# 2016 AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR TASMANIA

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

# IMPORTANT NOTICE

## Purpose

AEMO has prepared this document to provide information about its 2016 transmission connection point forecasts for Tasmania, as at the date of publication.

AEMO publishes these connection point forecasts as requested by the Council of Australian Governments' energy market reform implementation plan.

This publication is based on information available to AEMO as at 1 February 2016, 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.

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## Acknowledgement

AEMO acknowledges the support, co-operation and contribution from TasNetworks in providing data and information used in this publication.

# EXECUTIVE SUMMARY

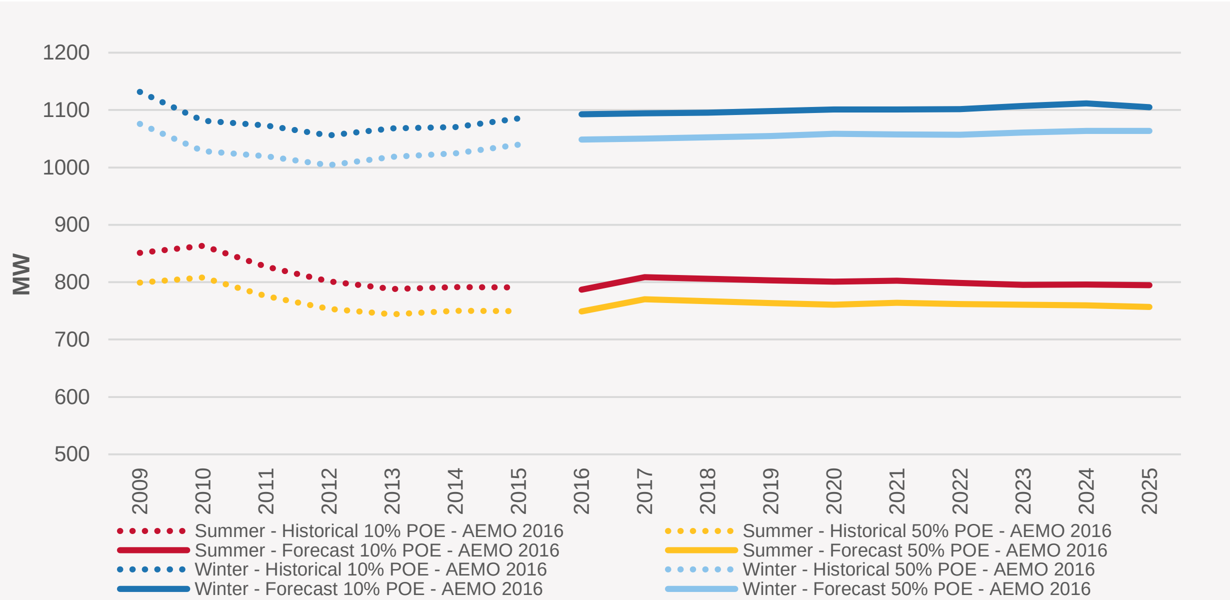
AEMO has developed Maximum Demand (MD) transmission connection point forecasts for Tasmania to provide insights to local changes and trends in MD from 2015–16 to 2024–25.

Together with the regional-level MD forecasts published in AEMO's *National Electricity Forecasting Report* (NEFR)[1], the forecasts provide an independent and holistic view of electricity demand in the National Electricity Market (NEM). This increased transparency is intended to lead to more efficient network investment decisions, and ultimately provide long-term benefits to energy consumers.

This report provides 10% and 50% Probability of Exceedance (POE)[2] MD forecasts, for both summer (2015–16 to 2024–25) and winter (2016 to 2025).

AEMO's forecast of Tasmania connection point MD, in Figure 1, shows demand is forecast to remain close to current levels over the outlook period for both summer and winter. Table 1 summarises the main features of the forecasts.

**Figure 1 AEMO summer and winter forecasts for 10% POE and 50% POE[a]**




[a] Some direct-connection industrial loads are excluded due to confidentiality.

**Table 1 AEMO 2016 connection point forecast average annual rates of change, 10% POE**

| Category | Summer | Winter |
|---|---|---|
| **Total connection point MD** | 0.11% | 0.12% |
| **Typical range of individual growth rates** | −7.0% to 8.4% | −1.2% to 1.7% |

**Key features:**

- **Overall transmission connection point MD in Tasmania is expected to remain close to current levels during the outlook period.**
- **Forecast changes in MD at some connection points are driven primarily by load transfers and industrial closures.**

**Compared to the 2014 Update[3] forecasts:**

- **The AEMO 2016 summer forecast (10% POE) is 29 MW (3.5%) lower than AEMO's 2014 Update forecast at 2023–24, and the AEMO 2016 winter forecast (10% POE) is 85 MW (8.3%) higher than AEMO's 2014 Update forecast at 2024. This is attributed mainly to the collective effect of differences in retail electricity price, population, and economic growth, included in the regional MD forecast through the reconciliation process to the 2015 NEFR Update.[1]**

[1] AEMO. *2015 National Electricity Forecasting Report* and *2015 National Electricity Forecasting Report Update*. Both available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.

[2] Probability of exceedance (POE) is the likelihood that a maximum demand forecast will be met or exceeded. A 10% POE MD forecast is expected to be exceeded, on average, one year in 10. A 50% POE projection is expected to be exceeded, on average, one year in two.

[3] AEMO. *2014 Update: AEMO Transmission Connection Point Forecasting Report for Tasmania*. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting/Transmission-Connection-Point-Forecasting-Report-for-Tasmania-Update.

