TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR NEW SOUTH WALES AND TASMANIA

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about transmission connection point forecasts for New South Wales and Tasmania.

AEMO publishes these connection point forecasts as requested by the Commonwealth of Australian Government's energy market reform implementation plan. This publication is based on information available to AEMO as at 31 July 2014, although AEMO has endeavoured to incorporate more recent information where practical.

Disclaimer

AEMO has made every effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the national electricity market might require, and does not amount to a recommendation of any investment.

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Acknowledgement

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EXECUTIVE SUMMARY

The Australian Energy Market Operator (AEMO) has produced the first independent electricity demand forecasting report of maximum demand (MD) at transmission connection point level for New South Wales (including the Australian Capital Territory) and Tasmania.

AEMO has developed these connection point forecasts at the request of the Council of Australian Governments (COAG) as part of its energy market reform implementation plan. The forecasts will be submitted to the Australian Energy Regulator (AER) as an independent reference for the 2014 regulatory determinations for TransGrid and TasNetworks. The AER assesses these network service providers' (NSPs) investment requirements.

AEMO's MD forecasts, developed at the point where the transmission network meets the distribution network, provide transparent, granular demand information at a local level. Together with the regional level MD forecasts published in AEMO's National Electricity Forecasting Report, the forecasts provide an independent and holistic view of electricity demand in the National Electricity Market (NEM). The increased transparency of demand forecasts supports efficient network investment for the long-term benefit of consumers.

MD forecasts at the connection point will also be used as an input into AEMO's planning studies, further strengthening AEMO's independent assessment of network infrastructure development requirements across the transmission system.

In developing these connection point forecasts, AEMO consulted widely with stakeholders, in particular the relevant transmission and distribution NSPs and the AER. This involved sharing local knowledge of the network, understanding differences in forecasting methodologies, and exchanging data.

AEMO has implemented a forecasting methodology that will be applied across all NEM regions, supporting a consistent and transparent approach to connection point forecasts in all states.

Results

Key findings of AEMO's connection point forecasts from 2014-15 to 2023-24 are:

In New South Wales:

Positive growth at New South Wales connection points is primarily driven by population growth and a positive economic outlook that is incorporated into the forecasts through reconciliation to the regional forecast. Declines in growth are driven primarily by load transfers, energy efficiency savings, and rooftop PV output during summer.

- Average annual 50% probability of exceedence (POE) growth rates, are on average moderate over the outlook period for summer and winter at 0.4% and 0.6% respectively. Summer growth rates for 10% POE were stronger at 0.5% while winter was the same at 0.6%.
- Summer 10% POE average annual growth rates range between -3.5% and 7.9%. The highest average annual growth rate (7.9%) is forecast at the Mount Piper connection point where mining loads are expected to increase demand. Excluding Mount Piper, the average annual growth rate, on average is 0.4%.
- Winter 10% POE average annual growth rates range from -6.4% to 8.1%. The highest average annual growth rate (8.1%) is forecast at Mount Piper, where future mining loads are expected to increase demand. Excluding Mount Piper, the average annual growth rate, on average is 0.5%.

In Tasmania:

Positive growth at Tasmanian connection points is primarily driven by major loads coming online which included loads from mining activity, irrigation and commercial developments. These account for seven of the 12 connection points with average annual growth of more than 1%. Declines in growth are driven primarily by industrial load closures (such as at the Newton connection point), energy efficiency savings, and rooftop PV output during summer.

- Average annual 50% POE growth rates, are on average relatively flat over the outlook period, at 0.3% and 0.2% for summer and winter respectively.
- Summer 10% POE average annual growth rates range between -1.0% and 2.2%, with the exception of Newton which has an average annual growth rate of -30.3% due to a major industrial load recently announcing plans to enter maintenance mode in late-2015. Excluding Newton, the average annual forecast growth rate, on average is 0.4%.
- Winter 10% POE average annual growth rates range between -1.4% and 4.5%, with the exception of Newton, which has an average annual growth rate of -31.8% due to a major industrial load recently announcing plans to enter maintenance mode in late-2015. Excluding Newton, the average annual forecast growth rate, on average is 0.3%.

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1 – INTRODUCTION

Under Clause 5.12 in the National Electricity Rules (NER), each transmission network service provider (TNSP) must undertake an annual planning review which analyses the future operation of its transmission network. The review must use transmission connection point forecasts provided by the local distribution network service providers (DNSPs), planning proposals, and other relevant information.

In its December 2012 energy market reform implementation plan[1], the COAG requested AEMO to begin providing independent demand[2] forecasts to improve the AER's ability to analyse the demand forecasts submitted by NSPs. This increased transparency will lead to more efficient network investment decisions, ultimately providing long-term benefits to energy consumers.

In 2013-14 AEMO started developing transmission connection point forecasts for New South Wales (including the ACT) and Tasmania. In 2014-15 AEMO will extend this work to Victoria, South Australia, and Queensland.

By July 2015, AEMO will have developed its first complete set of transmission connection point forecasts for all NEM regions. These will be updated annually.

This report covers transmission connection point forecasts for New South Wales and Tasmania. The forecasts are developed using a consistent methodology published on AEMO's website in June 2013[3], which facilitates:

- Consistency: across regional (state) borders.
- Relevance: taking into account economic, policy, and technological developments.
- Transparency: providing a detailed breakdown to increase understanding and help scenario analysis in investment decision-making.
- Accountability: performance monitoring of actual demand against forecast demand.

AEMO has developed 10% and 50% POE MD forecasts for a 10-year outlook period for summer (2014-15 to 2023-24) and winter (2014 to 2023).

In developing the forecasts, AEMO consulted extensively with NSPs in New South Wales and Tasmania. This included face-to-face meetings, data sharing, and exchanging local level information.

To further maintain the independence of these forecasts, AEMO engaged ACIL Allen as an independent advisor to the modelling process, and Frontier Economics as an independent peer reviewer.

1.1 Report structure

This report is structured as follows:

- Chapter 1: Introduction
- Chapter 2: Provides an overview of the forecasting process. This includes a summary of the timeline, the methodology and how it was implemented, and a high-level comparison of key differences between AEMO's independent forecasts and NSP forecasts.
- Chapter 3: Highlights key results for New South Wales and Tasmania. This includes graphs of 10% and 50% POE (summer and winter) forecasts, a summary of the average annual growth rates for each connection point across the outlook period, and key features of the connection points.
- Chapter 4: Provides a list of improvements AEMO has identified as requiring further investigation.

[1] COAG. *COAG Energy Market Reform – Implementation Plan.* Available at: https://www.coag.gov.au/node/481.
[2] Demand in this document is defined as operational demand of electricity from residential, commercial and large industrial sectors (excluding transmission losses) as supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, typically measured in MW.
[3] AEMO. *Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Demand – Report.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting.

- Appendix A: Provides a detailed breakdown of growth rates by connection point.
- Appendix B: Provides a list of data shared between AEMO and NSPs.
- Appendix C: Provides the definition of aggregated connection points in New South Wales.

1.2 Supplementary information on AEMO's website

Supplementary information to this report includes:

- A spreadsheet with the following information for each transmission connection point:
  - 10% POE and 50% POE forecasts over a 10-year outlook period, summer and winter.
  - High-level commentary.
  - Historical and forecast data.
- Reports from ACIL Allen Consulting (independent advisor) and Frontier Economics (independent peer reviewer) providing a review of AEMO's forecasts.

All documents are available on AEMO's website[4].

4 http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts

2 – FORECASTING PROCESS OVERVIEW

Shortly after publishing the connection point forecasting methodology in June 2013, AEMO began developing the forecasts. This involved engaging with all relevant stakeholders throughout the process as described in Section 2.1 and implementing a methodology that adheres to a set of best practice principles as described in Section 2.2.

In developing the forecasts, technical input was provided by ACIL Allen and Frontier Economics, as detailed below. Discussions with NSPs revealed some differences in methodologies which are described in Section 2.4.

2.1 Timeline

Developing connection point forecasts involves multiple stages as outlined in the table below.

Table 1: Outline of connection point forecast development

Date	Stage
June 2013	Published consistent methodology after consultation with stakeholders.
January 2014	Met with NSPs. Discussed assumptions, data, and local level information. Produced draft forecasts of subset of key connection points.
February 2014	Independent peer review of draft forecasts of subset of key connection points. Met with NSPs. Discussed assumptions, methodology, data sharing, and local level information.
March 2014	Met with NSPs. Discussed assumptions, methodology, data sharing, and local level information.
June 2014	Produced draft forecasts for all connection points. Met with NSPs. Discussed draft forecasts, assumptions, methodology, data sharing, and local level information. Presented draft results and methodology overview to AER.
July 2014	Independent advisor confirmed implementation of methodology and peer reviewer confirmed robust forecasts. Published report and forecasts.

After publishing the methodology, AEMO developed forecasts for a subset of key connection points.[5] This enabled ACIL Allen to review AEMO's implementation of the consistent methodology, and allowed Frontier Economics to conduct an independent peer review of the forecasts early in the project. It also facilitated productive discussions between AEMO and NSPs.

This approach was then repeated for the full set of connection points, with Frontier Economics conducting two additional reviews of the final forecasts. The review findings by ACIL Allen and Frontier Economics confirmed that AEMO's forecasts are robust. Their reports are available on AEMO's website.

