Jemena Electricity Networks (Vic) Ltd

2021 -26 Electricity Distribution Price Review Regulatory Proposal

Attachment 07-01

Annual revenue requirement

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Glossary

Current regulatory period	The regulatory control period covering 1 January 2016 to 31 December 2020
Draft Plan	On 31 January 2019, we released our Draft Plan which outlined the feedback we received from our customers, our proposed expenditure and how plans met our customer expectations
Intervening period	The six months between the end of the current regulatory period and beginning of the next regulatory period covering 1 Jan 2021 to 30 Jun 2021
Next regulatory period	The regulatory control period covering 1 July 2021 to 30 June 2026
RoR Instrument	AER's 2018 Rate of Return Instrument

Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CAM	Cost Allocation Methodology
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
ECA	Energy Consumers Australia
EBSS	Efficiency Carryover Mechanism
EDPR	Electricity Distribution Price Review
F&A	Framework and Approach
FY	Financial Year
JEN	Jemena Electricity Networks
NER	National Electricity Rules
NPV	Net Present Value
PIAC	Public Interest Advisory Centre
PTRM	Post-Tax Revenue Model
RAB	Regulatory Asset Base
SCS	Standard Control Service
TAB	Tax Asset Base
WACC	Weighted Average Cost of Capital

Overview

This chapter of our Regulatory Proposal sets out the revenue that we require over the period 1 July 2021 to 30 June 2026 regulatory control period (**next regulatory period**) to provide Standard Control Services (**SCS**). Specifically, the next regulatory period will commence on 1 July 2021 for a duration of five years.[1]

Through our building block model, we have identified the need to recover $1,286M ($2021) in revenue over this period which will allow us to meet the levels of safety and services valued by our customers while prudently balancing our cost and prices over the long term. To determine the revenue we need, we have followed the requirements set out in the National Electricity Rules (**NER**).[2]

Below, we outline how we engaged with our customers on this important topic of revenue requirement and how we have forecast the Annual Revenue Requirement:

- Section 1 outlines the overall approach used to calculate our required revenues
- Sections 2 to 6 describe key inputs to the building block revenue calculation, namely:
  - return on capital (Section 2)
  - regulatory depreciation (Section 3)
  - operating expenditure (Section 4)
  - corporate income tax (Section 5)
  - revenue adjustments (Section 6)
- Section 7 concludes by explaining how the unsmoothed building block revenue has been used to determine a smoothed Annual Revenue Requirement and revenue path for tariffs over the next regulatory period.

All values are in the end of year (June) $2021 terms unless otherwise stated.

Our engagement with our customers

Throughout our customer engagement program, we heard that affordability is a key issue across all of our customer groups. More specifically, our customers told us they want our network to be operated as efficiently as possible and to pass on savings through lower network prices.[3] Our SCS revenue requirement delivers on what we heard from our customers about energy affordability by offering a price reduction over the next regulatory period.

Our customers also said they valued price certainty, asking us to keep prices stable from year to year.[4] We have smoothed our required revenue to promote price stability over the next regulatory period. We elaborate on this step in section 7.1 of this attachment.

At the same time, our customers have told us that they value—and expect us to maintain—the safety, security and reliability of our services, and the customer service that they receive. Improved affordability, therefore, cannot come at the cost of service performance—the right balance is needed.

1 NER, S6.1.3(13). Refer to *JEN regulatory proposal for the intervening period* for details regarding the setting of revenues for the six month transition period (arising between 1 January 2021 to 30 June 2021) to give effect to the transition of regulatory year from calendar year to financial year.

2 NER cl 6.3.1(c).

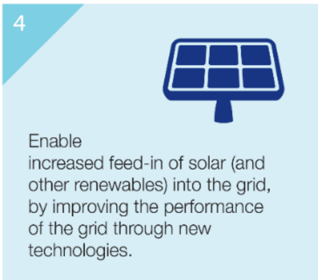
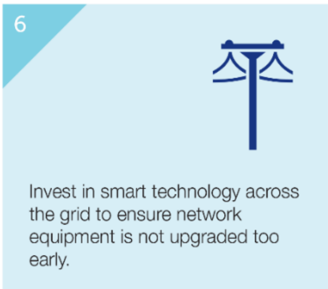
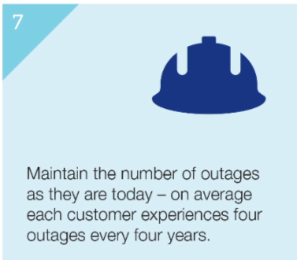
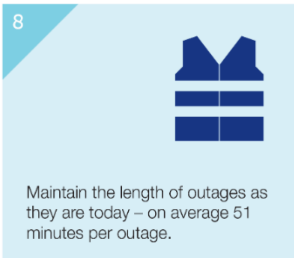
3 Attachment 02-02 *Peoples Panel Engagement Report*, s1.6.1.

4 Attachment 02-04 *Reconvening the Jemena people's panel*, s 3.1.

Feedback from our People's Panel

Our Peoples Panel gave us specific feedback on the activities they thought we should focus on in the next regulatory period. We outline these in Table OV–1 below and explain how these recommendations have been captured in our annual revenue required.

