Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Submission on revocation and substitution

Attachment 5-1 Revenue requirement and true-up

Public

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ABBREVIATIONS

AAR	Annual Revenue Requirement
capex	Capital Expenditure
CPI	Consumer Price Index
DMIA	Demand Management Incentive Allowance
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
MAR	Maximal Allowed Revenue
NER	National Electricity Rules
NPV	Net Present Value
opex	Operating Expenditure
Optimal NEO Position	The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity.
PTRM	Post-Tax Revenue Model
RAB	Regulatory Asset Base
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base

OVERVIEW

Key messages

- In developing our proposed revenues and X-factors, our submission complies with all relevant National Electricity Rules (**NER**) requirements, including using a 'building block' approach and the AER's post-tax revenue model. In doing so, we have also taken into account the changes occurring in our energy market and our customers' priorities and preferences.
- Our submission total annual revenue requirement for the 2016 regulatory period is $1,430m.[1] This amount reflects the efficient costs of providing our distribution services and meeting the safety and service levels our customers expect and value, while prudently balancing cost and price pressures in future regulatory periods.
- Our April 2015 proposal 'smoothed' revenue requirement (or MAR) and X-factors that reflected our customers' feedback. However, the preliminary decision will cause volatility in JEN's revenue path.
- Our submission promotes the **Optimal NEO Position**[2] given:
  - The ARR provides sufficient revenue over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers value over this period
  - The MAR and X-factors minimise price volatility inconsistent with our customers' preference to offset the introduction of a new 'demand' charge in 2018
  - Minor modifications are required to the RAB roll-forward method to ensure it appropriately captures the impact of inflation.

1. The April 2015 proposal (together with any supporting material contained or referred to in the April 2015 proposal) is incorporated into, and forms part of, this submission.

2. Table OV–1 summarises our response to the preliminary decision.

Table OV–1: Overview of our submission response to the preliminary decision on revenue requirement

Forecast category	Preliminary decision	Our response to AER PD	Our submission
Annual revenue requirement (**AAR**) ('building block costs')	Lowered AAR over the 2016 regulatory period (relative to our April 2015 proposal) due to lower forecast expenditure, rate of return, and depreciation allowances		Proposes materially higher AAR, due to higher forecast expenditure, rate of return and depreciation allowances
Maximal allowed revenue (**MAR**) ('smoothed' revenue) and X-factors	Lowered due to the lower AAR, while front-loading MAR reductions into 2016 and 2017		Proposes higher MAR (due to the higher AAR) and to target price reductions in 2018 to support new demand tariffs proposed for that year

1 All dollar values are reported in $2015, unless otherwise stated.

2 The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity.

Forecast category	Preliminary decision	Our response to AER PD	Our submission
Regulatory asset base (**RAB**) roll-forward and depreciation	Largely accepted our proposed methods for establishing the opening 2016 RAB and for forecasting depreciation over the 2016 regulatory period, with some changes to historical inflation, expenditure and rate of return adjustment and to the method for depreciation existing assets over that period	≈	Largely adopts the preliminary decision, except for the change to historical inflation
Tax asset base (**TAB**) roll-forward	Accepted our proposed method for estimating the opening 2016 TAB, with some minor refinements to asset lives and classes	✓	Adopts the preliminary decision, with only minor updates to reflect our proposed expenditure and asset disposals

3. The NER require that we propose the 'X-factors' that determine the average change in our network revenue for distribution services in each year of the regulatory period. The X-factors should reflect the average annual changes in our revenue—on top of changes in the Consumer Price Index (**CPI**)—necessary for us to invest in, operate and maintain our network efficiently, and earn a reasonable return on our investment in this network over the period.

4. The NER require us to determine the X-factors by:

- Calculating our AAR for each year of the regulatory period using a building block approach,[3] including our proposed:
  - Returns on and of capital (including opening capital base, forecast capital expenditure (**capex**), rate of return and regulatory depreciation)
  - Operating and tax costs
  - Other revenue adjustments, including any rewards or penalties from the incentive schemes outlined in chapter 5.
- Calculating our MAR or 'smoothed revenues' for each year of the 2016 regulatory period so that the ARR and MAR for the total period are equal in net present value terms[4]
- Calculating the X-factors for each year of the 2016 regulatory period to recover the MAR.

5. In developing our proposed X-factors we complied with all relevant NER requirements, including using the AER's post-tax revenue model (**PTRM**).[5] We also consider the changes occurring in our energy market and their implications for our network and our customers over the 2016 regulatory period and beyond, as well as our customers' priorities and preferences.

6. The following sections of this attachment provide:

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3 NER cl 6.4.3 requires the ARR for each regulatory year to be determined using a building block approach.

