Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review
Regulatory proposal

Attachment 3-5

JEN Demand Summary Report

(ELE RP 0001)

Public

30 April 2015

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GLOSSARY

Average daily temperature	The average of maximum daytime and minimum overnight temperatures.
Probability of Exceedance	The likelihood that a given level of maximum demand will be exceeded in any given year.

ABBREVIATIONS

AEMO	Australian Energy Market Operator
EUSE	Expected unserved energy
Fdr	Feeder
HV	High Voltage
JEN	Jemena Electricity Networks
LV	Low Voltage
MD	Maximum Demand
MW	Mega-Watt
MWh	Megawatt hour
NEO	National Electricity Objective
NER	National Electricity Rules
POE	Probability of Exceedance
PV	Photovoltaic cell
RIT-D	Regulatory investment test for distribution
Rules	National Electricity Rules
SBY	Sunbury Zone Substation
TCPR	Transmission Connection Planning Report
TS	Terminal Station
URD	Underground Residential Distribution
VCR	Value of customer reliability
ZSS	Zone Substation

OVERVIEW

1. Distribution companies plan network augmentation in order to meet customer demand. It follows, therefore, that demand forecasts are a key driver of future augmentation capital expenditure. However, it is important to recognise that the relevant demand forecasts are location specific or 'spatial' rather than network-wide or state-wide.

2. The importance of spatial demand forecasts in network augmentation planning becomes clear when the planning approach is fully understood. We, like other Victorian distributors, adopt a probabilistic approach to network planning. This method is essentially a cost benefit analysis that is focused on delivering efficient outcomes for customers. For a particular feeder, zone substation or terminal station an assessment is made of the available capacity (maximum asset loading), and the risk that customer demand will exceed the available capacity, leading to unserved energy.

3. The efficiency of the planning approach depends on sound information. If the available capacity or the expected demand is misjudged, the potential value to customers of adding network capacity will either be over or understated. As a consequence, customers will either be exposed to unacceptable risks of supply interruptions or the costs of excess network capacity.

4. In our network, the spatial maximum demand growth forecasts over the next six years (from 2015 to 2021)[1] show a wide variation compared to the network average of 1.36% per annum. The table below shows that the growth rates in Footscray East and Melbourne Airport, for example, are expected to exceed 5% per annum[2]. In a significant number of other areas demand will stagnate or decline. This illustrates the importance of planning to meet location specific demand, rather than taking a network average.

Table 1: Localised variation in forecast peak demand 2015-2021

Season	Supply Area Average Annual Growth (2015-2021)			
	Strong growth (> 5% pa)	High growth (3-5% pa)	Medium growth (1-3% pa)	Low growth or decline (<1% pa)
Summer	Footscray East, Kalkallo, Melbourne Airport, Watsonia	Fairfield, Somerton, Sydenham, Tullamarine,	Airport West, Broadmeadows South, Coburg South, Coolaroo, Sunbury	Australian Glass Manufacturers, Braybrook, Broadmeadows, Coburg North, East Preston, Essendon, North Essendon, Flemington, Footscray West, Heidelberg, North Heidelberg, Melbourne Water, Newport, Pascoe Vale, Preston, St Albans, Thomastown, Tottenham, Visyboard, Yarraville

Source: Jemena Electricity Networks, 2014 Distribution Annual Planning Review, page iv.

5. In terms of forecasting methodology, it is important to recognise the value of combining 'bottom up' and 'top down' demand forecasting methods. In particular, state-wide or network-wide demand forecasts provide a useful method for verifying that the spatial demand forecasts are robust in aggregate.

1 Jemena Electricity Networks (Vic) Ltd, *2014 Distribution Annual Planning Report*, page iv.

2 Based on 50% POE summer maximum demand.

6. We engaged an external consultant, ACIL Allen, to conduct econometric modelling to forecast JEN demand at each terminal station that supplies our network, and for our network as a whole (a 'top down' approach). The forecasts for terminal stations and our total network demand were prepared using multiple weather scenarios. We prepare spatial demand forecasts (using a 'bottom up' approach), which are reconciled to the forecasts prepared by ACIL Allen.

7. ACIL Allen applies the same forecasting methodology as it developed for the Australian Energy Market Operator (**AEMO**). This provides assurance that the approach is robust and independent. In 2014, AEMO employed ACIL Allen's methodology to produce a demand forecast for Victorian terminal stations for the first time. In the 2014 Transmission Connection Planning Report, the Victorian distributors identified a number of issues with AEMO's forecasts, primarily relating to AEMO's use of input data. While these issues still need to be resolved, it is instructive to note the maximum demand forecasts for specific Victorian terminal stations in AEMO's report ranged from -6.5% to 11.3% per annum for the ten year period to 2024. Our spatial demand forecasts fall within a narrower band, but also exhibit substantial variation across the network.

8. The National Electricity Rules (**NER**) and National Electricity Objective (**NEO**) require distributors to develop efficient and prudent capital expenditure forecasts. For the reasons already noted, it is the spatial demand forecasts coupled with the available capacity at those particular locations – not network averages – that drive efficient augmentation capital expenditure. Our demand forecasting methodology and augmentation planning method (as described in the Distribution Annual Planning Report and this Demand Summary Report) delivers efficient outcomes for customers, and therefore complies with the NER requirements.

9. Contrary to our planning and demand forecasting approach, if system-wide average demand forecasts were adopted in high growth locations, the forecast energy at risk would be biased downwards. The consequence of this approach is that efficient investment would not occur, and customers would be exposed to uneconomic outcomes (including increased risk of supply interruption). Such outcomes would be contrary to the NEO and NER requirements regarding capital expenditure forecasting and application of the regulatory investment test for distribution (**RIT-D**).

10. It should be noted that AEMO published an updated Value of Customer Reliability (**VCR**) review report in September 2014[3]. Using AEMO's VCR review report and applying our customer load composition, comprising an approximate 31% residential, 46% commercial and 23% industrial split, a VCR of $38.40 kWh has been calculated and applied in preparing our capital expenditure proposal. This is a reduction from AEMO's previous estimate ($63 per kWh), which will tend to defer augmentation capital expenditure projects, other things being equal

[3] AEMO. 2014 Value of customer reliability review. Available at http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

1. INTRODUCTION

1.1 PURPOSE

11. The purpose of this report is to explain our demand forecasts in the forthcoming regulatory period as a key driver of our augmentation capital expenditure plans.

12. In preparing this report, we are conscious that some stakeholders may expect the increasing penetration of solar PVs to reduce demand and avoid the need for network augmentation. While we agree that solar PVs and other technologies will drive fundamental change for network businesses, the particular drivers for peak demand and network augmentation are complex. From a planning perspective, we must analyse and model these drivers carefully to ensure that sufficient network capacity is provided to meet customer demand.

13. This report seeks to explain the drivers of peak demand and network augmentation. In particular, the report explains that:

- While average demand growth for our network as a whole is expected to be modest by historical standards, it will remain positive
- Network averages mask significant spatial differences in demand and network utilisation. Our network is characterised by some areas that are in decline, while others are expected to grow significantly. We must model these local network conditions to identify and address emerging 'pinch points' on the network
- We adopt a robust forecasting approach in relation to demand and network augmentation. In particular, we combine a 'bottom up' assessment to capture spatial differences across the network, with 'top down' modelling to forecast system demand growth
- Our demand forecasting approach delivers augmentation plans that are prudent and efficient.

1.2 SCOPE

14. This report provides a summary of the following matters:

- Our network planning approach and the role of demand forecasts
- Our demand forecasts for the forthcoming regulatory period
- Our demand forecasting methodology
- An explanation of how our demand forecasts and current network utilisation drive network augmentation decisions, with reference to Sunbury Zone Substation as a case study
- An explanation of why our approach complies with the NER requirements and the NEO.