Table OV–1: People's Panel recommendations that are addressed in our annual revenue requirement

Recommendation	Relationship to annual revenue requirement
	A key feature of our Regulatory Proposal is our Future Grid program.[5] In it we outline the activities we plan to undertake which encompass a range of network and non-network capital expenditures as well as operating expenditure. Our program includes several "Enabling DER" activities, which will build a foundation for the network to support increased two-way flows and energy trading by customers in future by enabling greater feed-in of solar and other renewables. We include these amounts in our building block proposal to recover the efficient costs of greater DER enablement through the revenues we collect.
	A key feature of our Regulatory Proposal is our Future Grid program.[6] In it we outline the activities we plan to undertake which encompass a range of network and non-network capital expenditures as well as operating expenditure. Our program includes several "Optimised Asset Investment" activities, through which we propose to use real-time condition monitoring of network assets and other activities to improve network utilisation further. This will help us optimise future network investment decisions and put downward pressure on network prices in the future. We include these amounts in our building block proposal to recover the efficient costs of greater DER enablement through the revenues we collect.
 	Through our efficient and prudent investment strategies, we have developed optimised capital and operating expenditure forecasts which will allow us to ensure our network's future reliability is consistent with the performance expected by our customers. Our capital and operating expenditures are reflected within the building block models to ensure revenue sufficiency.

More detail on our customer engagement program and the feedback we have received from our customers is further described in Attachments 02-01 to 02-06. The rest of this attachment explains how our annual revenue requirement supports our customers' preferred outcomes.

Taking on board all of our customers' feedback, we developed a draft plan (**Draft Plan**) and released it in January 2019 for consultation. Additionally, in March 2019, we held a deep dive session, several stakeholders and the

5 See Attachment 05-04 *Future Grid investment proposal*.

6 See Attachment 05-04 *Future Grid investment proposal*.

AER, who expressed an interest in the Draft Plan. We received specific feedback in response to our Draft Plan. We list this at Appendix A with our responses to this feedback.

Our forecast SCS revenue requirement

Table OV–2 details our unsmoothed building block and smoothed SCS revenue and X-factors for the next regulatory period. We have prepared this forecast using the Australian Energy Regulator's (**AER**) Post-Tax Revenue Model (**PTRM**).[7]

Table OV–2: SCS Building block and smoothed revenue ($ June 2021, millions)

Building blocks[8]	FY22	FY23	FY24	FY25	FY26	Total
Return on capital	72.8	74.4	75.6	75.2	73.9	**371.9**
Depreciation	45.9	50.6	52.1	54.8	55.9	**259.4**
Operating expenditure	110.5	112.8	115.7	117.7	119.8	**576.6**
Revenue adjustment (including incentives)	13.3	11.8	10.1	7.3	7.3	**49.8**
Tax	6.9	5.3	4.3	6.0	5.9	**28.5**
Total revenue requirement – unsmoothed[9]	**249.4**	**254.9**	**257.9**	**261.1**	**262.9**	**1,286.2**
Revenue path[10]	7.79%	0.00%	0.00%	0.00%	0.00%	
Total revenue requirement – smoothed	**257.1**	**257.1**	**257.1**	**257.1**	**257.1**	**1,285.5**

To demonstrate that we have delivered to our customers' expectations regarding affordability, Figure OV– provides a view of our smoothed Annual Revenue Requirement over the three regulatory control periods from 2010 to 2026. As can be observed, the revenue required per customer (right-hand side axis) has been falling in real terms since 2015.

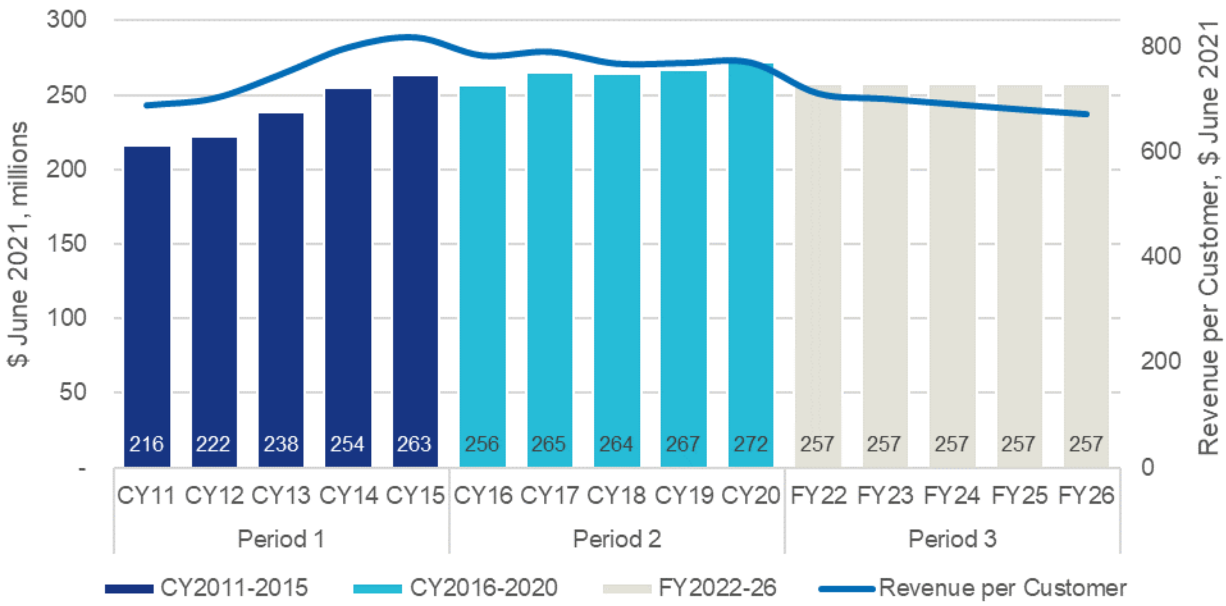
7 Refer to Attachment 07-15 *SCS PTRM FY22-26*.

