

Demand-driven AUGEX

Forecast review

Report for TransGrid 23 September 2021

The Power of Commitment

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Executive summary

TransGrid requested GHD to critically review demand forecasts for key network locations at which major network augmentation (AUGEX) projects are planned. Accordingly, we have reviewed the relevant forecasts by comparing them with AEMO forecasts where possible, and by assessing the reasonableness of the methods used to derive each forecast and the input assumptions.

The inclusion of large amounts of new customer load in western Sydney and specific mining and industrial loads in north-western and central New South Wales may be key points of contention, as they cause the forecast demand to deviate significantly above recent historical trend growth. However, processes followed by NSW DNSPs that resulted in incorporation of customer advised projects were generally conservatively low and largely unchanged processes used to develop previous years' forecasts.

The strength of DNSP forecasting lies in their depth of local knowledge and details, whereas the strength of AEMO forecasting lies with consistency of approach at a regional and NEM-wide level.

The most likely demand forecasts used by TransGrid for planned electricity consumer projects are considered to be the DNSP forecasts that have included detailed assessment and discounting. However, network planning at locations where the demand forecast includes a relatively large growth component made up of planned electricity consumer projects may consider alternative scenarios for with and without the projects.

The role of the load forecasts in determining the need for the AUGEX projects specified by TransGrid is summarised in the table below.

Project description	TransGrid reference	Impact of load forecast
Supply to Sydney West area	N2371	This project concerns Sydney West. This substation will only take a fraction of the current demand forecast increase in summer maximum demand before the firm capacity of the transformers is exceeded. Sydney West transformer capacity of 1,500 MVA forecast will be exceeded in summer 2023/24 under the latest forecast. Under last year's forecast the transformer capacity would not have been exceeded 2029/30.
Supply to Western Sydney priority growth area	1687	This project concerns Sydney West, Macarthur and Vineyard. The issue at Sydney West is described above.
		The firm capacity of the Macarthur transformers of 472 MVA forecast will be exceeded in summer 2027/28 under the current demand forecast, one year later than under last year's forecast
Supply to Vineyard area	N2373	The firm capacity of the Vineyard transformers of 750 MVA forecast will be exceeded in summer 2026/27 under the current demand forecast, one year later than under last year's forecast.
Maintain voltage in the Vineyard area	N2360	The limitation on the capacity of the Vineyard transformers is described above.
Supply to north-west slopes area	1693	Committed customer projects in north-west New South Wales cannot be reliably accommodated without network augmentation.
		In particular, network quality will deteriorate following commencement of the Narrabri Gas Project in 2025/26 and may require load shedding in the event of an N-1 contingency.
Maintain voltage in Beryl area	1316	A number of planned customer projects will result in voltage stability network limitations in the 132 kV system and thermal limits in the 330 kV system.
		Existing voltage constraints will only worsen with forecast load growth. However, the load forecast at Beryl is not the primary driver of already existing voltage constraints.
Supply to Bathurst, Orange and Parkes	N2384	Forecast demand growth due to a number of existing and planned mine expansions in the Orange and Parkes areas will result in voltage stability

Table 1 Impact of load forecasts on the specified AUGEX projects

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Project description	TransGrid reference	Impact of load forecast		
		network limitations in the 132 kV system and thermal limits in the 330 kV system.		
Supply to ACT – network capability (Contingent Project)	N2293	Supply reliability and resilience to the ACT will deteriorate following planned decommissioning of two transformers at Canberra substation. This AUGEX requirement is contingent on the timing of this asset decommissioning.		
Maintain voltage in the alpine area	N2645	Planned customer loads in the alpine region will result in undervoltage and risk of load shedding. This risk will increase if planned spot loads go ahead and Cooma growth is as forecast. The majority of the step-up in load will occur in winter 2026.		
Supply to far west NSW network	1698	The existing load forecast for Broken Hill does not include an allowance for either the proposed Cobalt Blue () or Hawsons Iron ore () mining developments. Should either go ahead, potential network impacts would include voltage levels outside secure operating limits.		

Based on information available to us, we consider that other aspects of the forecast development represent standard industry practices and were carefully implemented. Overall, the evidence considered, the general approach taken by each DNSP, the level of careful application of that approach and the level of detailed local understanding demonstrated suggest that each of TransGrid's connection point demand forecasts generally represent a realistic expectation of future demand and forecast AUGEX requirements.

This report is subject to, and must be read in conjunction with, the limitations set out in section 1

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1. Introduction

TransGrid's forthcoming Revenue Proposal to the AER on 31 January 2022 includes provision, among other things, for nine network augmentation (AUGEX) projects at five main locations, at which each project is principally driven by expected future demand. These projects, their locations and associated transmission connection points are shown below in Table 1.

Location	Project description	Project reference	Connection point(s)
	Supply to Sydney West Area	N2371	Sydney West
Western Sydney	Supply to Western Sydney Priority Growth area	1687	Sydney West & Macarthur
western Sydney	Supply to Vineyard area	N2373	Vineyard
	Maintain Voltage in the Vineyard Area	N2360	Vineyard
North West	Supply to North-West Slopes Area	1693	Gunnedah & Narrabri
Control Woot	Maintain voltage in Beryl area	1316	Beryl
Central West	Supply to Bathurst, Orange and Parkes	N2384	Orange, Parkes & Panorama
Australian Capital Territory	Supply to ACT - Network Capability	NTBA12	Canberra, Williamsdale, Stockdill & Queanbeyan supply to Evoenergy
Snowy mountains	Maintain voltage in the alpine area	N2545	Cooma & Munyang
Broken Hill	Supply to Far West NSW Network	1698	Broken Hill

 Table 1
 TransGrid demand driven AUGEX projects of concern and associated locations

Source: TransGrid.

Demand forecasts for the relevant connection points have been recently updated and have been published by TransGrid in the 2021 Transmission Annual Planning Report (TAPR). TransGrid is reliant on Distribution Network Service Providers (DNSPs) in New South Wales and the Australian Capital Territory to prepare these forecasts.

1.1 Purpose of this report

The purpose of this report is to document our review which:

- demonstrates the extent to which the demand forecast at each specified location represents a realistic expectation of future demand
- identifies elements of the forecasts that are contingent on identifiable electricity consumer projects; and
- ascertains whether TransGrid has adequately considered the role of non-network options.

1.2 Scope and limitations

This review includes:

- Comparisons of the forecasts with previous and similar current forecasts, discussion of the reasonableness of the inputs, assumptions and forecast outcomes (section 2)
- A description of the demand forecasting methods used to prepare forecasts at the connection points listed in Table 1 and an outline of AEMO's Transmission Connection Point methods and parallel forecast outcomes, reconciling differences in methods and outcomes in comparison with TransGrid's forecasts (section 3)
- Explanations for the derivation of spot loads at each connection point and discussion of supporting evidence for the load-related projects (considering any previous reviews provided by Transgrid into spot loads) (section 4)
- Reporting of our analysis of historical and forecast trends in demand, including discussion of the impact of COVID-19, at each connection point (section 2)

 Our independent view of each connection point forecast, sensitivity analysis for each project and its forecast expenditure in relation to variances in the respective demand forecast and other pertinent conclusions (section 4)

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1.3 Assumptions

Current forecasts are as published in the 2021 TAPR

Network characteristics and developing network constraints are as portrayed by TransGrid

2. Overview and high-level assessment

Increases in NSW electricity demand may be generally expected over the next 10 years as a consequence of population growth and expanding economic activity. However, energy efficiency measures, behind the meter small scale and larger scale embedded generation, advances in technology and consumer preferences are all having an increasing impact on the demand forecasts. In the long term, electricity demand may also be increasingly driven by new energy policies aimed at achieving greenhouse gas emissions reductions. Therefore, it is possible to predict high rates of economic expansion without expecting corresponding growth in electricity demand.

Considering all the above on a region-wide level, the 2021 TransGrid medium scenario growth forecast summer maximum demand growth rate for NSW as a whole is 0.7 per cent per annum between 2020/21 and 2029/30 We note that variation in growth across the region for different supply points ranges from over 8 per cent to less than minus 2 per cent, for a host of reasons including concentrated commercial expansion, a new coal seam gas project and network re-configuration. We also note that AEMO's 2021 ESOO 50% POE forecast for NSW between summer 2020/21 and 2029/30 indicates a growth of 0.9% per annum.

The relevant substation demand forecasts for review are shown in Table 2, where the forecasts for 2029/30 are 50% probability of exceedence (POE) for the most likely scenario.

TransGrid substations	Maximum demand 2019/20*	Maxiumum demand 2029/30**	DNSP	New spot loads included in the demand forecast	Comments
Macarthur 66 kV & 132 kV, Sydney West and Vineyard	1,822	3,177	Endeavour Energy	Multiple data centre, industrial, commercial and residential spot loads	Planned building, construction and infrastructure growth in Western Sydney region will accommodate new city centre and international airport.
Gunnedah and Narrabri	77	143	Essential Energy	Mining loads, Narrabri Gas Project	The planned Narrabri Gas Project will double electricity demand
Beryl, Orange 66 kV & 132 kV, Panorama and Parkes 66 kV & 132 kV	441	488	Essential Energy	Mining and industrial load	Planned mining expansion dominates growth
Canberra, Stockdill, Williamsdale and Queanbeyan 66 kV supply to Evoenergy	583	627	Essential Energy/Evoenergy	Notable forecast growth in data centres in the Australian Capital Territory	Overall forecast growth is slightly higher than the forecast for NSW as a whole, but re- configuration of load allocated to individual connection points will follow decommissioning of Evoenergy's Fishwick zone substation in 2022
Cooma 66 kV & 132 kV, Munyang	71	81	Essential Energy	Snow making equipment, ski lifts	Overall growth in this area between 2022 and 2030 is forecast to be 1 MW, but this masks relatively large proportional growth at Munyang
Broken Hill 22 kV & 220 kV	50	61	Essential Energy	Broken Hill pipeline	No forecast load growth beyond summer 2021/22
Total	2,391	4,496			

Table 2 Connection points of interest

* Estimated 50% POE summer maximum demand for all named connection points except Cooma and Munyang (MW) – winter for Cooma and Munyang.