15. This document is a summary report. Further detailed analysis and supporting information is provided in the following documents:

- ACIL Allen's JEN Demand Report (November 2014)
- ACIL Allen's JEN Demand Quantities Report (November 2014)
- JEN Load Demand Forecasts 2014 Report

- JEN 2014 Distribution Annual Planning Report
- JEN Network Augmentation Planning Criteria (JEN PR 0007).

1.3 OBJECTIVES

16. The objectives of this report are:

- To explain that demand growth and asset utilisation vary significantly across our network, and therefore capacity constraints can emerge at a number of different points within the network, even under assumptions of relatively modest average growth rates in demand
- To demonstrate that our approach to demand forecasting and network planning will deliver efficient outcomes for customers.

2. NETWORK PLANNING AND DEMAND FORECASTING

17. The purpose of this chapter is to explain our network planning approach and the relevance of the spatial demand forecasts in this process. This chapter therefore provides the following information:

- Section 2.1 provides an overview of our network planning methodology, which is principally probabilistic planning
- Section 2.2 explains our approach to network limitation assessments
- Section 2.3 explains the concept of energy at risk
- Section 2.4 explains the concept of expected unserved energy
- Section 2.5 sets out concluding observations, which reiterate the central importance of spatial demand forecasts in facilitating efficient network planning.

2.1 OVERVIEW OF NETWORK PLANNING METHODOLOGY

18. We adopt two analytical planning methodologies:

- The probabilistic method, which is the standard planning approach in Victoria, is regarded as good practice. It is also consistent with the RIT-D, which is specified in the NER. We apply this method to network assets with the most significant constraints and associated augmentation costs, including:
  - Transmission connection points
  - Sub-transmission lines
  - Zone substations
  - High-voltage (HV) feeder lines when demand is forecast up to the maximum safe loading limit.
- The deterministic method, which is a simplified approach that is only applied to:
  - HV feeders when demand is forecast to exceed the maximum safe loading limit
  - Distribution substations and associated low-voltage (LV) networks.

19. Probabilistic planning, which is our principal planning method, is a cost-benefit approach to network augmentation. It compares:

- The expected amount (and value) of energy that will not be supplied under a ‘do nothing’ option; and
- The expected cost of feasible network and non-network options that would reduce or eliminate the identified network capacity issue.

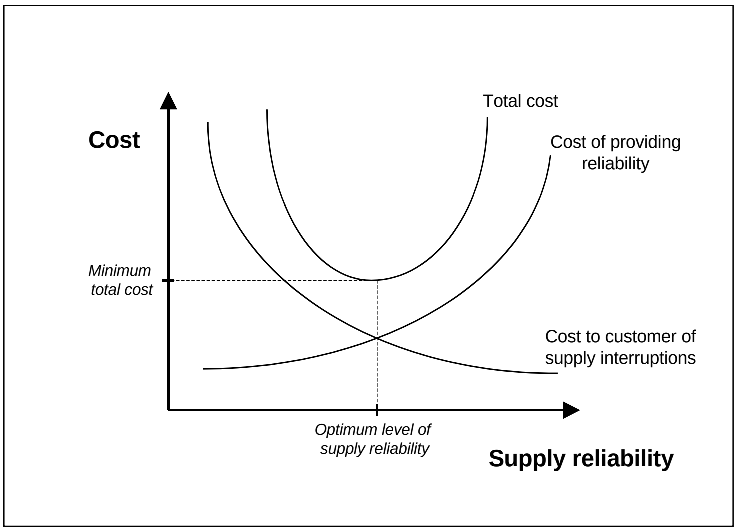
20. The option that maximises the net benefit, which includes the ‘do nothing’ option, is selected.

21. An important aspect of probabilistic planning is that it exposes customers to the risk that network capacity may not be sufficient to meet actual demand. Under this planning approach, action is only taken to address the risk of a capacity shortage if this outcome is less costly to customers than the expected cost of the outage. It should be noted that one source of risk is the demand forecast, especially as weather may have a significant impact on

actual demand. For this reason, maximum demand forecasts are reported on a probability of exceedance (**POE**) basis, to denote the probability that the actual demand will exceed the forecast.

22. The planning approach requires us to estimate the expected costs of 'doing nothing', and to determine whether 'doing something' minimises total costs to customers. This approach is illustrated in the figure below.

Figure 2.1: Minimising the total costs to customers



Source: JEN, Network Augmentation Planning Criteria- Technical Methodology, Inputs and Assumptions, JEN PR 0007, December 2014, page 7.

23. The practical application of probabilistic planning involves four key stages:

- Network limitation assessment, which involves determining the extent of network constraints for various network contingencies and demand forecast scenarios
- Energy at risk analysis, where we identify the annual energy at risk of not being supplied as a result of these network constraints
- Expected unserved energy (**EUSE**) calculation, which considers the probability of the forecast demand and contingency occurring, and weights the energy at risk by that probability to determine an expected amount of unserved energy
- Calculating the cost of EUSE, where the EUSE is transformed into a dollar cost by multiplying the VCR by the expected unserved energy.

24. We comment on the first three steps of the probabilistic planning approach in the remainder of this chapter. In relation to the final step, it is useful to comment briefly on AEMO's latest VCR estimate.

25. In September 2014, AEMO published a final report on its 2013–2014 review of the VCR[4]. Using AEMO's VCR review report and applying our customer load composition, comprising an approximate 31% residential, 46% commercial and 23% industrial split, a VCR of $38.40 kWh has been calculated and applied in preparing our capital expenditure proposal. This is a reduction from AEMO's previous estimate ($63 per kWh), which will tend to defer augmentation capital expenditure projects, other things being equal.

[4] AEMO, *Value of Customer Reliability Review Final Report*, September 2014.

2.2 NETWORK LIMITATION ASSESSMENT

26. A network limitation is assessed by comparing the peak asset loading (under a range of different scenarios and network contingencies) with the asset's rating for each year in the forward planning period. The comparison identifies the extent to which asset overload will occur without corrective action.

27. The analysis of network limitations includes the following key inputs and assumptions:

- Season (winter and/or summer). Although our network is typically summer peaking, both periods are assessed because there may be some circumstances when a winter peak will exceed the relevant winter rating of assets
- POE, which defines the likelihood that the actual maximum demand (which results in EUSE) will differ from the forecast due to more extreme or benign temperature conditions.
- The expected levels of embedded generation and demand-side support, which can affect the asset loading. However, we do not assume that embedded generation is available at times of maximum demand unless network support contracts are in place
- Contingencies, which can significantly affect asset loading. We consider loading for both system-normal conditions and following the most credible single contingency
- Pre and post-contingent operator actions, which can affect asset loading and the maximum load limit (and therefore the EUSE) are considered. Specifically, we consider likely operator actions given the relevant contingency conditions.

28. It is important to note that the network limitation assessment is asset-specific and location specific. We must have regard to the actual conditions 'on the ground'. Spatial demand forecasts, which recognise variations in the level of demand and the expected rate of growth in demand across our network, are essential inputs to the network limitation assessment.