4 Subject to minimising the variance between the expected revenue and the annual revenue requirement in 2020.

5 NER cl 6.3.1(c) requires the building block proposal to be prepared in accordance with the AER's PTRM, and must comply with the requirements any relevant regulatory information instrument.

- Our proposed ARR for each year of the 2016 regulatory period using a building block approach (Section 2)
- Our proposed MAR for each year of the 2016 regulatory period—so that the ARR and MAR for the total period are equal in net present value terms (Section 3)
- Our proposed X-factors for each year of the 2016 regulatory period to recover the MAR (Section 4)
- Our proposed approach to true-up revenues and prices for the preliminary decision (Section 5).

7. For sections 2-5 we also outline the difference between this submission, the preliminary decision and our April 2015 proposal.

1. PROPOSED ANNUAL REVENUE REQUIREMENT

1.1 OVERVIEW

8. The ARR represents the amount of revenue we need to generate over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers value over this period.

9. To calculate our proposed ARR, we used a building block approach.[6] This involved calculating and summing the following building block costs: return on capital (or funding costs); return of capital (depreciation); forecast operating expenditure (**opex**); forecast tax costs; and other revenue adjustments (see Box 6–1 in our April 2015 proposal).

10. Table 1–1 set out our proposed ARR and building block costs for distribution over the 2016 regulatory period.

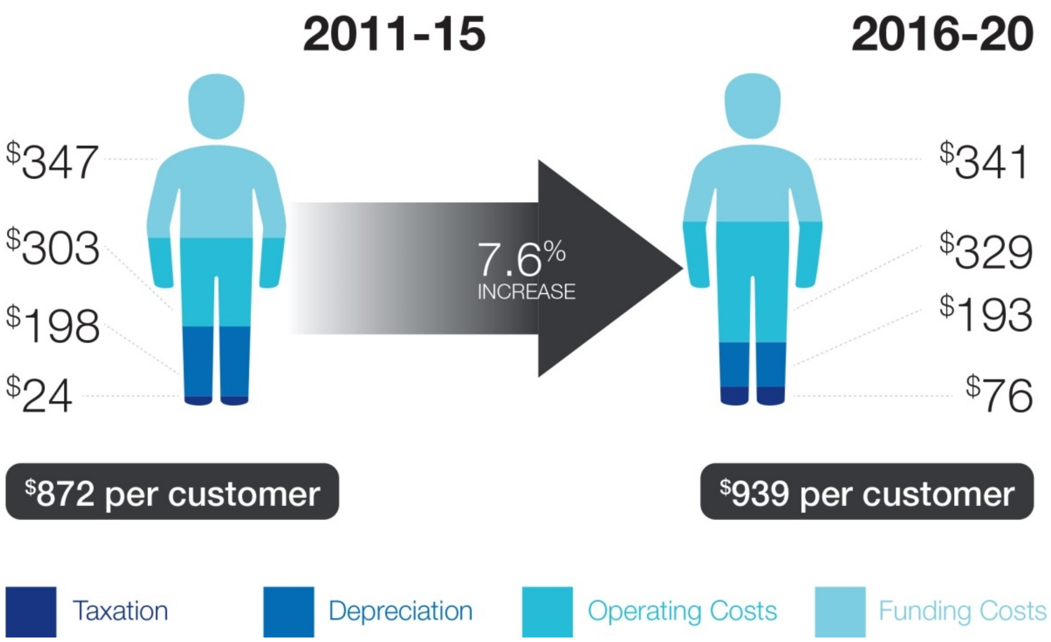
Table 1–1: Proposed ARR for distribution services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
Return on capital (funding costs)	101.06	105.04	111.97	113.38	114.33	**545.78**
Return of capital (depreciation)	57.74	45.17	52.83	52.35	56.43	**264.52**
Forecast opex	93.81	91.83	93.28	95.59	96.38	**470.89**
Tax costs	27.44	22.61	23.50	23.45	23.78	**120.76**
Other revenue adjustments	9.00	0.17	10.72	8.13	(0.13)	**27.89**
Total annual revenue requirement	**289.05**	**264.83**	**292.29**	**292.90**	**290.77**	**1,429.85**

11. Table 1–1 compares the proposed building block costs for the 2016 regulatory period with those approved by the AER for the 2011 regulatory period on a cost per customer basis.

6 Our approach for calculating the ARR complies with NER cl 6.4.3 and the AER's PTRM.

Figure 1–1: ARR for distribution services per customer – proposed for 2016 regulatory period compared with approved for 2011 regulatory period ($2015)[7,8]



12. The following sub-section outlines each of our proposed building block costs in more detail, including the approaches we used to calculate them.

1.2 RETURN ON CAPITAL

1.2.1 JEN'S APRIL 2015 PROPOSAL

13. Our April 2015 proposal included a return on capital allowance of $467.57m. This is the largest of the building block costs.