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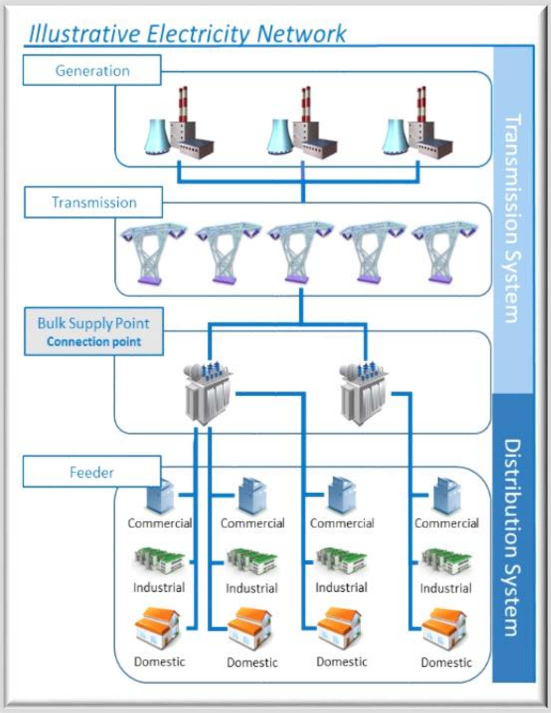
# 1. INTRODUCTION

In its role as independent market and system operator, AEMO develops maximum demand (MD) forecasts for each transmission connection point, to provide a higher level of detail than AEMO's *National Electricity Forecasting Report* (NEFR) about changes in demand and observations on local trends. Together with the regional level MD forecasts published in the NEFR, the transmission connection point forecasts provide an independent and transparent view of electricity demand in the NEM, supporting efficient network investment and policy decisions for the long-term benefit of consumers.

AEMO provides non-coincident forecasts in this report, because they represent the MD required for connection asset planning and also affect network planning. Non-coincident forecasts are the MD forecasts of a connection point, regardless of when the system peak occurs. Coincident forecasts are the MD forecasts of a connection point at the time system peak occurs.

## 1.1 Connection point definition

AEMO's connection point forecasting methodology, published in June 2013[4], defines a transmission connection point as the physical point at which the assets owned by a transmission network service provider (TNSP) meet the assets owned by a distribution network service provider (DNSP), as illustrated (right).




These may also be known as bulk supply points (BSPs), terminal stations, or exit points, and in the NEM's market metering and settlements processes they are called transmission node identities (TNIs).[5]

Connection points may be connected to one another at the distribution network level. In situations where this interconnectivity is extensive, AEMO develops a forecast for the aggregated load.

## 1.2 Forecast scope

The forecasts in this report:

- Apply to active power (MW) at each connection point (see Section 1.3 for information about accessing reactive power estimates).
- Exclude transmission system losses and power station auxiliary loads.

Embedded generators, which are mentioned in the dynamic interface (see Section 1.3), are assumed to be off at the time of forecast MD.

Where there is just one customer at a connection point, AEMO has only published forecasts if the customer has given permission.

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

[5] For a complete list of TNIs, refer to *List of regional boundaries and Marginal Loss Factors for the 2014–15 financial year.* Available: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/List-of-Regional-Boundaries-and-Marginal-Loss-Factors-for-the-2015-16-Financial-Year.

## 1.3 Supplementary information on AEMO's website

Supplementary information to this report is available on AEMO's website.[6]

**Table 2 Supplementary information**

| Resource | Description |
|---|---|
| **Dynamic interface** **http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting** | An Excel workbook with the following information for each transmission connection point:<br>• Historical and forecast MD, including 10% POE and 50% POE, for active power.<br>• Coincident and non-coincident values.<br>• High-level commentary.<br>• The option to export all forecast and historical data. |
| **Reactive power system forecast spreadsheet** | Separate spreadsheet for reactive power forecasts at each transmission connection point, providing complementary information for power system studies. |
| **Interactive planning map** **http://www.aemo.com.au/electricity/planning/interactive-map/** | The interactive map complements AEMO's planning publications to enhance readability and clarity. The map contains various layers, including layers displaying forecasts and planning information. |

## 1.4 Improvements to the forecasting methodology

As part of its commitment to continuous improvement, AEMO published the *Transmission Connection Point Forecasting Action Plan* in October 2014.[7] In it, AEMO identified possible areas of improvement in the forecasting process relating to forecast inputs and methodologies. Several improvements were incorporated into the development of the current forecasts. A summary is provided in Table 3.

**Table 3 Improvements implemented for Tasmanian connection point forecasts, since the 2014 Update forecasts**

| Improvement description | Approach | Benefit | Implemented |
|---|---|---|---|
| Improve estimates of rooftop PV generation. | Apply a new rooftop PV model, developed in 2015 by the University of Melbourne and AEMO. | The adjustments resulted in more realistic treatment of rooftop PV with variation depending on the time of day and level of cloud cover, and spatial location. | Yes |
| Review options for determining if time-trend is non-linear. | Apply new statistical test for determining if time trend is non-linear, with horizon value to constrain forecast. | This reduced the need for subjective judgements in determining whether a linear or non-linear trend should be implemented. | Yes |
| Investigate opportunities to improve the reconciliation process. | Reconcile the non-coincident forecasts to the general rate of change of the system forecast, rather than derive them from coincident forecasts using diversity factors. | System-level drivers of growth are included by reconciling to the growth rate. The chance of a step shift in the non-coincident forecasts is eliminated. | Yes |

[6] Supplementary information is available at http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

[7] AEMO. *Transmission Connection Point Forecasting Action Plan.* Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

# 2. RESULTS

## 2.1 Aggregated AEMO 2016 connection point forecasts

Historically, MD in Tasmania has grown until 2008, after which demand has decreased and subsequently plateaued. The aggregated forecasts are reconciled to AEMO's 2015 NEFR Update, which incorporates the effects of changes in electricity prices, population growth, and changes in Gross State Product (GSP).