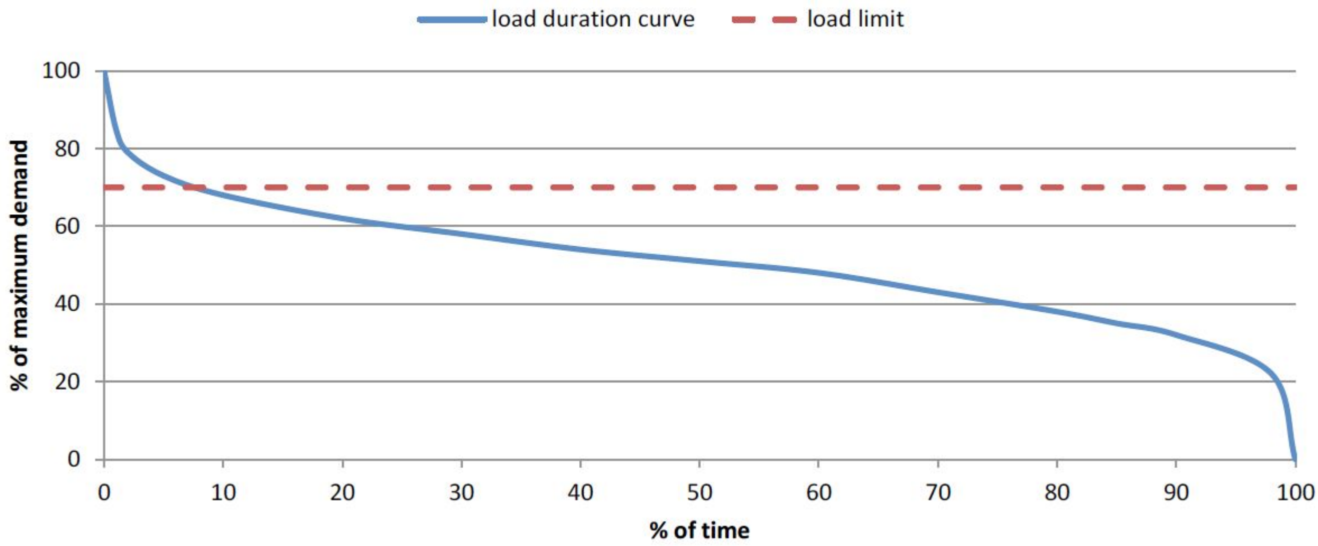
2.3 ENERGY AT RISK ANALYSIS

29. Energy at risk refers to the total energy that may not be supplied under contingency events, particularly around the maximum demand period. A contingency event refers to the loss or failure of part of the network, with N-1 referring to the loss of one critical element, such as a transformer.

30. Energy at risk can be approximated by using a load duration curve that reflects the maximum demand scenario for a given asset. It is calculated as the amounts of energy under the load duration curve, but above the asset load limit (where the load limit is typically the asset's N-1 rating). The load duration curve is typically based on representative historical hourly load data scaled to the forecast maximum demand.

31. Figure 2.2 shows a load duration curve with a horizontal line representing the load limit following a specific contingency for a particular terminal station, zone substation or feeder.

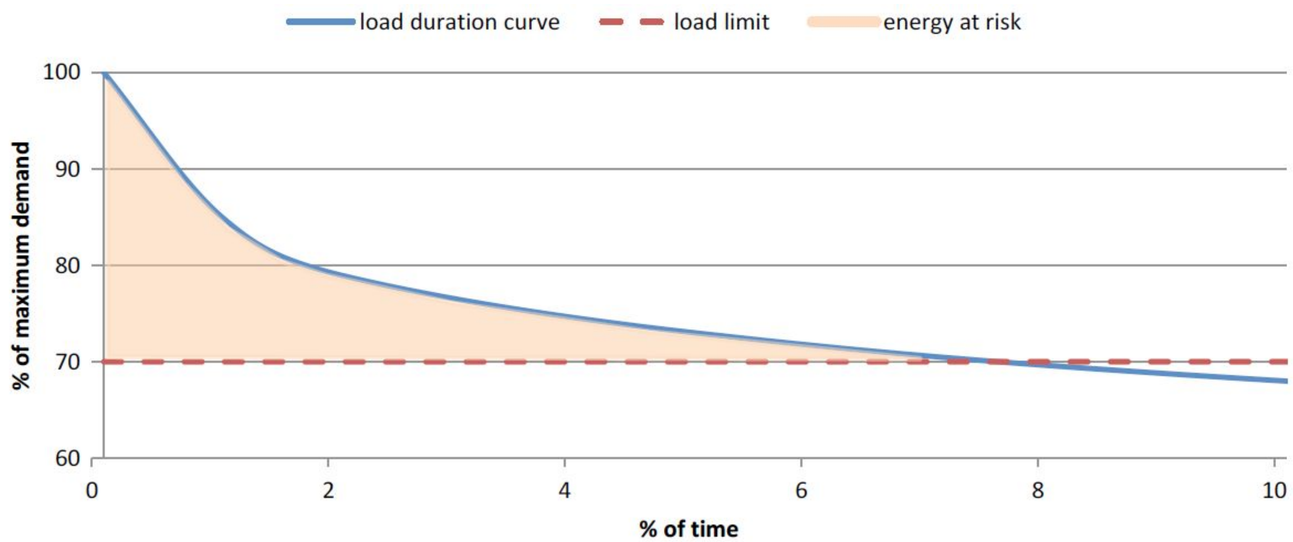
Figure 2.2: Load duration curve and load limit relationship



Source: Jemena Electricity Networks, 2014 Distribution Annual Planning Review, page 19.

32. Figure 2.3 shows the same figure, magnified around that part of the load duration curve closest to maximum demand. This effectively illustrates the energy at risk calculation, which is represented by the area under the load duration curve and above the load limit.

Figure 2.3: Energy-at-risk calculation for the area of the load duration curve above the load limit



33.

Source: Jemena Electricity Networks, 2014 Distribution Annual Planning Review, page 19.

34. It is evident from the above diagram that spatial demand forecasts are a critical input in determining the load at risk at a specific terminal station, zone substation or network feeder. An average 'network wide' approach to demand forecasting would not provide an appropriate assessment of energy at risk at a specific location.

2.4 EXPECTED UNSERVED ENERGY

35. For a specific maximum demand scenario and contingency, the EUSE measure in megawatt hours (**MWh**) is the product of:

- The energy at risk calculated for a given network state; and
- The probability of being in that network state.

36. Typically, the probability of being in an N-1 contingency is determined by the probability of a transformer outage or sub-transmission line outage.

2.5 KEY OBSERVATIONS

37. As already explained in section 2.1, applying the VCR to the expected unserved energy calculates the expected cost of the 'do nothing' option. The probabilistic planning approach requires that the cost of 'do something' options are weighed against the costs of 'do nothing'. In this way, an optimal solution (which may be 'do nothing') is identified.

38. For the purpose of this report, however, the key observation is that the probabilistic analysis is substantially location and asset specific – in terms of both:

- Calculating the costs of the 'do nothing' option, which will reflect the location-specific demand forecast and the capacity rating of the assets at that location; and
- The costs of the potentially feasible solutions.

39. As such, it is the spatial demand forecasts that drive economically efficient augmentation decisions. In particular, spatial demand forecasts are critical for:

- Determining the maximum asset loading; and
- Estimating the energy at risk.

40. In the next chapter we will explain some of the factors that are driving spatial variation in demand across our network, including high-rise residential and commercial developments. As explained in further detail in section 6.2, adopting spatial demand forecasts is key to ensuring that our investment decisions are efficient in accordance with the NER and the NEO. It would not be prudent or efficient to conduct network planning on the basis of system wide forecasts.

3. DEMAND FORECASTS FOR 2016-2020

41. The purpose of this chapter is to summarise our demand forecasts for the forthcoming regulatory period, and highlight the significant spatial variation in forecast demand growth across the network. As explained in Chapter 2, spatial demand forecasts are central to efficient network development planning.

3.1 NETWORK AVERAGE GROWTH RATES

42. On average, peak demand is forecast to grow at 1.36% per annum over the next six years (2015 to 2021), on a 50% POE basis. This compares to the historical average growth rate of 2.44% per annum over the past nine years. As discussed in section 3.2, however, the 'headline' growth rates mask important spatial differences in demand growth rates at different points across the network.