** Forecast medium scenario 50% POE summer maximum demand for all named connection points (MW). Source: TransGrid, partially based on information supplied by Endeavour Energy and Essential Energy. The demand forecasts for Macarthur, Sydney West and Vineyard are the most significant. Taken together, demand at these connection points is forecast to increase by over 1,300 MW. All of the forecast growth is accounted for by specific spot loads or lot releases. However, this increase is concentrated at Sydney West, where TransGrid's forecast is now 353 MW higher in 2029/30 than the equivalent forecast published in the 2020 TAPR, as shown in Figure 1.



Figure 1 Forecasts for Sydney West, Vineyard and Macarthur (combined 66 kV and 132 kV) published in 2021 and 2020

The demand forecasts for Western Sydney are discussed further in section 2.1. Given the dominant weighting of the Western Sydney connection points in total load growth for the connection points under review, and the reliance of the forecast on new connection requests, the high-level assessment focuses on this area.

2.1 Growth in Western Sydney

The Western Sydney Region as defined by NSW Department of Planning and Environment comprises 14 Local Government Areas (LGAs), including Blue Mountains, Hawkesbury, Penrith, The Hills, Blacktown, Parramatta, Holroyd, Auburn, Fairfield, Bankstown, Liverpool, Camden, Campbelltown and Wollondilly. Endeavour Energy supplies electricity to the vast majority of these LGAs, from bulk supply connection points at Holroyd, Ingleburn, Liverpool, Macarthur, Regentville, Sydney West and Vineyard. The population of Western Sydney is expected to grow by around half a million people in the next 10 years. Already densely populated, it currently accounts for about a quarter of NSW summer maximum demand. The NSW Government plans to develop a third city (Bradfield) in south-west Sydney to join the existing business centres in eastern Sydney (Sydney CBD) and the west (Parramatta). Several major developments have commissioning dates timed to coincide with the operation of the new Western Sydney Airport (Nancy Bird Walton) in 2026.

2.1.1 Comparison with AEMO forecast

The AEMO forecast¹ for Western Sydney Region maximum demand includes the total load for the connection points noted above. It therefore includes the specific locations of interest to this review, which are defined in Table 2 and shown highlighted in Figure 2, as well as additional loads. The TransGrid forecast for the sum of all Western Sydney connection points is considerably higher than the AEMO forecast. This is illustrated in Figure 3, which shows Transgrid 50% POE summer maximum forecasts for Macarthur, Sydney West, Vineyard and other locations, superimposed against AEMO's forecast.

A direct comparison cannot be made between the TransGrid and AEMO forecast for the wider Western Sydney demand for the following reasons:

- AEMO removes the effect of distribution connected generation from their measure of maximum demand, then
 add back the effects of a normalised estimate whereas TransGrid sources generally include actual demand
 reduction due to generation that normally runs.
- The AEMO historical data shown is unadjusted, whereas TransGrid sources represent the estimated 50% POE level of demand (the AEMO 50% POE estimate for 2020/21 is the first forecast period, whereas the TransGrid estimate for that year is the weather corrected actual demand).
- The TransGrid total for the seven connection points that make up the wider Western Sydney are approximated for the sake of comparison with the AEMO forecast using non-coincident data.

However, enormity of the difference between the two forecast growth rates is such that differences due to weather correction and inclusions does not detract from the observation that the forecast growth rates are vastly different.

2.1.2 Inclusions in the TransGrid forecasts

Turning to the specific connection points of interest, Macarthur, Sydney West and Vineyard, their combined weather corrected summer demand reached 2,222 MW in 2020/21, an increase of 22 per cent compared with the previous summer. Over the next 10 years, TransGrid forecasts average annual growth of 5.1%, 3.7% and 4.2% for Macarthur, Sydney West and Vineyard, respectively, or 955 MW in total between 202021 and 2029/30. As Figure 4 shows, most existing (i.e., general) load is on a slight downward trend, with increases in activity represented by lot releases almost exactly offsetting this reduction over time. Additional forecast growth is made up of designated spot loads which comprise hundreds of individual items.

While lot releases primarily consist of new residential developments occurring over time, the spot loads represent individual network connections and are categorised as either industrial, commercial or residential developments, or data centres. Around 60 per cent of the total growth shown is at Sydney West, with both Macarthur and Vineyard each representing about 20 per cent each. This provides an urgent line of enquiry into the discovery and inclusion process for spot loads in the forecast developed by Endeavour Energy and accepted by TransGrid.

¹ AEMO (2021) Transmission Connection Point Forecasting Methodology, July, https://aemo.com.au/energy-systems/electricity/nationalelectricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-connection-point-forecasting and AEMO (2020) Transmission Connection Point Forecasts for New South Wales, including the Australian Capital Territory, Dynamic Interface, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planningdata/transmission-connection-point-forecasting/new-south-wales-including-the-australian-capital-territory.



Figure 2 Western Sydney connection points of interest







Figure 4 Actual and forecast 50% POE summer maximum demand for Macarthur, Sydney West and Vineyard (MW)

2.2 North-west New South Wales

Forecast growth in Gunnedah and Narrabri² shown below in Figure 5 and Figure 6 includes the Boggabri mine loads which are connected to TransGrid's 132 kV network. Also included, on the 66 kV side, are the planned development of the Vickery Coal Whitehaven mine, the Carroll Cotton Gin and the approved Narrabri Gas Project (NGP). By comparison, the AEMO forecasts for Gunnedah 66 kV and Narrabri 66 kV provide for a similar flat outlook for existing connections, but do not appear to allow for any such future projects. The Vickery mine and the NGP constitute the increases in the forecasts since last year.



Figure 5 Act

Actual and forecast 50% POE summer maximum demand for Gunnedah

² Boggabri North and Bogabri East mines are connected to TransGrid's 132 kV network between Narrabri.



Figure 6 Actual and forecast 50% POE summer maximum demand for Narrabri

2.3 Central west NSW

Overall, TransGrid forecasts that central west (Orange, Panorama, Beryl and Parkes) area summer demand in total will increase by 61 MW by 2029/30. Half of the forecast central west growth is due to the expansion of the Cadia mine which is connected at the Orange 132 kV bus (Figure 7). This is part of a multiple-year expansion which is already underway. There is no equivalent AEMO forecast for comparison. Similarly, the TransGrid forecast for Parkes 132 kV (Figure 8) allows for the ongoing expansion of the North Parkes mine, whereas there is no equivalent AEMO forecast for the North Parkes mine, whereas there is no equivalent AEMO forecast for the transGrid forecast for this location. Connection points that are comparable are discussed below.

2.3.1 Orange 66 kV and 132 kV

There is practically no forecast demand growth at Orange 66 kV. Both the TransGrid and AEMO forecasts are in close agreement. The 132 kV load consist entirely of the Cadia mine, which in the middle of its planned expansion between 2019/20 and 2022/23. There have been no significant changes since the previous year's forecasts.



Figure 7 Actual and forecast 50% POE summer maximum demand for Orange

2.3.2 Parkes 66 kV and 132 kV

The forecast for Parkes 66 kV allows for a small additional mining load but is otherwise flat. TransGrid and AEMO forecasts agree from 2023 onwards. The 132 kV load is determined by planned activity at the North Parkes mine. Last year's forecasts were slightly higher.



Figure 8

Actual and forecast 50% POE summer maximum demand for Parkes

2.3.3 Panorama

As shown in Figure 9, TransGrid forecasts that demand growth at Panorama is set to increase by a total of 6 MW over the next 10 years, at a comparable rate to the previous five years, when temperature corrected.

The TransGrid forecast is a projection of temperature corrected historical growth. The equivalent AEMO actual data for 2018/19 and 2019/20, which is not temperature corrected, was confirmed by Essential Energy. While the AEMO temperature-corrected forecast, in contrast with the TransGrid forecast, shows no growth, the Transgrid forecast is only 3 MW higher at the end of the forecast period. Last year's forecast included lower growth but the temperature-corrected level was significantly higher.



Figure 9 Actual and forecast 50% POE summer maximum demand for Panorama

2.3.4 Beryl

Historical growth (temperature-corrected) at Beryl has recently averaged almost 6 per cent a year and is forecast by TransGrid to increase at a lesser rate of around 1 per cent a year for the next 10 years. Growth at Beryl is attributed to load growth of downstream zone substations equating to around 0.7 MW a year. Local mining loads are assumed to remain constant.

The 2021 TransGrid forecast for Beryl contrasts with AEMO's zero-growth forecast as well as last year's TransGrid forecast (see Figure 10). AEMO's actual data, which is not temperature corrected, illustrates the range of potential variation between actual load data and the temperature-corrected trend.



Figure 10 Actual and forecast 50% POE summer maximum demand for Beryl

2.4 Australian Capital Territory

Electricity is currently supplied to the Australian Capital Territory via the Canberra, Williamsdale and Stockdill 132 kV substations and from the supply to Evoenergy's Fyshwick zone substation from Queanbeyan at 66 kV. As shown in Figure 11, TransGrid is forecasting summer demand overall to grow by 0.8 per cent per annum, but this masks strong growth at Canberra and Williamsdale connection points in 2023/24, after load is redistributed following the retirement of supply via Queanbeyan. As forecast by TransGrid, growth also allows for future new data centre load which will likely be spread across multiple supply points. This load appears to have been brought forward compared to the previous year's forecast.

