2014 AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR SOUTH AUSTRALIA

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this transmission connection point forecasting report for South Australia at the request of the Council of Australian Governments' Energy Council.

This publication is based on information available to AEMO as at 1 December 2014.

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution from SA Power Networks and ElectraNet in providing data and information used in this publication.

EXECUTIVE SUMMARY

This report details the Australian Energy Market Operator's (AEMO) first maximum demand (MD) forecasts at transmission connection point level for South Australia. It follows the publication of AEMO's first transmission connection point forecasting reports for New South Wales and Tasmania in July 2014, and Victoria in September 2014.[1]

AEMO has developed these reports at the request of the Council of Australian Governments (COAG) as part of its energy market reform implementation plan, and will extend this work to include all National Electricity Market (NEM) regions by mid-2015. The reports are updated annually.

AEMO's MD forecasts, developed at the points where the transmission network connects with distribution networks, provide transparent, granular demand information at a local level. Together with the regional-level MD forecasts published in AEMO's National Electricity Forecasting Report[2] (NEFR), they provide an independent and holistic view of electricity demand in the NEM. This increased transparency of MD forecasts helps to inform efficient network investment decisions for the long-term benefit of consumers.

MD forecasts at transmission connection point level are also used as an input into AEMO's planning studies, supporting AEMO's independent assessment of transmission network infrastructure development needs across the NEM.

AEMO consults widely with stakeholders in developing the transmission connection point forecasts, and in particular with the relevant distribution network service providers (DNSPs). This involves sharing local knowledge about the network, understanding differences in forecasting methodologies, and exchanging data.

AEMO is committed to continuous improvement of its forecasting capabilities and has enhanced its transmission connection point forecasting methodology since publishing the Victorian report, particularly in relation to historical data analysis and the effects of rooftop photovoltaics (PV). These improvements are in line with AEMO's Transmission Connection Point Forecasting Action Plan[3]. AEMO will adopt this same methodology as the basis for all future transmission connection point forecasts.

Key findings

AEMO has developed 10% and 50% probability of exceedance (POE) South Australian 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).

Forecast	Region level average annual growth rate (10% POE)	Range of average annual connection point growth rates (10% POE)
Summer MD	0.0%	-2.2% to 21.5%
Winter MD	0.8%	-2.5% to 27.1%

Notes

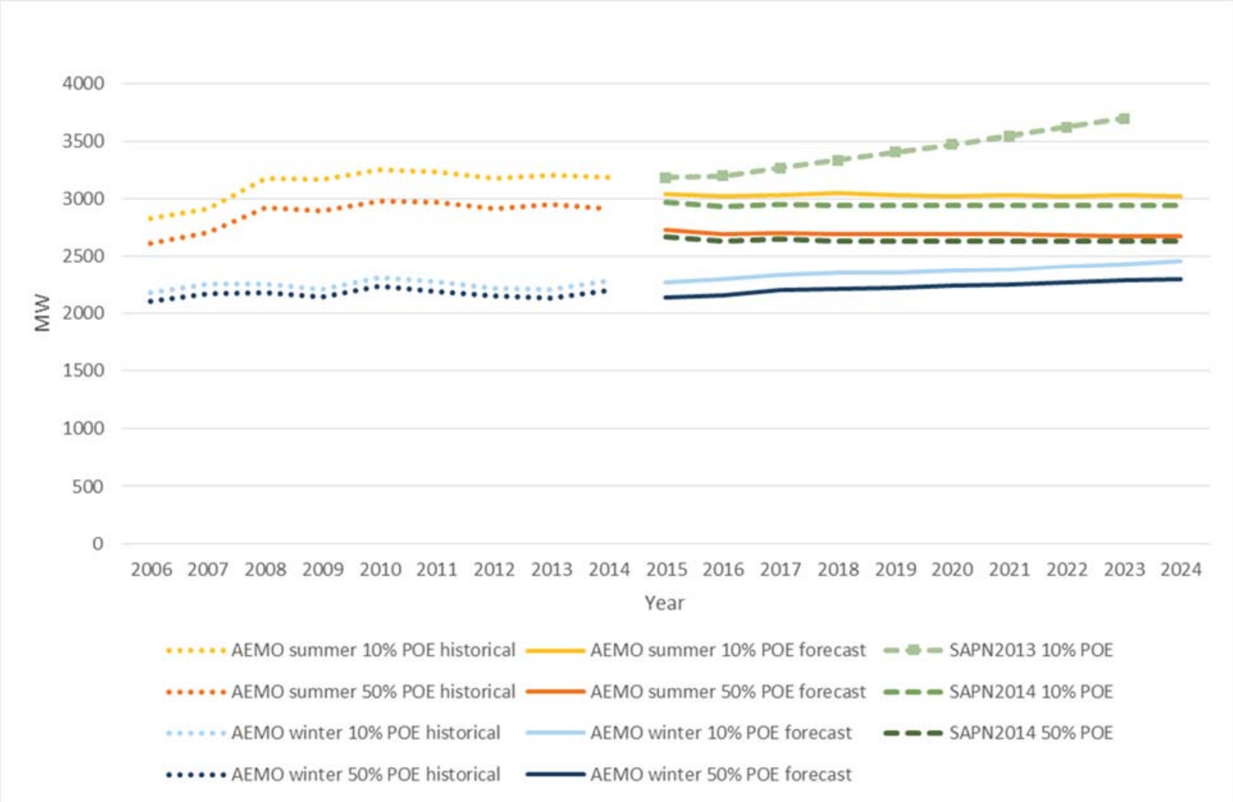
- Overall forecast MD in South Australia is flattening, but is forecast to increase at some individual connection points.
- If Stony Point is excluded, summer 10% POE average annual growth rates range between -2.2% to 3.1%, and winter 10% POE average annual growth rates range between -2.5% to 4.8%.
- Stony Point has an average annual growth rate of 21.5% (summer) and 27.1% (winter) due to a new diesel terminal coming online by 2017.
- Positive growth is primarily driven by block loads and load transfers, population growth and a positive economic outlook, which is incorporated into the forecasts through reconciliation to the regional forecast (NEFR 2014).
- Declines in growth are driven primarily by load transfers, energy efficiency savings, and rooftop PV output during summer.