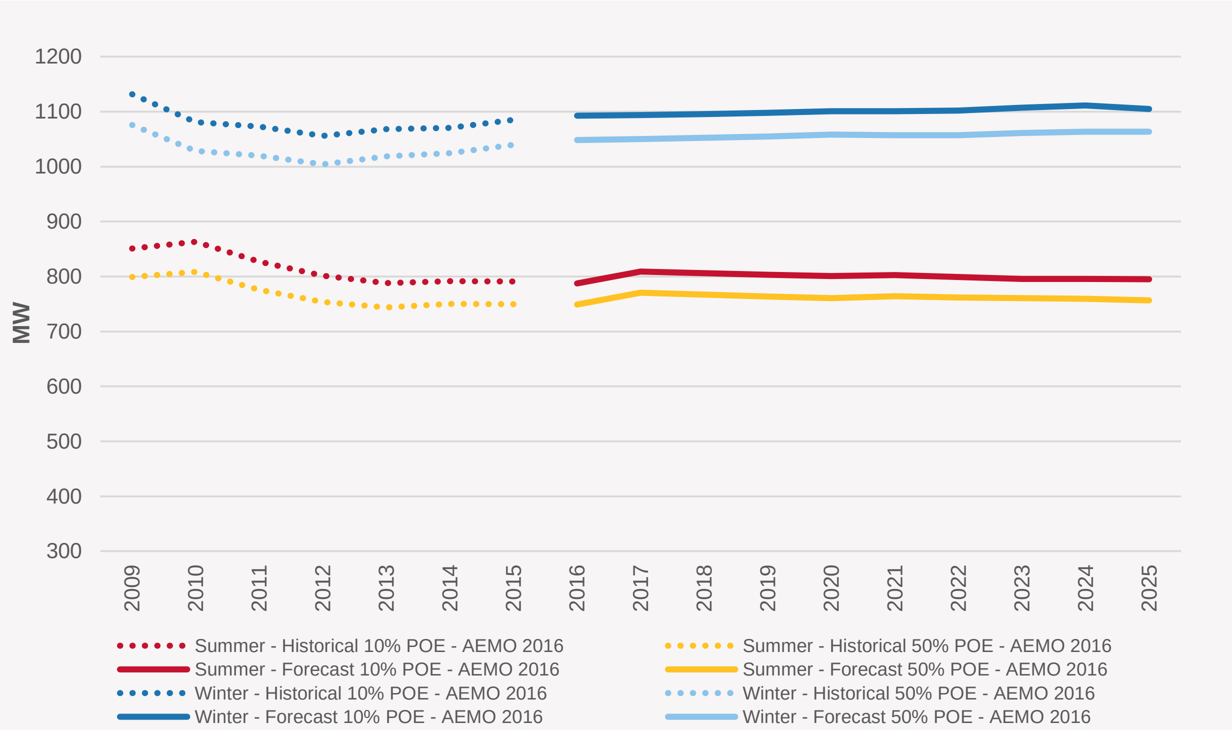
AEMO forecasts both winter and summer connection point MD for Tasmania to remain close to current levels over the outlook period. Regional average annual growth over the winter outlook period is increasing at 0.12% and 0.16% for the 10% and 50% POE forecasts respectively. For the summer forecasts, over the outlook period, the average annual growth is increasing at 0.11% for both the 10% and 50% POE forecasts.The forecasts are shown in Figure 2. Winter MD is greater than summer, as Tasmania is a winter peaking region.

Key insights from the aggregate-level forecasts are:

- The aggregated forecasts show a slight growth in MD until winter 2016, due to increasing population and GSP driving an increase in residential and commercial demand. From winter 2016, demand is forecast to remain flat, due to increasing electricity prices offsetting demand growth driven by population growth, consistant with the 2015 NEFR update.
- The difference between 10% and 50% POE levels in winter is slightly higher than that of summer, and demonstrates that winter MD exhibits a slightly greater year-to-year variability than summer MD.

AEMO notes that energy consumption by industrial loads in Tasmania has been reduced temporarily in early 2016 and that a number of new embedded generators may come online in the near future. This has not been included in AEMO's modelling[8].

**Figure 2 AEMO's aggregated, non-coincident 2016 forecasts[a]**




[a] Some direct-connection industrial loads are excluded due to confidentiality.

[8] Changes to industrial load consumption has been in reponse to the Basslink outage on 20 December 2015. This is not expected to have an impact on long term forecasts of maximum demand as it is a temporary change. As embedded generators are assumed to not be generating at time of maximum demand, any additional embedded generators are not expected to have an impact on the connection point forecasts.

## 2.2 Individual AEMO 2016 connection point results and insights

While aggregated demand is forecast to remain close to current levels, individual connection point forecasts[9] increase at some locations, and decrease at others, due to various drivers.

Connection points with average annual increases or decreases of more than 2% are shown in Table 4, as well as the drivers of demand.

See Appendix B for plotted individual 10% POE rates of change for each connection point.

