DRAFT DECISION

SA Power Networks Distribution Determination 2020 to 2025

Overview

October 2019

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Australian Competition and Consumer Commission,
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About our decision

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set a maximum revenue that network businesses are allowed to recover from customers in providing network services.

The National Electricity Law and Rules (NEL and NER) provide the regulatory framework governing electricity transmission and distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[1]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

SA Power Networks is the owner and operator of the South Australia electricity distribution system. On 31 January 2019, SA Power Networks submitted its regulatory proposal for the five year regulatory period commencing 1 July 2020.

Following the release of this draft decision, SA Power Networks will now have the opportunity to submit a revised proposal by 10 December 2019 in response to our findings. Submissions from stakeholders on both the draft decision and revised proposal are invited by 15 January 2020.

The table below sets out the key milestones for our review of SA Power Networks' proposal:

Milestone	Date
SA Power Networks submitted its proposal	31 January 2019
AER issues paper published	28 March 2019
Public forum on SA Power Networks' proposal held in Adelaide	4 April 2019
Submissions on AER's issues paper and SA Power Networks' proposal closed	16 May 2019
AER draft decision published	8 October 2019
Public forum on draft decision	30 October 2019
SA Power Networks submits revised proposal	10 December 2019
Submissions on draft decision and revised proposal due	15 January 2020
AER final decision to be published	30 April 2020

[1] NEL, s. 7.

Invitation for submissions

In response to our draft decision, SA Power Networks now has the opportunity to submit a revised proposal for its next regulatory control period (2020-25) by 10 December 2019. Submissions on our draft decision and SA Power Networks' revised proposal are invited from interested stakeholders by 15 January 2020. We will consider and respond to all submissions received by that date in our final determination.

Submissions should be sent to: SAPN@aer.gov.au

Alternatively, submissions can be sent to:

Warwick Anderson
General Manager
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process.

Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

(3) All non-confidential submissions will be placed on our website.[2]

[2] For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy* (June 2014), which is available on our website: https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

Note

This overview forms part of the AER's draft decision on the distribution determination that will apply to SA Power Networks for the 2020–25 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanism

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATO	Australian Tax Office
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP14	Consumer Challenge Panel, sub-panel 14
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DSO	distribution system operator
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ERP	equity risk premium
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NSP	network service provider

Shortened form	Extended form
opex	operating expenditure
PPI	partial performance indicators
Pricing Order	electricity pricing order
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

Executive summary

The Australian Energy Regulator (AER) regulates electricity transmission and distribution networks in all Australian jurisdictions except Western Australia.

As part of this process, regulated electricity network businesses must periodically apply to us for a ruling on the amount of money they can collect from their customers to run their business.

We use our insights and expertise to determine how much money the businesses can recover from consumers for using their networks.

We are currently doing this for SA Power Networks for the 2020–25 regulatory period.

This draft decision allows SA Power Networks to recover $3905.3 million from its customers for the 2020–25 period.

This is $309.2 million less than the $4214.5 million SA Power Networks proposed.

The revenue we allow forms the distribution network component of electricity bills. Other components of the electricity bill include generation, transmission environmental policy and retail costs. We estimate that if this draft decision is implemented average residential customers and small business customers in South Australia will save, leading to a drop of $20 and $90, respectively by 2024–25.

In making this draft decision we took three key factors into account:

- Ensuring that consumers pay no more than they need for safe and reliable services
- SA Power Networks' engagement with consumers
- Recognition that an evolving electricity system requires investment.

This draft decision finds a material difference between what SA Power Networks proposes and what we consider efficient spending on capital expenditure (capex) with regard to SA Power Networks' need for future investment.

SA Power Networks has demonstrated timely and effective engagement with its consumers and stakeholders, but there are concerns that their feedback, especially around balancing prices with other competing priorities, is not reflected in the proposal.

Our draft decision also recognises that the way South Australians engage with electricity is changing, and that the rapid uptake in rooftop solar is having a significant impact on SA Power Networks' network. Accordingly, our draft decision reflects SA Power Networks' need to develop new ways to address the evolving needs of consumers.

What are the next steps?

SA Power Networks now has the opportunity to consider our draft decision.

It must submit its revised proposal and supporting material by 10 December 2019.[3]

We will make the final determination by 30 April 2020.

Detailed explanations of other factors informing our draft decision can be found in the overview section and attachments to this draft determination.

What does this mean for consumers?

We estimate that if this draft decision is implemented, network charges in 2024–25 would be:

- $20 lower for average residential customers in South Australia
- $90 lower for average small business customers in South Australia.

The average annual electricity bill for a residential or small business customer is estimated to be around 1 per cent lower in 2025 compared to the current level.[4]

What does this mean for SA Power Networks?

- The total allowed revenue provides for SA Power Networks' operating and capital expenditure.
- It also provides a rate of return of 4.95 per cent consistent with current market conditions.
- Tax allowance has been reduced in line with our recent review of the regulatory tax approach and the 2018 rate of return instrument resulting in a reduction of $226.1 million compared to the 2015–20 regulatory period.

Ensuring that consumers pay no more than they need for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a cornerstone of the regulatory determination process. This involves us assessing whether a business' proposal is a reasonable and realistic forecast of how much money it needs for the safe and reliable operation of the network.

To do this we use a range of materials including SA Power Networks' formal regulatory proposal, submissions from stakeholders and our own analysis. Additionally we met with SA Power Networks representatives to discuss the proposal.

This draft decision finds a significant difference between what SA Power Networks proposes and what we consider efficient spending on capex, especially regarding the need for future investment.

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3 The numbers in this draft determination may change in the final determination.

4 Compared to the current level, holding all other components of the bill constant.

Our decision to allow SA Power Networks lower amounts of money to spend in this regard reflects what we consider a reasonable forecast of the spending required to deliver safe and reliable electricity services over the next five years.

SA Power Networks has provided some justification and supporting evidence for its proposed capex investment. However, there are gaps in this information which prevent us from supporting its proposal. SA Power Networks has the opportunity to address these concerns in its revised proposal and we will carefully consider additional material before making our final decision.

SA Power Networks' engagement with consumers

SA Power Networks demonstrated effective early engagement with its consumers and stakeholders, but there are concerns their feedback, especially around affordability, is not reflected in the regulatory proposal.

Consumers and other stakeholders that took part in SA Power Networks' engagement process told the company they had three major priorities: keeping prices low, network reliability and safety and the transition to a new energy future. SA Power Networks has reflected these, in part, in its proposal.

However, in balancing these competing priorities, stakeholders told us that SA Power Networks could do more to reflect their views, notably in keeping prices low.

Stakeholder feedback also urged us to evaluate the proposal to ensure that the forecast expenditures represent value for money.

SA Power Networks' consumer engagement has improved significantly from the 2015–20 process. Continued robust engagement will lead to a more informed revised proposal and give consumers and other stakeholders' confidence that SA Power Networks' proposals work in their long term interest.

Recognition that an evolving electricity system requires investment

The way South Australians engage with electricity is changing, and the rapid uptake in rooftop solar is having a significant impact on networks. This draft decision reflects SA Power Networks' work to develop new operational systems to engage with technologies like Distributed Energy Resources (DER) and others to address the evolving needs of consumers.

The future impacts of Electric Vehicles (EVs) and electric storage are uncertain but increasing levels of solar photo-voltaic (PV) installations are causing voltage issues in the low voltage (LV) network.

This draft decision approves $34.1 million for SA Power Networks to develop a new LV management program. This program will allow the use of new technologies and will also harness data to manage the energy flows and optimise generation across the network.

SA Power Networks undertook good analysis of PV driven voltage problems and developed an effective cost benefit analysis and business case. We consider that SA Power Networks' proposed program provides an efficient solution.

SA Power Networks has also taken positive steps in developing new tariffs that alleviate voltage problems by increasing demand during the middle of the day.

1 Our draft decision

Our draft decision would allow SA Power Networks to recover a total revenue of $3905.3 million ($ nominal) from its customers from 1 July 2020 to 30 June 2025.

SA Power Networks is regulated using a revenue cap. Incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

Our draft decision for SA Power Networks determines the total revenue it can recover from customers for the provision of common distribution services (standard control services (SCS)). This forms the basis of SA Power Networks' distribution tariffs for the 2020–25 regulatory control period. SA Power Networks' Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from customers.

SA Power Networks also provides alternative control services (ACS), the costs of which are recovered only from users of those services, through a capped price on the individual service.[5] These costs are considered separately to our building block determination.[6] SA Power Networks has not proposed to provide any services on a negotiated basis in the 2020–25 regulatory control period.[7]

1.1 What is driving revenue

The changing impact of inflation over time makes it difficult to compare revenue from one period to the next on a like-for-like basis. To do this, we use ‘real’ values based on a common year (in this case, 2019–20[8]), which have been adjusted for the impact of inflation. Figures in this section are presented in real $2019–20 terms unless otherwise stated.

The total revenue allowance in this 2020–25 draft decision is 6.4 per cent lower than the allowed revenue provided for in our 2015–20 final decision. Figure 1 shows an initial revenue decrease from 2019–20 levels by 13.3 per cent in 2020–21, then staying constant over 2021–25.

Figure 1 shows our draft decision for SA Power Networks' smoothed revenue for the 2020–25 regulatory control period, and its allowed revenues over the 2010–2020 regulatory control periods.