In June 2014, AEMO provided the draft forecasts to the NSPs, and then to the AER along with an overview of the methodology.

[5] Key connection points were selected based on network limitations that AEMO believes are likely to occur over the next seven years. The network limitations were identified through the review of the 2013 National Transmission Network Development Plan (NTNDP) and NSCAS study results, the 2013 TNSP Annual Planning Reports and the capital expenditure list provided as part of the NCIPAP process. In addition, some key connection points relate to major asset replacement projects that AEMO studied in more detail. This comprised about a quarter of the connection points in New South Wales and half the connections points in Tasmania.

2.2 Forecast verification

To develop robust forecasts, AEMO followed several benchmark forecasting characteristics listed by the AER.[6] The table below lists these and outlines how AEMO addressed each.

Table 2: Characteristics of good forecasting techniques listed by the AER

Characteristic	AEMO implementation
Accuracy and unbiased data	Used AEMO wholesale meter data where possible. Data that was shared by the DNSPs was checked and verified with AEMO's databases where possible.
Transparency and repeatability	Engaged stakeholder in forecast development, including the AER and all NSPs. Developed and published consistent methodology. Independent peer reviewer independently reproduced AEMO's forecasts using the same data and modelling code provided by AEMO. Code base was internally peer reviewed.
Incorporation of key drivers and exclusion of spurious drivers	Consistent methodology incorporates most relevant demand drivers from time series trends, technological improvements (e.g., solar PV and energy efficiency) and regional economic and demographic drivers.
Model validation and testing	Forecasts were independently reviewed by Frontier Economics. Incorporated statistical significance testing for selection of starting point.
Accuracy and consistency of forecasts at different levels of aggregation	Connection point forecasts have been reconciled to the 2014 NEFR forecasts. AEMO will monitor the accuracy of the forecasts.
Use of the most recent input information	AEMO used demand data to the end of February 2014; the latest data available given the project timeframe. AEMO also monitored new developments and incorporated them where possible.

[6] AER. *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17, November 2011,* Attachment 3.2 p. 76. Available at: http://www.aer.gov.au/sites/default/files/Aurora%202012-17%20draft%20distribution%20determination.pdf.

2.3 Modelling

The forecasting methodology, published in June 2013[7], comprises seven major steps.

Table 3: Key steps in consistent methodology

Step	Description
1. Prepare data	Obtain and clean demand and weather data. Determine demand profile and demand mix.[8]
2. Weather normalise	Determine weather sensitivity at each connection point.
3. Select starting point	Determine where the forecasts should start from: last historical point or time trend line.
4. Select growth rate	Determine a growth rate to forecast future demand.
5. Baseline forecasts	Apply growth rate to selected starting point.
6. Apply post model adjustments	Adjust for rooftop PV and energy efficiency. The amount of rooftop PV and energy efficiency adjustments were derived from the 2014 National Electricity Forecast Report (NEFR).
7. Reconcile to system forecasts	Make the forecasts consistent with the 2014 NEFR thereby applying regional-level economic and demographic growth drivers at the connection point level. The regional forecasts were taken directly from the 2014 NEFR.[9]

Further information on the approach used to develop rooftop PV and energy efficiency forecasts is found in the Forecasting Methodology Information Paper.[10] In addition, the Monash report detailing how the 2014 NEFR maximum demand forecasts were developed is found in the Monash Electricity Forecasting Model Technical Report.[11]

The flowchart shown in Figure 1 (next page) details how AEMO's implemented this methodology.

Figure 1: Implementation of forecasting methodology

[7] AEMO. *Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Demand – Report.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting.

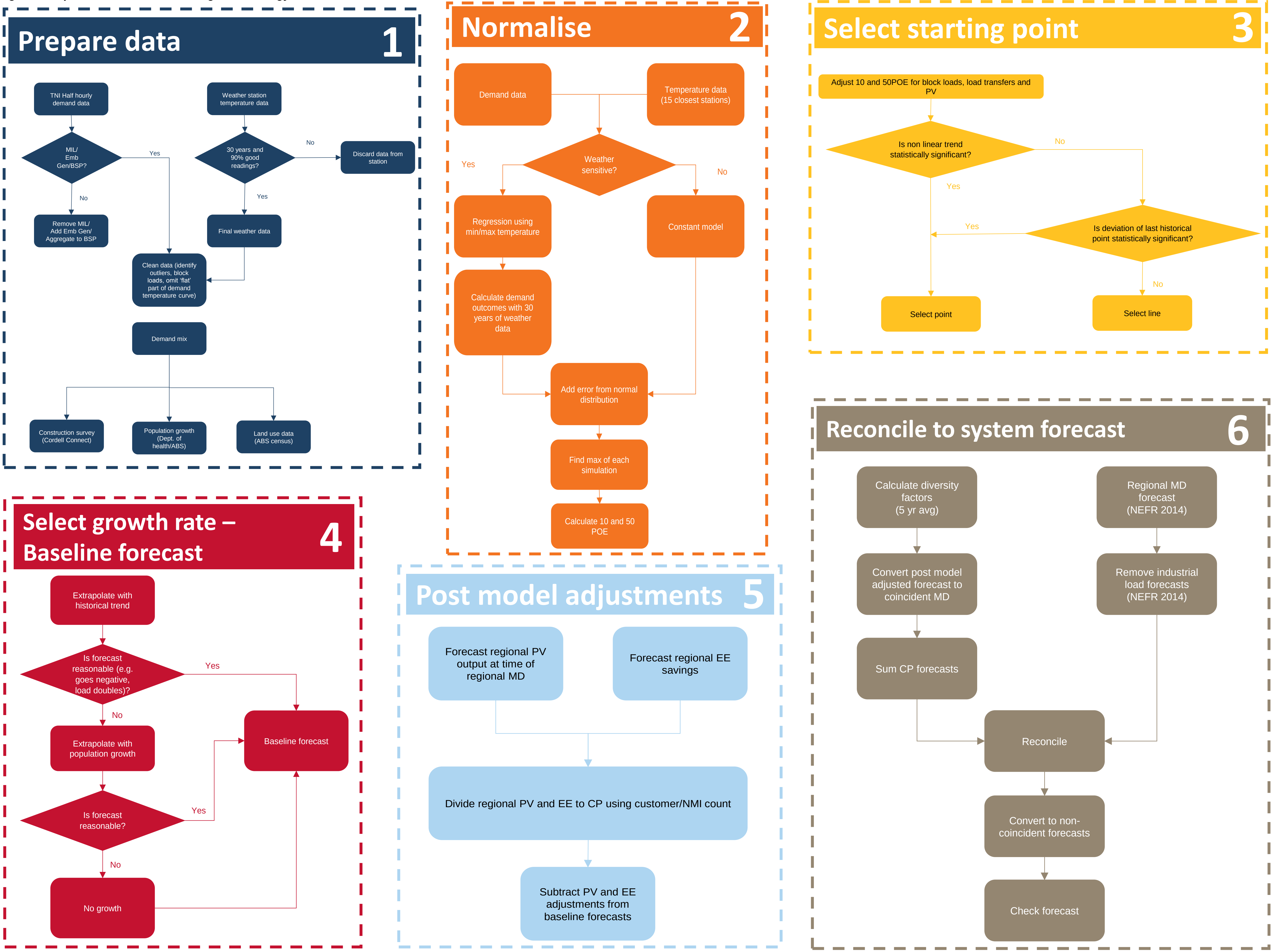
[8] The type of loads connected to each connection point (e.g., residential, agricultural, industrial).

[9] AEMO. *2014 National Electricity Forecasting Report*. Available at: http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.

[10] AEMO. *Forecasting Methodology Information Paper.* Available at http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

[11] Monash University. *Monash Electricity Forecasting Model Technical Report.* Available at http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/~/media/Files/Other/planning/NEFR/2014/2014%20Supplementary/Monash_Electricity_Forecasting_Model_Technical_Report.ashx

Figure 1: Implementation of forecasting methodology



2.4 Differences between AEMO and NSP methodologies

A key outcome of AEMO's engagement with NSPs was a better understanding of NSP forecasting methodologies. Several key differences between AEMO's approach and the various methodologies used by NSPs were identified. These are summarised in the table below.

Table 4: Common differences between AEMO and NSP methodologies

Description	AEMO	NSPs[12]
Rooftop PV	Explicitly accounted for rooftop PV. Derived directly from the 2014 NEFR. Regional rooftop PV contributions were disaggregated to connection points based on number of residential customers per connection point.	Of the seven NSPs, only one accounts for rooftop PV explicitly in their connection point forecasts.
Energy efficiency	Accounted for energy efficiency above historical trend. Derived the additional energy efficiency adjustment from the 2014 NEFR. Regional energy efficiency savings were disaggregated to connection points based on number of non-industrial customers per connection point.	Only one NSP accounted for energy efficiency explicitly. A common NSP view is that energy efficiency savings are inherent in the historical data and need not be accounted for explicitly.
Major industrial loads	Used the major industrial load forecasts from the 2014 NEFR. This was based on surveys conducted directly with each major industrial customer with loads greater than 10 MW.	NSPs derived major industrial load forecasts from direct contact with the customer and historical trends but at potentially different times during the year. As such, market conditions and outlooks might differ. One NSP also incorporated growth based on forecasts of each industry sector.
Reconciliation to state level forecasts	Reconciled the connection point forecasts to the 2014 NEFR forecasts.	One TNSP did not reconcile to a state level forecast. One TNSP commissioned an external consultant to develop state level forecast. The forecasts assumptions differed from the economic assumptions made in the 2014 NEFR.

