3.9	-1.5%
Nulkaba 33_11kV	19.8	19.6	18.9	21.0	20.9	21.0	23.0	21.7	21.7	21.8	22.1	22.3	22.5	22.7	-0.2%
Paxton 33_11kV	5.2	4.7	5.2	5.2	5.3	5.5	6.2	6.3	6.4	6.5	6.6	6.6	6.7	6.8	1.3%
Pelican 33_11kV	11.0	10.7	9.5	11.5	10.5	12.0	12.1	11.8	11.4	11.2	11.3	11.5	11.7	11.8	-0.4%
Raymond Terr NEW 33_11kV		22.5	19.2	26.8	20.9	22.9	23.9	22.6	21.7	21.2	21.3	21.6	21.9	22.3	-1.0%
Rouchel 33_11kV	1.3	1.1	1.0	1.2	1.2	1.3	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	-0.2%
Rutherford 33_11kV	28.7	27.6	28.0	27.7	27.2	28.5	31.5	31.6	30.9	30.6	30.8	31.1	31.4	31.8	0.1%
Scone 66_11kV	17.8	14.9	15.3	18.0	16.1	16.6	17.0	16.8	16.4	16.3	16.4	16.6	16.8	17.0	0.0%
Singleton 66_11kV	21.8	19.1	19.2	22.8	20.6	20.0	22.1	21.6	21.1	20.8	20.9	21.1	21.4	21.6	-0.4%
Singleton North 66_11kV	18.5	17.1	17.4	18.2	16.8	17.5	18.8	18.2	18.0	17.9	18.1	18.3	18.5	18.6	-0.2%
Stockton 33_11kV	7.1	7.0	6.8	6.7	7.3	7.9	9.2	8.6	8.6	8.7	8.8	8.9	9.0	9.1	0.0%
Swansea 33_11kV	12.0	10.8	11.1	9.8	10.3	11.5	12.3	12.1	12.0	12.1	12.3	12.4	12.6	12.8	0.5%
Tanilba Bay 33_11kV	7.3	6.5	6.7	8.8	9.2	10.4	11.0	10.8	10.8	10.8	11.0	11.2	11.3	11.5	0.6%
Tarro 33_11kV	25.6	24.6	23.6	21.8	20.5	22.0	23.4	23.4	22.8	22.5	22.8	23.0	23.4	23.7	0.2%
Telarah 33_11kV	15.2	17.1	18.3	15.7	16.2	12.9	13.4	13.6	13.6	13.7	14.0	14.2	14.4	14.7	1.3%
Thornton 33_11kV	31.1	31.5	31.4	35.0	33.4	31.9	34.1	30.3	29.7	30.2	30.4	30.5	31.0	31.5	-1.1%
Tighes Hill 33_11kV								23.2	21.7	20.9	20.8	21.0	21.3	21.6	-1.2%
Tomago 33_11kV			3.5	13.4	14.1	11.9	12.0	11.6	11.0	10.6	10.6	10.6	10.7	10.8	-1.5%
Tomalpin 33_11kV	1.8	1.4	1.8	1.6	1.7	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	-2.4%
Tomaree 33_11kV			14.0	14.1	13.7	15.5	17.7	16.3	16.0	15.9	16.2	16.5	16.8	17.1	-0.5%
Williamtown 33_11kV	16.5	15.3	14.4	14.4	3.7	4.6	5.0	4.9	4.9	5.0	5.0	5.0	5.0	5.0	0.1%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Hunter Zone Substation Winter 50 POE Forecasts (132kV)

Hunter Zone Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Adamstown 132_11kV	10.2	26.2	25.3	25.3	23.2	24.1	22.0	22.3	22.1	21.5	21.2	21.7	22.3	23.0	0.6%
Argenton 132_11kV	28.7	29.7	28.5	26.9	26.4	24.9	28.6	22.3	21.5	20.4	19.8	20.1	20.7	21.3	-4.1%
Brandy Hill 132_11kV				1.8	4.8	5.7	6.1	6.1	6.0	5.9	5.8	5.9	6.0	6.2	0.3%
Broadmeadow 132_11kV					9.1	10.1	20.8	21.0	20.7	20.2	19.9	20.2	20.6	21.0	0.1%
Charlestown 132_11kV				26.3	26.2	26.6	27.7	27.2	26.8	26.0	25.7	26.1	26.6	27.1	-0.3%
Jesmond 132_11kV		30.4	35.9	32.0	33.6	34.7	35.3	34.5	33.0	31.7	31.2	31.8	32.6	33.6	-0.7%
Kurri 132_11kV		21.0	21.0	19.0	19.1	19.5	16.4	17.9	17.5	16.8	16.6	16.9	17.4	17.9	1.3%
Maryland 132_11kV	19.0	16.4	13.9	13.2	12.1	13.3	14.4	13.8	13.7	13.3	13.2	13.5	13.8	14.3	-0.1%
Mayfield West 132_11kV	17.1	21.3	21.2	20.5	15.8	22.4	22.3	21.2	28.6	27.5	27.0	27.2	27.6	28.0	3.3%
Morisset 132_11kV	18.4	18.2	17.3	18.1	18.0	18.8	18.6	18.2	17.6	16.8	16.5	16.8	17.2	17.6	-0.8%
Rathmines 132_11kV				13.5	13.3	13.0	13.4	11.5	11.0	10.4	10.2	10.4	10.7	11.0	-2.7%
Rothbury 132_11kV	6.0	6.0	6.0	5.6	5.9	5.9	6.6	6.5	6.3	6.0	5.9	6.0	6.1	6.2	-0.9%
Toronto West 132_11kV								20.4	17.1	16.7	16.5	16.7	16.9	17.2	-2.8%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Hunter Zone Substation Winter 50 POE Forecasts (33/66kV)

Hunter Zone Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Aberdeen 66_11kV					4.3	3.9	3.8	3.8	3.7	3.5	3.5	3.5	3.6	3.7	-0.3%
Avondale 33_11kV	12.6	12.6	12.0	9.5	9.3	9.7	9.5	9.6	10.1	9.8	9.7	9.8	10.0	10.2	1.0%
Baerami 33_11kV	0.6	0.7	0.7	0.7	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	-0.3%
Branxton 66_11kV	8.8	8.5	8.9	8.6	9.2	9.1	9.0	9.1	9.1	8.9	8.9	9.1	9.3	9.5	0.9%
Cardiff 33_11kV	17.8	17.9	17.3	15.1	14.5	16.9	14.0	16.4	16.0	15.5	15.2	15.4	15.7	16.1	2.1%
Cessnock 33_11kV	17.0	16.8	16.5	15.2	14.9	15.3	15.3	15.1							
Cessnock South 33_11kV									15.0	14.5	14.3	14.6	15.0	15.4	0.5%
Croudace Bay 33_11kV	19.7	19.3	18.5	17.4	16.1	16.9	16.3	15.5	15.1	14.6	14.3	14.6	14.9	15.3	-0.9%
Denman 66_11kV	4.7	4.2	4.3	4.3	4.4	3.8	3.5	3.6	3.4	3.2	3.1	3.2	3.2	3.3	-0.8%
Edgeworth 33_11kV	11.9	12.0	13.9	12.9	14.1	15.3	15.9	16.5	16.7	16.6	16.6	16.8	17.1	17.5	1.3%
Gateshead 33_11kV	13.2	13.0	12.0	13.6	13.4	13.6	13.7	13.7	13.4	12.9	12.7	12.9	13.2	13.5	-0.2%
Jewells 33_11kV	15.0	14.5	13.9	13.1	12.9	13.2	12.9	12.7	12.3	11.8	11.5	11.8	12.0	12.3	-0.7%
Kotara 33_11kV	19.4	16.1	17.3	16.4	16.0	17.5	18.1	17.3	17.0	16.5	16.3	16.5	16.8	17.2	-0.7%
Lemington 66_11kV	1.8	1.9	1.9	1.7	2.6	2.2	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	-0.7%
Maitland 33_11kV				0.0	14.4	15.6	16.8	16.9	16.6	16.2	16.1	16.5	17.1	17.7	0.7%
Medowie 33_11kV						8.8	9.3	9.4	9.2	8.8	8.7	8.9	9.2	9.5	0.3%
Merriwa 33_11kV	3.0	3.3	3.0	2.8	2.9	2.8	2.8	2.7	2.6	2.5	2.4	2.5	2.5	2.6	-0.9%
Metford 33_11kV							22.3	23.5	23.3	22.7	22.4	22.6	22.9	23.2	0.6%
Mitchell Line 66_11kV	9.9	9.4	9.2	8.8	9.4	8.4	8.7	8.7	8.4	8.1	7.9	8.0	8.2	8.4	-0.5%
Mitchells Flat 66_11kV	1.0	0.9	0.9	0.8	0.8	0.8	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	-0.8%
Moonan 33_11kV	1.1	1.0	1.1	1.0	1.0	1.1	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	-0.8%
Mt Hutton 33_11kV	16.0	15.6	15.3	14.0	13.9	14.1	13.8	13.8	13.6	13.1	12.9	13.1	13.5	13.8	0.0%
Mt Thorley 66_11kV	7.1	7.3	7.3	6.8	5.8	5.6	5.5	5.5	5.3	5.1	4.9	5.0	5.1	5.2	-0.8%
Muswellbrook 33_11kV	14.2	12.2	12.1	11.1	11.4	11.9	11.9	10.6	11.5	11.0	10.8	11.0	11.2	11.5	-0.4%
Nelson Bay 33_11kV	39.0	36.9	37.3	20.9	21.8	22.4	22.9	20.9	20.1	19.1	18.7	19.2	19.8	20.5	-1.6%
New Lambton 33_11kV	20.1	17.1	15.7	13.6	13.5	13.6	11.6	11.6	11.6	10.7	10.3	10.4	10.7	11.0	-0.7%
Newcastle CBD 33_11kV	33.2	33.8	32.4	32.5	33.4	33.5	33.1	32.0	31.1	29.7	29.1	29.5	30.2	31.0	-0.9%
Newdell 66_11kV	9.9	8.9	10.3	10.7	3.8	3.3	3.5	3.4	3.2	2.9	2.8	2.8	2.9	3.0	-2.4%
Nulkaba 33_11kV	13.0	12.7	12.8	13.0	13.6	13.8	14.0	13.9	13.7	13.2	13.0	13.2	13.6	13.9	-0.1%
Paxton 33_11kV	4.1	4.1	4.1	3.9	4.0	4.2	4.5	4.5	4.5	4.5	4.5	4.6	4.7	4.9	1.0%
Pelican 33_11kV	10.8	10.6	10.3	10.0	10.4	10.4	10.4	10.1	9.6	9.1	8.8	9.0	9.2	9.5	-1.4%
Raymond Terr NEW 33_11kV		13.1	17.0	18.5	20.0	18.0	18.2	18.2	17.8	17.1	16.8	17.1	17.6	18.1	-0.1%
Rouchel 33_11kV	1.1	1.0	0.9	1.1	0.9	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	-0.3%
Rutherford 33_11kV	18.5	20.5	21.1	20.6	20.9	21.7	21.6	22.4	22.0	21.2	20.9	21.3	21.9	22.5	0.6%
Scone 66_11kV	14.5	12.9	12.7	12.6	13.1	13.0	12.7	12.6	12.4	12.0	11.7	11.9	12.1	12.4	-0.3%
Singleton 66_11kV	13.7	13.2	13.3	12.5	14.5	14.3	14.3	15.1	15.2	14.8	14.7	14.8	15.1	15.4	1.1%
Singleton North 66_11kV	13.8	12.8	12.8	12.3	12.6	12.5	12.4	12.1	11.6	11.1	10.8	11.0	11.3	11.6	-0.9%
Stockton 33_11kV	6.1	5.9	5.7	5.7	6.1	6.5	6.9	7.0	7.0	6.9	6.9	7.0	7.2	7.4	1.0%
Swansea 33_11kV	12.6	12.3	11.9	11.2	11.1	11.6	11.5	11.4	11.1	10.7	10.6	10.8	11.1	11.3	-0.2%
Tanilba Bay 33_11kV	7.6	7.3	7.1	7.3	9.1	9.6	9.6	9.5	9.3	9.0	8.9	9.1	9.4	9.6	0.0%
Tarro 33_11kV	20.5	18.8	19.2	19.0	16.2	17.9	18.3	17.4	17.1	16.2	15.8	16.0	16.3	16.8	-1.2%
Telarah 33_11kV	13.0	10.2	10.5	10.9	9.6	10.3	8.4	8.4	8.4	8.1	8.1	8.4	8.7	9.1	1.3%
Thornton 33_11kV	20.1	21.3	21.8	19.8	21.4	22.3	20.5	18.8	18.4	18.6	18.5	19.1	19.8	20.6	0.1%
Tighes Hill 33_11kV									19.6	18.8	18.5	18.7	19.1	19.6	-0.1%
Tomago 33_11kV			4.2	13.5	12.7	12.0	11.5	12.9	12.6	12.2	12.0	12.0	12.1	12.3	0.9%
Tomalpin 33_11kV	1.5	1.7	1.6	1.4	1.3	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	-3.7%
Tomaree 33_11kV				14.4	14.9	14.8	15.0	14.9	14.5	13.9	13.8	14.1	14.5	15.0	0.0%
Williamtown 33_11kV	12.8	12.6	12.2	11.2	11.3	3.2	3.4	3.3	3.2	3.2	3.1	3.1	3.1	3.2	-1.1%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

2.4.2 Hunter Region Sub-transmisson Substation 50 POE Forecasts

The tables following detail the actual and 50 POE forecast summer and winter maximum electricity demand for the period from 2010/11 to 2023/24. The calculated 7 year forecast compounded annual growth rate (CAGR) is displayed for each sub-transmission substation.

Note that the forecast demand data (2017/18 to 2023/24) presented in the tables includes only committed load transfers and projects that have received final Ausgrid Board approval.

Hunter Sub-transmission Substation Summer 50 POE Forecasts (132kV)

Hunter STS Locations	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	CAGR
Summer Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Argenton 132_33kV	81.8	93.7	88.6	85.2	86.1	95.1	92.0	95.2	94.5	94.4	95.2	95.9	96.7	97.5	0.8%
Awaba 132_33kV	38.5	24.9	23.4	22.4	20.3	23.2	20.7	8.1	8.1	8.1	8.1	8.1	8.1	8.1	-12.6%
Beresfield 132_33kV	103.6	100.2	95.6	105.5	89.9	91.9	97.9	89.9	88.8	89.3	90.0	91.0	92.0	93.0	-0.7%
Eraring 132_33kV	33.2	31.3	29.7	28.3	30.5	30.0	31.1	31.5	31.5	31.4	31.5	31.6	31.7	31.8	0.3%
Kooragang 132_33kV	34.1	56.2	61.6	63.4	69.5	65.1	66.1	67.9	67.9	67.9	67.9	67.9	67.9	67.9	0.4%
Kurri 132_33kV	124.4	134.6	118.3	129.0	123.7	132.0	131.5	132.8	129.8	129.2	130.2	131.6	133.1	134.6	0.3%
Merewether 132_33kV	229.2	221.6	172.2	167.3	156.0	151.4	157.9	147.7	141.8	138.6	139.1	140.9	143.0	144.9	-1.2%
Mitchell Line 132_66kV	65.2	74.8	71.2	81.3	77.6	79.1	77.7	87.2	36.9	36.2	36.4	36.9	37.4	37.9	-9.8%
Muswellbrook 132_33kV	25.2	23.8	21.3	25.6	17.0	18.1	19.8	18.8	18.4	18.3	18.4	18.6	18.8	19.0	-0.6%
Singleton 132_66kV	136.5	148.9	147.7	150.0	149.8	159.6	154.6	155.3	154.2	153.7	154.1	154.6	155.2	155.8	0.1%
Tomago 132_33kV	118.1	106.7	109.7	106.5	102.0	113.1	120.0	122.0	119.9	119.1	120.1	121.6	123.1	124.7	0.5%
Waratah (Domestic) 132_33k	96.4	31.6	23.3	6.2	5.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	-0.1%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

Hunter Sub-transmission Substation Winter 50 POE Forecasts (132kV)

Hunter STS Locations	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR
Winter Forecast	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	MVA	%
Argenton 132_33kV	31.3	93.7	88.6	85.2	86.1	95.1	92.0	95.2	94.5	94.4	95.2	95.9	96.7	97.5	0.8%
Awaba 132_33kV	38.5	24.9	23.4	22.4	20.3	23.2	20.7	8.1	8.1	8.1	8.1	8.1	8.1	8.1	-12.6%
Beresfield 132_33kV	103.6	100.2	95.6	105.5	89.9	91.9	97.9	89.9	88.8	89.3	90.0	91.0	92.0	93.0	-0.7%
Eraring 132_33kV	33.2	31.3	29.7	28.3	30.5	30.0	31.1	31.5	31.5	31.4	31.5	31.6	31.7	31.8	0.3%
Kooragang 132_33kV	34.1	56.2	61.6	63.4	69.5	65.1	66.1	67.9	67.9	67.9	67.9	67.9	67.9	67.9	0.4%
Kurri 132_33kV	124.4	134.6	118.3	129.0	123.7	132.0	131.5	132.8	129.8	129.2	130.2	131.6	133.1	134.6	0.3%
Merewether 132_33kV	229.2	221.6	172.2	167.3	156.0	151.4	157.9	147.7	141.8	138.6	139.1	140.9	143.0	144.9	-1.2%
Mitchell Line 132_66kV	65.2	74.8	71.2	81.3	77.6	79.1	77.7	87.2	36.9	36.2	36.4	36.9	37.4	37.9	-9.8%
Muswellbrook 132_33kV	25.2	23.8	21.3	25.6	17.0	18.1	19.8	18.8	18.4	18.3	18.4	18.6	18.8	19.0	-0.6%
Singleton 132_66kV	136.5	148.9	147.7	150.0	149.8	159.6	154.6	155.3	154.2	153.7	154.1	154.6	155.2	155.8	0.1%
Tomago 132_33kV	118.1	106.7	109.7	106.5	102.0	113.1	120.0	122.0	119.9	119.1	120.1	121.6	123.1	124.7	0.5%
Waratah (Domestic) 132_33kV	96.4	31.6	23.3	6.2	5.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	-0.1%

Note: Empty cells are due to closure of an existing zone substation or commissioning of new zone substation.

3 Demand Drivers

This section provides a summary of the principal drivers of maximum electricity demand; both negative and positive. Common drivers which can result in increasing or decreasing demand include income or economic effects, electricity prices, population and a range of emerging technologies. Detailed below are the primary drivers considered as part of Ausgrid's demand forecasts.

3.1 Weather

The weather is a key driver of maximum demand in both summer and winter. This is due principally to the significant energy required to heat or cool buildings during the summer and winter periods. Weather sensitive customer loads such as air conditioners, heaters and refrigeration can significantly increase both maximum demand and energy consumption with maximum demand strongly correlated to temperature.

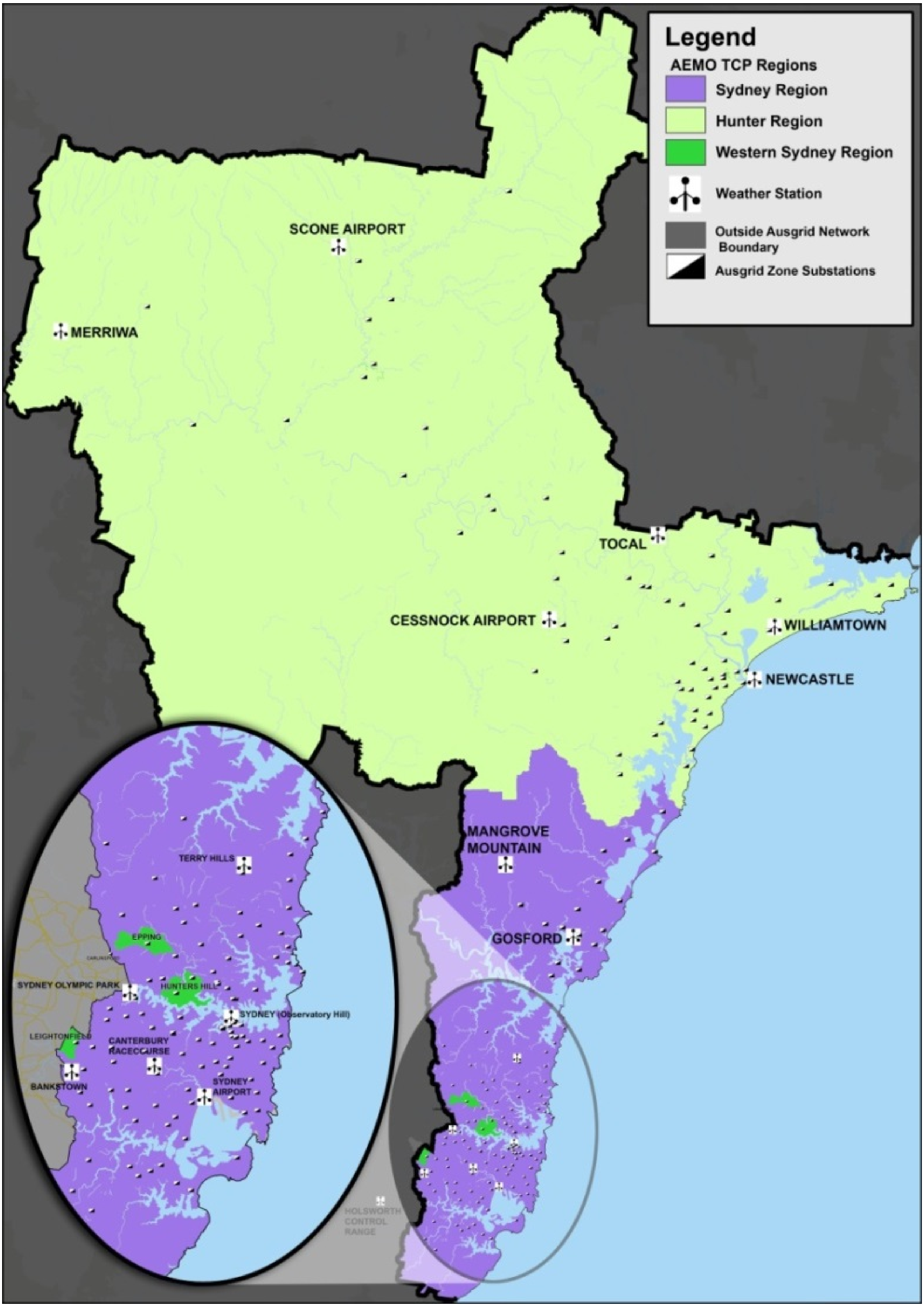
During extreme weather events, demand for electricity is at its highest, but the probability of such weather events can be low. It is for this reason that forecasts are produced for a range of Probability of Exceedance (POE) levels. Ausgrid produces forecasts for 50% POE, 90% POE and 10% POE levels with the 50 POE forecast used as the central forecast as part of the assessment of options for an identified need. The 10 POE forecasts and 90 POE forecasts are used as part of an assessment of 'reasonable' scenarios which are designed to test alternate sets of key assumptions and whether they affect selection of the preferred option.

Ausgrid's forecast methodology weather corrects historical loads to enable statistical trend line calculation of growth rates and the determination of probabilistic forecast loads. See Section 4 for details on the weather correction process.

In light of the importance and influence of the weather correction process, we have detailed aspects of the weather correction design process in the sub-sections below to provide further clarity to this demand driver.

3.1.1 Weather Station Allocation

Each individual substation is allocated to a nearby weather station. This allocation to each substation is based on geographical proximity to the weather station, perceived local weather conditions of the substation location and availability of the temperature data. This is particularly important for correctly estimating the temperature sensitivities of customer demand of the substation being modelled. For example coastal suburbs tend to experience cooling sea breezes that locations further away from the coast will not experience. Allocating an inappropriate weather station to these substations can falsely represent the true temperature sensitivity of the customer load in these coastal regions. In the chart following are shown the 15 separate weather stations used for Ausgrid's maximum demand forecasts.



3.1.2 Weather Series Period

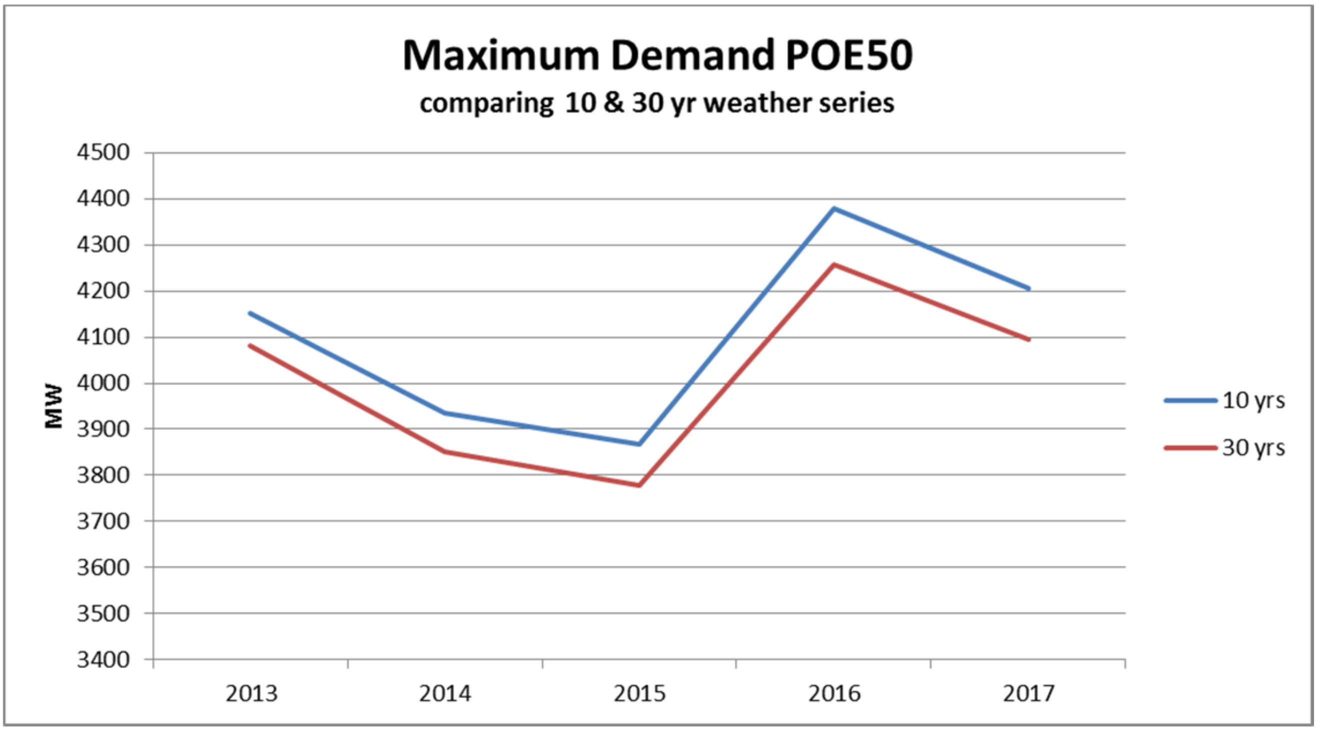
The time period used for the weather correction process is influential as the data chosen is an input into the weather simulation. And there is a range of competing advice on the recommended time period to use. In their advice to AEMO in 2013, ACIL Allen recommended the use of a *"a very long time series, thirty years or more*"[2]. However, we also note that SKM-MMA, in its review of Aurora Energy's maximum demand forecasting methodology[3], recommended that Aurora use a 20 year weather series following their assessment of Tasmania weather data.

Ausgrid uses the most recent 10 year period for weather normalisation so as to ensure that rising temperatures due to climate change do not unduly influence the weather correction process. This shorter weather period length was not noted as a concern or subject to a recommended review or modification as part of a 2013 review of Ausgrid's forecast methodology by SKM-MMA[4].

The most recent review of Ausgrid's forecast methodology by GHD Advisory notes that '*Randomly drawn temperatures only reflect true percentiles if there is no underlying trend. If there is a significant warming trend in the last 10 years, the POE levels calculated by Ausgrid may not reflect the true POE levels*'[5] and '*the bias resulting from ignoring climate warming would be likely to increase proportionally with the length of the temperature series used to determine POE levels of maximum electricity demand. For example, using a sample of temperatures collected over 20 years might double the error from this source, compared with the use of a sample of temperatures collected from the most recent 10 years.*'[6]

Recent analysis of the impact from using different time period lengths showed that longer periods results in consistently lower weather corrected demand. The result of rising temperatures means that use of a 30 year time series would understate weather normalised maximum demand as the weather correction processes would be sampling milder temperatures in the earlier years of the weather set.

As a demonstration of the impact of rising temperatures, the 50 POE weather corrected maximum demand for the 10 year or 30 year weather series using a Sydney Bureau of Meteorology weather station is shown in the chart below. An average difference of 95 MW over 5 years can be seen which amounts to around 2.3% of the Sydney region weather corrected maximum demand. The difference is biased in one direction.