The AEMO forecast for the Australian Capital Territory consists of individual non-coincident forecasts for the 13 Evoenergy zone substation loads. When added together the total AEMO forecast is higher than the TransGrid total forecast, possibly due to the different treatment of embedded generation and diversity between zone substations. However, the growth rate of each forecast is not dissimilar for the Australian Capital Territory in total.



Figure 11 Actual³ and forecast 50% POE summer maximum demand for Williamsdale, Stockdill, Canberra and Queanbeyan (Evoenergy)

³ All actual data for ACT was estimated from the AEMO forecasting report.

2.5 Snowy Mountains

As shown in Figure 12 and Figure 13 separately, winter 2020 maximum demand⁴ for all of Cooma and Munyang together was 110 MW in temperature corrected terms. This is forecast by TransGrid to increase to 118 MW by winter 2029. The forecasts for Cooma 66 kV and Munyang are below last year's forecasts and the forecast for Cooma 132 kV is higher than last year.

AEMO's total forecast increase is similar, rising from 101 MW to 107 MW over the same period. TransGrid and AEMO include similar spot load increases at Munyang, However, AEMO's share of total demand is weighted more towards Munyang, compared to TransGrid's estimated 50% POE load levels.



Figure 12 Actual⁶ and forecast 50% POE winter maximum demand for Cooma

⁴ Winter demand in the Snowy Mountains region far exceeds summer demand due to seasonal tourism, snow lifts and winter heating loads.

⁵ All actual data for Alpine Region was estimated from the AEMO forecasting report.



Figure 13 Actual and forecast 50% POE winter maximum demand for Munyang

2.6 Broken Hill

Broken Hill load in total can fluctuate by up to around 10 MW a year, as shown in Figure 14. The general supply 22 kV load is forecast to grow by a further 1 MW next year, and no change is anticipated in the 220 kV mining load. Last year's forecast for the 22 kV load, by contrast, allowed for significant growth.

There is no AEMO equivalent forecast for Broken Hill 220 kV. The equivalent AEMO forecast for the 22 kV load is also flat but is at a slightly higher level than the TransGrid forecast, possibly due to the different treatment of embedded generation.



Figure 14 Actual and forecast 50% POE summer maximum demand for Broken Hill

3. Forecasting methodology

The connection point forecasts presented by TransGrid are initially prepared by NSW Distribution Network Service Providers (DNSPs), before being reviewed by TransGrid. This section therefore examines the various processes used in the preparation of the forecasts by each relevant DNSP and how these processes differ from AEMO's methodology. The examination draws mainly on published information⁶, although some details on the specific treatment of spot loads were clarified by discussion between TransGrid and the DNSPs during the course of this review.

The general approach to preparing non-coincident connection point forecasts used by AEMO and DNSPs follows a linear process, starting with data collection and preparation, proceeding to determine a weather-corrected actual starting point and then projecting the identified underlying historical trend into the future and adjusting for post-model adjustments. Below we use AEMO's specific approach as a reference point to identify points of difference with processes described by Endeavour Energy, Essential Energy and Evoenergy

3.1 Overview of AEMO demand forecasting process

The current AEMO connection point forecasting methodology is reproduced in Figure 15⁷. The process is based on project the underlying, temperature-corrected non-coincident historical connection point forecasts for each region of the NEM are reconciled to the regional (top-down) forecast, as part of AEMO's approach and inputs to its NSW regional forecast⁸.



Figure 15 Complete AEMO Connection Point Forecasting Methodology

3.1.1 Data collection

As might be expected, data collected by AEMO includes:

- half-hourly sub-station, embedded generator and large industrial loads for relevant connection points
- half-hourly temperatures at selected weather stations
- small and large-scale PV capacity by postcode and installation date
- numbers of meters supplied by each connection point
- estimated connection point supply boundaries, LGA population estimates

⁶ AEMO connection point methodology is found at: AEMO (2021a) Transmission Connection Point Forecasting Methodology, July, found at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planningdata/transmission-connection-point-forecasting; and DNSP forecasting methodology descriptions are found in each Distribution Annual Planning Report (DAPR), at: Endeavour Energy (2020) 2020 DAPR, December, https://www.endeavourenergy.com.au/modern-grid/creatingthe-modern-grid/network-planning/distribution-annual-planning-report, Essential Energy (2021) 2020 DAPR version 2, July, https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/regulatory-reports-and-network-information, Evoenergy (2020) 2020 DAPR, December, https://www.evoenergy.com.au/about-us/reports-and-publications/annual-planning-report.

 ⁷ Figure 4 in AEMO (2021a).
 ⁸ AEMO (2021b) AEMO Forecasting Approach – Electricity Demand Forecasting Methodology, May, found at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

- population projections by sub-region
- forecast PV installation, battery energy storage, electric vehicle numbers by postcode and half-hourly usage profiles

3.1.2 Data preparation

Any metering errors data outliers or other detected anomalies are corrected in the raw historical load traces. The traces are then adjusted to remove the effects of embedded generation, behind the meter generation, large industrial loads that are separately metered and visible spot loads, transfers and outages that cause a deviation form underlying trends. The resulting data series are the underlying demands which represent growth due to new connections or fundamental changes in energy appliance use by typical energy consumers.

AEMO classifies load data into either summer, winter or shoulder season and sets flags for public holidays, school holidays, the Christmas period and weekend and working weekday types.

3.1.3 Treatment of embedded generation and industrial loads and weather station selection

Rather than use actual historical generation and large loads, AEMO estimates normalised patterns based on modelled half-hourly values for the time of year and day type. For rooftop PV generation in particular an estimate is all that is possible. In the data preparation stage, it is these estimated generation effects that are removed.

The most suitable weather station to represent each connection point depends on its location relative to the respective connection point, the quality and continuity of the recorded temperature data and the statistical relationship between demand and temperature. Appropriate weather stations are selected for each connection point by trial and error. In some cases, a weighted average of multiple weather stations is selected.

3.1.4 Determining starting points

AEMO estimates the weather corrected historical underlying maximum and minimum demands in MW for each connection point by estimating a statistical relationship between half-hourly underlying demand, temperature and calendar/time of day variables. The weather relationships tested by AEMO allow for linear, quadratic and cubic transformations and 3-hour and 6-hour rolling averages. The model with the best predictive capability (trading off between accuracy and lack of bias) is selected using a machine learning algorithm, where a high priority in the selection process is given to k-fold cross section validation. This essentially means that the model is trained on a one sub-sample of data and tested against forecasts made on the remaining sub-sample.

The selected underlying demand-temperature model is simulated using 12 years of temperature data and randomly sampled model residuals. Including model residuals drawn from an appropriate empirical distribution accounts for demand variability that is not captured in the weather relationship. Given the relatively short historical period of the alternative weather samples, and the ultimate purpose to develop a 10-year forecast, the AEMO weather simulations do not incorporate climate adjustments. From the numerous simulations the maximum and minimum demands are selected for each season and percentiles across all similarly defined maxima and minima determine the 10% and 50% POE levels.

Normalised contribution factors (i.e., the estimated load at the time of maximum/minimum demand) for embedded large loads that were removed in the data preparation stage are added back. Normalised contribution factors (i.e., the estimated generation at the time of maximum/minimum demand) for embedded generation and small-scale PV generation are removed. Normalised contributions average the simulated contributions over a range of percentiles and therefore avoid inclusion of extreme values.

3.1.5 Forecast probability of exceedance for future

From the starting point determined in section 3.1.4, AEMO applies a population growth factor to underlying, weather corrected demand corresponding to the population sub-region and the estimated number of retail connections fed by the connection point. This procedure may be overridden in the presence of other information available.

Rooftop and other PV generation is added based on capacity installed forecasts provided by AEMO's consultant. Similarly, EV charging and battery profile forecasts are used to estimate the impact on maximum and minimum underlying demand.

The simulated impact of small, embedded generators is reinstated in the forecast, where future capacity also includes committed retirements and future new capacity where known.

Existing large loads that were previously excluded from the data, along with a limited set of expected new spot loads, are added back to the forecasts. AEMO would be keen to avoid the following issues with adding known future loads into the forecast:

- double counting of future organic growth (which is represented by an extension of historical trends) and the inclusion of numerous relatively small spot loads, which it may be argued are the concrete manifestation of the previously mentioned organic growth
- overoptimism that connection enquiries representing developers' projects will be converted into actual homes, factories and commercial premises
- overestimation of realised loads consequent upon a planned connection capacity

Previous presentations by AEMO have highlighted that known spot loads provided by DNSPs are only considered if they meet a certain size threshold. AEMO also apply a "75% probability of proceeding" threshold for including individual spot loads. This is likely to exclude large amounts of prospective load where there is an expectation of numerous smaller connections, rather than a few large ones. It also raises the question of how the 75% probability is determined.

AEMO then adjusts the resulting operational demand forecast to account for future block loads and any proposed transfers between connection points. Information about probable future block loads is given to AEMO by DNSPs. On AEMO's request. AEMO then reviews and applies this information, however there is no published explanation that might reveal the details of this vetting of block load information. AEMO's conservative approach to including additional block loads may be intended to avoid double counting of numerous small load increases in both the projected underlying trend and new additions. However, this approach may result in a downwards bias in AEMO's connection point forecasts relative to those of the DNSPs.

3.1.6 Forecast seasonal non-coincident forecasts, reactive power and power factors

AEMO's non-coincident forecasts of operational demand in MW are produced as described above. Additional processing and information also determine reactive power and power factors.

