Jemena Electricity Networks (Vic) Ltd

2016-2020 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 7-3 Demand forecast

Public

6 January 2016

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ABBREVIATIONS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulatory
AMI	Advanced Metering Infrastructure
GSP	Gross State Product
JEN	Jemena Electricity Networks (Vic) Ltd
PoE	Probability of Exceedance

OVERVIEW

Key messages

- We welcome that the preliminary decision recognises that our demand forecasts reflect a realistic expectation of demand over the 2016 regulatory period.[1]
- As anticipated in the preliminary decision, we have updated our peak demand forecast to take into account the additional year of actual network data, the updated 2015 Australian Energy Market Operator (**AEMO**) forecast,[2] and updated Victorian economic outlook data (gross state product) and electricity prices.
- We have assessed key forecast demand drivers and consider that our updated demand forecast remains a realistic expectation of demand over the 2016 regulatory period.
- We provide additional support for our chosen forecasting method in response to observations made by Dr Darryl Biggar.

1. Table 1–1 provides a snapshot of Jemena Electricity Networks (Vic) Ltd's (**JEN's**) response to the preliminary decision on maximum demand.

Table 1–1: Overview of our response to preliminary decision on demand

Demand	Our response to preliminary decision
Maximum demand forecast	

1 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, pp 6-9, 6-37, 6-40, 6-46, 6-47, 6-61, 6-62, 6-101, 6-111, 6-112

2 AEMO, *National Electricity Forecasting Report*, June 2015

1. INTRODUCTION

1.1 PURPOSE

2. The purpose of this attachment is to explain JEN's update to its demand forecasts undertaken for the 2016 regulatory period. The demand forecasts are a key driver of our augmentation capital expenditure and are an input into the operating expenditure scale escalation (using ratcheted demand).

3. In this submission attachment, we set out:

- Background information related to our demand forecasting approach, including what has been updated since our April 2015 proposal (Chapter 2)
- Our updated demand forecasts for the 2016 regulatory period (Chapter 3)
- Support for why our demand forecasting method is a robust approach (Chapter 4).

1.2 SCOPE

4. JEN's April 2015 proposal details our demand forecasting method and our previous forecast.[3] JEN engaged ACIL Allen Consulting to produce its demand forecasts. For the purposes of explaining that method and forecast our April 2015 proposal (and all supporting evidence and other material contained, or referred to, in it) is incorporated into, and forms part of, this submission.

5. This attachment focuses on the update and areas of difference from that proposal.[4] This includes the following matters:

- Including the 2014-15 summer peak demand data that was not available at the time of developing our April 2015 proposal (demand forecasts were finalised in November 2014)
- Increasing the consistency with the Australian Energy Market Operator's (**AEMO's**) method by updating the Victorian economic outlook data (gross state product) and AEMO's forecast of Victorian electricity prices
- Responding to Dr Daryl Biggar's observations on our chosen forecast method.

6. This attachment refers to the following documents that contain additional detailed analysis and supporting information:

- ACIL Allen's updated demand report (Attachment 7-4)
- ACIL Allen's updated consumption forecasting model (Attachment 7-5)[5]
- JEN's load demand forecasts 2015 (Attachment 7-6).

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3 JEN's April 2015 proposal included the forecast from ACIL Allen prepared in November 2014.

4 Jemena Electricity Networks, *2016-20 Electricity Distribution Price Review Regulatory proposal, Attachment 3-1,* 30 April 2015.

5 Attachment 7-5 includes two models for ACIL Allen's summer demand forecast and winter demand forecast.

1.3 PRELIMINARY DECISION

7. JEN welcomes the acknowledgment in the preliminary decision that our demand forecasts reflect a realistic expectation of demand over the 2016 regulatory period.[6] In particular:[7]

   - Our adopted method—consistent with AEMO's approach—would result in more realistic forecasts when compared to other models assessed
   - Our forecast is similar to that of AEMO's forecast and broadly in line with historical trends.

8. The Australian Energy Regulator (**AER**) used AEMO's forecast as a comparison to JEN's forecasts.[8] The preliminary decision also set out the AER's expectation that JEN would update its demand forecast to capture additional information, including:

   - the most recent demand data[9]
   - AEMO's revised connection point forecasts (from the AEMO 2015 National Electricity Forecasting report and 2015 Transmission Connection Point Forecast report for Victoria).[10]

9. In addition, Dr Darryl Biggar undertook an assessment of JEN's demand forecasting method. Dr Biggar made some observations, including:[11]

   - JEN's approach is relatively clear and transparent
   - Concern that solar PV, energy efficiency and the impact of tariff reform were not adequately captured by the model
   - The forecasts were prepared in November 2014 without benefit of one further years' experience of summer demand.

