2014 UPDATE: AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR TASMANIA

Published: February **2015**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has updated its Connection Point Forecasts for Tasmania to incorporate the 2014 winter season.

This publication is based on information available to AEMO as at 1 February 2015.

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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

Following AEMO's 2014 National Electricity Forecasting Report[1] (NEFR) Update, AEMO has updated the Connection Point Forecasts for Tasmania[2] previously published in July 2014, to incorporate the 2014 winter season. This 2014 Update reflects a number of improvements made to AEMO's methodology as outlined in AEMO's Transmission Connection Point Forecasting Action Plan.[3] AEMO intends to adopt this same methodology as the basis for forthcoming regions.

Key findings

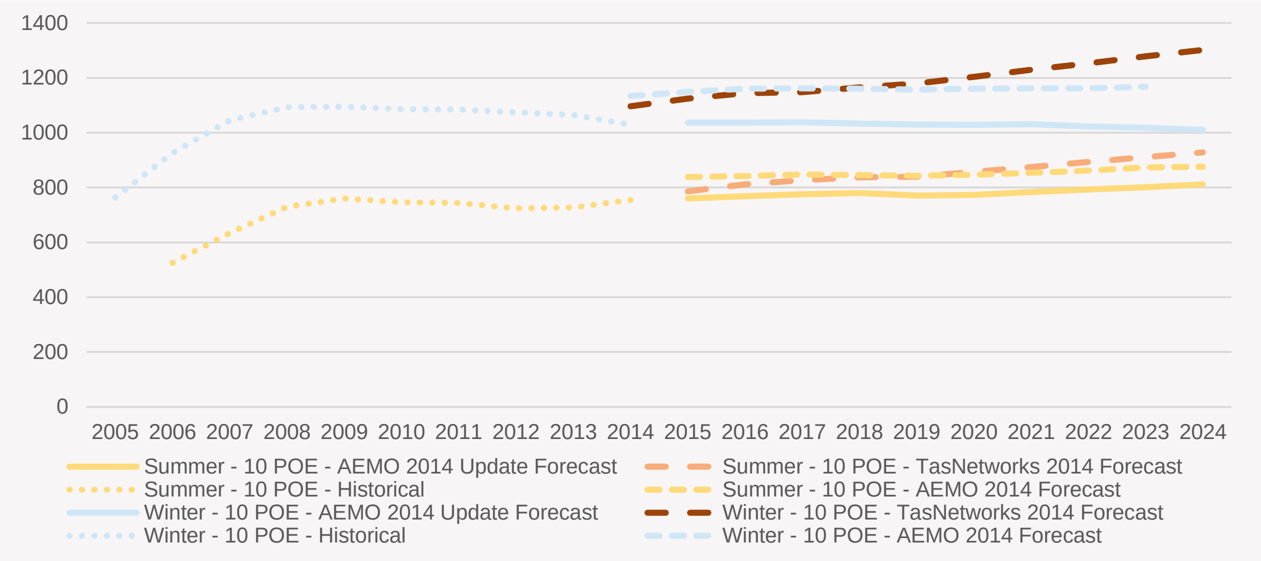
Forecast	2014 Region-level average annual growth rate (10% POE)	2014 Update Region-level average annual growth rate (10% POE)
Winter	0.33%	–0.29%
Summer	0.49%	0.72%

Forecast	Differences between AEMO 2014 and 2014 Update aggregated MD forecasts (10 POE)
Winter MD	AEMO's updated connection point forecast is 12.85% (150 MW) lower than the previous forecast at the end of the 10-year outlook period.
Summer MD	AEMO's updated connection point forecast is 7.4% (65 MW) lower than the previous forecast at the end of the 10-year outlook period.

This 2014 Update demonstrates a lower growth rate for winter maximum demand (MD), illustrating a continuing decline in actual residential and commercial MD, despite increases in Tasmania's gross state product. This is also consistent with the 2014 NEFR Update.[1]

Figure 1 below shows the comparison between AEMO's 2014 aggregated non-coincident connection point forecasts for Tasmania and AEMO's 2014 Update forecasts, as well as TasNetworks aggregated 2014 forecast. At the end of the outlook period, AEMO's aggregated forecasts are lower than those of TasNetworks (28.9% lower for winter and 14.5% lower for summer).

Figure 1 AEMO forecasts and TasNetworks aggregated 10% POE forecasts



TasNetworks has only prepared 10% POE forecasts for the 10-year outlook period.

1 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.
2 AEMO. *Transmission Connection Point Forecasts.* Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting. Viewed: 22 January 2015.
3 AEMO. *Transmission Connection Point Forecasting Action Plan*, October 2014 Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting/AEMO-Transmission-Connection-Point-Forecasting-Action-Plan. Viewed: 22 January 2015

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1. INTRODUCTION

This report is the second time AEMO has developed transmission connection point forecasts for Tasmania, and incorporates a range of changes to the forecasting methodology.

In October 2014, AEMO published the Transmission Connection Point Forecasting Action Plan[3], listing areas of further improvement that AEMO intends to focus on when producing future transmission connection point forecasts. AEMO has implemented some of these improvements for the update of the Tasmanian connection point forecasts.

