2015 AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR VICTORIA

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1	30/9/2015	
2	22/12/2015	Page 6, Section 2.2 – Details regarding commissioning of new terminal stations updated Page 12 and 13, Appendix B – Charts updated and footnote modified

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about its 2015 transmission connection point forecasts for Victoria, 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, and for the Victorian declared transmission system as required by the National Electricity Rules clause 5.11.1(a).

This publication is based on information available to AEMO as at 18 September 2015, 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 AusNet Services, CitiPower and Powercor Australia, United Energy, and Jemena in providing data and information used in this publication.

EXECUTIVE SUMMARY

AEMO has developed Maximum Demand (MD) transmission connection point forecasts for Victoria to provide detailed insights to local changes and trends in MD from 2015–16 to 2024–25. Published forecasts for the Victorian declared transmission system are also required by the National Electricity Rules clause 5.11.1(a).

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 (2015 to 2024).

AEMO's forecast of Victorian connection point MD, in Figure 1, shows increasing demand over the outlook period for both summer and winter. Table 1 summarises the drivers of this growth.

Figure 1 AEMO summer and winter forecasts for 10% POE and 50% POE[3]

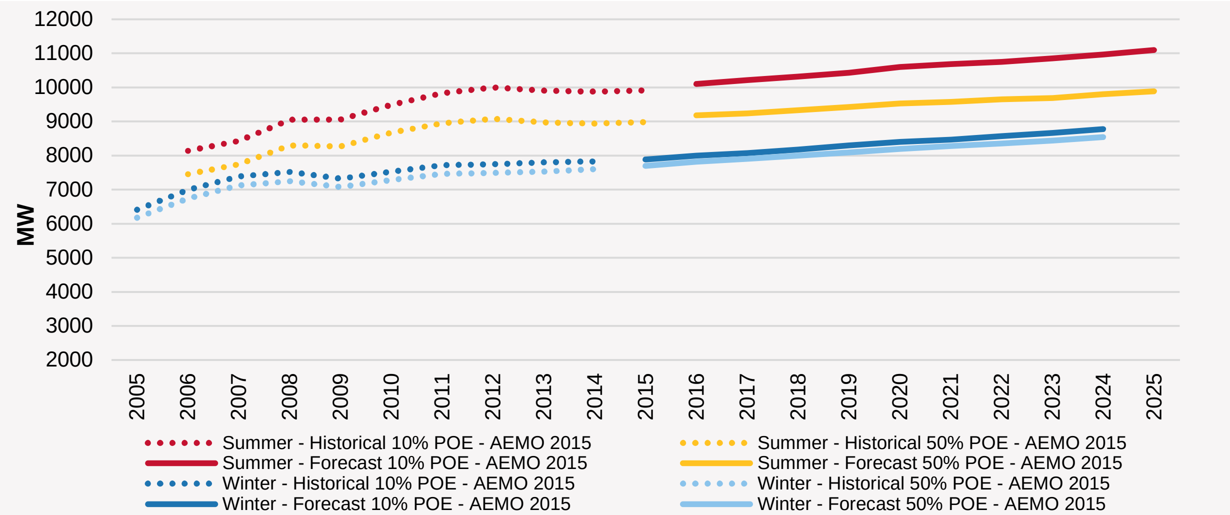

Table 1 AEMO 2015 connection point forecast average annual rates of change, 10% POE

Category	Summer	Winter
Total connection point MD	1.1%	1.2%
Range of individual growth rates	-7.8% to 2.9%	-14.0% to 4.3%

Key drivers:

- **Overall transmission connection point MD in Victoria is increasing in the outlook period.**
- **The increase in overall MD is primarily attributed to population and economic growth in Victoria.**
- **Declines in MD at some connection points are driven primarily by load transfers and industrial closures, energy efficiency savings, and rooftop photovoltaic (PV) output during summer.**

Compared to the 2014 forecasts:

- **The AEMO 2015 summer forecast (10% POE) is 803 MW higher than AEMO's 2014 forecast at 2023–24, attributed mainly to lower electricity prices and stronger economic growth at the regional level.**
- **The AEMO 2015 winter forecast (10% POE) is 140 MW lower than AEMO's 2014 forecast at 2023–24, mainly due to lower forecast 10% POE levels at the start of the forecast.**

[1] AEMO. 2015 National Electricity Forecasting Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.

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

[3] The figure includes direct transmission-connected customer load forecasts, in addition to forecasts for DNSP networks.