Based upon the latest climate change research, this would not be representative of weather patterns going forward for a summer forecast. From the three emissions scenarios published by CSIRO[7], there is a clear warming trend in historical temperatures from around the mid-1970s onwards, with all three scenarios projecting a continuation of warming effects out to at least 2040. See charts following.

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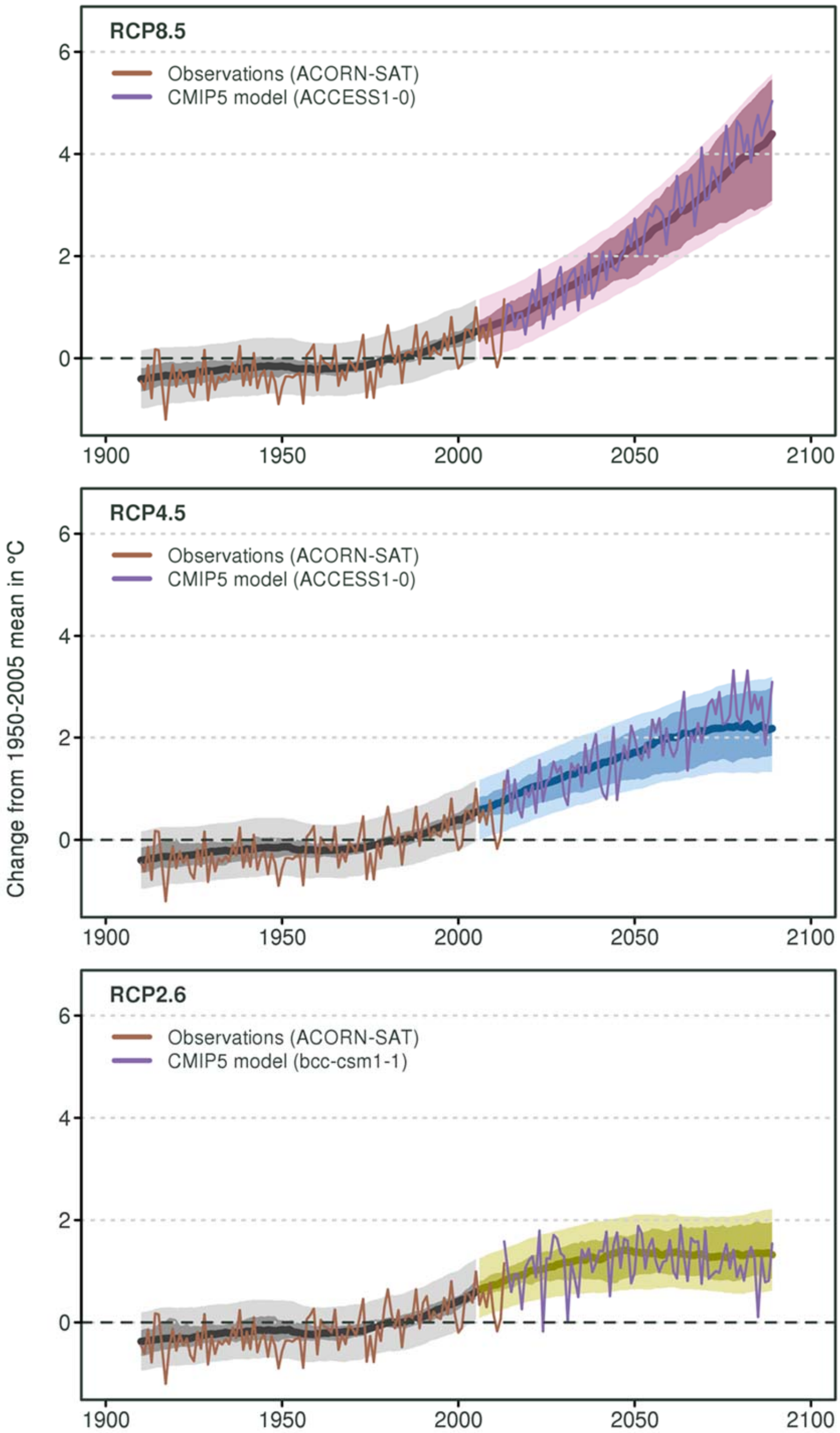
[2] ACIL Allen, Connection Point Forecasting–A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand, Jun 2013, p11
[3] SKM-MMA, Review of Aurora Energy 's maximum demand forecasting methodologies in its 2012 to 2017 regulatory proposal, 2011
[4] SKM-MMA, Review of Ausgrid's spatial demand forecast methodology and its implementation, 2013
[5] GHD, Review of 2017 demand and customer connection forecasts, Dec 2017, p23
[6] *Ibid, p23*
[7] *CSIRO, Climate Change in Australia, Projections for Australia's NRM Regions, 2015, pg92*



As recommended by GHD, the introduction of a climate warming modelling adjustment might be used to correct for rising temperatures, but there has been no detailed analysis completed to derive the adjustment process. In the absence of such a process, Ausgrid has retained use of a 10 year time period to ensure older, less representative, temperature data is not included in the weather normalisation process.

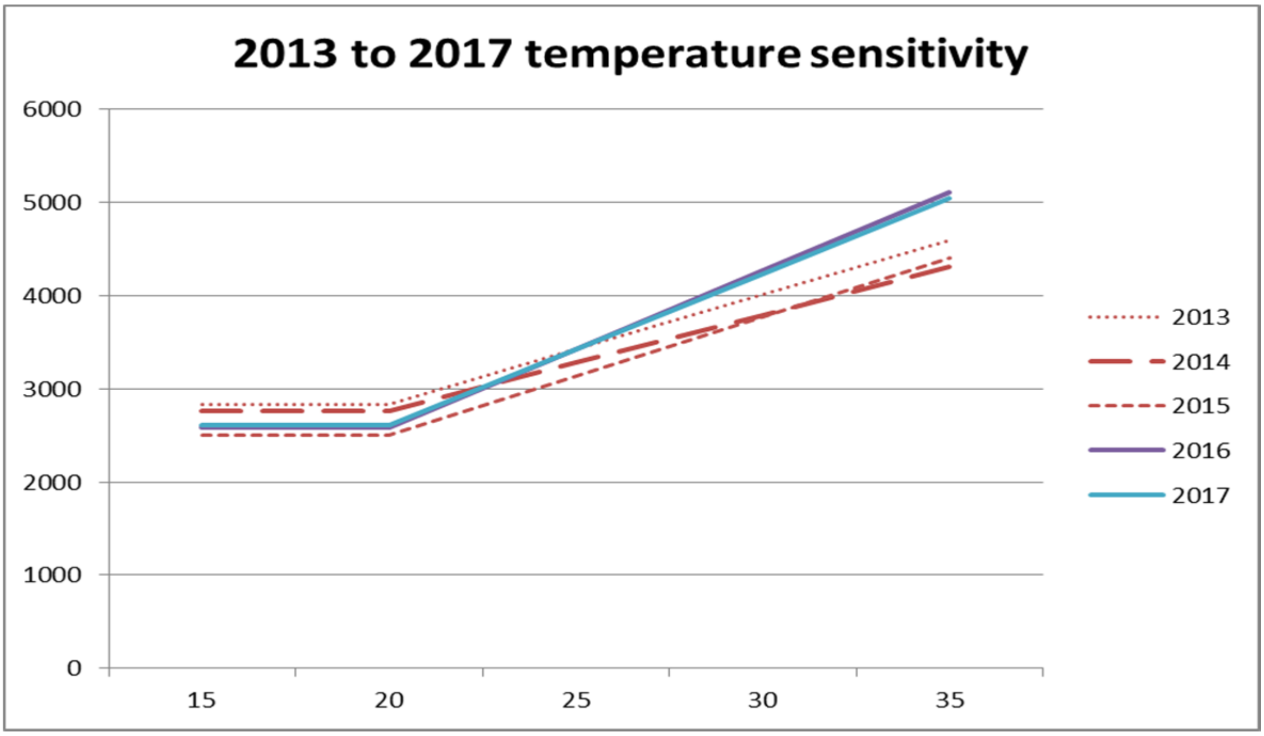
3.1.3 Data Pooling

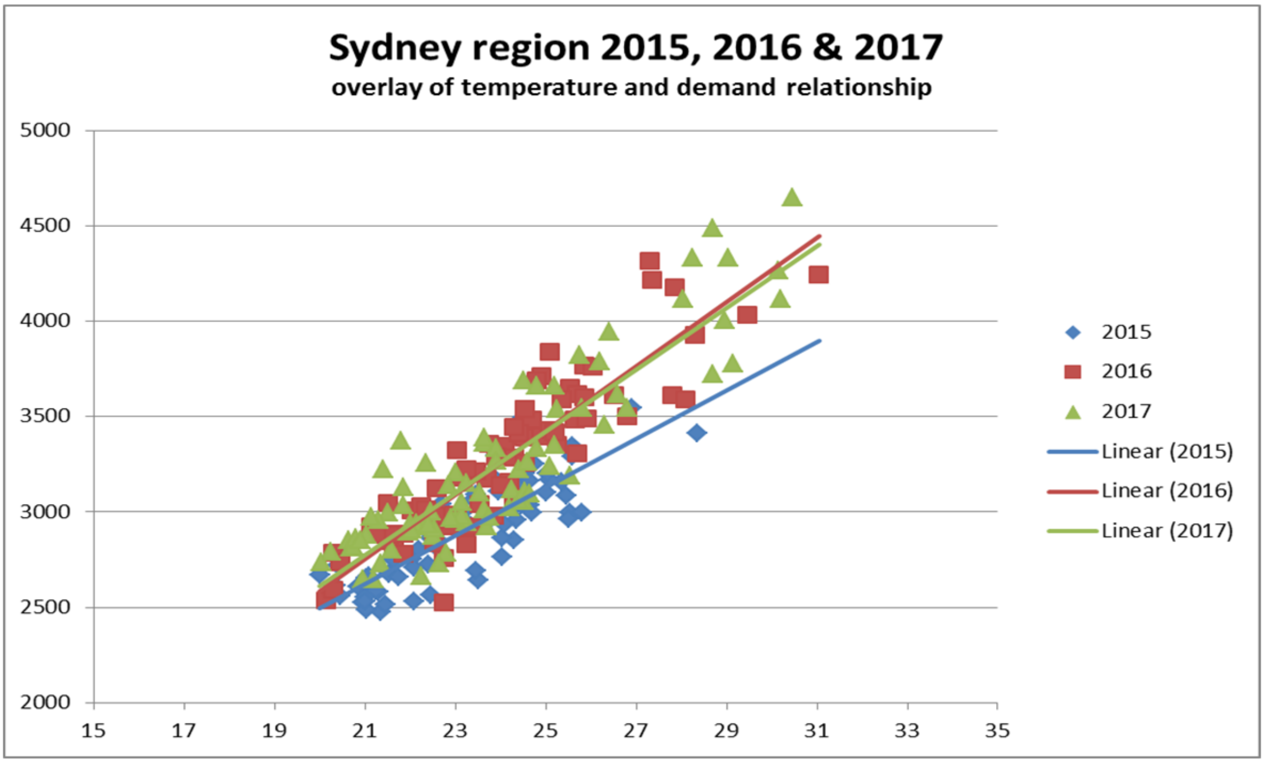
Pooling is a technique that can be used to adjust for mild summers by using data from adjacent seasons to bolster the size of the dataset. We note that ACIL Allen in their report to AEMO recommended that "*data used for normalisation (weather) should relate to only one season (that is, only one season's summer or winter). The exception to this is if the season in question was very mild. In this case there may not be enough data to describe the relationship between temperature and demand at extreme conditions accurately.*"[8] This advice attempts to

[8] *ACIL Allen, Connection Point Forecasting–A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand, Jun 2013, p27*

balance both the risk of insufficient data in a single year and the risk that a change in customer response over the time period may be masked by the merging of the data.

For Ausgrid' most recent 2017 and 2016 forecasts, we have elected not to pool data from separate years in the weather correction process. We believe that pooling is unnecessary as there are a sufficient number of high temperature and high demand days to provide a high degree of confidence in the temperature and demand relationship for these years. Note that our internal analysis of results from pooled and unpooled weather correction outcomes indicates that this approach has avoided a masking of a change in temperature sensitivity that occurred between 2015 and 2016. See charts following which detail the change in temperature sensitivity over the period from 2013 to 2017.





3.2 Changes in large customer demand (block loads)

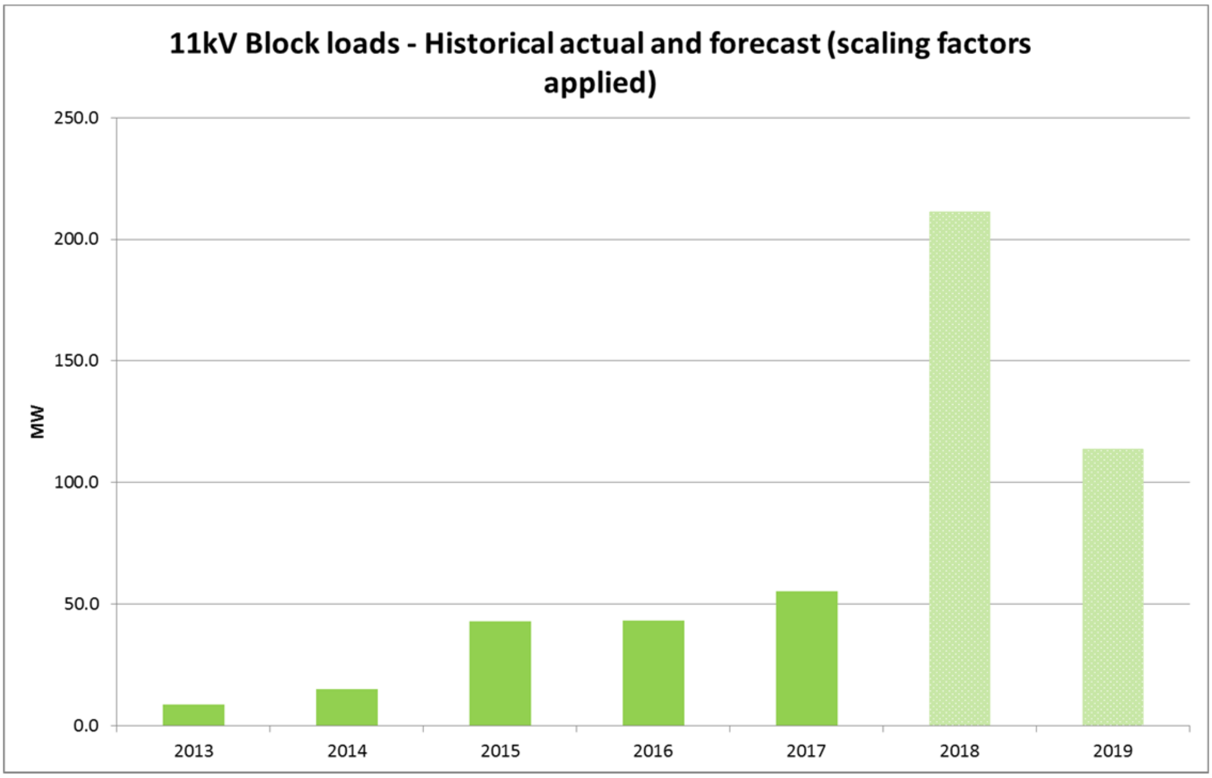
An identified step change in demand due to a new large customer connection or disconnection is commonly referred to as a block load. Such changes in demand can be of sufficient size to influence whether there is a need for network investment. Importantly, these large changes in demand can obscure the underlying change in demand of a network asset such as a zone substation. Adjustments to the historical data for block loads allows the organic, underlying demand trend to be discovered so that any projection of the trend does not include such effects.

ACIL Allen's report to AEMO recommended that '*adjustments should be made to remove the impact of block loads from the historical data*'[9] and that '*in principle, block load and organic growth should be dealt with separately*'.[10]

Ausgrid agrees with this approach and consequently has developed and introduced a comprehensive assessment of customer connections to assess change in demand due to block loads independently from change in demand due to underlying changes in organic customer demand. This assessment process tracks all connections applications greater than 50 amps at 11kV and all applications at 33kV and above. The 50 amp threshold was selected as it reflects a possible new load of 1 MW or about 5% of the load on a zone substation with a load of 20 MW. At the 11kV level, the total of the block loads at each zone substation is aggregated in each year and tested against the 50 amps threshold before inclusion in the forecast. For the 2017 forecast, a total of about 1900 connection applications over 11 years (7 historical and 4 forecast) were assessed to effectively identify historical and future block load activity and uncover the underlying trend for each zone substation.

This assessment tracks not only the customer demand requested, but also the actual resultant demand for historical customer connections. This allows for the calculation of scaling factors that can be applied to proposed connection requests to ensure that forecast demand is not overestimated. By removing commissioned block loads from the historical trend, the underlying trend net of block loads is discovered avoiding the need to apply estimates or thresholds to the assessment of future block loads. This approach helps avoid both the risk of double counting and under or over estimating future demand.

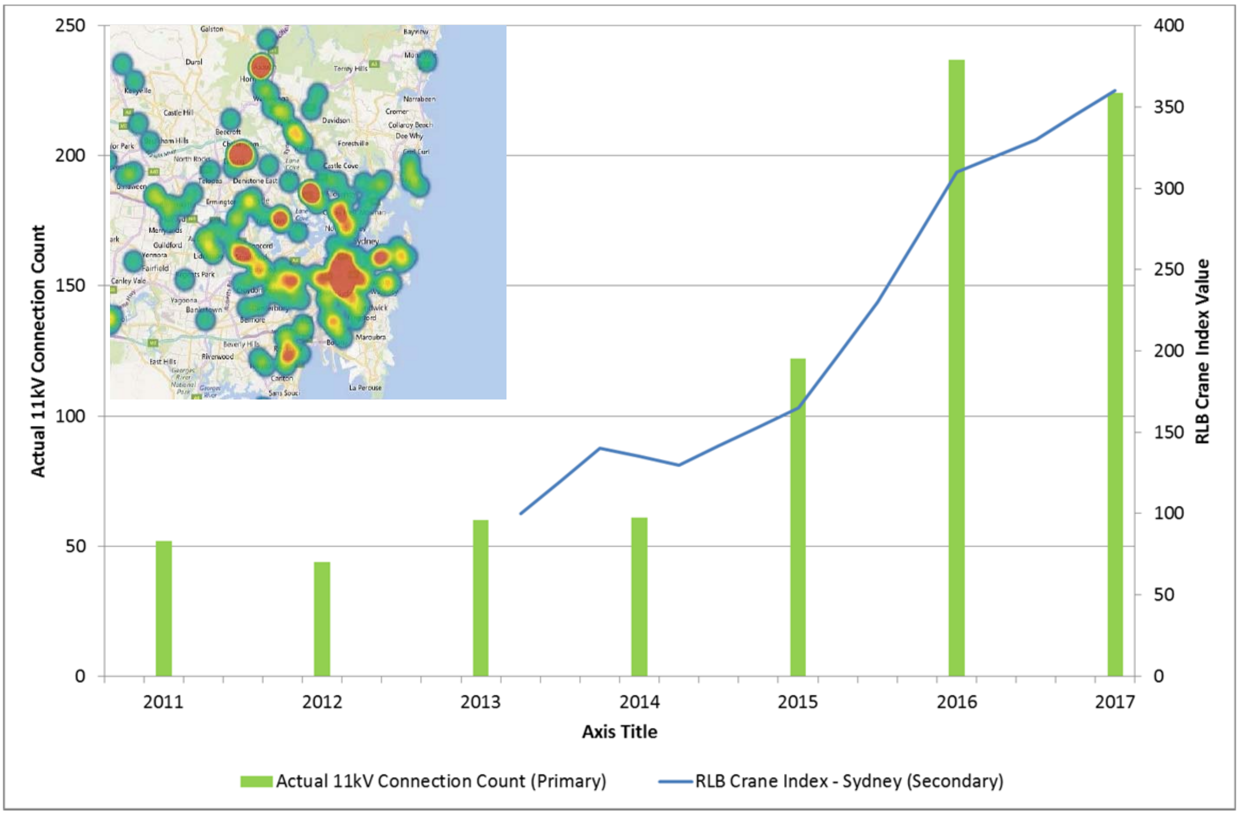
The recent surge in customer connection activity reinforces the need for this approach. New 11kV customer connections to be commissioned in 2018 are forecast to be four times that of recent years with a large drop forecast in 2019 and an expectation of a further decline in 2020. This large increase in connected bock loads follows several years of heightened connection application activity. See chart following which details historical actual demand from commissioned 11kV customer connections and scaled forecast demand.



The forecasted increase is supported by external data such as the RLB crane index which tracks construction crane activity in Australia. The figure below shows the RLB crane index since 2013 rising in line with the actual number of 11kV customer connection applications over the same time period. Commissioned new load typically

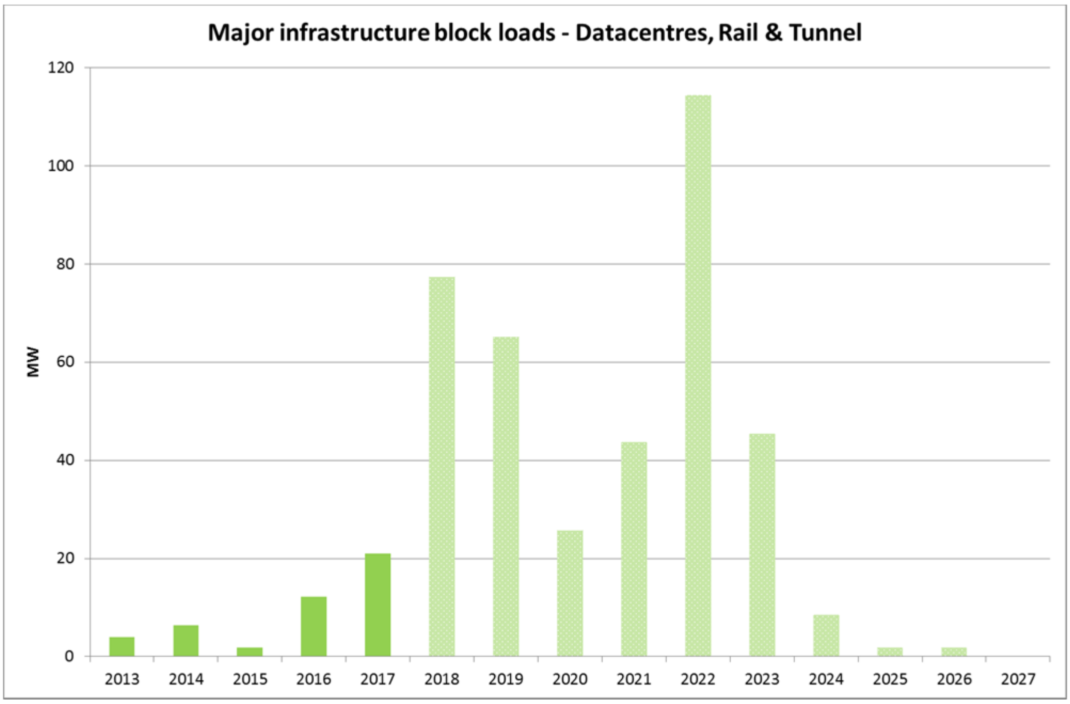
[9] *ACIL Allen, Connection Point Forecasting–A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand, Jun 2013, p XI*
[10] *Ibid, pg. 6*

lags a connection application by one to two years. The map insert also shows a heat map of where the cranes are erected within the Sydney Metropolitan region. The map clearly shows the CBD, southern and eastern suburbs, and the northern rail corridor heavily populated by crane activity.



Note that under this process, when the volume of 11kV block loads declines as forecast, the underlying trend is not affected by the out of trend block load activity and the lower future rate of new connections will result in a lower forecast maximum. In contrast, inclusion of 11kV block loads in the determination of the trend would have resulted in an under forecast in the near term and an over forecast of demand in future.

New major customer connections (typically 33kV and above) are also experiencing similar significant growth during this period of heightened construction and investment activity in the Sydney region. Many of these new loads are related to State Government investment in new road tunnels (Westconnex), rail (Metro and Light Rail) and a surge in demand for data centre capacity. See chart following which details the historical actual and scaled forecast commissioned major customer load. More detail on Ausgrid’s treatment of block loads is found in Section 5.7.



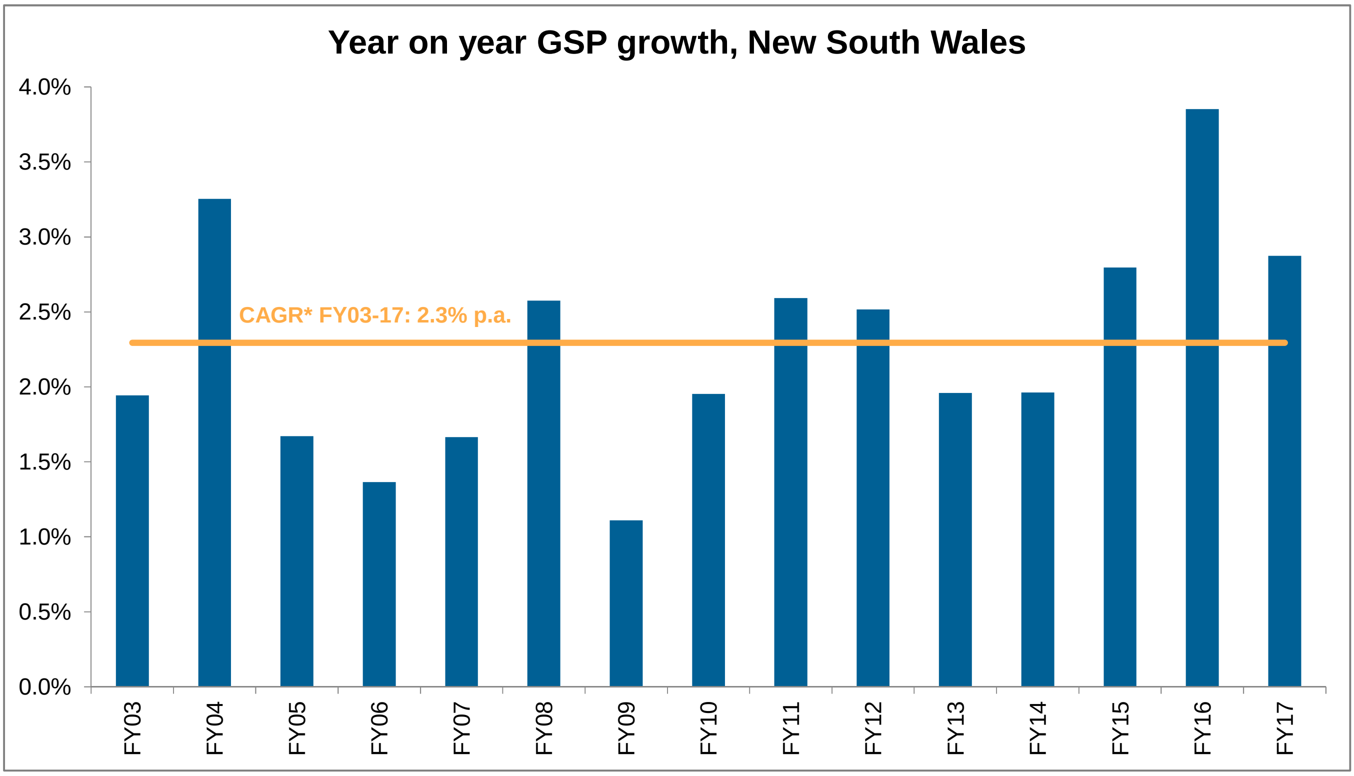
3.3 Economic Drivers

Increasing demand for electricity has historically been correlated to growth in economic activity. For example, higher levels of economic activity and incomes can drive greater business activity and higher levels of household appliance ownership. Conversely, negative growth in economic activity can result in business closure. Ausgrid assesses customer demand for electricity against both the NSW Gross State Product (GSP) and NSW Real Household Disposable Income (RHDI).

Ausgrid's current practice is to source the historical and forecast data for NSW Gross State Product (GSP) and Real Household Disposable Income (RHDI) from the Australian Energy Market Operator (AEMO) who in turn source this information from expert external economic advisors. For the Ausgrid's 2017 forecasts, the data is as used by AEMO for their 2017 forecasts.