[1] AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 23/09/2014.
[2] AEMO. *National Energy Forecasting Report 2014.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed 11/09/2014.
[3] AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 01/12/2014.

Forecast	Differences between AEMO and DNSP aggregated MD forecasts
Summer MD	AEMO's connection point forecast is 3% (85 MW) higher than the DNSP's forecast at the end of 10-year outlook period.
Winter MD	Winter forecasts are not prepared by the DNSP.
AEMO and the DNSP fundamentally apply the same methodology therefore differences relate to interpretation of the methodology. Key differences: • Different selection process for forecast starting points. • Different assessment of energy efficiency impact and rooftop PV.	

Figure 1 shows AEMO's aggregated summer[4] and winter historical data and forecasts. It also shows the DNSP's summer forecasts for 2013 (10% POE only) and 2014.

Figure 1 AEMO and DNSP aggregated 10% POE connection point forecasts



4 The DNSP only prepared a 10% POE summer forecast in 2013. In 2014 the DNSP only prepared summer forecasts.

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1. INTRODUCTION

In its December 2012 energy market reform implementation plan[5], COAG requested that AEMO begin providing demand[6] forecasts to improve the Australian Energy Regulator's (AER) ability to analyse the demand forecasts submitted by network service providers. This increased transparency is expected to lead to more efficient network development, benefitting electricity consumers in the long term.

This report presents AEMO's first transmission connection point forecasts for South Australia, and follows the publication of AEMO's first connection point forecasting reports for New South Wales, Tasmania, and Victoria[1].

AEMO will extend this work to Queensland, and by July 2015 will have developed its first complete set of transmission connection point forecasts for all NEM regions. The forecasts will be updated annually.

The forecasts are developed using a consistent methodology across all regions. The methodology was published on AEMO's website in June 2013.[7] This facilitates:

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

In October 2014, AEMO published the Transmission Connection Point Forecasting Action Plan[8], 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 production of the South Australian 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 the South Australian DNSP (SA Power Networks) and TNSP (ElectraNet). This included data sharing and exchanging local-level information.

AEMO also engaged Frontier Economics to act as an advisor and to independently peer review the modelling process.

5 COAG. *COAG Energy Market Reform – Implementation Plan.* Available at: https://www.coag.gov.au/node/481. Viewed 11/09/2014.
6 Demand in this document is defined as operational demand for 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 megawatts.
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. Viewed 11/09/2014.
8 AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 01/12/2014.

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.
- Chapter 3: Highlights key results for South Australia. 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 a list of data shared between AEMO and the 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.
- A report from Frontier Economics (independent peer reviewer) providing a review of AEMO's forecasts.

All documents are available with this report on AEMO's website.[9]

[9] AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 01/12/2014.

2. FORECASTING PROCESS OVERVIEW

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

2.1 Forecasting principles

AEMO sought to develop a forecasting process and methodology incorporating benchmark forecasting characteristics listed by the AER.[10]

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

Table 1 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	Engaged stakeholders in forecast development, including the DNSP and the TNSP. Developed and published consistent methodology. 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., rooftop 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 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 forecasts. 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.

2.2 Connection point definition

AEMO's connection point forecasting methodology, published in June 2013[11], 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).[12] 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 41 South Australian distribution network connection points, and 10 connection points for direct transmission-connected customers.

- 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.

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[10] AER. November 2011. *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17.* Attachment 3.2 p. 76. Available at: http://www.aer.gov.au/sites/default/files/Aurora%202012-17%20draft%20distribution%20determination.pdf. Viewed 19/09/2014.