43. It is also important to note that our forecast average demand growth rate for the network is higher than the forecast growth rates published by AEMO in its first transmission connection point demand forecasting report for Victoria[5]. The reasons for this difference are explained in section 4.4 of this report.

44. Table 3-1 and Figure 3.1 below present the 'headline' forecast demand growth for our network.

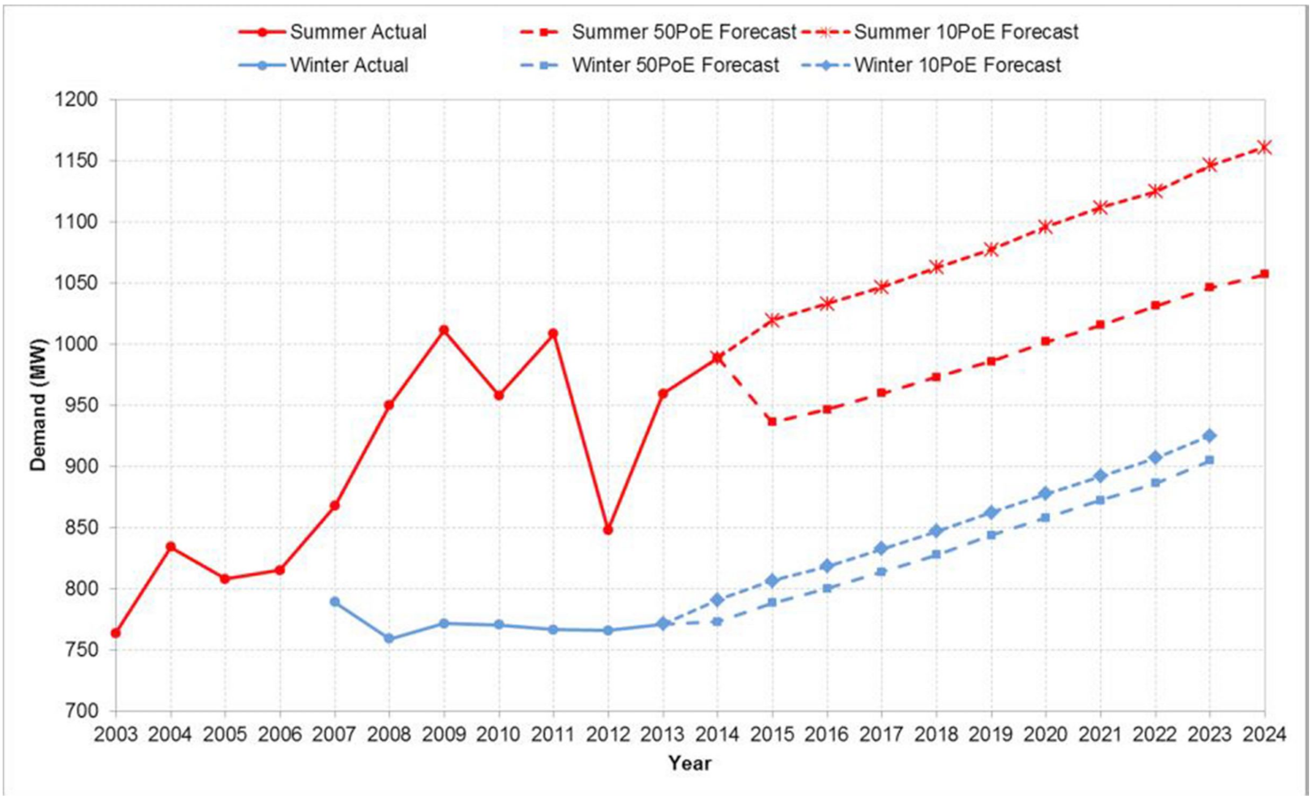
Table 3-1: Actual and forecast JEN network maximum demand

Demand (MW)	Actual		Forecast										Average annual growth	
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015-21	2015-24
Summer (50PoE)	959	988	936	947	959	973	986	1002	1015	1031	1046	1057	1.36%	1.35%
Winter (50PoE)	771	773	788	800	814	827	843	858	872	886	905		1.70%	1.77%
Summer (10PoE)	959	988	1019	1033	1046	1063	1077	1096	1112	1125	1146	1161	1.46%	1.46%
Winter (10PoE)	771	791	806	818	832	847	862	877	892	907	925		1.69%	1.76%
Maximum demand is forecast to grow over the forecast period largely driven by a projected return to trend GDP growth and a stabilisation of electricity prices.														

Source: Jemena Electricity Networks, *Load Demand Forecasts 2014*, page 7.

5 AEMO, *Transmission Connection Point Forecasting Report for Victoria - Forecasts Developed by AEMO*, September 2014

Figure 3.1: Actual and forecast JEN network maximum demand



Source: Jemena Electricity Networks, *Load Demand Forecasts 2014*, page 7.

3.2 SPATIAL DEMAND GROWTH

45. The forecast network growth in peak demand indicates that future demand will grow more slowly compared to recent historical trend growth rates. The increasing penetration of solar photovoltaics (**PV**) is one of the factors leading to a slowing in demand growth on our network. In effect, the future growth in demand will be met partly by increased solar PV and battery capacity, thereby reducing the demand on the network.

46. Importantly, however, the 'headline' growth rate described in section 3.1 is an average for our network as a whole. It does not provide any information about localised or 'spatial variation' in demand growth. However, as explained in Chapter 2 of this report, it is spatial demand forecasts that drive network augmentation decisions. Therefore, spatial demand forecasts are a key input to our network planning (as described in chapter 2).

47. Table 3-2 shows the significant variation in peak demand growth across our network. It illustrates the importance of considering local or spatial variation in demand, rather than simply focusing on the network average. For example, the average annual growth in peak demand of 1.36% provides no indication of the growth in customer demand at Footscray East, Melbourne Airport, Fairfield, Somerton, Sydenham and Tullamarine, all of which are expected to exceed 3% per annum. We must plan the network on the basis of forecast localised demand, not on the basis of network-wide averages.

Table 3-2: Localised variation in forecast peak demand 2015-2021

Season	Supply Area Average Annual Growth (2015-2021)			
	Strong growth (> 5% pa)	High growth (3-5% pa)	Medium growth (1-3% pa)	Low growth or decline (<1% pa)
Summer	Footscray East, Kalkallo, Melbourne Airport, Watsonia	Fairfield, Somerton, Sydenham, Tullamarine,	Airport West, Broadmeadows South, Coburg South, Coolaroo, Sunbury	Australian Glass Manufacturers, Braybrook, Broadmeadows, Coburg North, East Preston, Essendon, North Essendon, Flemington, Footscray West, Heidelberg, North Heidelberg, Melbourne Water, Newport, Pascoe Vale, Preston, St Albans, Thomastown, Tottenham, Visyboard, Yarraville

Source: Jemena Electricity Networks, 2014 Distribution Annual Planning Review, page iv.