[12] This covers TNSPs and DNSPs in New South Wales and Tasmania.

3 – RESULT HIGHLIGHTS

This section summarises the key results of the New South Wales and Tasmanian forecasts. It details connection point trends and growth drivers for each region. Additional detailed information for each connection point is available in the supplementary spreadsheets on AEMO's website[13].

3.1.1 New South Wales

Aggregated connection point trend

Historical demand in New South Wales has declined since 2010, with summer demand in 2013-14 showing signs of levelling out. Demand is forecast to increase in line with the 2014 NEFR; this is captured at the connection point level through the reconciliation process. Both historical and forecast demand of the aggregated connection points are shown in Figure 2.

The average annual growth rate over the outlook period (non-coincident, summer) is a modest 1.1% for 50% POE forecasts, and 1.2% for 10% POE. This aligns with the growth forecast for the region in the 2014 NEFR over the outlook period. Winter growth is comparable at 1.1% for both 10% and 50% POE.

Since 2010, maximum demand in New South Wales has been declining. This trend has been observed across all NEM regions as a result of large unforseen reductions in industrial demand following the global financial crisis, the high Australian dollar and higher input costs.

Any growth in the residential and commercial sectors has been partially offset by increasing energy efficiency and growth in rooftop PV which has resulted in a reduced rate of maximum demand growth. The 2014 NEFR forecasts that the offsetting impact of rooftop PV will continue over the outlook period in all regions expect in New South Wales where the impact will be seen to a much lesser extent due to the lowest forecast growth in rooftop PV installation across the NEM. Further information supporting this forecast is provided in the Forecast Methodology Information Paper.[14]

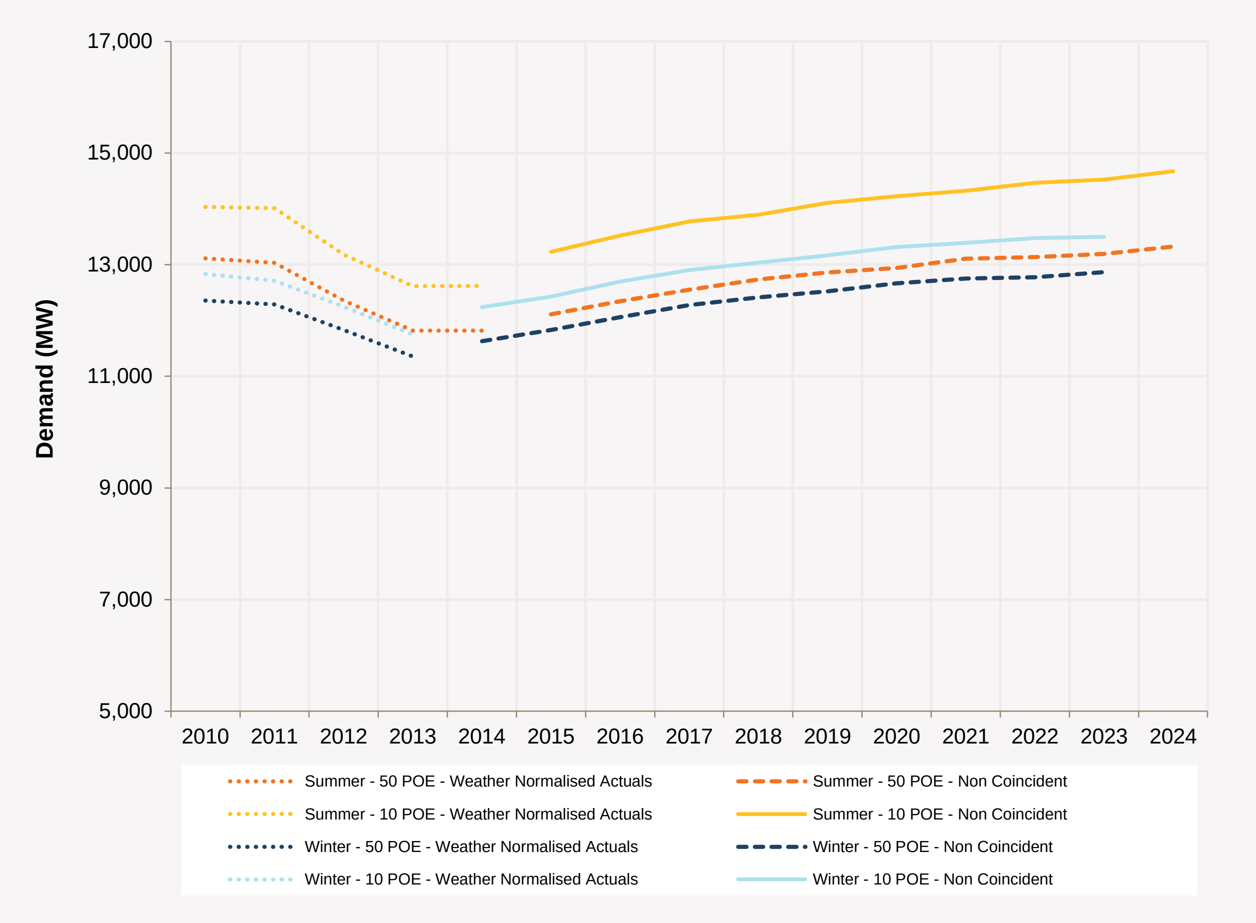
The net effect of the growth in residential and commercial sectors combined with the energy efficiency and rooftop PV is that small increases in peak demand are forecast for New South Wales, albeit at a much slower rate than previous forecasts. Comparing forecasts from the 2014 NEFR with forecasts published in the 2011 Electricity Statement of Opportunity (ESOO), summer maximum demand has decreased and exhibits flatter growth. In the 2014 NEFR, summer maximum demand is forecast to be 13,438 MW in 2014-15 compared to 16,781 MW which was forecast in the 2011 ESOO.

Figure 2 shows the last summer, the weather corrected summer maximum demand steadied, reflecting a stabilising of the industrial demand reductions seen over recent years. Overall, the forecast maximum demand shows that peak demand is increasing, but at a significantly lower rate than previously, with forecast demand growth not expected to achieve the historical record of 14,744 MW (in 2011) until after 2022-23.

[13] http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts

[14] AEMO. *Forecasting Methodology Information Paper.* Available at http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

Figure 2: 50% and 10% POE non-coincident aggregated connection point forecasts for New South Wales



Connection point trends

While the aggregate growth rate for New South Wales is moderate, average annual growth rates vary by connection point, and are distributed above and below the overall rate of 1.1%.

Summer 50% POE forecast growth ranges between -4.0% and 8.0%. The highest growth rate (8.0%) occurs at Mount Piper connection point and is due to mining loads that come online over the outlook period. The most significant decline (4.0%) is expected to occur at Wagga North 66 kV connection point due to load transfers.

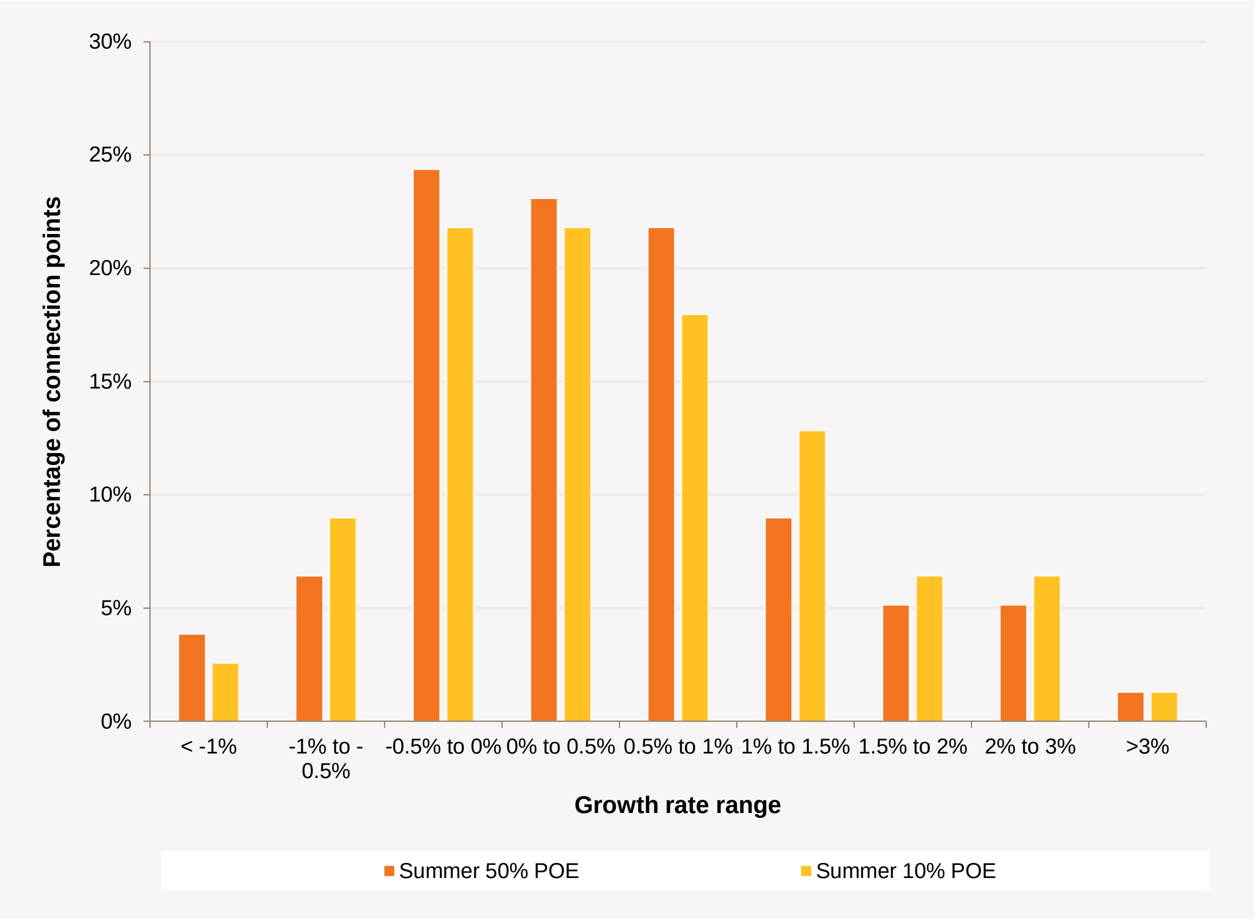
The average annual growth rate, on average is 0.4% for the 50% POE summer forecasts and 0.6% for the 10% POE summer forecasts.