8 Consistent with the requirements of NER cl 6.4.3.

9 Building block revenue requirement.

10 A positive number corresponds to a price decrease and vice versa. The year 1 price change represents a movement from CY20 to FY22.

Figure OV–1: Our smoothed revenues ($ June 2021, millions)



Changes since releasing our Draft Plan

As outlined in Attachment 02-01 *Overview of our customer and stakeholder engagement program*, feedback from our customers on our Draft Plan largely supported our proposals for the next regulatory period, this is because we captured our customer preferences ahead of developing the Draft Plan. We have, however, continued to refine our plans since our Draft Plan was published meaning that we have made some changes, but these are mostly in response to regulatory change or market movements.

The revenue that we require to deliver our Regulatory Proposal is $97M ($2021) lower than the revenue we forecast in our Draft Plan. The key drivers for the change in our forecast:

- a reduction in the return on capital of $93M, driven by market conditions
- a reduction in tax allowance of $14M due to lower forecast revenue
- an additional $42M in our forecast operating costs, due to step changes in operating expenditure not incorporated in the base year costs as a result of new or increased external obligations on JEN's business[11]
- a reduction of $32M from other items such as a revised capital expenditure forecast[12] to align with the new regulatory period timing, a change in opex base year and updated incentive payments.

List of revenue requirement attachments

Table OV-3 below outlines the documents related to our Regulatory Proposal, and in particular, relevant to calculating the annual revenue requirement as outlined in this document.

Table OV–3: List of revenue requirement attachments

Attachment	Name
02-01	JEN - Att 02-01 Our customer, stakeholder and community engagement
07-01	Annual revenue requirement (this document)

11 See Attachment 06-05 *Operating expenditure step changes*.

12 Return on capital and regulatory depreciation impact.

Attachment	Name
07-02	Rate of return
07-03	Debt averaging periods
07-04	Regulatory Asset Base
07-05	Incentive mechanisms
07-15	SCS PTRM FY22-26
07-16	Rate of return model
07-17	SCS Roll Forward Model CY16-HY21
07-18	SCS Depreciation model CY16-HY21
07-19	EBSS model
07-20	CESS model
06-04	SCS Opex Model FY22-26

1. Our approach

In this section, we discuss how we developed our revenue forecast to recover the efficient costs of providing SCS in the next regulatory period.

1.1 Models used

To forecast our SCS revenue requirement, we use financial models developed and published by the AER for electricity distribution businesses. Specifically, we have used the following models provided by the AER in September 2019, to roll-forward our regulatory asset base (**RAB**)[13] and determine revenues for the next regulatory period, taking into account the impact of the intervening period:[14]

- Roll-forward models (**RFM**):
  - the SCS Roll Forward Model (**RFM**) for CY16 to CY20 (version 2, December 2016) – Attachment 07-21
  - the SCS RFM for CY16 to 30 June 2021 (version 2, December 2016) – Attachment 07-17
- Depreciation models:
  - the SCS Depreciation Model for CY16 to CY20 – Attachment 07-22
  - the SCS Depreciation Model for CY16 to 30 June 2021 – Attachment 07-18
- Post-Tax Revenue Models (**PTRM**):
  - the SCS PTRM for 1 Jan 2021 to 30 June 2021 (version 3, January 2015) – Attachment 07-23
  - the SCS PTRM for 1 July 2021 to 30 June 2026 (version 4, April 2019) – Attachment 07-15.

The inputs to, and approaches used within, these models are outlined in our Regulatory Proposal. These have been developed consistent with the requirements in the NER.[15]

1.2 Standard control service revenue requirement

We have used the AER's PTRM to calculate JEN's total revenue requirement for SCS comprising the sum of the following forecasts (consistent with the methodology set out in clause 6.4.3 of the NER):

- *Return on capital*—also known as the return on assets, represents the benchmark financing costs of investing in our network
- *Regulatory depreciation*—also known as the return of capital, is straight-line depreciation (which represents the payback of our investment on our network) less the indexation of the RAB
- *Operating expenditure allowance*—this represents the estimated costs of operating and maintaining our distribution network
- *Corporate income tax allowance*—this represents the estimated benchmark corporate income tax costs for our network
- *Revenue adjustments*—which includes adjustments for incentive scheme revenue outcomes such as the Efficiency Benefits Sharing Scheme (**EBSS**), Capital Efficiency Sharing Scheme (**CESS**) and shared asset revenue.