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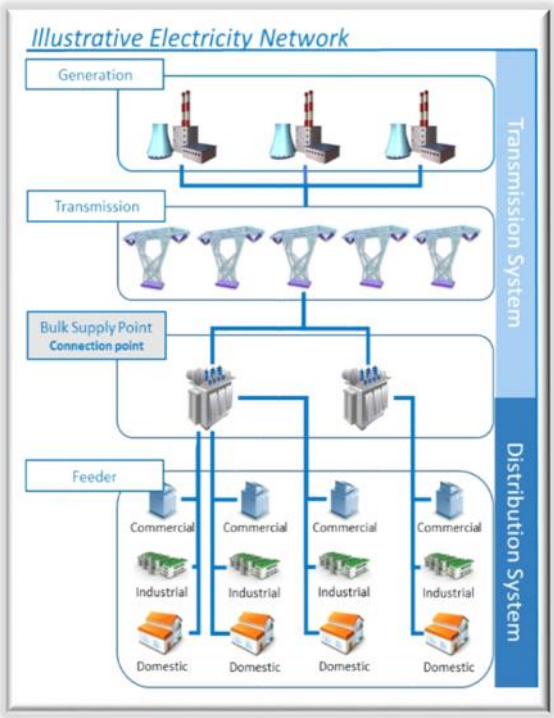
1. INTRODUCTION

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 network and asset 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] In Victoria these points are further distinguished by physical features of the network assets and operation, such as voltage.

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. Viewed 17 September 2015.

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. Viewed 17 September 2015.

1.3 Supplementary information on AEMO's website

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

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: • Historical and forecast MD, including 10% POE and 50% POE, for active power. • Coincident and non-coincident values. • High-level commentary. • The option to export all the forecasts.
Reactive power system forecast spreadsheet	Separate spreadsheet for reactive power forecasts at each transmission connection point, providing complementary information for power system studies.
Frontier Economics report. High level review of transmission connection point forecasts: VIC	Independent peer review of AEMO's forecasts and methodology.

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.[6] In it, AEMO identified possible areas of improvement in the forecasting process relating to forecast inputs and methodologies. Several improvements were incorporated into development of the current forecasts. A summary is in Table 3.

Table 3 Improvements implemented for Victorian connection point forecasts

Improvement description	Approach	Benefit	Implemented
Adjust historical data for block loads entry and exits, load transfers, and rooftop PV, at the daily or half-hourly level.	Adjustments for block loads entry and exits, load transfers, and estimated rooftop PV output were applied to the data at the half-hourly level, before weather normalisation.	The adjustments resulted in: • Clearer handling of step changes that occurred mid-season. • A streamlined data preparation process for forecasting. • More realistic treatment of rooftop PV with variation 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 rates of increase. The cubic trend provided an impartial alternative forecast for situations when the time trend was found to be non-linear (statistical test).	Yes
Investigate effectiveness of using pooled data across years to determine sensitivity to weather.	Pooling data was tested and adopted using three-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 MD days, calculated the difference between the peak with and without rooftop PV, and applied this difference as the post model adjustment.	The adjustment: • Takes into account the daily load profile at each connection point. • Inherently allows the time of MD to change as rooftop PV output increases with increasing installed capacity.	Yes
Investigate opportunities to improve the reconciliation process.	Reconcile the non-coincident forecasts to the rate of change of the system forecast, rather than derive them from the 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 AEMO. Transmission Connection Point Forecasting Action Plan. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