Winter growth is slightly stronger than summer, with 86% of connection points showing positive growth compared to 65% for summer.

While most connection points exhibited positive growth, the growth rates tend to be small; 80% of connection points have summer 50% POE growth of less than 1%, as shown in Figure 3.

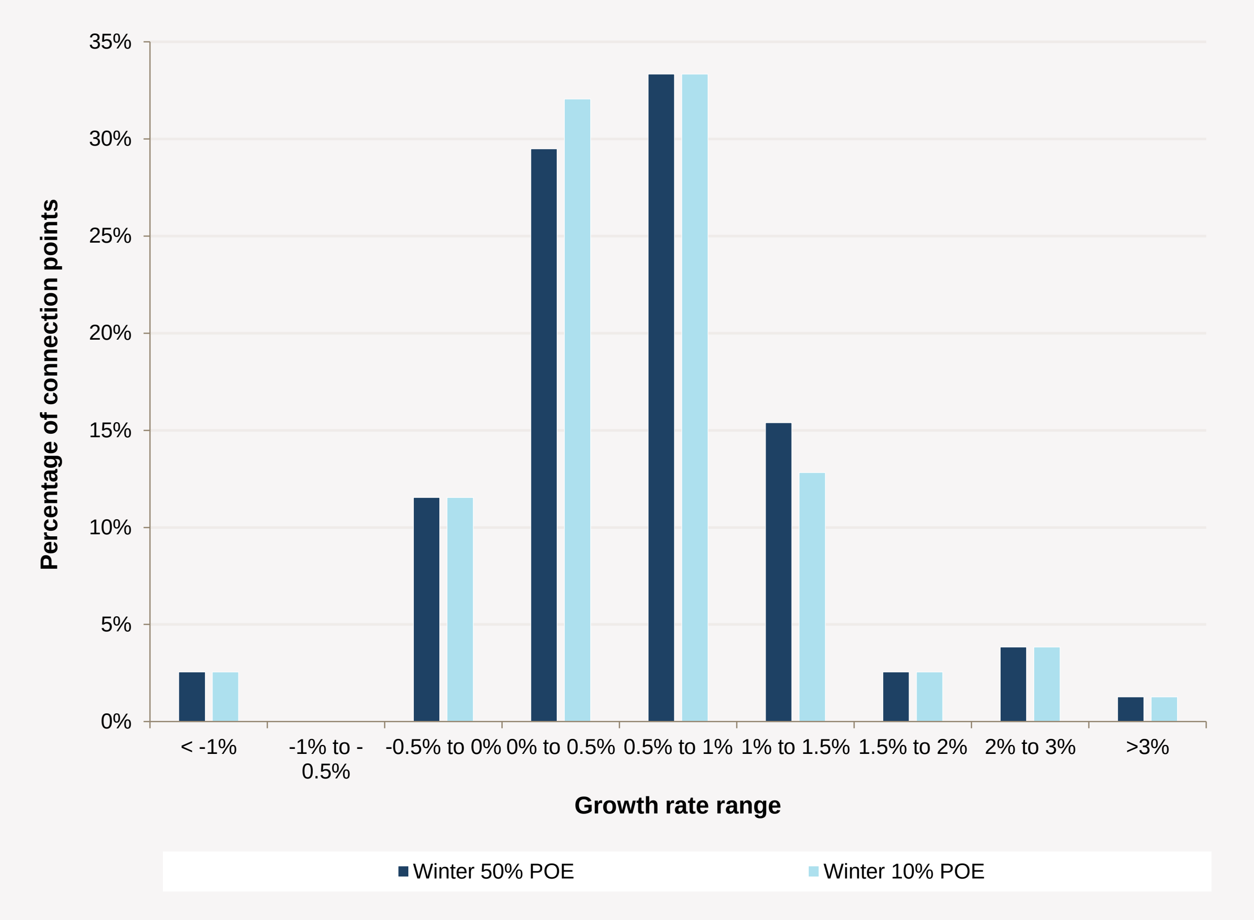
Summer 10% POE growth rates are generally higher than the 50% POE counterparts, with 6.4% of connection points growing between 2% and 3%.

Figure 3: Distribution of summer MD growth rates for New South Wales, 2015-24



Winter growth rates tend to be greater than zero, with 78% of connection points having 50% POE growth rates between 0.0% and 1.5%. The distribution of winter growth rates is shown in Figure 4

Figure 4: Distribution of winter MD growth rates for New South Wales, 2014-23



Growth drivers

Across summer and winter, at 10% POE, six unique connection points show average annual growth rates over 2.0%. Of these, four are due to block loads or load transfers occurring over the forecast period. This includes Mount Piper, Dapto and a connection point with a large industrial load, where block loads are expected from the mining sector. The other three connection points in this growth category either exhibited historical demand growth or are expected to exhibit growth because of positive population projections and economic indicators for the areas.

The most significant forecast decline in the summer forecasts occurs at Wagga North (both the 66 kV and the 132 kV connection points, 4.0% and 2.7% respectively, at the 50% POE) where load transfers and changes in industrial activity are expected to occur.

Most New South Wales connection points peak in summer due to cooling-related energy consumption. Summer peaks can be exacerbated by use of water pumps for irrigation (for example, locations in the Murrumbidgee Irrigation Area such as Griffith).

Several connection points peak in winter. While causes are usually specific to the connection point, key drivers include the cold winters and mild summers in elevated, cool climate regions such as Cooma and Orange, and seasonal differences in industrial or agricultural activity such as cotton ginning in early winter around Moree.

A breakdown of the 50% POE growth rate for each connection point is shown in Appendix A.