Key features of the summer forecasts are:

- Forecast average annual rates of change for 10% POE are between +8.4% (Morington) and –7.0% (Lindisfarne). Drivers are listed in Table 4.
- 43% of connection points show positive growth or no growth over the outlook period for their 10% POE average annual rates, with 60% of these having small growth rates between 0.0% to 1.0%.
- Of the eight connection points with summer growth above 1%, five of these connection points have either new loads connected or transfers from other connection points over the outlook period.
- Even though Tasmania is a winter peaking region, the connection points of Avoca, Meadowbank, Port Latta, Palmerston, Wesley Vale, and Wayatinah displayed higher MD in summer than winter. These connection points, excluding Wesley Vale and Wayatinah, predominantly service irrigation and agriculture-related loads.

Key features of the winter forecasts are:

- Forecast average annual rates of change for 10% POE are between +1.7% (Kingston 33 kV) and –1.2% (Queenstown). Drivers are listed in Table 4.
- 55% of connection points are forecast to have positive growth or no growth for their 10% POE average annual rates. Of these, 92% have a growth rate between 0.00% and 1.0%.
- Of the two connection points with growth rates above 1.0%, one of these connection points has either new loads connected or transfers from other connection points over the outlook period.
- Load transfers from Lindisfarne to Mornington, Trevallyn to Mowbray, and Risdon to Mornington are scheduled to occur in 2016.

**Table 4 Drivers at connection points with average annual increase or decrease greater than 2%[a]**

| Season | Forecast MD increase greater than 2% | Forecast MD decrease greater than 2% |
|---|---|---|
| **Summer** | **Mornington:** Due to load transfers from Lindisfarne and Risdon.<br>**Triabunna:** Due to block load being connected.<br>**Mowbray:** Load transfer from Trevallyn. | **Queenstown:** Due to population and economic growth.<br>**Lindisfarne:** Load transfer to Mornington.<br>**Kingston 11 kV:** Due to population and economic growth. |
| **Winter** | **None.** | **None.** |

[a] 2% is set to capture extreme rates. Major industrial loads are excluded due to confidentiality.

[9] Refer to the dynamic interface for detailed information on individual connection points. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

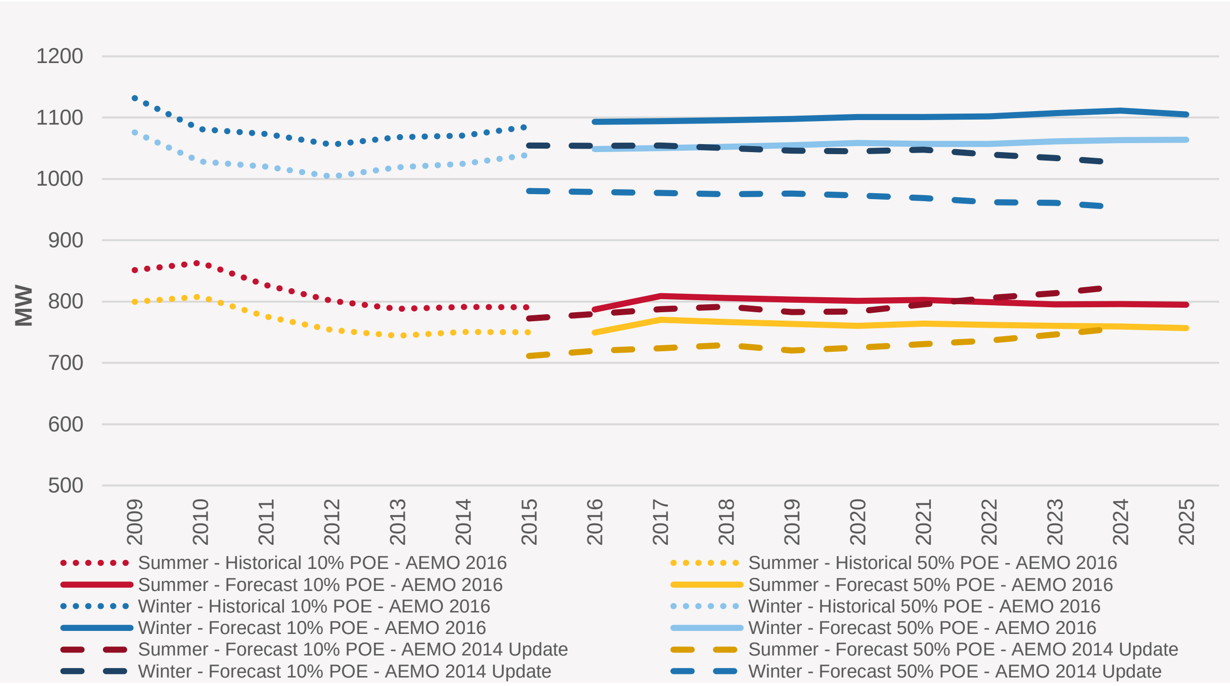
## 2.3 Comparison of AEMO's 2014 Update and 2016 forecasts

AEMO's 2014 Update connection point MD forecasts and 2016 connection point MD forecasts are plotted in Figure 3, and the growth rates are compared in Table 5.

- Summer 10% POE MD forecasts have decreased by 3.5% at 2023–24.
- Winter 10% POE MD forecasts have increased by 8.3% at 2024.

Reasons for these changes are summarised in Table 6.

**Figure 3 AEMO 2014 Update and 2016 (10% and 50% POE) connection point MD forecasts (excluding direct-connect loads) [a]**




[a] Some direct-connect industrial loads are excluded due to confidentiality.