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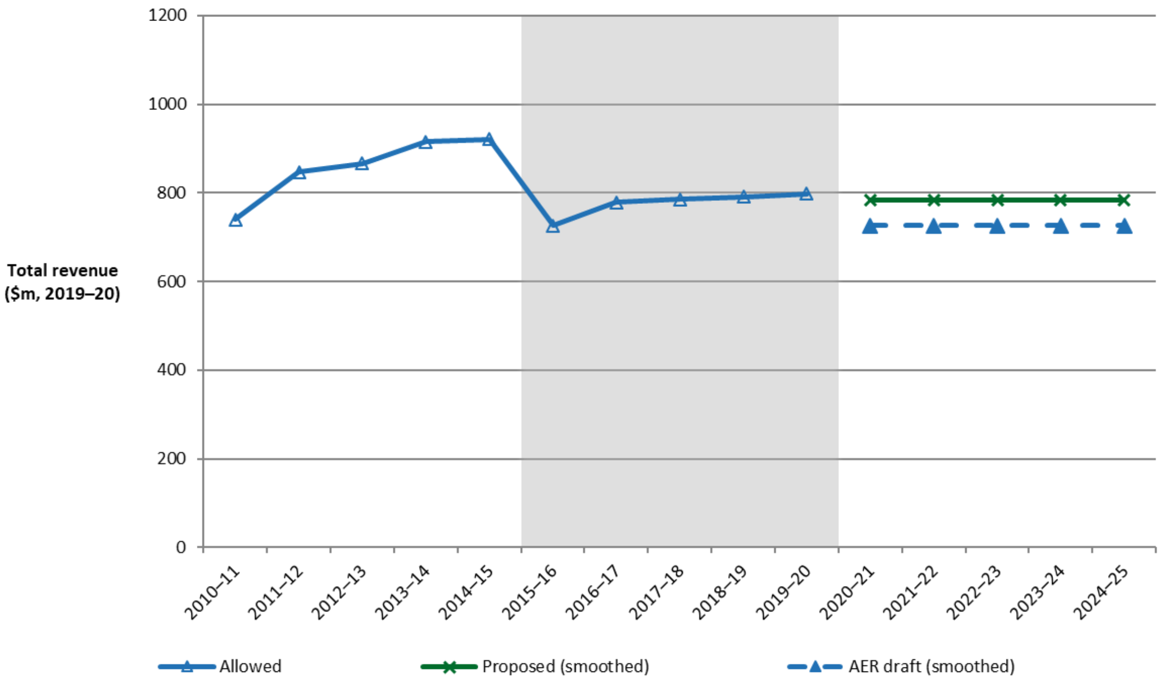
5 Public lighting services will be regulated under a price cap for the first time in the 2020–25 regulatory control period. Previously they were classified as negotiated distribution services. See: AER, *SA Power Networks 2020–25, Final framework and approach*, July 2018.

6 We discuss alternative control services in Attachment 15 to this draft decision.

7 Our distribution determination for SA Power Networks includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because SA Power Networks has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2020–25 regulatory control period.

8 That is, 30 June 2020 dollar terms based on SA Power Networks' estimated actual revenue for 2019–20.

Figure 1 Revenue over time ($ million, 2019–20)



Source: AER analysis, smoothed revenue.

Figure 2 highlights the key drivers of the change in SA Power Networks' allowed revenue from the 2015–20 regulatory control period compared to what we expect in the 2020–25 regulatory control period. It illustrates that the largest driver of change is the return on capital building block. The nominal (WACC) has decreased from around 6.17 per cent in the 2015–20 regulatory control period to 4.95 per cent for the 2020–25 regulatory control period.[9] Figure 2 also shows a decrease in the net tax allowance building block. This decrease is driven by the changes we made to our regulatory tax approach and the 2018 rate of return instrument.[10]

On the other hand, our draft decision provides for higher:

- forecast regulatory depreciation driven by the rising RAB over the 2015–20 regulatory control period and forecast capex over the 2020–25 regulatory control period.[11]
- opex compared to the 2015–20 regulatory control period, despite our draft decision to reduce the proposed amount by 5.0 per cent.[12]
- incentive scheme payments compared to the 2015–20 regulatory control period.[13]

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9 The WACC is a nominal WACC unless stated otherwise. The real WACC is impacted to a similar degree. Please see section 2.2 for further details.

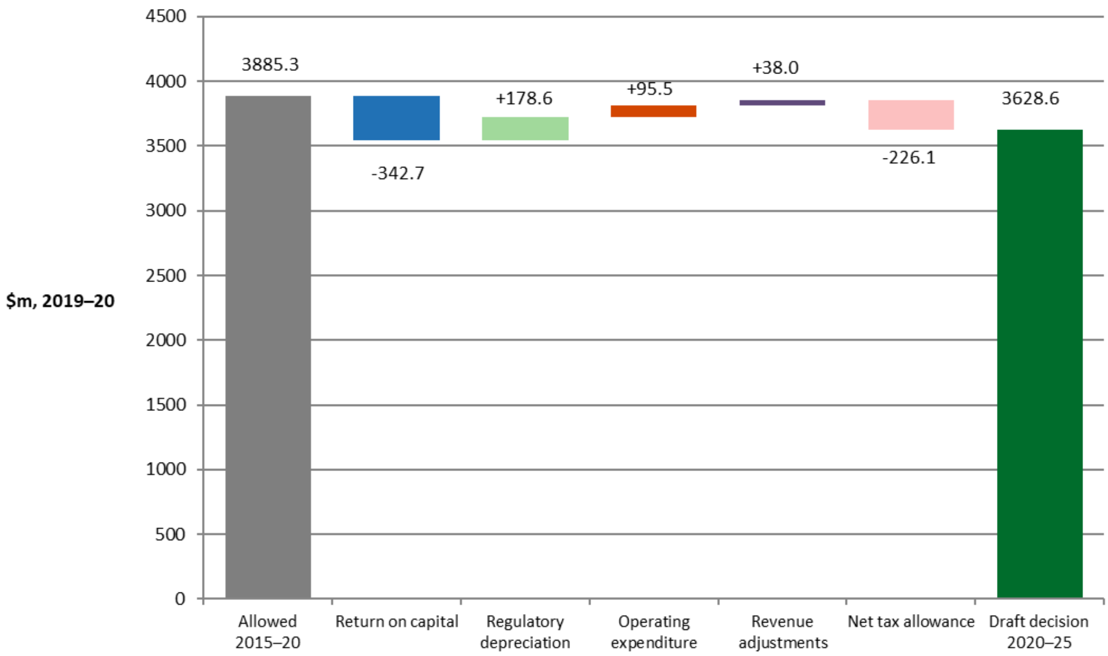
10 Please see section 2.6 for further details.

11 Please see section 2.3 for further details.

12 Please see section 2.5 for further details.

13 Please see section 2.7 for further details.

Figure 2 Change in revenue from 2015–20 to 2020–25 ($ million, 2019–20)



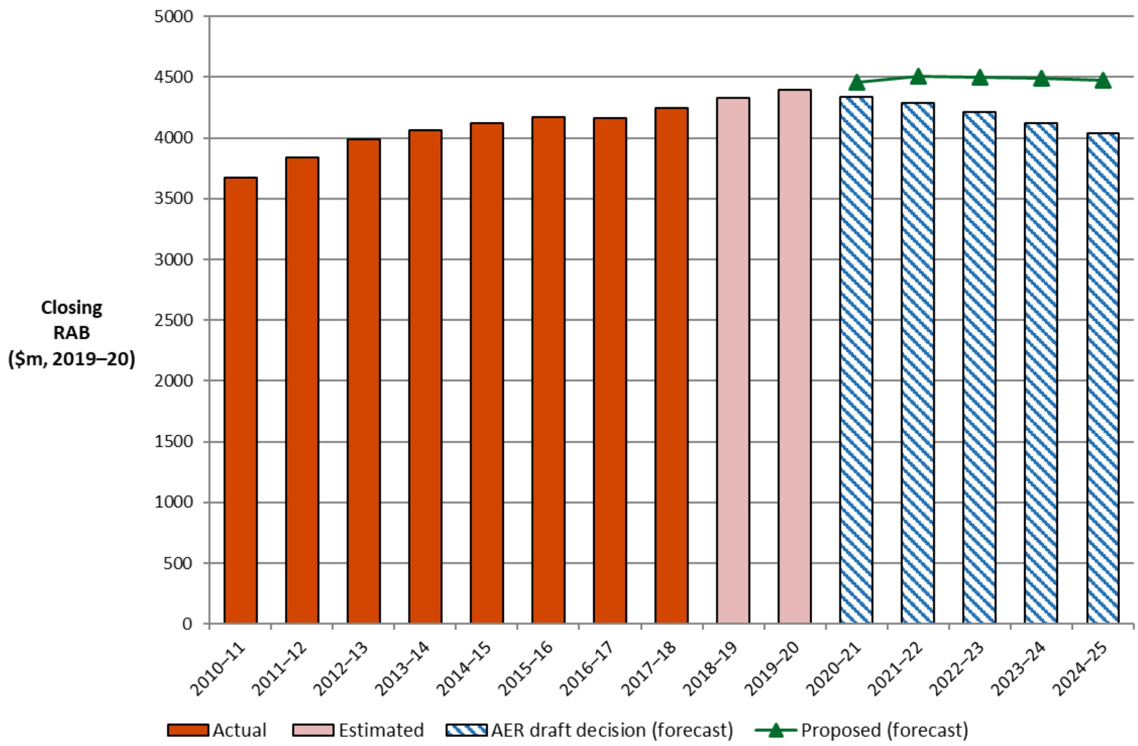
Source: AER analysis. Building block revenue.

Note: Revenue adjustments include increments or decrements accrued under incentives schemes such as the CESS, EBSS and DMIAM.

Figure 3 compares our draft decision forecast RAB to SA Power Networks' proposed and actual RAB. SA Power Networks' RAB is forecast to decrease by around 8.1 per cent in value over the 2020–25 regulatory control period, following a 6.5 per cent increase in the 2015–20 regulatory control period.[14] This change is mainly driven by lower forecast capex for the 2020–25 regulatory control period compared to capex incurred (and estimated) in the 2015–20 regulatory period.

[14] Please see section 2.1 for further details.

Figure 3 Value of SA Power Networks' RAB over time ($ million, 2019–20)



Source: AER analysis.

1.2 Key differences between our draft decision and SA Power Networks' proposal

Our draft decision provides for a lower revenue allowance than that proposed by SA Power Networks. The total revenue in this draft decision for the 2020–25 regulatory period is $3905.3 million ($ nominal), which is 7.3 per cent lower than SA Power Networks' proposed $4214.5 million ($ nominal).