[11] 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. Viewed 16/09/2014.

[12] For a complete list of TNIs, refer to *List of regional boundaries and Marginal Loss Factors for the 2014-15 financial year.* Available at: 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 16/09/2014.

- 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.

2.3 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.[13] 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 South Australian forecasts.

A summary of the investigations and outcomes is presented in Table 2.

Table 2 Improvements investigated for the South Australian 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 alternate forecast for situations when the time trend was found to be non-linear (statistical test).	Yes
Improve disaggregation of regional energy efficiency and rooftop PV estimates.	Detailed customer and installed capacity information was provided by the DNSP. These datasets were considered the best available and used to disaggregate regional forecast components.	Use of detailed customer and installed capacity information meant: • Increased confidence in the rooftop PV output calculations at each connection point. • Increased confidence in the energy efficiency estimates for each connection point.	Yes
Investigate effectiveness of using pooled data across years to determine weather sensitivity.	Pooling data was tested using 5-year windows.	The improvement is designed to increase the stability of coefficients in the weather-demand modelling process; however, improvements in the treatment of historical data helped this and thereby reduced the immediate benefits of pooling. Further testing and evaluation is required.	No
Investigate use of alternate methods or variables, such as day-of-week effects or other calendar effects.	Day of week, variables for holidays and lagged weather variables were tested.	Immediate benefits were not detected for the forecasts and there is potential for over-fitting. However, this improvement could be combined with pooling. As such further testing and evaluation is required.	No
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 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

[13] AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 01/12/2014.

2.4 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 3 Key steps in forecasting methodology

Step	Description
1. Prepare data	Obtain and clean demand and weather data. Determine demand profile and demand mix.[14]
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.
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. [15]

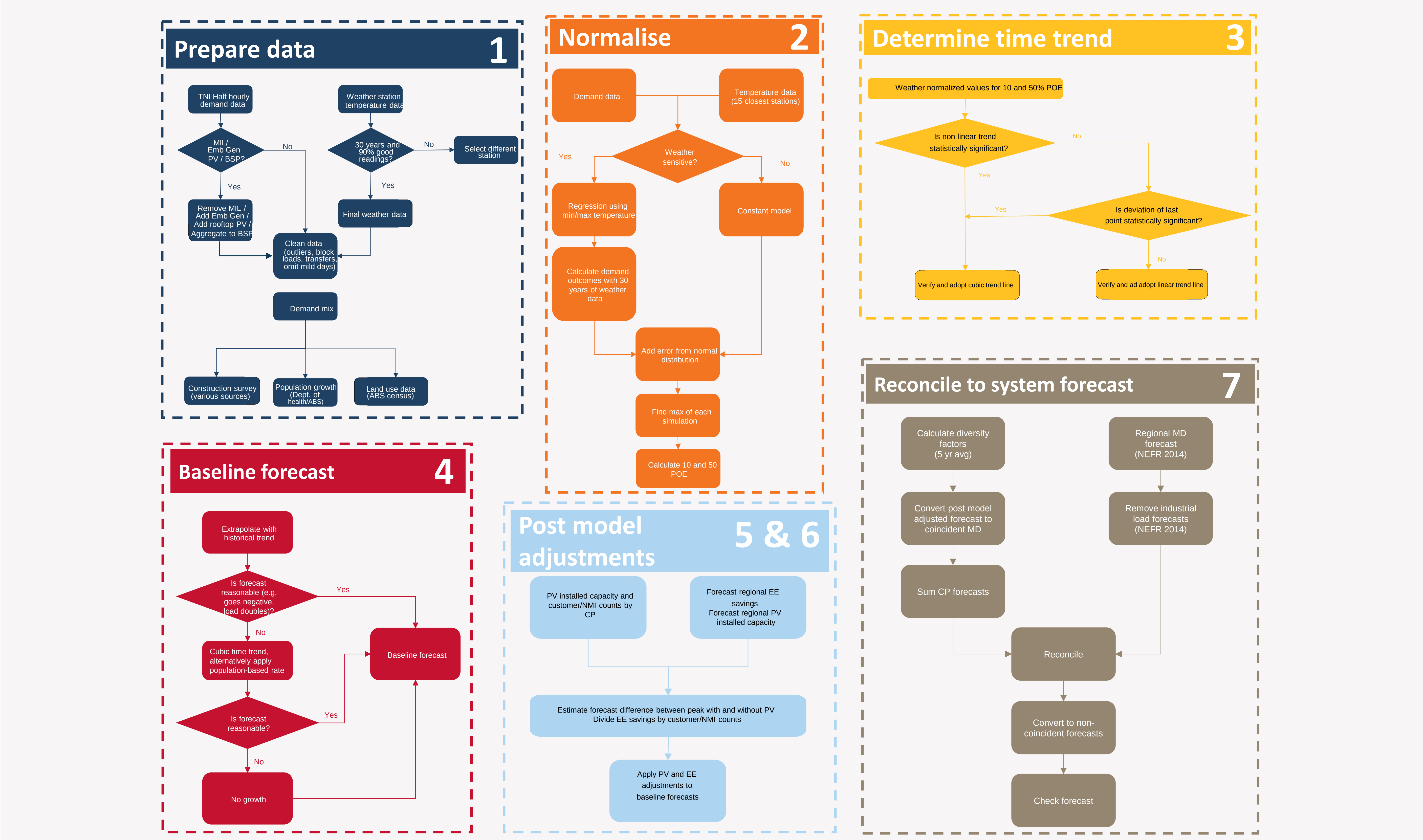
AEMO's forecasting methodology for reactive power is based on historical power factors for connection point MD. These power factors generally remain constant over consecutive seasons. For this reason, forecasts are developed by applying average historical power factors to the final active power forecasts.