3.3.1 NSW Gross State Product

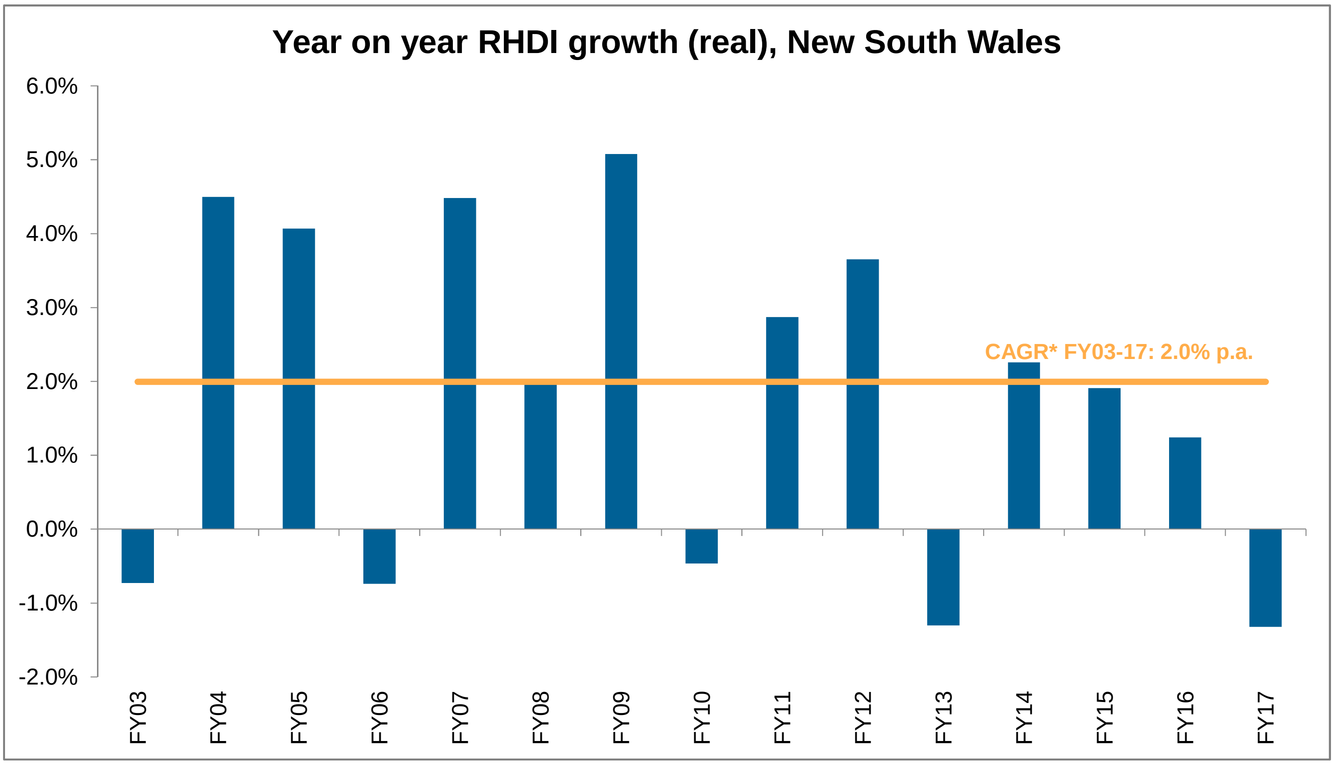
NSW Gross State Product has recently recorded an increasing trend with growth of 2.9% per annum in the year to June 2017. In the coming years, the economy is expected to continue its trend and grow at a rate of about 2.2% to 2.5% per annum between FY18 and FY24.



**CAGR: Compound annual growth rate, Source: ABS*

3.3.2 Household disposable income

The residential consumption has historically been linked to Real Household Disposable Income as it is related to the consumer behavior on consumption and ownership of appliances. In NSW, Real Household Disposable Income grew by an average of 2.0% per annum between FY03 and FY17. In the coming years RHDI is forecast to grow at an average rate of about 1.3% per annum between FY18 and FY24.



**CAGR: Compound annual growth rate, Source: ABS*

3.4 Electricity Prices

Electricity consumption is negatively correlated with electricity prices as it directly affects consumer behaviour. Higher electricity prices incentivise consumers to invest in technologies which would help to decrease their electricity usage, such as energy efficiency, solar power and batteries or use less electricity such as taking shorter showers. Lower electricity prices, on the other hand, have an opposite effect, freeing consumers from high energy bill concerns and incentivising growth in energy use.

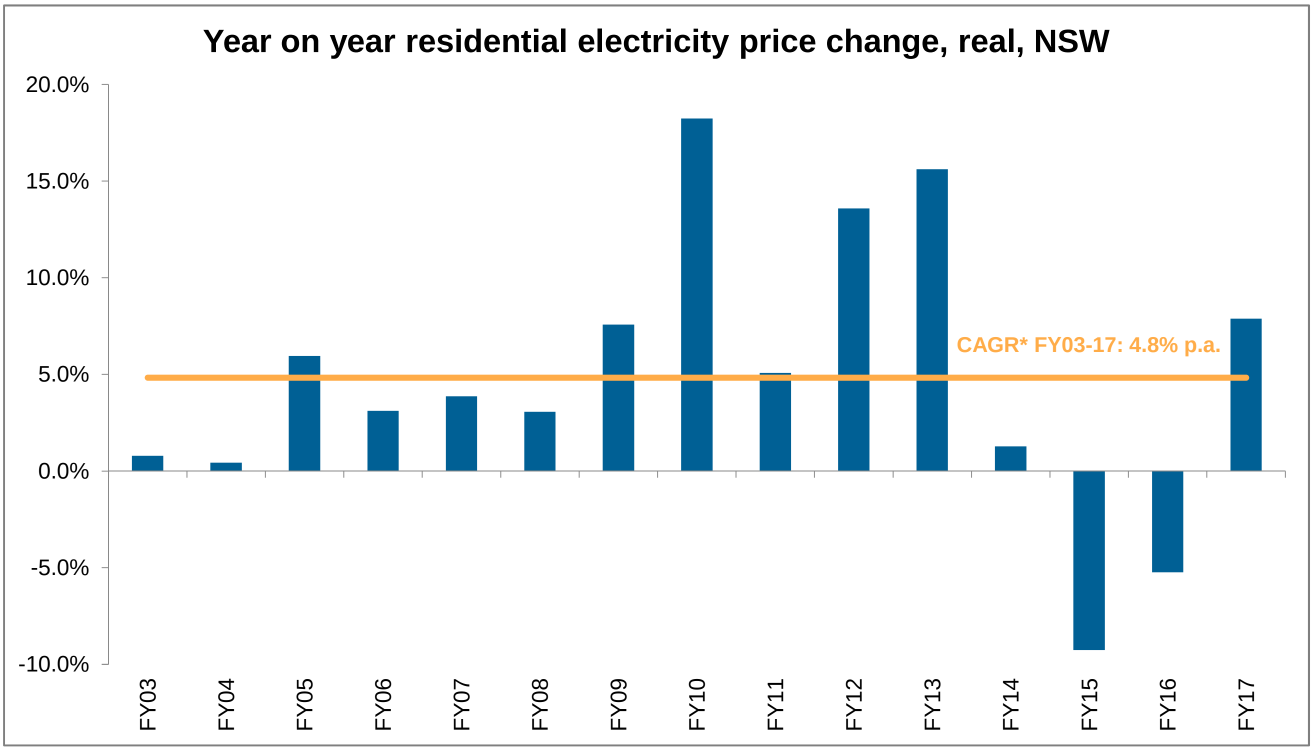
The latest electricity price forecasts used in this year's forecast predicted a very sharp increase in retail electricity prices in the short term, around +20% for residential customers and around +30% for business customers over the first two years. The projected price increases were driven by wholesale electricity price increases. In late June 2017, all of the big 3 energy retailers (Origin, AGL and Energy Australia) announced significant price rises effective 1 July 2017 of a scale that was in line with the electricity price projections used in our 2017 forecast.

Analysis of the period from 2009 to 2014, when customer demand for electricity declined, has shown that the rising prices were a major contributor to declining demand. In this period, electricity prices rose by around 65% for residential customers. The customer price sensitivity derived from analysis of the historical period has been applied to Ausgrid's forecast using electricity price forecasts derived from the Australian Energy Market Operator (AEMO). The effect of the customer price response reaches a maximum in 2020 where around 400 MW is removed from our summer forecast at the system level.

As noted above, for the 2017 forecast, trends in residential and non-residential electricity prices were obtained from the Australian Energy Market Operator (AEMO). Previous trends in electricity prices for residential and non-residential customers are shown in the following two sections.

3.4.1 Residential electricity prices

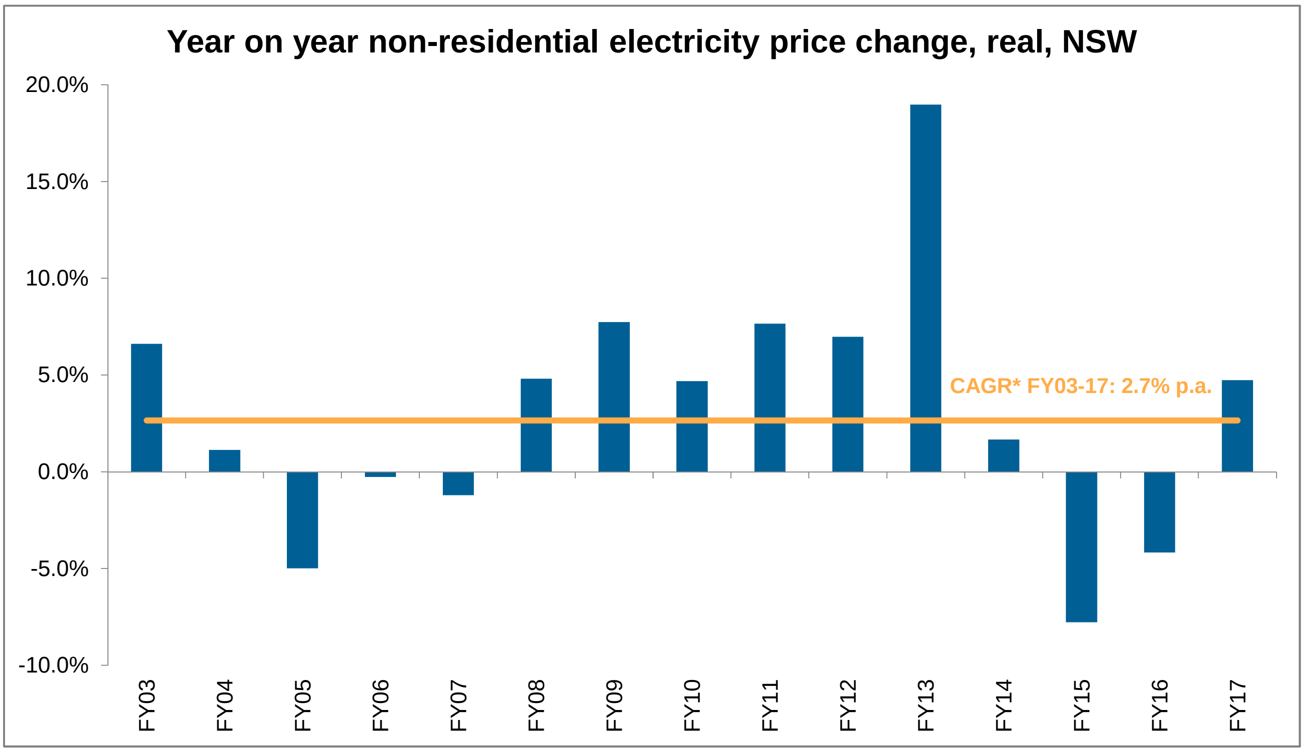
Residential electricity prices increased annually between FY05 and FY14, before an easing of prices in FY15 and FY16. As noted above, prices have recently increased in FY17 due to wholesale price rises. Between FY03 and FY17, the residential electricity price grew at an average rate of 4.8% per annum. While residential electricity prices are predicted to rise in FY18 and FY19, they are then forecast to decline in the following years. The average growth rate over the period from FY17 to FY24 is projected to be +2.5% per annum, lower than the historical average growth from FY03 to FY17.



**CAGR: Compound annual growth rate, Source: ABS*

3.4.2 Non-residential electricity prices

Non-residential electricity prices also increased annually between FY08 and FY14 before easing in FY15 and FY16. As noted above, prices have recently increased in FY17 due to wholesale price rises. Between FY03 and FY17, the residential electricity price grew at an average rate of 2.7% per annum. While non-residential electricity prices are predicted to rise in FY18 and FY19, they are then forecast to decline in the following years. The average growth rate over the period from FY17 to FY24 is projected to be +3.2% per annum for small business, +3.9% for large businesses and +4.4% for very large industrial customers.

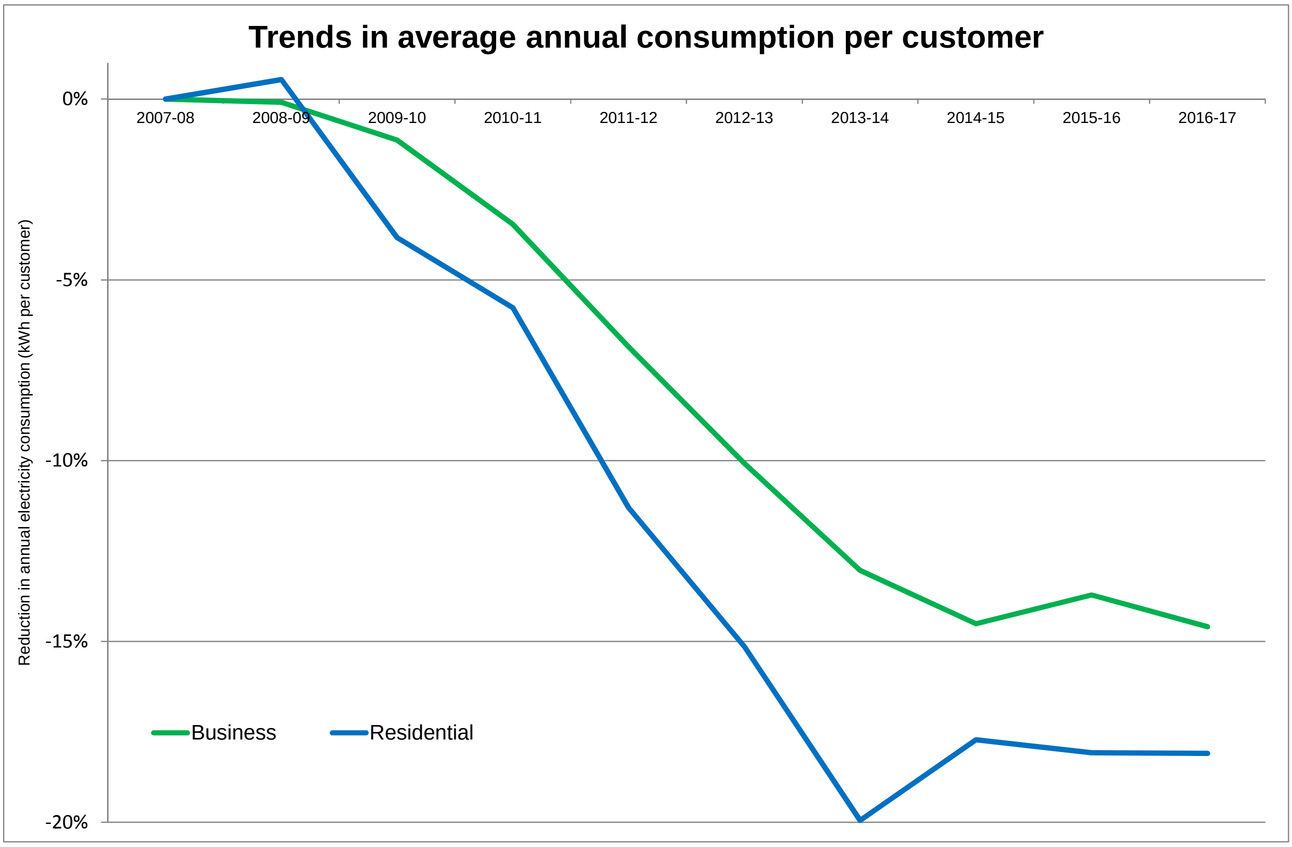


**CAGR: Compound annual growth rate, Source: ABS*

3.5 Energy Efficiency

One of the largest contributors to the reduction of electricity usage on a per customer basis and subsequent reduction and stabilisation of the growth in maximum demand has been the take up of energy efficient appliances by customers and the improving energy efficiency of homes and buildings.

Within the Ausgrid network area, annual electricity usage on a per customer basis reduced by 15 to 20% over the 6 year period between 2008-09 and 2014-15 but has since stabilised for both residential and non-residential customers. For example, the average annual consumption for Ausgrid's residential customers was around 7.0 to 7.4 MWh per year during the 4-year period between 2005-06 and 2008-09 but has now stabilised at around 5.6 to 5.7 MWh per year over the most recent 4-year period between 2013-14 and 2016-17.



The effects of the main energy efficiency government programs are considered in the Ausgrid 2017 forecast in two main ways. Firstly, the effects of energy efficiency programs are considered in the econometric system model by using an "electricity services" approach as recommended by Frontier economics in their review of AEMO's 2013 National Electricity Forecasts[11]. Secondly, future energy efficiency effects are considered as an out of trend post model adjustment.

Both historical and forecast demand impacts from Commonwealth and New South Wales government energy efficiency programs are obtained for three key programs:

(1) The Equipment Energy Efficiency (E3) program which is a cross jurisdictional program through which the Australian Government, states and territories collaborate to deliver a single, integrated program on energy efficiency standards and energy labelling for equipment and appliances. This includes a national minimum energy performance standards (MEPS) program for major residential appliances such as air conditioners, refrigerators, televisions, clothes washers and dryers, as well as commercial products as such as motors and chillers.

(2) The Building Code of Australia (BCA) which sets minimum energy performance standards for buildings.

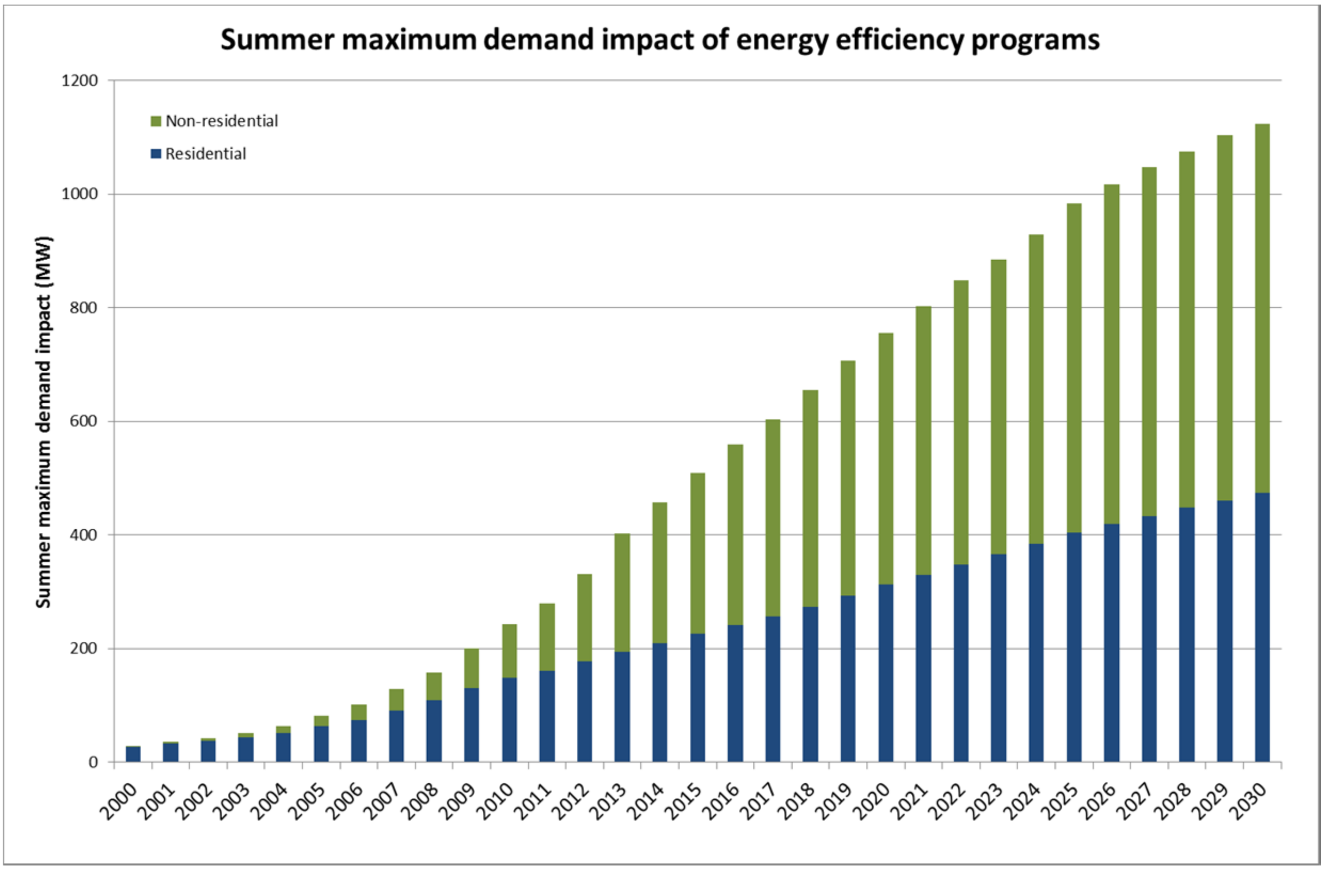
(3) The NSW Energy Savings Scheme (ESS) and its predecessor the NSW Greenhouse Gas Abatement Scheme (GGAS) which encourages customers to invest in energy efficiency improvements in their homes and businesses by obligating electricity retailers to purchase Energy Saving Certificates (ESCs) for accredited energy savings activities under the Scheme.

11 Frontier Economics, Review of AEMO's 2013 National Electricity Forecasts, p3,4

The relationship between average demand savings and maximum demand savings from energy efficiency initiatives is a complex issue and depends on the exact nature of the individual programs[12]. For example, an increase in the minimum energy performance of air conditioners being sold in Australia would have a strong correlation between average and maximum demand in summer whereas residential lighting efficiency would have a stronger correlation to winter maximum demand savings. Commercial lighting efficiency on the other hand would result in summer maximum demand savings as most business and commercial office operate lighting during summer working weekdays.

Ausgrid obtains the historical and forecast demand impacts for these three main energy efficiency programs as outlined above from external expert advice and consultancies supplemented with internal analysis and review where required. These details are covered in more depth in Section 5.1.

The overall system level impact of energy efficiency program on summer maximum demand from 2000 to 2030 is shown in the following chart.



Note that this chart shows the total projected demand impact from energy efficiency programs. We forecast the net out of trend energy efficiency activity to reduce overall network maximum summer demand by 175MW by 2024 and by around 370MW by 2030.

3.6 Rooftop Photovoltaic Systems

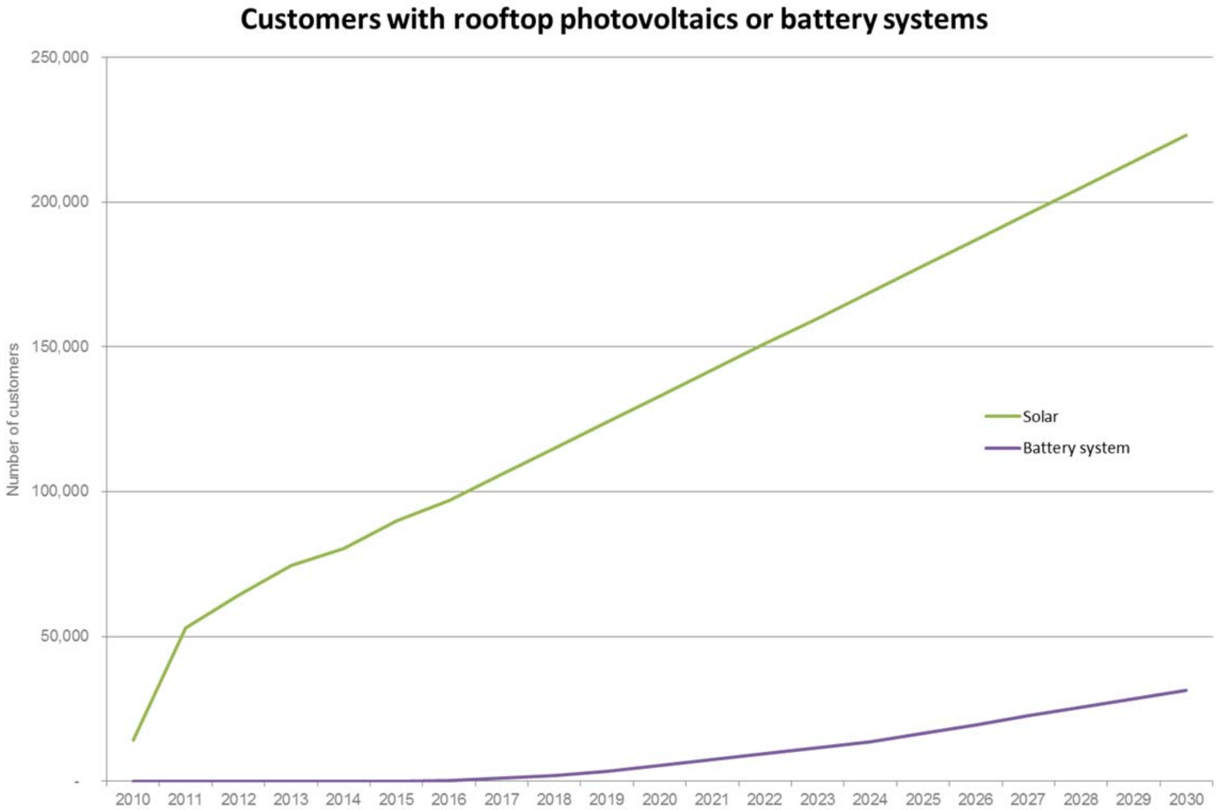
The installation of rooftop photovoltaic systems on homes and businesses in the Ausgrid network area has been continuing at a steady rate over the last couple of years. The installation of rooftop photovoltaic systems generally reduces average demand on network assets further upstream when the systems generate throughout the day (with the maximum reduction occurring in the middle of the day). However, the magnitude of the maximum demand reduction on a network asset depends largely on the correlation between the photovoltaic systems generation profile and the asset load profile at times of maximum demand. This is covered in more detail in Section 5.2.

Using postcode information from the Clean Energy Regulator we estimate that as at June 2017 the total solar panel capacity reached just over 350 MW for the Ausgrid network area with around 112,000 solar installations or around 6 to 7% of Ausgrid electricity customers with a photovoltaic system. This is the second lowest penetration of solar installations of any DNSP in Australia, behind CitiPower which serves the Melbourne CBD area only. Ausgrid's low take-up of PV by customers relative to some other networks in Australia is influenced by the large percentage

12 ACIL Allen, Connection Point Forecasting – A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand (June 2013), pg. 49-53

(35%-40%) of customers who live in apartments. As such, the impact of photovoltaic systems in reducing demand for Ausgrid has been small in comparison to other networks in Australia.

The historic and forecast number of solar customers and battery customers in Ausgrid's network area is shown below. The share of new solar customers with both PV and a battery system is forecast to be 11% of new solar customers in 2018 growing to 33% of new solar customers by 2025. By 2030, 14% of total cumulative solar customers are forecast to have storage systems.