AEMO has developed 10% and 50% probability of exceedance (POE) MD forecasts for active power (in MW) and reactive power (in MVAr) for a 10-year outlook period for summer (2014–15 to 2023–24) and winter (2015 to 2024).

In developing the forecasts, AEMO consulted with TasNetworks (Tasmanian NSP). This included data sharing and exchanging local-level information.

AEMO also engaged Frontier Economics to act as an advisor during this process, in particular with implementing improvements to the forecasting methodology.

1.1 Report structure

This report is structured as follows:

- Chapter 1: Introduction
- Chapter 2: Highlights key results for 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.
- Appendix A: Provides a detailed breakdown of growth rates by connection point.
- Appendix B: Provides an overview of the forecasting process. This includes a summary of the methodology and how it was implemented.
- Appendix C: Provides a list of data shared between AEMO and the Distribution Network Service Provider (DNSP).

1.2 Supplementary information on AEMO's website

Supplementary information to this report includes:

- A dynamic interface with the following information for each transmission connection point:
  - 10% POE and 50% POE active power (MW) forecasts over a 10-year outlook period, summer and winter.
  - High-level commentary.
  - Historical and forecast data.
- A spreadsheet for reactive power (MVAr) for each transmission connection point.

All documents are available with this report on AEMO's website.

3 AEMO. *Transmission Connection Point Forecasting Action Plan* October 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting/AEMO-Transmission-Connection-Point-Forecasting-Action-Plan Viewed: 23 January 2015

2. RESULT HIGHLIGHTS

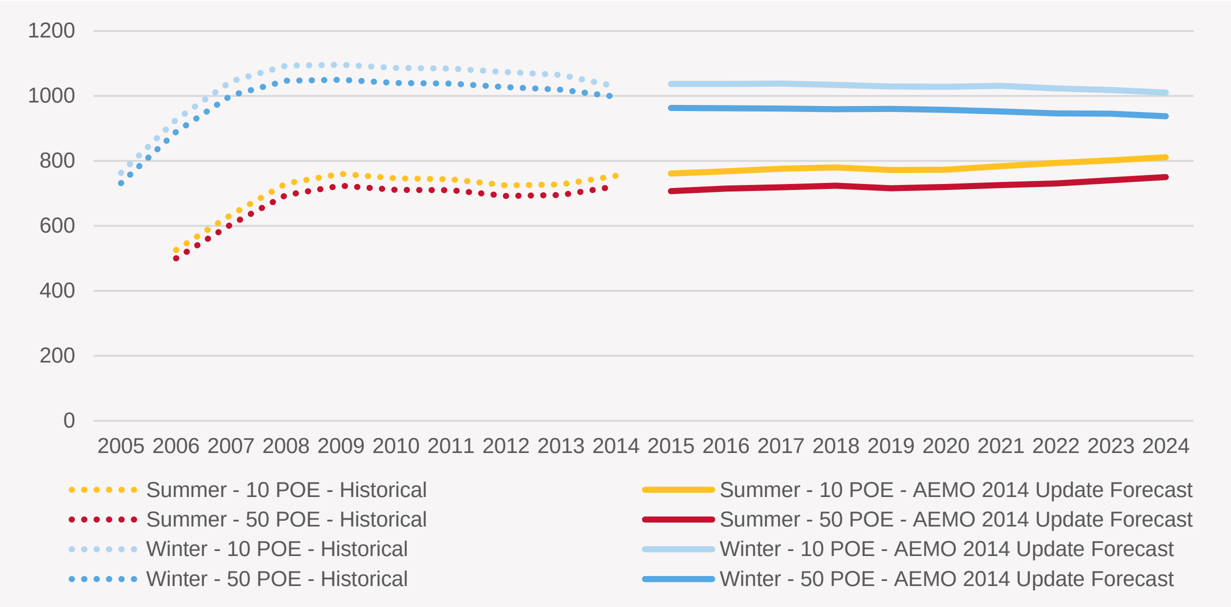
This section summarises the key findings of the Tasmanian transmission connection point forecasts, for the outlook period for summer (2014–15 to 2023–24) and winter (2015 to 2024). Additional information for each connection point is available in the dynamic interface on AEMO's website, published in conjunction with this report.

2.1 Aggregated connection point trend

Over the outlook period, winter MD is expected to decrease slightly while summer MD increases at a low rate. At the aggregate level, winter MD is higher than summer MD. Figure 2 shows historical and forecast aggregated connection point demand.

Regional average annual growth over the outlook period for winter is negative at –0.29% for the 10% POE and –0.30% for the 50% POE forecasts. Forecast summer demand growth is stronger than winter, at 0.72% for 10% POE and 0.67% for 50% POE. This aligns with the MD forecasts for the region in the 2014 NEFR update[4] over the outlook period, which is incorporated into the connection point forecasts through the reconciliation step of the forecasting process.

Figure 2 AEMO 10% and 50% POE non-coincident aggregated connection point forecasts



While this is the aggregate demand growth for Tasmania, average annual growth varies by connection point, and is distributed above and below the overall region growth rates.

Winter 10% POE average annual growth ranges from –1.97% (Port Latta) to 4.43% (Emu Bay), with the exception of Newton which has an average annual growth rate of –32.39% due to a major industrial load entering maintenance mode in late 2015. Appendix A (Figure 5) shows that 83% of connection points have winter 10% POE growth of less than 1.0%.