14. We calculated this allowance using three key inputs: our proposed opening value of the asset base; forecast capex; and proposed rate of return. Each of these inputs is outlined below, and detailed in Attachment 5-4, Attachment 7-1 and Attachment 6-1.[9]

1.2.2 PRELIMINARY DECISION

15. The preliminary decision did not accept our proposed return on capital allowance, and instead adopted a value of $384.92m. This decision rejected our proposed rate of return and forecast RAB.

7 Other revenue adjustments are captured in the operating expenditure category.

8 These per customer costs were derived by dividing the building block costs by actual and forecast customer numbers.

9 We have calculated our proposed return on capital allowance consistent with NER cl 6.5.2 and the AER's PTRM.

1.2.3 JEN'S RESPONSE AND THIS SUBMISSION

16. For our submission, the return on capital makes up around 38.2% of our total distribution services building block costs, or $545.78m. Table 1–2 compares our submission to the April 2015 proposal and the preliminary decision.

17. Our submission remains consistent with our April 2015 proposal. It also incorporates new material that has come about since April 2015, including expert reports included with the preliminary decision and positions considered in the recent Australian Competition Tribunal hearing.

18. In light of this new material, our submission adopts the immediate transition to the trailing average return on debt—which raises our proposed return on capital allowance above that in our April 2015 proposal. Attachment 6-1 explains this transition further (as well as other parts of our rate of return submission).

Table 1–2: Proposed return on capital allowance for distribution services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
April 2015 proposal	83.44	88.03	93.70	98.72	103.69	**467.57**
Preliminary decision	69.67	72.72	77.10	80.82	84.60	**384.92**
January 2016 submission	101.06	105.04	111.97	113.38	114.33	**545.78**

1.2.4 PROPOSED OPENING VALUE OF THE ASSET BASE

1.2.4.1 JEN's April 2015 proposal

19. Our proposal included an opening RAB of $1,190.84m. This is the value of assets we use in providing regulated distribution services, and represents the (as yet) unrecovered past capital investments we have made to provide services to our customers.[10] The value of the RAB changes over time. As we invest in new assets, this expenditure is added to the RAB. As our assets depreciate, this value is subtracted from the RAB. And as customers make capital contributions or we dispose of assets, these proceeds are subtracted from the RAB.

20. To calculate the opening value of the RAB for the 2016 regulatory period, we used an approach consistent with the NER[11] and the AER's RAB roll-forward models.[12] This involved taking the opening RAB for the 2011 regulatory period, and adjusting this value to take account of our actual and expected capex over that period, as well as the depreciation of our assets over that period and several other factors (see Box 6–2 in our April 2015 proposal).

1.2.4.2 Preliminary decision

21. This preliminary decision adopted an opening RAB of $1,187.01m. This decision largely accepted our April 2015 proposal except for some minor changes, including to how historical inflation is used to roll-forward the RAB to the end of 2015.

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10 NER cl 6.5.1(a) states that the regulatory asset base "is the value of those assets that are used by the Distribution Network Service Provider to provide standard control services, but only to the extent that they are used to provide such services."

11 NER cl 6.5.1 and NER cl S6.2.

12 On 26 June 2008, in accordance with cl 6.5.1 of the NER, the AER published a Roll forward model, an associated handbook and final decision document (https://www.aer.gov.au/node/6908).

1.2.4.3 JEN's response and this submission

22. Our submission proposes an opening RAB of $1,198.55m, largely adopting the preliminary decision except for the change to historical inflation. This value is $7.69m and $11.54m higher than our April 2015 proposal and the preliminary decision respectively.

23. More detail on our approach and our populated AER models are provided as Appendix 2-3 and Appendix 2-4

Table 1–3: Proposed opening value of RAB for distribution services ($2015, $millions)

Opening value of RAB for distribution services	As at 1 Jan 2016
April 2015 proposal	1,190.84
Preliminary decision	1,187.01
January 2016 submission	1,198.55

1.2.5 FORECAST CAPEX

1.2.5.1 JEN's April 2015 proposal

24. Our proposal included $841.17m in capex for distribution services over the 2016 regulatory period.

1.2.5.2 Preliminary decision

25. The preliminary decision accepted most of our proposed capex, except for some augmentation capex and other minor capex. This decision adopted capex of $773.55m over the 2016 regulatory period.

1.2.5.3 JEN's response and this submission

26. Our submission proposes capex of $862.53m over the 2016 regulatory period. This forecast is compared to those from the April 2015 submission and the preliminary decision in Table 1–4.

27. Although consistent with our April 2015 proposal, this submission is $21.36m higher principally due to new forecast expenditure needed to respond to recent rule changes made by the Australian Energy Market Commissions on power of choice. More information on this expenditure—including how the proposed capital program represents the efficient level of expenditure required to provide the distribution services that our customers value—is provided in Attachment 7-1.