The biggest contributor to the difference between our draft decision revenue and SA Power Networks' proposal is the current rate of return (and therefore the return on capital). Whilst SA Power Networks applied the 2018 rate of return instrument and proposed a 5.43 per cent rate of return, currently the risk free rate and cost of debt is lower than at the time of its proposal, leading to a rate of return of 4.95 per cent. Consequently, the revenue for the cost of capital component is lower by $223 million ($ nominal) compared to SA Power Networks' proposal.

SA Power Networks' regulatory proposal included a $1 placeholder amount for its forecast tax allowance. This is because at the time SA Power Networks lodged its proposal, we had not yet finalised the revision to the PTRM (version 4) to be applied to

SA Power Networks.[15] With the finalisation of the revised PTRM in April 2019, SA Power Networks has since provided the necessary inputs for us to model the forecast tax allowance. Applying the new tax approach and the 2018 rate of return instrument has resulted in SA Power Networks receiving a $37.6 million ($ nominal) tax allowance.

SA Power Networks has not sufficiently justified the prudency or efficiency of its proposed level of forecast capex. Our substitute capex forecast is $473 million ($2019–20) or 27.5 per cent lower than the proposal. This leads to a lower forecast RAB than SA Power Networks' proposal. The lower forecast RAB also contributes to our lower draft decision revenues through a lower regulatory depreciation allowance.

Our approach to forecasting opex is largely the same as SA Power Networks. However, our forecast rate of change by which we trend opex forward is lower than SA Power Networks' proposal. SA Power Networks also did not apply our standard productivity adjustment. Our alternative opex forecast is $1472.9 million ($2019–20) which is 5.0 per cent lower than SA Power Networks' forecast.

1.3 Expected impact of our draft decision on electricity bills

SA Power Networks' distribution network charges makes up around 31 per cent of the total residential and 29 per cent of the total small business retail electricity bills paid by customers in South Australia.[16] Other components of the electricity bill include environmental policy costs, wholesale electricity costs and retail costs. Figure 4 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to customers by their chosen electricity retailer.

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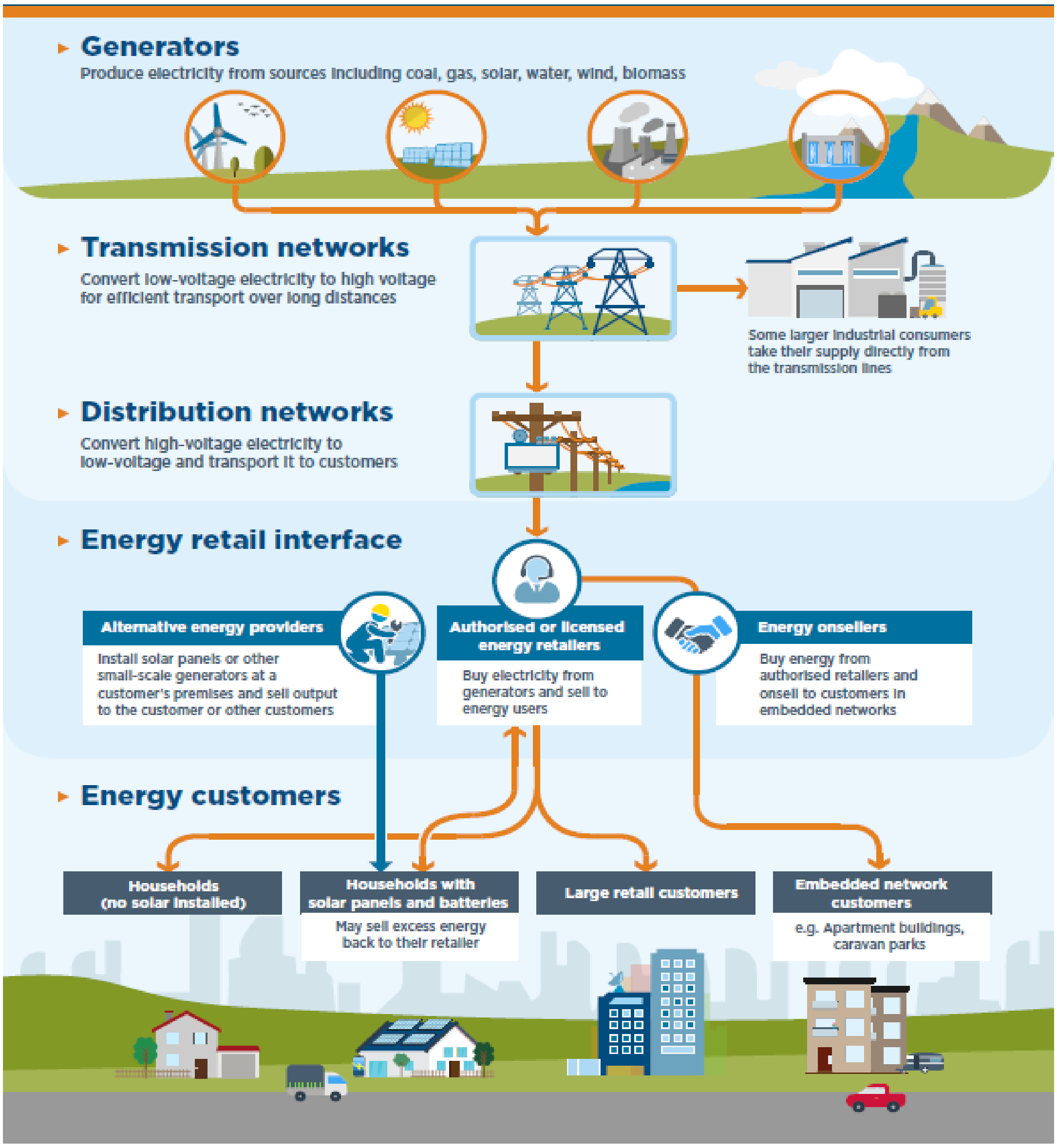
15 The revisions we made to the PTRM (version 4) reflect the outcomes of our recent review of the regulatory tax approach. Please see AER Post-tax revenue models (transmission and distribution) - April 2019 amendment, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/post-tax-revenue-models-transmission-and-distribution-april-2019-amendment.

16 SA Power Networks, *RE: SA Power Networks - information request #066 - Bill impact calculation inputs,* July 2019.

Figure 4 Electricity supply chain



Source: AER, *State of the Energy Market*, December 2018, p. 28.

Table 1 shows the estimated average annual impact of our draft decision for the 2020–25 regulatory control period on electricity bills for residential and small business customers. These estimates suggest a 1.0 per cent ($ nominal) decrease over the five-year 2020–25 regulatory control period for both residential and small business customers. The impact of distribution network charges on the retail bill is dependent on how retailers structure their standing or market offers to customers.

We estimate the expected bill impact by varying the distribution charges in accordance with our 2020–25 draft decision, while holding all other components constant. This approach isolates the effect of our draft decision on distribution network tariffs from other parts of the bill. However, this does not imply that other components will remain unchanged across the regulatory control period.[17]

We estimate that were this draft decision to be implemented, then on 30 June 2025 distribution network charges ($ nominal) in South Australia would be:

- $20 lower for an average residential customer[18]
- $90 lower for an average small business customer[19]

than what we expect them to be on 30 June 2020.

This compares to SA Power Networks' proposal of $25 and $113 increases for the average residential and small business customers, respectively.[20] [21]

Table 1 Estimated contribution to annual electricity bills for the 2020–25 regulatory control period ($ nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25
AER draft decision						
Residential annual bill	1941[a]	1878	1889	1901	1912	1921
Annual change[c]		–63 (–3.3%)	12 (0.6%)	12 (0.6%)	11 (0.6%)	9 (0.5%)
Small business annual bill	9120[b]	8837	8889	8942	8990	9030
Annual change[c]		–283 (–3.1%)	52 (0.6%)	53 (0.6%)	48 (0.5%)	40 (0.4%)
SA Power Networks' proposal						
Residential annual bill	1941[a]	1919	1932	1945	1957	1966
Annual change[c]		–22 (–1.1%)	13 (0.7%)	13 (0.7%)	12 (0.6%)	10 (0.5%)
Small business annual bill	9120[b]	9023	9080	9138	9189	9233
Annual change[c]		–97 (–1.1%)	56 (0.6%)	58 (0.6%)	52 (0.6%)	44 (0.5%)

Source: AER analysis; AER, *Final determination, Default Market Offer Prices 2019–20*, p. 8; SA Power Networks - *RIN 7 - Workbook 7 - Bill Impacts*, January 2019.

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17 It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since SA Power Networks operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2020–25 regulatory control period.

18 This equates to a 1.0 per cent decrease in the average residential customer's total electricity bill over five years.

19 This equates to a 1.0 per cent decrease in the average small business customer's total electricity bill over five years.

20 This equates to a 1.3 per cent increase in the average residential customer's total electricity bill over five years.

21 This equates to a 1.2 per cent increase in the average small business customer's total electricity bill over five years.

(a) Annual bill for 2019–20 is sourced from [AER, Final determination, Default Market Offer Prices 2019–20](), and reflects the average consumption of 4000 kWh for residential customers in South Australia.

(b) Annual bill for 2019–20 is sourced from [AER, Final determination, Default Market Offer Prices 2019–20](), and reflects the average consumption of 20000 kWh for small business customers in South Australia.

(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2019–20 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by SA Power Networks. Actual bill impacts will vary depending on electricity consumption and tariff class.

Further detail on our draft decision impact on overall bills is set out in attachment 1.

1.4 SA Power Networks' consumer engagement

The NEO puts the long term interests of consumers at the centre of our decisions as a regulator and the way SA Power Networks operates its network. An important part of this is ensuring the regulatory proposals SA Power Networks puts to us for approval reflects the NEO, and that SA Power Networks has engaged with its consumers to determine how best to provide services that align with their long term interests.

Consumer engagement in this context is about SA Power Networks working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence SA Power Networks' decisions. In the regulatory process, stronger consumer engagement can help us test service providers' expenditure proposals, and can raise alternative views on matters such as service priorities, capital expenditure proposals and tariff structures.