**Table 5 Region-level average change rates (10% POE)**

| Forecast | 2014 Update Region level average annual change rate | 2016 Region level average annual change rate |
|---|---|---|
| Summer | 0.73% | 0.11% |
| Winter | −0.30% | 0.12% |

**Table 6 Differences between AEMO 2014 Update and 2016 forecasts (10% POE)**

| Forecast | Differences between AEMO 2014 Update and 2016 aggregated MD forecasts (10% POE) |
|---|---|
| Summer MD | AEMO's updated connection point forecast is 3.5% (29 MW) lower than the previous forecast at 2023–24. |
| Winter MD | AEMO's updated connection point forecast is 8.3% (85 MW) higher than the previous forecast at 2024. |

**Key drivers for change:**

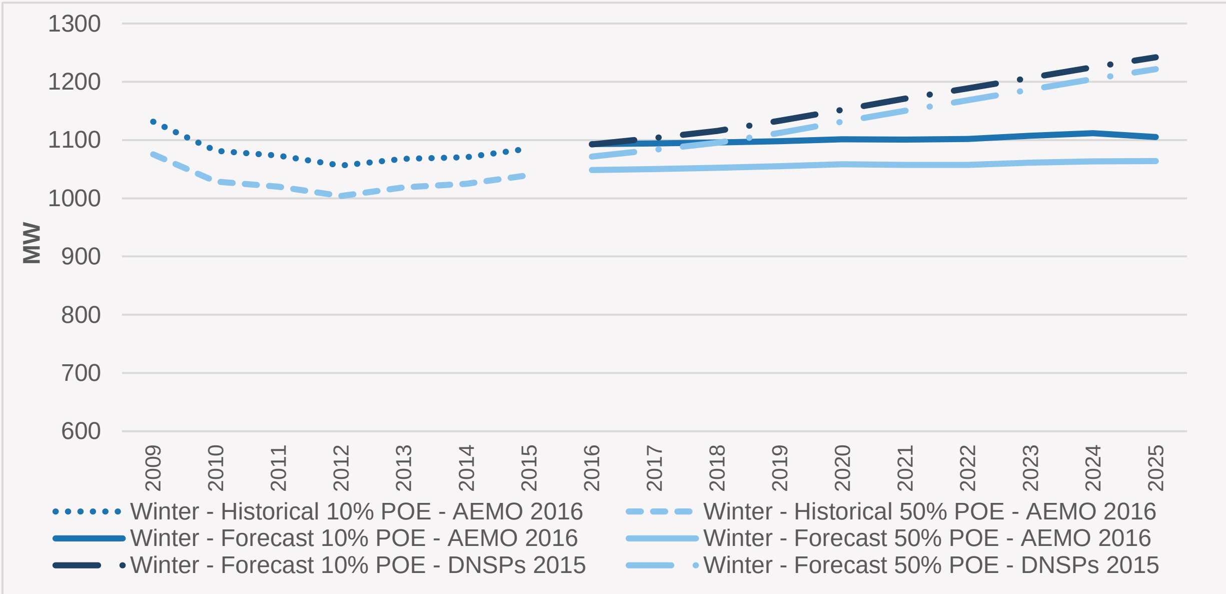
- **Changes in the system forecasts produced in the 2014 NEFR Update (used in the reconciliation of the 2014 Update Forecasts) compared to the 2015 NEFR (used in the 2016 Connection Point Forecasts). These differences are attributed to changes in population, economic growth and electricity prices in Tasmania as well as changes in NEFR forecasting methodology.**
- **Declines in MD at some connection points are driven primarily by load transfers and industrial closures.**
- **The increase in MD during the later years of the outlook period is due to electricity price forecasts being lower in the 2015 NEFR Update compared to those used for the 2014 NEFR Update towards the end of the outlook period.**
- **Methodology changes in the connection point forecasting process, as outlined in table 3 above.**

## 2.4 Comparison of AEMO 2016 forecasts and TasNetworks 2016 forecasts

At the end of the outlook period, AEMO's Tasmanian winter connection point MD forecasts are 12.4% lower than those of TasNetworks (10% POE). TasNetworks does not forecast summer MD.

Figure 4 plots the comparison. It shows that TasNetworks 10% POE winter forecast starts below AEMO's, but then increases at a growth rate higher than AEMO's forecast, exceeding AEMO's forecast in 2017 and reaching a MD 137 MW higher than AEMO's forecast in 2025.

**Figure 4 AEMO and TasNetworks aggregated, non-coincident 10% POE forecasts[a]**




a The figure excludes direct transmission-connected customer load forecasts which are not distribution-connected and not included in TasNetworks distribution network forecast. Connection points forecasts by TasNetworks are used as the basis for comparisons in both Figure 3 and Figure 4.

The outcome of the comparison in this section demonstrates that, overall, the effect of methodology differences on forecast winter MD is significant. The difference is primarily attributed to the reconciliation step. AEMO's aggregated connection points are reconciled to the general rate of change of the state forecast in the 2015 NEFR Update. TasNetworks commissions an external consultant to develop their state level forecast, which has different assumptions to the NEFR. Table 7 summarises the key differences in methodology between AEMO's and TasNetworks' forecasts.