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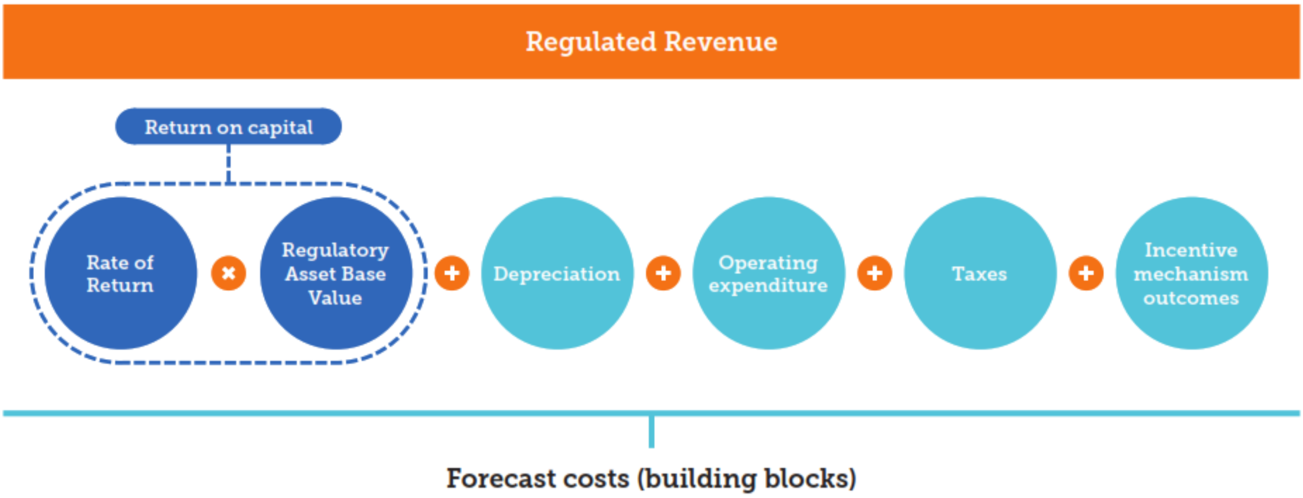
13 See Attachment 07-04 *Regulatory asset base*.

14 The period over which revenue is determined is transitioning from a calendar year basis to a financial year basis. This change results in a gap period—1 January 2021 to 30 June 2021 (**Intervening Period**) that is being managed as a special transition process as further discussed in *JEN's regulatory proposal for the intervening period*.

15 NER cl 6.3.1(c) requires the building block proposal to be prepared accordance with the AER's PTRM, and other relevant requirements of Part C of Chapter 6, and in accordance with Schedule 6.1.

Together these are referred to as **building block costs.** Figure 1–1 below demonstrates how these costs are collated to calculate the building block revenue we require to provide SCS.

Figure 1–1: Building block costs/ revenue requirement



Once we calculate the building block revenue requirement for each regulatory year of the regulatory period, we then ‘smooth’ out the year to year volatility to reduce any significant variation in our revenues—and therefore our network charges. We undertake to smooth revenue by applying X-factors so that the net present value of our building block costs or revenue requirement and smoothed revenue over the next regulatory period are equal—ensuring that we recover no more than our efficient costs. The annual X-factors represent the implied average revenue changes between regulatory years and the smoothed revenue represents the Annual Revenue Requirement.

2. Return on capital

2.1 Forecast requirement

Receiving a fair rate of return is essential for us to continue to invest in our network in a manner that best supports our customers' long-term interests.

The return on capital, or the cost of financing investment in the network, seeks to compensate our debt and equity holders for the opportunity cost of lending or investing their funds in our network. These funds are essential to delivering safe and reliable service outcomes to our customers.

We use a placeholder rate of return (specified as a nominal vanilla weighted average cost of capital (**WACC**)) of 4.80% in the next regulatory period. This rate is calculated using the methods and assumptions set out in the AER's 2018 Rate of Return Instrument (**RoR Instrument**) modified by the AER for the inclusion of the Intervening period.[16]

The rate of return is then multiplied by the opening RAB each year to determine the return on capital for that year, as summarised in Table 2–1 and as required by clause 6.5.2 of the NER.[17]

The rate of return of 4.80% is significantly lower from that applying over the regulatory control period covering 1 January 2016 to 31 December 2020 (**current regulatory period**) and is a significant factor contributing to the reduction in revenue we are proposing for the next regulatory period.

Table 2–1: Return on capital building block for the next regulatory period ($ nominal, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Opening RAB ($M)	1,551.1	1,662.2	1,772.0	1,850.6	1,909.1	N/A
Rate of return (%)(1)	4.80%	4.69%	4.58%	4.46%	4.35%	N/A
Return on capital building block ($M)	**74.5**	**78.0**	**81.1**	**82.6**	**83.0**	**399.2**

(1) The rate of return will be updated for changes to the actual averaging period inputs proposed in Attachment 07-03 *Averaging periods*.

2.2 Rate of return

To calculate the overall rate of return, separate approaches under the RoR Instrument are used to calculate the return on debt and return on equity. Once derived, the return on debt and return on equity are combined using the proportions (weights) based on benchmark gearing level (60% debt to 40% equity).

Table 2–2 below, summarises the key components used.[18]

16 AER, *DORIS - D19-155548 Application of the 2018 RoR Instrument to Vic DNSPs from 1 Jan 2021,* 4 October 2019.

17 The applicable RAB roll-forward models are included as Attachment 07-17 *SCS RFM CY16-FY21* and Attachment 07-21 *SCS RFM CY16-CY20*, and the approach we adopt to calculating the RAB is described further in Attachment 07-04 *Regulatory asset base*.