SA Power Networks began an extensive consumer engagement in early 2017 and learnt the following key customer expectations:

- Keeping prices down;
- A safe and reliable network; and
- Transitioning to a new energy future.[22]

Submissions to our issues paper, and the regulatory proposal, observed a marked improvement in SA Power Networks' customer engagement processes. For example, submissions from Business SA[23], the South Australian Wine Industry Association (SAWIA)[24], John Herbst[25] and the Local Government Association[26], supported by a

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22 SA Power Networks, *Customer and Stakeholder Engagement Report,* January 2019, p. 6; SA Power Networks, *2020-25 Regulatory proposal – Overview*, January 2019, p. 10.

23 Business SA, *Submission on SA Power Networks Regulatory Proposal 2020-25*, 16 May 2019

24 South Australian Wine Industry Association, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 15 May 2019.

25 John Herbst, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 23 May 2019, p. 8.

26 Local Government Association, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 16 May 2019 supported by individual submissions from: City of Charles Sturt; City of Holdfast Bay; City of Norwood, Pynham and St Peters; City of Onkaparinga; City of Port Lincoln; and City of West Torrens.

number of local South Australian Councils were unambiguous in their support for SA Power Networks' improved engagement process.

However, a number of submissions were more mixed in their assessment of the engagement program, particularly the outcomes achieved from the process. A number of submissions, including from our Consumer Challenge Sub-Panel (CCP14) and irrigators[27] suggested that SA Power Networks could do more work to find additional savings, resulting in a lower revenue requirement, which could be passed on to consumers.[28] Energy Consumers Australia (ECA) stated that it would like to see SA Power Networks continue to challenge itself on further savings. The ECA noted that there is an opportunity for an additional revenue reduction of $240 million. [29] With reference to SA Power Networks' review of its customer engagement strategy, the ECA noted:

> "However, one of the overwhelming themes from the March 2019 workshop was that stakeholders wanted engagement where they could advocate and influence outcomes on behalf of their constituent groups. This is at the heart of good consumer engagement – the opportunity to influence and collaborate with network businesses on matters that are not only important to the business, but to consumers. We encourage SAPN to allow itself to be more informed and influenced by consumer stakeholders and to reflect this guidance in its business documentation and decisions."[30]

The South Australian Minister for Energy and Mining, the Hon Dan van-Holst Pellekaan in his submission, also acknowledged the well-organised consultation process run by SA Power Networks, but then added the following observation:

> "While SAPN correctly identify the three key consumer concerns raised during their consultation, their Regulatory Proposal does not address other key underlying consumer and stakeholder concerns from their consultations."[31]

CCP14 stated:

> "SAPN’s conclusion on “balance” is to maintain a ‘steady ship’ based on its relatively good performance to date on measures such as productivity and rate of increase in network prices. SAPN argues that this performance means their ability to make further improvements is very limited. There are many aspects of the SAPN Proposal that reflect a relatively efficient network that is seeking to cope with a number of environmental, commercial and social challenges in serving its customers, including the impact of the world-leading levels of

[27] Irrigator submissions include: South Australian Wine Industry Association, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 15 May 2019; Central Irrigation Trust, *Submission on SA Power Networks Regulatory Proposal 2020-25*, 16 May 2019.

[28] CCP14, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 16 May 2019, p 8-9.

[29] ECA, *Submission on SA Power Networks Regulatory Proposal 2020-25*, 16 May 2019, p .9.

[30] ECA, *Submission on SA Power Networks Regulatory Proposal 2020-25*, 16 May 2019, p .8.

[31] SA Minister for Energy and Mining, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 16 May 2019, p. 5-6.

> Distributed Energy Resources (DER) on its network. However, based on its observations of consumer feedback, CCP14 believes that this 'steady as she goes' approach is no longer what consumers are expecting. While it is likely to maintain current service levels and performance, it does not adequately reflect the changing view of customers who are demanding lower energy prices underpinned by a trust that the utility is doing everything in its power to perform more efficiently, find new ways of managing risk and to 'work with less' wherever reasonably possible."[32]

CCP14 described the engagement process as a lost opportunity to develop a regulatory proposal that responded to customer feedback during the engagement process and on SA Power Networks' draft plan.[33] Despite that, CCP14 also acknowledged that engagement sessions were very well run, with excellent documentation and received positively by stakeholders.[34]

This draft decision is the half-way mark in our review of SA Power Networks' proposal. SA Power Networks now has the opportunity to respond to our draft decision in a revised proposal, a process that we consider would benefit from further consideration of consumer views.

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32 CCP14, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 16 May 2019, p.4.

33 CCP14, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 16 May 2019, p. 27-28.

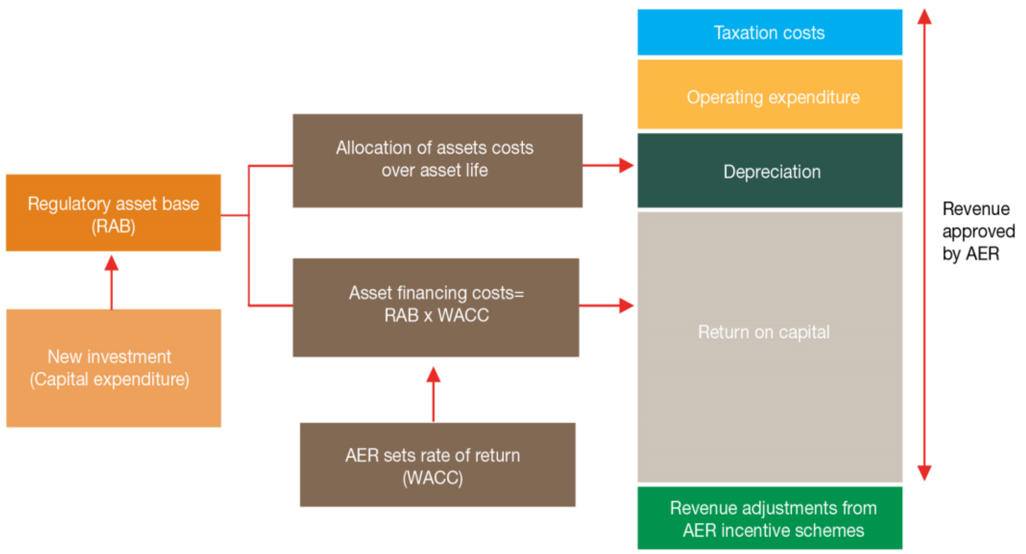
34 CCP14, *Submission on SA Power Networks Regulatory Proposal 2020-25,* 16 May 2019, p. 29.

2 Key components of our draft decision on revenue

The total revenue SA Power Networks proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2020–25 regulatory control period. SA Power Networks' proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach to determine a total revenue allowance (see Figure 5) which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of incentive schemes, such as the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) that applied to SA Power Networks for the 2015–20 regulatory control period and the Demand Management Innovation Allowance Mechanism (DMIAM) allowance for 2020–25 (section 2.7).

Figure 5 The building block model to forecast network revenue



We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework, which aims to promote the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our draft decision on SA Power Networks' distribution revenues for the 2020–25 regulatory control period is set out in Table 2.

Table 2 AER's draft decision on SA Power Networks' revenues for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Return on capital	217.6	214.8	211.8	207.3	202.3	1053.7
Regulatory depreciation[a]	220.3	232.2	243.7	249.6	242.0	1187.7
Operating expenditure[b]	298.9	307.9	317.1	326.0	335.2	1585.1
Revenue adjustments[c]	17.5	–14.2	13.4	7.1	15.0	38.8
Net tax allowance	6.5	6.3	7.2	8.9	8.7	37.6
Annual revenue requirement (unsmoothed)	760.8	746.9	793.2	798.9	803.1	3902.9
Annual expected revenue (smoothed)	**743.7**	**761.9**	**780.6**	**799.7**	**819.3**	**3905.3**
X factor[d]	n/a[e]	0.00%	0.00%	0.00%	0.00%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS) and demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue. In this draft decision, a 0.00% X factor means that the revenue will stay constant in real terms and forecast to vary in line with expected inflation.

(e) SA Power Networks is not required to apply an X factor for 2020–21 because we set the 2020–21 expected revenue in this decision. The expected revenue for 2020–21 is around 13.3 per cent lower than the approved total annual revenue for 2019–20 in real terms, or 11.2 per cent lower in nominal terms.

In the sections below, we discuss each component of our draft decision on SA Power Networks' revenue for 2020–25 in turn.

2.1 Regulatory asset base

The RAB is the value of assets used by SA Power Networks to provide regulated distribution services. The value of the RAB substantially impacts SA Power Networks' revenue requirement, and the price consumers ultimately pay. This makes it a key issue for many stakeholders. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

As part of our decision on SA Power Networks' revenue for 2020–25, we make a decision on SA Power Networks' opening RAB as at 1 July 2020. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block allowances.

We have determined an opening RAB value of $4393.3 million as at 1 July 2020 for SA Power Networks. This value is $24.4 million (or 0.6 per cent) lower than SA Power Networks' proposed opening RAB of $4417.7 million ($ nominal) as at 1 July 2020.[35] While we largely accept the proposed methodology for calculating the opening RAB, we made the following revisions to SA Power Networks' proposed inputs to the roll forward model (RFM):

- Corrected the actual CPI for 2014–15.
- Corrected the adjustment for movements in capitalised provisions over the 2015–20 period.
- Reversed the 2017–18 actual capex input for 'Land' and 'Easements' asset classes.
- Updated inputs as newer information has become available since SA Power Networks submitted its proposal. These updates include:
    - actual CPI for 2018–19 and updated inflation estimate for 2019–20
    - WACC input for 2019–20 following the return on debt update for that year in the 2015–20 post-tax revenue model (PTRM)
    - forecast straight-line depreciation for 2019–20 following the return on debt update for that year in the 2015–20 PTRM

equity raising cost input for 2015–16 following the 2019–20 return on debt update in the 2015–20 PTRM.

Table 3 sets out the roll forward of the RAB to the end of the 2015–20 regulatory control period.

[35] SA Power Networks, *2020–25 Regulatory proposal – Attachment 2 – Regulatory asset base*, January 2019, p. 9.