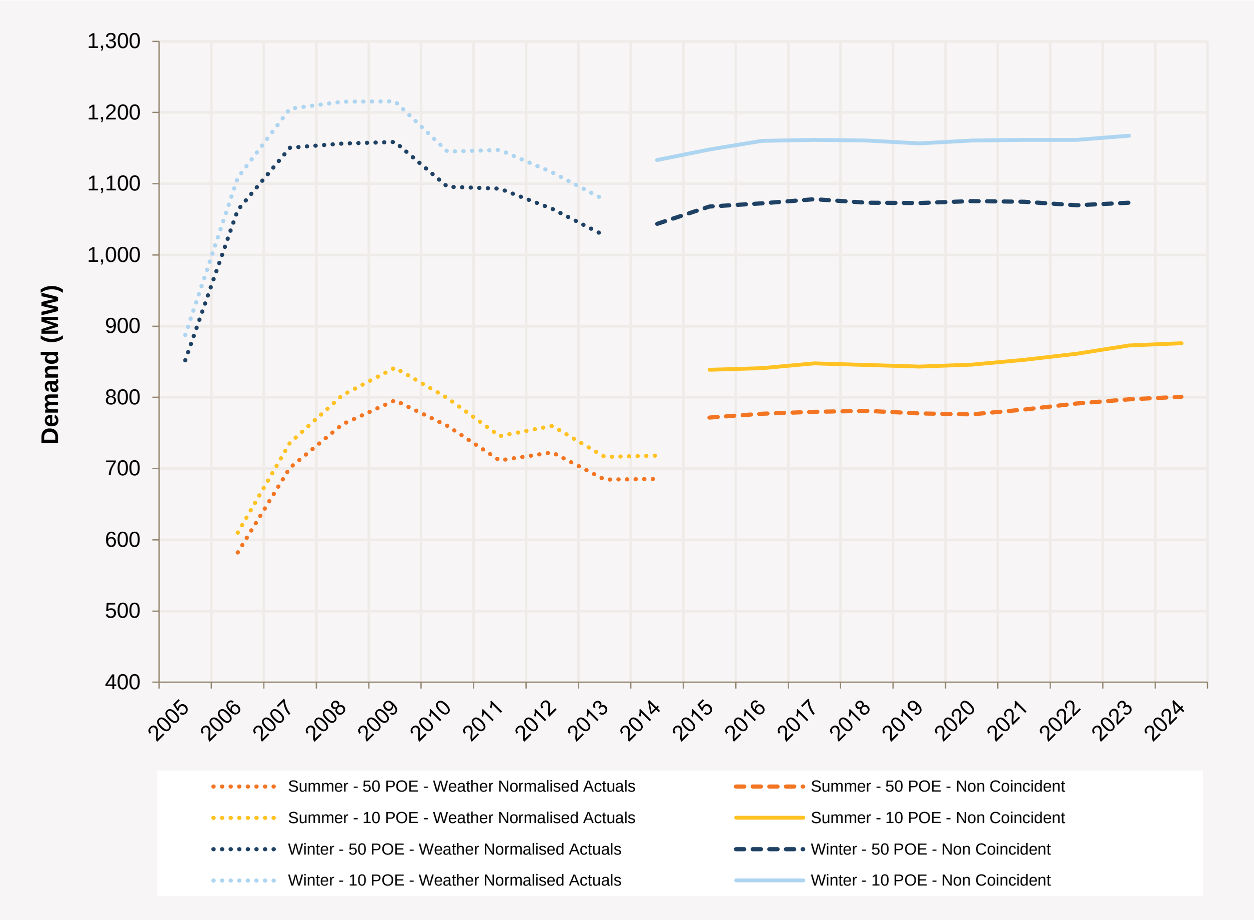
3.1.2 Tasmania

Aggregated connection point trend

Tasmanian historical demand grew until around 2009 and has since been falling steadily. Demand is forecast to grow modestly in line with the 2014 NEFR forecasts; this is captured at the connection point level through the reconciliation process. Both historical and forecasts demand of the aggregated connection points are shown in Figure 5 and show the demand levels for the residential and commercial sector.

The average annual growth rate over the outlook period (non-coincident, winter) is a modest 0.3% for the 10% and 50% POE. Summer growth was marginally stronger with a 0.5% and 0.4% average annual growth for 10% and 50% POE respectively. This reflects summer growth as seen in the 2014 NEFR that is incorporated into the connection point forecasts through the reconciliation process.

Figure 5: 50% and 10% POE non-coincident aggregated connection point forecasts for Tasmania



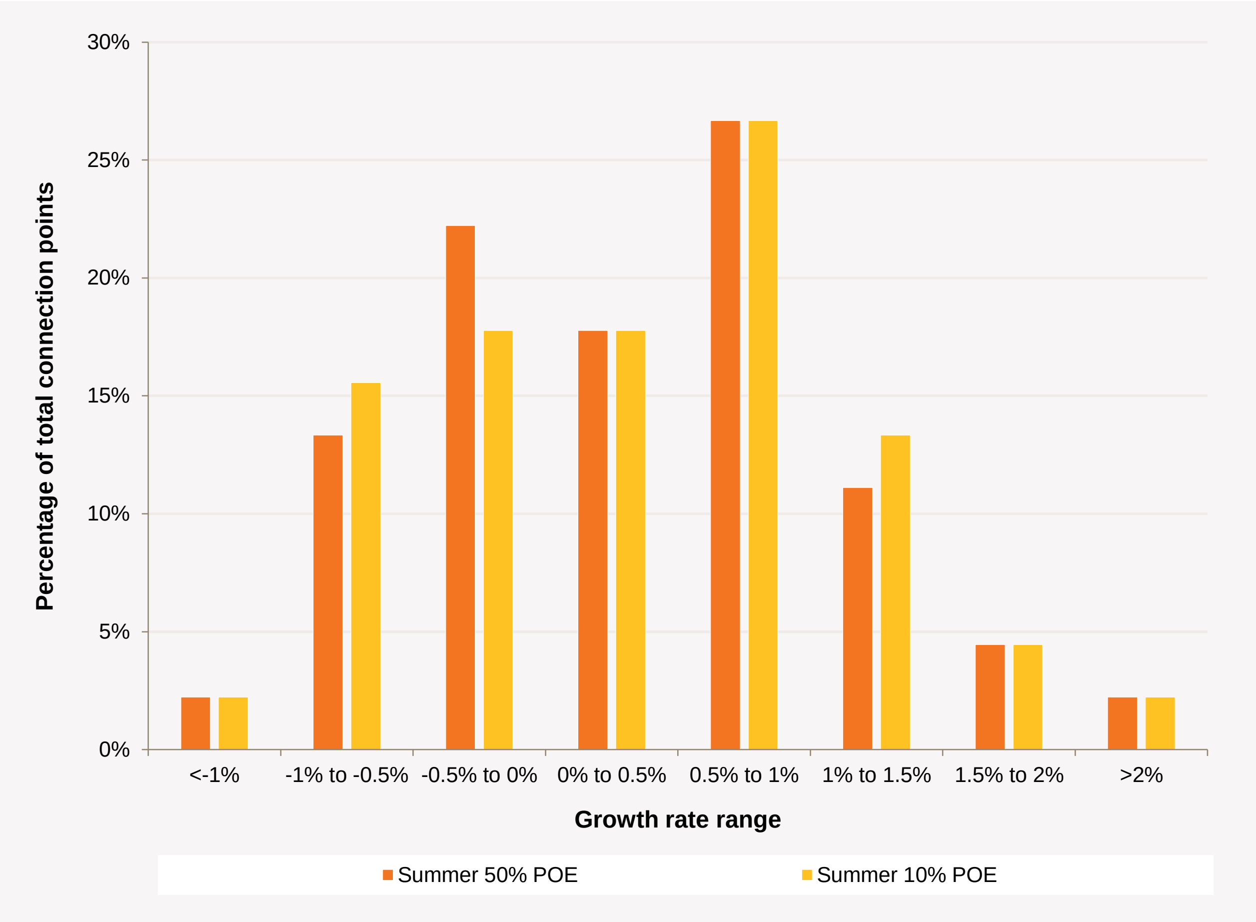
Connection point trends

While the aggregate growth rate for Tasmania is modest, average annual growth rates vary by connection point.

The summer 10% POE forecast average annual growth ranged between -1.0% to 2.2% with the exception of Newton which has an average annual growth rate of -30.3% due to a major industrial load recently announcing plans to enter maintenance mode in late-2015. Excluding Newton, the forecast average annual growth rate, on average is 0.4%.

Summer growth is slightly stronger than winter, with 64% of connection points showing positive growth. While most connection points exhibit positive growth, the growth rates are small, with 44% growing between 0.0% and 1.0% as shown in Figure 6.

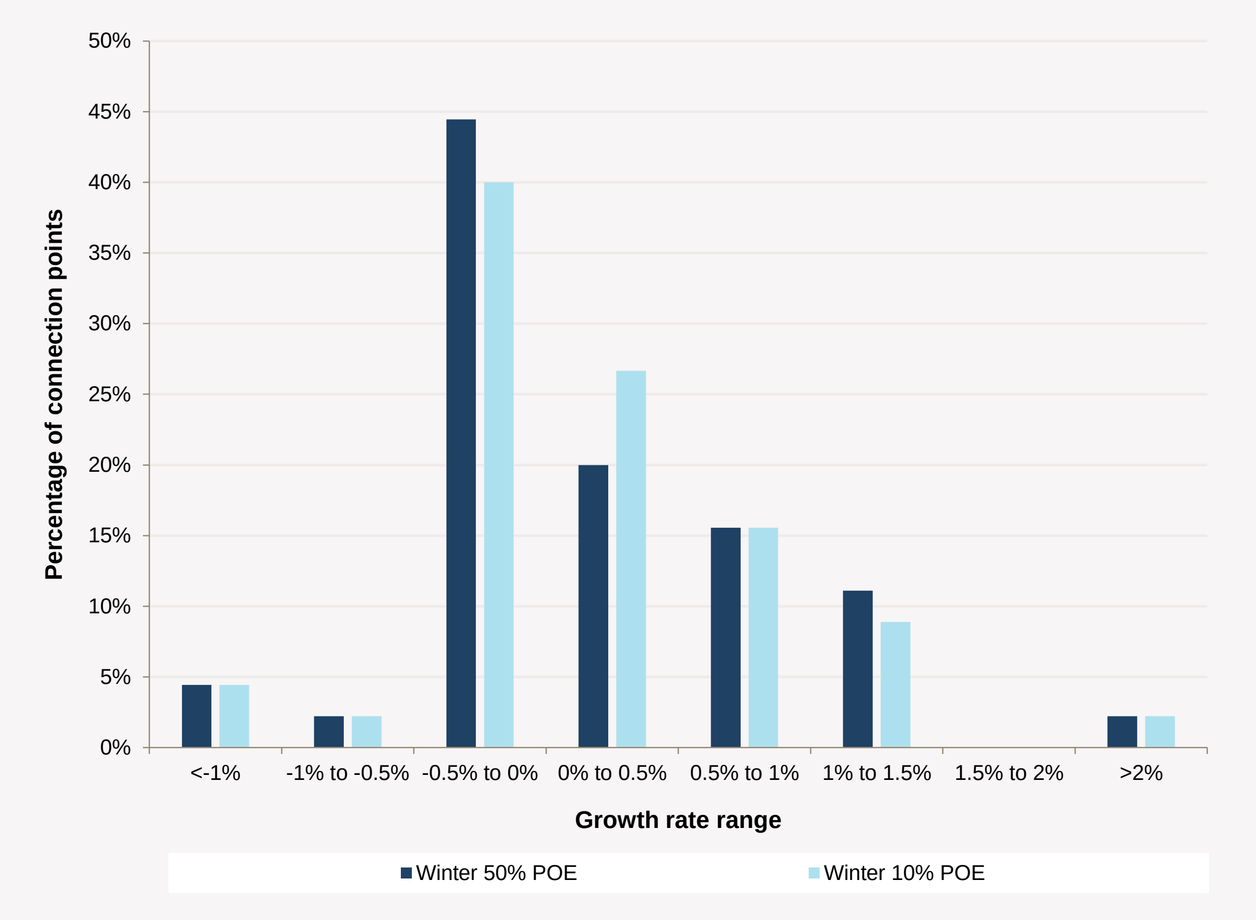
Figure 6: Distribution of summer MD growth rates for Tasmania, 2015-24



The winter 10% POE forecast average annual growth rates ranged from -1.4% to 4.5% with the exception of Newton which has an average annual growth rate of -31.8% due to a major industrial load recently announcing plans to enter maintenance mode in late-2015. Excluding Newton, the forecast average annual growth rate, on average was 0.3%.