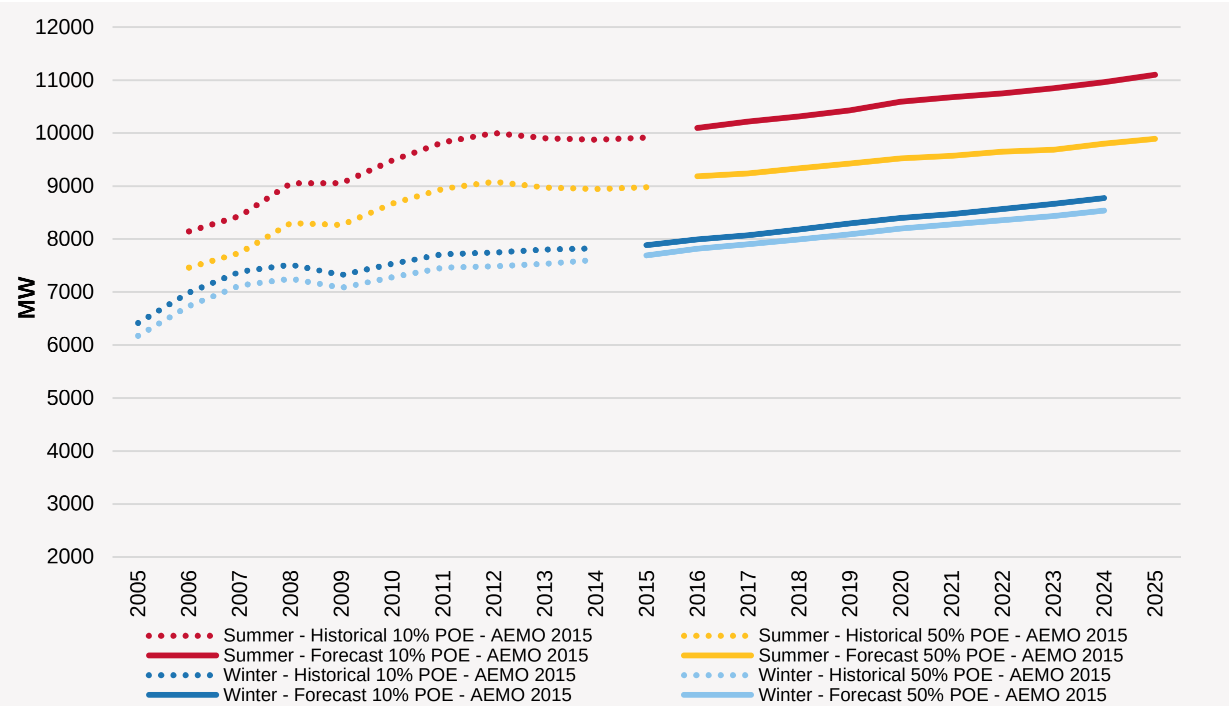
2. RESULTS

2.1 Aggregated AEMO 2015 connection point forecasts

AEMO forecasts summertime connection point MD for Victoria increasing, at a rate of 1.1% per annum. This growth is attributed to increasing population and Gross State Product (GSP), which drives residential and commercial MD. The forecasts are shown in Figure 2.

Growth in summer MD is softened by rooftop PV, which is forecast to continue to impact summer Victorian connection point MD. The impact of rooftop PV is expected to increase, with the overall summer offset growing from 3.1% to 6.5% over the outlook period. In winter, rooftop PV is expected to offset demand by 0.3% to 0.6% over the outlook period, because most connection points peak later in the day or in the evening.

Figure 2 AEMO's aggregated, non-coincident 2015 forecasts[7]



Note that major industrial loads are included in this figure, but are not included in comparison figures because these loads are not distribution-connected and therefore not forecast by the DNSPs.

[7] The figure includes direct transmission-connected customer load forecasts.

2.2 Individual AEMO 2015 connection point results and insights

While aggregated demand is increasing, individual connection point forecasts[8] increase at some locations, and decrease at others, due to different drivers.

Key features of the summer forecasts are:

- New connection point Deer Park 66 kV is to be commissioned by summer 2017-18 and take load from East Keilor, West Keilor, Altona West and Altona Brooklyn. It is expected to be summer-peaking.
- New connection point Brunswick 66 kV is to be commissioned by summer 2016-17 and take load from West Melbourne 22 kV, West Melbourne 66 kV and Richmond 66 kV. It is expected to be summer-peaking.
- Average annual rates of change are between +2.9% (Kerang Powercor 66 kV and Keilor East Jemena 66 kV) and -7.8% (Richmond 34 CitiPower 66 kV) for 10% POE.
- 83% of connection points are forecast to have summer 10% POE average annual rates of less than + 1.2% (which is the approximate projected Victorian population growth rate).

Key features of the winter forecasts are:

- Average annual rates of change are between +4.3% (Keilor East Jemena 66 kV) and -14.0% (West Melbourne CitiPower 22 kV) for 10% POE. Drivers are listed in Table 4. Note also that transmission-connected industrial loads are excluded from this analysis due to confidentiality.
- 86% of connection points are forecast to have winter 10% POE average annual rates of less than 1.2% (which is the approximate projected Victorian population growth rate).

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.

[8] 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.

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

Season	Forecast MD increase greater than 2%	Forecast MD decrease greater than 2%
Summer	**Kerang (Powercor) 66 kV:** Population growth. **Keilor East (Jemena) 66 kV:** Population growth. **Richmond (CitiPower) 22 kV**: Temporary load transfer beginning in 2015-16, causing a lower starting point. **South Morang (AusNet) 66 kV:** Population growth. **Wodonga (AusNet) 22 kV:** Population growth. **Tyabb (United Energy) 66 kV:** Population growth. **Wemen (Powercor) 66 kV:** Population growth. **West Melbourne (Jemena) 66 kV:** Population and economic growth. **Altona West (Powercor) 66 kV:** Population and economic growth. **Fishermans Bend (Citipower) 66 kV:** Population and economic growth.	**West Melbourne (CitiPower) 22 kV:** Load transfer to the new Brunswick 66 kV. **Keilor West (Powercor) 66 kV:** Load transfer to the new Deer Park terminal station. **Khancoban (Essential Energy) 11 kV:** Population.
Winter	**Keilor East (Jemena) 66 kV:** Population growth. **Terang (Powercor) 66 kV:** Industrial load increases. **Richmond (CitiPower) 22 kV:** Population growth. **Brunswick (Jemena) 22 kV:** Industrial load increases **South Morang (AusNet) 66 kV:** Population growth. **Bendigo (Powercor) 22 kV:** Load transfer from 66 kV. **East Rowville 34 (United Energy) 66 kV:** Industrial load increases and population growth. **Richmond 12 (CitiPower) 66 kV:** Load transfer from 22 kV and population growth.	**West Melbourne (CitiPower) 22 kV:** Load transfer to the new Brunswick 66 kV. **Richmond 34 (CitiPower) 66 kV:** Load transfer to the new Brunswick 66 kV. **Khancoban (Essential Energy) 11 kV:** Population. **Keilor West (Powercor) 66 kV:** Load transfer to the new Deer Park terminal station. **Keilor East (Powercor) 66 kV:** Load transfer to the new Deer Park terminal station. **West Melbourne (CitiPower) 66 kV:** Load transfer to the new Brunswick 66 kV.