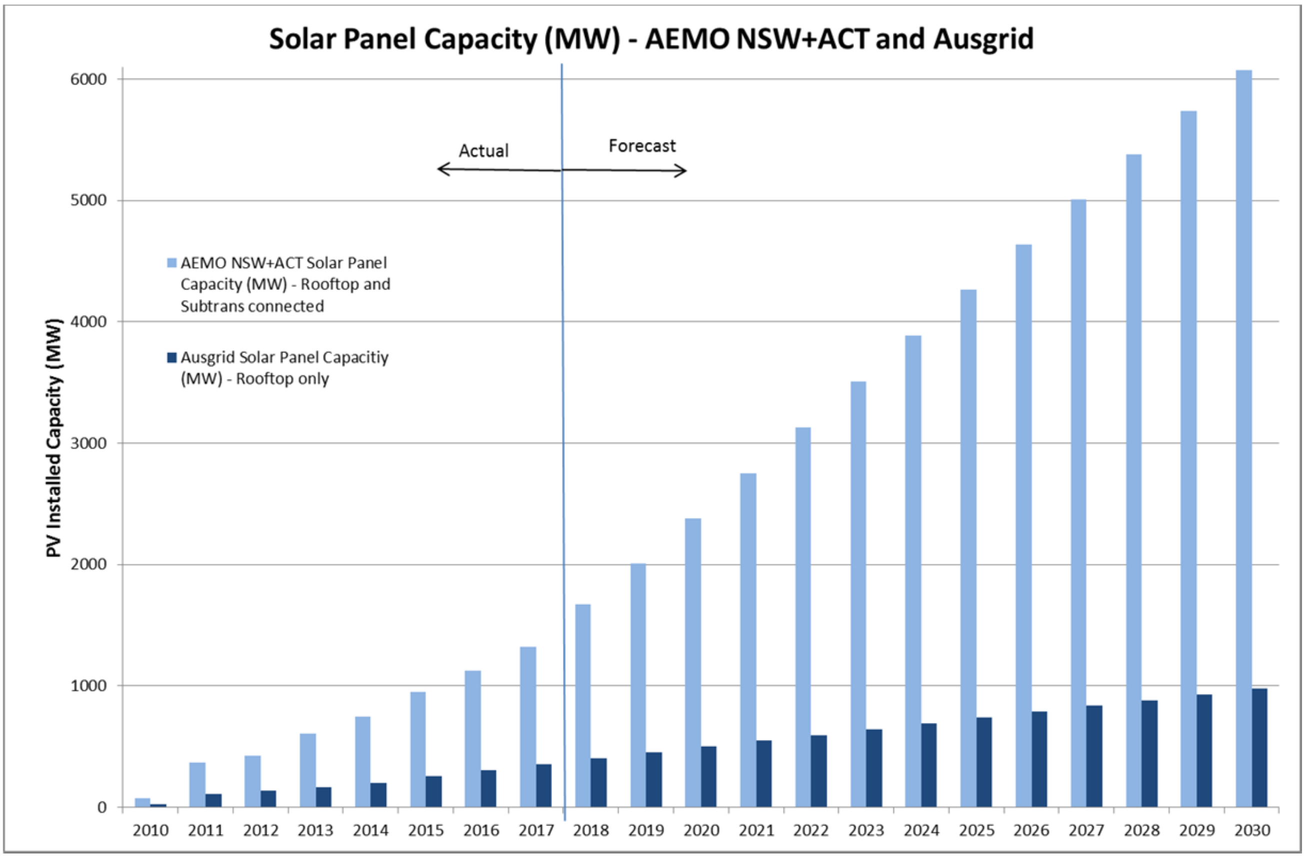


The average monthly solar installation capacity was around 4 MW per month over the 2015 and 2016 years for Ausgrid's network area. During this period solar system prices, government subsidies and electricity prices were reasonably stable and, as a result, payback periods for investing in a solar system would also have been reasonably stable. The forecast total PV uptake in the future, which includes PV systems paired with battery storage systems, uses a linear projection of this rate of around +4MW of installed panel capacity per month or +48MW per year. Take-up of rooftop PV is not expected to approach saturation levels for some time and so has not been considered in our assessment at this time.

Based on these rates, total PV uptake in Ausgrid's network area is projected to reach around 691MW installed rooftop photovoltaics by 2024. This is an additional 341 MW of solar panel capacity. This equates to an additional maximum demand reduction at the time of Ausgrid system summer peak demand (16:30 to 17:00 AEDST) of -129 MW by 2024.

The following chart shows the NSW and ACT solar panel capacity and the Ausgrid solar panel capacity to 2017 as per the Clean Energy Regulator data. Also shown is AEMO's solar forecast for NSW and the ACT and Ausgrid's solar forecast from 2018 to 2030.

Note that the figures for Ausgrid's PV forecast are solely for behind the meter (principally rooftop) solar installations. Large scale solar and wind farms are typically connected at 33kV or above and are considered as part of the assessment of block loads. In Ausgrid's 2017 forecast, the block loads assessment includes the connection of 135 MW of renewable generators with demand on relevant assets adjusted accordingly per the block loads post model adjustment process (refer Section 5.7). AEMO's NSW + ACT forecast will include both rooftop PV and large scale solar generators located on both distribution and transmission high voltage feeders.



We note that the rate of photovoltaic system installs has picked up in recent months (first half of 2017); likely in response to rises in electricity prices in 2016-17 and 2017-18. Uncertainty remains though as to whether this is just a temporary increase in the rate of solar panel capacity or whether it will lead to a sustained higher level of solar panel capacity being installed that will continue into the future. For the 2018 forecast Ausgrid will review the solar and battery forecast projections to take into account recent changes in electricity prices as well as the implications of potential changes to national energy policies (such as the National Energy Guarantee and Renewable Energy Target).

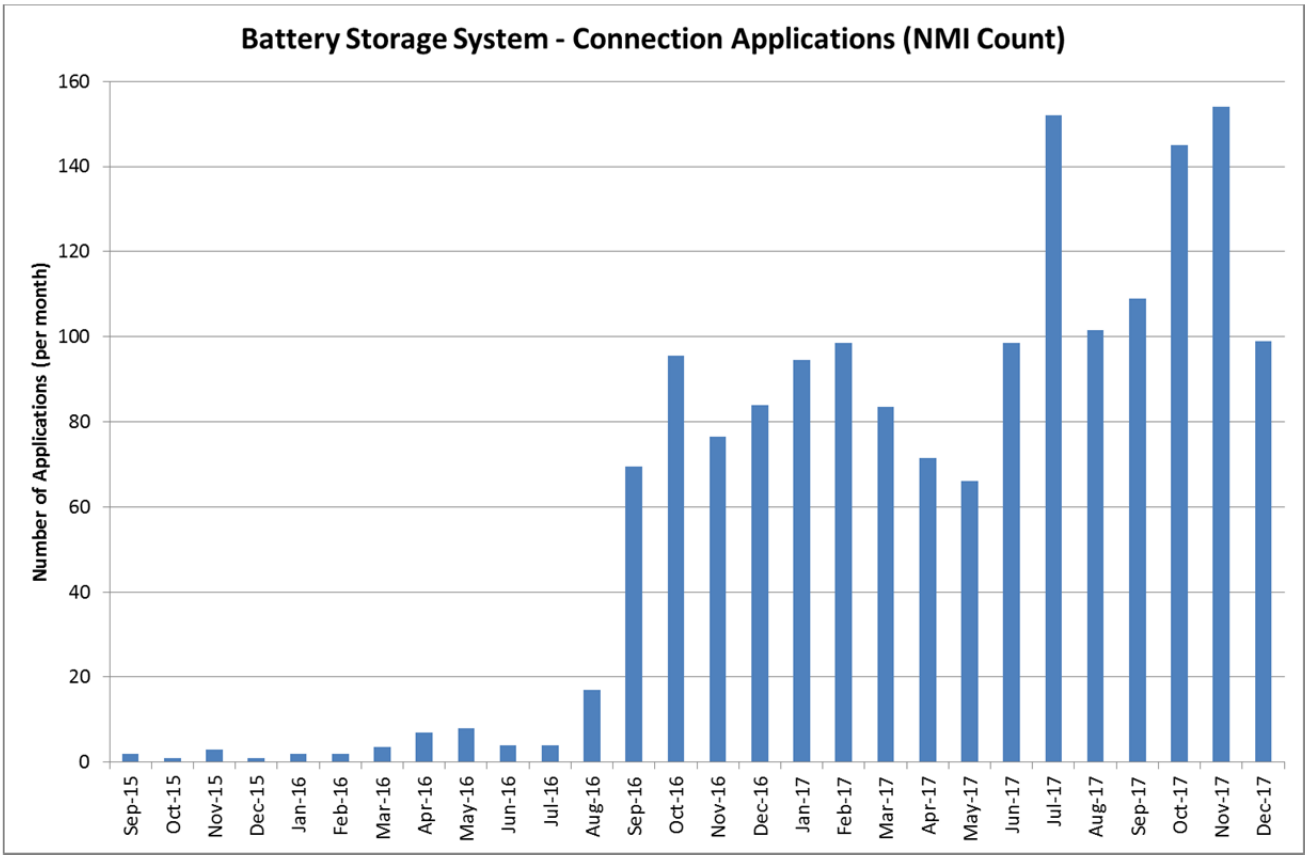
The impact of rooftop photovoltaics on maximum demand at the zone substation level is accounted for in determining the baseline trend as well as forecasting forward based on the time of peak for each zone substation. The methodology used to allocate maximum demand reductions to each zone substation for rooftop photovoltaic installations is discussed in more detail in Section 5.2. As noted, this is solely for behind the meter (principally rooftop) solar installations. A total of 135 MW in large scale solar and wind farms, connected at 33kV and above, are considered as part of the assessment of block loads (refer Section 5.7).

3.7 Emerging Technologies

3.7.1 Battery Storage Systems

Similar to rooftop photovoltaic systems, batteries paired with a photovoltaic system will generally reduce maximum demand and it is expected that a battery and photovoltaic system will reduce maximum demand more than a photovoltaic system on its own. A battery storage system is generally used to store solar energy for later use during peak times or to charge during off peak times to use the energy during peak times when on a time of use tariff. This will result in a higher average impact in reducing maximum demand than a photovoltaic system without a battery.

The maximum demand impact of battery storage systems was first introduced in the 2016 maximum demand forecast and the 2017 forecast has been updated to reflect an increasing take up of household battery systems over the 2016-17 year. Ausgrid had received around 1000 battery connection applications (as at June 2017) and continue to receive around 100 applications per month. See chart following which details the number of connection applications for battery storage systems received by Ausgrid over the past 2 years.



Updates to the battery model in 2017 include an update to battery price assumptions which declined significantly between 2016 and 2017. The modelling is now based on a larger household battery system size of 14kWh nominal storage capacity. For further details of the battery modelling please refer to Section 5.3.

At system level, battery storage systems paired with a photovoltaic system are projected to reduce system total summer maximum demand by around -27 MW by 2024 and -63 MW by 2030 based on a projected battery storage system count of around 13,500 and 31,500 respectively.

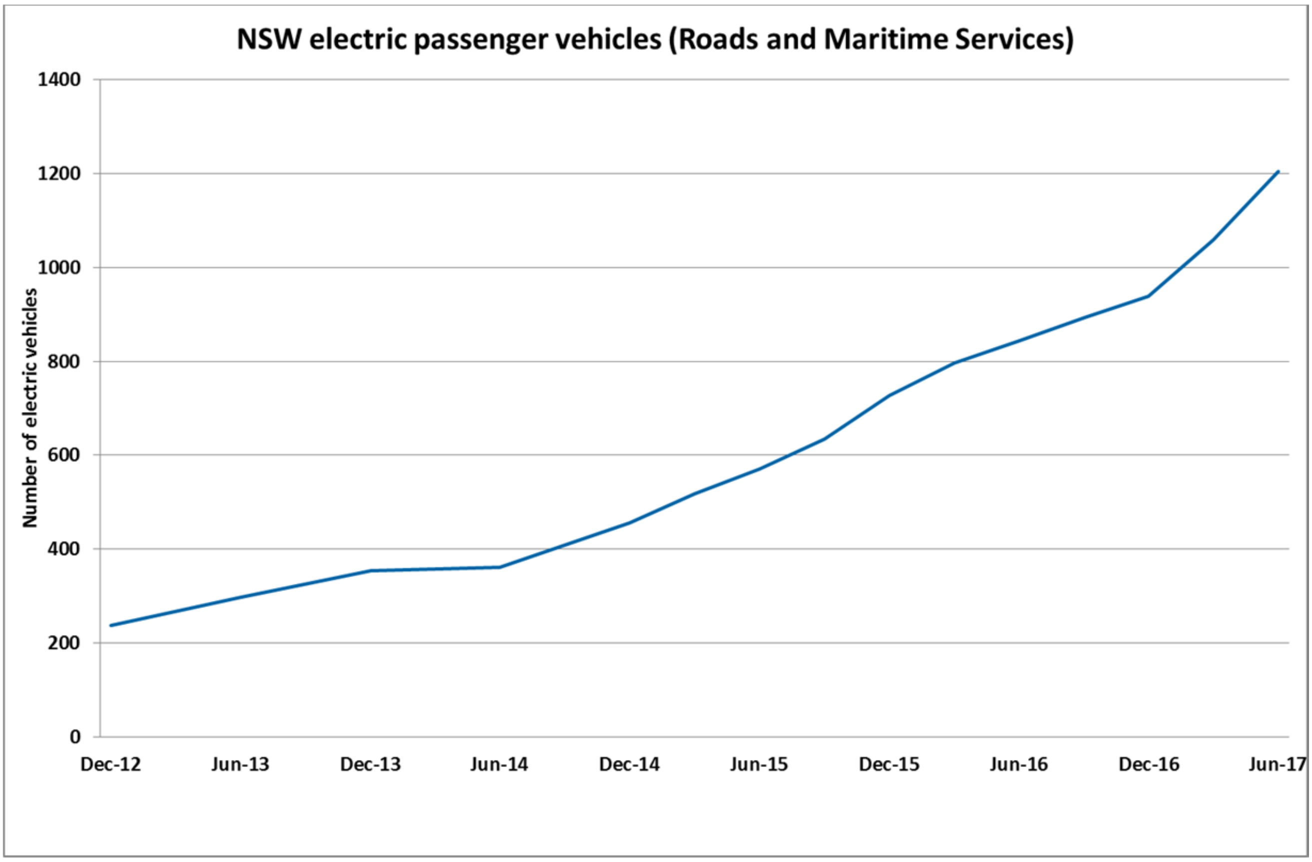
3.7.2 Electric Vehicles (EV)

The impact of electric vehicle charging will result in a net increase in maximum demand on average and the 2017 forecast includes an estimate of this impact on maximum demand. The Ausgrid EV forecast has been guided by the AEMO Insights report for electric vehicles[13] with the NSW projections being adjusted for a slower than predicted take up over the 2018 and 2019 years as supported by New South Wales electric vehicle registration data. The proportion of the NSW forecast predicted to be in Ausgrid's network area was also estimated from the NSW vehicle registration by Local Government Area.

The number of registered electric vehicles in the Ausgrid area is estimated to be 1,000 as at June 2017 and we predict around 50,000 by 2024 and 275,000 by 2030 to be garaged within the Ausgrid network area. Note that the future uptake of EVs in Australia in terms of scale and timing is highly uncertain at this point in time and many projections have tended to overstate the take up of EVs in Australia that have actually occurred so far.

This estimate is based upon vehicle registration information from NSW Roads and Maritime Services – see chart following of the number of registered electric passenger vehicles in NSW which shows there were 1,204 electric passenger vehicles registered in NSW as at June 2017.[14] Note there were about 2.9m passenger vehicles in NSW as at June 2017.[15]

[13] *AEMO and Energeia, AEMO Insights Report: Electric Vehicles (2016)*
[14] *http://www.rms.nsw.gov.au/about/corporate-publications/statistics/registrationandlicensing/tables/table114_2017q2.html*
[15] *http://www.rms.nsw.gov.au/about/corporate-publications/statistics/registrationandlicensing/tables/table113_2017q2.html*



Although most EV charging is likely to occur at home in the off peak periods, EV charging trial results in Australia and the USA have shown that there is a non-zero electrical demand for EV charging during the peak periods on working weekdays, mainly due to away from home charging (work or public charging stations). Based on these studies it has been assumed that the maximum demand impact of electric vehicles to be +0.3kW per vehicle.

The Ausgrid forecast estimates a maximum demand impact of +15 MW by 2024 and +82 MW by 2030 on the system peak demand due to the charging of electric vehicles. This reaches over +260 MW by 2040 but the impact is heavily dependent on the take up of electric vehicles which is highly uncertain at this point in time

Further details on the maximum demand impacts of electric vehicles in the Ausgrid network area and how it is treated as a post-model adjustment is covered in Section 5.4

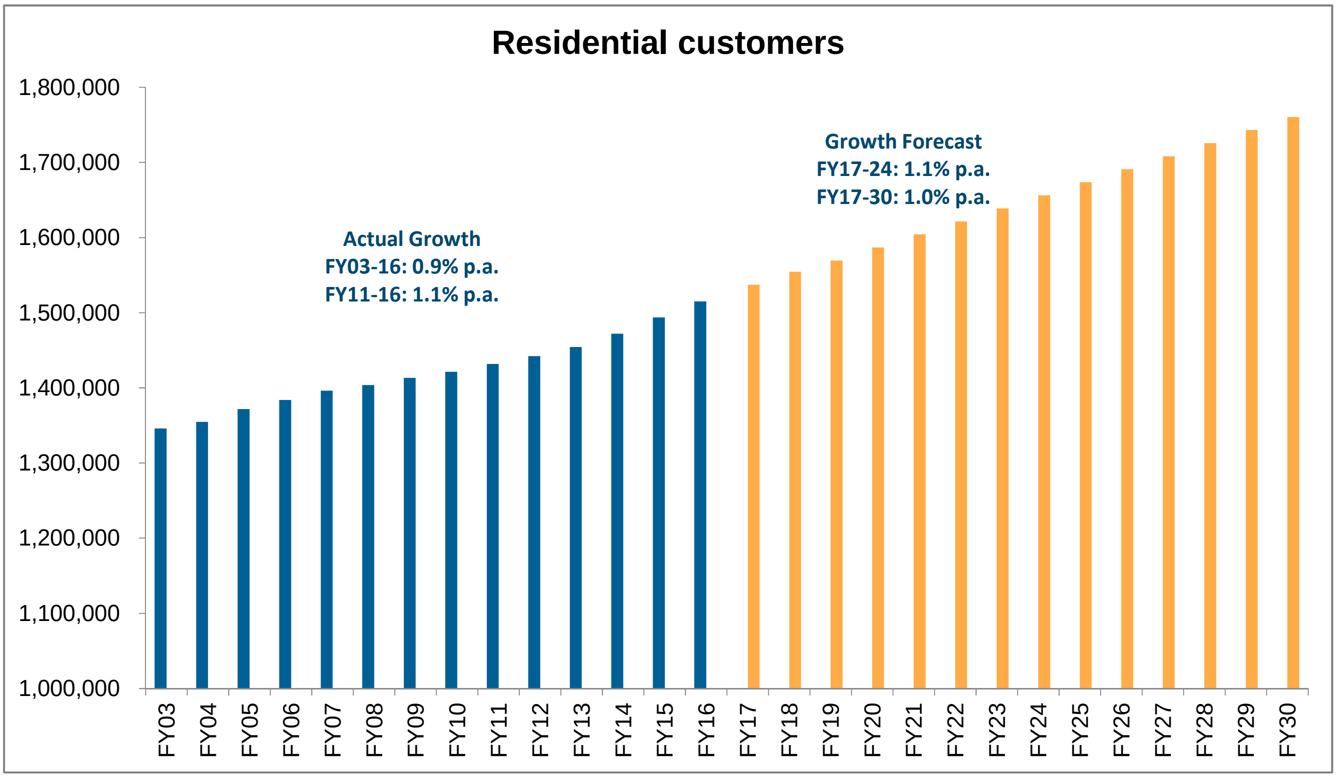
3.8 Number of Households (Population)

Growth in the number of households due to an increasing population is one of the main drivers of increasing maximum demand. As the number of new residential customers connecting to the network increases, the maximum demand increases.

The number of residential customers has been on an increasing trend, growing by 1.0% per annum between 2003 and 2017. The recent years showed a relatively higher increase with 1.1% per annum between 2011 and 2016.

The steady increase in the residential customer numbers is expected to continue. The period until FY24 is expected to have a relatively higher growth rate of 1.1% per annum in line with the trend since FY11, while the long term forecast has a slower rate at 1.0% per annum. The residential customer forecast is based on NSW Housing Industry Association (HIA) for dwelling starts by financial year (dated Mar-17) and the NSW Department of Planning's (DoP) "A Plan for Growing Sydney"[16] household growth figures (dated Aug-16). See Section 5.5 for further details.

[16] *http://www.planning.nsw.gov.au/Plans-for-your-area/Sydney/A-Plan-for-Growing-Sydney*



3.9 Residential Air-conditioners

Residential air conditioners have been a significant contributing factor to increasing electricity maximum demand on hot summer days in the past, particularly during the 2000 to 2010 period. However, air conditioning penetration appears to have stabilised at around two thirds of all NSW households and the average electrical efficiency of air conditioning appliances in households is substantially better than a decade ago due to Commonwealth Government initiatives including Mandatory Performance Efficiency Standards (MEPS) and the household insulation scheme.

Although residential air conditioners is still one of the largest contributors to summer peak demand, the continued growth of maximum demand due to increasing air conditioner ownership is now much lower than in the past. While there is a degree of uncertainty associated with the outlook for air conditioner ownership and usage, it is considered highly likely that their impact on increasing maximum demand over the regulatory control period to 2023/24 will be much less than was the case in the preceding decade. Consequently, the impact of rising ownership of air conditioners has a very modest impact on the maximum demand forecasts.

Both the impact of slightly higher levels of air conditioner ownership and higher energy efficiency levels are included in Ausgrid's forecast as post model adjustments. See Section 5.6 for further details.

3.10 Other drivers

3.10.1 Cost reflective network pricing

As part of the Power of Choice reforms implemented by the Australian Energy Market Commission (AEMC), the National Electricity Rules were changed on 1 December 2014 to require regulated network companies such as Ausgrid to structure their electricity prices to better reflect the costs of providing the electricity. This is commonly termed cost reflective pricing. Ausgrid's time of use tariff, available to all customers since 2004, is an example of a more cost reflective tariff.

Under these reforms, the AEMC expects peak demand to moderate as customers shift their usage in response to the new tariffs. As this remains a recent reform and changes to customer tariff remain modest, Ausgrid has not chosen at this time to develop and introduce a post model adjustment to account for the impact of this change. We would note though that as the use of Ausgrid's time of use tariff by customers has grown steadily from close to zero small customers in 2004 to the current level of over 500,000 small residential and business customers, we expect that the historical trend includes this demand response effect and so is included in the econometric and spatial trends used to derive the demand forecast.

Ausgrid will continue to monitor the introduction of more cost reflective tariffs and assess the impact on customer usage patterns. Where customer demand is projected to change at a rate different from the past, a post model adjustment procedure will be developed and introduced.

3.10.2 Demand response

Demand response is typically defined as a temporary shift in customer demand in response to an incentive from retailers or networks. For the purposes of the forecast, we have defined demand response as separate to a customer response to a cost reflective network or retail tariff which is commonly considered a more permanent change in customer behaviour and demand.

Where networks or retailers contract with customers to reduce peak demand, an adjustment to the historical record should be introduced to ensure that the trend accurately reflects underlying demand in the absence of this temporary customer response. This would be similar to the need to adjust the historical record for abnormal network switching.

Where information is available and the demand change is material, Ausgrid accounts for demand response activity. In 2017, no adjustments were made.

The introduction of improved information due to the recent rule change by AEMO may help to improve the accuracy of this element of the forecast.

4 Methodology

The electricity demand forecasts consist of integrating two forecast components:

- A baseline trend for each of Ausgrid's 181 zone and 33 sub-transmission substations is calculated using historic 15-minute demand data, weather data for the closest Bureau of Methodology weather station and adjustments based on historic information for embedded generation, block loads and load transfers.
- A system level econometric model taking into account historical information on the main demand driver variables of household income, gross state product and electricity price. Further post-modelling adjustments are also applied for energy efficiency, embedded generation, emerging technologies (batteries and electric vehicles), customer growth and increasing air conditioner penetration.

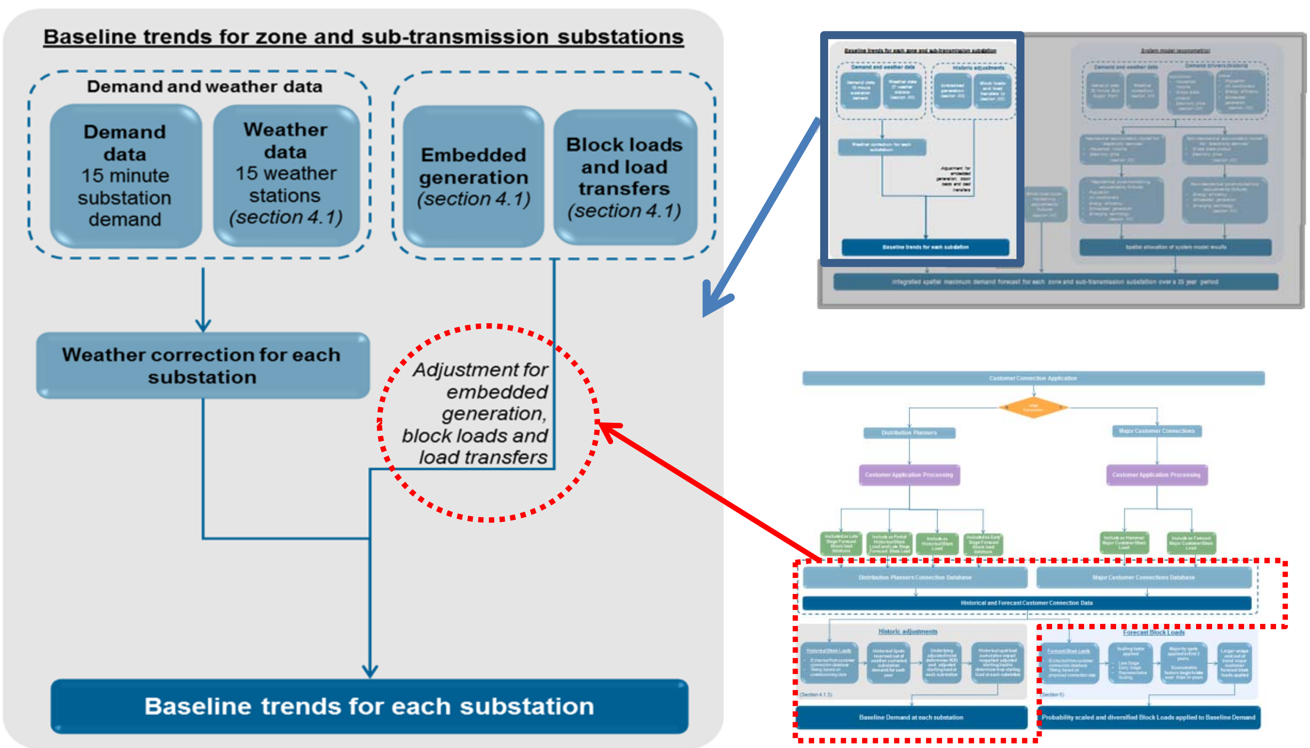
Refer to the flow chart in Section 1.5 for an overview of the methodology. The detailed methodology for each element is described below.

4.1 Underlying trend – Local Zone and Sub-transmission Substations

The process for deriving the local substation forecast is comprised of the following components:

- Demand and Weather data – refer Section 4.1.1
  - o Gather inputs
  - o Cleanse data
- Weather Correction for each Substation – refer Section 4.1.2
  - o Determine temperature sensitivity
  - o Normalise data
  - o Apply manual adjustments where required
- Historic adjustments – refer Section 4.1.3
  - o Historical network load transfer adjustments
  - o Historical block load adjustments
  - o Historical embedded generation adjustments
- Underlying trend – refer Section 4.1.4
  - o Determine starting point and underlying rate of growth

Please refer to the section of the process noted below as per the overall methodology flow chart detailed in Section 1.5 and the block load assessment process flow chart detailed in Section 5.7.