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.

[14] The type of loads connected to each connection point (e.g., residential, agricultural, industrial).
[15] AEMO. *National Energy Forecasting Report 2014.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed 11/09/2014.

Figure 2 Implementation of forecasting methodology



2.5 Differences between AEMO and DNSP methodology

A key outcome of AEMO's engagement with the DNSP was a better understanding of DNSP forecasting methodologies. In 2014, the DNSP implemented a new forecasting methodology, which is generally consistent with AEMO's.[16] Key differences between AEMO's and the DNSP's approach are identified and summarised in Table 4.

Table 4 Identified differences between AEMO and DNSP methodologies

Description	AEMO	South Australian DNSP
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 included in the forecasts based on measured performance of typical PV installations, installed PV capacity, time of maximum demand, and forecast PV growth rate.
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 considered to be inherent in the historical data and need not be accounted for explicitly.
Starting point	Forecasts start from the historical trend line, which may be linear or cubic.	Forecasts start from the most recent historical point.
Reconciliation to region-level forecasts	Forecasts are reconciled to the 2014 NEFR forecasts.	Forecasts are reconciled to the 2014 NEFR forecast growth rate.
Embedded generation	Embedded generating units are assumed not to be generating at the time of MD.	Output of some embedded generating units are assumed to be at a particular level at the time of maximum demand.
Winter forecasts	Summer and winter forecasts are developed.	Only summer forecasts are developed.

[16] 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. Viewed 11/09/2014.

3. RESULT HIGHLIGHTS

This section summarises the key findings of the South Australian 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.