10. To support our submission, we respond to each of these areas raised in Dr Biggar's assessment in Section 4.

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6 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, pp 6-9, 6-37, 6-40, 6-46, 6-47, 6-61, 6-62, 6-101, 6-111, 6-112. JEN notes that there are two instances in the preliminary decision where the AER makes a contradictory statement on whether it has accepted our demand forecast (p. 6-27). These appear to be typographical as they refer to Appendix C, where the AER has clearly accepted our demand forecast. The AER preliminary decision reasons for reductions to capex are for reasons other than the demand forecast

7 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-112

8 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-112

9 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-109

10 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-101

11 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, September 2015, pp 18-19

2. JEN'S DEMAND FORECASTING APPROACH

11. JEN detailed its demand forecasting approach in its April 2015 proposal.[12] We have not changed this approach—the updates set out in this attachment relate solely to updates to the data inputs. We provide an overview of this approach below.

2.1 OVERVIEW OF OUR APPROACH

12. JEN's demand forecasting method recognises the value of combining 'bottom up' and 'top down' demand forecasting. In particular, we use state-wide or network-wide demand forecasts to provide a useful method for verifying that our location specific, or 'spatial', demand forecasts are robust in aggregate.[13] This aligns with the AER assessment, which also considers demand forecasts at the system level and more local level.[14]

13. In our network, the spatial maximum demand growth forecasts over the next six years (from 2016 to 2021)[15] show a wide variation compared to the network average of 1.02% per annum (see Table A1–1). Table 2–1 shows that the growth rate in Sunbury, for example, is expected to exceed 3% per annum.[16] 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 2–1: Localised variation in forecast peak demand 2016-2021

Season	Supply area average annual growth (2016-2021)			
	Strong growth (> 5% pa)	High growth (3-5% pa)	Medium growth (1-3% pa)	Low growth or decline (<1% pa)
Summer	Kalkallo, Tullamarine, Watsonia	Somerton, Sunbury	Airport West, Coburg South, Coolaroo, Fairfield, Flemington, Footscray East, Sydenham, Yarraville	Braybrook, Broadmeadows, Broadmeadows South, Coburg North, East Preston, Essendon, North Essendon, Footscray West, Heidelberg, North Heidelberg, Newport, Pascoe Vale, Preston, St Albans, Thomastown, Tottenham

Source: Jemena Electricity Networks, 2015 Distribution Annual Planning Report, page v, December 2015.

14. For our April 2015 proposal, 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). We used ACIL Allen to repeat this approach with the updated inputs set out in section 3.1. As with our April 2015 demand forecasts, the updated forecasts were prepared using multiple weather

12 JEN, *2016-20 Electricity distribution price review regulatory proposal, Attachment 3-5—JEN demand summary report*, 30 April 2015

13 It is important to not rely solely on system-wide average demand forecasts. If these 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**)

14 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-100

15 Jemena Electricity Networks (Vic) Ltd, *2015 Distribution Annual Planning Report*, p v, December 2015

16 Based on 50% PoE summer maximum demand

scenarios. Internally, we prepared updated spatial demand forecasts (using a 'bottom up' approach), which were then reconciled to the updated forecasts prepared by ACIL Allen (see Attachment 7-6).

15. ACIL Allen applies the same forecasting method that it developed for AEMO: this provides assurance that the approach is robust and independent. Having considered this approach, the preliminary decision concluded that:[17]

> *ACIL Allen's forecasts are likely to reflect a realistic expectation of demand over the 2016–20 period.*

[17] AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-112

3. JEN'S RESPONSE AND THIS SUBMISSION

16. The purpose of this chapter is to set out our response to the AER's preliminary decision and to summarise our updated demand forecasts for the 2016 regulatory period.

3.1 OUR RESPONSE TO THE PRELIMINARY DECISION

17. As anticipated by the AER, JEN has updated its demand forecast to take into account the most up-to-date information available and to better align our model with inputs used by the AEMO.