Table 3 AER's draft decision on SA Power Networks' RAB for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19[a]	2019–20[b]
Opening RAB	3778.4	3884.9	3931.8	4088.9	4246.4
Capital expenditure[c]	251.7	274.3	374.2	388.3	400.7
Inflation indexation on opening RAB [d]	63.8	57.3	75.1	73.0	84.9
Less: straight-line depreciation[e]	208.9	284.8	292.2	303.7	318.3
Interim closing RAB	3884.9	3931.8	4088.9	4246.4	4413.7
Difference between estimated and actual capex in 2014–15					–15.7
Return on difference for 2014–15 capex					–4.7
Closing RAB as at 30 June 2020					**4393.3**

Source: AER analysis.

(a) Based on estimated capex. We will update the RAB roll forward for actual capex in the final decision.

(b) Based on estimated capex provided by SA Power Networks. We expect to update the RAB roll forward with a revised capex estimate in the final decision, and true-up the RAB for actual capex at the next reset.

(c) Net of disposals and capital contributions, and adjusted for actual CPI and half-year WACC.

(d) We will update the RAB roll forward for actual CPI for 2019–20 in the final decision.

(e) Adjusted for actual CPI. Based on forecast capex.

We have determined a forecast closing RAB value of $4558.9 million ($ nominal) as at 30 June 2025 for SA Power Networks. This is $500.7 million (or 9.9 per cent) lower than SA Power Networks' proposed closing RAB value of $5059.6 million ($ nominal).[36] Our draft decision on the forecast closing RAB value reflects the amended opening RAB as at 1 July 2020, and our draft decisions on the expected inflation rate (attachment 3), forecast depreciation (attachment 4) and forecast capex (attachment 5).[37]

Table 4 sets out our draft decision on the forecast RAB values for SA Power Networks over the 2020–25 regulatory control period.

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[36] SA Power Networks, *2020–25 Regulatory proposal – Support document – 1.1 PTRM model - Public,* 31 January 2019.

[37] Capex enters the RAB net of forecast disposals. Capex also includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our draft decision on the forecast RAB also reflects our amendments to the rate of return for the 2020–25 regulatory control period.

Table 4 AER's draft decision on SA Power Networks' RAB for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25
Opening RAB	4393.3	4447.5	4502.9	4528.4	4542.8
Capital expenditure[a]	274.6	287.6	269.2	264.0	258.1
Inflation indexation on opening RAB	107.6	109.0	110.3	110.9	111.3
Less: straight-line depreciation	327.9	341.1	354.0	360.6	353.3
Closing RAB	**4447.5**	**4502.9**	**4528.4**	**4542.8**	**4558.9**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the PTRM, the capex includes a half-year WACC allowance to compensate for the six month period before capex is added to the RAB for revenue modelling.

We accept SA Power Networks' proposal that the forecast depreciation approach is to be used to establish the opening RAB at the commencement of the 2025–30 regulatory control period. This approach is consistent with our Framework and Approach (F&A).[38]

Further detail on our draft decision regarding the RAB is set out in attachment 2.

2.2 Rate of return and value of imputation credits

The return each business is to receive on its RAB (the ‘return on capital’) is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.

An accurate estimate of the rate of return is necessary to promote efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

As required under the NEL, we have applied the 2018 rate of return Instrument

38 AER, *Final framework and approach for SA Power Networks – Regulatory control period commencing 1 July 2020, July 2018*, p. 83.

(2018 instrument)[39] and estimated a placeholder allowed rate of return of 4.95 per cent (nominal vanilla) for this decision which will be updated for our final decision on the averaging periods.[40] SA Power Networks' regulatory proposal adopted the 2018 instrument.[41]

Our calculated rate of return, in Table 5, will apply to the first year of the 2020–25 regulatory period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with the 2018 instrument to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Our draft decision is to accept SA Power Networks' proposed risk free rate[42] and debt averaging periods because they satisfied the 2018 instrument.[43]

Further detail on our draft decision in regards to SA Power Networks' allowed rate of return is set out in attachment 3.

Table 5 Draft decision on SA Power Networks' rate of return (% nominal)

	Previous Regulatory Period (2015–20)	SA Power Networks' Proposal (2020–25)	AER draft decision (2020–25)	Allowed return over regulatory control period
Nominal risk free rate	2.96%	2.44%	1.32%[a]	
Market risk premium	6.5%	6.1%	6.1%	
Equity beta	0.7	0.6	0.6	
Return on equity (nominal post–tax)	7.5%	6.1%	4.98%	Constant (%)
Return on debt (nominal pre–tax)	5.28%	4.98%	4.93%	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.17%	5.43%	4.95%	Updated annually for return on debt
Forecast inflation	2.5%	2.47%	2.45%	Constant (%)

Source: AER analysis.

[a] Calculated using a placeholder averaging period of 20 business days ending 31 July 2019.

39 AER, *Rate of return instrument*, December 2018. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision.

40 The legislative amendments to replace the (previous) non-binding Rate of Return Guidelines with a binding legislative instrument were passed by the South Australian Parliament in December 2018. See, *Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018 (SA)*. NGL, Chapter 2, Part 1, division 1A; NEL, Part 3, division 1B.

41 SA Power Networks, *2020-25 Regulatory proposal*, January 2019, p. 9.

42 This is also known as the return on equity averaging period.

43 AER, *Rate of return instrument*, December 2018, clauses 7–8, 23–25, 36.

Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

SA Power Networks' regulatory proposal did not accept the AER's standard approach to estimating benchmark debt raising costs. SA Power Networks proposed a higher allowance for direct debt raising costs and stated that further examination of indirect debt raising costs should occur.[44]

We have reviewed SA Power Networks' proposal and the evidence currently before us does not sufficiently support its proposed allowance for debt raising costs. However, we agree that it will be necessary to obtain more information from across the sector to inform potential changes to the benchmark. Our draft decision reflects the information currently before us, including updated data from Chairmont, an expert we commissioned.[45]

Attachment 3 contains our draft decision reasoning on the benchmark calculation of debt raising costs. We have set total debt raising costs of $7.2 million ($2019–20) and zero equity raising costs.

Imputation credits

Our draft decision applies a gamma of 0.585 as per the binding 2018 Instrument.[46] SA Power Networks' proposal has adopted the 2018 instrument for gamma.[47]

2.3 Regulatory depreciation (return of capital)

Regulatory depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). SA Power Networks invests capital in large assets to provide electricity network services to its customers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from customers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance. The regulatory depreciation allowance is the net total of the straight-line depreciation less the inflation indexation adjustment of the RAB.

Our draft decision on SA Power Networks' revenue for 2020–25 includes a regulatory depreciation allowance of $1187.7 million ($ nominal). This is $45.5 million

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44 Indirect costs refers to costs arising from management of liquidity and refinancing risk.

45 Chairmont, *AER debt raising costs*, 28 June 2019.

46 AER, *Rate of return instrument*, December 2018, cl. 27.

47 SA Power Networks, *2020-25 Regulatory proposal*, January 2019, p. 9.

(3.7 per cent) lower than SA Power Networks' proposal. We adopt the same approach to regulatory depreciation as SA Power Networks, including its proposed standard asset lives, which determine how quickly an asset class is removed from the RAB. We have, in principle, accepted SA Power Networks' proposal to include new asset classes for shorter lived assets but have accepted only some of the proposed assets be included in these asset classes.

We accept SA Power Networks' proposal to continue with its year-by-year tracking approach. We required only minor changes to its depreciation tracking model. The difference in our draft decision and the proposed regulatory depreciation allowance is largely due to the following determinations on related parts of our decision:

- expected inflation over the 2020–25 regulatory control period (attachment 3), and
- forecast capex (attachment 5) including its effect on the projected RAB over the 2020–25 regulatory control period.[48]

Further detail on our draft decision regarding depreciation is set out in attachment 4.

2.4 Capital expenditure

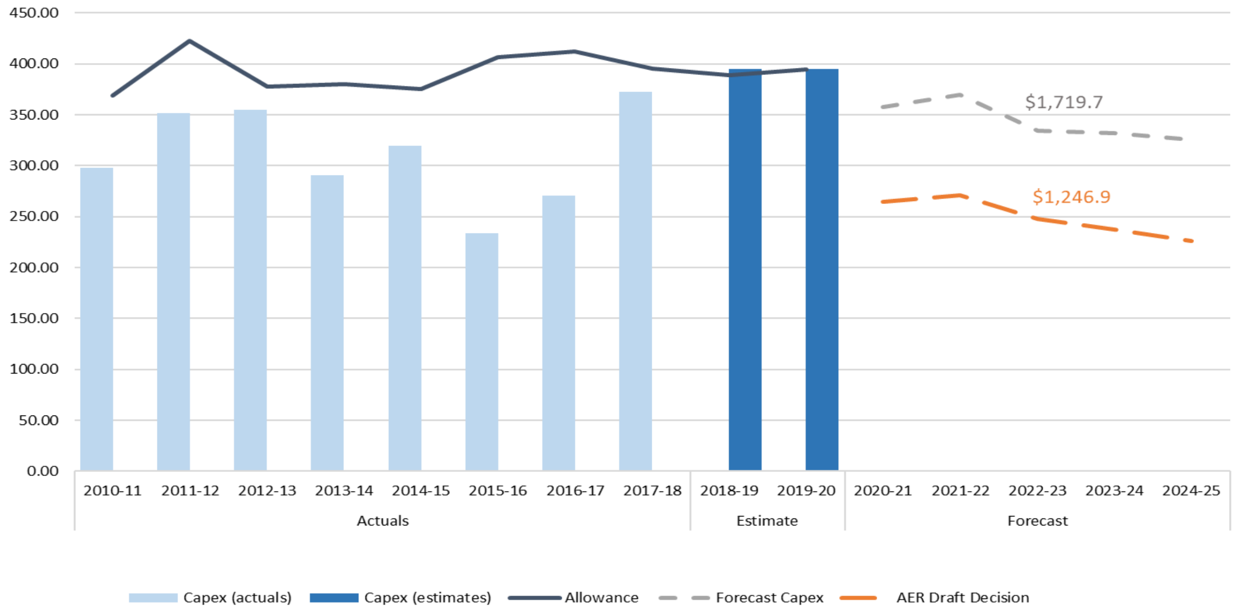
Capital expenditure (capex) refers to the investment in assets to provide network services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. Capex is added to SA Power Networks' RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision on SA Power Networks' revenue includes a total net capex forecast of $1246.9 million ($2019–20) for the 2020–25 regulatory control period. This is 27.5 per cent lower than SA Power Networks' proposed $1719.7 million ($2019–20).