Summer 10% POE average annual growth rates range between –0.95% (Kingston 11kV) to 6.68% (Emu Bay), with the exception of Newton, which has an average annual growth rate of –30.40% due to a major industrial load entering maintenance mode in late 2015. Appendix A (Figure 6) shows the summer growth rates.

4 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.

Forecast summer demand growth is stronger than winter, with 62% of connection points showing positive growth compared to 43% for winter which is in line with AEMO's 2014 NEFR Update[5] for Tasmania.

AEMO applies constant power factors to determine the reactive power forecast, so the distribution of reactive power growth rates is the same as the distribution of active power growth rates.

Growth drivers

Appendix A shows a breakdown of the 10% POE growth rates for each connection point. Key growth drivers are shown in Table 1.

Table 1 Drivers at connection points with growth or decline greater than 2%

Season	10% POE: average annual growth over 2%	10% POE: average annual decline over 2%
Winter	**Avoca, Palmerston:** Expected to grow due to increased agricultural and industrial load consumption. **Emu Bay, Triabunna, and Waddamana:** Expected to grow due to increased industrial load consumption.	**Newton:** Major industrial load entering maintenance mode in late 2015
Summer	**Emu Bay, Triabunna, St. Marys, Queenstown, and Meadowbank:** Expected to grow due to increased industrial load consumption. **Avoca:** Expected to grow due to increased agricultural and industrial load consumption.	**Newton:** Major industrial load entering maintenance mode in late 2015

5 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.

2.2 Comparison of AEMO 2014 and 2014 Update forecasts

AEMO has implemented several improvements to its connection point forecasts for Tasmania, as detailed in Appendix B. Figure 3 below shows the comparison between AEMO's aggregated non-coincident 2014 connection point forecasts for Tasmania and AEMO's 2014 update forecasts. Winter 10% POE MD forecasts have decreased by 12.85% while summer 10% POE MD forecasts have decreased by 7.4%. Reasons for this reduction are detailed in the table below.

Figure 3 AEMO 2014 and 2014 Update (10% and 50% POE) aggregated non-coincident forecasts

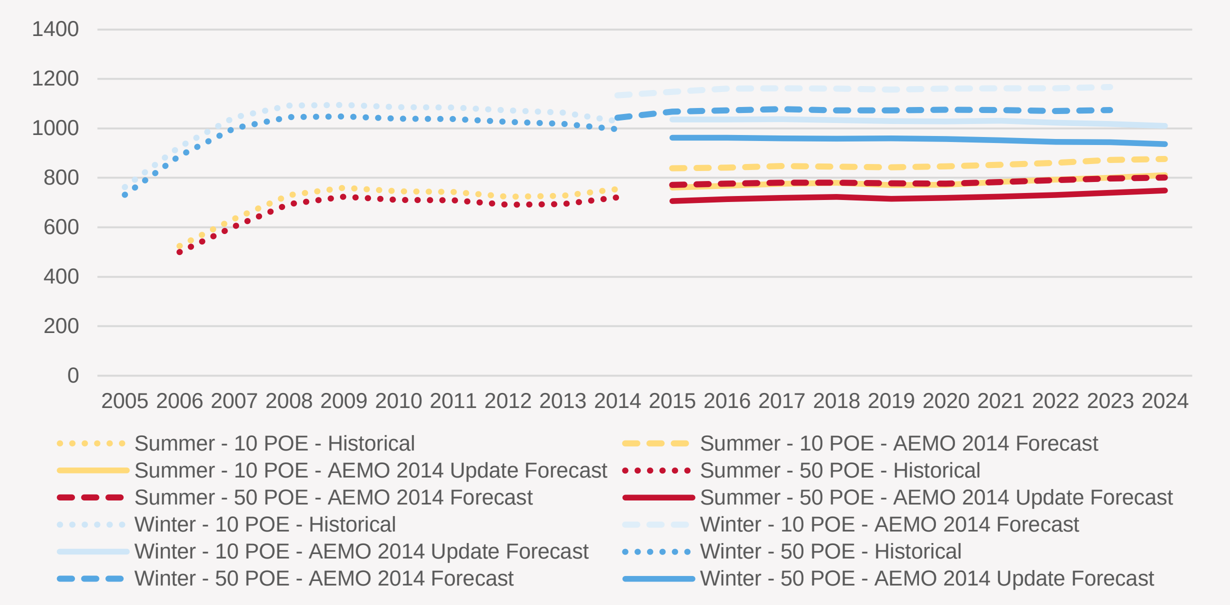


Table 2 Region-level average growth rates

Forecast	2014 Region-level average annual growth rate (10% POE)	2014 Update Region-level average annual growth rate (10% POE)
Winter	0.33%	–0.29%
Summer	0.49%	0.72%

Table 3 Differences between AEMO 2014 and 2014 Update forecasts

Forecast	Differences between AEMO 2014 and 2014 Update aggregated MD forecasts (10 POE)
Winter MD	AEMO's updated connection point forecast is 12.85% (150 MW) lower than the previous forecast at the end of the 10-year outlook period.
Summer MD	AEMO's updated connection point forecast is 7.4% (65 MW) lower than the previous forecast at the end of the 10-year outlook period.