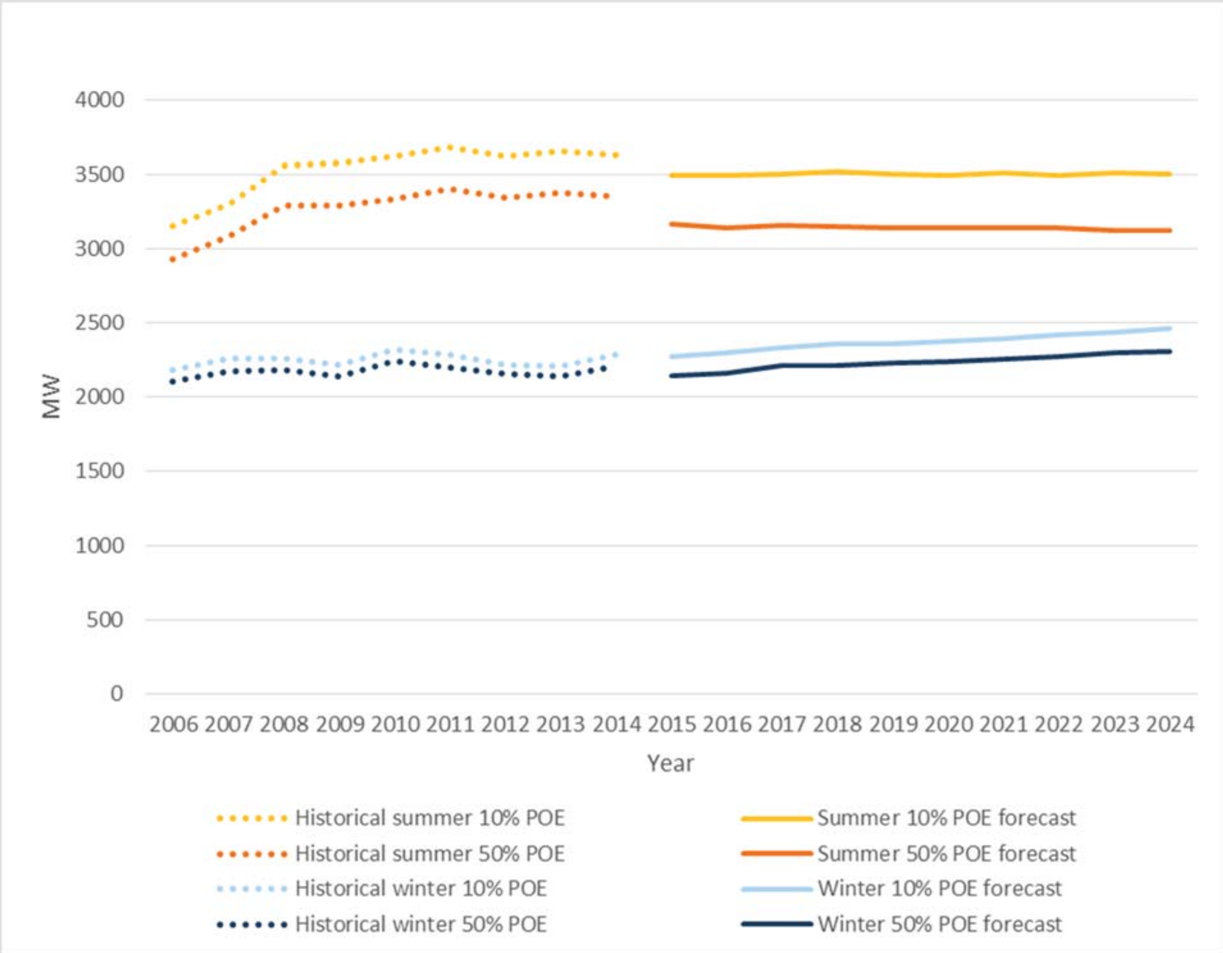
3.1 Aggregated connection point trend

Over the outlook period, summer MD is expected to remain flat as increased residential and commercial consumption is offset by increased rooftop PV penetration and increased energy efficiency. Winter MD is expected to increase at a moderate rate. Figure 4 shows historical and forecast aggregated connection point demand.

Regional average annual growth over the outlook period for summer is flat at 0.0% for the 10% POE forecasts. The summer 50% POE forecasts decline by 0.1%. This aligns with the MD forecasts for the region in the 2014 NEFR over the outlook period.

Forecast winter demand growth is stronger than summer, at 0.8% for both 10% and 50% POE. Winter growth is not suppressed by rooftop PV as the vast majority of connection points peak in the evening during winter. At the aggregate level, winter MD is lower than summer MD.

Figure 3 50% and 10% POE non-coincident aggregated connection point forecasts



While the aggregate demand growth for South Australia is flat, average annual growth varies by connection point, and is distributed above and below the overall region summer growth rate of 0.0%.

Summer 10% POE average annual growth rates range between -2.2% to 3.1%, with the exception of Stony Point which has an average annual growth rate of 21.5% due to a new diesel terminal coming online by 2017. The most significant decline (-2.2%) is expected to occur at Ardrossan West due to a transfer to Dalrymple in 2017.

Average annual growth by connection point is 0.04% for the 10% POE and -0.11% for the 50% POE summer forecasts. Figure 4 shows that 90% of connection points have summer 10% POE growth of less than 1.0%.

Forecast winter demand growth is stronger than summer, with 92% of connection points showing positive growth compared to 57% for summer. The difference is largely driven by increasing rooftop PV generation affecting summer MD, while the evening winter MD is not affected by rooftop PV generation.

Winter 10% POE average annual growth ranges from -2.5% (Ardrossan West) to 4.8% (Dalrymple), with the exception of Stony Point which has an average annual growth rate of 27.1% due to a new diesel terminal coming online by 2017. Figure 5 shows the distribution of winter growth rates.

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.