Figure 6 illustrates the change in SA Power Networks' capex over time. We have observed that, compared to historical actual capex, SA Power Networks is estimating a step up, of around 26 per cent, in expenditure for the last two years of the current regulatory period.

[48] Capex enters the RAB net of forecast disposals and capital contributions. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our draft decision on the RAB (attachment 2) also reflects our updates to the WACC for the 2020–25 regulatory control period.

Figure 6 SA Power Networks' capex over time ($ million, 2019–20)



Source: AER analysis

There are number of factors contributing to our lower substitute capex forecast:

- Insufficient evidence to support the prudency and efficiency of SA Power Networks' forecast capex. We encourage SA Power Networks to address the issues we have identified in its revised proposal. In particular, we have not included an allowance for a number of non-recurrent projects and programs, given the lack of detail and information in support of this proposed capex in SA Power Networks' forecast. We have engaged extensively with SA Power Networks on the reasons for our placeholder for these programs and projects and the evidence required to satisfy us on the prudency and efficiency of that expenditure;
- Based on the information before us, we consider that some programs are not required. Further, there appeared to be a lack of rigour in the testing of reasonableness of the forecast. This contrasts with the more comprehensive detailed options analysis undertaken at annual budgeting once capex allowance is confirmed. We have therefore concluded that we do not have confidence in the prudency and efficiency of forecast capex.
- Where SA Power Networks' programs are of a recurrent nature such as repex or recurrent ICT we have relied more on confidence in its actual spend, especially in cases where we have revealed costs. We have therefore relied on these when testing SA Power Networks' forecast or in coming up with our substitute estimate;
- We have observed inflated risk assumptions in SA Power Networks' modelling, particularly in repex, which is likely to overstate the required capex to mitigate that risk. Similarly, for its ICT capex, we have observed that SA Power Networks has overstated the forecast benefits that it expects from some of its non-recurrent ICT capex;

- While we have accepted forecast capex of $30.3 million for SA Power Networks' Distribution System Operator (DSO) transition program,[49] there is lack of a top-down challenge which we would typically see where interrelationships exist between programs and projects. This is evident in SA Power Network's augex proposal where its proposed capex for low voltage (LV) monitoring, voltage regulation and quality of supply appear ad-hoc, particularly their interrelationship with the DSO transition project.
- On a number of occasions, SA Power Networks' program level build-up was inconsistent with its asset management plans or its total forecast. This inconsistency further reduces our confidence in SA Power Networks' proposed forecast capex.

The differences between the total forecast of $1719.7 million in SA Power Networks' proposal and the lower forecast of $1246.9 million that we have substituted in our draft decision are summarised in Table 6 below.

Table 6 Assessment of required capex by driver 2020–25 ($ million, 2019–20)

Category	Initial proposal	AER draft decision	$	%
Repex	$637.2	$508.5	-$128.6	-20.2%
DER Management capex	$106.6	$74.7	-$32.0	-30.0%
Augex	$265.4	$187.3	-$78.1	-29.4%
Gross Connections	$553.0	$513.6	-$39.4	-7.1%
ICT	$284.6	$196.8	-$87.7	-30.8%
Fleet	$116.6	$79.9	-$36.7	-31.5%
Property	$61.5	-	-$61.5	-100%
Other non-network	$42.2	$30.2	-$11.9	-28.3%
Capitalised overheads	$62.4	$56.0	-$6.4	-10.3%
Superannuation adjustment	-$38.3	-$37.4	-$1.0	-2.5%
Gross Capex	**$2091.1**	**$1609.6**	**-$481.5**	**-23.0%**
Less capcons	$350.1	$347.1	-$3.0	-0.9%
Less disposals	$21.4	$15.7	-$5.7	-26.8%
Net Capex	**$1719.7**	**$1246.9**	**-$472.8**	**-27.5%**

49 SA Power Networks' proposed LV management program, which we refer to as the 'Distribution System Operator (DSO) transition program' relates to the development of new operational systems and business processes to actively manage solar PV integration, battery storage and virtual power plants.

Source: AER analysis.

Notes: Table excludes equity raising costs. Numbers may not add due to rounding. The draft decision position includes modelling adjustments relating to SA Power Networks' CPI and real price escalation assumptions.

Further detail on our draft decision regarding capex is set out in attachment 5. In its revised proposal, we encourage SA Power Networks to have regard to our detailed observations in attachment 5 to this draft decision, particularly where we have noted a lack of supporting material that would otherwise justify the prudency and efficiency of its forecast. We will carefully consider additional material before making our final decision.

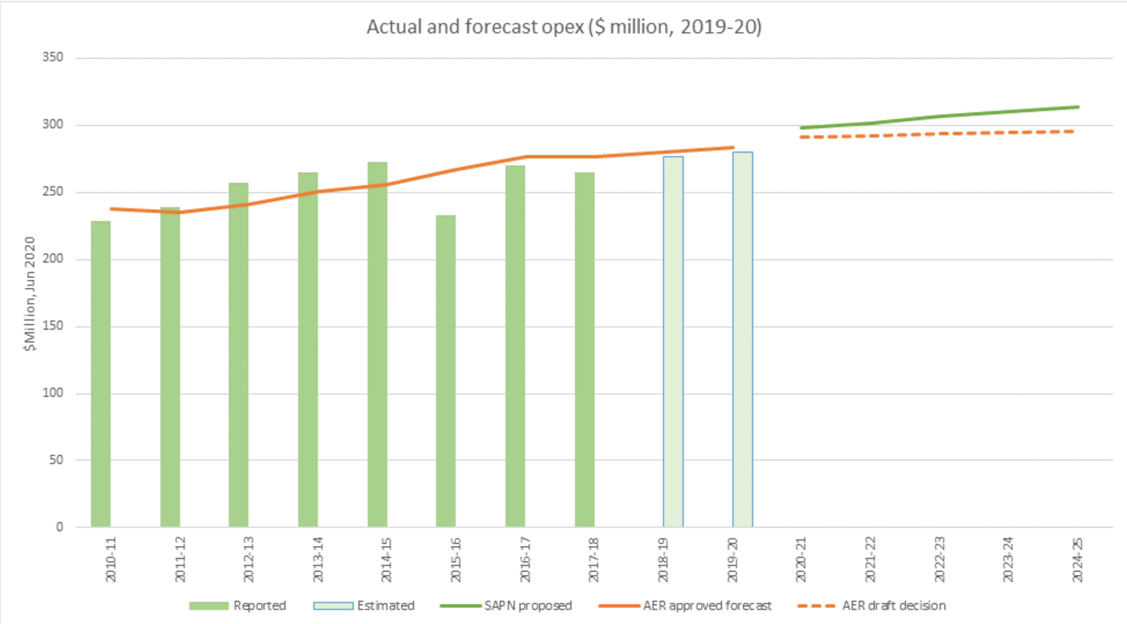
2.5 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of prescribed distribution standard control services. Forecast opex is one of the building blocks we use to determine SA Power Networks' total regulated revenue requirement.

Our draft decision is to include our alternative total opex forecast of $1472.9 million ($2019–20) in SA Power Networks’ allowed revenue for the 2020–25 period. This is $78.1 million, or 5.0 per cent, lower than SA Power Networks’ total opex forecast of $1551.0 million ($2019–20) [50]

Figure 7 shows SA Power Networks’ actual opex, our previous approved forecast, proposed opex for the next 5 years and our draft decision.

Figure 7 SA Power Networks' opex over time ($ million, 2019–20)



50 Including debt raising costs.

Source: SA Power Networks, *2020-25 Regulatory proposal - RIN 1 - Workbook 1 - Regulatory determination template 2020–25,* January 2019; AER analysis.

Note: Excludes debt raising costs.

Table 7 sets out SA Power Networks' proposal and our alternative estimate for the draft decision.

Table 7 Comparison of SA Power Networks' proposal and our draft decision on opex ($ million, 2019–20)

Opex category	SA Power Networks proposal	AER draft decision	Difference ($)
Base (reported opex in 2018–19)	1 381.0	1 381.0	–
2018–19 to 2019–20 increment	18.0	16.6	–1.4
Trend: Output growth	30.6	25.6	–5.0
Trend: Real price growth	25.7	9.7	–16.0
Trend: Productivity growth	–	–20.8	–20.8
Step changes	75.1	53.6	–21.5
Total opex (excluding debt raising costs)	**1 530.4**	**1 465.7**	**–64.7**
Debt raising costs	20.5	7.2	–13.3
Total opex (including debt raising costs)	**1 551.0**	**1 472.9**	**–78.1**

Source: SA Power Networks, *2020-25 Regulatory proposal - RIN 1 - Workbook 1 - Regulatory determination template 2020-25,* January 2019; SA Power Networks, *2020–25 Regulatory proposal - Attachment 6 - Operating expenditure*, 31 January 2019; AER analysis.

Note: Numbers may not add up to totals due to rounding.

Similar to SA Power Networks we start with the 2018–19 base year opex of $276.2 million ($2019–20). From our assessment of revealed cost data and a range of benchmarking techniques we see that SA Power Networks has been relatively efficient over time.[51] Given this, we have used the base opex forecast for 2018–19 in developing our alternative estimate. We will review this and update our benchmarking analysis for our final decision, taking into account the actual opex in 2018–19 included in SA Power Network's revised proposal.

The following factors have contributed to our lower alternative total opex forecast:

- Our forecast rate of change by which we trend opex forward over the next five years is 0.3 per cent each year. This is lower than SA Power Networks' proposed 1.3 per cent per year. This difference is due to:

[51] See Attachment 6 for a fuller description of our economic benchmarking and base opex assessment.