4.1.1 Demand and Weather Data

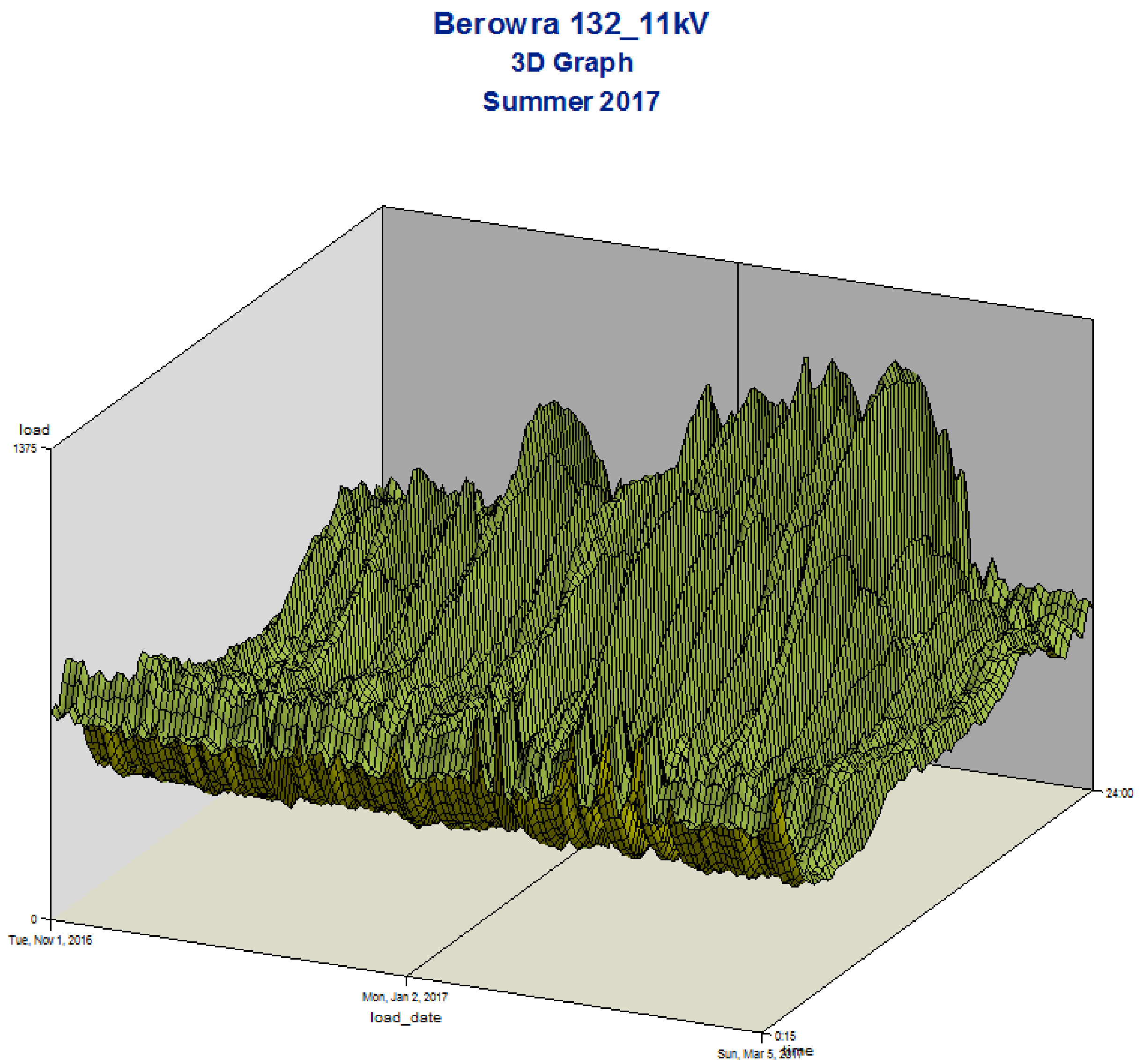
Gather Inputs

Raw metered electricity demand data is obtained for zone substations and sub-transmission substations for the most recent 7 years at 15 minute intervals and 10 years of half hourly weather data is obtained from the Bureau of Meteorology for weather stations across Ausgrid's network area. Each zone and sub-transmission substation is assigned a representative Bureau of Meteorology weather station. By default, each substation is assigned the geographically closest weather station, data quality and availability permitting. Network configuration data is obtained from Ausgrid's planning and customer connections groups.

Cleanse Data

The metered electricity demand data is cleansed to remove abnormal loads (generally resulting from temporary network switching and abnormal configurations). On days where abnormal load switching or a data error is detected in the demand data, that day is typically removed from the data set. If the day in question is deemed to be close to a maximum demand day, then the affected intervals are interpolated. Cleansing prevents abnormally switched loads from distorting historical trends.

Note that this step is carried out in conjunction with the weather correction simulation step below and is carried out using graphical visualisation techniques.



The maximum demand for each day is determined from the cleansed interval demand data. The largest daily maximum demand is therefore selected as the maximum demand for the season. The cleansed weather data is then weather corrected using a simulation technique.

4.1.2 Weather Correction

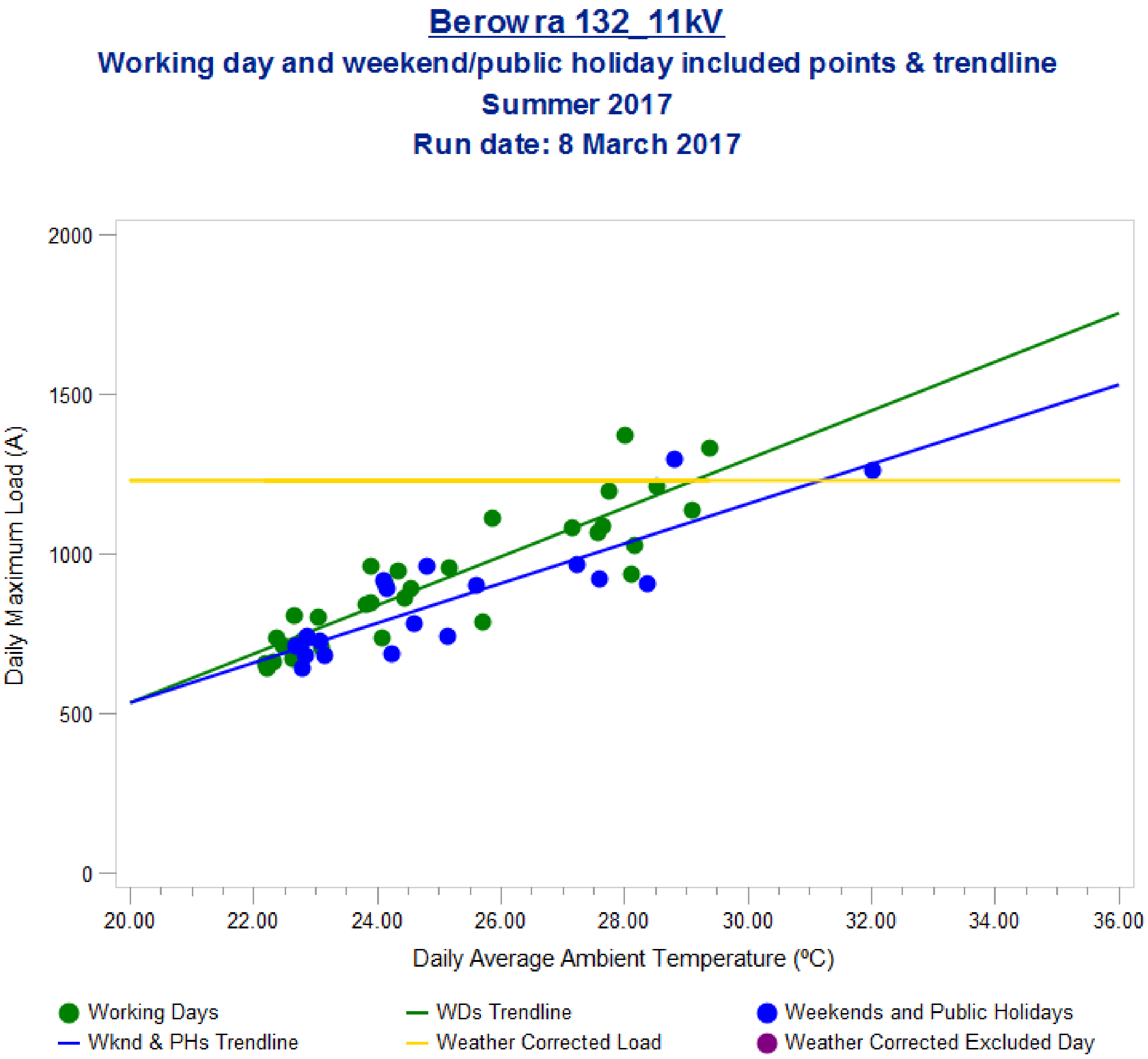
The process used to weather correct each zone substation and sub-transmission substation is described below.

Determining temperature sensitivity

Daily average temperature is calculated for each weather station. Daily average temperature is the average of daily temperature intervals. Ambient dry bulb temperature is used. Daily maximum demand is related to daily average temperature and displayed as a scatter plot. The knee point temperature is determined, which is the temperature the substation begins to show temperature sensitivity.

Each day is classified as either a working day or non-working day. Weekends, public holidays and the Christmas holiday period (21 December to 6 January – summer only) are assigned as non-working days. The remaining days are the working days. The summer is 1 November to mid-March, with the close date determined by the likelihood of high demand days in the remaining March period. The winter period is 1 May to 31 August. These dates are chosen as it represents the times of year most likely to show consistent temperature sensitivity for weather dependent substations.

Analysis is completed for non-working days as well due to a number of substations that service holiday destinations. Substations that serve a high share of residential customers or are in areas frequented during holidays have the potential to experience their seasonal maximum demand on non-working days.



A linear fit is applied separately to the working days and non-working days. The slope, intercept and standard error (SE) are calculated for both the linear fit of working days and the linear fit of non-working days as per the following equation.

D = S x temp + c

where

D = maximum demand for each zone substation;

S = derived temperature sensitivity for each zone substation;

temp = daily average temperature for the representative Bureau of Meteorology weather station; and

c = intercept.

The standard error of the regression fit (SE) is also calculated, which is a measure of the degree of scatter around the line of best fit. The SE is used for the simulation step.

Note that when maximum daily demand is plotted against the corresponding daily average temperature, the plot exhibits a bend at an average daily temperature value. As temperature increases beyond this temperature value, demand increases as temperature increases. This is referred to as the knee point. For winter, as temperature cools below a point of inflection, demand increases as temperature decreases. The knee points for summer and winter are not equal. Between these two knee points demand is stable and does not exhibit temperature sensitivity. A default knee point temperature of 22°C for summer and 15°C for winter is applied, subject to overrides on a case by case basis. Data points representing daily maximum demand on days below the knee point for summer and above the knee point for winter (not temperature sensitive) are excluded prior to estimating a line of best fit which is then used for the weather correction simulation.

Major customers connected to a sub-transmission substation and large generators do not have weather correction applied as these customers do not exhibit a weather correlation. For these substations, weather corrected demand is the same as the actual maximum demand.

Normalise Data

Simulation of the daily average temperature is done by drawing at random from the 10 years of weather history for the relevant weather station. Simulation uses the relevant working day or non-working day linear fit parameters. The simulated maximum demand is calculated as per the equation below:

$D = S \times temp + c + N(0,SE)$

where

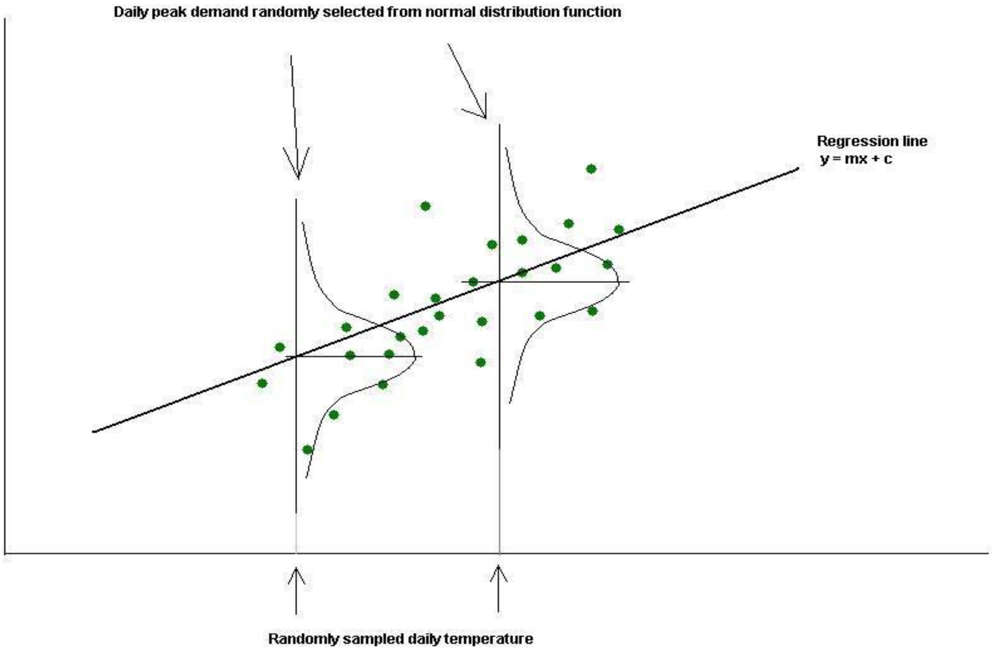
D = simulated daily maximum demand for each zone substation;

S = estimated temperature sensitivity derived from above for each zone substation;

temp = simulated daily average temperature drawn randomly from 10 years' of historical observations;

c = constant of regression; and

N(0,SE) = a random number drawn from a normal distribution with mean = 0 and standard deviation = SE. SE as derived from above for each zone substation.



This simulation process is repeated for each day of each season for a total of 2000 seasons, capturing the maximum for each iteration. The 50 POE maximum demand is the median of the 2000 simulated maximum demands. Any POE level can be determined by taking the appropriate percentile of the 2000 simulated maximums.

Apply Manual Overrides where required

As part of the data cleansing process, the interval demand data and the daily maximum demand vs daily average temperature plots are assessed individually by the forecaster using graphical methods and overrides or exclusions may be applied. One or more of the following overrides may be applied:

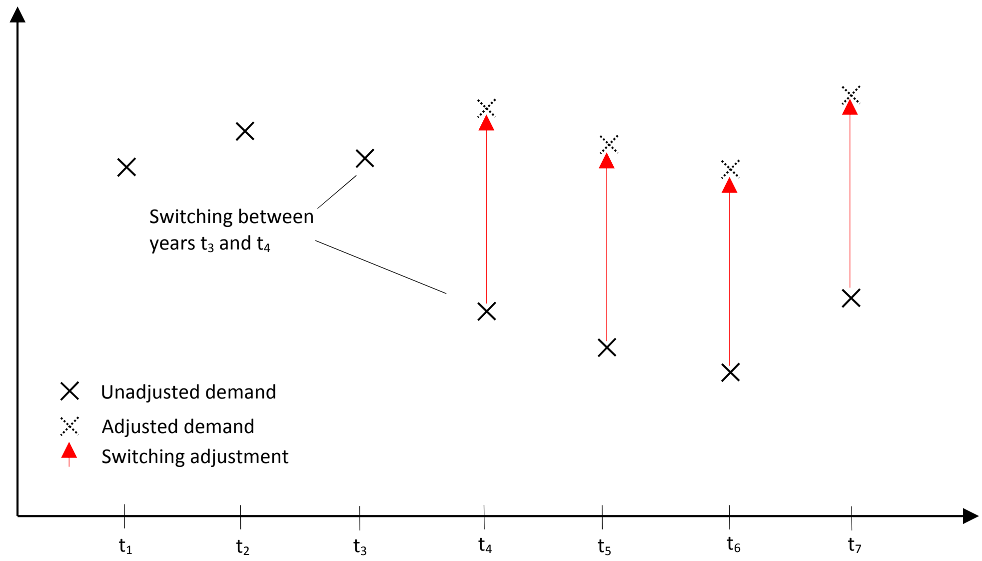
- Days that are obvious outliers on the daily maximum vs daily average temperature scatter graph are removed. Note, that this type of exclusion is rare.
- For substations where the load is not weather dependent, then no weather correction is applied and so the weather corrected maximum demand is overridden to be the same as the actual maximum demand.
- Substations where a temperature sensitivity inflection point differs from the default seasonal knee point assigned for that season can have their knee-point changed to better reflect the temperature sensitivity relationship exhibited at the substation.

4.1.3 Historic adjustments

The weather corrected loads are adjusted to remove the effect of step changes in demand that would distort the calculation of the underlying trend. This reveals the underlying trend in the metered electricity demand from customers for each substation.

Historical network load transfer adjustments

Where an alteration to the network configuration has resulted in a step change in demand at a substation, the historical change is reversed in order to determine the true underlying demand trend. An alteration to network configuration is commonly a load transfer from one substation to another. See the figure below which displays the adjustment required where a network load transfer can obscure the underlying trend. The step change is reversed to allow the underlying demand trend to be calculated.



Historical block load adjustments

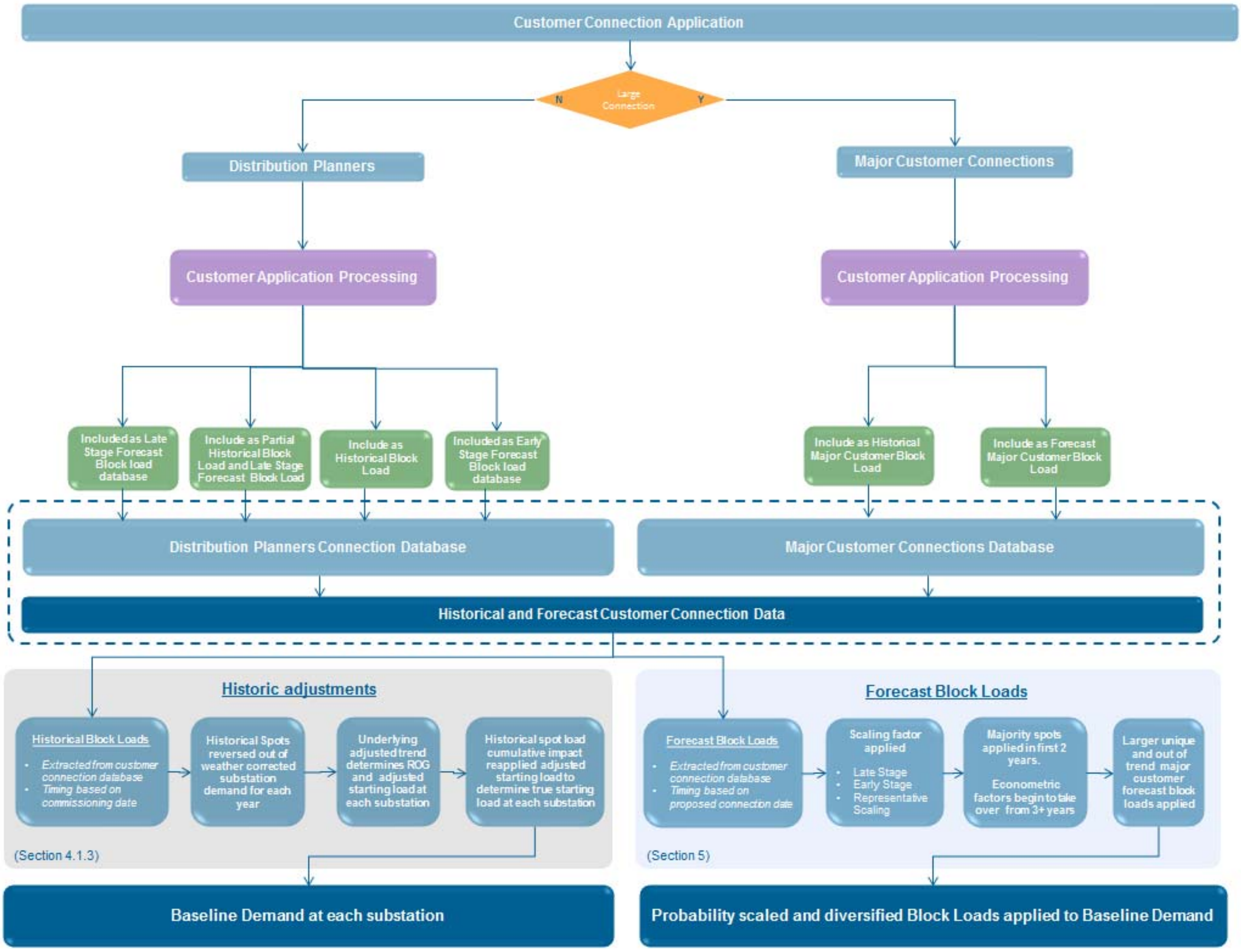
Where a step change in demand due to a new large customer connection (commonly referred to as a block load) is identified, the historical change is reversed in order to determine the true underlying demand trend. These large changes in demand can obscure the underlying change in demand of a network asset. Note that the figure above can also represent the adjustment required when a large customer disconnection or one-off reduction in load has occurred.

This process involves a comprehensive assessment of customer connections to assess change in demand due to block loads independently from change in demand due to underlying changes in demand. This assessment process tracks all connections applications greater than 50 amps at 11kV and all applications at 33kV and above. The 50 amp threshold was selected as it reflects a possible new load of 1 MW or about 3% the load on a zone substation with a load of 30 MW (average Ausgrid zone substation load).

Only substations that have 50 amps (11kV) or more in total of customer connections in the preceding 7 years of history have these connections reversed out. Substations that have customer connections totaling less than 50 amps are not adjusted a these connections are deemed small enough to be part of the organic trend for the substation.

This assessment tracks not only the customer demand requested, but also the resultant demand for historical customer connections. This allows for the calculation of scaling factors that can be applied to proposed connection requests to ensure that forecast demand is not overestimated. By removing commissioned block loads from the historical trend, the underlying trend is discovered avoiding the need to apply estimates or thresholds to the assessment of future block loads. This approach avoids both the risk of double counting and under or over estimating future demand.

A flow chart detailing the assessment of block loads is shown below with further detail in Section 5.7.



<u>Historical Embedded Generation Adjustments</u>

An adjustment for embedded generation at time of peak is made and applied in a similar fashion to the adjustment for step changes due to network configuration. This ensures that the historical load data includes the impact of downstream embedded generation that was generating at the time of peak.

The calculation of historical peak demand impact of embedded solar generation at each substation is calculated as follows:

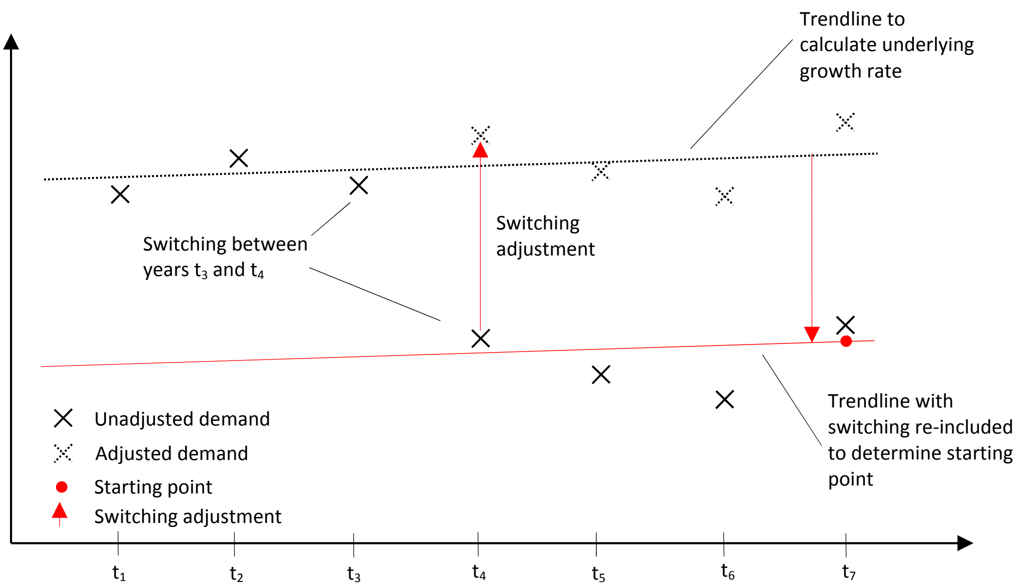
- Embedded solar generation demand for all 30 minute intervals is modelled from a representative sample of customer interval meter data (gross metered systems) for customer solar power systems.
- Historical solar embedded generation (30 minute intervals) at each zone substation is then estimated from the embedded generation demand model and historical customer solar connection information.
- The substation weather corrected demand is adjusted for the peak demand impact of connected solar so that demand is trended without the impact of solar generation. This is similar to the adjustments made for historical step changes in demand.
- Where a dispatchable generator is expected to have a material impact on peak load that is not accurately reflected in the historical data and information is available about generator output and reliability, the forecast is adjusted to reflect the expected impact of the generator, taking into account the historical reliability of the generator and expectations about its future reliability, including weather dependency where relevant, when the generator was installed and whether it is a temporary or permanent installation, contractual obligations for Ausgrid to provide backup or standby supply to a site, and any network support agreements with the generator. Larger generators that are relied on for network support are generally included as a negative spot load. In determining whether a generator is 'large', Ausgrid uses the same approach as is used for spot loads and transfers.

This process ensures that the underlying customer demand for electricity is assessed.

4.1.4 Underlying trend

Baseline Trends for each substation location

The underlying rate of growth and starting point demand are calculated for each zone and sub-transmission substation. Regression of the adjusted and weather corrected demand calculates the underlying rate of growth using a line of best fit. Any step changes in demand (network load transfers, historical bock loads and embedded generation) are then reinserted to arrive at the starting point. Adjustment for future transfers of existing load between substations are also applied to the baseline trends of the substation locations affected. Refer to the figure below describing the calculation of the underlying trend and determination of the starting point demand.



4.2 System model (Econometric)

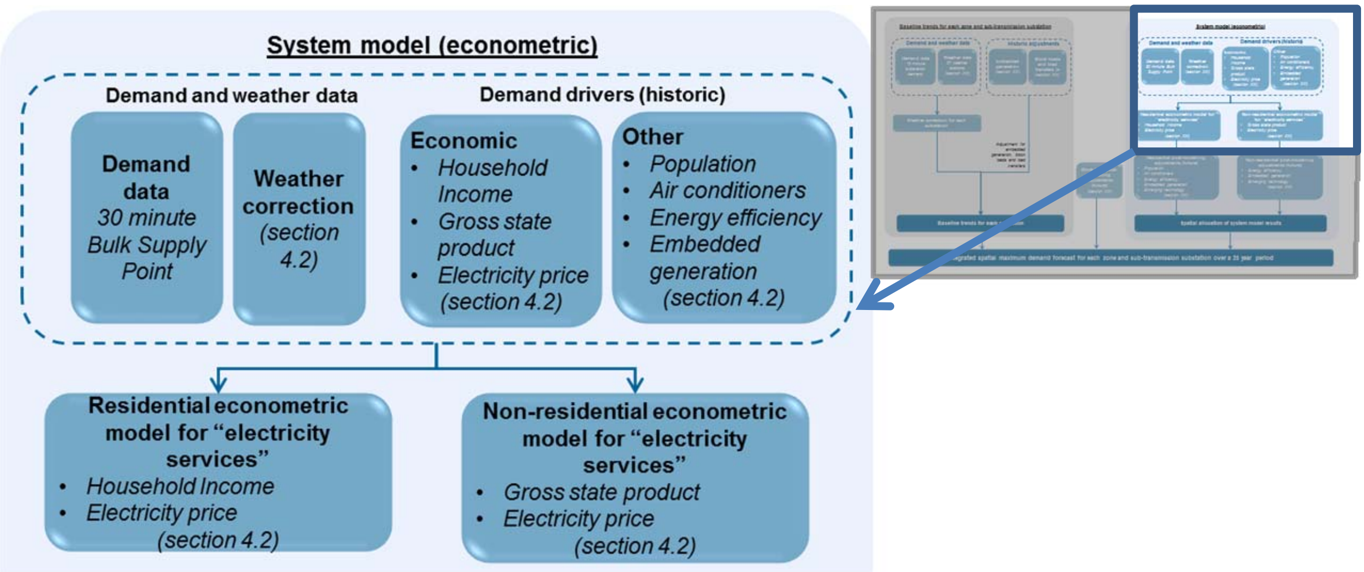
The system level forecast is based upon an econometric model with post-model adjustments applied for energy efficiency, rooftop photovoltaic systems, battery storage systems, electric vehicles, customer growth and air conditioner penetration.

The econometric model serves to estimate price and income elasticities at a whole of network level with post model adjustments made to adjust for effects not considered to be included within the model. The resultant system level demand forecast is then allocated to all Ausgrid zone substations.

The process for deriving the system level forecast is comprised of the following components:

- Demand and Weather data – refer Section 4.2.1
  - Gather inputs
  - Cleanse data
  - Derive sectoral data
- Weather Correction – refer Section 4.2.2
  - Determine temperature sensitivity
  - Normalise data
  - Apply manual adjustments where required
- Establish 'electricity services' dependent variable – refer Section 4.2.3
- Determine demand driver elasticities – refer Section 4.2.4
  - Gather driver data
  - Calculate elasticities
- Apply post model adjustments – refer Section 4.2.5
- Spatial allocation – refer Section 4.2.6

Please refer to the section of the process noted below as per the overall methodology flow chart detailed in Section 1.5 and the block load assessment process flow chart detailed in Section 5.7.



4.2.1 Demand and Weather Data

Gather Inputs

Raw metered electricity demand data is obtained for total system demand from 2003 onwards at 30 minute intervals. The data is sourced from bulk supply point meters; typically located on the secondary voltage side of all 132 kV supply points on Ausgrid's network.

Raw metered electricity demand data is obtained from all 1.7 million Ausgrid customers including interval meter data for about 650,000 customers.

Ten years of half hourly weather data is obtained from the Bureau of Meteorology. Sydney Observatory Hill weather station has been chosen as the representative weather stations for Ausgrid's entire network area due principally to its location adjacent to the larger load centres.

Cleanse Data

The metered electricity demand data is cleansed to remove abnormal data which might result from meter error. Where errors are detected in the meter data, that customer data is removed from the data set. For bulk supply point data, if data errors are deemed to be close to a maximum demand day, then the affected intervals are interpolated. Cleansing prevents poor data from distorting historical trends.

Derive Sectoral Data

The weather correction for the system level demand is similar to that for each zone substation but is separated into residential and non-residential components to allow regression of the driver variables for each customer sector.