18 We set out how we calculate the rate of return in Attachment 07-16 *Rate of return model*, and explain our approach in Attachment 07-02 *Rate of return*.

Table 2–2: Rate of Return for the next regulatory period

Parameters	Value (%)
Nominal risk-free rate (placeholder)	1.04%
Market risk premium	6.10%
Equity beta	0.6
Return on equity	4.70%
Return on debt (placeholder)	4.87%
Gearing	60.00%
Nominal vanilla rate of return	**4.80%**
Forecast annual inflation	2.37%

(1) Return on equity and return on debt are based on placeholder averaging periods as per Attachment 07-03 *Averaging periods*.

The return on debt, return on equity and nominal WACC estimates will be updated in our revised proposal to reflect the actual averaging periods (as set out in Attachment 07-03 *Averaging periods*), consistent with the approach outlined in the AER's RoR Instrument. The rate of return will also be updated annually during the next regulatory period as a result of the annual update of the return on debt in accordance with the ROR Instrument.

3. Regulatory depreciation

3.1 Forecast requirement

Depreciation represents the decline in the value of an asset over time. Including forecast regulatory depreciation in our building block proposal enables us to fully recover the capital investments that we make over the economic life of assets. It also enables us to fund the purchase of replacement assets so that we can continue to provide our services in the future.

Table 3–1 summaries our forecast depreciation over the next regulatory period, determined by applying the real straight-line depreciation method on existing and forecast new assets and then deducting indexation of the RAB.

Table 3–1: Forecast regulatory depreciation over the next regulatory period(1)

	FY22	FY23	FY24	FY25	FY26	Total
Straight-line depreciation ($ June 2021, millions)	81.8	88.1	91.2	94.7	96.1	**451.9**
Straight-line deprecation ($Nominal, millions)	83.7	92.4	97.8	103.9	108.0	**485.8**
Inflation on the opening RAB ($Nominal, millions)[2]	36.7	39.3	41.9	43.8	45.1	**206.8**
Regulatory depreciation ($Nominal, millions)	**47.0**	**53.0**	**55.9**	**60.2**	**62.9**	**279.0**

(1) Sources: Attachment 07-15 *SCS PTRM FY22-26*. (2) Using forecast inflation of 2.37%.

3.2 Straight-line depreciation

We forecast depreciation over the next regulatory period by applying the straight-line depreciation consistent with the AER's PTRM and requirements of clause 6.5.5 of the NER. This methodology (outlined in Attachment 07-04 *Regulatory asset base*) involves depreciation on:

- existing assets in our RAB at the start of the next regulatory period, calculated using year on year tracking approach
- forecast capital expenditure over the next regulatory period based on their standard asset lives.

The depreciation methodology adopted will result in the value of each asset being recovered only once over the asset's economic life.

3.3 Indexation

An allowance for asset indexation is calculated by multiplying the opening value of the RAB each year by forecast inflation for the next regulatory period (outlined in Attachment 07-04 *Regulatory asset base*). Indexation is calculated in Attachment 07-15 *SCS PTRM FY22-26*, which is then used to both adjust the RAB and reduce the regulatory depreciation allowance.

4. Operating expenditure

4.1 Forecast requirement

Operating expenditure is a significant component of network expenditure, accounting for approximately 45% of JEN's total cost for SCS over the next regulatory period. Our operating expenditure program delivers critical activities to support the operation and maintenance of our assets, and the continued efficient administration and management of our distribution business.

We have used the AER's preferred approach[19] to forecasting operating expenditure over the next regulatory period. This involves us adopting the:

- *the base, step and trend approach*—applied to the overall operating expenditure amount within the adjusted base year (CY18), net of operating expenditure cost categories that are subject to specific annual forecasts over the next regulatory period
- *specific annual forecast approach*—for the remaining items where base year costs are not representative of future costs.

The forecast operating expenditure for the next regulatory period is $577M ($2021). Our forecast is summarised in Table 4–1. Attachment 06-01 *Operating expenditure* further explains our operating expenditure forecast in more detail, including why we consider it is consistent with clause 6.5.6 of the NER.

Table 4–1: Operating expenditure forecast for the next regulatory period ($ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Base operating expenditure	99.1	99.1	99.1	99.1	99.1	**495.6**
Step changes	6.7	7.5	8.9	9.4	10.0	**42.4**
Trend	2.3	3.8	5.3	6.8	8.3	**26.4**
Other specific items (1)	2.4	2.4	2.4	2.5	2.5	**12.1**
Total forecast operating expenditure	**110.5**	**112.8**	**115.7**	**117.7**	**119.8**	**576.6**

(1) Includes debt raising costs, Guaranteed Service Level payments and licence fees payable to Energy Safe Victoria (**ESV**).

19 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, Section 4.

5. Corporate income tax

5.1 Forecast requirement

Compensation for the cost of the tax is necessary to ensure that sufficient funds are available to meet our tax obligations. The NER require that the cost of corporate tax is estimated as a separate building block.[20]

Apart from capital expenditure and operating expenditure, the principal inputs that go into that calculation of the tax building block item are taxable income, the statutory income tax rate, and the value of imputation credits (**gamma**).[21]

Combining these inputs and incorporating the outcome from recent AER reviews (refer to section 5.2 below), we estimate a tax building block of $29M over the next regulatory period, as set out in Table 5–1.