Key differences:

- Improvements to weather normalisation:
  - Historical data was adjusted at half-hourly intervals before normalising for weather variations, enabling better analysis of changes that occurred mid-season.
  - Weather sensitivity was determined by using data across a three-year window, improving the stability of the weather demand modelling process.
- Previously, only linear trends were fitted to the weather-normalised historical data. In the updated forecasts, non-linear (cubic) models were also fitted to weather normalised historical data, to allow for non-linear trends.
- This 2014 Update demonstrates a lower growth rate for winter MD, illustrating a continuing decline in actual residential and commercial MD, despite increases in Tasmania's gross state product. This is also consistent with the 2014 NEFR Update.[6]

6 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.

2.3 Comparison of AEMO and TasNetworks forecasts

At the end of the outlook period AEMO's aggregated winter forecasts are 28.9% lower than those of TasNetworks. AEMO's summer forecasts are 14.5% lower than those TasNetworks. Figure 4 plots the aggregated, non-coincident forecasts.

Figure 4 AEMO and TasNetworks aggregated non-coincident 10% POE forecasts

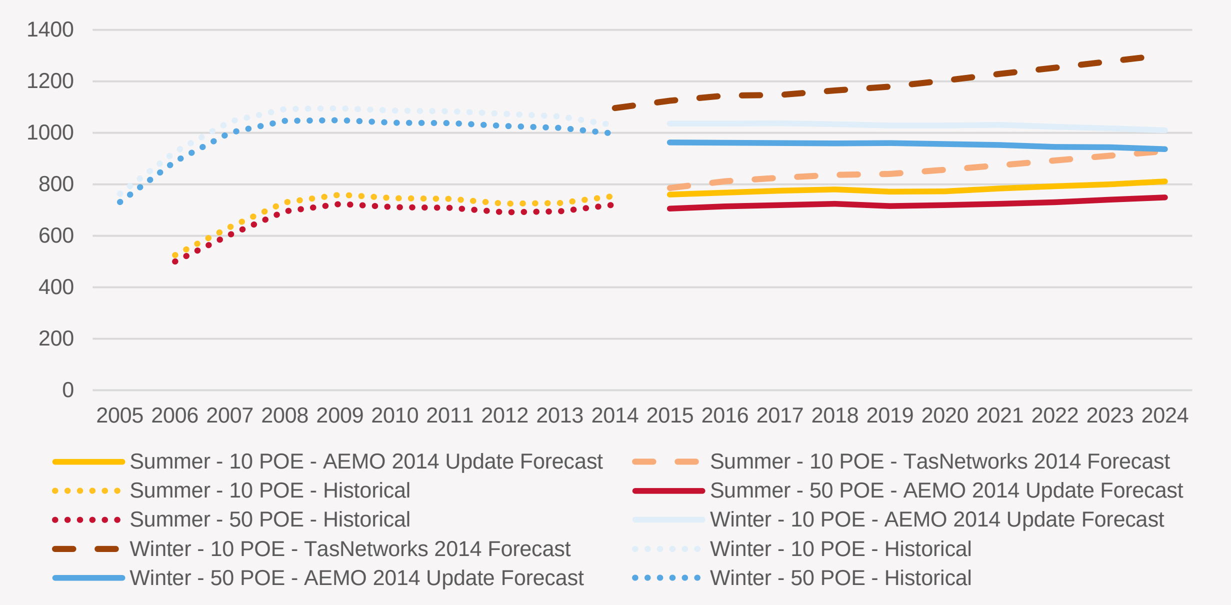


Table 4 Differences between AEMO and TasNetworks forecasts

Forecast	Differences between AEMO and DNSP aggregated MD forecasts
Winter MD	AEMO's connection point forecast is 28.9% (292 MW) lower than TasNetworks forecast at the end of 10-year outlook period.
Summer MD	AEMO's connection point forecast is 14.5% (117 MW) lower than TasNetworks forecast at the end of 10-year outlook period.

Table 5 Identified differences between AEMO and TasNetworks 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 explicitly accounted for in the forecasts. However, in this region, rooftop PV 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 2014 NEFR Update[7] forecasts.	Commissioned an external consultant to develop the state level forecast. The forecast assumptions for GSP, population and electricity price differ from those used in the 2014 NEFR Update due to timing of forecasts and data sources.
Major Industrial Loads	Used the major industrial load forecasts from the 2014 NEFR Update. This was based on surveys conducted directly with each major industrial customer with loads greater than 10MW.	Incorporated growth based on the forecasts from each industry sector.

7 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.