3.1.7 Reconciling with regional forecasts for coincident forecasts

Coincident forecasts are calculated from the non-coincident forecasts by applying diversity adjustment factors. These generally represent average historical average diversity in the previous three years, defined as the ratio of demand at a connection point at the time of NSW wide maximum demand for a season to the maximum demand at the connection point (non-coincident) in the same season.

AEMO then adjusts all connection point forecasts for each NEM region so that they the sum of coincident connection point demands is equivalent to the separately developed top-down regional forecast. This process uses a constant adjustment factor for all connection points. In order to undertake the reconciliation, AEMO has to make allowances for large industrial loads (connection points not covered by the published forecast) and transmission losses. AEMO's reconciliation has in the past biased AEMO's connection point forecasts downwards relative to the unadjusted forecasts based on information which is specific to the individual location.

3.2 Comparison of DNSP with AEMO demand forecasting processes

Table 3 some of the eccentricities of the DNSP forecast methods, compared with AEMO's approach. At a high level, a principal difference is that, while AEMO prepares forecasts based on connection point load data, the DNSPs are principally focussed on preparing forecasts at the zone substation level. Their connection point

forecasts are then derived from the addition of relevant zone substation demands, with appropriate adjustments for diversity and network losses. This means that is highly unlikely that the temperature-corrected levels of maximum demand at connection points that feed numerous zone substations will exactly align between AEMO and DNSP estimations, although the identified underlying growth trends should not be dissimilar.

Each of the DNSPs and AEMO have an approach to weather correction which uses a statistical relationship between demand and temperature, and which generates a frequency distribution of possible results using a range of historical temperatures and the unexplained error in the estimated statistical relationship. This allows estimation of 50% POE demand levels and is a standard industry approach. While each organisation's specific forecast method differs in the details of how this approach is implemented, each may be valid for their particular circumstances. Based on the comparisons in section 2 above, it appears that the outcomes between AEMO and DNSP trend projections were only significantly different for Beryl and Panorama.

AEMO undertakes an analysis of embedded generating units and provides a value to reduce the connection point forecast by the most likely amount of generation for each location at the time of maximum demand (which could be zero). In contrast the DNSP forecasts generally include the historically measured effect of embedded generators in reducing demand where it offers firm capacity.

Another significant potential source of difference lies in the adjustments of the historical data for the effects of distributed energy resources (DER) and allowances of such in the forecasts. Endeavour Energy augments the projected trend forecast with post model adjustments which include solar PV, battery energy storage, electric vehicle charging and the effects of energy efficiency programs such as Minimum Energy Performance Standards (MEPS), NSW Energy Savings Scheme (ESS) and changes to the building code. Essential Energy provides no published details on the magnitude of residential PV, electric vehicles, etc. impacts are incorporated in the forecasts, although they explicitly conform closely to the AEMO methodology. Evoenergy captures the offsetting effect of increased rooftop PV generation through its organic growth forecast trend component. Generally speaking, any differences in DER assumptions for each forecast do not appear to be significant over the time horizon considered.

Neither AEMO nor the DNSP forecasts explicitly address the short-term or long-term impacts of the COVID-19 pandemic on the economy, population growth or demand for electricity.

Table 3 summarises points of methodological difference between AEMO and DNSP forecasting.

AEMO steps in forecast preparation	Endeavour	Essential	Evoenergy
Overall:			
AEMO develops forecasts at those connection points in each NEM region to which are connected more than a single customer and which are not part of a meshed local system. Significant NSW growth areas including Sydney CBD and Western Sydney are treated as an aggregated area for the purposes of the AEMO connection pint forecasts Connection point forecasts are based around a normalised, weather corrected historical trend, modified by future spot loads and post-model adjustments	Forecasting steps applied at zone substation level, with the connection point forecast then determined by an appropriate combination of the relevant zone substations Zone substation forecasts are based around a normalised, weather corrected historical trend, modified by future spot loads and post-model adjustments No minimum demand forecast	Forecasting steps applied at zone substation level, with the connection point forecast then determined by an appropriate combination of the relevant zone substations Zone substation forecasts are based around a normalised, weather corrected historical trend, modified by future spot loads and post-model adjustments No minimum demand forecast	Forecasting steps applied at zone substation level, with the connection point forecast then determined by an appropriate combination of the relevant zone substations Evoenergy employs a systematic and formal decomposition of historical demand into baseline, organic growth and weather variation components and forecasts maximum and minimum demands based on modelled values fitted from an assumed extreme distribution No minimum demand forecast
Data callection:			

Table 3 Comparison of DNSP forecast methods with AEMO procedure

Data collection:

AEMO steps in forecast preparation	Endeavour	Essential	Evoenergy			
Emphasis is on statistical analysis of historical data The data used to prepare the forecasts is the metered data at the relevant	Emphasis on connection enquiry/application information The data used to propage the forecasts is	Emphasis on connection enquiry/application information The data used to propage the forecasts is	Emphasis on connection enquiry/application information The data used to propage the forecasts is			
connection points	zone substation SCADA data	zone substation SCADA data	zone substation SCADA data			
Data preparation:						
AEMO uses entire years of half-hourly data, divided into separate seasons and flagged for day types Forecasts are generally prepared on the basis of five years of historical data A variety of weather station half-hourly data is collected	Seasonal definitions may vary from those used by AEMO Data from one of two weather stations used (appropriate for the franchise area)	Some sample data analysed in total rather than after being split into summer and winter season if there is little variation between seasons (giving a larger sample) Forecasts prepared on the basis of 10 years of historical demand data Historical data adjusted for short-term load transfers and abnormal metering outputs, but no adjustment for DER mentioned	The description of the methodology is silent on data preparation Uses temperature data from two weather stations for the last 25 years Evoenergy provides the only forecasts to explicitly allow for climate warming of 0.01 °C per year			
Treatment of embedded generation an	d industrial loads, and wea	ather station selection:	1			
Development of a normalised half- hourly generation and weather corrected, or otherwise normalised, half-hourly load profile for each generator/load	Some embedded generation is assumed to not be operating at the time of maximum demand Inclusion in the forecast of land release developments and spot loads	Demand reduced due to embedded generation where such generation provides firm capacity				
Determining starting points:						
AEMO estimates a demand- temperature-season/day type relationship for each location using data for the entire year. A frequency distribution is then generated from multiple simulations using 12 years of weather data and the unexplained model errors. The 50% POE demand is drawn from this frequency distribution.	Some substations are not weather corrected because there is not a strong correlation between demand and weather Estimates demand weather relationship using 6 years of data instead of one year at a time Relationships separate for summer and winter Accounts for impact of successive hot/cold days by using temperature variables lagged by one day Weather correction simulations are based on 24 years of temperature variation	Starting point for forecasts is taken to be either the most recent weather corrected actual or its predicted value based on a historical trend – either the trend in raw demand or the trend in weather corrected demand may be used				

AEMO steps in forecast preparation	Endeavour	Essential	Evoenergy		
	Identified weather corrected trend forms the base level forecast				
Forecast probability of exceedance for future:					
 Basic growth is driven by forecast population growth/customer numbers. Additional information used to modify the basic growth forecast includes: DER (rooftop PV, battery charging/discharging and electric vehicle charging) future changes in embedded generation capacity future block loads that have a 75% chance of proceeding All future information is drawn from information requests to DNSPs 	Incorporates planner's inputs (expected developments and spot loads, load transfers) Applies post-model adjustments according to each zone substation's mix of residential, commercial and industrial customers Includes impacts of new energy efficiency policies Local knowledge applied to assess each forecast in line with expectation Diversity factors estimated in relation to zone substations and bulk supply points	A mix of trend analysis and local knowledge of significant changes due to network configuration, customer mix or other factors determine the adopted growth rate – trend analysis results in the adoption of the median of various possible trends that fit the historical data Initial forecasts extend for 10 years using the identified trend growth, post-model adjustments are then applied - major spot load developments, such as mining loads and major subdivisions, if they represent "reasonably firm" step load increases – no mention of rooftop PV, batteries EV, energy efficiency	Growth is time dependent (i.e., a linear time trend) but is postulated to capture economic growth – more complex polynomials did not result in a better fit New expected block loads are added to the modelled forecasts - the description of the methodology is silent on allowance for PV etc		
Forecast seasonal non-coincident forecasts, reactive power and power factors:					
AEMO applies diversity factors to the non-coincident forecasts, which are based on historical averages, to generate coincident forecasts AEMO applies power factors to the active power forecasts, which are based on historical averages, to generate reactive power forecasts	Not dissimilar to AEMO's approach, but outside the scope of this report	Not dissimilar to AEMO's approach, but outside the scope of this report	Not dissimilar to AEMO's approach, but outside the scope of this report		
Reconciling with regional forecasts for coincident forecasts:					
AEMO adds all coincident connection point maximum and minimum demand forecasts for each year, plus estimates of "missing" load (those locations for which the forecast is not prepared for publication) and network losses. These totals are then compared with AEMO's independently derived whole of region forecasts. Each connection point forecast is then adjusted by a similar proportion so that they are consistent as a whole with the regional forecast	TransGrid's primary check connection point forecasts supplies) with its own top-o as being within an expecte	effectively compares the add (originally prepared by the for down forecast for NSW. Sma d margin of forecast uncerta	dition of all coincident our DNSPs which it Il differences are accepted inty		

3.3 Treatment of spot loads

Demand growth from existing connections no longer presents a significant driver of network expenditure as appliance efficiency and behind-the-meter PV generation offsets any increased electricity use. Instead, new connections are major drivers of demand growth, particularly in western Sydney, but also in Narrabri, Parkes and elsewhere that are affected by specific gas and mining developments.