Note: 2% is set to capture extreme rates. Major industrial loads are excluded due to confidentiality. Deer Park and Brunswick 66 kV are excluded, as these are new connection points.

2.3 Comparison of AEMO's 2014 and 2015 forecasts

The comparison between AEMO's 2015 connection point MD forecasts and AEMO's 2014 forecasts is plotted in Figure 3, and the growth rates are compared in Table 5.

- Summer 10% POE MD forecasts have increased by 7.8% at 2023-24.
- Winter 10% POE MD forecasts have decreased by 1.8% at 2023.

Reasons for these changes are summarised in Table 6.

Figure 3 AEMO 2014 and 2015 (10% and 50% POE) connection point MD forecasts (excluding direct-connect loads)

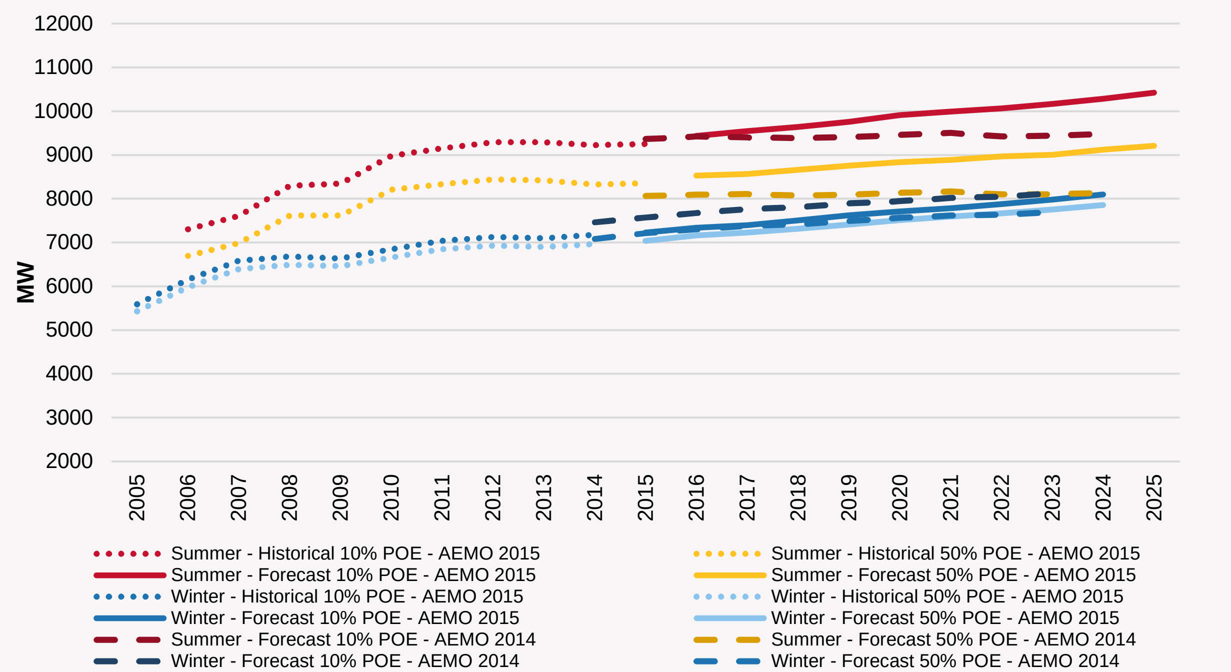


Table 5 Region-level average change rates (10% POE)

Forecast	2014 Region level average annual change rate	2015 Region level average annual change rate
Summer	0.1%	1.1%
Winter	0.9%	1.2%

Table 6 Differences between AEMO 2014 and 2015 forecasts (10% POE)

Forecast	Differences between AEMO 2014 and 2015 aggregated MD forecasts (10% POE)
Summer MD	AEMO's updated connection point forecast is 7.8% (803 MW) higher than the previous forecast at 2023-24.
Winter MD	AEMO's updated connection point forecast is 1.8% (140 MW) lower than the previous forecast at 2023.