18. We have updated the maximum demand forecast to:

- Include the actual data for 2014-15 summer[18]
- Replace the Victorian Government's forecasts of Gross State Product (**GSP**) with AEMO's 2015 economic forecasts from the National Electricity Forecasting report[19]
- Replace ACIL Allen forecast of retail electricity prices with forecasts provided in AEMO's 2015 National Electricity Forecasting report.

19. By greater alignment with AEMO forecasts, we have sought to address concerns that our forecast exceeds and contrasts with the AEMO forecasts.[20]

20. The update results in slightly lower system maximum demand, but retains the significant spatial variation in forecast demand growth across the network. As explained in our April 2015 proposal[21], spatial demand forecasts are central to efficient network development planning.

21. In addition, we note that both the April 2015 proposal and updated forecasts do account for solar PV and energy efficiency as set out in Chapter 4.

3.2 OUR SUBMISSION SUMMER AND WINTER FORECASTS

3.2.1 UPDATED MAXIMUM DEMAND FORECASTS

22. ACIL Allen has updated their demand forecasts (see Attachment 7-4 and Attachment 7-5) and JEN has used these for this submission. We have extracted the key forecast information showing a comparison to our April 2015 proposal (see Appendix A) and showing the demand forecast over time (Figure 3–1).

23. The projected growth is marginally slower under the updated submission forecast than the April 2015 proposal, which used the November 2014 forecast).

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18 This update addresses a concern by Dr Biggar that JEN's forecasts were prepared in November 2014 without benefit of one further years' experience of summer demand

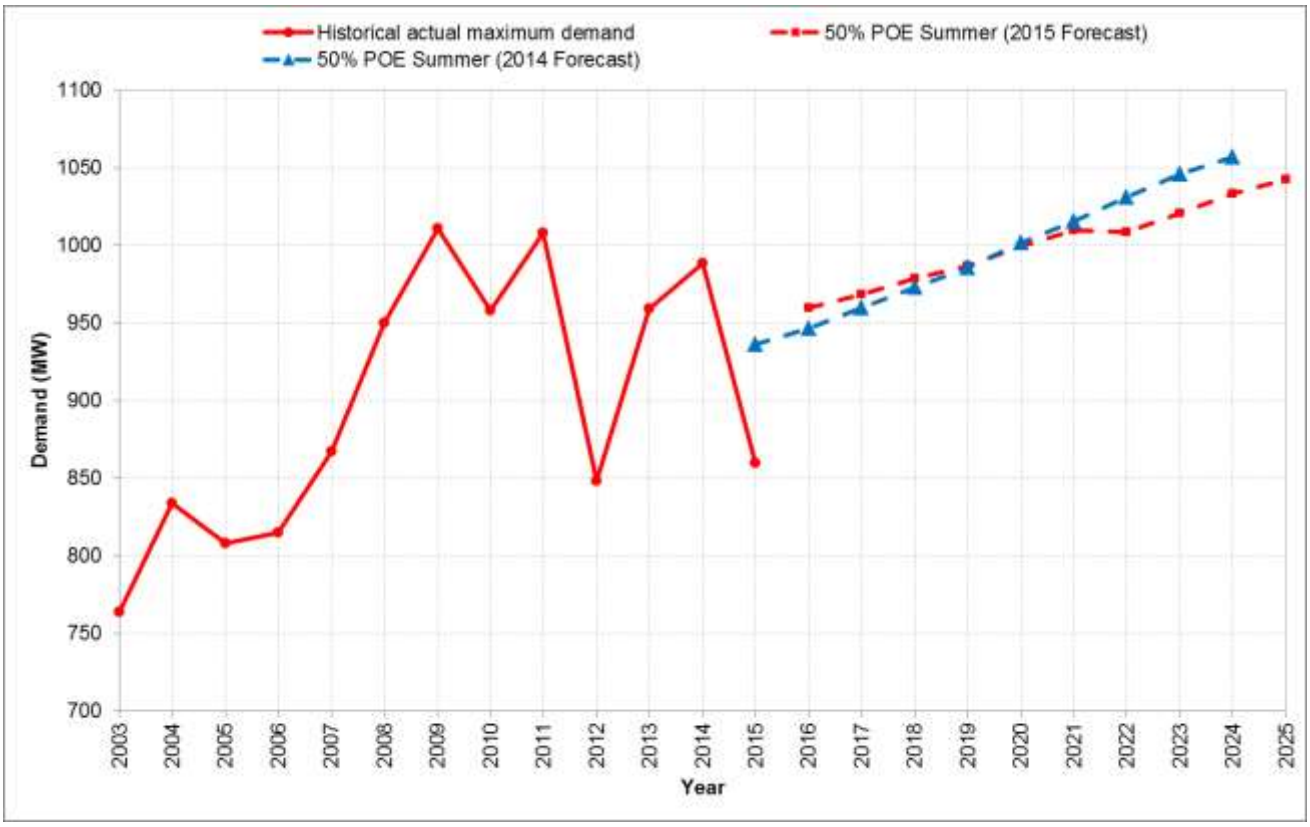
19 AEMO, *National Electricity Forecasting report for the National Electricity Market*, June 2015