Table 5–1: Tax building block for the next regulatory period ($ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Taxable Income	55.2	42.8	34.9	48.6	47.6	**229.1**
Income tax payable	16.5	12.8	10.5	14.6	14.3	**68.7**
Less value of imputation credits	-9.7	-7.5	-6.1	-8.5	-8.4	**-40.2**
Tax building block	**6.9**	**5.3**	**4.3**	**6.0**	**5.9**	**28.5**

(1) Taxable income determined as per PTRM (which is included as Attachment 07-15 *SCS PTRM FY22-26*).

(2) The tax building block is equal to taxable income x benchmark tax rate x (1 – benchmark imputation credits) as outlined in cl 6.5.3.

The tax building block is calculated in the PTRM consistent with the RoR Instrument and the AER's recommendations in its recent tax review (refer to section 5.2 below). The calculation of the corporate income tax building block item for the next regulatory period is detailed in Attachment 07-15 *SCS PTRM FY22-26* and is consistent with clause 6.5.3.

5.2 Recent AER reviews

The AER completed two key reviews in December 2018 that affect how the cost of corporate income tax is calculated.

- First, the AER developed a RoR Instrument that sets out how the allowed rate of return should be estimated.[22] The RoR Instrument sets the value of imputation credits (gamma parameter) to 0.585.
- Second, the AER completed its review of how corporate income tax should be estimated.[23] From this review, the two key recommendations were to:
  - use the diminishing value method to depreciate future capital expenditure for tax purposes
  - recognise any future capital expenditure that is immediately expensed for tax purposes consistent with businesses' actual practice.

We have incorporated the outcomes from both reviews in our calculation of the corporate income tax building block.

[20] NER cl 6.5.3.

[21] The value of Gamma is outlined in the AER's RoR instrument.

[22] AER, *Rate of return instrument*, 17 December 2018.

[23] AER, *Review of regulatory tax approach: Final Report*, 17 December 2018.

6. Revenue adjustments

6.1 Summary

Revenue adjustments account for incentive scheme payments and penalties and some other adjustments needed to give effect to the NER requirements.

For the next regulatory period, we are proposing the following adjustments:

- a positive adjustment earned through the EBSS[24]
- a positive adjustment earned through the CESS[25]
- a positive adjustment for Demand Management Incentive Allowance (**DMIA**)[26]
- a negative adjustment for shared asset revenue.[27]

We estimate a revenue adjustment building block of $50M over the next regulatory period, as set out in Table 6–1.

Table 6–1: Revenue adjustments (including incentive schemes) ($ June 2021, millions)

Revenue adjustment	FY22	FY23	FY24	FY25	FY26	Total
Efficiency benefits sharing scheme	8.1	6.5	4.9	2.1	2.1	**23.6**
Capital expenditure sharing scheme	5.1	5.1	5.1	5.1	5.1	**25.6**
Demand management incentive allowance	0.4	0.4	0.4	0.4	0.4	**2.0**
Shared assets	-0.3	-0.3	-0.3	-0.3	-0.3	**-1.5**
Total	**13.3**	**11.8**	**10.1**	**7.3**	**7.3**	**49.8**

6.2 Incentive schemes

6.2.1 Efficiency Benefit Sharing Scheme

Our operating expenditure is currently subject to EBSS period which incentivises us to reduce our operating costs over time by penalising us for increases and rewarding us for decreases—relative to our regulatory allowance.

The AER approved EBSS for the current regulatory period and has incorporated some minor updates to how that scheme works with the intervening period.[28] We are forecasting a positive carryover amount of $24M when applying the EBSS—that amount is added to the required revenue over the next regulatory period. The calculation of this carryover amount is detailed in Attachment 07-19 *EBSS model.*

As discussed in Attachment 07-05 *Incentive mechanisms,* we are proposing to retain the EBSS for the next regulatory period. This approach will further incentivise us to continue seeking efficiency improvements—benefiting both our customers and us.

24 NER cl 6.4.3(a)(5) & 6.5.8.

25 NER cl 6.4.3(a)(5) & 6.5.8A.

26 NER cl 6.4.3(a)(5) and 6.6.3A.

27 NER cl 6.4.3(a)(6A) and 6.4.4.

28 AER, *Final Decision, Jemena distribution determination 2016 to 2020, Attachment 9 – Efficiency benefit sharing scheme*, May 2016, Section 9.5.2.

6.2.2 Capital Efficiency Sharing Scheme

The CESS incentivises us to spend capital expenditure efficiently and share the benefits of these efficiencies with our customers.

We are projecting to underspend our capital expenditure allowances over the current regulatory period which will result in $26M of CESS payments. The CESS model, provided as Attachment 07-20 *CESS model*, sets out our calculation of the proposed CESS payments. The forecast CESS adjustment demonstrates that we are also responding to the incentives to reduce our capital expenditure.

As outlined in Attachment 07-05 *Incentive mechanisms,* we propose retaining the **CESS** in the next regulatory period.

6.2.3 Demand Management Incentive Allowance

The DMIA provides research and development funding to pursue innovative demand management projects. It is provided through an annual, ex-ante allowance in the form of a fixed amount of additional revenue for each regulatory year of a regulatory control period.