Key drivers for change:

- **The increase in overall MD is primarily attributed to population and economic growth in Victoria.**
- **Declines in MD at some connection points are driven primarily by load transfers and industrial closures, energy efficiency savings, and rooftop photovoltaic (PV) output during summer.**

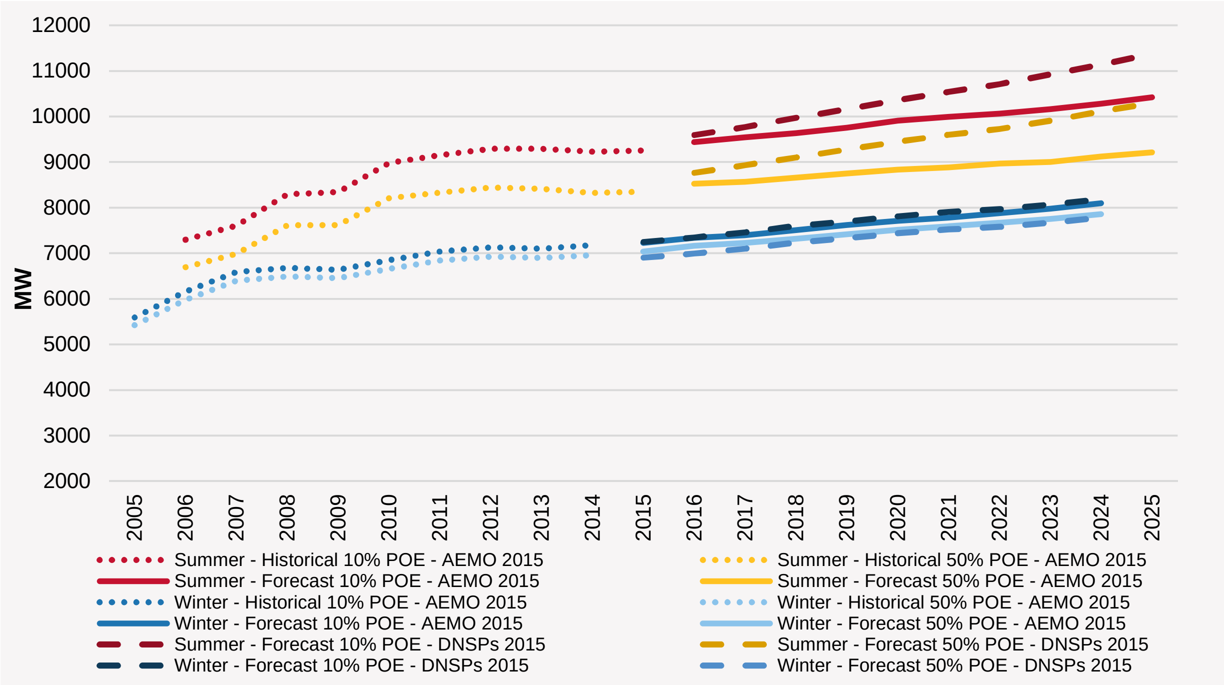
Key methodological differences:

- **Improvements were made to the methodology that provided clearer trends for the forecast process (see section 1.4).**
- **Economic and population projections were updated in the 2015 NEFR and a more favourable economic projection has led to an increase in MD, included through the reconciliation step in the forecasting process.**
- **The method for forecasting rooftop PV adjustments was improved (see section 1.4) and this resulted in smaller rooftop PV offsets later in the outlook period.**

2.4 Comparison of AEMO 2015 forecasts and DNSP 2015 forecasts

At the end of the outlook period AEMO's Victorian connection point MD forecasts are 9.3% lower than those of the Victorian DNSPs (10% POE). The winter differences are negligible. Figure 4 plots the comparison, where it can be seen that the DNSP 50% POE summer forecast is closest to AEMO's 10% POE forecast by 2024-25.

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



The key differences between the 2015 AEMO forecasts and the DNSP forecasts are summarised in Table 7. Key areas which contribute to differences are listed in Table 8.

Table 7 Differences between AEMO and VIC DNSP forecasts

Forecast	Differences between AEMO and DNSP aggregated MD forecasts (10%POE)
Summer MD	AEMO's connection point forecast is 9.3% (958 MW) lower than the VIC DNSP forecast at 2024-25.
Winter MD	AEMO's connection point forecast is 1.1% (90 MW) lower than the VIC DNSP forecast at 2023.