**Table 7 Identified differences between AEMO and TasNetowrks methodologies**

| Description | AEMO | TasNetworks |
|---|---|---|
| **Rooftop PV** | Forecasts are formed from historical demand data that excludes rooftop PV. The forecasts are then re-adjusted for the effect of PV, based on the difference between the peak with and without PV. | Rooftop PV is not accounted for explicitly in the forecasts, however in this region this has a minimal effect during winter. |
| **Energy efficiency** | Energy efficiency forecast represents the additional impact of energy efficiency measures above the trend included in the historical data. | Energy efficiency savings are not explicitly accounted for in the forecasts. |
| **Reconciliation to state level forecasts** | Forecasts are reconciled to the 2015 NEFR Update forecasts. | Commissioned an external consultant to develop state level forecast. The forecast assumptions differed from the economic assumptions made in the 2015 NEFR Update. |
| **Major industrial loads** | Used the major industrial load forecasts from the 2015 NEFR. This was based on surveys conducted directly with each major industrial customer. | Incorporated growth based on forecasts of each industry sector. |

# APPENDIX A. FORECASTING METHODOLOGY

## Active power

The flowchart in Figure 5 (next page) details how AEMO has implemented its methodology for the active power MD forecasts.

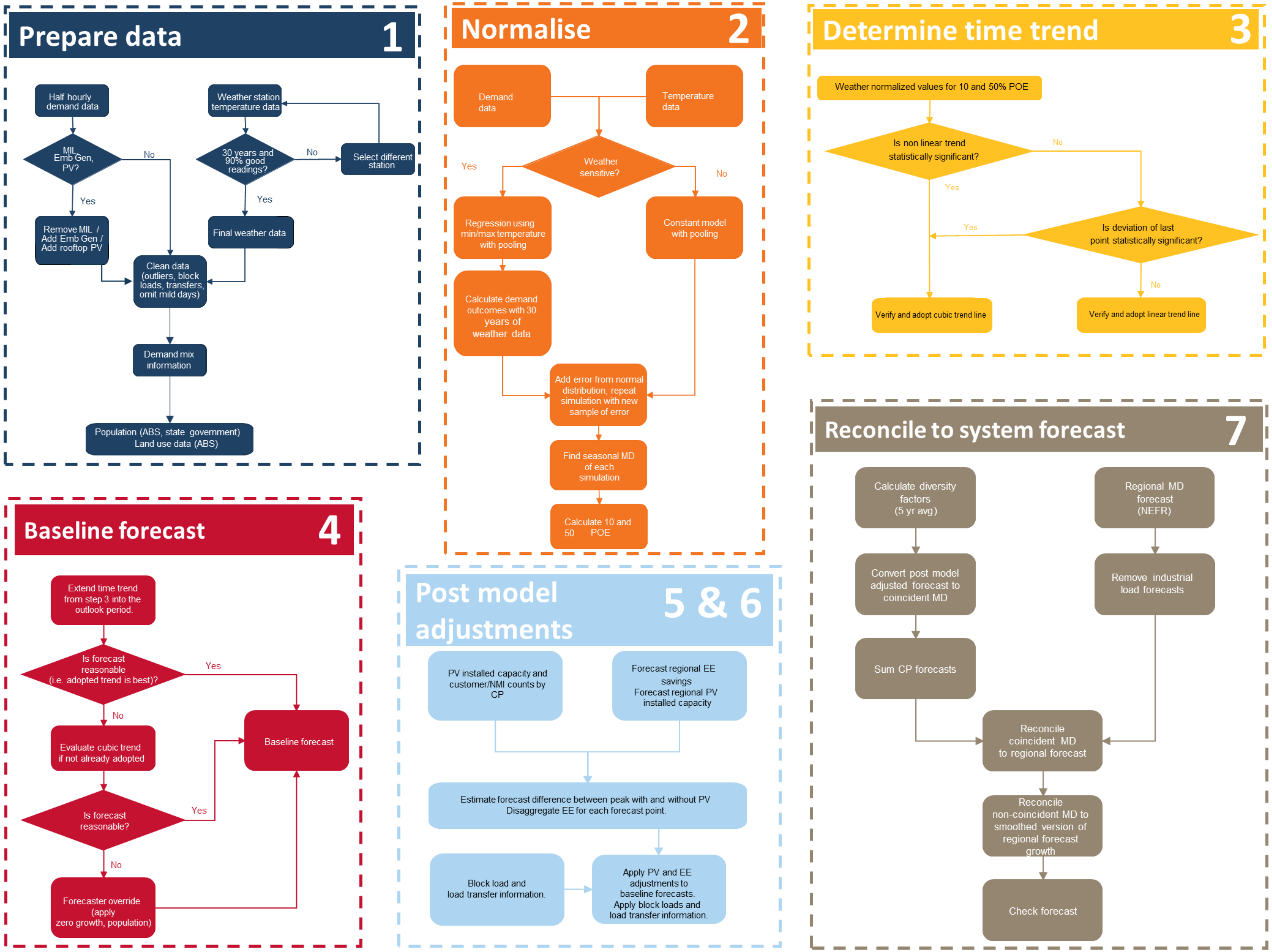
## Reactive power

In addition to the active power MD forecasts, AEMO estimates reactive power demand at the time of active power MD, as this information is required for power system studies. To determine the reactive power estimates, AEMO applies a seasonal power factor to each connection point, derived from recent historical data.

AEMO has found that power factors typically don’t exhibit a clear trend. For this reason, the power factors derived from historical data are adopted to calculate the reactive power estimates for the outlook period.