Figure 4 Distribution of summer MD growth rates for South Australia, 2015–24

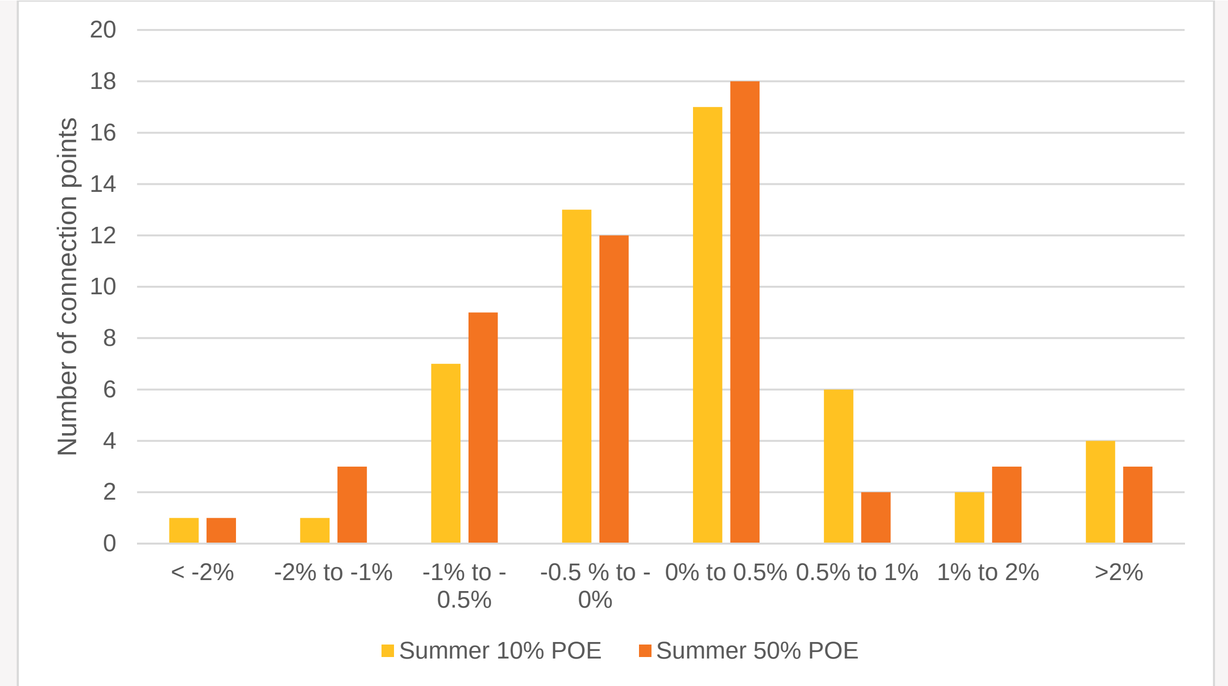
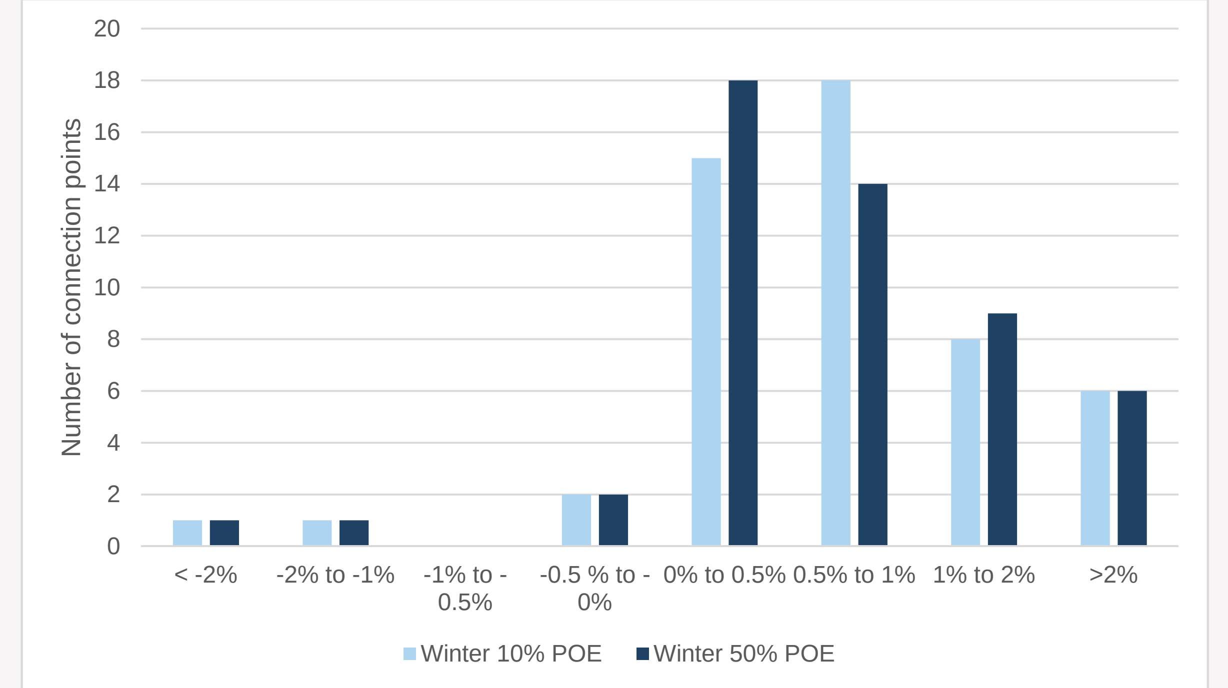


Figure 5 Distribution of winter MD growth rates for South Australia, 2014–23



Growth drivers

Appendix A shows a breakdown of the 10% POE growth rates for each connection point. Key growth drivers are shown in Table 5.