Table 8 Identified differences between AEMO and VIC DNSP methodologies

Description	AEMO	VIC DNSPs
Reconciliation to a system-level forecast	AEMO has reconciled its connection point MD forecast to the 2015 NEFR growth rate.	Forecasts of the Victorian DNSPs are usually reconciled to system-level forecasts of each DNSP network.
Forecast development	AEMO bases its forecasts upon the historical trend of weather-normalised MD.	VIC DNSPs employ different approaches including customer forecasting, simulations with population and other variables, as well as historical trending methods like AEMO.
Embedded generation	Embedded generating units are assumed not to be generating at the time of maximum demand.	Output of some embedded generating units are assumed to be at a particular level at the time of maximum demand.
Rooftop PV	AEMO calculates post model adjustments based on forecast installed capacity from the NEFR.	VIC DNSPs calculate post model adjustments based on their own forecasts of installed capacity.

APPENDIX A. FORECASTING METHODOLOGY

Active power

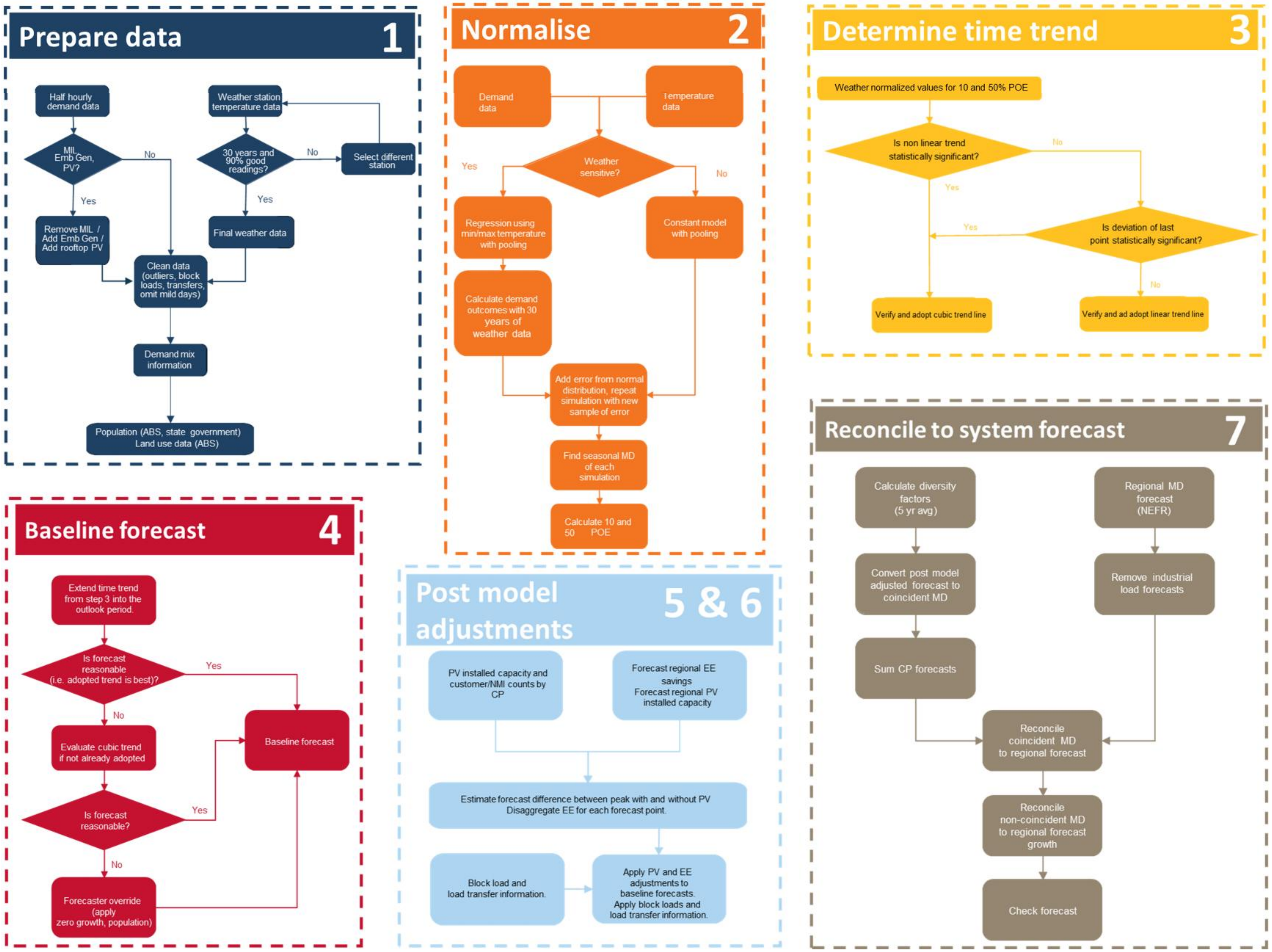
The flowchart in Figure 5 (next page) details how AEMO has implemented its methodology for the active power MD forecasts.

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 active power estimates for the outlook period.