20 Consumer Challenge Panel, CCP Sub-panel 3, *Response to proposals from Victorian electricity distribution network service providers*, August 2015, pp 32–37

21 Jemena Electricity Networks, *2016-20 Electricity Distribution Price Review Regulatory proposal, Attachment 3-5 'JEN summary demand report',* 30 April 2015

24. Our submission demand forecast is slightly higher earlier in the forecasting period and lower in later years as compared to our April 2015 proposal. At the 50 per cent probability of exceedance (**PoE**) level the updated projection is for annual growth of 1.02 per cent compared to 1.36 per cent in our April 2015 proposal, over the next regulatory period.

Figure 3–1: Actual and forecast JEN network maximum demand



3.2.2 RATCHETED DEMAND

25. While maximum demand may grow or fall from year to year, forecast ratcheted maximum demand[22] also drives our costs[23] given we need to provide, and have historically provided, capacity to meet all previous maximum demand levels. Inclusion and consideration of ratcheted demand is consistent with Economic Insights' economic benchmarking report.[24]

26. JEN's updated forecast ratcheted demand is shown in Table 3–1.

[22] 'Ratcheted' maximum demand is the higher of the forecast maximum demand for a year and the previous years' forecast (or actual) maximum demand

[23] This includes operating costs as discussed in Attachment 8-1

[24] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp 40–41

Table 3–1: JEN ratcheted demand forecast

	2015 (actual)[25]	2016	2017	2018	2019	2020
Maximum demand[26] (MW)	957.9	980.0	988.9	999.7	1008.0	1021.2

25 The actual value was 875.9MW with the 50 PoE corrected value being 957.9MW

26 This is based on JEN's 50 PoE non-coincident demand forecast

4. RESPONSE TO OBSERVATIONS MADE REGARDING OUR METHOD

4.1 PRELIMINARY DECISION

27. The preliminary decision considered an assessment of JEN's demand forecasting method by Dr Biggar. Dr Biggar outlined that JEN's approach is clear and transparent, but also outlined some concern that the model did not adequately capture solar PV, energy efficiency and the impact of tariff reform.[27] He also noted that the summer of 2014-15 had not been included due to the timing of the modelling.

28. Having considered Dr Biggar's assessment, the preliminary decision accepted JEN's forecast as being realistic expectation of demand.[28]

29. We have had regard to Dr Biggar's concerns and, on balance, we maintain that JEN's method (as updated in this submission) remains likely to reflect a realistic expectation of demand over the 2016 regulatory period, in particular as more up-to-date information is adopted. This is because:

- JEN adopts the same method as AEMO, which the AER considers is likely to result in more realistic forecasts when compared to other models they have assessed[29]—this is even further aligned with JEN now using updated AEMO forecasts for GSP and retail electricity prices
- JEN's forecast growth rate is similar to AEMO's for the 2016 regulatory period (which we have used as a comparison)
- JEN's forecasts for the 50 PoE level are broadly in line with average actual demand experienced over the 2011-15 period. While JEN forecasts growth in demand in some parts of its network, the spatial forecasts include some areas where maximum demand decreases.