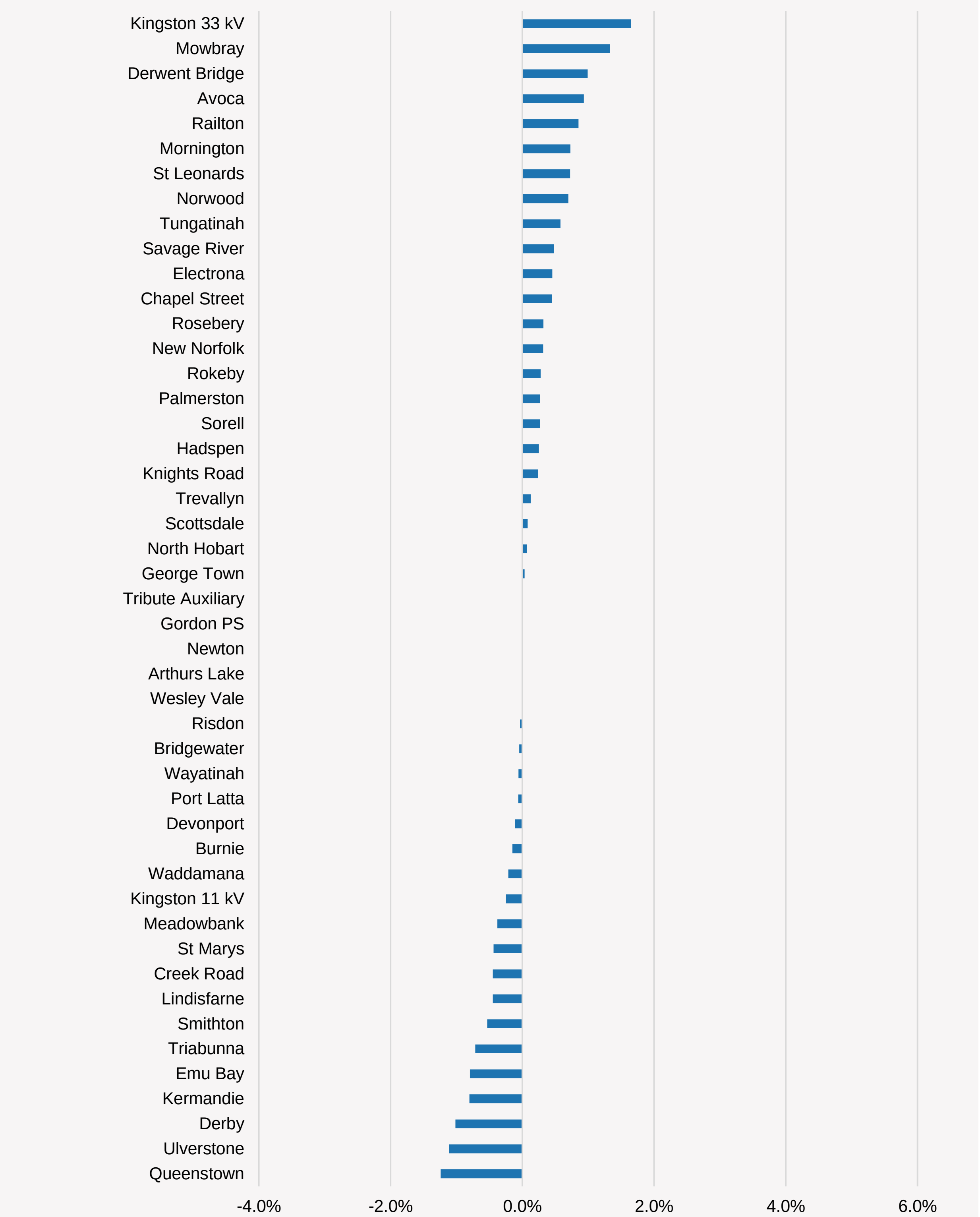
AEMO will review this approach in future forecasting exercises to confirm its appropriateness.