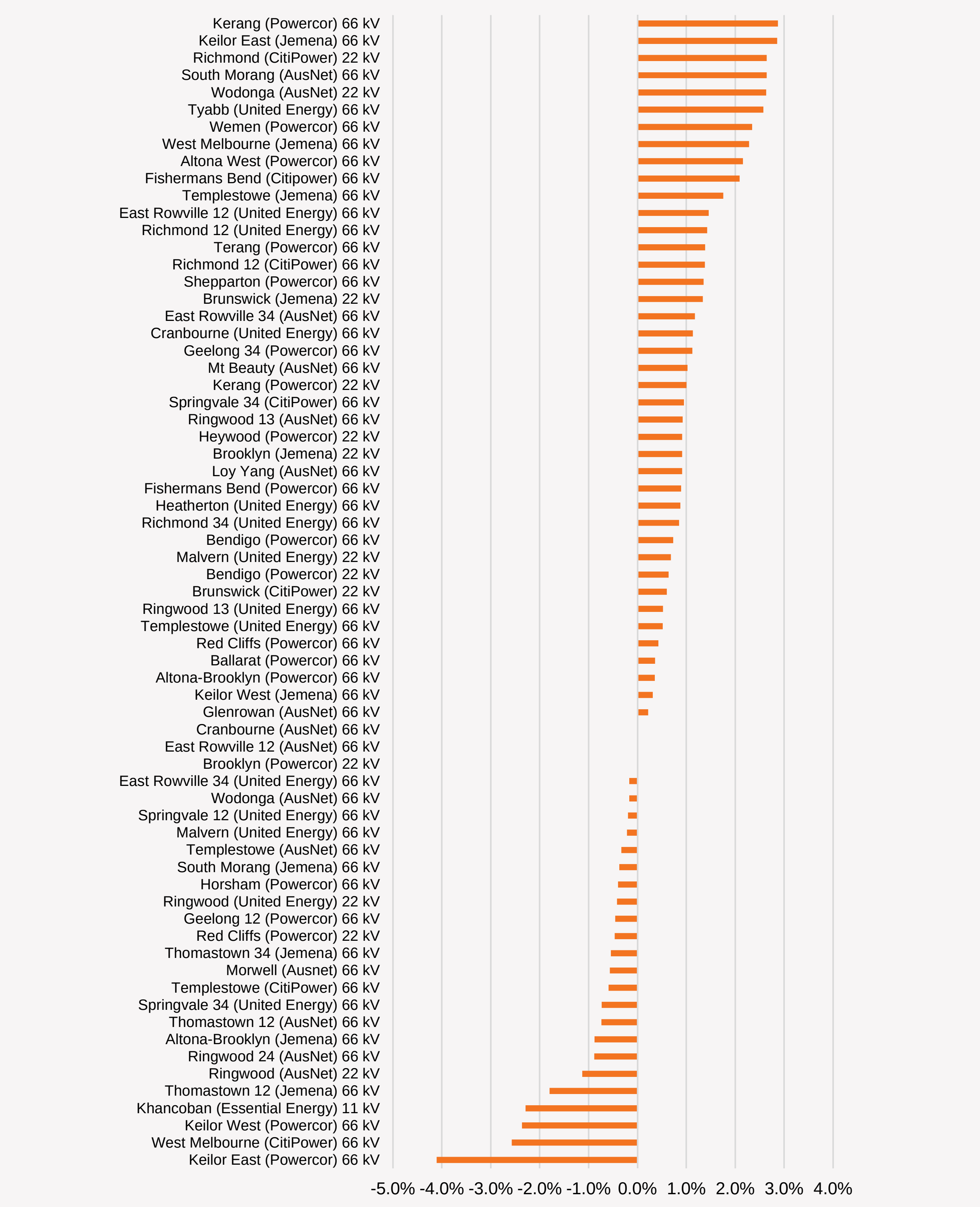
AEMO will review this approach in future forecasting exercises to confirm its appropriateness.