30. We agree with the preliminary decision, but for completeness we have addressed concerns raised by Dr Biggar below. ACIL Allen has also addressed these in their updated report.[30]

4.2 SOLAR PV AND ENERGY EFFICIENCY

31. Dr Biggar sets out concerns that solar PV and energy efficiency is not included in the model:[31]

> *As emphasised throughout this report, this approach is appropriate as long as the assumed relationship effectively captures all of the key drivers and has captured them in the correct way. It is not clear that ACIL Allen's model has achieved this. In particular, it appears that ACIL Allen's model treats all of the recent down-turn in demand as due to an increase in electricity prices or a*

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27 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's Demand Forecasting Methodology*, September 2015, pp 18-19

28 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, pp 6-9, 6-37, 6-40, 6-46, 6-47, 6-61, 6-62, 6-101, 6-111, 6-112

29 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure*, October 2015, p 6-112

30 Attachment 7-5, *ACIL Allen Consulting, Electricity Demand Forecasts updated following the AER's preliminary decision*, December 2015, Chapter 3

31 2015 Victorian Electricity Distribution Pricing Review: An Assessment of the VIC DNSP's demand forecasting methodology, Darryl Biggar, 25 September 2015, p 18

> *decrease in GSP. If there is some other change in the market (such as permanent, long-term trends in energy efficiency or investment in solar PV which has had a permanent change on electricity demand) it is not clear that this would be adequately captured in ACIL Allen's model.*

32. JEN agrees that it is important to take into account the impact of incremental solar PV when forecasting maximum demand. In response to Dr Biggar's concern, we note that the ACIL Allen approach that produced our maximum demand forecasts does do this by making:

- A post model adjustment for solar PV at the terminal station level[32]—this adjustment estimates the output of increased solar penetration and subtracts this from the projected latent demand[33]
- An adjustment at the system level for consistency with the terminal station level adjustment—this uses ACIL Allen capacity projections and AEMO derived capacity factors.[34]

33. The approach to estimating the projected uptake of solar PV is transparently set out ACIL Allen's initial report.[35] The solar deducted from JEN's updated maximum demand forecast is shown in Table 2.1 of Attachment 7-4.

4.3 IT IS APPROPRIATE TO NOT MAKE AN EXPLICIT ADJUSTMENT FOR INCREASED ENERGY EFFICIENCY

34. While correct in noting that JEN's estimate of maximum demand is not adjusted for energy efficiency, we have assessed ACIL Allen's explanation[36] and consider this is an appropriate approach. In particular:

- It is not clear that energy efficiency improvements do reduce peak demand
- There is no increased policy emphasis on energy efficiency from the Victorian or Commonwealth Governments and this is already built into base data
- The model already adjusts for price and interrelationship between price and energy efficiency, which means there is a risk of double counting.

4.4 IMPACT OF TARIFF REFORM

35. Dr Biggar sets out:[37]

> *The model also does not account for the potential effects of the change in tariff structure which has been proposed by Jemena. As noted elsewhere in this report, Jemena argue that a primary rationale for the introduction of a demand-based tariff is that such a tariff will reduce peak demand, thereby reducing network costs.*

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32 JEN, *2016-20 Electricity Distribution Price Review Regulatory Proposal, Attachment 3-1 Electricity demand forecasts report, ACIL Allen Consulting*, 30 April 2015, p 43

33 Ibid

34 Ibid, p 46

35 Ibid, Chapter 6

36 Attachment 7-5, *ACIL Allen Consulting, Electricity Demand Forecasts updated following the AER's preliminary decision*, December 2015, p 12-14

37 2015 Victorian Electricity Distribution Pricing Review: An Assessment of the VIC DNSP's demand forecasting methodology, Darryl Biggar, 25 September 2015, p 19

36. JEN's maximum demand forecast has not adjusted for the impact of tariff reform. We consider this is appropriate as:

- The impact of the tariffs on maximum demand levels for the 2016 regulatory period is currently uncertain for the following reasons:[38]
  - The Victorian Government has notified JEN that maximum demand tariffs must be opt in for residential and small business customers for 2017-2020[39]—opt in arrangements, such as time of use, have typically had very low uptake[40]
  - JEN's network tariffs (including metering) are around 37 per cent of an average residential customer's retail bill and this proportion is expected to decrease following the advanced metering infrastructure (**AMI**) price reductions—once fully cost-reflective, the demand element will make up approximately 41 to 44 per cent of an average residential customer's network bill (or around 16 per cent of their retail bill)
  - For most customers, the shift down in network charges will offset any increase due to tariff reform
  - Maximum demand tariffs will be introduced for residential and small business customers in 2018, and therefore cannot be expected to have any impact in 2016 or 2017
  - By design there will be a transition to cost-reflective pricing, so we'd expect less demand response during the 2016 regulatory period than in future regulatory periods[41]
  - Large business customers (and some small business customers) are already subject to maximum demand tariffs
  - It is not yet clear how, or if, retailers will pass these price signals on to residential and small business customers in their product offerings
  - It is not yet clear how customers will react once facing the price signal—lagged response to electricity tariff reform is commonly observed with price signals taking effect over two distinct timeframes; short term[42] and long term[43], with the elasticities of each being different.[44]
- Cost-reflective pricing seeks to encourage efficient usage and investment, and is not necessarily a demand management tool. If customers value consuming energy in the peak, and continue to do so when faced with cost-reflective pricing, then it is efficient for JEN to invest to manage this peak usage.[45]