Table 1–4: Proposed capex for distribution ($2015, $millions)

Gross capex	2016	2017	2018	2019	2020	Total
April 2015 proposal	158.24	183.64	177.13	167.60	154.56	**841.17**
Preliminary decision	150.23	161.81	154.69	158.68	148.13	**773.55**
January 2016 submission	167.75	203.84	169.32	168.49	153.12	**862.53**

(1) Gross capex and excludes equity raising costs. Equity raising costs are discussed in Attachment 6-1.

1.2.6 PROPOSED RATE OF RETURN

1.2.6.1 JEN's April 2015 proposal

28. Our proposal included a rate of return on 7.18%, which we calculated using an approach consistent with the requirements in the NER.[13] We have expressed the rate of return as a 'nominal vanilla WACC' consistent with the NER and the AER's rate of return guideline;[14] however, we have departed from the guideline in several areas (see Attachment 6–1).

1.2.6.2 Preliminary decision

29. The preliminary decision rejected our proposal, and instead adopted a rate of return of 6.02%—which was calculated using the methods set out in the guideline. This decision raised concerns with most aspects of our proposal, including how we proposed to transition to the trailing average return on debt.

1.2.6.3 JEN's response and this submission

30. Our submission proposes a rate of return of 8.62% for the 2016 regulatory period, as shown in Table 1–5.

31. Since our April 2015 proposal, we have revised our approach to estimating the rate of return to reflect new expert evidence and detailed consideration of rate of return issues before the Australian Competition Tribunal. Most notably in how to transition to the trailing average return on debt. We now propose an immediate transition. We have also looked at an alternative method for estimating the return on equity that seeks to apply the AER's foundation model approach in a way that satisfies the NER requirements, consistent with our April 2015 proposal.

32. Attachment 6–1 provides more detail on our submission, including how it ensures we can attract the funds needed to provide the distribution services our customers value, and how our approach and assumptions for calculating it differ from the AER's guidelines. Attachments 6–2 to 6–14 provide additional detail and expert analysis.

Table 1–5: Proposed rate of return ('nominal vanilla WACC') (%)

Parameters	JEN proposal
April 2015 proposal	7.18%
Preliminary decision	6.02%
January 2016 submission	8.62%

(1) Return on debt, return on equity, and nominal WACC are estimated using data from different sample averaging periods. For the April 2015 proposal this was the 20 business days to 30 January 2015 (inclusive). For the preliminary decision, the return on debt was estimated using the 4 – 28 August 2015 period, while for the return on equity the 4 – 31 August 2015 period was used. For the January 2016 submission the 20 business days to 30 September 2015 (inclusive) was used for both the returns on debt and equity as a placeholder averaging period. We propose updating both estimates to reflect the periods set out in Attachment 6-3.

(2) Our gamma proposal is outlined in section 1.5, and supported by Attachments 6–1.

[13] NER cl 6.5.2 (b) – (q).

[14] AER, *Better regulation, Rate of return guideline*, December 2013.

1.3 RETURN OF CAPITAL (DEPRECIATION)

1.3.1 JEN'S APRIL 2015 PROPOSAL

33. Our proposal included a return of capital allowance for distribution services of $225.70m over the 2016 regulatory period. We calculated this allowance using an approach consistent with the NER[15] and the AER's PTRM (see Box 6–3 of our April 2015 proposal).

1.3.2 PRELIMINARY DECISION

34. The preliminary decision generally accepted our proposal, and included an allowance of $220.74m over the 2016 regulatory period. The $4.96m reduction was due to lower forecast capex, a lower opening RAB, and other minor changes.

1.3.3 JEN'S RESPONSE AND THIS SUBMISSION

35. Our submission includes an allowance of $264.52m (as shown in Table 1–1), which represents around 18.5% of our total distribution service building block costs. This is $39.82m higher than the April 2015 proposal, principally due to adopting lower forecast inflation and including new expenditure on power of choice (which has a short asset life).

36. The model we used to calculate this is provided as Attachment 5-2, including our nominated depreciation schedule, and is explained in Attachment 5-4. Forecast inflation is explained in Attachment 6-1.

Table 1–6: Proposed return of capital allowance for distribution services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
April 2015 proposal	43.07	49.63	48.40	39.24	45.36	**225.70**
Preliminary decision	51.73	39.32	39.90	43.01	46.77	**220.74**
January 2016 submission	57.74	45.17	52.83	52.35	56.43	**264.52**

1.4 FORECAST OPEX

1.4.1 JEN'S APRIL 2015 PROPOSAL

37. This included forecast opex for distribution services of $499.01m for the 2016 regulatory period. This was calculated using a base, step and trend method.