Using Ausgrid's interval meter data for over 650,000 individual residential and non-residential customers in combination with the interval meter data from the bulk supply point meters, a linear regression model is developed to estimate the interval data for non-interval metered customers in aggregate for each customer segment. This allows allocation of all customer demand to a residential sector total and a non-residential sector total separately.

The non-residential segment is further broken down into small, medium and large customers. Demand from the large non-residential demand is not weather dependent and is not weather corrected. Non-working days are not included.

4.2.2 Weather Correction

The process used to weather correct the residential and non-residential sectors system demand is described below.

Determining temperature sensitivity

Daily average temperature is calculated for the representative weather station, which is Sydney Observatory Hill. Daily average temperature is the average of daily temperature intervals. Ambient dry bulb temperature is used. Daily maximum demand is related to daily average temperature and displayed as a scatter plot. Data is analysed to determine at what temperature the customer sector begins to show temperature sensitivity.

Each day is classified as either a working day or non-working day. Weekends, public holidays and Christmas period (21 Dec to 6 Jan – summer only) are excluded. The remaining days are the working days. Summer is 1 Nov to mid-March and winter is 1 May to 31 Aug. These dates are chosen as it represents the times of year most likely to show consistent temperature sensitivity.

A linear fit is applied separately to the working days. The slope, intercept and standard error (SE) are calculated for the linear fit of working days as per the following equation.

$D = S \times temp + c$

Where

D = maximum demand for each customer sector;

S = derived temperature sensitivity for each customer sector;

temp = daily average temperature for the representative Bureau of Meteorology weather station; and

c = intercept.

The standard error of the regression fit (SE) is also calculated, which is a measure of the degree of scatter around the line of best fit. The SE is used for the simulation step.

The large customer sector, comprising about 400 customers, does not exhibit temperature sensitivity and so a weather correction is not applied. For this customer sector, weather corrected demand is the same as the actual metered maximum demand.

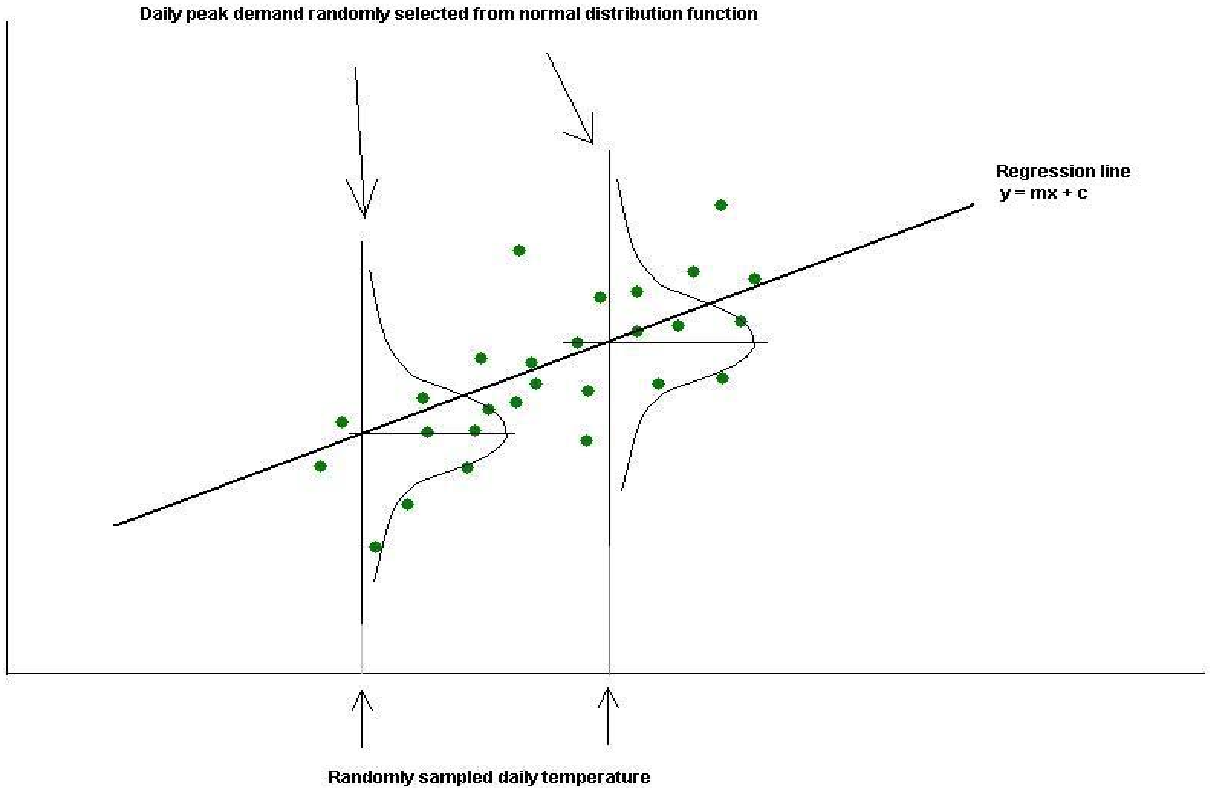
Normalise Data

Simulation of the daily average temperature is done by drawing at random from the 10 years of weather history for the representative weather station. Simulation uses the relevant working day linear fit parameters. The simulated maximum demand is calculated as per the equation below:

D = S x temp + c + N(0,SE)

Where

> *D = simulated daily maximum demand for each customer sector;*
>
> *S = estimated temperature sensitivity derived from above for each customer sector;*
>
> *temp = simulated daily average temperature drawn randomly from 10 years' of historical observations;*
>
> *c = constant of regression; and*
>
> *N(0,SE) = a random number drawn from a normal distribution with mean = 0 and standard deviation = SE. SE as derived from above for each customer sector.*



This simulation process is repeated for each day of each season for a total of 2000 seasons, capturing the maximum for each iteration. The 50 POE maximum demand is the median of the 2000 simulated maximum demands. Any POE level can be determined by taking the appropriate percentile of the 2000 simulated maximums.

4.2.3 Econometric Model for 'Electricity Services'

The econometric model is made up of separate models for residential and non-residential customer sectors. Both the residential and non-residential models relate the change in electricity demand to price and income driver variables specific to that sector.

Electricity services – dependent variable

Similar to the substation level assessment, total system grid and customer supplied electricity is combined to derive the final customer demand. This is because the driver variables of income levels and electricity price are considered to influence total customer usage and not grid supplied electricity only.

Additionally, the impact on demand due to the increasing energy efficiency of appliances and buildings is combined with the total customer electricity use to derive "electricity services". As noted by Frontier Economics in their independent peer review of the Australian Energy Market Operator's National Electricity Forecasts, they suggest '*that AEMO investigate alternative approaches to accounting for energy efficiency savings*', noting that '*as energy efficiency savings continue to grow, it will become increasingly difficult to determine how much of the energy efficiency savings is captured by the econometric model and how much post modelling adjustment needs to be made.*'[17]

In response to this advice, in 2013 Ausgrid assessed the impact of energy efficiency adjustments on the econometric model results and observed that the historic change in energy efficiency improvement was collinear with the historical customer price response. At a time when electricity prices were rising and customer price response had a material impact on forecast demand, it was recognised that without including energy efficiency in the econometric model, there was a risk that historical energy efficiency improvements would be identified as a price response in the model outputs.

For this reason, 'Electricity services' is derived for each customer sector as grid supplied electricity demand plus customer demand supplied by their own rooftop photovoltaic generation plus the impact on demand due to the increasing energy efficiency of appliances and buildings. The demand data are thus adjusted to remove the effect of historical energy efficiency and reflect true underlying demand for the services that are powered by electricity in the absence of the impacts from energy efficiency. Long run elasticities are then derived from the 'electricity services' data.

4.2.4 Determine demand driver elasticities

The historical 'electricity services' for residential customers and the 'electricity services' for non-residential customers are then regressed against the separate independent variables of price and income using a log-log regression model. The econometric model determines the elasticities for both income and price for each of the residential and non-residential customer sectors.

The elasticities were estimated using a historical time series from 2003 to 2016. The price variable was lagged using either a 1 year lag, 2 year lag or without lag. The income variables; rhdi for the residential model and gsp for the non-residential model, were not lagged. The length of the time series was also varied, from 2003-16 to 2011-16. Each model, a combination of lagged or unlagged price, and a given length of time series, was run through a linear regression model using the model specifications described below.

A preferred model for both the residential customer segment and the non-residential customer segment was selected based on a combination of the following statistical tests:

- high correlation coefficient (R^2) for overall model;
- small prob(t) statistic for the price and income variables;
- income elasticity having a positive (+) sign; and
- price elasticity having a negative (-) sign;

<u>Residential Econometric Model</u>

The residential driver variables are the change in real retail residential electricity prices and the change in real average household disposable income.

The equation used to estimate the residential price and income elasticities is as follows:

$$ln\,(D_{res}) = \varepsilon_{rhdi} \times ln(RHDI) + \varepsilon_{res\ price} \times ln(res\ price) + c$$

where

D_{res} = *residential sector electricity services maximum demand per customer;*

ε_{rhdi} = *derived elasticity for RHDI;*

RHDI = real household disposable income;

$\varepsilon_{res\ price}$ = *derived elasticity for residential electricity price;*

res price = residential electricity price; and

[17] *Frontier Economics, 2013, 'Review of AEMO's 2013 National Electricity Forecasts', pg. 3*

c = constant term.

For the residential sector projections, the RHDI and price elasticities are applied as growth factors to the previous year's diversified maximum demand per customer, for residential customers as follows:

$D_t = D_{t-1} \times [1 + \Delta_{rhdi} \times \varepsilon_{rhdi} + \Delta_{resprice} \times \varepsilon_{res\ price}]$

where

D_t = the diversified maximum demand per residential customer in year t;

D_{t-1} = the diversified maximum demand per residential customer in year t-1;

Δ_{rhdi} = annual percent change in RHDI

ε_{rhdi} = derived elasticity for RHDI;

$\Delta_{resprice}$ = annual percent change in residential electricity price; and

$\varepsilon_{res\ price}$ = derived elasticity for residential electricity price.

The total residential sector maximum demand in each year is then the sum product of the diversified maximum demand per residential customer each year and the number of residential customers each year. The methodology used to forecast the number of residential customers is described in Section 5.5.

Non-Residential Econometric Model

The non-residential driver variables are the change in real retail non-residential electricity prices and the change in NSW Gross State Product (GSP).

The equation used to estimate the non-residential price and income elasticities is as follows:

$\ln (D_{non\text{-}res}) = \varepsilon_{gsp} \times \ln(GSP) + \varepsilon_{nr\ price} \times \ln(nr\ price) + c$

where

$D_{non\text{-}res}$ = non-residential sector electricity services maximum demand per customer;

ε_{gsp} = derived elasticity for GSP;

GSP = NSW Gross State Product;

$\varepsilon_{nr\ price}$ = derived elasticity for non-residential electricity price;

nr price = non-residential electricity price; and

c = constant term.

For the non-residential sector projections, the GSP and price elasticities are applied as growth factors to the previous year's diversified maximum demand for all non-residential customers as follows:

$D_t = D_{t-1} \times [1 + \Delta_{gsp} \times \varepsilon_{gsp} + \Delta_{nr\ price} \times \varepsilon_{nr\ price}]$

where

D_t = the non-residential sector electricity services maximum demand in year t;

D_{t-1} = the non-residential sector electricity services maximum demand in year t-1;

Δ_{gsp} = annual percent change in GSP;

ε_{gsp} = derived elasticity for GSP;

$\Delta_{nr\ price}$ = annual percent change in non-residential electricity price; and

$\varepsilon_{nr\ price}$ = derived elasticity for non-residential electricity price.

4.2.5 Apply post model adjustments

Post model adjustments are applied to the system model to adjust for out of trend activity. That is, where a change in customer electricity demand is expected to vary from the historical trend, an adjustment is made to modify the forecast model to account from this change.

Common types of activities which warrant post model adjustments include an increased rate of energy efficiency activity by customers, customer installation of rooftop photovoltaics and battery storage systems, customer take-up of electric vehicles, new residential customers due to population growth, an increased penetration of residential air conditioners and new large customer connections (block loads).

Refer to Section 5 for details on how post model adjustments are applied to the system model.

4.2.6 Spatial allocation

The final system level maximum demand results are then allocated to zone substations using a range of allocation techniques appropriate to the specific element of the system level forecast. The allocation process is as per the table below.

Forecast element	Allocation method
Income / GSP	The maximum demand impacts are allocated separately for residential and non-residential customers and then allocated spatially using the proportion of residential and non-residential demand for each zone substation.
Price	The maximum demand impacts are allocated separately for residential and non-residential customers and then allocated spatially using the proportion of residential and non-residential demand for each zone substation.
Energy Efficiency	The maximum demand impacts are allocated separately for residential and non-residential customers and then allocated spatially using the proportion of residential and non-residential demand for each zone substation.
Rooftop PV	Spatial allocation is based upon the current penetration of rooftop photovoltaics by zone substation.
Battery Storage	Spatial allocation is based upon the current penetration of rooftop photovoltaics by zone substation.
Electric Vehicles	Allocation is based on a glide path from the existing allocation of EVs based on EV registrations from the NSW RMS data towards a long-run allocation based on a gross LGA income measure (average household income x number of households except for very low income households) taken from ABS data.
Population	Spatial allocation based upon the NSW Department of Planning data at the Local Government area level, adjusted for substation service boundaries.
Block loads	Specific to each zone substation as per connection requirements.

4.3 Blended Forecast

The electricity demand forecasts consist of integrating the two forecast components. The baseline trend for each zone and sub-transmission substation, adjusted for embedded generation, block loads and load transfers is used for the first two years of the forecast for each zone and sub-transmission substation. The system level econometric model corrected for post-model adjustments and allocated to each zone and sub-transmission substation is used for the first years 5 and beyond of the forecast for each zone and sub-transmission substation. A transition period applies to years 3 and 4 of the forecast where the short term forecast trend is blended with the econometric model forecast, using a linear ramping.

5 Post Model Adjustments

Post model adjustments are applied to the system model to adjust for out of trend activity. That is, where a change in customer electricity demand is expected to vary from the historical trend, an adjustment should be made to modify the forecast model to account for this change.

Common types of activities which warrant post model adjustments include an increased rate of energy efficiency activity by customers, customer installation of rooftop photovoltaics and battery storage systems, customer take-up of electric vehicles, new residential customers due to population growth, an increased penetration of residential air conditioners and new large customer connections (block loads).

Each post model adjustment is applied in a manner that considers whether that element was adjusted for in determining the historical trend. This determines whether the post model adjustment for that element is applied in full or as an out-of-trend adjustment. Maximum demand impacts are firstly calculated at the whole of network level and then spatially disaggregated to individual zone substations covered in more detail in each following sub-sections.

5.1 Energy Efficiency

Energy efficiency activity is largely policy driven, and a high level assessment indicated there was no significant policy change for the three main energy efficiency programs between 2016 and 2017. For the 2017 forecast the same historical and forecast energy efficiency adjustments from the 2016 forecast were used with a different start year (2017) used to calculate the out of trend post modelling adjustments.

The historical and forecast demand impacts from energy efficiency programs are obtained from external consultancy advice with supplementary analysis and review from Ausgrid. Further details for each major energy efficiency program are below.

5.1.1 Equipment Energy Efficiency (E3) Program

The Equipment Energy Efficiency (E3) program includes around 50 distinct different programs including the implementation of various minimum energy performance standards and energy labelling initiatives across many residential and commercial appliances. Prior to the 2016 forecast, Ausgrid engaged George Wilkenfeld[18] to review and produce a revised E3 national energy savings projection that incorporated a review and critique of some major appliance energy efficiency programs including televisions, lighting, refrigerators, residential air conditioners as well as commercial cooling and refrigeration. As part of this work the allocation of energy savings to NSW and the Ausgrid network area was also reviewed.

The maximum demand contribution for residential and non-residential customers is derived from the energy savings using an overall system load factor from the seasonal daily load factor on the day of system peak.

For the 2017 forecast the same historic and forecast E3 maximum demand impact projections were used.

5.1.2 NSW Energy Saving Scheme (ESS) and Greenhouse Gas Abatement Scheme

In 2015, a revision of the impacts of the NSW ESS and GGAS schemes was undertaken internally using forecast activity data supplied by the NSW Office of Environment and Heritage as well as historic certificate data from the ESS web portal. This involved a more detailed analysis of the proposed scheme activities and applying specific load factor adjustments to convert energy savings to maximum demand as well as applying factors for free-ridership[19],[20] to correct for activity that would have occurred otherwise. In 2016, the historic and forecast impacts of the NSW ESS and GGAS was reviewed again to account for actual ESS activity and the official extension of the NSW ESS until 2025.

For the 2017 forecast the same historic and forecast NSW ESS maximum demand impact projections were used.

[18] George Wilkenfeld and Associates, Review of E3 Program Impact Projections for post modelling adjustments to the NSW DNSPs long-term energy forecasts, 2016
[19] The Cadmus Group Inc, Home Energy Services Net-to-Gross Evaluation: Part of the Massachusetts Residential Retrofit and Low Income Program Area Evaluation (June 2012)
[20] Navigant, Custom Free Ridership and Participant Spillover Jurisdictional Review (May, 2013)

5.1.3 Building Code of Australia (BCA), building shell improvements.

No significant review of the energy efficiency impact projections for the Building Code of Australia programs has been undertaken since the original consultancy by Energy Efficient Strategies[21] on post-modelling adjustments was conducted for the 2014 forecast.

5.1.4 Historical trend adjustments and spatial allocation

The historical effect of energy efficiency programs is taken into account in the "electricity services" approach in the econometric model discussed earlier. The historical maximum demand impacts due to energy efficiency are considered part of the historical baseline trend for each zone substation and no energy efficiency adjustments are made to derive the underlying trend. Future energy efficiency adjustments therefore represent the impact of energy efficiency programs that is additional to the baseline trend and therefore an out of trend adjustment is made using forecast energy efficiency impacts.

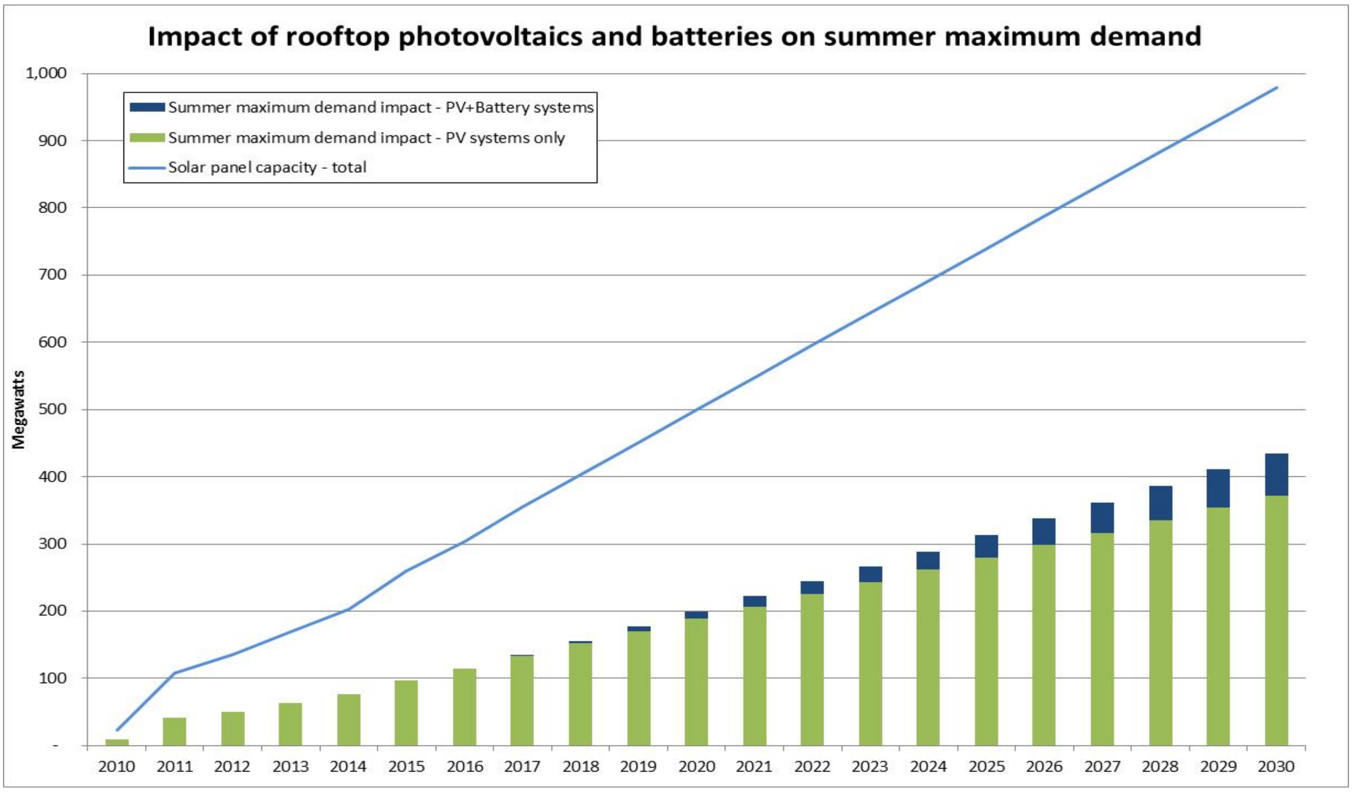
The maximum demand impacts for energy efficiency programs are allocated separately for residential and non-residential customers and then allocated spatially using the proportion of residential and non-residential demand for each zone substation.

5.2 Rooftop Photovoltaic (PV) Systems

The maximum demand impact from rooftop photovoltaic systems on homes and businesses in our network area is determined for each zone substation and our methodology separates rooftop solar systems without a battery system from combined PV and battery storage systems since the maximum demand impacts between the two differ markedly. This section refers to rooftop photovoltaic systems without batteries which are the majority of installations at this point in time.

The figures for Ausgrid's Rooftop PV forecast are solely for behind the meter (principally rooftop) solar installations. Large scale solar and wind farms are typically connected at 33kV or above and are considered as part of the assessment of block loads. In Ausgrid's 2017 forecast, the block loads assessment includes the connection of 135 MW of renewable generators with demand on relevant assets adjusted accordingly per the block loads post model adjustment process (refer Section 5.7).

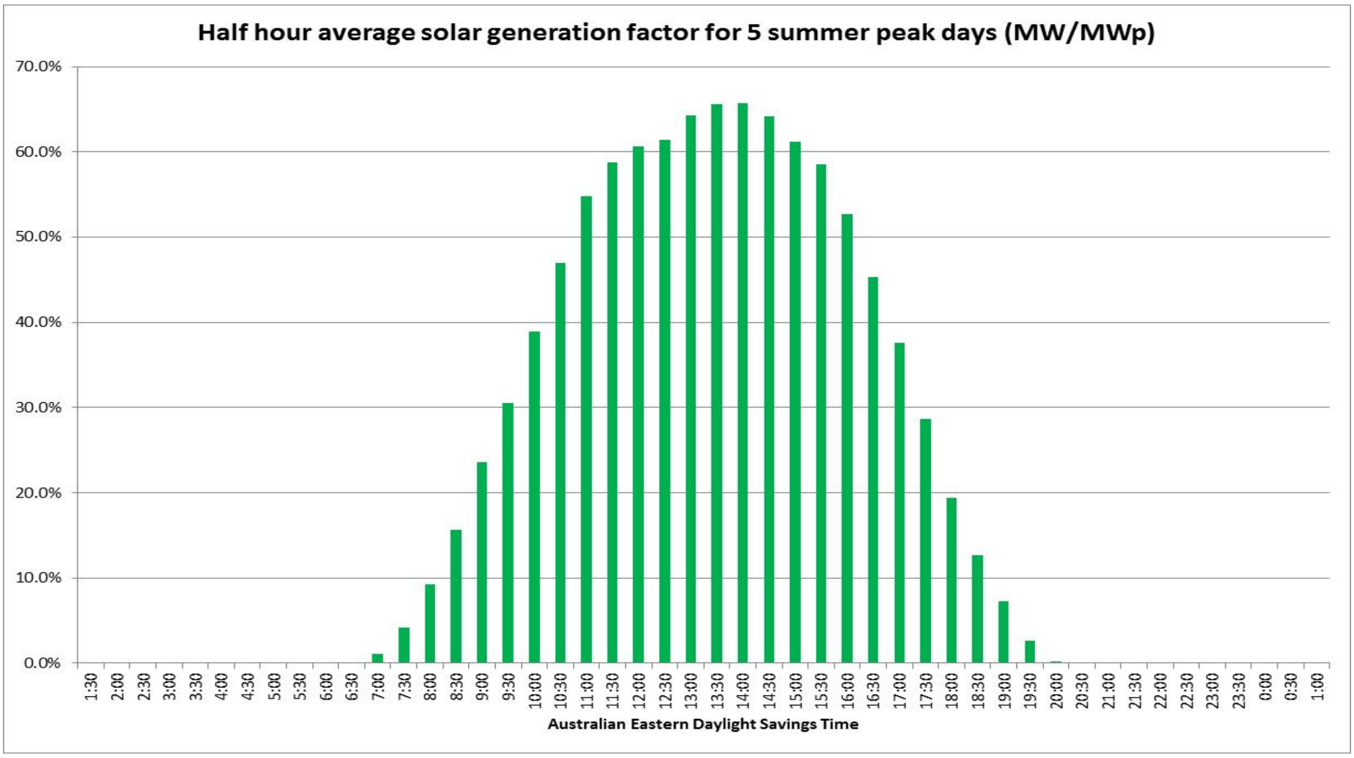
The following graph shows the estimated impact of solar photovoltaic systems in reducing maximum summer demand at the Ausgrid system level, which peaks in summer generally around 16:30 to 17:00 AEDST.



[21] *Energy Efficiency Strategies, IT Power, Beletich Associates, Review of post modelling adjustments to the NSW DNSPs long-term energy forecasts, A study for Ausgrid, Endeavour Energy and Essential Energy (September, 2013)*

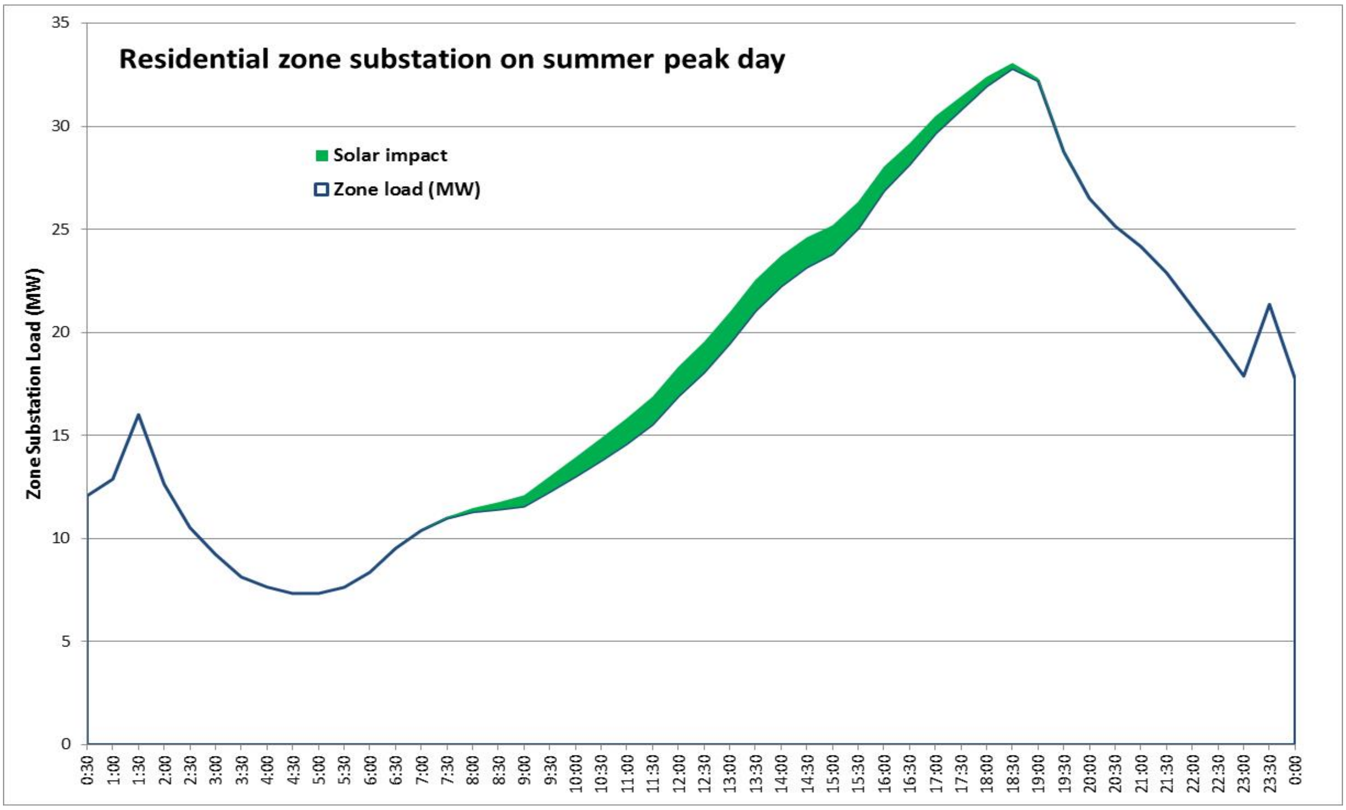
5.2.1 Historical trend adjustments and spatial allocation

The post model adjustments for PV systems are applied in summer only. Solar generation curves are based on measured solar system performance of actual systems and derived from analysis of around 26,700 separately (gross) metered solar customers, under as-built conditions. Peak demand savings are calculated from the solar generation curve shown below and the individual time of peak of each zone substation. Note that peak solar output per 1kW of installed PV capacity is around 0.67 kW in the middle of the day but reduces to 0.2 kW by 5:30-6:00pm in the afternoon (AEDST).