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38 These uncertainties do not mean that tariff reform is not the right thing to do, as providing cost reflective network tariff signals is important to ensure efficient customer electricity consumption choices (and/or retailers make efficient decisions when developing tariff offerings for their customers').

39 Hon Lily D'Ambrosio MP, Letter to Paul Adams, 21 December 2015

40 The Victorian government has previously estimated that only around 6,000 customers (0.3% of residential customers) chose a flexible price in the first year following its introduction despite an extensive communications campaign.

41 The residential and small business customer tariffs will be introduced in 2018 at 50% of cost reflective levels and move to 70% by 2020. In 2018, this equates to approximately 19% of a typical residential customers' network bill and 7% of their retail bill (assuming it is passed through by retailers). By 2020, this would be approximately 27% of the network bill and 10% of the retail bill.

42 Short term elasticity response—this is usually an immediate response to a price signal, and does not lead to sustained reductions in demand due to customer fatigue. It has negligible—if any—impact on demand.

43 Long term elasticity response—over the longer term—approximately 5 to 7 years—a more sustained elasticity response occurs as customers change over appliances in response to the new price signals. There is little to no economic case for bringing forward these appliance replacements due to price signals.

44 See for example, P.B. Goodwin, A review of demand elasticities with special reference to short and long run effects on price changes, Journal of Transport Economics and Policy, May 1992. Available here: http://www.bath.ac.uk/e-journals/jtep/pdf/Volume_XXV1_No_2_155-169.pdf

45 JEN may trial specific demand management initiatives where we expect quantifiable savings in energy usage and/or peak demand.

- Tariff reform[46] has been underway for a number of years and is part of the current electricity land-scape—meaning it is now incorporated into the baseline data from which new forecasts are derived.
- ACIL Allen has developed a potential method, but acknowledges that this is untested and difficult to calibrate, providing results that would be somewhat speculative.[47]

[46] For example, the introduction of flexible pricing and feed in tariffs

[47] Attachment 7-5, *ACIL Allen Consulting, Electricity Demand Forecasts updated following the AER's preliminary decision*, December 2015, p 14

Attachment A
Demand forecast

Jemena

A1. JEN MAXIMUM DEMAND FORECAST

Table A1–1: Actual and forecast JEN network maximum demand

Demand (MW)	Actual (shaded blue)		Forecast										Average annual growth	
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2015-21	2015-24
	April 2015 proposal													
Summer (50 PoE)	988	936	947	959	973	986	1002	1015	1031	1046	1057	n/a	1.36%	1.35%
Winter (50 PoE)	773	788	800	814	827	843	858	872	886	905	n/a	n/a	1.70%	1.77%
Summer (10 PoE)	988	1019	1033	1046	1063	1077	1096	1112	1125	1146	1161	n/a	1.46%	1.46%
Winter (10 PoE)	791	806	818	832	847	862	877	892	907	925	n/a	n/a	1.69%	1.76%
	Submission case (updated forecast)												2016-21	2016-25
Summer (50 PoE)	988	859	960	968	979	987	1000	1009	1008	1021	1033	1042	1.02%	0.92%
Winter (50 PoE)	729	808	823	838	850	863	877	890	892	908	924	n/a	1.66%	1.50%
Summer (10 PoE)	988	859	1048	1059	1072	1083	1094	1109	1110	1119	1138	1145	1.13%	0.98%
Winter (10 PoE)	729	827	843	857	869	883	896	910	913	927	945	n/a	1.63%	1.49%

(1) All figures are rounded to nearest MW. Unrounded numbers are provided in ACIL Allen's report and model (Attachment 7-4 and 7-5 respectively)

Source: ACIL Allen Consulting, JEN Electricity Demand Forecasts, December 2015