1.4.2 PRELIMINARY DECISION

38. The preliminary decision rejected some of our April 2015 proposal, only accepting $390.07m over the 2016 regulatory period. This decision did accept our proposed rate of change or step changes, nor our proposal to classify some expenditure (that was previously regulated under the advanced metering infrastructure cost recovery order in council) as relating to distribution services.

15 NER cl 6.5.5.

1.4.3 JEN'S RESPONSE AND THIS SUBMISSION

39. Our submission is largely consistent with our April 2015 proposal, and includes $470.89m of opex over the 2016 regulatory period. This represents 32.9% of our total distribution services building block costs, and is shown in Table 1–1).

40. Our submission is $80.82m higher than in the preliminary decision due to a higher rate of change, higher step changes and a reclassification of some expenditure as distribution rather than metering services. Appendix 8-1 provides more details of our submission, including how our proposed expenditure represents the efficient level of expenditure required to operate and maintain our network.

Table 1–7: Proposed forecast opex for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	95.37	95.36	98.51	103.18	106.60	**499.01**
Preliminary decision	76.42	76.70	77.68	79.00	80.26	**390.07**
January 2016 submission	93.81	91.83	93.28	95.59	96.38	**470.89**

(1) Opex includes debt raising costs, which is further discussed in Attachment 6-1. This may differ to how opex is reported in other parts of our submission, where debt raising costs are often excluded.

1.5 TAX COSTS

1.5.1 JEN'S APRIL 2015 PROPOSAL

41. Our proposal included a tax cost allowance for distribution services over the 2016 regulatory period of $90.23m. We calculated this allowance using an approach consistent with the NER[16] and the AER's PTRM (see Box 6–4 of our April 2015 proposal). Tax costs are calculated by first forecasting taxable income, and then forecasting how much tax would be paid on this (less a deduction for the value of imputation credits).

1.5.2 PRELIMINARY DECISION

42. The preliminary decision largely accepted our approach to calculating tax costs, but rejected some inputs to it (including for the value of imputation credits). This decision adopted a tax cost allowance of $58.56m over the 2016 regulatory period.

1.5.3 JEN'S RESPONSE AND THIS SUBMISSION

43. Our submission includes a tax cost allowance of $120.76m (shown in Table 1–1 and Figure 1–1), which represents 8.4% of our total distribution services building block costs.

44. Our approach to calculating tax costs and the opening TAB is consistent with that in our April 2015 proposal and the preliminary decision. The tax costs only differ due to changes in other inputs, such as the allowed rate of return and forecast capex. Our calculation of tax costs is provided in Attachment 5-2, and relies on the inputs used for all other building blocks as well as the opening TAB (which is further explained in Attachment 5-4 and modelled in Attachment 5-3).

16 NER cl 6.5.3.

Table 1–8: Proposed tax cost allowance for distribution services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
April 2015 proposal	18.63	18.10	20.23	16.26	17.01	**90.23**
Preliminary decision	14.42	10.62	11.16	11.17	11.19	**58.56**
January 2016 submission	27.44	22.61	23.50	23.45	23.78	**120.76**

1.6 OTHER REVENUE ADJUSTMENTS

1.6.1 JEN'S APRIL 2015 PROPOSAL

45. Our proposal included an allowance to cover all relevant revenue adjustments (of $25.19m over the 2016 regulatory period). These revenue adjustments relate to:

- **The efficiency benefit sharing scheme (EBSS)**—rewards and penalties under these schemes are added to or subtracted from the ARR as a separate building block in the 2016 regulatory period. The model we used for the EBSS calculation (see Attachment 8–3). The adjustment for the EBSS reflects the benefit we expect to receive under this scheme.
- **The close out of the 2010 s-factor performance scheme**—the 2011 electricity distribution price review (**EDPR**) determination elected to close out the s-factor scheme in the 2016 regulatory period (see Attachment 3-1). To this end, a revenue adjustment is included which also accounts for the close out of the scheme and the time value of money (see Attachment 5–5).
- **Shared asset revenue**—the adjustment for shared asset revenue reflects the benefits we and our customers receive from distribution assets being shared in providing both regulated and unregulated services in the 2016 regulatory period. We calculated this revenue in line with the AER's shared asset guidelines[17] and PTRM.

1.6.2 PRELIMINARY DECISION

46. The preliminary decision largely accepted our proposal:

- EBSS was accepted, subject to some slight changes to account for provisions and regulatory reporting costs over the 2011 regulatory period
- The close out of the 2010 s-factor performance scheme was accepted without change
- Shared asset revenue was also accepted without change.

47. This decision gave an allowance for other revenue adjustments of $28.05m over the 2016 regulatory period, which included a $1m demand management incentive allowance (**DMIA**).

1.6.3 JEN'S RESPONSE AND THIS SUBMISSION

48. Our submission adopts the preliminary decision and includes an allowance of $27.89m, with the only reduction in the EBSS adjustment. This allowance accounts for 2.0% of our total distribution services building block costs.