During the current regulatory period, the AER undertook a review of the DMIA mechanism.[29] An outcome of this review was the change in the way DMIA is calculated for electricity distribution businesses. Before the review, electricity distribution businesses were given a fixed amount in each regulatory decision, broadly in proportion to the size of the network business. Following the review, the DMIA is now calculated as $200,000 ($2017 Real) plus 0.075% of our Annual Revenue Requirement for each regulatory year.

Consistent with the final Framework and Approach (**F&A**)[30] for the Victorian distribution businesses, and consistent with our preference to incentivise innovation, we propose to include the DMIA in our building block proposal for the next regulatory period.

6.3 Other Revenue Adjustments – Shared Asset Revenue

Some assets we use to provide SCS also provide non-standard control services. For example, we allow companies to use our power poles to attach their telecommunications equipment to provide services to their customers. The adjustment for shared asset revenue reflects the benefits that our customers and we receive from distribution assets being shared in providing both SCS and unregulated services.

We have calculated this revenue adjustment in line with the AER's Shared Asset Guidelines.[31] The guideline states that shared asset cost reductions should be determined in advance for each regulatory year and based on 10% of revenues that are earned from shared assets and expected to exceed 1% of Annual Revenue Requirement for SCS.

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29 AER, *Demand Management Innovation Allowance Mechanism Electricity distribution network service providers*, December 2017.

30 AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021,* January 2019. We note that the F&A was decided before the change in regulatory period to a financial year basis, however, we consider it to be instructive in terms of the approach the AER will undertake to considering our Regulatory Proposal.

31 AER, *Better Regulation, Shared Asset Guideline*, November 2013.

7. X factors and revenue path

7.1 Revenue path

We considered our revenue path following significant customer feedback on this topic, as outlined in Chapter 2 of the Regulatory Proposal. In one of our Peoples Panel sessions,[32] we specifically asked about the profile that electricity prices should take from year to year. The overwhelming response was that electricity prices should remain stable over time. Although we have no control over price stability for other cost components in the electricity supply chain, we have committed to a flat revenue path for SCS as a part of our regulatory proposal to reduce distribution network bill volatility.

We consider this revenue path meets our customer preferences for:

- affordability—by delivering an initial revenue decrease of 7.79% in FY22 compared to CY20.
- steady network charges—through a flat revenue path.

In addition to our customer preferences, we must also meet rule requirements with regards to setting the revenue path. As demonstrated in Table 7–1 our forecast smoothed and unsmoothed SCS building block revenue over the next regulatory period has the same net present value (**NPV**) demonstrating that our building block proposal does not over-compensate us because of smoothing. We also note that our revenue path leaves a gap of 2.2% between smoothed and unsmoothed revenue in FY26. We are aware the AER generally prefers a maximum gap of 3%[33] and may allow a wider gap where there is strong customer support. We note the gap in our building block proposal is within the AER's preferred range and consistent with the NER requirements.[34]

The smoothed revenue profile is calculated using the AER's PTRM (by making smoothed revenues equal to required (i.e. unsmothered) revenues in net present value terms) and is summarised in the table below.

Table 7–1: Proposed SCS revenue and revenue path ($ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	NPV
Unsmoothed revenue requirement	249.4	254.9	257.9	261.1	262.9	**1,203.6**
Smoothed revenue requirement	257.1	257.1	257.1	257.1	257.1	**1,203.6**
Revenue path (% pa) (1)	**-7.79%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**N/A**

(1) Relative to CY20 revenue.

7.2 Revenue per customer

Affordability is particularly important to our customers. To demonstrate, transparently, the impacts of our revenue requirement on our customers, we have reported SCS revenue per customer over the current regulatory period and the next regulatory period. This demonstrates that our proposed revenue will lead to sizeable reductions in revenue per customer over the next regulatory period, and is significantly lower than the $770 revenue per customer in CY20.

Table 7–2 outlines the SCS revenue per customer.

[32] *Attachment 02-04 Reconvening the Jemena People's Panel,* section 3.1.

[33] AER, *Draft Decision, SA Power Networks Distribution Determination 2020 to 2025, Attachment 1 – Annual revenue requirement,* October 2019, section 1.3.

[34] NER cl 6.5.9(b)(2).

Table 7–2: Standard Control Services revenue per customer ($ June 2021, dollars)

	FY22	FY23	FY24	FY25	FY26
Revenue per customer ($) – smoothed	711.3	701.0	690.9	680.9	671.6
Annual change	N/A	-1.45%	-1.44%	-1.45%	-1.36%

Appendix A
Feedback on our draft plan

A1. Feedback on our draft plan

The following table sets out the specific feedback we received on our draft plan relevant to our annual revenue requirement, as well as the responses to this feedback.