Table 5 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%
Summer	**Stony Point**: A small connection point that is expected to grow with increased industrial activity in the region. **Dalrymple**: Expected to grow due to load transfer from Ardrossan West. **Port Pirie System**: Industrial customer restart is expected in 2017. **Kadina East**: Expected to grow due to growth in commercial, industrial and agricultural load consumption and a weaker impact of rooftop PV due to the time of MD being later in the day.	**Ardrossan West:** Expected to decline due to load transfer to Dalrymple.
Winter	**Stony Point:** A small connection point that is expected to grow with increased industrial activity in the region. **Dalrymple**: Expected to grow due to load transfer from Ardrossan West. **Port Pirie System**: Industrial customer restart is expected in 2017. **Mobilong**: Increased agricultural activity and population are expected to drive demand **Angas Creek**: Increased agricultural activity and population are expected to drive demand. **Mt Barker/Mt Barker South:** Increasing population in the region is expected to drive demand.	**Ardrossan West:** Expected to decline due to load transfer to Dalrymple.

3.2 Comparison of AEMO and DNSP summer forecasts

At the end of the outlook period AEMO's aggregated summer forecasts are 3% higher than the DNSP's. Figure 6 plots the aggregated, non-coincident forecasts.

A key reason for the difference lies in the forecast starting point selection, as noted in Table 4.

The comparison suggests that the 2014 DNSP and AEMO summer forecasts align well at the aggregate level.

Figure 6 AEMO and DNSP aggregated 10% POE summer forecasts

APPENDIX A. GROWTH BY CONNECTION POINT

Figure 7 South Australia 10% POE summer 10-year average annual growth rates, 2014–15 to 2023–24