17 AER, *Better Regulation, Shared asset guideline*, November 2013.

We also propose to increase the DMIA to $5.56m (from $1m) as set out in Attachment 3-1, but have not included this in our PTRM (Attachment 5-2).

49. Table 1–9 sets out our proposed other revenue adjustments for distribution services, compared to those in our April 2015 proposal and the preliminary decision. Other adjustments, such as trueing up revenue from year-to-year under a revenue cap mechanism or service target performance incentive scheme (**STPIS**) benefits or penalties are managed through the price control formulae rather than an adjustment to the building block model.

Table 1–9: Proposed other revenue adjustments for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
EBSS	5.29	(0.01)	10.52	7.24	-	**23.05**
Close out of 2010 s-factor scheme	3.81	-	-	-	-	**3.81**
Shared asset revenue	(0.34)	(0.34)	(0.34)	(0.33)	(0.33)	**(1.68)**
DMIA	-	-	-	-	-	**-**
Total revenue	**8.76**	**(0.34)**	**10.19**	**6.91**	**(0.33)**	**25.19**
Preliminary decision						
EBSS	5.02	(0.14)	11.27	8.76	-	**24.92**
Close out of 2010 s-factor scheme	3.81	-	-	-	-	**3.81**
Shared asset revenue	(0.34)	(0.34)	(0.34)	(0.33)	(0.33)	**(1.68)**
DMIA	0.20	0.20	0.20	0.20	0.20	**1.00**
Total revenue	**8.70**	**(0.28)**	**11.14**	**8.63**	**(0.13)**	**28.05**
January 2016 submission						
EBSS	5.33	0.31	10.85	8.27	-	**24.76**
Close out of 2010 s-factor scheme	3.81	-	-	-	-	**3.81**
Shared asset revenue	(0.34)	(0.34)	(0.34)	(0.33)	(0.33)	**(1.68)**
DMIA[1]	0.20	0.20	0.20	0.20	0.20	**1.00**
Total revenue	**9.00**	**0.17**	**10.72**	**8.13**	**(0.13)**	**27.89**

(1) We propose a DMIA of $5.56m over the 2016 regulatory period as outlined in Attachment 3-1, or $1.09m, $1.23m, $1.31m, $0.96m, and $0.67m over each of the 2016 to 2020 years.

2. PROPOSED MAXIMUM ALLOWED REVENUES

2.1 JEN'S APRIL 2015 PROPOSAL

50. We 'smoothed' our proposed ARR to derive MAR for each year of the 2016 regulatory period using an approach consistent with NER requirements and the AER's PTRM. We ensured the MAR is equal to the ARR in net present value (**NPV**) terms, subject to minimising the variance between the expected revenue and the ARR in 2020.[18]

51. This gave total MAR for our distribution services of $1,306.12m over the period, or $1,144.38m in NPV terms. Our proposed MAR reflected:

- Our customers' preference for us to pass on our cost savings over the 2016 regulatory period in a way that introduces our proposed changes to our network tariff structure as soon as practical, but also minimises the impact of these changes on specific groups of customers (as a result of a decrease in the MAR in 2018)[19] and provides an opportunity for customers to change their behaviour to minimise their bills (see Attachment 1-4)
- Our intention to minimise the potential for price shocks between the 2016 regulatory period and the subsequent regulatory period[20]
- The modest increases in forecast energy consumption over the period.

2.2 PRELIMINARY DECISION

52. The preliminary decision rejected our proposed MAR, by rejecting both our proposed ARR (as discussed earlier) and our proposal to smooth this ARR to target price reductions in 2018 (to support the introduction of new demand tariffs). This decision included total MAR of $1,080.03m, or $978.49m in NPV terms. It also front-loaded all MAR reductions into 2016 and 2017.

2.3 JEN'S RESPONSE AND THIS SUBMISSION

53. Our submission includes total MAR of $1,437.36m, or $1,199.23m in NPV terms—and is compared to that in our April 2015 proposal and the preliminary decision in Table 2–1.

54. Although the smoothing built into this is consistent with our April 2015 proposal (with price reductions in 2018), the MAR is $131.11m higher in total due to a higher rate of return and higher forecast capex on short lived assets (i.e. to support the power of choice reforms). Importantly, to support price reductions in 2018 our proposed MAR steps up materially in 2017. This is, in part, to offset the 2016 MAR reductions included in preliminary decision—and the customer impact of this will be partially offset by further proposed reductions in our metering charges in 2017.

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18 NER, cl 6.5.9.

19 A decrease in the MAR in 2018 for our distribution services will allow us to decrease the fixed and consumption charges to offset the introduction of a new maximum demand charge for residential and small business customers.