- We used our standard approach (using output weights from all of our benchmarking models) to forecast expected increases in the costs of operating a larger network (output growth). SA Power Networks proposed an alternative approach that used the weights from only two of our benchmarking models.
- We have used forecasts of real labour price increases in the utilities sector in SA prepared for us by Deloitte Access Economics (Deloitte). This is a change from our standard approach of averaging the forecasts from Deloitte and the business's consultant (generally BIS Oxford Economics), which SA Power Networks proposed. Our analysis shows that, over the period 2007 to 2018, Deloitte's real wage price index growth forecasts have been more accurate.
- We applied the 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision.[52] Although SA Power Networks did not adopt our productivity growth forecast in its proposal, it has since advised that it will adopt the 0.5 per cent per year forecast in its revised proposal.[53]

- We have accepted the need for all six step-changes proposed by SA Power Networks but have reduced the proposed amounts as some increases were not well supported. We have adjusted down the amount for reclassification of cable and conductor minor repairs from repex to opex to reflect past actual expenditure. We have also adjusted the Guaranteed Service Level (GSL) reliability payments step change using a longer data series to calculate the forecast to better reflect payments going forward.

We have set out the reasons for our draft decision on opex in more detail in attachment 6. Our opex model, which calculates our alternative estimate of opex, is available on our website.

2.6 Corporate income tax

The building block approach to the calculation of revenue includes an allowance for the estimated cost of corporate income tax payable by SA Power Networks. We recently completed a review of the regulatory tax approach (the tax review) and decided to make some changes to our approach.[54] Given the timing of our final report on the tax review, SA Power Networks proposed a placeholder corporate income tax allowance of

52 AER, *Final decision, Forecasting productivity growth for electricity distributors*, March 2019.

53 SA Power Networks, *Letter to AER SA Power Networks Regulatory Proposal 2020-25*, 3 June 2019.

54 In May 2018, we commenced a review of our regulatory tax approach. We released the final report of the review in December 2018, which identified some required changes to our approach to estimating tax depreciation expenses in our regulatory models (PTRM and RFM). We published a new version of the PTRM (version 4) in April 2019 and have used the new version of the PTRM for this draft decision.

$1 for 2020–25.[55] Our draft decision has implemented the tax review changes and determined a corporate income tax allowance of $37.6 million ($ nominal) in SA Power Networks' revenue for 2020–25.

In our draft decision, we applied the latest version of the PTRM (version 4) released in April 2019 to implement the findings of the tax review. We have recognised immediate expensing of some forecast capex for the calculation of tax depreciation. We also applied the diminishing value (DV) method for tax depreciation to all new depreciable assets except for forecast capex associated with buildings (capital works) and in-house software.[56] These changes have reduced SA Power Networks' proposed corporate income tax allowance by about $116.3 million (or 80.9 per cent) compared to if it was estimated under the previous tax approach.[57] Our draft decision corporate income tax allowance is higher than SA Power Networks' proposed $1 placeholder due to the impact of immediate expensing of capex being somewhat smaller than SA Power Networks had anticipated.[58]

In addition to the above matters, our draft decision does not accept SA Power Networks' proposal to adjust the opening tax asset base as at 1 July 2020 to reflect the immediately expensed capex incurred in the 2015–20 regulatory control period.[59] SA Power Networks estimated its proposal would add around $15 million ($ nominal) to the cost of corporate income tax for the 2020–25 regulatory period if it was accepted.[60] We consider the estimated cost of corporate income tax calculated using SA Power Networks' proposed approach would be higher than the benchmark efficient amount and therefore not in the long term interest of customers.[61]

We accept SA Power Networks' proposed standard tax asset lives for all of its asset classes. Further, we determine standard tax asset lives of 40 years and 4 years respectively for the two new asset classes of 'Buildings - capital works' and 'In-house software' that are subject to the straight-line method of tax depreciation.

We also accept SA Power Networks' proposal to continue using the year-by-year tracking approach for tax depreciation of its existing assets. Under this approach, the

55 At the time of the submission of SA Power Network's regulatory proposal, we had not finalised our version 4 PTRM amendments to implement the tax review findings.

56 All assets acquired prior to 30 June 2020 will continue to be depreciated using the straight-line depreciation method for tax purposes, until these assets are fully depreciated.

57 The reduction is calculated based on the expenditure and rate of return inputs from SA Power Networks' proposed model.

58 The correction for movements in capitalised provisions over the 2015–20 regulatory control period noted above for the RAB also affected the tax asset base (TAB). This correction therefore also had a minor impact on the draft decision corporate income tax allowance.

59 This proposed downward adjustment was put forward by SA Power Networks in June 2019 after the submission of its regulatory proposal, and after the closing date for stakeholder submissions on the regulatory proposal. SA Power Networks, *Email Response to AER information request #007*, 3 June 2019.

60 Other than the impact on the 2020–25 regulatory control period, it should be noted that SA Power Networks' proposal will also increase the cost of corporate income tax for regulatory control period(s) beyond 2020–25 if accepted.

61 Please see section 7.4.2 of attachment 7 for detailed reasons.

capex for each year of a regulatory control period is depreciated individually for tax purposes.

Our adjustments to the return on capital (attachments 2, 3 and 5) and the regulatory depreciation (attachment 4) building blocks affect revenues, in turn impact the tax calculation. The changes affecting revenues are discussed in attachment 1.

Table 8 set out our draft decision on the cost of corporate income tax for SA Power Networks over the 2020–25 regulatory control period.

Table 8 AER's draft decision on SA Power Networks' cost of corporate income tax for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Tax payable	15.6	15.1	17.4	21.4	21.0	90.5
Less: value of imputation credits	9.1	8.9	10.2	12.5	12.3	53.0
Net corporate income tax	**6.5**	**6.3**	**7.2**	**8.9**	**8.7**	**37.6**

Source: AER analysis.

Further detail on our draft decision regarding corporate income tax is set out in attachment 7.

2.7 Revenue adjustments

Our draft decision on SA Power Networks' total revenue also included a number of adjustments:

- Efficiency benefit sharing mechanism (EBSS) — SA Power Networks has accrued EBSS carryovers totalling –$30.7 million ($2019–20) from the operation of the EBSS in the 2015–20 regulatory control period. This is $0.6 million lower than SA Power Networks' proposal of –$30.1 million ($2019–20). The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users.
- Capital expenditure sharing scheme (CESS) — SA Power Networks has accrued rewards under the CESS, which we applied in the current 2015–20 regulatory control period to incentivise SA Power Networks to undertake efficient capex throughout the period. The CESS rewards efficiency gains and penalises efficiency losses, each measured by reference to the difference between forecast and actual capex. In the 2015–20 period, SA Power Networks out-performed our capex forecast, and our draft decision is to approve a CESS revenue increment amount of $69.0 million ($2019–20).
- Demand management innovation allowance mechanism (DMIAM) — an allowance of $3.78 million ($2019–20) has been applied to SA Power Networks over the 2020–25 regulatory control period. The DMIAM aims to encourage distribution

businesses to find investments that are lower cost alternatives to investing in network solutions.

The following section sets out our draft decision on the incentive schemes.

3 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination we've discussed in section 2 above, to encourage SA Power Networks to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

The incentive schemes that might apply to an electricity distribution network as part of our decision are:

- the opex efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS)
- the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM).

Once we make our decision on SA Power Networks' revenue cap, it has an incentive to provide services at the lowest possible cost, because its returns are determined by its actual costs of providing services. Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. If networks reduce their costs to below our forecast of efficient costs, the savings are shared with their customers in future regulatory periods through a lower opex allowance and a lower RAB.

The DMIS and the DMIAM provide businesses an incentive to undertake efficient expenditure on non-network options relating to demand management; and research and development in demand management projects that have the potential to reduce long term network costs.

The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance and not simply cutting costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years.

Our draft decision is that each of the EBSS, CESS, STPIS, DMIS and DMIAM should apply to SA Power Networks for the 2020–25 regulatory control period.

We discuss our draft decisions on each incentive scheme further in attachments 8 to 11.

4 Tariff structure statement

The requirement on distributors to prepare a tariff structure statement arises following significant reforms to the Rules governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- providing better price signals to retailers—underlying network tariffs that reflect what it costs to use electricity at different times
- transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for the entire duration of the regulatory control period.

It is important to note that distributors charge retailers for the network services provided to end-customers and there is no obligation on retailers to pass the network tariff structure through to their end-customers. The structure of retail prices should be determined in the market by retailers responding to consumer preferences and competitive pressures.

The purpose of network tariff reform is to improve the cost reflectivity of the price signals that distributors charge retailers for the cost of providing electricity network capacity for their end customers. Retailers can then make informed decisions about how best to manage the financial risks under more cost reflective network pricing. In some instances, retailers could rely on non-price measures, such as well targeted demand management initiatives, to manage these commercial risks. In other situations retailers may be encouraged to pass through cost reflective network tariff structures to end-customers if they believe that these customers are well placed to respond to these price signals and potentially be rewarded for doing so. Alternatively, retailers could provide "insurance-style" retail products where retailers face the cost reflective network tariff structures but continue to offer end-customers simple flat rate offers. At present, it is more common for retailers to pass through the cost reflective network tariff structures to large business customers, than for residential or small business customers.