Just over half of all connection points (53%) showed positive growth rates; however, the rates are modest with 42% growing between just 0.0% and 1.0%. A further 40% of all connection points grow between -0.5% and 0.0% as shown in Figure 7.

Figure 7: Distribution of winter MD growth rates for Tasmania, 2014-23



Growth drivers

Across summer and winter at the 10% and 50% POE, 12 connection points show growth rates over 1%. Of these, seven are due to block loads coming online during the forecast period. The types of block loads coming online include extended mining activity, additional irrigation loads, and developments such as the Royal Hobart Hospital and Myer store development in Hobart.

A further three connection points exhibited strong historical growth (Norwood, Port Latta, and Rokeby); and two have current loads of less than 1 MW (Wesley Vale and Derwent Bridge).

The lowest growth rate of less than -30% occurs at Newton where a major industrial load recently announced plans to enter care and maintenance mode in late-2015. Declines in growth at other connection points are typically caused by energy efficiency savings and in summer, rooftop PV. The impact of rooftop PV is also evident in Figure 5, which shows that more connection points have growth rates between -1.0% and -0.5% in summer than in winter as shown in Figure 7.

While most Tasmanian connection points typically peak in winter due to heating loads, there are several that peak in summer. The MD at these connection points (including Avoca, Derby, Port Latta, Meadowbank, Palmerston, Railton and Smithton) are typically driven by irrigation and agriculture-related loads. Winter growth rates at these connection points are generally negative, with Avoca, Derwent Bridge, and Meadowbank showing the three lowest 10% POE growth apart from Newton.

A breakdown of the growth rate for each connection point is shown in Appendix A.

4 – FUTURE IMPROVEMENTS

In developing the connection point forecasts for the first time, AEMO identified several areas that require further investigation and improvement. These include:

- Comparing adopted weather normalisation approach to alternatives. Test the inclusion of other weather variables, such as humidity and wind speed.
- Investigating alternative approaches for rooftop PV and energy efficiency disaggregation.
- Improving modelling techniques to cater for non-linear behaviour in historical demand data.
- Incorporating new data sources and getting more direct access to local level sources.
- Gaining a better understanding of the different dynamics at the regional and connection point level and their relationship in the reconciliation process.
- Obtaining better timing information of forecast developments, such as new housing estates and land releases.
- Obtaining better information on large industrial loads and improving relationships with businesses.
- Investigating more representative accounting approaches for embedded generation in historical and forecast demand data.
- Examining economic assumptions more closely.

AEMO plans to investigate these items and publish an improvement action plan on its website before end of 2014.

GLOSSARY

Definitions

Many of the listed terms are already defined in the National Electricity Rules (NER), version 54.[15] For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have been clarified, and these terms are highlighted in grey.

Term	Definition
Annualised average (growth rate)	The compound average growth rate, which is the year-over-year growth rate over a specified number of years.
Block loads	Large loads that are connected or disconnected from the network
Bulk supply point	Station at which electricity is typically transformed from the higher transmission network voltage to a lower one.
Connection point	The point at which the transmission and distribution network meet.
Coincident forecasts	Maximum demand forecasts of a connection point at the time of system peak. See diversity factor.
Distribution losses	Electrical energy losses incurred in transporting electrical energy through a distribution system.
Distribution network	A network that is not a transmission network.
Distribution system	A distribution network, together with the connection assets associated with the distribution network (such as transformers), which is connected to another transmission or distribution system.
Diversity factor	Refers to the ratio of the maximum demand of a connection point/terminal station to the demand of that connection point at the time of system peak. This is sometimes referred to as the demand factor, and is always less than or equal to one. When the diversity factor equals one, the connection point peak coincides with the system peak.
Electrical energy	The average electrical power over a time period, multiplied by the length of the time period.
Electrical power	The instantaneous rate at which electrical energy is consumed, generated or transmitted.
Electricity demand	The electrical power requirement met by generating units.
Energy efficiency	Potential annual energy or maximum demand that is mitigated by the introduction of energy efficiency measures.
Generating system	A system comprising one or more generating units and additional plant that is located on the generator's side of the connection point.
Generating unit	The plant that generates electricity and all the related equipment essential to its functioning as a single entity.
Generation	The production of electrical power by converting another form of energy in a generating unit.

[15] An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/rules.php.

Term	Definition
Installed capacity	The generating capacity in megawatts of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
Large industrial load	There are a small number of large industrial loads—typically transmission-connected customers—that account for a large proportion of annual energy in each National Electricity Market (NEM) region. They generally maintain consistent levels of annual energy and maximum demand in the short term, and are weather insensitive. Significant changes in large industrial load occur when plants open, expand, close, or partially close.
Load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another network or the amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.
Load transfer	A deliberate shift of electricity demand from one point to another.
Maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the National Electricity Rules (NER).
Network service provider (transmission – TNSP; distribution – DNSP)	A person who engages in the activity of owning, controlling, or operating a transmission or distribution system.
Network Meter Identifier (NMI)	A unique identifier for connection points and associated metering points used for customer registration and transfer, change control and data transfer.
Non-scheduled generating unit	A generating unit that does not have its output controlled through the central dispatch process and that is classified as a non-scheduled generating unit in accordance with Chapter 2 of the National Electricity Rules (NER).
Non-coincident forecasts	The maximum demand forecasts of a connection point, irrespective of when the system peak occurs.
On-site generation	Generation, generally small-scale, that is co-located with a major load, such as combined heat and power systems at industrial plants.
Operational consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation, auxiliary loads and transmission losses, typically measured in MWh.
Power system	The National Electricity Market's (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement.
Probability of exceedance (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
Reconciled forecasts	Forecasts that have been scaled such that the sum of all connection points equal to the regional forecasts.

Term	Definition
Region	An area determined by the AEMC in accordance with Chapter 2A of the National Electricity Rules (NER).
Residential and commercial load	The annual energy or maximum demand relating to all consumers except large industrial load. Mass market load is the load on the network, after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
Rooftop photovoltaic (PV) systems	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop to convert sunlight into electricity.
Scheduled generating unit	A generating unit that has its output controlled through the central dispatch process and that is classified as a scheduled generating unit in accordance with Chapter 2 of the National Electricity Rules (NER).
Sent-out	A measure of demand or energy (in megawatts (MW) or megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
Semi-scheduled generating unit	A generating unit that has a total capacity of at least 30 MW, intermittent output, and may have its output limited to prevent violation of network constraint equations.
Small non-scheduled generation (SNSG)	Non-scheduled generating units that generally have capacity less than 30 MW.
Summer	Unless otherwise specified, refers to the period 1 November–31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania only).
Transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission system.
Transmission Node Identity (TNI)	Identifier of connection points across the NEM.
Transmission network	A network within any National Electricity Market (NEM) participating jurisdiction operating at nominal voltages of 220 kV and above plus: • (a) any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network, • (b) any part of a network operating at nominal voltages between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.
Transmission system	A transmission network, together with the connection assets associated with the transmission network (such as transformers), which is connected to another transmission or distribution system.
Winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).
Zone substation	Station within the distribution network where incoming electricity is transformed from a higher voltage from the connection or bulk supply point to a lower one. Electricity is then provided to feeders which lower the voltages even lower for distribution to customers.