20 For example, if we smoothed the revenue over the 2016 regulatory period in a way that the ARR or smoothed revenue in 2020 was significantly less than the building block costs or unsmoothed revenue in 2020, then prices may need to increase in the following regulatory period to meet the required revenues.

Table 2–1: Proposed MAR for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal							
ARR (building block costs)	249.27	250.77	271.02	264.31	272.32	**1,307.70**	**1,144.38**
MAR (‘smoothed’ revenue)	256.94	259.68	258.84	263.14	267.51	**1,306.12**	**1,144.38**
Preliminary decision							
ARR (building block costs)	220.94	199.08	216.99	222.62	222.70	**1,082.34**	**978.49**
MAR (‘smoothed’ revenue)	232.68	212.95	210.11	211.46	212.82	**1,080.03**	**978.49**
January 2016 submission							
ARR (building block costs)	289.05	264.83	292.29	292.90	290.77	**1,429.85**	**1,199.23**
MAR (‘smoothed’ revenue)	233.39	296.43	296.50	302.49	308.55	**1,437.36**	**1,199.23**

(1) The NPV is calculated by discounting the ARR and MAR cash flows, using the nominal vanilla WACC.

3. PROPOSED X-FACTORS FOR REVENUE

3.1 JEN'S APRIL 2015 PROPOSAL

55. Our distribution services will be regulated through a revenue cap in the 2016 regulatory period, with the form of control being CPI-X. The X-factors for the 2016 regulatory period need to reflect the reduction in our revenue (on top of CPI inflation) necessary to allows us to recover our MAR in each year of the period.

56. As noted above, we have ensured that the MAR is equal to the ARR in net present value terms, and hence the X-factors are designed to achieve revenue equalisation, as required under the NER.[21] Here, a negative X-factor means an increase in revenue before inflation is considered.

57. As noted in section (1), our April 2015 proposal targeted price reductions in 2018 to support new demand tariffs proposed to start from that year. It did this by adopting a revenue path (or X-factors) that support these reductions once forecast demand is factored in.

3.2 PRELIMINARY DECISION

58. The preliminary decision rejected this proposal, and instead front-loaded reductions in 2016 and 2017.

3.3 JEN'S RESPONSE AND THIS SUBMISSION

59. Our submission continues to target price reductions in 2018, consistent with our April 2015 proposal and our customers' stated preferences. Our proposed X-factors for MAR are shown in Table 3–1. We calculated these X-factors consistent with the NER[22] and the AER's PTRM (our model is provided as Attachment 5–2).

Table 3–1: Proposed X-factors for distribution services MAR (%)

Building block cost	2016	2017	2018	2019	2020
April 2015 proposal	(0.29%)	(1.06%)	0.32%	(1.66%)	(1.66%)
Preliminary decision	9.18%	8.48%	1.34%	(0.64%)	(0.64%)
January 2016 submission[1]	9.18%	(27.01%)	(0.02%)	(2.02%)	(2.00%)

(1) This proposed revenue path supports price reductions in 2018 based on our demand forecasts. Specifically, the resulting price path includes real price changes of (9.17%), 30.70%, (1.90%) over 2016 to 2018 and no changes for 2019 and 2020. The 2017 price increase is needed to support the 2018 price reduction, which is, in part, needed to reverse the 2016 price reduction built into the preliminary decision.

60. Note that the proposed X-factors for the MAR do not necessarily determine the actual movements in our individual network tariffs or the actual customer bill outcomes. This is because:

- **Revenue and price paths differ**—the X-factors are those under a revenue cap and therefore relate to the annual change in revenues. Prices necessary to recover the allowed revenues will depend on the demand forecast in each year

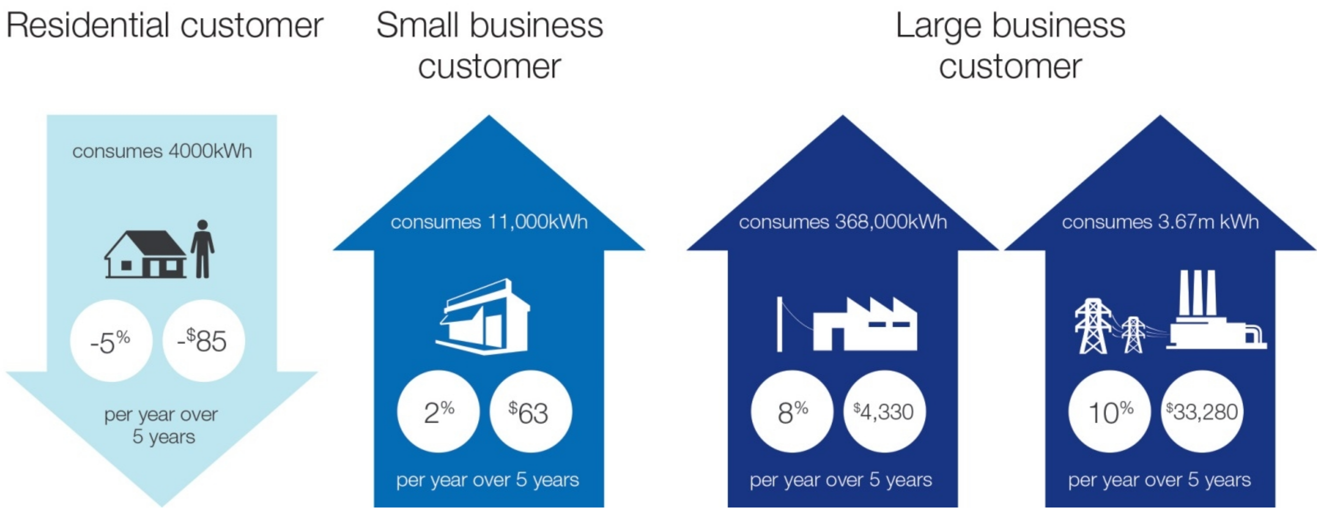
21 NER, cl 6.5.9.