The largest discrepancies between AEMO and DNSP forecasts, where they are comparable, appear to be in the inclusion or exclusion of spot loads. This issue is critical to comparing the forecasts for western Sydney, Narrabri and Gunnedah.

3.3.1 Treatment of western Sydney spot loads and lot releases

Endeavour Energy has shared with TransGrid detailed spot load/lot release information used for their forecasts. Substantial growth is planned in greenfield areas (mainly residential but also commercial/industrial). Many individual new loads are individually relatively small are large in aggregate. Endeavour Energy models load realisation using an 'S-curve'. However, in situations where developers target a specific number of lots per year lot releases are modelled as per year spot loads.

The historical average ratio of formal enquiries for connection to the number that actually proceed through to connection applications, (requiring the applicant to pays fees) is used as a measure of current applications expected to proceed through to connection. A disadvantage of using the connection applications database to estimate future load growth (which the S-curve methodology for larger developments attempts to correct) is that the development pipeline only represents development up to four years into the future. Inaccuracies in a downwards direction are likely to occur in relation to knowledge of projects towards the end of this forecast timeframe due to future applications that have not yet materialised.

Each connection application lodged with Endeavour Energy generally means that the applicant has sunk a significant amount of money, not only in application fees, but also on project approvals, the engagement of other service providers and initial design work. Projects that have reached this stage generally proceed to incur electrical load, either within the planned timeframe, or else after a delayed for one reason or another. Therefore, there is some chance that spot loads included in the connection point forecast and based on committed connection applications may not follow the expected timing. Endeavour Energy does not track or forecast such delays.

In order to account for the probability of connection enquiries being converted to connection applications, and connection applications proceeding as planned, Endeavour Energy applies an across the board 'load realisation probability factor' of 80%. This means that for a load application of 5 MVA, only 4 MVA is included in the demand forecast. Post-COVID, this load realisation factor has recently been adjusted downwards for the first few forecast years to account for the impacts of the COVID recession on economic development. A smoothed pathway back to 80% is assumed for each year's specific factor. The connection point forecasts are therefore significantly below the levels of capacity for which customers have applied.

In contrast, it is clear that AEMO has excluded at least half of the spot loads expected by Endeavour Energy for western Sydney and has not allowed for an unprecedented, planned expansion of western Sydney centred on a new airport and population hub, and sizable, unconnected private sector projects such as data centres. Sydney West is experiencing unprecedented growth in Data Centres attracting global players like Amazon and AirTrunk. A number of additional connection applications for data centres have been received and continue to be received by Endeavour Energy for the Sydney West network catchment area. These are block loads that will increase over time. Approximately 400 MVA of additional 132 kV data centre load is forecast by 2030.

Endeavour Energy are also jointly planning for a new connection point in the Aerotropolis area, potentially at TransGrid's Kemps Creek site. Until this new connection point is available, Sydney West will have to support the bulk of growth in the new Aerotropolis area, including the establishment of the areas around the new airport and Sydney's third city "Bradfield". Some limited support will be available from Macarthur once Endeavour Energy's planned interconnecting line is constructed. The forecast for this area suggests an additional 200 MVA of additional load, mostly commercial/industrial, by 2030.

For Sydney West, 50% of lot releases are industrial, 24% are commercial and 26% are Residential. The lot releases are based on actual applications and the load applied for is adjusted down by Endeavour Energy to reflect less than requested realisation of this load. However, developer driven delays from one year to the next are difficult to predict and at times load is realised later than the applications indicated.

Large spot loads (greater than or equal to 1.8 MW) account for almost 300 MW of additional load of which more than 200 MW is for data centres and the remainder includes Westmead Hospital and North Connex. Smaller spot loads (less than 1.8 MW) include 64% residential or mixed residential/commercial developments, 32% is for purely commercial developments and 28% is industrial

3.3.2 Treatment of north-west NSW spot loads

Essential Energy have included three projects that are in an advanced stage of planning (or construction has commenced) in their forecasts for Gunnedah and Narrabri, for which AEMO forecasts have made no allowance. All three projects have been undergone all necessary planning approvals.⁹¹⁰¹¹

⁹ https://narrabrigasproject.com.au/2020/11/santos-welcomes-federal-signoff-on-narrabri-gas-project/ Federal and state sign-off.

¹⁰ https://www.abc.net.au/news/2021-09-16/environment-minister-approves-vickery-mine-after-legal-challenge/100413308 Federal and state sign-off.

¹¹ https://www.theland.com.au/story/6849045/finally-construction-starts-on-carroll-cotton-cos-new-20m-gin/

4. Assessment of forecast outcomes

The DNSP zone substation forecast method of normalisation and weather correction of historical demand generally represent good industry practice and are unlikely to be responsible for significant different forecast outcomes when compared with equivalent AEMO forecasts. It is possible that the DNSP forecasts have generally under-forecast the impact of increasing behind the meter PV penetration, peak shifting using behind the meter energy storage and increasing appliance efficiency (DER), which would have resulted in a higher baseline forecast (i.e., before the addition of new spot loads) than is evident in the AEMO forecasts. There may also be small differences due to the different treatment of embedded generation. However, none of these methodological differences or differences in assumptions make a significant difference, except perhaps in the cases of forecast growth rates for Panorama and Beryl.

There are however significantly different outcomes for Sydney West, Macarthur, Vineyard, Gunnedah and Narrabri owing to differences between AEMO and DNSPs in allowances for new spot loads. DNSPs have followed a consistent process from one year to the next in the treatment of lot releases and spot loads. However, this consistent process is now dealing with an unprecedented volume of connection applications in western Sydney.

Network businesses have long planning horizons and would be neglecting their responsibilities if they neglected single projects that would impact significantly on electricity demand at a location (such as the Narrabri Gas Project). They also need to plan for the eventuality that a handful of large projects (such as data centres connecting to Sydney West), along with numerous smaller ones, will proceed after fulfilling all approval and planning requirements.

4.1 Western Sydney

4.1.1 Macarthur 66 kV and 132 kV

The TransGrid summer maximum demand forecast of 5.1% p.a. growth, totalling 193 MW, is dependent on expectations about lot releases and spot loads. The forecasts cannot be directly compared with AEMO's forecasts. The forecasts were prepared by Endeavour Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. There is a very detailed and rigorous consideration of material facts and local knowledge concerning spot loads and lot releases.

Although Endeavour Energy applied an additional discount to the spot load projections because of COVID, it may be the case that some private developments are connected at a much slower rate for a number of years in light of reduced immigration. Therefore, it may be wise to develop various future scenarios based on the DNSP forecast as a suitable basis to inform the planned pipeline of TransGrid projects.

4.1.2 Sydney West 132 kV

The TransGrid summer maximum demand forecast of 3.7% p.a. growth, totalling 496 MW, is dependent on expectations about lot releases and spot loads. The forecasts cannot be directly compared with AEMO's forecasts. The forecast was prepared by Endeavour Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. There is a very detailed and rigorous consideration of material facts and local knowledge concerning spot loads and lot releases.

Although Endeavour Energy applied an additional discount to the spot load projections because of COVID, it may be the case that some private developments are connected at a much slower rate for a number of years in light of reduced immigration. Therefore, it may be wise to develop various future scenarios based on the DNSP forecast as a suitable basis to inform the planned pipeline of TransGrid network projects.

4.1.3 Vineyard 132 kV

The TransGrid summer maximum demand forecast of 4.2% p.a. growth, totalling 265 MW, is dependent on expectations about lot releases and spot loads. The forecast cannot be directly compared with AEMO's forecasts. The forecast was prepared by Endeavour Energy using a series of steps similar to those used throughout the

industry, including AEMO. These steps are reasonable well documented. There is a very detailed and rigorous consideration of material facts and local knowledge concerning spot loads and lot releases.

Although Endeavour Energy applied an additional discount to the spot load projections because of COVID, it may be the case that some private developments are connected at a much slower rate for a number of years in light of reduced immigration. Therefore, it may be wise to develop various future scenarios based on the DNSP forecast as a suitable basis to inform the planned pipeline of TransGrid projects.

4.2 Essential Energy north-west

4.2.1 Gunnedah 66 kV

The TransGrid summer maximum demand forecast of 4.8% p.a. growth, totalling 15 MW, is dependent on expectations about specific spot loads. In the absence of those spot loads, the underlying growth aligns with AEMO's forecast. The forecast was prepared by Essential Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. There is a very detailed and rigorous consideration of material facts and local knowledge concerning spot loads and lot releases. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.2.2 Narrabri 66 kV

The TransGrid summer maximum demand forecast of 7.7% p.a. growth, totalling 49 MW, is dependent on expectations about specific spot loads. In the absence of those spot loads, the underlying growth aligns with AEMO's forecast. The forecast was prepared by Essential Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. There is a very detailed and rigorous consideration of material facts and local knowledge concerning spot loads and lot releases. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.3 Essential Energy central west

4.3.1 Beryl 66 kV

The TransGrid summer maximum demand forecast of 1.1% p.a. growth, totalling 9 MW, is dependent on the growth of individual zone substations downstream. The underlying growth exceeds AEMO's forecast for zero growth. However, the forecast was prepared by Essential Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.3.2 Orange 66 kV

The TransGrid summer maximum demand forecast of 0.9% p.a. growth, totalling 4 MW, is in line with historical growth and is almost identical to AEMO's independent forecast. The forecast was prepared by Essential Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.3.3 Orange 132 kV

The TransGrid summer maximum demand forecast of 1.9% p.a. growth, totalling 28 MW, is sustained by planned increased Cadia mine load. There is no equivalent published AEMO forecast. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.3.4 Panorama 66 kV

The TransGrid summer maximum demand forecast of 0.9% p.a. growth, totalling 6 MW, is based on the expectation that recent historical area growth will continue. The underlying growth exceeds AEMO's forecast for zero growth. However, the forecast was prepared by Essential Energy using a series of steps similar to those used

throughout the industry, including AEMO. These steps are reasonable well documented. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.3.5 Parkes 66 kV

The TransGrid summer maximum demand forecast of 1.4% p.a. growth, totalling 4 MW, is in line with historical growth and is almost identical to AEMO's independent forecast. Both forecasts appear to include the same spot load. The TransGrid forecast was prepared by Essential Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

Parkes 132 kV

The TransGrid summer maximum demand forecast of 2.7% p.a. growth, totalling 11 MW, is sustained by planned increased mining load. There is no equivalent published AEMO forecast. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.4 Australian Capital Territory

The AEMO ACT zone substation forecasts and the TransGrid ACT supply point forecasts are well aligned and appear to include the same spot load allowance for new data centre capacity.