MEASURES AND ABBREVIATIONS

Units of measure

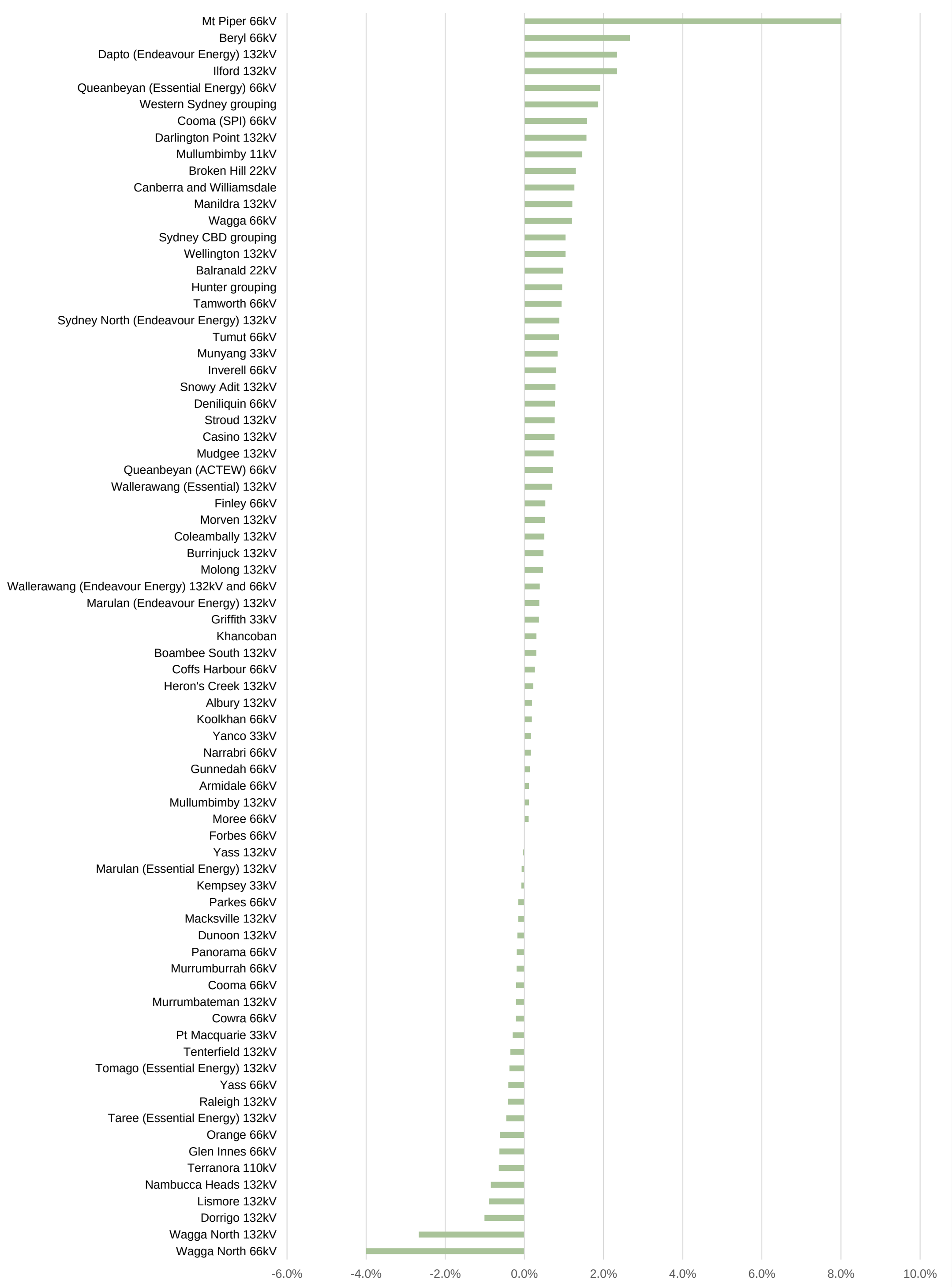
Abbreviation	Unit of Measure
kV	Kilo volt
MW	Megawatt
MWh	Megawatt hours

Abbreviations

Abbreviation	Expanded Name
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BSP	Bulk Supply Point
COAG	Council of Australian Governments
DNSP	Distribution Network Service Provider
MD	Maximum demand
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NER	National Electricity Rules
NMI	Network Meter Identifier
NSP	Network service provider
NSCAS	Network Support and Control Ancillary Services
NCIPAP	Network Capability Incentive Parameter Action Plan
NTNDP	National Transmission Network Development Plan
POE	Probability of Exceedence
PV	Photovoltaic
SNSG	Small Non-scheduled Generation
TNI	Transmission Node Identifier
TNSP	Transmission Network Service Provider

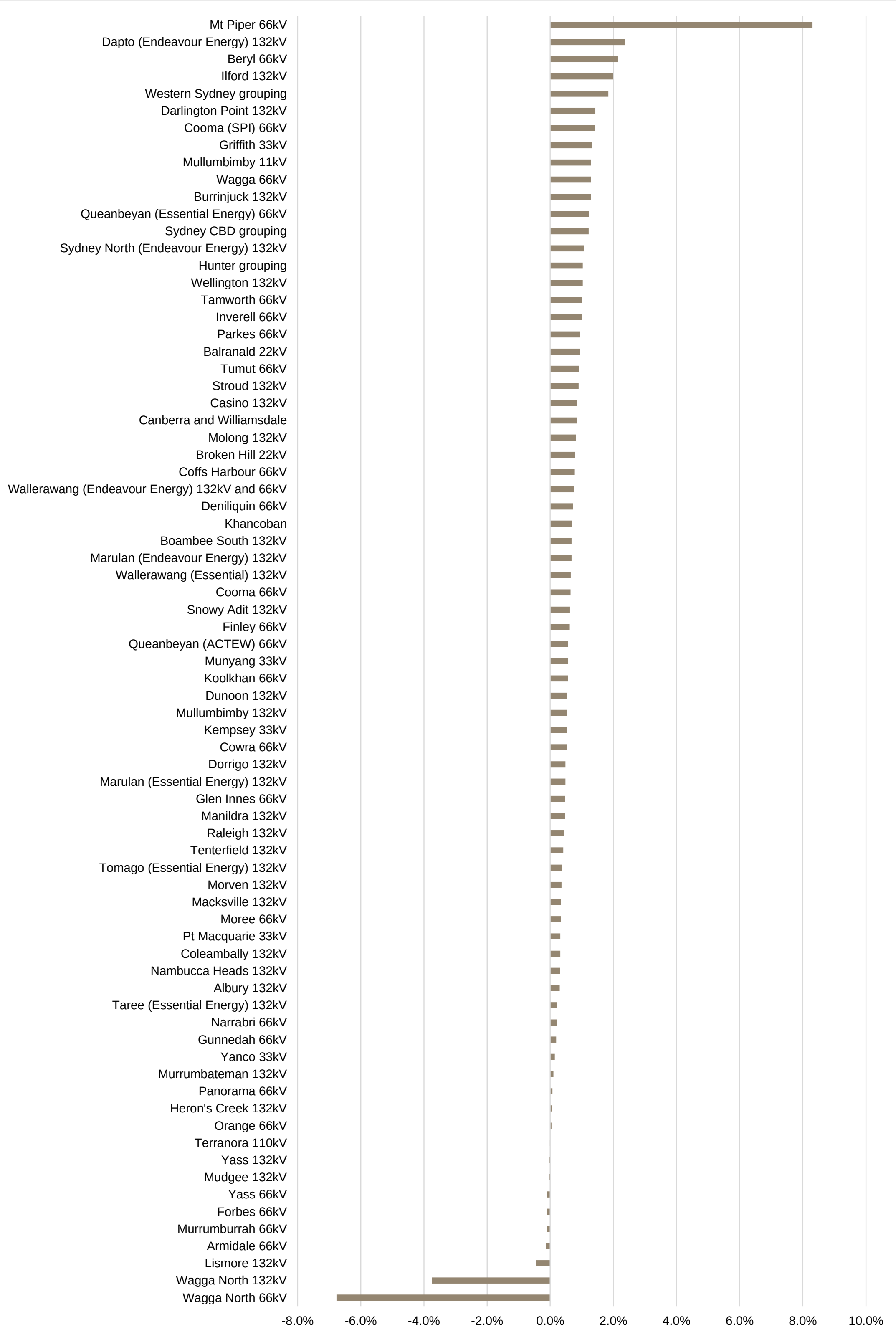
APPENDIX A – GROWTH RATES BY CONNECTION POINT

Figure 1: New South Wales 50% POE summer 10-year average annual growth rates, 2014-15 to 2023-24