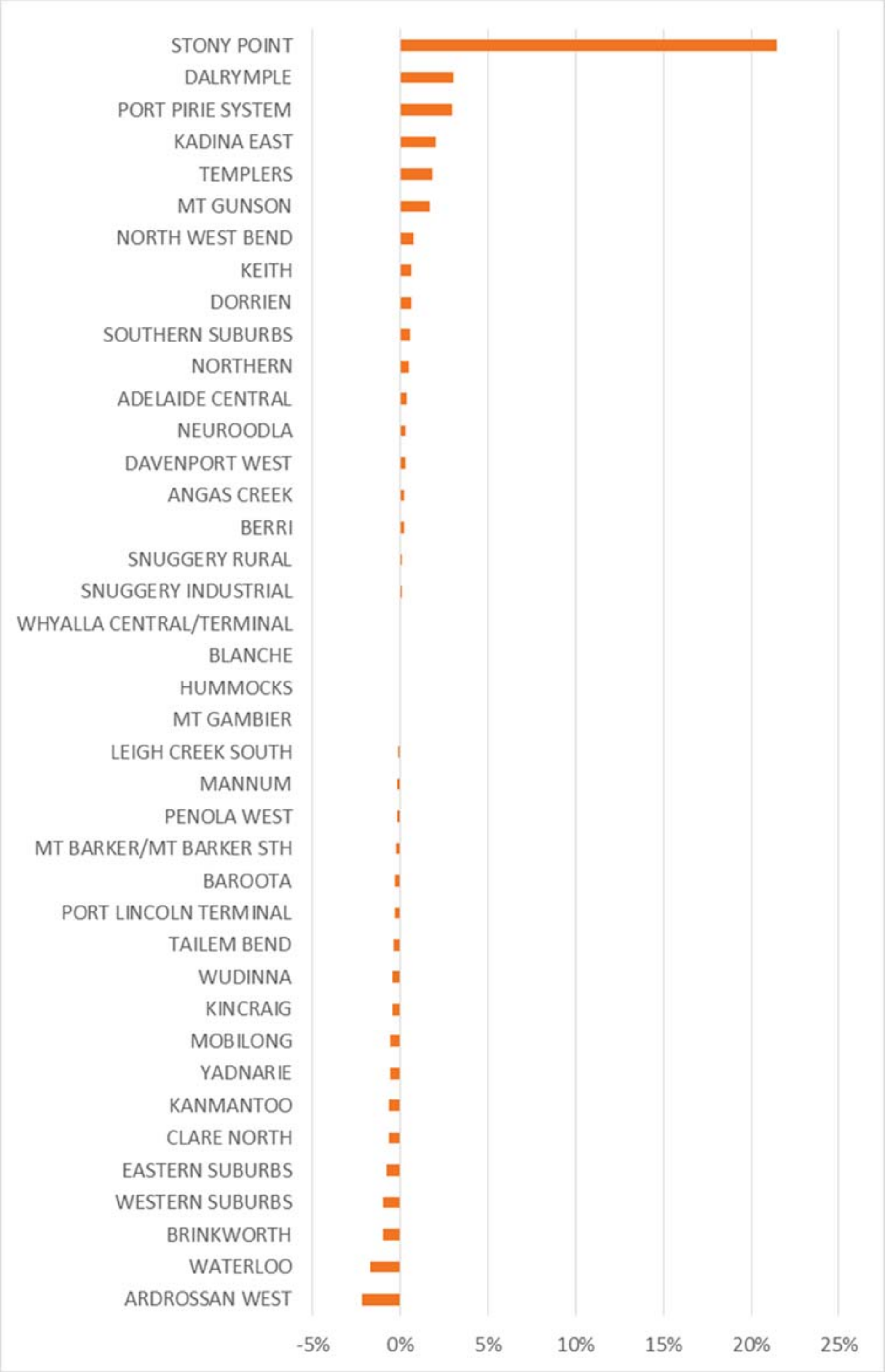
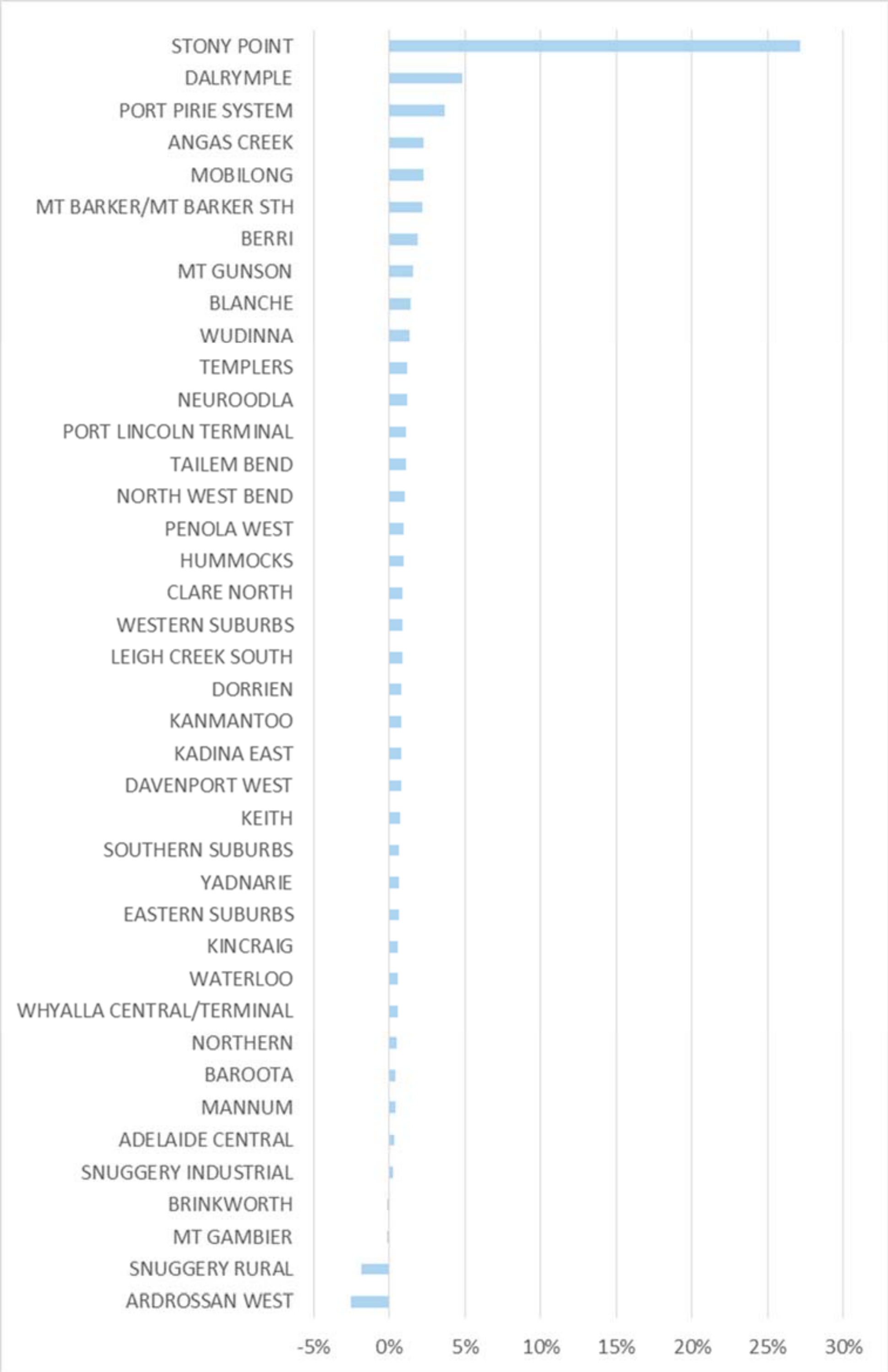


Figure 8 South Australia 10% POE winter 10-year average annual growth rates, 2014 to 2023



Note, large industrial loads / direct connect customers are excluded from Figures 7 and 8.

APPENDIX B. DATA SHARED BY NETWORK SERVICE PROVIDERS

Network service providers provided crucial data during the forecasting development process. Table 6 summarises the data provided.

Table 6 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 by TNI.
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.[17]
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 the conveyance of 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.

17 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..
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).
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).

Term	Definition
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