Among other matters, SA Power Networks' tariff structure statement must set out its tariff classes, proposed tariffs, the structures and charging parameters for each proposed tariff, the policies and procedures it will use to assign customers to tariffs, or reassign customers from one tariff to another and a description of the approach that it will take in setting tariff levels in each pricing proposal during the 2020–25 regulatory control period.[62]

In this determination we decide the structure of tariffs that will form the basis of annual pricing proposals throughout the regulatory control period.[63] We are also required to decide the policies and procedures for assigning or re-assigning customers to tariff classes.[64] While an indicative pricing schedule must accompany the tariff structure statement, SA Power Networks' tariff levels for each tariff for each year of the 2020–25 regulatory control period are not set as part of this determination.[65]

Tariffs for the regulatory year commencing 1 July 2020 will be subject to a separate approval process that takes place in May 2020, after we have made our final revenue determination in April 2020. In turn, tariffs for the following four years will also be approved on an annual basis.[66]

We commend SA Power Networks for the significant consultation it has undertaken to help develop its TSS, particularly the inclusion of a table outlining key customer feedback and how it was incorporated into the proposal. Additionally, SA Power Networks' proposal includes a clear strategy with analysis of the network costs to be reflected in the prices, as well as targeted measures intended to increase cost reflectivity and improve price signals. SA Power Networks proposed some significant changes to its tariffs and tariff structures for the 2020–25 regulatory control period, including:

- assigning all new customer connections, and reassigning customers who upgrade their connections or who receive a new smart meter as part of a new or replacement meter programme, to cost reflective tariffs
- reassigning all current residential customers with a Type 4 or Type 5 (interval) meter to the residential ToU tariff and off peak controlled load customers with Type 4 meters to the off peak controlled load ToU tariff
- refining the portfolio of cost reflective tariffs, such as aligning the off peak controlled load tariffs with the residential ToU tariff to provide clear, consistent signals and providing businesses a choice between actual and agreed demand measurements to offer flexibility
- introducing a ‘solar sponge’ period for time of use tariffs and changing off peak controlled load arrangements to encourage consumption when solar generation (and exports) are high
- introducing locational (CBD and non-CBD) tariffs for business customers to reflect the different peaks that occur in each area as a result of the absence of residential

62 NER, cl. 6.18.1A.

63 NER, cl. 6.12.1(14A).

64 NER, cl. 6.12.1(17).

65 NER, cl. 6.8.2(d)(1).

66 NER, cll. 6.18.2 and 6.18.8.

demand and PV generation in Adelaide’s CBD compared to the rest of South Australia.

Our draft decision is to approve SA Power Networks' TSS as it complies with the pricing principles set out in the NER.[67]

Attachment 18 sets out in detail our assessment of SA Power Networks' proposed tariff structure statement.

[67] NER, cl. 6.18.5.

5 The National Electricity Law and Rules

The (NEL and NER) provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[68]

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

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[69] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long term interests of consumers.[70] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[71]

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. [72]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[73] These are set out in appendix A and the relevant attachments. In coming to a decision that contributes to the achievement of the NEO, we have considered interrelationships of the constituent components of our draft decision in the relevant attachments. Examples include:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark

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68 NEL, s. 7.

69 NEL, s. 16(1)(a).

70 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

71 Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

72 NEL, s. 16(1)(d).

73 NER, cl. 6.12.1.

efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3 and 7).

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[74] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account. [75]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long term interests of consumers.[76] A particular economically efficient outcome may nevertheless not be in the long term interests of consumers, depending on how prices are structured and risks allocated within the market. [77] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree than others would. For example, we consider that:

- the long term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[78]

- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable leading to safety, security and reliability concerns.[79]

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74 Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

75 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

76 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].

77 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

78 NEL, s. 7A(7).

79 NEL, s. 7A(6).

A Constituent decisions

Our draft decision on SA Power Networks' distribution determination for the 2020–25 regulatory control period includes the following constituent components:

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the AER's draft decision is that the classification of services as set out in attachment 12 will apply to SA Power Networks for the 2020–25 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's draft decision is not to approve the annual revenue requirement set out in SA Power Networks' building block proposal. Our draft decision on SA Power Networks' annual revenue requirement for each year of the 2020–25 regulatory control period is set out in attachment 1 of the draft decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve SA Power Networks' proposal that the regulatory control period will commence on 1 July 2020. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve SA Power Networks' proposal that the length of the regulatory control period will be 5 years from 1 July 2020 to 30 June 2025.
The AER did not receive a request for an asset exemption under clause 6.4.B.1(a)(1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) of the NER and acting in accordance with clause 6.5.7(d), the AER's draft decision is not to accept SA Power Networks' proposed total forecast net capital expenditure of $1719.7 million ($2019–20). Our draft decision therefore includes a substitute estimate of SA Power Networks' total forecast net capex for the 2020–25 regulatory control period of $1246.9 million ($2019–20). The reasons for our draft decision are set out in attachment 5 of the draft decision.
In accordance with clause 6.12.1(4)(ii) of the NER and acting in accordance with clause 6.5.6(d), the AER's draft decision is not to accept SA Power Networks' proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIA of $1551.0 million ($2019–20). Our draft decision therefore includes a substitute estimate of SA Power Networks total forecast opex for the 2020–25 regulatory control period of $1472.9 million ($2019–20) including debt raising costs and exclusive of DMIAM. The reasons for our draft decision are set out in attachment 6 of the draft decision.
In accordance with clause 6.12.1(4A)(i) of the NER, the AER's draft decision is to not accept the contingent project proposed by SA Power Networks. This is discussed in attachment 5 of the draft decision.
In accordance with clause 6.12.1(5) of the NER and the 2018 Rate of Return Instrument, the AER's draft decision is that the allowed rate of return for the 2020–21 regulatory year is 4.95 per cent (nominal vanilla) as set out in attachment 3 of the draft decision. The rate of return for the remaining regulatory years 2021–25 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

Constituent decision

In accordance with clause 6.12.1(5A) of the NER and the 2018 Rate of Return Instrument, the AER's draft decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in section 2.2 of this draft decision overview.

In accordance with clause 6.12.1(6) of the NER, the AER's draft decision on SA Power Networks' regulatory asset base as at 1 July 2020 in accordance with clause 6.5.1 and schedule 6.2 is $4393.3 million ($ nominal). This is discussed in attachment 2 of the draft decision.

In accordance with clause 6.12.1(7) of the NER, the AER's draft decision is not to accept SA Power Networks' proposed corporate income tax of $1 ($ nominal). Our draft decision on SA Power Networks corporate income tax is $37.6 million ($ nominal). This is discussed in attachment 7 of the draft decision.

In accordance with clause 6.12.1(8) of the NER, the AER's draft decision is to not approve the depreciation schedules submitted by SA Power Networks. Our draft decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in attachment 4 of the draft decision.

In accordance with clause 6.12.1(9) of the NER, the AER makes the following draft decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme is to apply:

- We will apply version 2 of the EBSS to SA Power Networks in the 2020–25 regulatory control period. This is discussed in attachment 8 of the draft decision.
- We will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to SA Power Networks in the 2020–25 regulatory control period. This is discussed in attachment 9 of the draft decision.
- We will apply our STPIS to SA Power Networks for the 2020–25 regulatory control period. This is discussed in attachment 10 of the draft decision.
- We will apply the DMIS and DMIAM to SA Power Networks in the 2020–25 regulatory control period. This is discussed in attachment 11 of the draft decision.

In accordance with clause 6.12.1(10) of the NER, the AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft determination including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's draft decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for SA Power Networks for any given regulatory year is the total annual revenue calculated using the formula in attachment 13 plus any adjustment required to move the DUoS under/over account to zero. This is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's draft decision on the form of the control mechanism for alternative control services is to apply price caps for all these services. This is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's draft decision is that SA Power Networks must maintain a DUoS unders and

Constituent decision

overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(14) of the NER, the AER's draft decision is to apply the following nominated pass through events to SA Power Networks for the 2020–25 regulatory control period in accordance with clause 6.5.10:

- Terrorism event
- Insurance cap event
- Natural disaster event
- Insurer credit risk event

These events have the definitions set out in Attachment 14 of the draft decision.

In accordance with clause 6.12.1(14A) of the NER, the AER's draft decision is to approve the tariff structure statement proposed by SA Power Networks. This is discussed in attachment 18 of the draft decision.

In accordance with clause 6.12.1(15) of the NER, the AER's draft decision is to apply the negotiating framework as proposed by SA Power Networks. This is discussed in attachment 16 of the draft decision.

In accordance with clause 6.12.1(16) of the NER, the AER's draft decision is to apply the negotiated distribution services criteria published in February 2019 to SA Power Networks. This is discussed in attachment 16 of the draft decision.

In accordance with clause 6.12.1(17) of the NER, the AER's draft decision on the policies and procedures for assigning retail customers to tariff classes for SA Power Networks is set out in attachment 18 of the draft decision.

In accordance with clause 6.12.1(18) of the NER, the AER's draft decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of SA Power Networks' regulatory control period as at 1 July 2025. This is discussed in attachment 2 of the draft decision.

In accordance with clause 6.12.1(19) of the NER, the AER's draft decision on how SA Power Networks is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(20) of the NER, the AER's draft decision is to require SA Power Networks to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 13 of the draft decision.

In accordance with clause 6.12.1(21) of the NER, the AER's draft decision is to amend the SA Power Networks' proposed connection policy as set out in attachment 17 of the draft decision.

B List of submissions

We received 33 public submissions in response to SA Power Networks' revenue proposal. These are listed below.

Submission from	Date received
AGL	26/06/2019
Anonymous	26/03/2019
Anonymous	18/06/2019
Business SA	16/05/2019
CCP14	16/05/2019
Central Irrigation Trust	24/04/2019
City of Charles Sturt	20/05/2019
City of Holdfast Bay	14/04/2019
City of Norwood Payneham & St Peters	15/05/2016
City of Onkapringa	15/05/2019
City of Port Lincoln	14/04/2019
City of West Torrens	15/05/2019
Clean Energy Council	16/05/2019
CSIRO	16/05/2019
EnergyAustralia	16/06/2019
Energy & Water Ombudsman SA	15/05/2019
Energy Consumers Australia	20/5/2019
GreenSync	16/05/2019
John Herbst	23/05/2019
Local Government Association of South Australia	15/05/2019
Origin Energy	19/05/2019
Penelope Crossly	16/05/2019
Redback Technologies	16/05/2019

Submission from	Date received
Red & Lumo Energy	16/05/2019
SACOSS	14/04/2019
SAFCA Uniting Communities & The Energy Project	22/05/2019
SA Minister for Energy and Mining	16/05/2019
South Australian Wine Industry Association	15/05/2019
Tesla Energy	16/06/2019
The Energy Project	16/05/2019
Total Environment Centre	16/05/2019
Trans Tasman Energy Group	16/06/2019
UNSW Centre of Energy and Environmental Markets	16/05/2019