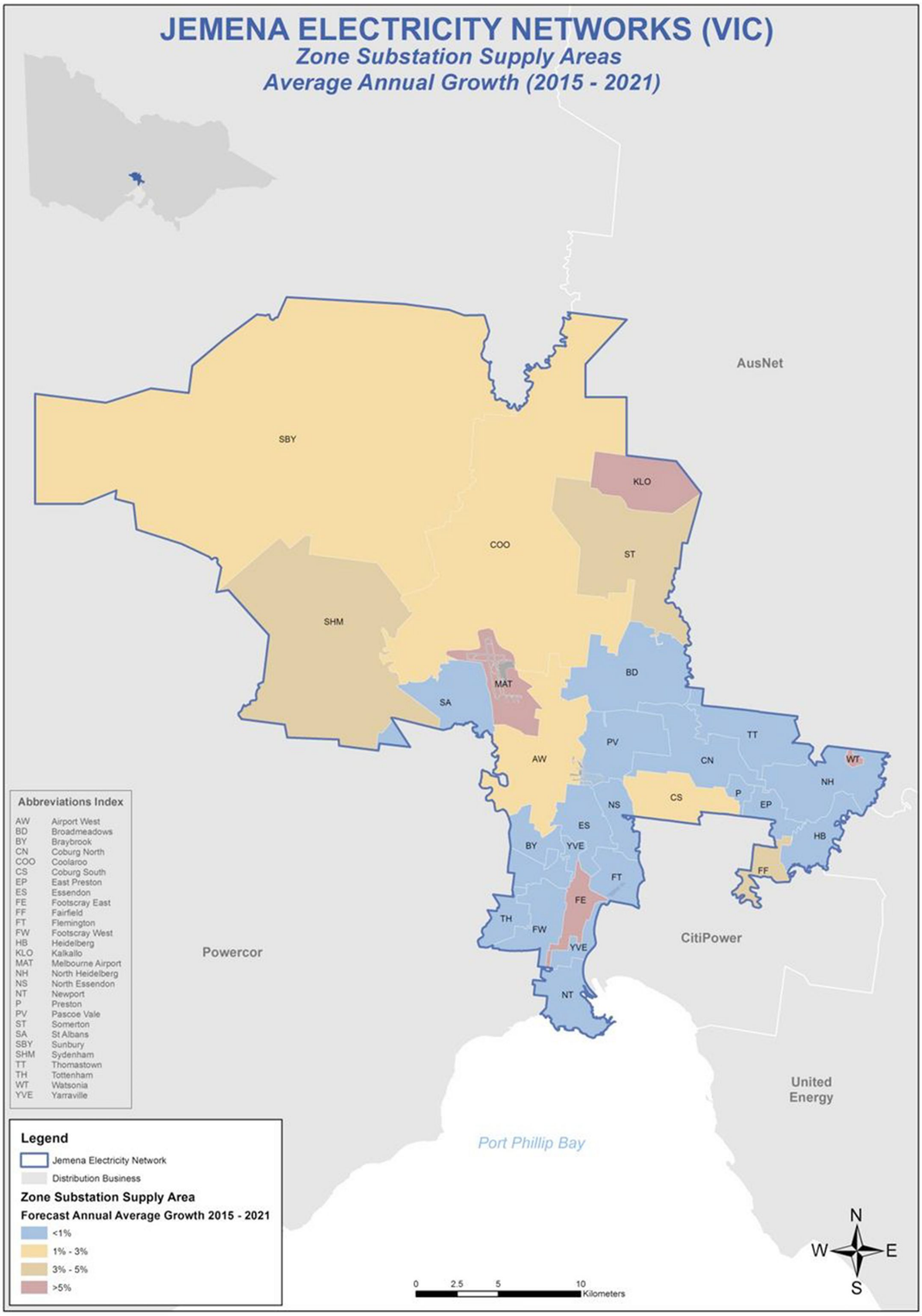
48. Table 3-2 shows that there are significant areas where demand growth is lower than average or is expected to decline. Manufacturing closures, such as Ford Motors in Broadmeadows, are key drivers of the localised reductions in network demand.

49. Demand growth in other areas is driven by the following factors:

- New developments associated with urban sprawl towards the edge of the Urban Growth Boundary
- Amendments to planning schemes to allow high density living in inner urban areas, such as Coburg (Moreland City Council) and Preston (City of Darebin)
- Expansion of community facilities and services, including the Footscray Central Activities District, Essendon Airport and Melbourne International Airport.

50. Figure 3.2 shows our forecast demand growth by zone substation. It illustrates the significant geographical variation in spatial demand growth.

Figure 3.2: Forecast demand growth by zone substation supply area



Source: Jemena Electricity Networks, *2014 Distribution Annual Planning Review*, page 29.

3.3 DRIVERS OF SPATIAL VARIATION IN DEMAND GROWTH

52. Our demand forecasting methodology is discussed in detail in chapter 4 of this report. It is worth noting here, however, that loads associated with confirmed new developments or development proposals that have a high likelihood of proceeding are reflected in our forecasts. The principal developments driving significant demand growth in specific locations on our network are summarised below:

- Development of underground residential distribution (**URD**) and industrial estates in the Kalkallo, Craigieburn and Mickleham areas covered by the Northern Growth Corridor, currently supplied from Somerton and Kalkallo zone substations
- Proposed new Victrack workshop in Diggers Rest and continued URD estate developments within the Sydenham supply area
- Continued URD and commercial estate developments within the Sunbury supply area
- Continued URD estates expansion within the Greenvale area, currently supplied from Coolaroo Zone Substation
- New commercial development within Melbourne Airport Business Park
- New high rise residential and office buildings within the Footscray Central Activities District, currently supplied by Footscray East Zone Substation
- On-going commercial and industrial estate developments within Airport West and Tullamarine supply areas
- Redevelopment of the Amcor site in Fairfield to multiple high rise residential and office buildings, which will be supplied from Fairfield Zone Substation
- Essendon Airport Development, currently supplied from Airport West Zone Substation
- On-going URD and commercial developments within the Pentridge area, currently supplied from Coburg South Zone Substation
- On-going developments at the CSL site, currently supplied from Coburg North Zone Substation.

4. DEMAND FORECASTING METHODOLOGY

53. The purpose of this chapter is to explain our demand forecasting methodology.

54. It explains that the spatial demand forecasts, which are central to our network development plans, are reconciled with system and terminal station demand forecasts prepared by ACIL Allen. The latter forecasts are developed using the same methodology employed by AEMO.

4.1 OVERVIEW

55. The methodology for preparing maximum demand forecasts calls for two independent sets of forecasts as follows:

- The spatial level ('bottom up') forecast, which is prepared by us; and
- The system level ('top down') forecast, which is prepared by an independent external economic forecaster, ACIL Allen Consulting.

56. We reconcile our spatial forecasts to the system level forecast to produce the final set of maximum demand forecasts. As a result, our spatial forecast is equal to the independent external system forecast at the total network level. We adopt spatial forecasts for network planning purposes, as it provides specific forecasts at the feeder and zone substation levels.

57. The spatial and system level forecasting methodologies are discussed in turn below.

4.2 SPATIAL DEMAND FORECASTS

58. Our spatial demand forecasts are built up from a feeder level, to zone substation level, and then to terminal station level, taking into account diversity at each level of aggregation. The overall forecasting procedure therefore comprises the following five phases to finalise the spatial forecast:

- Phase 1: Feeder forecast
- Phase 2: Zone substation forecast
- Phase 3: Terminal station forecast
- Phase 4: Forecast coincident demand
- Phase 5: Reconcile spatial forecasts with system forecast prepared by external independent expert.

59. As explained below, the forecasts developed in each of the first three phases are based on local information.

60. Phase 1 captures significant customer load changes (both additions and reductions in load) for each feeder by making use of local information such as:

- New connections, generally associated with residential subdivisions, and commercial and industrial development projects
- Load demand changes identified through consultation with large customers

- Local information sources such as newspapers, media, and information on urban planning and economic development available from local councils and the Department of Transport, Planning and Local Infrastructure.

61. Planned load transfers between feeders from proposed feeder re-configurations and new feeder works are also determined and incorporated into the feeder forecast.