APPENDIX A. GROWTH BY CONNECTION POINT

Figure 5 Tasmania 10% POE winter 10-year average annual growth rates, 2015 to 2024

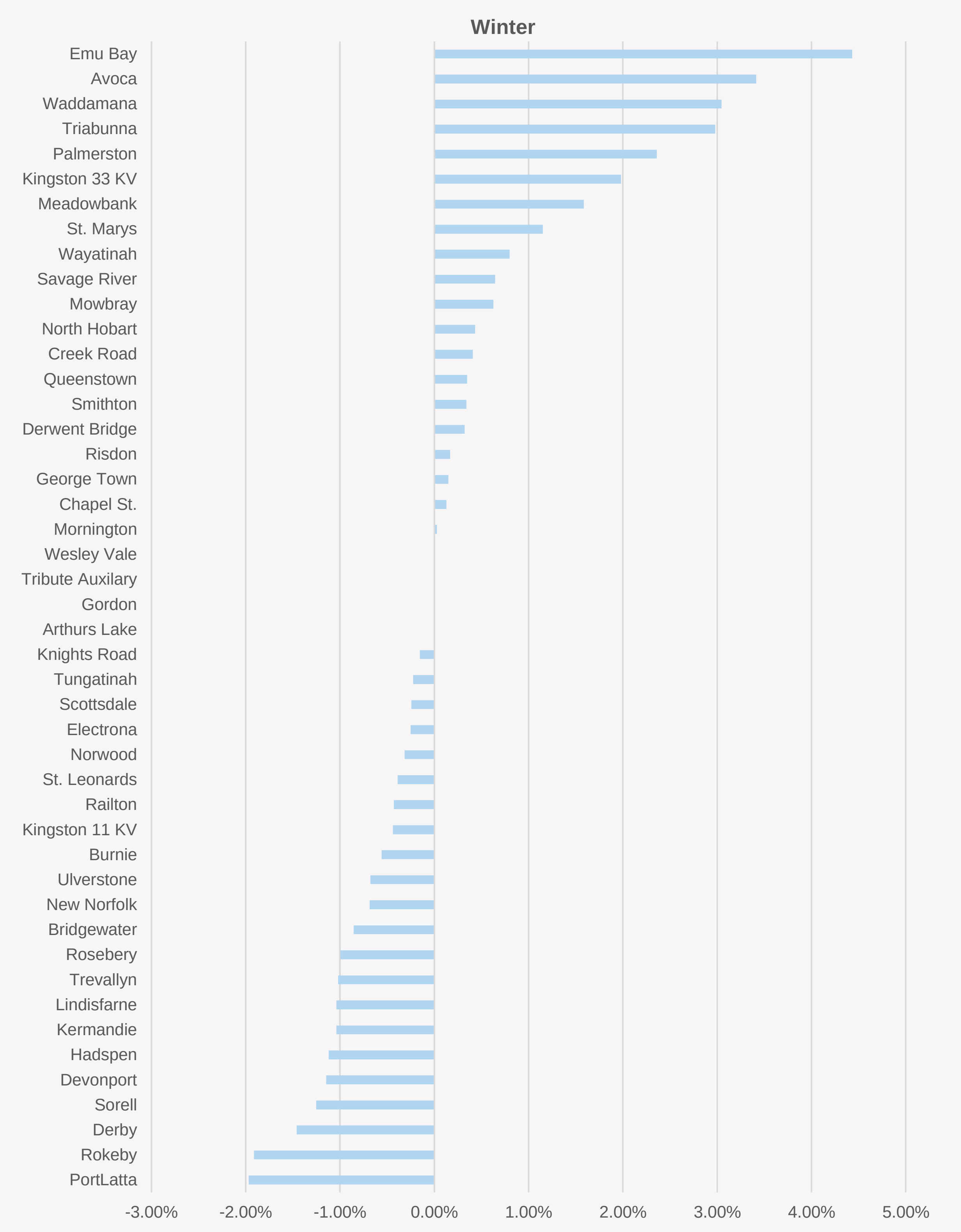
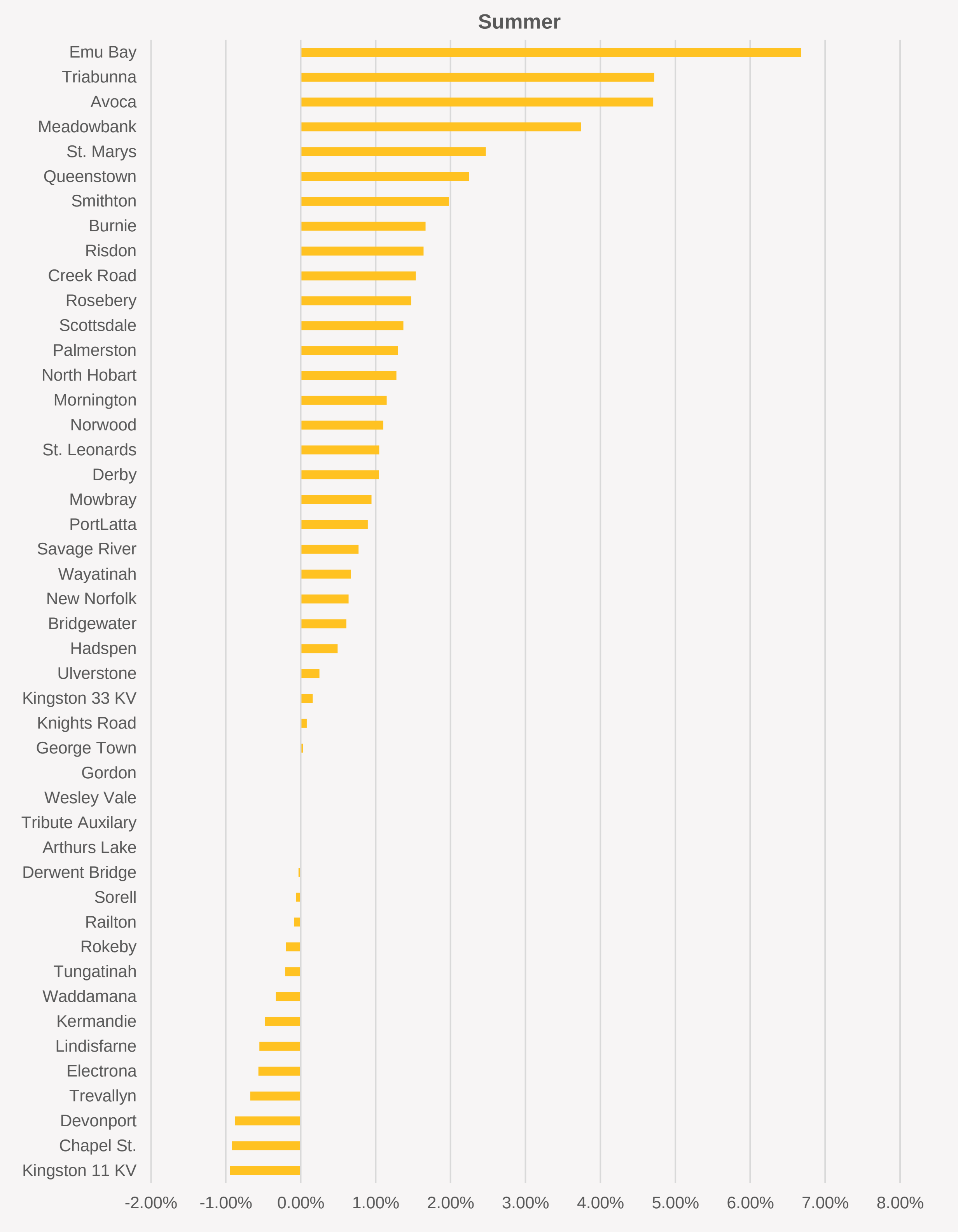