Who	Chapter	Topic	Feedback	Our Response
Jemena's Customer Council	Revenue Recovery	Pricing	Questions regarding the impact of AMI metering on prices were raised by our Customer Council. They felt that customers had been paying for the advanced metering infrastructure (AMI) for a long time and that it was important to understand how long that would continue and where JEN was placed in taking advantage of the benefits of AMI data compared with our peers.	Each business has a different program of work so it is difficult to compare but we believe we are broadly in line with other distribution businesses concerning developments in use of AMI data and subsequent benefits to customers. Benefits include reducing the cost of reading meters as well as lower retail price offers and faster retail transfers. The Victorian Government is identifying additional opportunities with distribution business input.
			The Customer Council also queried how customer investments and behaviour behind the meter (for example, solar and/or battery installations, electric vehicle charging) are likely to impact the nature of pricing and customers without these technologies.	Existing and emerging market developments mean that customers' usage profiles are diverging over time. Today and in future, customers are driving changes that are affecting peak demand through: • Continued growth in air-conditioner load, exacerbating the early evening peak • The emergence of electric vehicles (EV's) which could exacerbate the early evening peak. • Future take-up of home batteries with solar PV effectively allowing PV generation to be shifted to any time period. • Continued new connections are driven by state population growth. The first two trends suggest peak pricing in the early evening should be considered to encourage less usage during that time, to reduce future augmentation investment. The third trend suggests peak pricing in the early evening and off-peak pricing around midday to promote self-use of solar generation to be shifted from noon to early evening. In recognition of these trends, and to reduce the impact on those without these technologies, we are proposing assignment onto our new two-rate time of use tariff for: • New connections • Three-phase meter upgrades • New solar and/or battery installations.

Who	Chapter	Topic	Feedback	Our Response
				We would also like to include owners of electric vehicles, although currently lack a credible means to identify these customers. Should a register of customers who purchase electric vehicles or other robust means of identifying an electric vehicle customer over the 2021-26 period, we would also seek to assign these customers to the new time of use tariff. In the absence of this information, we will work with other stakeholders to encourage electric vehicle owners to opt-in to the new time of use tariff.
ECA	Revenue Recovery		The ECA wanted to understand how affordability concerns raised by the People's Panel were addressed. They also suggested we inform customers more about changes we have made to improve aspects of our operation under our control such as efficiency separately from the impacts of tax and WACC decisions made by the AER and therefore outside of our control.	We understand that there are things that JEN is unable to control that contribute to price changes such as regulatory decisions. There are also things JEN has control over that influence prices. In our most recent People's Panel engagement, we provided more detail on the components of pricing and have also ensured it is included in our proposal.
People's Panel	Revenue Recovery	The wider market	Our People's Panel would like to see Jemena and other distribution businesses exert more influence over retailers so that cost reductions are passed on to customers.	Due to limitations in ownership and control, we are not able to directly control the way retailers operate. We are however seeking to engage on customer network tariff price reductions with retailers and as joint signatories to the energy charter with retailers, have committed to working better together towards improving customer experience and customer perceptions of the industry.
Jemena's Customer Council			Jemena's Customer Council felt that energy literacy needed to be improved in our broader community and that it was the responsibility of JEN and other distribution businesses. They also felt that distribution businesses have a role in assisting households to adapt their behaviour to take advantage of tariff reforms.	JEN committed to one of the initial People's Panel recommendations to engage more with the community to improve energy literacy and ensure customers, including those who are most vulnerable, are better informed in ways to manage their energy needs. We have been active in participation and leading the Energy Charter and the opportunity this brings to work across the industry to improve outcomes for customers, specifically groups focused on literacy and understanding such as the language used on bills. We also continue to (and have increased) our commitment to local organisations that support this objective such as the Brotherhood of St Lawrence and Uniting Kildonan, and we work in partnership with these grass-roots organisations to impact the community we serve.

Who	Chapter	Topic	Feedback	Our Response
				• In Summer 2018 Jemena partnered with Uniting Vic/Tas to co-deliver the *Power Changers Community Connections* program. • The purpose was to help JEN customers better understand how energy and their bills work, share tips to keep energy use and bills down while staying comfortable on hot days and advise other support available (concessions, utility relief grants, etc). • Over four months, we delivered (8) community energy information sessions and (50) free home energy visits to over 150 vulnerable, CALD and other community members across the JEN area. Feedback from participants was positive. • Jemena and Uniting are rerunning the program across the 2019 Summer period.
Business Customers through the Customer Council	Capital Expenditure		Business customers voiced their concern about grid connection processes across distribution businesses in that some requests for connection of new solar have been refused. The reasons provided include that there is already too much solar on their network or, they have no need for excess generation.	We have pre-empted the situation of customers increasingly being prevented from connecting solar systems to the distribution network in considering our smart grid strategy. The investment required by Jemena to implement this strategy is included in our regulatory proposal.
Jemena's Customer Council		Tariff reform	The Customer Council considered that the high level of smart-meter penetration meant Victoria has the capability to move fast on tariff reform but expressed concern over the potential for material customer impacts.	Led by our customers and stakeholders, we have worked in collaboration with the other Victorian distribution businesses to develop our proposed household and small business tariff offerings and assignment policies. We undertook extensive customer impact analysis of mass reassignments from single rate to time of use tariffs for: • every smart meter customer (where we only know the customers demand profile and we do not know the customers' personal circumstances) • vulnerable customer impacts (where we surveyed willing customers to be able to ascertain the degree of vulnerability). This analysis demonstrated that while vulnerable customers as a group would be better off if everyone were reassigned to time of use tariffs, there would still be a significant number of households worse off. While some support exists for mass reassignment, we also heard strong views from some customer advocate groups that

Who	Chapter	Topic	Feedback	Our Response
				vulnerable customers should not be made worse off. Our proposed position is therefore to limit those assigned to a new default time of use to those who are making a significant investment decision and are consequently materially less likely to be vulnerable.