62. Phase 2 translates the information obtained at the feeder demand forecasts into a zone substation demand forecast by:

- Reconciling feeder demand to the previous year's maximum demand at the zone substation, correcting for any temporary load transfers and weather normalisation
- Applying diversity factors to convert non-coincident feeder demand to the zone substation peak demand
- Including load not captured at the feeder level forecast, such as growth in air conditioning load.

63. A similar approach is adopted in Phase 3 to translate zone substation demand forecasts to terminal station level forecasts. Phases 4 and 5 are focused on reconciling the terminal station forecasts with the system level forecasts:

- Phase 4 deals with the diversity factors that translate terminal station forecasts to system wide forecasts
- Phase 5 considers the impact on demand of government policies and macroeconomic conditions that are not captured by the 'bottom up' forecasts.

64. The spatial forecasting methodology produces a forecast for summer and winter peak demand conditions, each with a 10% and a 50% POE. Further details of the load forecasting methodology are set out in our Load Demand Forecast Procedure document[6].

4.3 SYSTEM LEVEL DEMAND FORECASTS

65. The system level forecasts are prepared by ACIL Allen, who apply the same econometric techniques as those used in assisting AEMO to forecast demand at the terminal station (transmission connection point) level.

66. ACIL Allen developed separate models to estimate demand for each terminal station that supplies our network, and for our network as a whole (a 'top down' approach). The forecasts for terminal stations and total network demand were prepared for the 10%, 50% and 90% POE levels. The forecasting methodology includes the following steps:

1. Obtain historical maximum demand data at each terminal station and system level.
2. Make adjustments to these data to approximate 'latent' demand by 'adding back' the impact of embedded generation, and remove outliers and non-working days.
3. Estimate regression models to relate demand to its drivers, which are:
   - Economic outlook for Victoria and our network supply area, as measured by the Victorian Gross State Product (GSP) growth rate
   - Photovoltaic (PV) generation capacity

6 Jemena Electricity Networks, *JEN PR 0507 - Load Demand Forecast Procedure*, December 2014.

  - Electricity prices
  - Variations in temperature patterns (weather).

4. Forecast maximum demand using these regression models and projections of drivers.
5. Bootstrapping (statistical re-sampling) historical weather data to produce 10%, 50% and 90% POE forecasts.
6. Reconcile the terminal station and system level forecasts.
7. Add back the (negative) effect of existing embedded generators and discrete demand shifts.
8. Make a post model adjustment to account for additional solar PV capacity.

67. The process was conducted separately for summer and winter to produce independent forecasts of maximum demand for both seasons.

68. The post model adjustment for PV capacity is made to the system level forecasts, and is applied to the spatial level forecasts through the reconciliation process. In order to assess the impact of PV capacity on future demand growth, ACIL Allen estimate:

- The number of installations
- The capacity of installations (per unit)
- The total installed capacity.

69. The modelling took into account the projected financial viability of installing PV systems. It also assessed the impact of announced reductions in Government support that may have caused customers to 'rush in' prior to the policy change.

70. As evidenced by the ACIL Allen report titled "Electricity Demand Forecasts", the forecasting methodology employed was both comprehensive and transparent. Specifically, ACIL Allen has reported its econometric modelling results, including coefficients and t-statistics. In addition, the modelling approach is consistent with that employed by ACIL Allen for AEMO in 2013[7], which further demonstrates their independence.

4.4 AEMO'S VICTORIAN CONNECTION POINT FORECASTS

71. As noted in section 3.1, AEMO published its first transmission connection point demand forecasts for Victoria in September 2014, using the methodology developed by ACIL Allen in 2013. AEMO summarises the key findings of its Victorian connection point forecasts from 2014–15 to 2023–24 in the following table, which is reproduced from AEMO's report[8].

[7] ACIL Allen, *Connection point forecasting - a nationally consistent methodology for forecasting maximum electricity demand*, 28 June 2013, available from www.aemo.gov.au

[8] AEMO, *Transmission Connection Point Forecasting Report for Victoria - Forecasts Developed by AEMO*, September 2014, page 1.

Figure 4.1: Key findings of AEMO's Victorian connection point forecasts from 2014–15 to 2023–24

Season	Region level average annual growth rate (10% POE)	Range of average annual connection point growth rates (10% POE)
Summer	0.1%	-6.5% to 11.3%
Winter	0.9%	-4.4% to 19.9%

Key Drivers:

- **Overall demand in Victoria is flattening, however there are some connection points that are growing requiring network investment.**
- **Positive growth is primarily driven by 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 photovoltaic (PV) output during summer.**

Source: AEMO, Transmission Connection Point Forecasting Report for Victoria - Forecasts Developed by AEMO, September 2014, page 1.

72. The figure above shows that AEMO forecasts an average demand growth rate in summer of 0.1% per year for Victoria as a whole (10% POE). It is instructive to note the wide range in AEMO's demand forecasts for transmission connection points, from -6.5% to +11.3% per annum across Victoria. This substantial variation in demand projections underscores some of the key messages of this Demand Summary Report:

- The rate of demand growth varies widely from location to location within a network
- Development of the network must be planned on the basis of forecasts of demand growth for each location it serves
- The network-wide average demand growth rate provides little, if any, meaningful information regarding the network investment that is required to meet the projected demand at specific terminal stations, zone substations and network feeders.

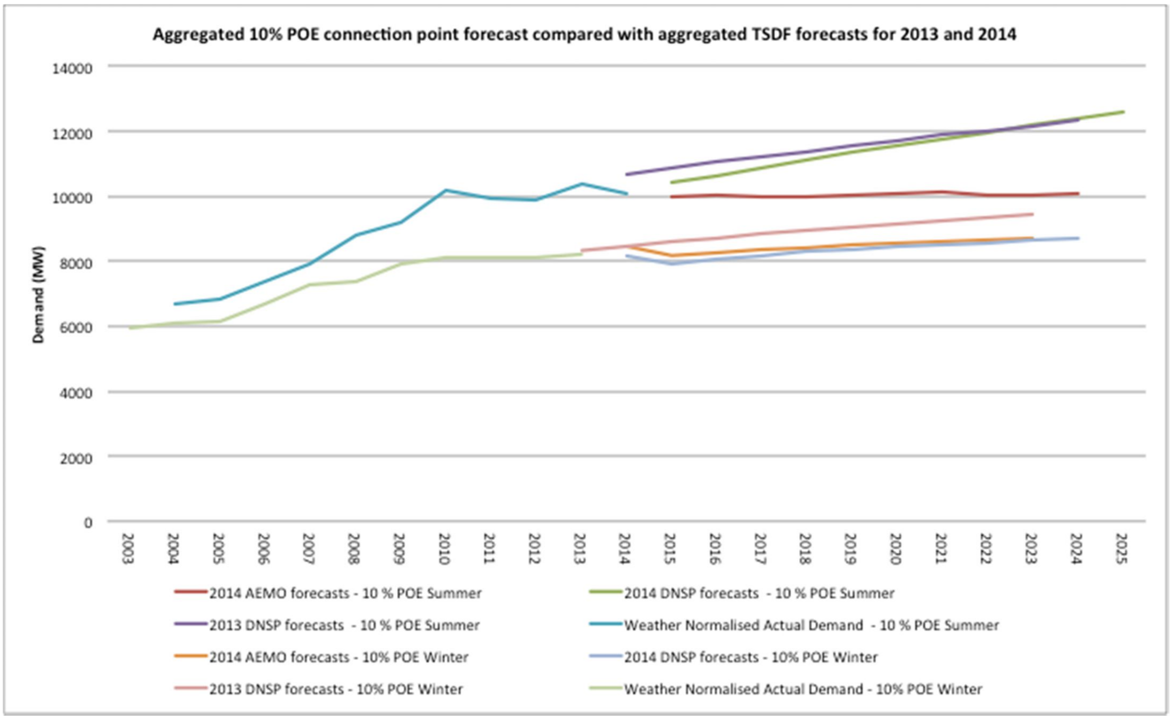
73. It is also important to acknowledge, however, that AEMO's Victorian connection point forecasts imply rates of spatial demand growth across our network that are below the forecasts presented in chapter 3 of this report. This raises a question as to whether we have over-stated our demand forecasts for the forthcoming regulatory period. That question was considered by the Victorian Distribution Businesses in their 2014 joint Transmission Connection Planning Report (TCPR), which stated the following[9]:

> *"The TSDF sets out Victorian transmission connection point demand forecasts as provided by Victorian participants, being the Victorian distributors and directly connected customers. In its capacity as the Transmission Network Service Provider for the Victorian shared transmission network, AEMO collates the TSDF report in accordance with clause 5.11.1 of the National Electricity Rules. It should be noted that the demand forecasts presented in the TSDF are compiled by AEMO from forecasts that reflect participants' expectations of future demand.*
>
> *Subsequent to AEMO's publication of the TSDF report, AEMO produced its first connection point forecasts for Victoria, which are derived from State based demand forecasts. A copy of AEMO's Victorian Connection Point Forecasting Report is available from its website at:*
>
> *http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting/Transmission-Connection-Point-Forecasting-Report-for-Victoria*

[9] Victorian Electricity Distribution Businesses, *Transmission Connection Planning Report*, December 2014, pages 33-34.

As noted below, there are differences in the aggregate demand forecasts in the TSDF report and AEMO's 2014 Victorian connection point forecasts. However, it is not possible to analyse these differences at a connection point level because the diversity data has not been published. From a connection planning perspective, understanding demand growth at each connection point is paramount, especially as Victoria is experiencing significant differential growth rates across the State.

The figure below is reproduced from AEMO's 2014 Victorian Connection Point Forecasting Report. It is useful in illustrating the magnitude of the differences between AEMO's connection point forecasts and those presented in the TSDF report (depicted as "DNSP forecasts"). As already noted, however, aggregated forecasts mask differential growth rates at connection points and, therefore, are of limited relevance from a planning perspective.



The Victorian DBs are continuing to work with AEMO to understand the approaches and assumptions behind the AEMO forecasts. The Victorian DBs' initial evaluation suggests that the main reasons for the differences between AEMO's connection point forecasts and the TSDF could relate to:

- *problems with AEMO's historical data sets, arising from misallocated State-wide demand forecasts to individual terminal stations or inappropriate treatment of load transfers;*
- *the magnitude of post-model adjustments undertaken by AEMO to allow for rooftop PV and energy efficiency impacts in particular;*
- *weather normalisation processes; and*
- *the relationship between AEMO's energy and demand forecasting models.*

Until these issues are fully understood and resolved through discussions with AEMO, it would not be prudent to adopt AEMO's 2014 connection point forecasts for the purpose of this Transmission Connection Planning Report. In reaching this conclusion, the Victorian DBs note that 2014 is the first edition of AEMO's transmission connection point forecasts for Victoria, and the methodology is *likely to evolve in subsequent editions. In these circumstances, and in light of planning risks associated with adopting the lower of AEMO's published forecasts, the DBs have adopted the TSDF forecasts for the purpose of preparing this Transmission Connection Planning Report."*

74. In formulating the forecasts presented in chapter 3 of this report, we considered the appropriateness of AEMO's 2014 transmission connection point forecasts for network planning purposes. We concur with the views and assessment set out in the 2014 TCPR (cited above). Notwithstanding the differences between its forecasts and those published by AEMO, we consider that our forecasts:

- Are more appropriate than any others that could have been adopted; and
- Represent a realistic expectation of the demand forecast in accordance with the requirements of Clause 6.5.6(c) (3) of the NER.

75. In reaching this conclusion, we note that ACIL Allen applies the same forecasting methodology as it developed for AEMO. The concerns identified by the Victorian distributors relate to the detailed application of the ACIL Allen methodology, including input data, rather than the methodology itself. These observations provide further assurance that our forecasts are robust, independent and fit for purpose.

5. NETWORK DEVELOPMENT PLANS

76. The purpose of this chapter is to set out a case study, which illustrates the importance of spatial demand forecasts in our network development planning.

5.1 SUNBURY ZONE SUBSTATION

77. Sunbury Zone Substation (**SBY**) comprises two 66/22 kV 16 MVA transformers, one 66/22 kV 10 MVA transformer and three 22 kV buses supplying six 22 kV feeder lines. SBY supplies areas of Sunbury, Diggers Rest, Bulla, Clarkefield and Gisborne South.

78. When the substation was originally developed in 1964, it was built with a basic and cost effective switching arrangement that was appropriate for the small and remotely located load that it originally supplied. The site was designed using 22 kV outdoor switchgear connecting its transformers in a single switching zone. This arrangement is prone to faults caused by wildlife contact, and most faults within the substation will result in a supply interruption to all customers supplied from SBY. In the past twenty years, such an event has occurred 18 times.

79. The SBY supply area has seen strong demand growth in the past ten years. The substation is now a key switching substation for five sub-transmission lines. The original design of the substation is no longer appropriate. In addition, the SBY supply area is a higher bushfire risk than most of our supply area.

80. Table 5-1 shows the forecast growth in demand results in an increasing exposure to unserved energy. By 2020, the 10% POE and 50% POE weighted expected cost of unserved energy is estimated to be approximately $13.3 million per annum compared to approximately $3.0 million in 2015. In the absence of any action to reduce the load at risk, customers served by SBY can expect to experience loss of supply valued at $13.3 million in 2020. It is noted that a downwardly biased demand forecast (based on the network average) would grossly understate the customer exposure in 2020, and may lead to the uneconomic deferral of actions aimed at reducing this exposure.

Table 5-1: Sunbury Zone Substation loading risk and limitation cost

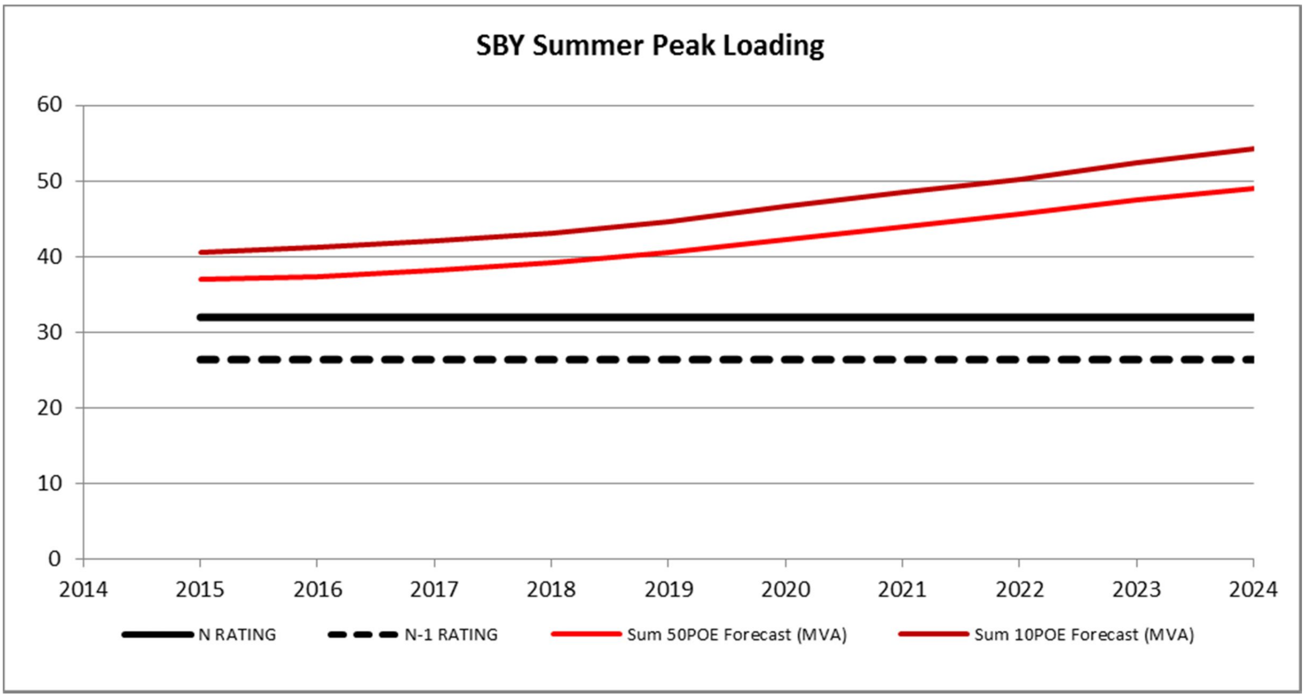
	2015	2016	2017	2018	2019	2020
10% POE MD (MVA)	40.6	41.2	42.1	43.2	44.7	46.6
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	154%	156%	159%	164%	169%	177%
Max load at risk (MVA)	14.2	14.8	15.7	16.8	18.3	20.2
Hours at risk (h)	162	194	259	344	463	606
EUSE (MWh)	77.3	92.2	120.1	159.2	227.1	347.1
10%POE and 50% POE weighted cost of EUSE ($ thousand)	2,968.2	3,538.5	4,610.7	6,114.1	8,720.6	13,328.5