Figure 5 Implementation of forecasting methodology



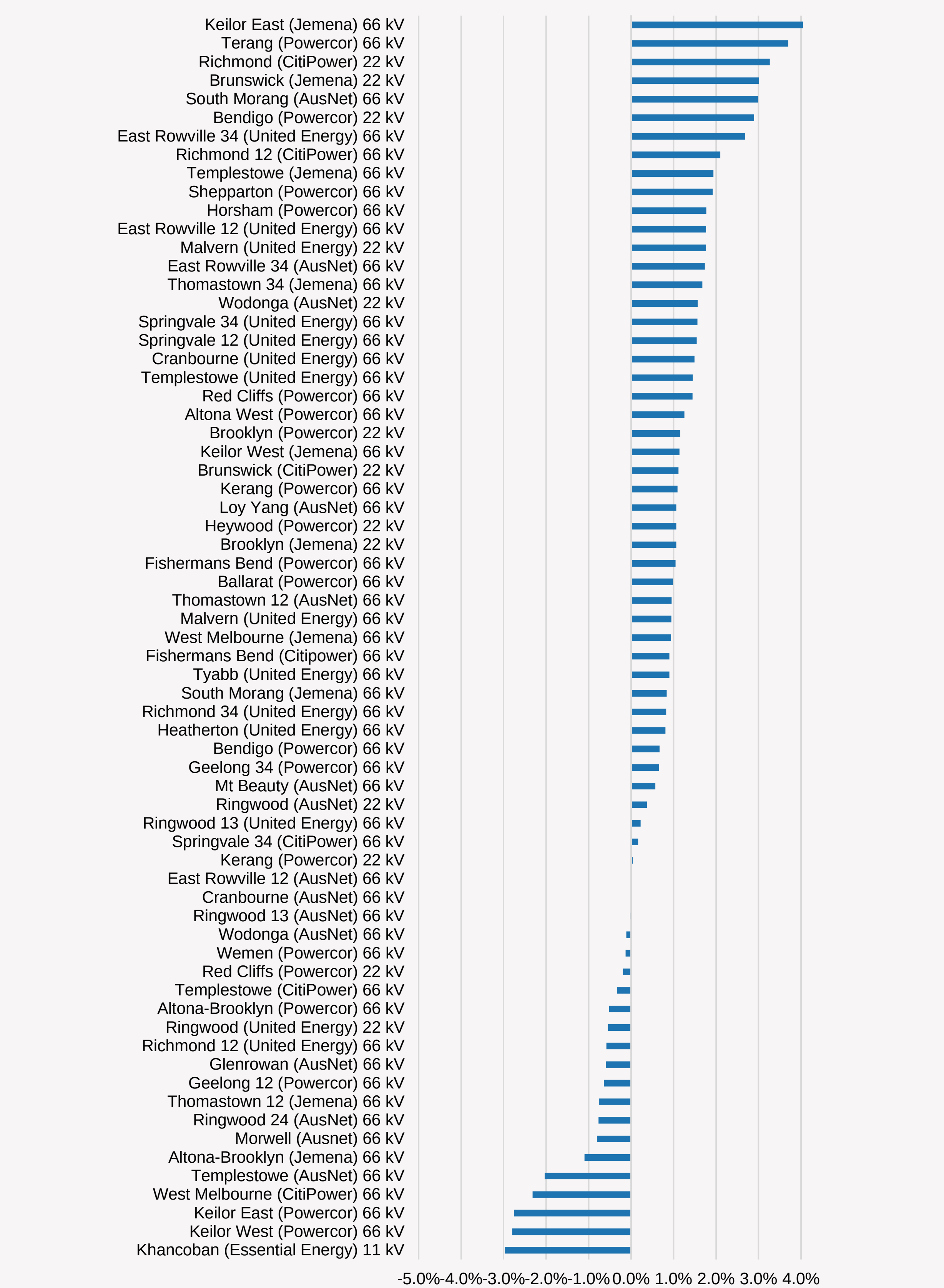
APPENDIX B. GROWTH RATES BY CONNECTION POINT

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



Notes: Some direct-connect industrial loads are excluded due to confidentiality. Brunswick (Powercor) 66 kV, Deer Park (Powercor) 66 kV, West Melbourne (Citipower) 22 kV and Richmond 34 (Citipower) 66 kV have been excluded from the above chart.

Figure 7 Victoria 10% POE winter 10-year average annual growth rates, 2014 to 2023



Notes: Some direct-connect industrial loads are excluded due to confidentiality. Brunswick (Powercor) 66 kV, Deer Park (Powercor) 66 kV, West Melbourne (Citipower) 22 kV and Richmond 34 (Citipower) 66 kV have been excluded from the above chart.

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 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.
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	A network which is not a 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. 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): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
Large industrial load	There are a small number of large industrial loads – typically transmission-connected customers – that account for a large proportion of annual energy in each National Electricity Market (NEM) region. They generally maintain consistent levels of annual energy and maximum demand in the short term, and are weather insensitive. Significant changes in large industrial load occur when plants open, expand, close, or partially close.
Load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another network or the amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.
Load transfer	A deliberate shift of electricity demand from one point to another.
Maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the National Electricity Rules (NER).
Network service provider (transmission – TNSP; distribution – DNSP)	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a Network Service Provider.

Term	Definition
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. 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.
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 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.
Region	An area determined by the AEMC in accordance with Chapter 2A of the National Electricity Rules (NER).
Residential and commercial load	The annual energy or maximum demand relating to all consumers except large industrial load. Mass market load is the load on the network, after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
Rooftop photovoltaic (PV) systems	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop to convert sunlight into electricity.
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: (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 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
CP	Connection Point
DNSP	Distribution Network Service Provider
MD	Maximum demand
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