22 NER, cl 6.5.9.

- **X-factors update annually**—under the form of control determined by the AER in its framework and approach paper, the X-factors will be updated annually to account for unforeseen changes in energy consumption[23] and annual movements in the return on debt.[24]

61. Actual movements in customers' bills will also depend on their specific circumstances, including which of our network tariffs they are on, and the amount of electricity they consume (including how they respond to our proposed changes in tariff structures). Figure 3–1 shows the change in average bills, by customer type, from 2015 to 2020 as a result of our submission—which highlights an average reduction for our residential customers.

Figure 3–1: Indicative customer impacts of our January 2016 submission (excluding inflation)



(1) Average bills include distribution, metering, wholesale and retail costs. Our analysis assumes that the wholesale and retail cost components remain constant in real terms, while the distribution and metering components vary as per our submission.

62. Also note that the proposed X-factor for distribution services in 2018 indicates a flattening in our revenue that is intended to coincide and assist with the transition to the proposed changes to our tariff structures for residential and small business customers (see Attachment 1-4). We have proposed this reduction, consistent with the NER and customer feedback, to mitigate the impact of transitioning to more cost-reflective tariff structures.[25]

63. The price control mechanism for updating the X-factors is provided as Attachment 2-2. Our proposed network tariffs—including the proposed changes in tariff structures and potential customer bill outcomes—are outlined in our tariff structures statement.

[23] The proposed X-factors have been determined based on our independent expert forecasts of demand for our distribution and metering services for each year of the 2016 regulatory period. Under a revenue cap the X-factors will be adjusted annually if actual energy consumption is over or under our forecast, to ensure we recover the approved ARR over the 2016 regulatory period.

[24] The AER developed a rate of return guideline in 2013 (AER, *Better regulation, Rate of return guideline*, December 2013). This guideline allows the return on capital component of the building blocks to be updated annually to account for annual movements in the cost of debt (see section **Error! Reference source not found.** for detail on the cost of debt). This was developed following changes to the NER in 2012 (see section **Error! Reference source not found.**). As a result of these annual updates to the return on capital component of the building blocks, the X-factors will be updated annually. (AER, *Proposed amendments to the electricity transmission and distribution network service providers' post-tax revenue models—Explanatory statement*, October 2014, p14.).

[25] A positive X factor for our distribution services in 2018 will allow us to decrease the fixed and consumption charges to offset the introduction of a new maximum demand charge for residential and small business customers.

4. TRUE-UP FOR PRELIMINARY DECISION

64. We expect the AER's final determination by the end of April 2016. As this falls within 2016, any change to allowances from those in the preliminary decision for that year will not be reflected in distribution service tariffs for that year; instead they need to be reflected in tariffs for 2017–20.

65. To true-up for any change in ARR (between the preliminary decision and final determination), we propose:

- Updating the ARR for the 2016 regulatory period to reflect the final determination
- Setting MAR for 2016 equal to that in the preliminary decision
- Determining the MAR over 2017–20 so that the NPV of MAR and AAR over the 2016 regulatory period are the same (as described in section (1)).

66. This is consistent with clause 11.60.4(d) of the NER—which governs such a true-up—and the approach adopted in the October 2015 South Australian and Queensland final electricity determinations.[26]

67. We also considered the impact that the preliminary determination will have on actual expenditure for 2016 and subsequent years given the timing of the final determination, and reflected this in our opex and capex forecasts where relevant (see Attachment 7-1 and Attachment 8-1). These forecasts will then feed into the relevant incentive mechanisms that apply to expenditure over the 2016 regulatory period.

68. We do not consider any other true-up is required for distribution services.

26 For instance, see AER, *Final decision: SA Power Networks determination 2015-16 to 2019-20*, October 2015.