Figure 6 Tasmania 10% POE summer 10-year average annual growth rates 2014–15 to 2023–24



Note: Industrial loads and Newton connection point are excluded from Figures 5 and 6

APPENDIX B. FORECASTING PROCESS OVERVIEW

This section summarises the underlying forecasting principles and methodology used by AEMO to develop the transmission connection point forecasts for Tasmania.

Forecasting principles

AEMO sought to develop a forecasting process and methodology incorporating benchmark forecasting characteristics listed by the AER.[8]

The table below lists these and outlines how AEMO addressed each characteristic.

Table 6 Characteristics of good forecasting techniques listed by the AER

Characteristic	AEMO implementation
Accuracy and unbiased data	AEMO used wholesale meter data where possible. Data shared by the DNSP was verified against AEMO's databases where possible.
Transparency and repeatability	AEMO engaged stakeholders in forecast development, including the DNSP and the TNSP. Developed and published consistent methodology. 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., rooftop PV and energy efficiency), and regional economic and demographic drivers.
Model validation and testing	Forecasts were peer reviewed within AEMO. Incorporated statistical significance testing for a selection of baseline forecast trends.
Accuracy and consistency of forecasts at different levels of aggregation	Transmission connection point forecasts were reconciled to the 2014 NEFR Update forecasts.[9] AEMO will monitor the forecast accuracy.
Use of the most recent input information	AEMO used demand data to the end of August 2014 to incorporate winter 2014. AEMO also monitored new developments and incorporated them where possible.

Connection point definition

AEMO's connection point forecasting methodology, published in June 2013[10], defines a transmission connection point as the physical point at which the assets owned by a TNSP meet the assets owned by a DNSP.

In the NEM, electricity is notionally bought and sold at the regional reference node (RRN) in each NEM region. However, electricity is physically bought and sold at transmission connection points, represented in market metering and settlements processes by transmission node identities (TNIs).[11] Each connection point TNI refers to a set of physical sub transmission lines that are owned by a DNSP and supplies a DNSP's customers.

Connection points may be connected to one another at the distribution network level.

To maintain a nationally consistent approach to transmission connection point forecasting, AEMO develops connection point forecasts at the TNI level for 47 Tasmanian distribution network connection points, and 10 connection points for direct transmission-connected customers.

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8 AER. November 2011. Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17. Attachment 3.2 p.76. Available: http://www.aer.gov.au/sites/default/files/Aurora%202012-17%20draft%20distribution%20determination.pdf. Viewed: 23 January 2015.

9 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.

10 AEMO. *Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Demand – Report*. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting. Viewed: 23 January 2015.

11 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-the-2014-15-Financial-Year. Viewed: 23 January 2015.

- The forecast applies to active power (MW) and reactive power (MVAr) MD at each connection point.
- The forecast excludes transmission system losses and power station auxiliary loads.
- Embedded generators, where mentioned, are assumed to be off at the time of connection point MD.
- Direct transmission connected customer forecasts are only published if AEMO has permission directly from the customer.

Forecasting methodology

To maintain a nationally consistent approach to transmission connection point forecasting, AEMO's transmission connection point forecasting methodology for active power comprises seven major steps.