4.4.1 Canberra 132 kV

The TransGrid summer maximum demand forecast of 1.9% p.a. growth, totalling 47 MW, mainly reflects a share of the redistribution of load from Queanbeyan following the retirement of supply from that location in 2025. There is no equivalent AEMO forecast at this level. The TransGrid forecast was prepared by Evoenergy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. On the basis that the predicted sharing of total ACT load between each supply point is correct, the DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.4.2 Queanbeyan 66 kV (supply to Evoenergy)

The TransGrid summer maximum demand forecast of -100% p.a. growth, totalling -23 MW, as supply to ACT from Queanbeyan is retired in 2025. There is no equivalent AEMO forecast at this level. The retirement is jointly planned by TransGrid and Evoenergy and the forecast is therefore a suitable basis to inform the planned pipeline of TransGrid projects.

4.4.3 Stockdill

The TransGrid summer maximum demand forecast zero growth is based on assumptions about the sharing of overall growth in the ACT. On the basis that this sharing is correct, the DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.4.4 Williamsdale 132 kV

The TransGrid summer maximum demand forecast of 1.1% p.a. growth, totalling 20 MW, mainly reflects a share of the redistribution of load from Queanbeyan following the retirement of supply from that location in 2025. There is no equivalent AEMO forecast at this level. The TransGrid forecast was prepared by Evoenergy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. On the basis that the predicted sharing of total ACT load between each supply point is correct, the DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.5 Snowy Mountains

4.5.1 Cooma

The Cooma 66 kV winter maximum demand was anticipated by TransGrid to fall by 7 MW in 2021 and thereafter remain constant throughout the forecast period. The Cooma 132 kV winter maximum demand forecast increases by 1.6% p.a. or 7 MW in total. Taken together this not significantly different to AEMO's forecast growth rate for Cooma, although there is some disagreement about the level of temperature-corrected load. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.5.2 Munyang

The Munyang winter maximum demand was anticipated by TransGrid to increase by 2.5% p.a. or 7 MW in total, due to planned ski field projects. Taken together this not significantly different to AEMO's forecast growth rate for Cooma, although there is some disagreement about the level of temperature-corrected load. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.6 Broken Hill

4.6.1 Broken Hill 22 kV

The TransGrid summer maximum demand forecast of 0.3% p.a. growth, totalling 1 MW, is aligned with average historical growth and is almost identical to AEMO's independent forecast. The forecast was prepared by Essential Energy using a series of steps similar to those used throughout the industry, including AEMO. These steps are reasonable well documented. Although the historical maximum demand exhibits large fluctuations, the DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

4.6.2 Broken Hill 220 kV

The TransGrid summer maximum demand forecast of zero growth is sustained by existing mining load. There is no equivalent published AEMO forecast. The DNSP forecast is a suitable basis to inform the planned pipeline of TransGrid projects.

5. Findings in relation to the demand forecasts

AEMO's top-down regional forecast for NSW is able to account for observable relationships between electricity demand and forecast economic growth, which, to a degree, may be more reliable than they would be at a connection point level, even if the necessary data were available. However, much information about future loads at an individual connection point is more tangible. With good local knowledge, both forecasts should have useful insights to offer. However, by scaling the primary connection point forecasts to be consistent with the top-down forecast AEMO is relegating local knowledge that contributes to each connection point's future growth to secondary importance.

Each DNSP is responsible for managing and planning numerous (in some cases 100s) of zone substations and is a primary point of contact for land developers, and investors in residential, commercial and industrial projects. Their understanding of local development and specific circumstances is well developed, and they have a major responsibility to ensure that the future network is able to reliably cater for future loads.

It is likely that the AEMO's conservative attitude towards spot loads acts to minimise the overall adjustment of the primary connection point forecasts down, which is to say that important learnings about locational growth such as at Sydney West are not taken into account when developing the top-down forecast.

It is always possible that some future spot loads that have been included in TransGrid's forecasts (i.e., after substantial discounting) may still be postponed due to economic circumstances or even cancelled. That Is not to say that the most reliable forecast has not been put forward, only those forecasts inherently include an element of uncertainty.

Based on the evidence considered, the general approach taken by each DNSP, the level of careful application of that approach and the level of detailed local understanding demonstrated suggest that each of TransGrid's connection point demand forecasts generally represent a realistic expectation of future demand.

The most likely demand forecasts for planned electricity consumer projects are likely to be those that DNSPs have included after detailed assessment and discounting. However, network planning at locations where the demand forecast includes a relatively large growth component made up of planned electricity consumer projects may consider alternative scenarios for with and without the projects.

6. Implications of the findings for the AUGEX projects

6.1 Impact of Demand Forecasts

Impact of the demand forecasts on specific TransGrid AUGEX projects is summarised in Table 4. A brief project reference overview is also provided.

Project description	TransGrid reference	Impact of load forecast		
Supply to Sydney West area	N2371	This project concerns Sydney West. This substation will only take a fraction of the current demand forecast increase in summer maximum demand before the firm capacity of the transformers is exceeded.		
		Sydney West transformer capacity of 1,500 MVA forecast will be exceeded in summer 2023/24 under the latest forecast.		
		Under last year's forecast the transformer capacity would not have been exceeded 2029/30.		
Supply to Western Sydney priority growth area	1687	This project concerns Sydney West, Macarthur and Vineyard. The issue at Sydney West is described above.		
		The firm capacity of the Macarthur transformers of 472 MVA forecast will be exceeded in summer 2027/28 under the current demand forecast, one year later than under last year's forecast		
Supply to Vineyard area	N2373	The firm capacity of the Vineyard transformers of 750 MVA forecast will be exceeded in summer 2026/27 under the current demand forecast, one year later than under last year's forecast.		
Maintain voltage in the Vineyard area	N2360	The limitation on the capacity of the Vineyard transformers is described above		
Supply to north-west slopes area	1693	Committed customer projects in north-west New South Wales cannot be reliably accommodated without network augmentation.		
		In particular, network quality will deteriorate following commencement of the Narrabri Gas Project in 2025/26 and may require load shedding in the event of an N-1 contingency.		
Maintain voltage in Beryl area	1316	A number of planned customer projects will result in voltage stability network limitations in the 132 kV system and thermal limits in the 330 kV system.		
		Existing voltage constraints will only worsen with forecast load growth. However, the load forecast at Beryl is not the primary driver of already existing voltage constraints.		
Supply to Bathurst, Orange and Parkes	N2384	Forecast demand growth due to a number of existing and planned mine expansions in the Orange and Parkes areas will result in voltage stability network limitations in the 132 kV system and thermal limits in the 330 kV system.		
Supply to ACT – network capability (Contingent Project)	N2293	Supply reliability and resilience to the ACT will deteriorate following planned decommissioning of two transformers at Canberra substation. AUGEX requirement is contingent on timing of asset decommissioning.		
Maintain voltage in the alpine area	N2645	Planned customer loads in the alpine region will result in undervoltage and risk of load shedding. This risk will increase if planned spot loads go ahead and Cooma growth is as forecast. The majority of the step-up in load will occur in winter 2026.		
Supply to far west NSW network	1698	The existing load forecast for Broken Hill does not include an allowance for either the proposed Cobalt Blue (50 MW) or Hawsons Iron ore (130 MW) mining developments. Should either go ahead, potential network impacts would include voltage levels outside secure operating limits		

Table 4 Impact of load forecasts on the specified AUGEX projects

6.2 **Project Drivers**¹²

6.2.1 Supply to Sydney West area

OER N2371

The need to provide additional bulk supply capacity into the Sydney West area to meet customers' demands for electricity and to meet connection point reliability requirements. The latest Endeavour Energy Zone Substation demand forecast shows rapid load grow in the Sydney West area due to the connection of new data centres and ongoing development of commercial and residential lands and associated infrastructure in the area. The significant demand growth is mainly driven by spot loads including data centres, metro train lines and large commercial/residential development. The latest Endeavour Energy POE50 summer maximum demand including the committed Data Centre and Aerotropolis spot loads is forecast to exceed the Sydney West BSP firm supply capability from 2022/23. There is an emerging risk of unserved energy at Sydney West BSP due to the increasing summer demand exceeding the firm capacity at the site. The gap between the POE50 demand forecast and firm transformer capacity is expected to increase from 62 MVA in 2023/24 to 731 MVA in 2029/30. This will result in load shedding under single or multiple outages of 330/132 kV transformers in order to contain loads to within ratings of the remaining in-service units.

6.2.2 Supply to Western Sydney priority growth area

NOSA 1687

Development of the Western Sydney International (Nancy Bird Walton) Airport was announced in 2014. Since the announcement, development of the surrounding area, both by the NSW Government and the private sector, is steadily progressing. The Greater Sydney Commission oversees planning for the greater Sydney region, including the overseeing of its vision for a metropolis of three cities, which includes the development of a Western Parklands City centred on the Western Sydney Airport. In late 2019 the NSW Government released draft precinct plans outlining development objectives and priorities associated with the Western Sydney Parklands City, including the Aerotropolis draft precinct.