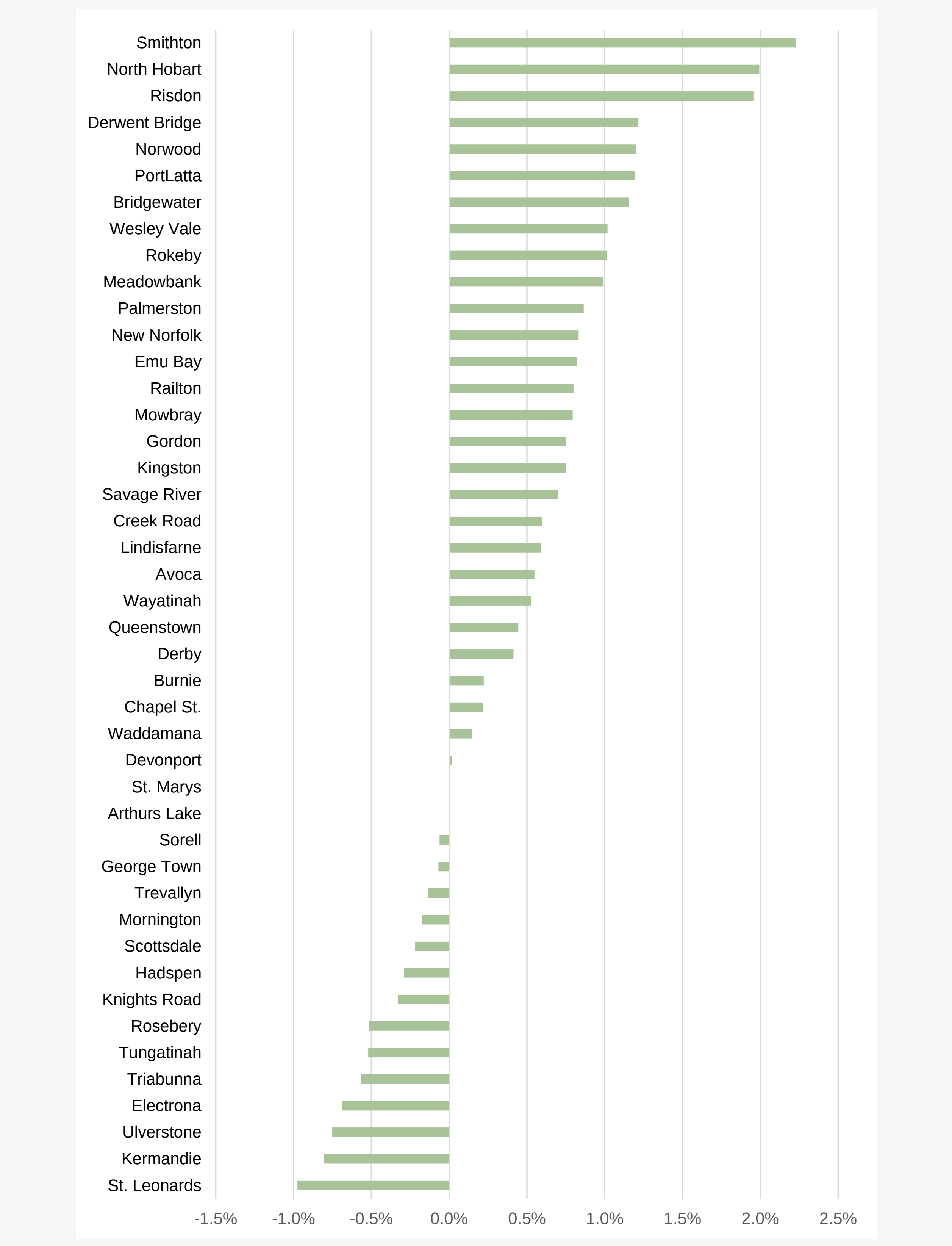
Note: Industrial loads are excluded.

Figure 2: New South Wales 50% POE winter 10-year average annual growth rates, 2014 to 2023



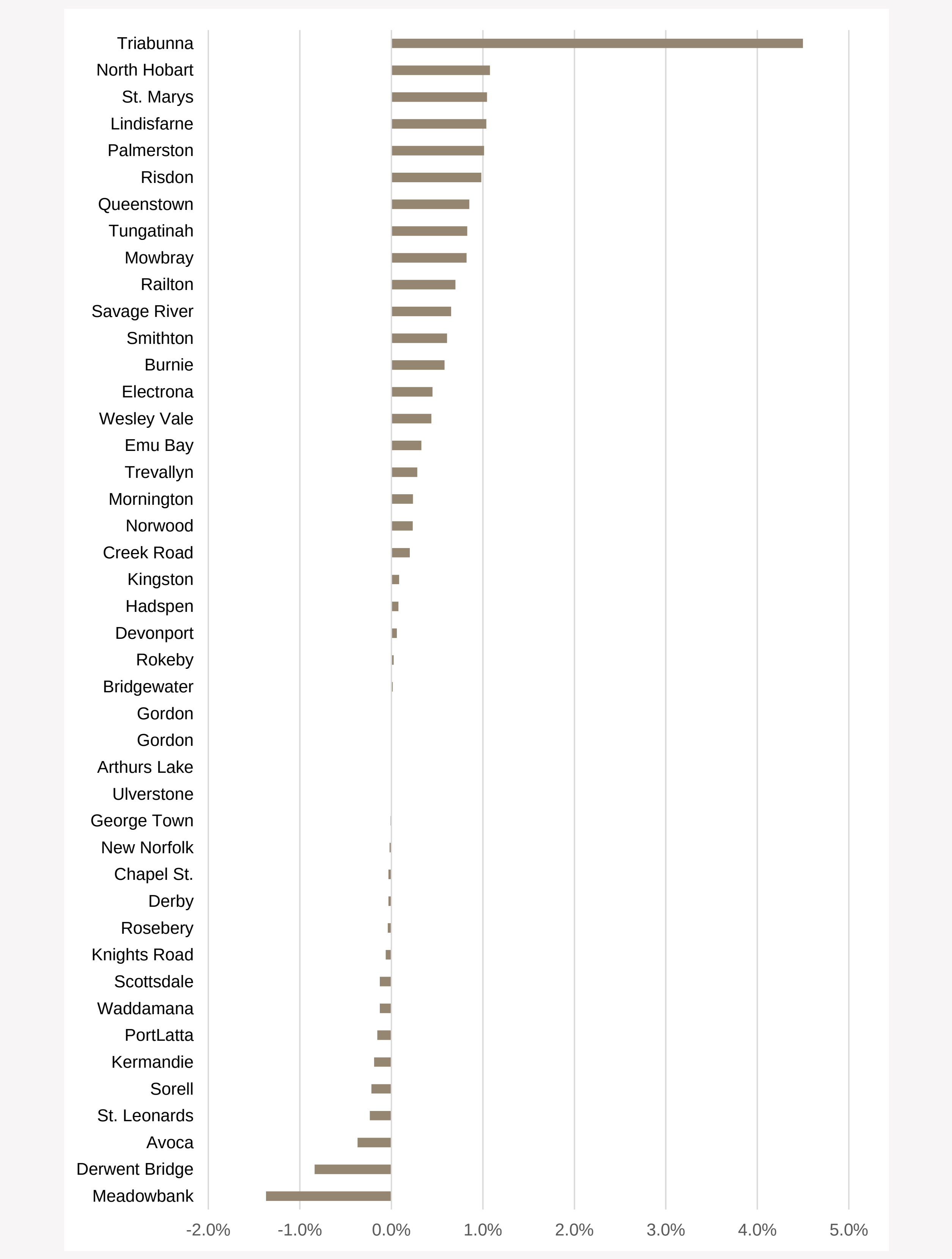
Note: Industrial loads are excluded.

Figure 3: Tasmanian 10% POE summer 10-year average annual growth rates, 2014-15 to 2023-24



Note: Industrial loads and Newton connection point are excluded.

Figure 4: Tasmanian 10% POE winter 10-year average annual growth rates, 2014 to 2023



Note: Industrial loads and Newton connection point are excluded.

APPENDIX B – DATA SHARED BY NSPS

During the process, NSPs provided data that was vital in AEMO's connection point forecast development. A list of data provided is outlined below:

Table 5: List of data provided by NSPs

Item	Description
Demand data	Half-hourly data was provided by most NSPs. Some provided peak demand information.
Embedded generation data	NMIs and half hourly data provided. This was cross-checked with AEMO data.
Exempt generation	NMIs or aggregated by TNI. Data provided at the half-hourly level where possible.
Industrial data	NMIs or aggregated by TNI. Data provided at the half-hourly level where possible.
Load transfers and block loads	Historical provided where possible. Forecasts were also provided where possible.
Maximum demand forecasts	Latest forecasts were made available to AEMO.
PV installed capacity	Provided by postcode and/or TNI where possible.
Network tariffs	Tariff types and volumes provided where possible.
Network configuration information	Provided on an ad hoc basis.
Demand mix and local information	Provided on an ad hoc basis.

APPENDIX C – AGGREGATED CONNECTION POINTS

In New South Wales, there were several areas with networks that were highly interconnected. Their interconnectedness meant that it was not feasible to correctly account for all the load transfers that occurred from one connection point to another.

To circumvent this issue, AEMO aggregated a number of connection points and developed forecasts for the aggregated area. The connection points for each aggregation are listed below.

Table 6: Aggregated connection points in New South Wales

Aggregation area	TNIs	Approximate bulk supply point (BSP) equivalent.
Sydney CBD	NBFN, NBFS, NBFW, NBG1, NBG3, NCAR, NCHM, NCHU, NCTB, NDRM, NGF3, NGSF, NGSQ, NGWF, NHBB, NHYM, NKN1, NLCV, NMBK, NMKV, NMPK, NMQP, NOR1, NOR6, NORB, NPH1, NPHT, NPT1, NPT3, NRZH, NRZL, NSE2, NSMB, NSN1, NSPT, NSW1, NSYS, NTG3, NTPR, NWYG.	Beaconsfield West, Haymarket, Rookwood Rd, Sydney East, Sydney North, Sydney South.
Hunter	NALC, NBH1, NBHL, NBRF, NKU1, NKU3, NKUR, NLD3, NMNP, NMRK, NMUN, NNEW, NTME, NTMG, NVP1, NWR1.	Liddell, Munmorah, Muswellbrook, Newcastle, Tomago, Tuggerah, Vales Point, Waratah West.
Western Sydney	NHLD, NING, NKCK, NLP1, NMC1, NMC2, NRGV, NSW2, NVYD.	Holroyd, Ingleburn, Liverpool, Macarthur, Regentville, Sydney West, Vineyard.
Canberra/ACT	ACA1, NWDL.	Canberra, Williamsdale.
Wallerawang	NWW6, NWW7.	Wallerawang (132 & 66 kV), Endeavour Energy's Wallerawang (132 & 66 kV).

Note: The bulk supply point equivalents represent an approximation of the aggregated TNIs. Load transfers in and out of aggregation areas and network configuration can lead to differences when comparing BSPs to TNIs. The Wallerawang aggregation is consistent with historical data; the connection point was relocated and in the process one connection point was separated into two.