Table 7 Key steps in forecasting methodology

Step	Description
1. Prepare data	Obtain and clean demand and weather data. Determine demand profile and demand mix.[12]
2. Weather normalise	Determine weather-sensitivity at each connection point and calculate weather-normalised POE values.
3. Determine time trend	Determine whether the historical time trend is linear or non-linear and adopt a trend line that reflects this (linear or cubic). Verify that the trend is reasonable when extrapolated to the future.
4. Baseline forecasts	Apply the time trend to the forecast years.
5. Apply post model adjustments	Adjust for energy efficiency, future block loads and load transfers. The energy efficiency adjustments were derived from the 2014 NEFR.[13]
6. Apply post model adjustments for rooftop PV	Using typical daily traces of demand on maximum demand days, calculate difference between the peak with zero PV and peak including PV. Apply this difference as the post model adjustment for rooftop PV.
7. Reconcile to system forecasts	Adjust the forecasts to take into account the effects of the growth drivers included in the relevant regional forecast. This includes regional-level economic and demographic growth drivers. The regional forecast was taken directly from the 2014 NEFR Update.[14]

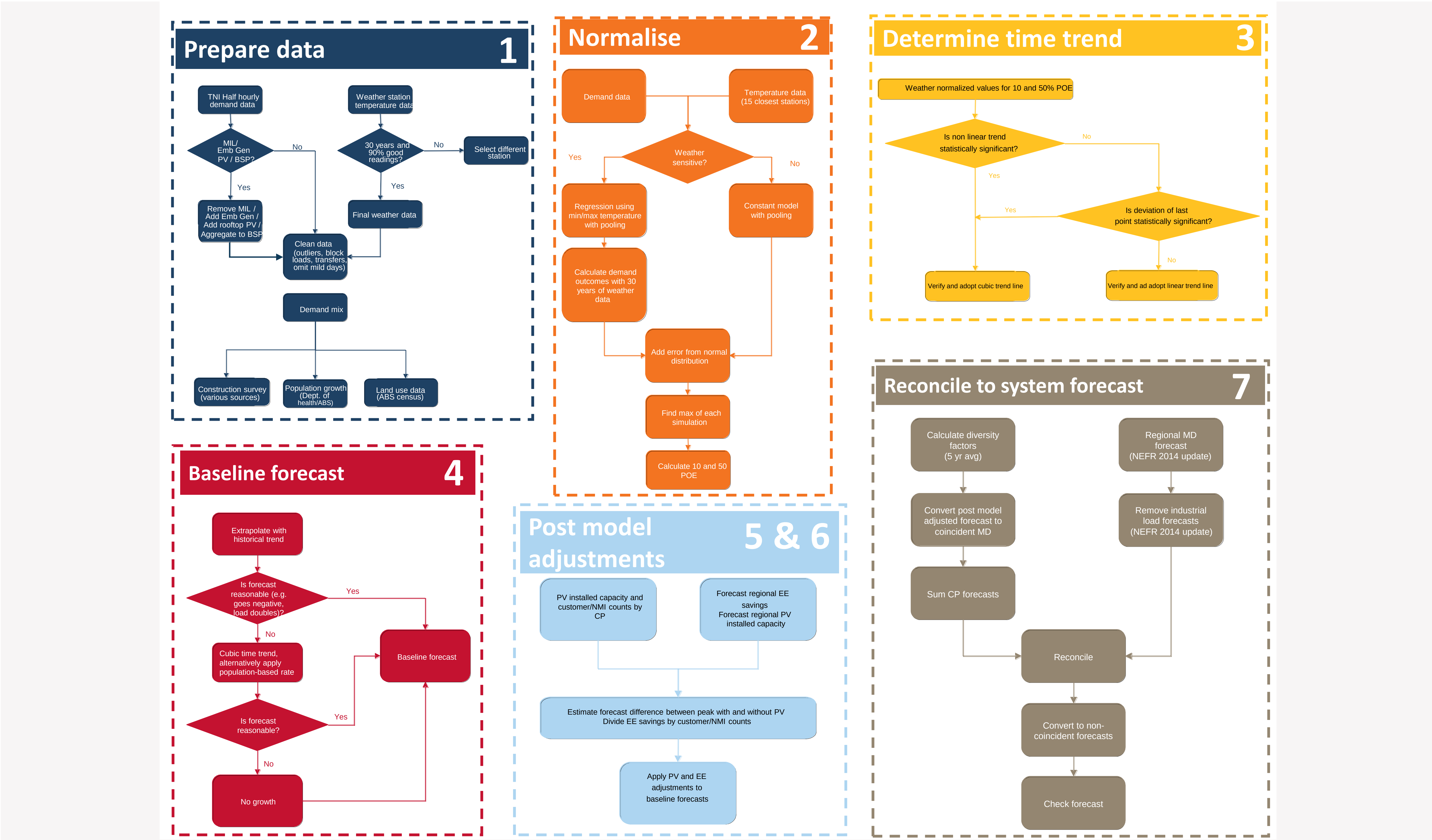
AEMO's forecasting methodology for reactive power is based on historical power factors for connection point MD. These power factors generally remain constant over consecutive seasons. For this reason, forecasts are developed by applying average historical power factors to the final active power forecasts.