Endeavour Energy's existing zone substations of Luddenham, Bringelly and Kemps Creek will initially provide sufficient capacity for small developments, but there is insufficient subtransmission and distribution system capacity to sustain development beyond the next two to four years. TransGrid has four bulk supply points which currently provide supply into the area via Endeavour Energy's subtransmission and distribution network. The four bulk supply points are: > Sydney West BSP > Macarthur BSP > Liverpool BSP > Regentville BSP All four bulk supply points are approaching capacity limitations in the medium term, but in particular Sydney West BSP is forecast to reach its firm supply capacity limit within five years. Therefore, establishment of additional bulk supply capacity is expected to be required.

6.2.3 Supply to Vineyard area

OER N2373

The North West Growth area in NSW Government's Precinct Planning has significant new developments planned for housing, local industry (including an industry park) and new associated commercial and social infrastructure. This development is expected to lead to fast load growth in the Endeavour Energy network supplied by Vineyard substation. The planned development is expected to result in the POE50 summer maximum demand at Vineyard forecast to exceed the Vineyard BSP firm supply capability by 2026/27. There is an emerging risk of unserved energy at Vineyard following the increase in summer demand beyond the firm capacity at the site. The gap between the POE50 demand forecast and firm transformer capacity is expected to increase from 25 MVA in

¹² TransGrid NOSA and OER references

2026/27 to 156 MVA in 2031/32. This will result in load shedding under single or multiple outages of 330/132 kV transformers in order to contain loads to within ratings of the remaining in-service transformer units.

6.2.4 Maintain voltage in the Vineyard area

OER N2360

To meet the requirement for maintaining reactive margin (voltage stability) limits as specified in the National Electricity Rules. Given the forecast demand growth in the Vineyard area and without network augmentation, the total demand on Vineyard BSP will need to be limited to 666 MVA to meet reactive margin requirements under the NER. The reactive margin at Vineyard 330 kV and 132 kV busbars will drop to below one percent of the fault level at those locations from summer 2024/25 under a single credible contingency of the 330 kV Line 29 that supplies the Vineyard BSP from Sydney West. To maintain the required reactive margin if the contingency occurs during high demand, load curtailment would be required from Summer 2024/25 based on the POE50 demand forecast.

6.2.5 Supply to north-west slopes area

NOSA 1693

The available capacity in the Gunnedah and Narrabri area is limited following connection of the Narrabri Gas Project by thermal constraints on 969 Line under system normal and for a contingent outage of 968 Line, and voltage stability constraints between Gunnedah and Narrabri. The thermal constraint on the 969 line can occur during system normal or a contingent outage of the 968 line for the low and central scenarios, when there is no generation in service in the area to offset the load. It can also occur during system normal from 2029 onwards in the central scenario even with some generation in service. The voltage stability constraint occurs for a trip of the 969 line, and is prevalent in both the low and central scenarios.

6.2.6 Maintain voltage in Beryl area

OER 1316

Power system studies have identified under voltage constraints and reactive margin shortfalls in the Beryl area for a contingent outage of line 94B7, particularly when the renewable generation in the area is not dispatched. To address this need, augmentation of the transmission network in the area is required in order to avoid unserved energy due to interruption of supply to loads in the area under (n-1) contingency conditions. Interruptions of supply under these conditions would be required to manage the emergence of voltage limits and reactive margin shortfalls being reached, and to avoid voltage collapse in the local 132 kV supply network.

6.2.7 Supply to Bathurst, Orange and Parkes

OER N2384

The available capacity in the Orange and Parkes areas is limited by voltage stability limits at Orange/Panorama and Parkes, and thermal limits between the 330 kV main system at Wollar, Wellington and Mt Piper and the 132 kV subsystem.

Power system studies have shown that the existing Central West network is not capable of supplying the forecast demand growth. A number of under voltage conditions and voltage step change violations (>10%) have been identified at various locations under (N-1) contingency and outage conditions. There are a number of needs already raised for this supply area, which investigate options to manage the risks associated with the load growth in the short to medium term. In addition to the longer-term voltage constraints the increased demand will also lead to thermal constraints particularly at times of low renewable generation dispatch in the Central West region.

6.2.8 Supply to ACT – network capability

OER N2293 (Reclassified as a Contingent Project)

TransGrid's Canberra 330/132 kV Substation has four 132 kV capacitors that support main grid voltage levels, configured as three 120MVAr banks and one 80MVAr bank. When maximum power transfer is required from the Snowy Mountains to Sydney (or vice versa), the voltage at Yass and Canberra must be maintained at high levels

to ensure voltage stability of the main grid. When any one of the capacitors at Canberra Substation are switched, a voltage step change is transferred to the Evoenergy distribution network which could cause temporary over or under-voltage conditions.

Further, Canberra 330 kV Substation was previously a four transformer substation with two 375 MVA, 330/132 kV transformers and two 400 MVA, 330/132 kV transformers. Following the commissioning of Stockdill 330/132 kV Substation in late 2020, the No.2 and No.3 Canberra transformers (400 MVA each) have been decommissioned, thereby reducing the transformer capacity at Canberra Substation to half. This change in network configuration increases the normal system impedance at the Canberra 132 kV busbar, which in turn increases the capacitor switching step voltage change, exacerbating the voltage step-change conditions that need to be addressed. These increased step changes are not expected to be manageable, using the existing operating processes.

6.2.9 Maintain voltage in the alpine area

OER N2645

To manage and to meet expected future demand growth in the Alpine area of New South Wales supplied from Munyang and Cooma Bulk Supply Points (BSP). The latest demand forecasts show that the winter peak demand at Munyang 33kV BSP is expected to continue to increase over the next 10 years. This is due to a number of spot loads associated with snow making and ski-related commercial loads in the Thredbo and Perisher areas that are planned to be connected to the network but take supply only during winter times.

Undervoltage (with associated risk of load shedding) will increase if planned spot loads go ahead and Cooma growth is as forecast. The majority of the step-up in load will occur in winter 2026. TransGrid has assessed the existing peak demand and the impact of the additional spot loads during winter times in the Alpine region for the planning horizon. This has identified existing and potential future network constraints that are required to be remediated to ensure that these loads can be connected to the network at their full capacity

6.2.10 Supply to far west NSW network

NOSA 1698

To meet or manage demand growth in the Broken Hill area, which is forecast to increase significantly over the next 10 years. TransGrid has identified new mine loads planning to connect to the Broken Hill area, with the forecast load expected to increase by 200MW by end of 2025 and a further 25 MW in 2029.

The existing load forecast for Broken Hill does not include an allowance for either the proposed Cobalt Blue (50 MW) or Hawsons Iron ore (130 MW) mining developments. Should either go ahead, potential network impacts would include voltage levels outside secure operating limits.

Appendices

Appendix A Endeavour Energy forecasting methodology

Peak demand forecasts are prepared for both the summer and winter season. Summer is defined as the fivemonth period between November and March while winter consists of the four-month period from May to August. The forecast method is based on a bottom-up approach and provides maximum MVA, MW and MVAr loads and the power factor expected for the summer and winter peak periods.

The forecasts are prepared for each zone substation and major customer substation, each transmission substation and TransGrid's Bulk Supply Points (BSPs) that supply the Endeavour Energy network. The total Endeavour Energy network peak demand is also forecast.

The forecasts consider planned load transfers, expected spot loads, land release developments and redevelopments in the area under consideration. Loads supplied by generation embedded in the network are also incorporated into the calculation of the maximum demand forecasts.

Historical and forecast peak demands at the Endeavour Energy total, bulk supply point, transmission substation and zone substation levels are corrected to normalised figures that represent a specific weather condition. Temperature Corrected Maximum Demand (TCMD) is the estimate of the likely peak demand that could be expected in the reference conditions with 10% and 50% Probability of Exceedance (PoE).

Weather correction is applied to the peak demands at substations where there is a strong relationship between demand and temperature. Summer demands at zone substations in the Blue Mountains and demands of all high voltage customers are not subject to any weather normalisation. However, the Blue Mountains substations are subject to weather normalisation for winter peak demands.

A weather normalisation methodology based on a simulation approach is used to normalise peak demand forecasts for Endeavour Energy's network area. Two reference weather stations are employed for temperature correction of the maximum demand for summer. A weather station at Nowra is used for the South Coast area which covers the Dapto BSP Region and the Richmond weather station is used for the remainder of the network. The temperature correction method utilises two steps:

- Development and updating of a regression model for estimating the relationship between demand, weather and periodic pattern (calendar effects) of demand; and
- Simulation of the demand using multi-years of historical weather data to produce 10% and 50% normalised demand values.

For the summer peak, the regression model uses the most recent six years of daily maximum demand and temperature values to determine the relationship between demand, weather and periodic patterns of demand. Various input parameters are employed in the model. Day-of-the-week variables account for the difference between the daily peak by day of the week and by workday/non-workday. A set of holiday variables are included to describe the load reductions associated with holiday periods. Separate variables are used for special days such as: New Year's Day, Australia Day, and Christmas Day. In addition, a school holiday variable captures the reduced loads which occur in residential Western Sydney during the school holiday period in December and January and the commensurate increase in demand seen in some south coast zone substations during the same period. Monthly and bi-monthly variables capture the key seasonal demand variations. Year variables describe the changes in base load level for each year. Previous hot day effect variables are also included to explain the impacts of successive hot days on the daily peak demand.