**Figure 5 Implementation of forecasting methodology**



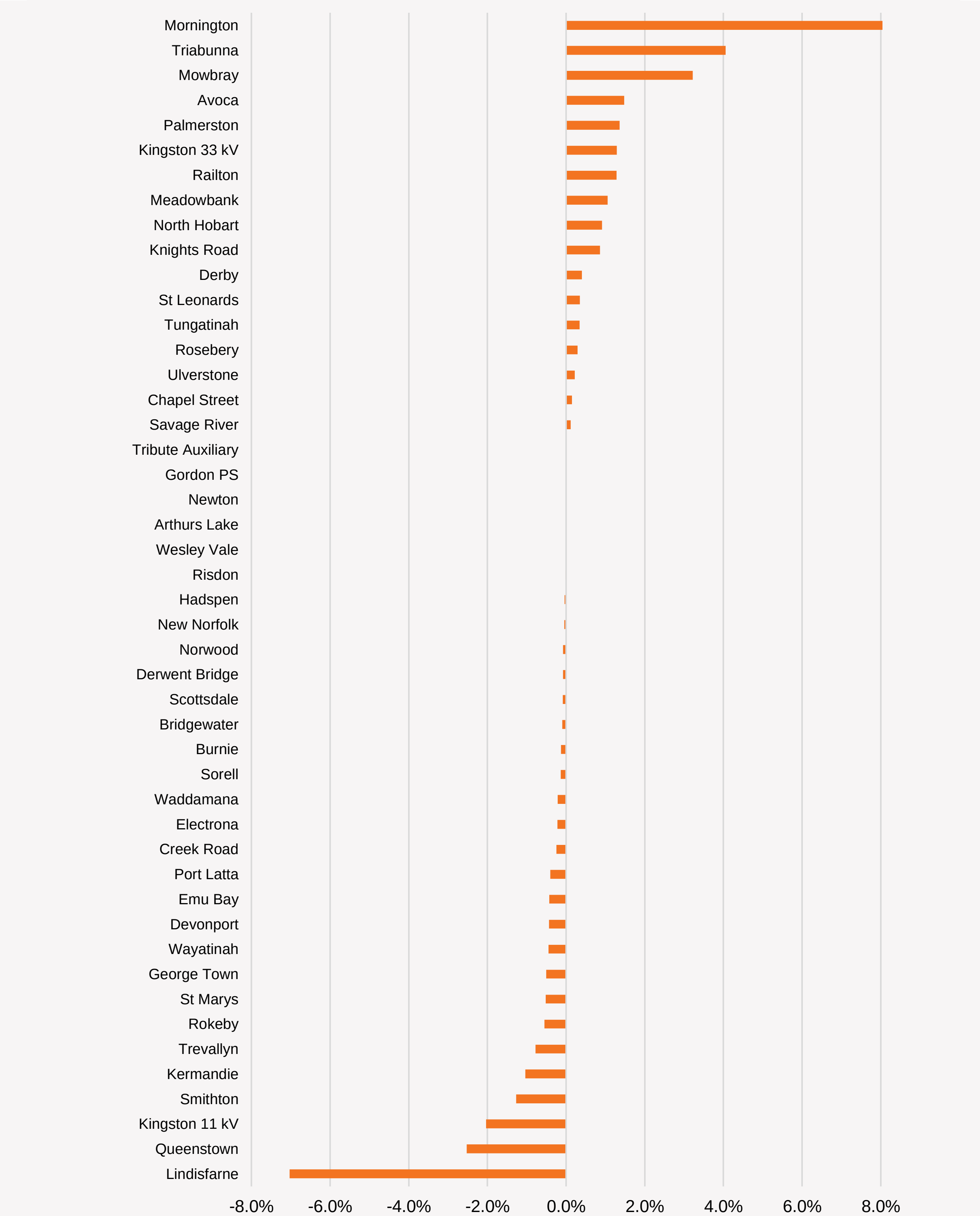
# APPENDIX B. GROWTH RATES BY CONNECTION POINT

**Figure 6 Tasmanian 10% POE winter 10-year average annual growth rates, 2016 to 2025[a]**




[a] Some direct-connect industrial loads are excluded due to confidentiality.

**Figure 7 Tasmanian 10% POE summer 10-year average annual growth rates, 2015–16 to 2024–25[a]**




[a] Some direct-connect industrial loads are excluded due to confidentiality.

# GLOSSARY

## Definitions

This report uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified. Other key terms used are listed below.

| Term | Definition |
| --- | --- |
| **Active energy** | A measure of the energy that can be converted into useful work, generally expressed in kilowatt hours (kWh). |
| **Active power** | The rate at which active energy is transferred. |
| **Apparent power** | The square root of the sum of the squares of the active power and the reactive power. |
| **Average annual (rate of change)** | 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** | A substation at which electricity is typically transformed from the higher transmission network voltage to a lower one. |
| **Connection point** | A point at which the transmission and distribution network meet. |
| **Coincident forecasts** | Maximum demand forecasts of a connection point at the time of system peak. |
| **Distribution network** | The downstream part of the energy network that distributes energy directly to customers. This is generally at lower voltages than the transmission network. |
| **Distribution system** | A distribution network, together with the connection assets associated with the distribution network (such as a transformer), which is connected to another transmission or distribution system.<br>Connection assets on their own do not constitute a distribution system. |
| **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 unit** | The actual generator of 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. |
| **Installed capacity** | The generating capacity in megawatts of the following (for example):<br>• A single generating unit.<br>• A number of generating units of a particular type or in a particular area.<br>• All of the generating units in a region.<br>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. |

| Term | Definition |
|---|---|
| **Network service provider (transmission – TNSP; distribution – DNSP)** | A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a Network Service Provider. |
| **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-coincident forecasts** | The maximum demand forecasts of a connection point, irrespective of when the system peak occurs. |
| **Probability of exceedance (POE) maximum demand (MD)** | 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.<br>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, one year in 10. |
| **Power factor** | The ratio of the active power to the apparent power at a metering point. |
| **Reactive energy** | A measure, in varhour (varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point. |
| **Reactive power** | The rate at which reactive energy is transferred. Reactive power is a necessary component of alternating current electricity which<br>is separate from active power and is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as:<br>• Alternating current generators<br>• Capacitors, including the capacitive effect of parallel transmission wires<br>• Synchronous condensers. |
| **Region** | An area determined by the Australian Energy Market Commission (AEMC) in accordance with Chapter 2A of the National Electricity Rules. |
| **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. |
| **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 network** | A network within any National Electricity Market (NEM) participating jurisdiction operating at nominal voltages of 220 kV and above plus:<br>(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<br>(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 Node Identity (TNI)** | Identifier of connection points across the NEM. |
| **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). |

# ABBREVIATIONS

| Term | Definition |
|---|---|
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| BSP | Bulk Supply Point |
| DNSP | Distribution Network Service Provider |
| MD | Maximum demand |
| MW | Megawatt |
| NMI | Network Meter Identifier |
| NEFR | National Electricity Forecast Report |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NSP | Network Service Provider |
| POE | Probability of Exceedance |
| PV | Photovoltaic |
| TNI | Transmission Node Identifier |
| TNSP | Transmission Network Service Provider |