PV adjustments are applied historically prior to deriving the underlying trend, with the adjustment based upon the total installed PV capacity connected to the zone substation, the individual time of peak of each substation in each historical year and the above PV generation curve.

For example, the below graph shows the load profile and impact of rooftop photovoltaics for a Sydney zone substation on the peak day in summer 2016-17. The time of maximum demand for this zone is at 6:30pm when the impact of solar is significantly reduced.



Since rooftop photovoltaic systems are adjusted for in deriving the historical trend, they are applied as a full adjustment in all the forecast years. Spatial allocation of the maximum demand impact of photovoltaic systems is based upon the current penetration of rooftop photovoltaics by zone substation.

5.3 Battery Storage Systems

One of the key drivers for customers to install a battery storage system is for storing excess solar energy that would otherwise be exported to the grid at a lower Feed-In-Tariff value. Energy is stored for use at other times of the day when the price of drawing electricity from the grid is higher, providing a bill benefit for the customer. If the customer is on a time of use pricing plan, another potential driver is the value gained by charging a battery during off peak times and discharging during peak times,

5.3.1 Residential battery model

Ausgrid developed a residential battery storage model for the 2016 forecast to estimate the payback periods for investing in a household battery system to inform take up rates. In addition, this model was used to estimate the maximum demand impacts for typical operation of a household battery system when paired with a photovoltaic system. The battery model was updated in 2017 with latest information including battery prices, battery sizes and electricity prices.

The 2017 residential battery model uses the actual half-hour load profiles from over 700 customers over the 2015-16 year in combination with separately metered half-hour solar system information for those same households. These actual load and solar generation profiles for these customers are used in combination with a battery operation model that charges and discharges the battery in each half hour to maximise electricity bill savings on a time of use tariff. Various battery operation algorithms were first tested and it was found the following battery operation algorithm of charging and discharging the battery was best at maximising the customer bill savings on average over a year:

- On weekdays, the battery is charged from the solar system during the day and is used during the peak period (2pm to 8pm) on working weekdays. Between 7am and 10am the battery is charged on excess solar energy, and during the middle of the day between 10am to 2pm the battery is charged directly from the solar system in order to maximise the potential for the battery being full prior to the peak period starting at 2pm.

- On weekends, when there is no peak period, the solar and battery system is charged and discharged during the day in order to minimise the excess solar energy exported to the grid and minimise import from the grid.

The 2017 battery model uses a 4 kW photovoltaic system paired with a Tesla Powerwall 2 (13 kWh usable storage capacity) as an indicative PV and battery combination system and models the import from and export to the grid in each half hour. The relevant 2017-18 retail electricity prices for each tariff rate from the major retailer in Ausgrid's network area was used in the modelling to estimate annual electricity bill savings (including the retailer feed-in tariff rate for net exported electricity). The following table shows the average bill savings results.

Annual Consumption Bands (kWh pa)	Sample size	Annual electricity bill savings ($ per year)		
		4kW Solar only	Additional battery	Solar/ Battery package
2,000 to 3,000	71	$478	$224	$702
3,000 to 4,000	79	$520	$281	$802
4,000 to 5,000	98	$576	$355	$931
5,000 to 6,000	90	$606	$392	$998
6,000 to 7,000	92	$644	$402	$1,046
7,000 to 8,000	84	$676	$420	$1,096
8,000 to 9,000	58	$715	$460	$1,175
9,000 to 10,000	47	$734	$458	$1,192
10,000 to 12,000	51	$761	$496	$1,257
12,000 to 15,000	48	$826	$478	$1,304

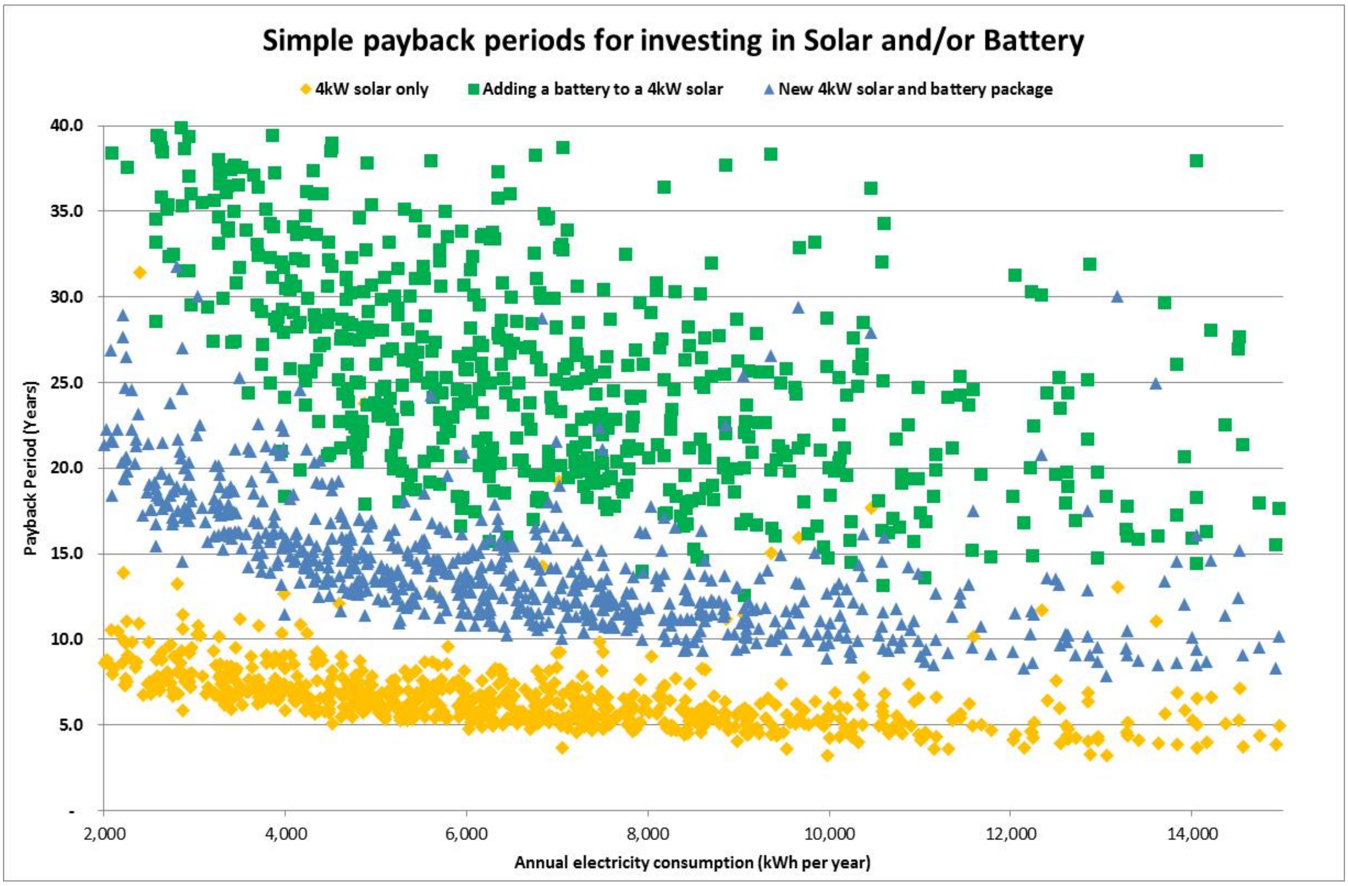
In order to estimate indicative payback periods a simple payback period calculation was performed using the annual electricity bill savings above and indicative prices of $4,000 for a 4 kW solar system (after STC rebates) and $10,000 Tesla Powerwall 2. The below table shows the payback period results:

Annual Consumption Bands (kWh pa)	Sample size	Simple payback period (years)		
		4kW Solar only	Additional battery	Solar/ Battery package
2,000 to 3,000	71	8.4	44.7	19.9
3,000 to 4,000	79	7.7	35.5	17.5
4,000 to 5,000	98	6.9	28.2	15.0
5,000 to 6,000	90	6.6	25.5	14.0
6,000 to 7,000	92	6.2	24.9	13.4
7,000 to 8,000	84	5.9	23.8	12.8
8,000 to 9,000	58	5.6	21.7	11.9
9,000 to 10,000	47	5.5	21.8	11.7
10,000 to 12,000	51	5.3	20.2	11.2
12,000 to 15,000	48	4.8	21.0	10.7

The results above show that a typical medium to large electricity consuming residential customer (5,000 to 15,000 kWh per year) the payback period for investing in a 4 kW photovoltaic system on its own is about 5 to 7 years. The incremental investment in a battery system if a customer already had a 4 kW solar system is 20 to 25 years. If a customer decides to invest in a combined 4 kW solar and battery system the payback period would be between 11 to 14 years. We estimate that fully installed battery system prices would need to reduce by another 75% from around $700 per kWh (Tesla Powerwall 2) to $200 per kWh to offer a similar investment payback value to a solar systems on their own (on average).

Note that income earned by battery owners for provision of market support or the impacts from the introduction of more cost reflective pricing have not been modelled at this stage. Both of these impacts will be considered as part of our forecast improvement plans for the 2018 forecast.

There is a big variation in annual savings and payback periods depending on individual customer usage behaviour across the daily profile and the year, even with the same solar or battery system size. The following chart shows a scatter plot of the payback period across the annual consumption range of the customers in the above table.



5.3.2 Uptake of battery storage systems

For the 2017 forecast, actual battery application data has been used to estimate the current number of batteries installed on the network as well as the initial battery installation take up rate. In total there were around 800 to 1000 recorded battery connection applications (as at June 2017). These battery applications have mostly occurred since September 2016, and the average rate over this time is about 100 per month, or about 1,000 to 1,200 a year. Anecdotally and through discussions with installers and suppliers of batteries there may also be additional batteries on the network where the paperwork to Ausgrid has not been submitted and for which we have no records.

For the start point assumption for battery storage for the 2017 forecast we have assumed a total of 7 MWh based on a total of 1,000 residential batteries to have been installed by the end of FY17 with an average storage capacity of 7 kWh each. Results from a customer survey of 86 early adopters of battery systems[22] showed that there was a range of different battery storage system sizes ranging from small systems of only a few kWh (e.g. Enphase) to larger systems of around 7 to 8 kWh (e.g. Tesla Powerwall 1). At the time of finalising the 2017 forecast, larger battery products such as Tesla Powerwall 2 had not yet been released.

For the medium 50 POE scenario we have assumed a continuing rate of installs of 1,000 per year in FY18, 1,500 in FY19, and 2,000 per year on average between FY20 and FY24 (the five years of the regulatory period). From

[22] *Ausgrid, Household solar and battery survey (April 2017) –https://www.ausgrid.com.au/Common/Industry/Demand-management/Energy-use-research-and-reports/research-and-trials.aspx*

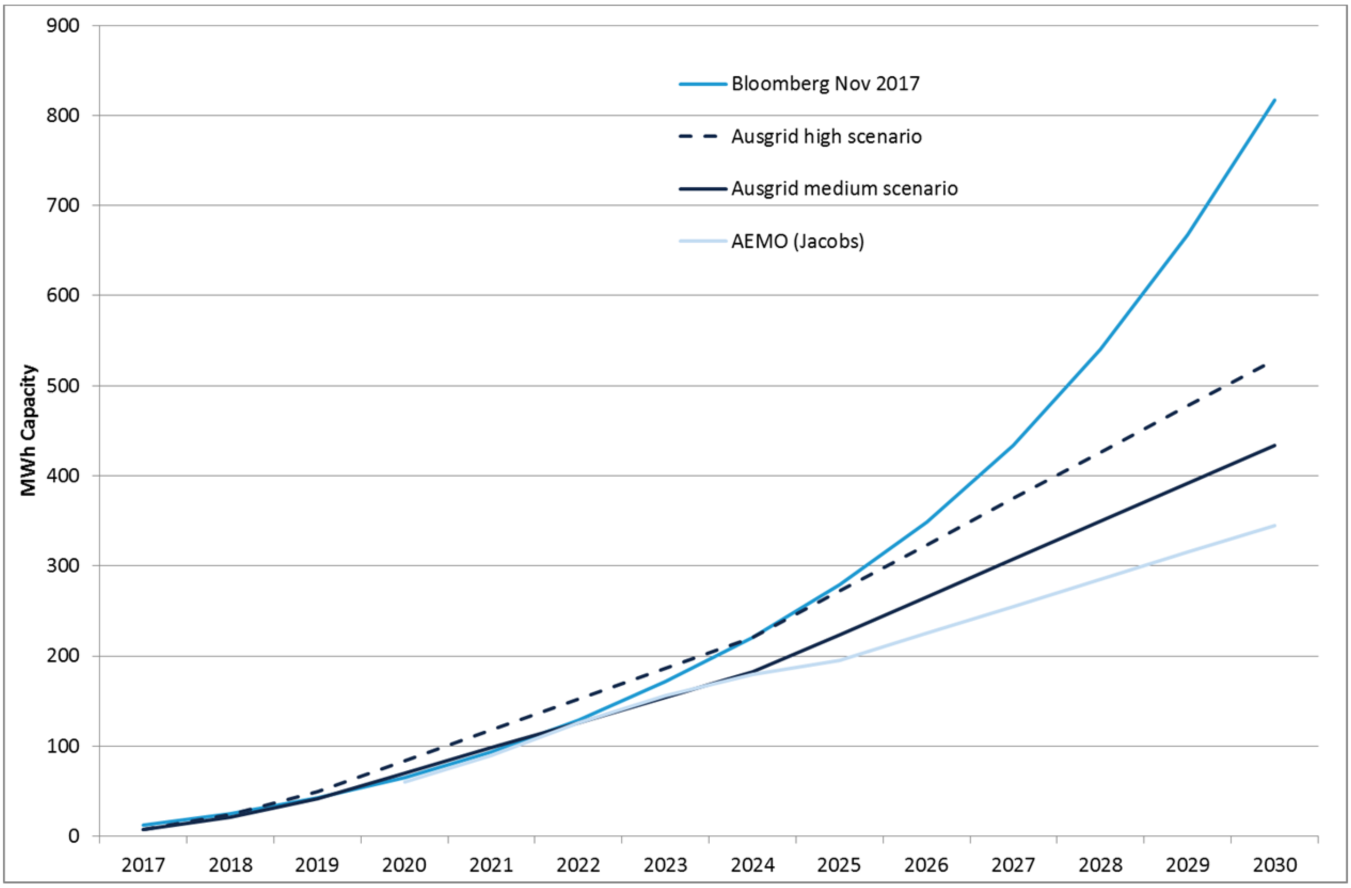
FY2025, 3,000 installs a year have been assumed. This compares to a relatively steady annual take up rate of solar installation of about 8,000 to 10,000 per year which has been experienced by Ausgrid over the last couple of years. Based on the above assumptions, we are projecting around 13,500 residential customers with battery storage by 2024 and around 31,500 systems by 2030. This means that around 20 to 25% of new solar installations across the network during the 2019-24 regulatory period would be a solar and battery combined system increasing to 30-40% of new solar being solar/battery packages from 2025 onwards.

At this time, no significant commercial battery storage is assumed in our modelling given that the main drivers for installing batteries are not as strong for most businesses. Most business customers with solar have a better match between business hours and solar generation hours leading to less excess solar energy being exported to the grid at a low value. In addition, the differential between off peak and peak prices of energy on a time of use tariff is less for business customers than residential customers. Businesses also tend to apply a stricter financial criterion on investments as a battery system investment would need to compete for capital and opportunity cost considerations.

Recent results from Ausgrid's Solar, Battery and Energy Efficiency survey of businesses indicates that businesses use payback periods in the range 4 to 6 years or when considering energy efficiency investments[23]. Furthermore, analysis of around 800 of Ausgrid's initial battery applications between Sep 2016 and Apr 2017 indicated that only 10 customers were on a business tariff (1% of the total), all of whom were small businesses. No medium or large business customer applications have yet to be received except for known trial or innovation projects.

In the latest AEMO projections for 2017 around 15% of the battery storage capacity in NSW and the ACT was assumed to come from the commercial sector[24] and AEMO's forecast starting point for storage capacity in NSW+ACT in 2017 was 101 MWh for their neutral scenario. The Ausgrid forecast has a forecast starting point of 7 MWh of battery storage capacity in 2017 based on actual customer battery application data and an estimate of the average size of battery systems derived from analysis of the battery applications.

The resultant storage capacity forecast is shown in the chart below with comparison forecasts shown from AEMO and the most recent Bloomberg New Energy Finance battery forecast published in Nov 2017. Note that the projected storage capacity included in Ausgrid's 2017 forecast is very similar to that from both AEMO and Bloomberg to 2024 but varies beyond then. This is principally due to the assumed exponential growth forecast by Bloomberg post 2025.



[23] Ausgrid, Business customer survey results: Solar, batteries and energy efficiency (December 2017) – https://www.ausgrid.com.au/Common/Industry/Demand-management/Energy-use-research-and-reports/research-and-trials.aspx

[24] Jacobs, Projections of uptake of small-scale systems, Australian Energy Market Operator (9 June 2017), page 32

Ausgrid's battery take up forecast assumptions will be reviewed annually using the most up to date information. For the 2018 forecast, impacts on customer returns from income earned by battery owners for provision of market support and the impacts from the introduction of more cost reflective pricing will be introduced.

5.3.3 Maximum demand impact of battery systems

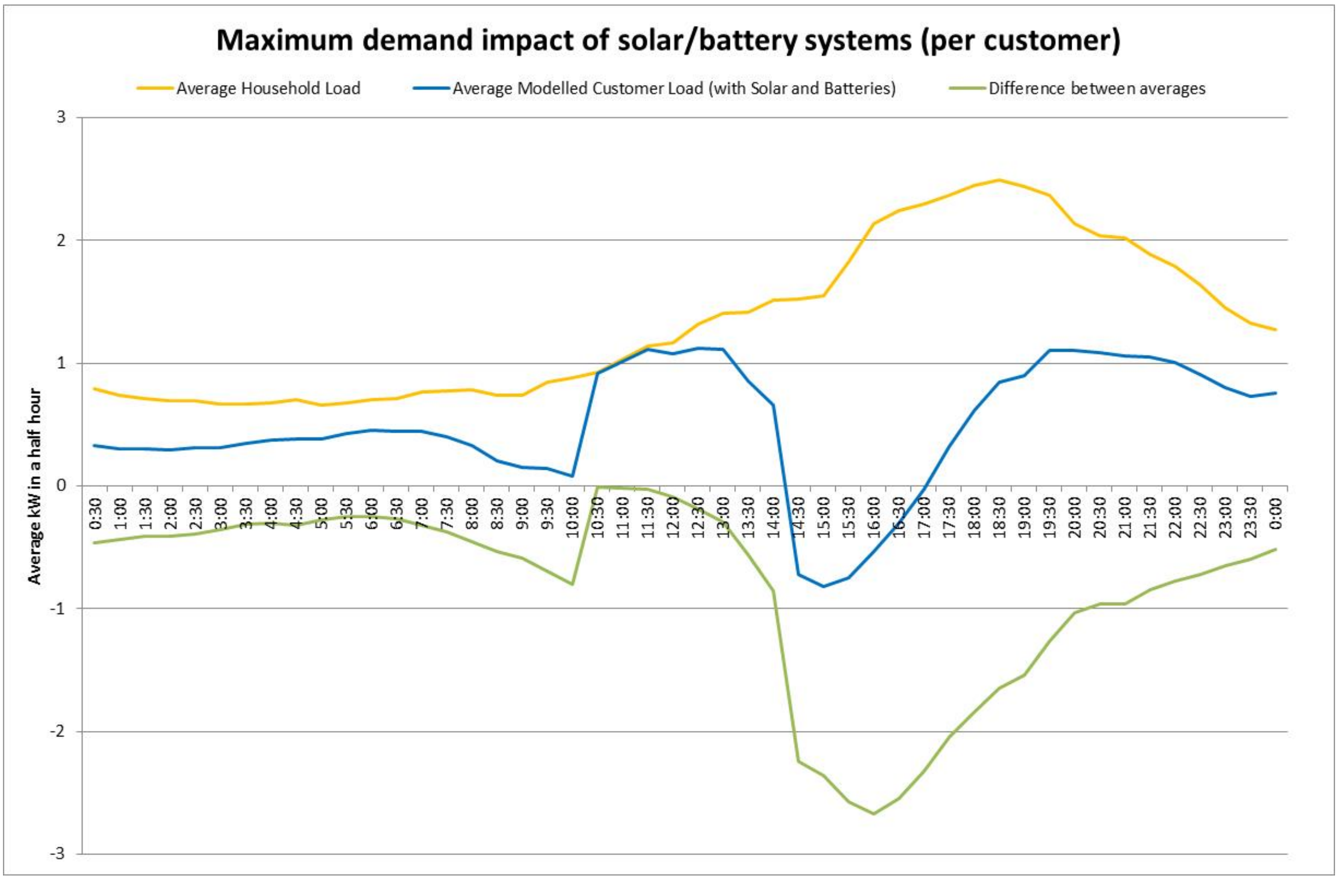
As the battery model calculates the modified customer profile for each half hour over a year it is possible to estimate the effect of batteries on reducing maximum demand on peak demand days.

The forecast impact at peak for future systems has been based upon the combination of a 4 kW solar power and 14 kWh battery system.

A subset of customers from the sample of 700 customers was chosen to derive an average maximum demand reduction for customers who would typically install a solar/battery system. The average solar customer in our network consumes between 7-8 MWh per year (household consumption only), so a sample of 68 customers in this bracket of annual consumption was chosen to analyse in more detail on two summer peak demand days during the 2015-16 summer (20 Nov 2015 and 25 Feb 2016).

The graph below shows the average household load profile of the 68 customers on the two days (orange line), and compares the modelled average load profile for the two days for the same 68 customers with a 4kW solar system plus Tesla Powerwall 2 battery (blue line).

The difference between the average household load profile and the average of the same customers with a modelled solar and battery system (green line) is the maximum demand savings which varies by the time of day. As can be seen, there is an approximate 2.5 kW load reduction at 2pm-5pm which then decreases to about 1kW load reduction by 8pm. This is mainly a function of the battery operation algorithm which attempts to optimise bill savings for the customer by storing solar energy in the battery to be used during peak times (2pm to 8pm).



5.3.4 Historical trend adjustments and spatial allocation

The maximum demand impacts from battery storage systems are not adjusted for in deriving the historical trends; however, as at June 2017 there were only around 1000 battery storage systems on the Ausgrid network. This is considered negligible and battery storage post model adjustments are applied as full adjustments in the forecast years.

Spatial allocation of the maximum demand impact of photovoltaic systems paired with a battery is based upon the current penetration of rooftop photovoltaics by zone substation.

5.4 Electric vehicles (EVs)

The post model adjustment for electric vehicles was introduced into our 2017 forecast and models the maximum demand impact from both battery electric vehicles and plug-in hybrid electric vehicles. The term electric vehicle in this methodology document refers to both.

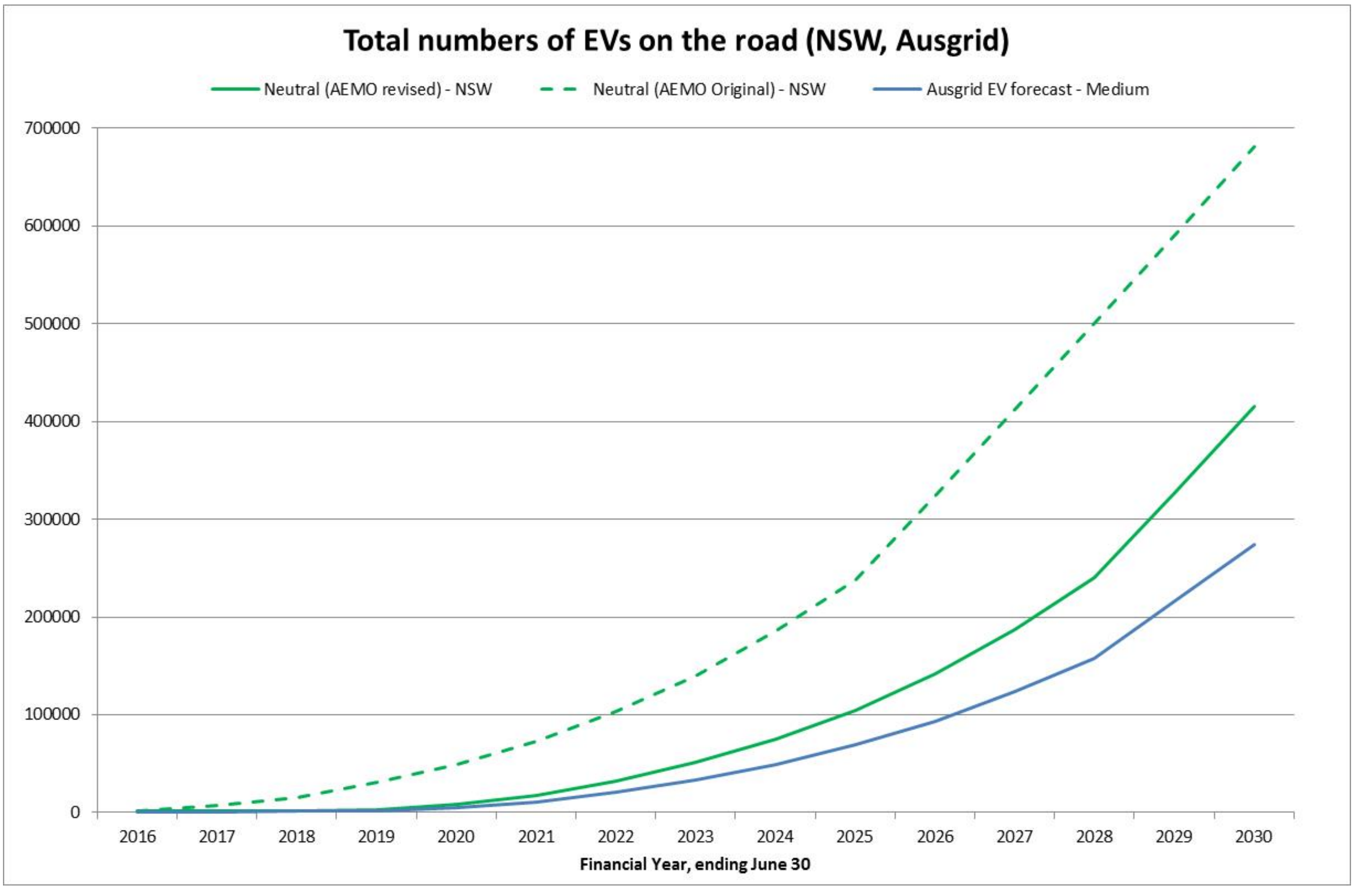
5.4.1 Uptake of electric vehicles

The number of EVs forecast for the Ausgrid network area has been derived from the AEMO Insights report[25] for Electric Vehicles with some adjustments based on NSW electric vehicle registration data to account for the slower than predicted take up of electric vehicles in NSW and allocation of the NSW forecast to the Ausgrid network area. The adjustments include:

- Projections for EV sales in NSW was delayed by 2 years as supported by NSW EV registration data;
- Two-thirds of EV sales in NSW occur in Ausgrid's network area as supported by NSW EV registration data obtained by Local Government Area;

The original AEMO neutral forecast scenario estimates that electric vehicle sales in NSW +ACT rises steadily from FY2018-19 to reach 14% of new vehicle sales by 2027-28. This increase in EV sales over the next ten years is projected to be driven by an increasing number of EV models being introduced on the Australian market which results in around 185,000 EVs on the road in NSW+ACT by 2024 and 680,000 by 2030.

The Ausgrid forecast delays this NSW+ACT AEMO forecast by 2-years and assumes that 66% of the NSW total would be garaged in Ausgrid's network area, resulting in a prediction of around 50,000 vehicles in Ausgrid's area by 2024 and 275,000 by 2030.