From the regression model, daily demands are estimated using 24 years of daily weather data available from the reference weather stations. Annual seasonal maximum demands are derived from the calculated daily demands. The 10% and 50% demand values are computed from the distribution of annual seasonal maximum demands to give the 10% and 50% PoE TCMD values. The TCMD values for the latest year are the starting points for the peak demand forecasts.

The peak demand forecast considers the growth or decline from the existing customers as well as the new customer connections. The forecasting process has two major steps:

Incorporating the network planner's inputs into the base level forecast.

The inputs include new developments planned to occur (lot releases), new load increases expected from customer applications (spot loads) and information regarding the transfer of load between zone or sub-transmission substations (load transfers).

- Applying post model adjustments (PMA).

PMAs are applied to each year of the forecast for each zone substation based on the zone substation's residential, commercial and industrial customer mix and its peak demand for the season. PMAs are designed and used to capture future changes in the peak demand resulting from solar generation, battery energy storage, electric vehicles and from different state and national energy policies/programs, such as the Minimum Energy Performance Standards (MEPS), NSW Energy Savings Scheme (ESS) and changes to the building code.

The final forecasts for all zone substations are reviewed for consistency with expected demand growth based on local knowledge of load transfers, embedded generation, proposed spot-loads and lot release information.

The forecast at transmission substations and bulk supply points is based on the rolled-up zone substation forecast and calculated using the corresponding historical diversity factors.

The diversity factor is considered to be the ratio between the summation of the individual peak demands of the lower level substations and compared to the measured peak demand of the higher-level substation for the same period.

Appendix B Essential Energy forecasting methodology

At a high level, the process consists of:

i. Data collection and collation

To cater for regional and local needs, a forecast of the demand at each zone substation is developed based on historical demands and information provided by major customers. Account is taken of load diversity between connection points. Embedded generation is recognised and included in the forecast where it offers firm capacity at the time of demand.

ii. Outlier removal / Data preparation

In order to ensure only system normal conditions are evaluated, short-term network switching and abnormal metering outputs are removed.

iii. Weather correction (or normalisation)

Historical demand is weather corrected in order to provide a reference set of conditions from which each year can be compared (with a probability of exceedance of 50 per cent). Daily temperatures and solar irradiance from relevant weather stations are used in the correction to account for various forms of demand behaviour.

iv. Repeat for each season over the time periods available

The forecast covers both summer and winter demands and uses data going back up to ten years. Where the load is very consistent the historical data is not analysed in separate seasons. This variation improves the accuracy of some forecasts, especially when step changes in total load occurs.

v. Determine the most applicable growth rate based on known variables

A series of short and long-term trends in the ten years of temperature-corrected historical demand are analysed and growth rate selected based on the median of such trends. Where the median does not accurately reflect a sites' growth (e.g. significant changes in historical configuration, customer mix, etc) an alternative growth rate is selected to reflect the current status of the site. In some cases, it may be necessary to remove certain time periods from the analysis where configuration changes have been deemed to impact the trend analysis.

vi. Determine starting point of forecasts

Forecasts generated from trending weather-corrected history and raw history are compared and the most suitable model is chosen as the starting point of each sites' forecast. Where both models generate poor results (e.g. small dataset, major configuration changes, etc) then the starting point is taken to be the value of the most recent historical seasonal maximum demand.

vii. Calculate forecast load

The forecast extends over a planning horizon of ten years, with the first five years published in this report. The forecast power factor used is the median of the power factor distribution based on the top 1% of half-hourly demands over the last three years.

viii. Apply any post model adjustments

Where there is known potential for the connection of major spot load developments, such as mining loads and major subdivisions, the forecast takes into account any reasonably firm step load increases in the medium term.

ix. Reconciliation of forecasts

Calculation to ensure the forecast aligns with upstream and downstream components, and identification of changes to previously developed forecasts.

Appendix C Evoenergy forecasting methodology

A fully Bayesian model for seasonal maximum and time-of-day minimum demand data was developed, motivated by the need for coherence, plausibility and parsimony of model assumptions and predictors affecting long term demand forecasts. The predictive performance of the model was assessed by comparing maximum demand forecasts with those from last year's annual planning report using the same historical data. 10-year forecasting results using the new parsimonious Bayesian model is consistent with the previously used Monash Electricity Forecasting Model (MEFM); and demonstrate the suitability of the Bayesian model framework for long term demand forecasting, both minimal and maximal.

The new long-term demand forecasting model implements a joint model for temperature T and maximum/minimum demand as a function of time (corresponding to a specific financial year and season/time-of-day) t.

Specifically, the maximum/minimum demand of measurement i is

where

$$\begin{split} \mu_{\text{baseline},i} &= \beta_{00,\text{MD}} + \sum_{k=1}^{N_{\text{ch}}} I\left(t_i, t_{\text{ch}, k}\right) \beta_{0k,\text{MD}}, \\ \mu_{\text{temp},i} &= \beta_{1,\text{MD}}(T_i - \min(T_i)), \\ \mu_{\text{growth},i} &= \beta_{2,\text{MD}} t_i, \end{split}$$

and the likelihood of is modelled using a Gumbel distribution:

$$\begin{array}{ll} T_i & \sim \operatorname{Gumbel}(\mu_{T,i},\sigma_T) \,, \\ \mu_{T,i} & = \beta_{0,T} + \beta_{1,T} t_i \,. \end{array}$$

The following (weakly) informative priors are used:

$$\begin{array}{ll} \beta_{0,T} & \sim \mathsf{N}(\min(T), \sqrt{\mathsf{abs}(\min(T))}, \\ \beta_{1,T} & \sim \mathsf{N}(0.01, 0.001), \\ \sigma_T & \sim \mathsf{Half-Cauchy}(0, 2.5), \\ \beta_{00,\mathsf{MD}} & \sim \mathsf{N}(\mathsf{mean}(\mathsf{MD}), 10\sqrt{\mathsf{mean}(\mathsf{MD})}), \\ \beta_{0k,\mathsf{MD}} & \sim \mathsf{N}(0, 10), \\ \beta_{0k,\mathsf{MD}} & \sim \mathsf{N}(0, 10) & \text{for maximum demand modelling} \\ \beta_{1,\mathsf{MD}} & \sim \begin{cases} \mathsf{N}(0, 10) & \text{for maximum demand modelling} \\ \mathsf{N}(0, 0.1) & \text{for minimum demand modelling}, \\ \beta_{2,\mathsf{MD}} & \sim \mathsf{N}(0, 3), \\ \sigma_{\mathsf{MD}} & \sim \mathsf{Half-Cauchy}(0, 2.5). \\ \end{array}$$

Key features of the model can be summarised as follows:

- Maximum demand is decomposed into a baseline, temperature and (organic) growth component. All three components have either a direct (baseline, growth) or indirect time dependence (temperature).
- The baseline component allows for historic block loads by fitting a piecewise constant to the observed data using the indicator function

$$I(t_i, t_{ch,k}) = \begin{cases} 1 & \text{if } t_i \ge t_{ch,k}, \\ 0 & \text{else}, \end{cases}$$

where t_{ch,k} is the time of the ch change point (block load).

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- For maximum demand modelling, the temperature component uses recorded annual extremal temperatures (maximum temperatures for the summer MD model, minimum temperatures for the winter MD model) for the years with recorded historical MD data. Simultaneously, the model estimates the parameters of the underlying Gumbel temperature distribution using all available temperature data. Annual extremal temperature data are available from 1996 onwards, and are averaged across two weather stations in the ACT (Canberra Airport and Isabella Plains (Tuggeranong)). Characterising both models jointly ensures that uncertainties in the parameter estimates from both the MD and T models are properly included in
- the long-term MD forecasts. For minimum demand modelling, a narrow and strongly informative prior centred around zero is chosen for β1,MD, whose regularisation properties characterise the lack of any strong temperature dependence in minimum demand data.
- In alignment with model parsimony, organic growth is modelled using a simple linear time dependence; it was confirmed that a higher-order polynomial fit to the historical MD data does not provide better forecasts. The organic growth component can be interpreted as the compound effect that captures economic growth as well as the MD offset due to increased PV generation.
- As with all Bayesian models, using sensible prior distributions on all parameters is critical to obtaining meaningful posterior densities. Specifically, a narrow and informative prior was chosen for ß1,T to include a small and realistic time dependent global warming effect. The mean time-dependent effect of 0.01 °C per year is in agreement with the observed changes in the global Australian climate system of about 1 °C since 1910 [Australian Government Department of Agriculture, Water and the Environment, Climate change]. All other weakly informative priors are chosen in agreement with common prior choice recommendations [Gelman, Prior Choice Recommendations].

Forecasts are then obtained following a three-step process:

- First, forecasts of temperature values T_{pred} for future years t_{pred} are obtained based on the fitted Gumbel model with posterior densities for the location μ_T and scale parameters σ_T.
- Posterior predictive densities of T_{pred} as well as posterior densities of all MD model parameters are then used to obtain MD predictions as posterior predictive densities MD_{pred} for all future years.
- Posterior predictive densities of maximum demand estimates are then adjusted for future block loads using afore-mentioned indicator function I(t_i, t_{ch}) which shifts the posterior predictive density by the future block load BL^q at time t_q. A table summarising future block loads is given in Table 29. Final MD estimates at the 100α% level is then obtained from the 100(1 α)% quantiles of the posterior predictive MD density at every year. Posterior predictive densities of minimum demand densities are not adjusted for future block loads, as the effect of block loads on minimum demand is difficult to assess; consequently, minimum demand estimates provide a lower bound on the forecast minimum demand trends.

All models are fitted to maximum and minimum demand data using the Bayesian inference framework and probabilistic programming language Stan [Stan Development Team, 2020, Stan Modeling Language Users Guide and Reference Manual] through the R interface rstan [Stan Development Team, 2020, RStan: the R interface to Stan, R package].