AEMO will review this approach in future forecasting exercises to confirm that it is appropriate.

The flowchart over the page details how AEMO has implemented this methodology.

12 The type of loads connected to each connection point (e.g., residential, agricultural, industrial).
13 AEMO. *National Energy Forecasting Report 2014*. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 23 January 2015.
14 AEMO. *Update: National Electricity Forecasting Report* December 2014. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed: 22 January 2015.

Figure 7 Implementation of forecasting methodology



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.[15] In accordance with the plan, AEMO investigated possible areas of improvement within the forecasting process relating to forecast inputs and methodologies. Several improvements were incorporated into the development of the Tasmanian forecasts.

A summary of the investigations and outcomes is presented in Table 8.

Table 8 Improvements implemented for the Tasmanian forecasts

Improvement description	Approach	Benefit	Implemented
Adjust historical data for block loads, load transfers, and rooftop PV at the daily or half-hourly level.	Adjustments for block loads and transfers and estimated rooftop PV output were applied to the data at the half hourly level, before weather normalisation.	The data was adjusted for: • Clearer handling of step changes that occurred mid-season. • A streamlined data preparation process for forecasting. • Realistic treatment of rooftop PV by using an adjustment that varies depending on the time of day and level of cloud cover.	Yes
Investigate use of non-linear models for time series trends and implement if improvements are found.	In addition to the linear trend, a cubic trend was fitted to the weather-normalised historical data to provide an alternative time trend for forecasting.	This reduced the need for subjective judgements in determining forecast growth rates. The cubic trend provided an impartial alternative forecast for situations when the time trend was found to be non-linear (statistical test).	Yes
Improve disaggregation of regional rooftop PV estimates.	Detailed installed capacity information was provided by TasNetworks. These datasets were considered the best available and used to disaggregate regional forecast components.	Use of detailed installed capacity information, meant: • Improved allocation of rooftop PV output to each connection point.	Yes
Investigate effectiveness of using pooled data across years to determine weather sensitivity.	Pooling data was tested using 3-year windows.	The improvement increased the stability of coefficients in the weather-demand modelling process.	Yes
Account for the time of day when making post model adjustments for rooftop PV.	Using typical, connection point-specific, daily traces of demand on maximum demand days, calculate the difference between the peak with and without rooftop PV. Apply this difference as the post model adjustment.	The adjustment takes into account the daily load profile at each connection point. The adjustment inherently allows the time of MD to change as rooftop PV output increases with increasing installed capacity.	Yes

[15] AEMO. *Transmission Connection Point Forecasts.* Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting. Viewed: 23 January 2015.

APPENDIX C. DATA SHARED BY NETWORK SERVICE PROVIDERS

Network service providers provided crucial data during the forecasting development process. Table 9 summarises the data provided.

Table 9 List of data provided by network service providers

Item	Description
Demand data	Half-hourly data was provided at points not covered by national grid meters.
Embedded generation data	NMIs and descriptions for registered and exempt generators were included in this exchange.
Industrial data	NMIs were provided for industrial loads. Data provided at the half-hourly level for the NEFR was also used.
Load transfers and block loads	Permanent shifts at the 10% POE level, for historical and forecast periods.
Maximum demand forecasts	Latest forecasts were made available to AEMO.
PV installed capacity	Provided a list of NMIs.
Customer types	Numbers of customers by category, by connection point.
Network configuration information	Wholesale NMIs and transformers were identified providing an understanding of the network. Knowledge on network configuration was also provided.
Demand mix and local information	Provided on an ad hoc basis.

GLOSSARY

Definitions

Many of the listed terms are already defined in the National Electricity Rules (NER), version 66.[16] For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have a specific meaning when used in this report. 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.
Active energy	A measure of electrical energy flow, being the time integral of the product of voltage and the in-phase component of current flow across a connection point, expressed in watthour (Wh).
Active power	The rate at which active energy is transferred.
Block loads	Large electrical 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. See diversity factor.
Distribution losses	Distribution losses are electrical energy losses incurred in distributing electricity over a distribution network.
Distribution network	A network which is not a transmission network.
Distribution system	A distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system. Connection assets on their own do not constitute a 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 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): 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.

16 An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules.

Term	Definition
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.
Meshed network	A power system network that is supplied by multiple 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 and who is registered by AEMO as a Network Service Provider. In Tasmania, TasNetworks is both the TNSP and DNSP.
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 megawatt hours (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 (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. 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.
Radial network	A distribution network that is supplied by a single connection 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 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: • Alternating current generators • Capacitors, including the capacitive effect of parallel transmission wires • Synchronous condensers.
Reconciled forecasts	Forecasts that have been scaled such that the sum of all connection points equal to the regional forecasts.
Region	An area determined by the AEMC in accordance with Chapter 2A of the National Electricity Rules (NER).

Term	Definition
Regional Reference Node	A location on a transmission or distribution network to be determined for each region 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 hour
MVAr	Megavolt ampere reactive

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
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
MIL	Major Industrial Load
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
POE	Probability of Exceedance
PV	Photovoltaic
RRN	Regional Reference Node
SNSG	Small Non-scheduled Generation
TNI	Transmission Node Identifier
TNSP	Transmission Network Service Provider