There is great uncertainty around the timing and scale of electric vehicle take up in Australia, and these assumptions will be reviewed and updated annually based on the latest available information.

5.4.2 Maximum demand impact of electric vehicles

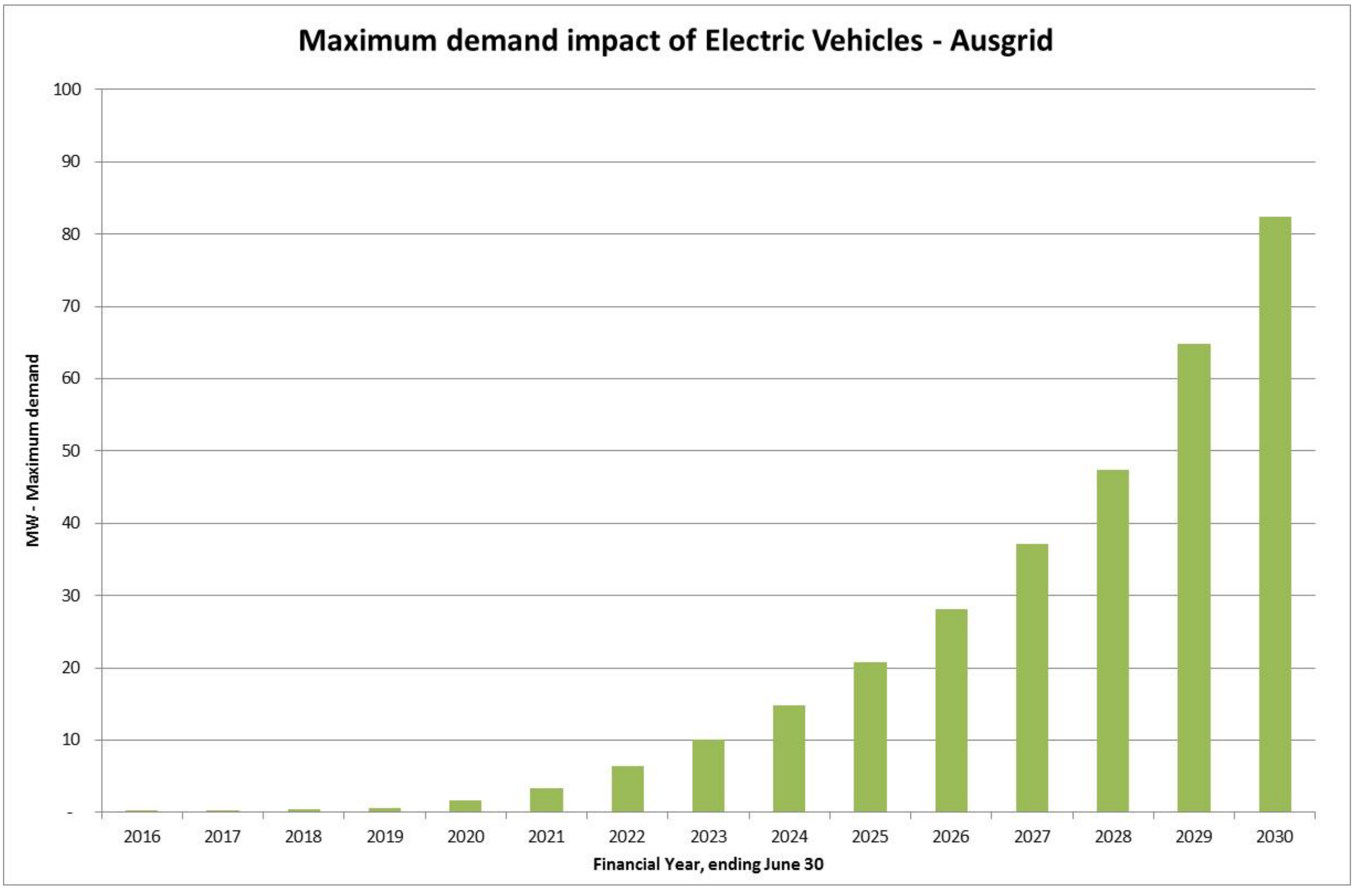
For each EV in Ausgrid's network we have assumed that the maximum demand contribution is a diversified load of 0.30 kW per vehicle. This differs from the AEMO Insights 2016 report which assumes that 100% of EV charging is conducted outside the peak period in NSW and therefore there would be zero peak impact.

[25] *AEMO and Energeia, AEMO Insights – Electric Vehicles (August 2016)*

This is supported by Smart Grid Smart City[26] trial results of 20 Mitsubishi iMIEV vehicles which indicated that the diversified electrical demand on a working weekday was between 0.3 kW to 0.4 kW during the peak periods (2pm to 8pm). This trial tested home charging behaviour with a flat and time of use pricing signal, as well as charging behaviour for corporate fleet vehicles.

Furthermore, results from the larger scale USA study of 8300 electric vehicles indicate that there is also a similar level of diversified electricity demand during the 2pm to 8pm time of day of between 0.2 kW to 0.4 kW per vehicle[27]. In particular, of those regions in the USA study with a strong overnight charging profile such as California (e.g. San Diego, San Francisco, Los Angeles), there is a non-zero electricity demand for electric vehicle charging during the weekday peak period due to vehicles charging away from home such as charging at work or public charging stations. For the three California trial areas (2800 vehicles) in the USA study the amount of home charging ranged between 70% to 90% depending on the away from home charging infrastructure availability (work or public).

The Ausgrid forecast estimates a maximum demand impact of +15 MW by 2024 and +82 MW by 2030 on the Ausgrid system peak demand due to the charging of electric vehicles which is shown in the following graph.



5.4.3 Historical trend adjustments and spatial allocation

The maximum demand impacts from electric vehicles are not adjusted for in deriving the historical trends, however, at present there are only around 800 electric vehicles estimated to be in our network area. This is considered negligible and electric vehicle post model adjustments are applied as full adjustments in the forecast years.

Allocation of electric vehicles is based on a glide path from the existing allocation of EVs based on EV registrations from the NSW RMS data towards a long-run allocation based on a gross LGA income measure (average household income x number of households except for very low income households) taken from ABS data.

5.5 Number of Households (Population)

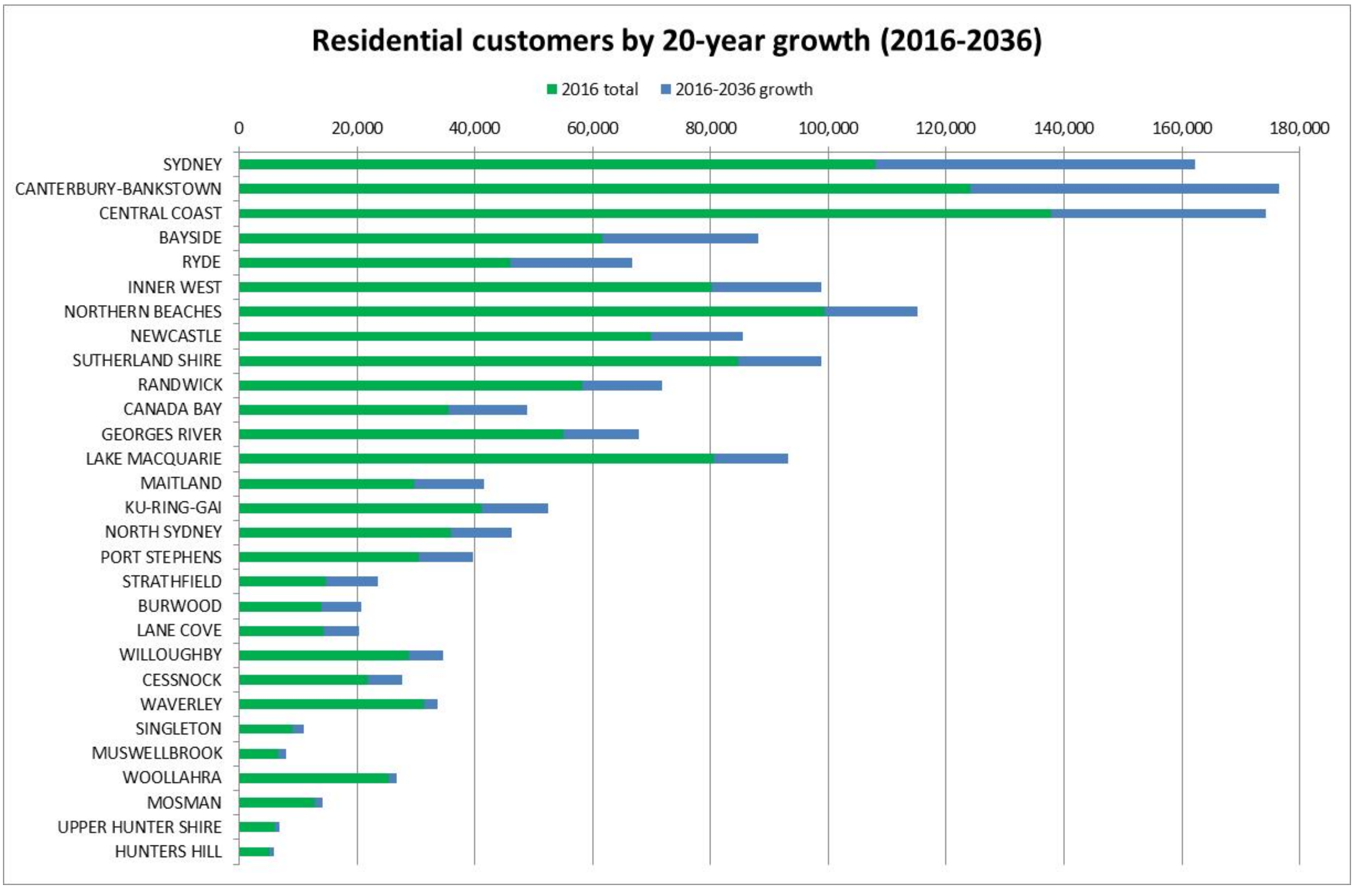
The residential customer growth adjustment models the maximum demand impact of new residential customers connecting to the network as the population increases over time. The source data for the household growth projections are taken from two sources:

[26] *Ausgrid, Smart Grid Smart City: Electric Vehicle Technical Compendium,2014*
[27] *Idaho National Laboratory, EV Project Electric Vehicle Charging Infrastructure Report,2013*

- The NSW Housing Industry Association (HIA) for dwelling starts by financial year (Mar 2017 version) used for the short term population projections; and

- The NSW Department of Planning's (DoP) "A Plan for Growing Sydney" household growth figures (Aug 2016 version) used for the longer term population projection.

The NSW DoP household growth figures, provided by local government area (LGA) and by 5 year tranches for the periods 2016 to 2036 are extracted from the dataset for Ausgrid LGAs only. The below chart shows the total customer growth rate from the DoP figures for LGAs in the Ausgrid network area for the period 2016 to 2036.



We consider dwelling starts from HIA as more indicative of the likely level of household growth in the short term with the DoP figures being more indicative for the longer term.

5.5.1 Historical trend adjustments and spatial allocation

The NSW HIA figures are applied as follows to obtain the short term customer growth projection:

- The NSW HIA figures, provided at a state-wide level, are converted into an annual percent change figure;

- The percent change figure is used to calculate the annual growth in residential customers based on the actual change in residential customer numbers from FY2016. This HIA percent change method is used up to FY2019.

The NSW DoP figures are applied as follows to obtain the longer term customer growth projection:

- In the period between 2019 and 2031, the annual change is based on the average difference between the projection of Ausgrid residential customers at end of the NSW HIA growth period (in 2019) and the NSW DoP's estimate of total households for Ausgrid LGAs in 2031.

- The change in residential customers for Ausgrid's network is assumed to follow the NSW DoP figures from 2031 onwards.

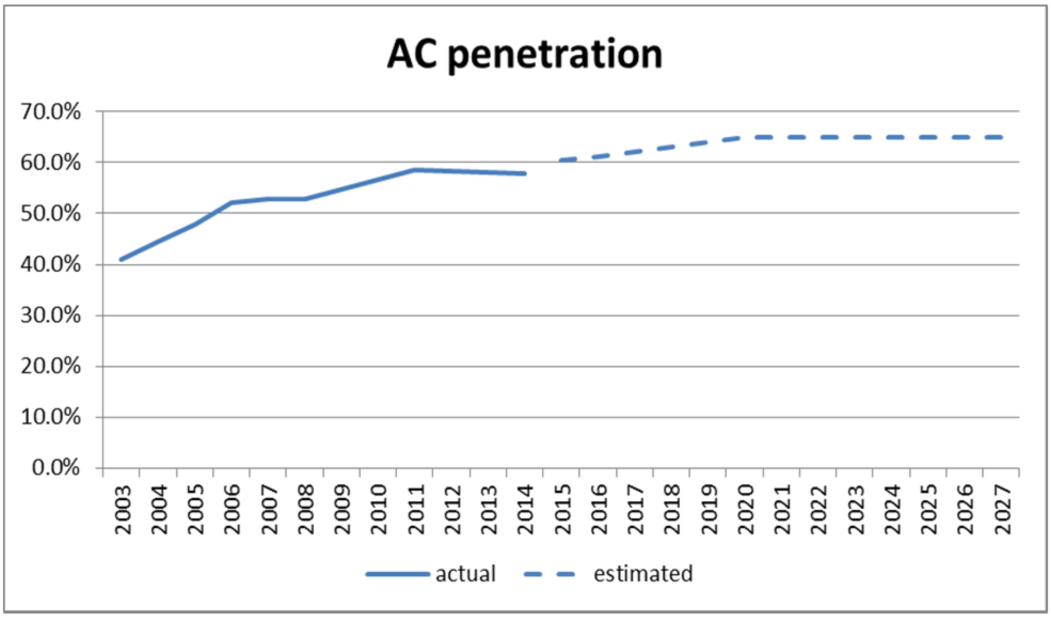
Spatial allocation of maximum demand impacts due to household growth is based upon the NSW Department of Planning data at the Local Government area level, adjusted for the substation service boundaries.

5.6 Residential Air-conditioners

The air-conditioning penetration adjustment models the impact of the growth air-conditioners in the residential customer segment using data from the base year of 2015. A linear fit is applied to the actual penetration between 2003 and 2014, which is projected forward resulting in an annual increase of around +1%. Saturation of 65% is applied which occurs in 2021.

The residential component impacts from forecast changes in air conditioner penetration rate are based upon an assessment of the trend in the data from the Australian Bureau of Statistics (ABS). For the 2017 forecast, the forecast change in the air conditioner penetration rate are minor since presently, air conditioning penetration rates are close to the 65% saturation level given by the ABS.

The impact of air-conditioning penetration which models the growth of air-conditioning penetration from the base year of 2015. The air-conditioning penetration impacts have been netted out of the population adjustment.



5.7 Block Loads

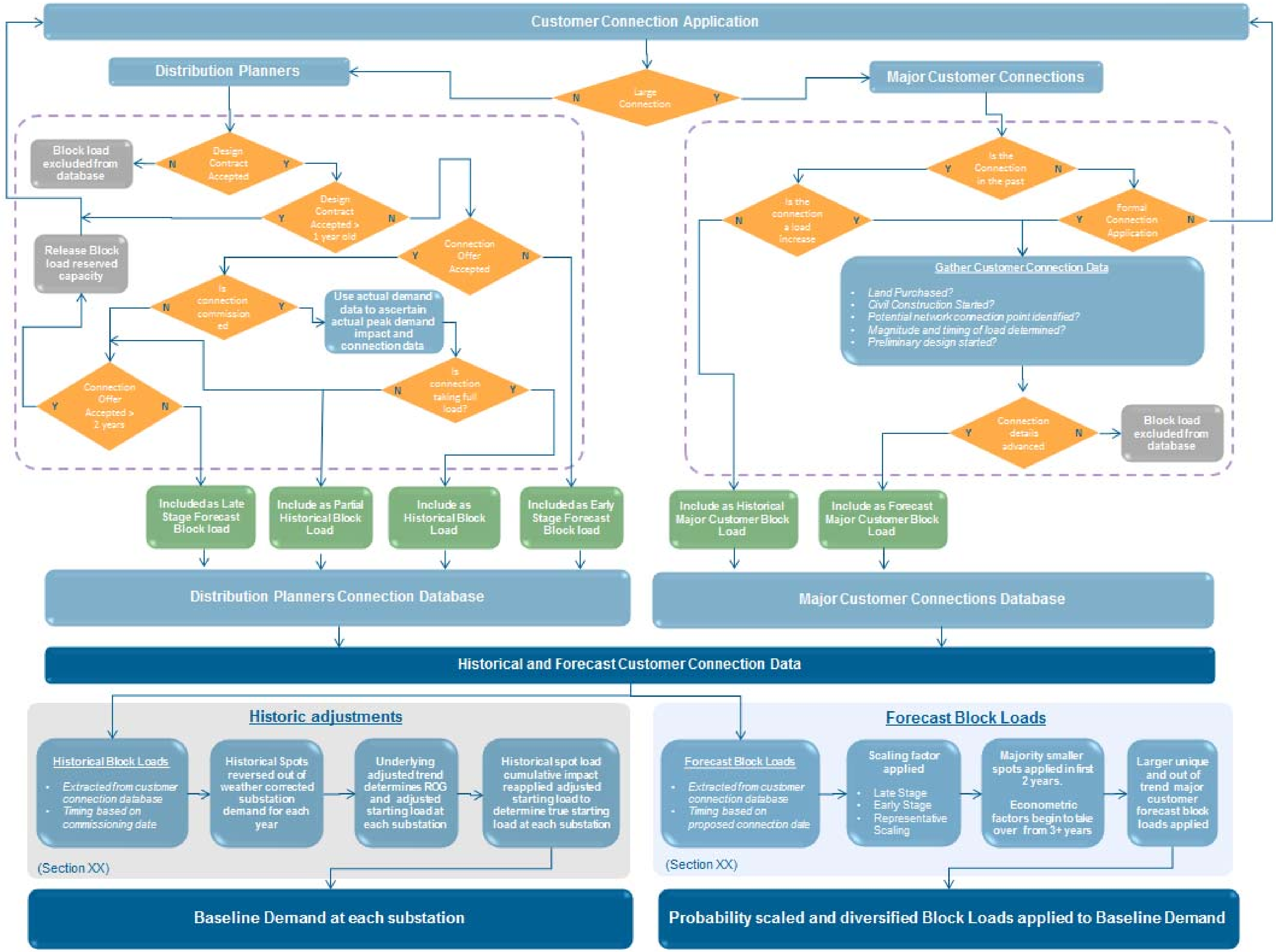
As with all post model adjustments, determining the scale of the adjustment is challenging. Traditional approaches have included the use of thresholds to define a narrow selection of block loads for detailed consideration and assessment, or the application of weighted probabilities on groups of block loads to account for the level of uncertainty of a customer connection proceeding and the scale of the eventual maximum demand. Each of these approaches can result in significant variation from actual resultant demand in some circumstances.

To reduce the risk associated with the application of estimated probabilities or thresholds, Ausgrid has adopted a comprehensive assessment process of all large customer connections to more accurately assess the probable impact on local zone substation demand. This involves the tracking and analysis of several thousand customer connection applications for seven years of historical data and four forecast years.

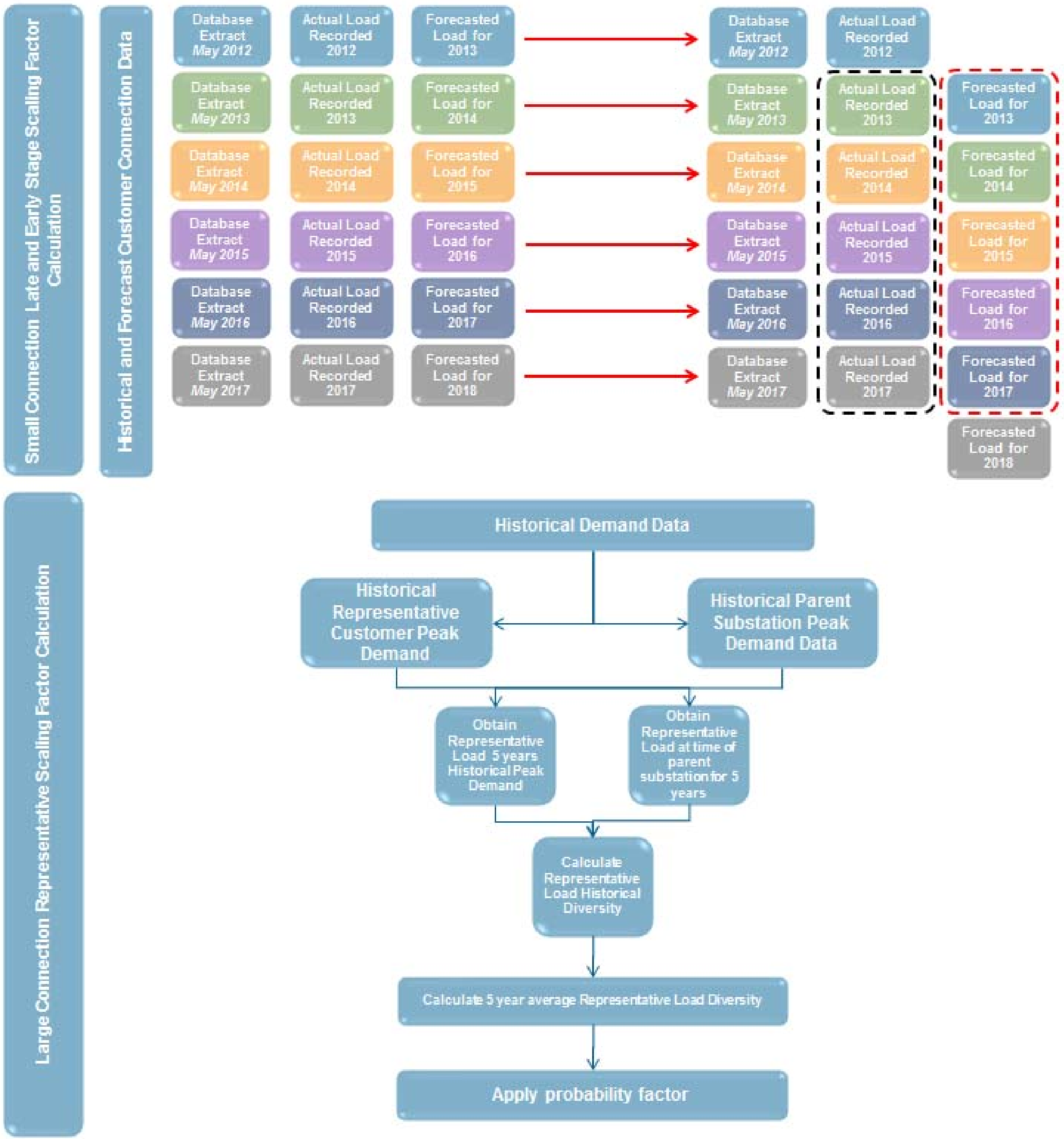
Similar to the treatment of rooftop photovoltaic systems, Ausgrid nets out the demand from all large customer connections to derive the underlying maximum demand trend. By removing commissioned block loads from the historical trend, the underlying trend is discovered avoiding the need to apply estimates or thresholds to the assessment of future block loads. And similarly to rooftop photovoltaic systems, the forecast demand impact from all future large customer connections can be included as a post model adjustment.

Note that block loads can result in either an increase or decrease in the forecast load (e.g. connection can be either a new load or generator connecting to a zone substation or high voltage sub-transmission feeder). The assessment process used for block loads is detailed in the flow charts and subsections following.

Customer connection application assessment process (block loads) – Part A



Customer connection application assessment process (block loads) – Part B



Small Connection Scaling Factor

Late Stage Scaling Factor

- *Scaling factor is the comparison of forecasted late stage block loads against actual realised block loads seen in the corresponding year*
- *Calculated late stage scaling factor in 0.78 for the 2017 forecast release*

Early Stage Scaling Factor

- *Similarly the early stage block load scaling factor is a comparison of forecasted early stage block loads against actual realised block loads seen in the corresponding year*
- *The early stage block load scaling factor is 0.34*

NB: All small connection block loads have load cycle diversity applied prior to scaling factors

Scaling factors applied to Block Loads by type and added to forecast

Large Connection Representative Scaling Factor

Representative Diversity Factor

- *Existing load types are assigned to each forecasted major customer connection as representative of future customers demand*
- *The representative load is analysed to determine its peak demand impact to the upstream network asset*
- *A range of 5 years of representative load peak demand impact is analysed and an average is taken. This is the representative diversity factor of the future customer demand*
- *A probability factor is then applied to the representative diversity*

Representative Probability Factor

- *Probability factor takes into account the probability of the connection proceeding*
- *The probability factor also is an adjustment for an unrealised component of customer connection requested demand*

Representative scaling factors applied to Block Loads and added to forecast

5.7.1 Block load classsification

Not all block loads are included in the netting out and post model adjustment processes. The assessment process tracks all connections applications greater than 50 amps at 11kV and all applications at 33kV and above. The 50 amp threshold was selected as it reflects a possible new load of 1 MW or about 3% the load on a zone substation with a load of 30 MW (average Ausgrid zone substation load). Refer to Part A of the flow diagram.

Block loads meeting this criteria are then classified as one of three block load types:

- Late stage 11kV block loads – where a connection agreement has been signed and associated connection fees have been paid by the customer.

- Early stage 11kV block loads - when negotiations over the method and timing of the customer connection continue.

- Major customer connections – commonly at 33kV and above, connection applications from unique customer segments where blending with general customer connections would be inappropriate (e.g. rail, mining, solar or wind farm)

The classifications have been chosen for principally for two reasons:

- Separation of early and late stage 11kV customer connections recognises the distinct variation in probability associated with the different development stage of the connection application.

- Major customer connections often relate to unique industry sectors where negotiation of connections arrangements can be lengthy, but often involve detailed discussions with the customer allowing for a greater level of understanding of the connection schedule and probability of proceeding.

5.7.2 Probabilistic scaling factors

As part of the process of assessing all customer connections at 11kV and above, the resultant customer demand and coincidence with zone substation peak are also identified and recorded. This allows for the development of actual resultant scaling factors to be derived for the early and late stage block loads. This process is described below. Refer to Part B of the flow diagram.

5.7.2.1 Late Stage Block Loads

As noted above, block loads connected to zone substations on the 11kV network are categorised according to how well progressed in Ausgrid's connection application process they are. Late stage block loads are those which reach the point where a detailed design package is received from the customer, usually via an Accredited Service Provider (ASP) acting on behalf of the customer. Analysis of historical connections applications has shown that such connection applications have a high likelihood of proceeding to energisation since significant costs have been incurred by the customer both to engage an ASP and complete the connection design.

Accordingly, our methodology applies strict criteria and segregates those connections that have progressed to or beyond the stage where a detailed design package has been received from those that have yet to proceed to this stage. Based on analysis of historical records of 11kV connections over 5 years of history, the resultant maximum demand at time of 11kV panel peak was found to be 78% of the requested demand capacity in the connection applications. Consequently, this probabilistic scaling factor is applied to all future connection applications identified as 'late stage block loads'. Note, this probabilistic factor is not to be confused with the coincidence factor, which accounts for peak demand occurring at different times and at different layers of the electricity network. The coincidence factor is applied separately.

5.7.2.2 Early Stage Block Loads

Early stage block loads are assessed in a similar manner to the late stage block loads. Based on analysis of historical records of 11kV connections over a number of recent years of history, the resultant maximum demand at time of 11kV panel peak was found to be 34% of the requested demand capacity in the connection applications. Consequently, this probabilistic scaling factor is applied to all future connection applications identified as 'early stage block loads'. Note, this probabilistic factor is not to be confused with the coincidence factor, which accounts for peak demand occurring at different times and at different layers of the electricity network. The coincidence factor is applied separately.

5.7.2.3 Probabilistic scaling factor for major customer connections (33kV+)

Major customer connections to our sub-transmission network at 33kV or above and select industry specific connections at 11kV (e.g. rail, mining, solar or wind farm) are scaled using a different methodology to general 11kV connections. These connections are typically large and pertain to a particular industry sector where there is often a scarcity of historical data for such connections, but more detailed discussions with the customer. This is in contrast to 11kV connections where there is a large number of fairly homogeneous data, with connections typically being small to medium residential and business developments.

Our methodology allocates each major connection to a particular industry, namely, rail, airport, datacentre, road tunnel, commercial/residential, mining, air force, navy, industrial, large solar generation, large wind generation and tri-generation and applies a deemed probability scaling factor based on whether the industry is considered commercial (0.80 factor) or infrastructure (0.90 factor).

Coincidence factors for major connections are also calculated based on industry category, using an average coincidence factor calculated from the actual data of an equivalent load type in recent history.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