Source: Jemena Electricity Networks, 2014 Distribution Annual Planning Review, page 104.

81. Figure 5.1 shows the summer 10% POE and 50% POE peak demand forecast (MVA) compared to the substation limits (MVA). In this particular example, the substation's overall system normal rating is limited by the capacity of the 10 MVA transformers, with the 16 MVA transformers unable to be operated at full capacity

under system normal conditions due to load sharing. As a consequence, there is only limited difference between the station's rating under N and N-1 conditions.

Figure 5.1: Sunbury Zone Substation maximum demand loading



Source: Jemena Electricity Networks, 2014 Distribution Annual Planning Review, page 104.

82. Our Distribution Annual Planning Report explains that we have considered several options for addressing the energy at risk, including:

- Establishing a new zone substation in the Bulla area, with two 20/33 MVA transformers
- Redevelopment of the substation by replacing the existing 10 MVA transformer with a new 20/33 MVA unit, and installing new 66 kV and 22 kV switchgear
- Establishing embedded generation suitably located in the SBY supply area
- Introducing demand management to reduce demand voluntarily at peak demand times and during network outages.

83. Our analysis has indicated that the zone substation redevelopment will maximise net benefits to customers, consistent with the requirements of the RIT-D.

5.2 OBSERVATIONS ON CASE STUDY

84. The case study illustrates how local demand conditions and asset limitations must be considered together in order to develop an efficient development plan.

85. Contrary to this approach, if a system-wide demand forecast were applied to the loading at SBY zone substation, the forecast energy at risk would have been biased downwards. The consequence of this approach is that efficient investment would not occur, and customers would be exposed to outcomes (including increased

risk of supply interruption) that are uneconomic. Such outcomes would be contrary to the NEO, the RIT-D requirements and the capital expenditure objectives in the NER.

86. The example illustrates the importance of a ‘bottom up’ assessment of network augmentation requirements. The ‘bottom up’ assessment requires spatial demand forecasts. Importantly, our demand forecasting approach ensures that spatial demand forecasts reconcile with ‘top down’ forecasts formulated by an independent forecaster, ACIL Allen. This approach ensures that the spatial demand forecasts are soundly based.

87. While the combination of ‘top down’ and ‘bottom up’ demand forecasting is appropriate, it is the spatial forecasts that must be applied for network planning purposes. For the reasons set out in this report, a network-wide average growth rate would lead to inefficient investment decisions, as illustrated by this case study.

6. DEMONSTRATING NER COMPLIANCE

88. The purpose of this chapter is to set out the principal regulatory obligations that are relevant to the tasks of preparing demand forecasts and augmentation capital expenditure plans. The chapter concludes by explaining why our approach to these tasks complies with these NER requirements.

6.1 RELEVANT REGULATORY OBLIGATIONS

89. Clause 6.5.7(a) of the NER requires a building block proposal to include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):

1. Meet or manage the expected demand for standard control services over that period
2. Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services
3. Maintain the quality, reliability and security of supply of standard control services
4. Maintain the safety of the distribution system through the supply of standard control services.

90. In addition, Clause 6.5.7(c) of the NER also requires the forecast expenditure to reasonably reflect each of the following capital expenditure criteria:

1. The efficient costs of achieving the capital expenditure objectives
2. The costs that a prudent operator would require to achieve the capital expenditure objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

91. For network investments exceeding $5 million, the distributor is required to conduct a RIT-D. Clause 5.17.1(b) of the NER states that the purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market. The NER also require the RIT-D to be based reasonable demand scenarios (Clause 5.17.1(c)).

92. Clause 16(1) of the National Electricity Law requires the AER to exercise its economic regulatory function or power in a manner that will or is likely to contribute to the achievement of the NEO. Section 7 of the NEL states that:

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system."*

6.2 IMPLICATIONS FOR DEMAND FORECASTING AND NETWORK PLANNING

93. In relation to demand forecasting and augmentation capital expenditure, the following observations can be drawn in relation to the regulatory provisions noted in section 6.1:

- Our capital expenditure forecasts must meet or manage the expected demand for standard control services (Clause 6.5.7(a) (1)). The demand for standard control services is derived from distribution customers. A realistic demand forecast, referred to in Clause 6.5.7(c) (3), should therefore be interpreted as a disaggregated or spatial demand forecast. A network-wide or averaged demand forecast would not enable us to *"meet or manage the expected demand for standard control services."*
- The capital expenditure criteria require us to take an efficient and prudent approach in determining the costs of achieving the capital expenditure objectives (clauses 6.5.7(c) (1) and (2)). Our probabilistic approach to network planning delivers efficient outcomes by selecting the option (including the 'do nothing' option) that maximises the net benefit to customers. In terms of prudency, we consider 10% POE and 50% POE location-specific maximum demand forecasts to determine the maximum asset loading and the expected unserved energy. A network-wide or averaged demand forecast would not be consistent with efficient or prudent capital expenditure plans because it would not reflect location-specific demand growth. As a consequence, it would provide distorted investment decisions that may lead to under- or over-investment
- The RIT-D requires us to conduct cost-benefit analysis for network augmentations that exceed $5 million. We are required to adopt reasonable demand scenarios in conducting the cost-benefit analysis. This requires us to adopt the best available, location-specific demand forecasts. The case study in chapter 5 illustrated the importance of load growth projections in estimating the expected value of unserved energy, and the efficient timing of an augmentation decision. A spatial demand forecast is therefore an important element in achieving compliance with the RIT-D obligations.

94. The NEO is concerned with promoting efficient investment for the long term interests of consumers with respect to price, quality, safety, reliability and security of supply of electricity. As already noted, our planning approach in relation to network augmentation is appropriately focused on investing to meet customers' needs. This is an inherently location-specific task, and therefore requires the kind of detailed planning undertaken in our Distribution Annual Planning Report. A 'top down' investment approach that ignored location-specific issues, such as current asset loadings and future demand growth, would deliver inefficient outcomes, outcomes, contrary to the NEO.