FINAL DECISION
SA Power Networks determination 2015−16 to 2019−20
Overview

October 2015

AUSTRALIAN
ENERGY
REGULATOR

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Note

This overview forms part of the AER's final decision on SA Power Networks' 2015–20 distribution determination. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators

Shortened form	Extended form
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

Revocation and substitution of preliminary decision

In November 2012, the Australian Energy Market Commission (AEMC) introduced major changes to the economic regulation of electricity distributors under chapter 6 of the National Electricity Rules (NER).[1]

To allow consumers to receive the benefit of the new rules the AEMC made transitional rules under chapter 11 of the NER. In accordance with those transitional rules, we:[2]

- made a preliminary determination for the 2015−20 regulatory control period on 29 April 2015. This preliminary determination formed the basis for approving prices for SA Power Networks' customers from 1 July 2015 to 30 June 2016.
- now revoke that preliminary determination and substitute it with a new distribution determination which takes effect at the date it is made and applies in respect of the 2015–20 regulatory control period (referred to as our final decision). The new distribution determination provides for adjustments over the regulatory control period to account for differences between the revenue that we approved for the 2015–16 regulatory year in the preliminary determination and in the final decision.[3]

1 AEMC, *Final Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

2 NER, cl. 11.60.4.

3 NER, cl. 11.60.4(d) and (e).

1 Introduction

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission and distribution systems in Australia except for Western Australia. SA Power Networks is the Distribution Network Service Provider (distributor) responsible for providing electricity distribution services in South Australia. We regulate the revenue SA Power Networks can recover from its customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework governing electricity networks. The National Electricity Objective (NEO), as set out in the NEL, is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.[4]

SA Power Networks was required to submit a regulatory proposal to us for approval.[5] The central component of a regulatory proposal is the amount of revenue SA Power Networks proposes to recover from consumers over the 2015−20 regulatory control period.[6] We assess SA Power Networks' proposal, using the NER's detailed rules including a 'building block model' to determine how much revenue a distributor requires to cover its efficient costs. We must decide whether to accept SA Power Networks' regulatory proposal. If we do not accept that SA Power Networks' proposal complies with the requirements of the NER, we must substitute an alternative amount of revenue that we are satisfied does comply. We must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NEO. Where there are two more possible decisions that will do so, we must make the decision that we are satisfied will contribute to the NEO to the greatest degree.

The NER sets out an incentive regime to guide our decision on a distributor's revenue.[7] Incentive regulation encourages distributors to spend efficiently and to share the benefits of efficiency gains with consumers.[8]

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4 NEL, s. 7.

5 NER, cl. 6.8.2.

6 NER, cll. 6.3.1 and 6.8.2.

7 NER, cl. 6.2.6(a) states that for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C (Building Block Determinations for standard control services). Further revenue and pricing principles (RPPs) state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.

8 AEMC, *Consultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, February 2015, p. 3.

Under this incentive regime, the revenue allowance we determine does not set SA Power Networks' actual operating budget. It is up to SA Power Networks to decide how best to use this revenue allowance in providing distribution services and complying with its obligations. To determine the revenue allowance, we assess and determine forecast expenditure required by SA Power Networks, acting as a prudent operator, incurring efficient costs in delivering safe and reliable distribution services. The regime works to provide SA Power Networks with incentives to outperform those forecasts, while delivering safe, reliable and secure services to its customers. In other words, a prudent operator is expected to respond to the incentives for distributors to innovate and invest in responses to changes in consumer needs and productive opportunities.[9] This is consistent with the NEO.

SA Power Networks submitted its initial regulatory proposal for the 2015–20 regulatory control period in October 2014. In April 2015, we published our first distribution determination for the 2015–20 regulatory control period (referred to as our preliminary decision), which took effect on 1 July 2015. At the same time as we published our preliminary decision, we invited submissions on the revocation and substitution of that determination. SA Power Networks submitted a revised proposal in July 2015. This final decision replaces the preliminary decision and is based on consultation and submissions from various stakeholders on SA Power Networks' initial and revised proposals as well as our preliminary decision.

In accordance with the transitional rules, we have revoked our preliminary decision. This overview, together with its attachments, constitutes our final decision on the making of a new distribution determination in substitution for that preliminary decision in response to SA Power Networks' revised regulatory proposal. The overview provides a summary of our final decision and its constituent components. It sets out the issues we covered, the conclusions we made, and how those conclusions were reached. We also explain why we are satisfied our decision contributes to the achievement of the NEO to the greatest degree. In our attachments we set out detailed analysis of the constituent components that make up SA Power Networks' revised proposal and our decision on each of them. Appendix A contains the full list of the constituent decisions of our final decision.

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

2 Decision

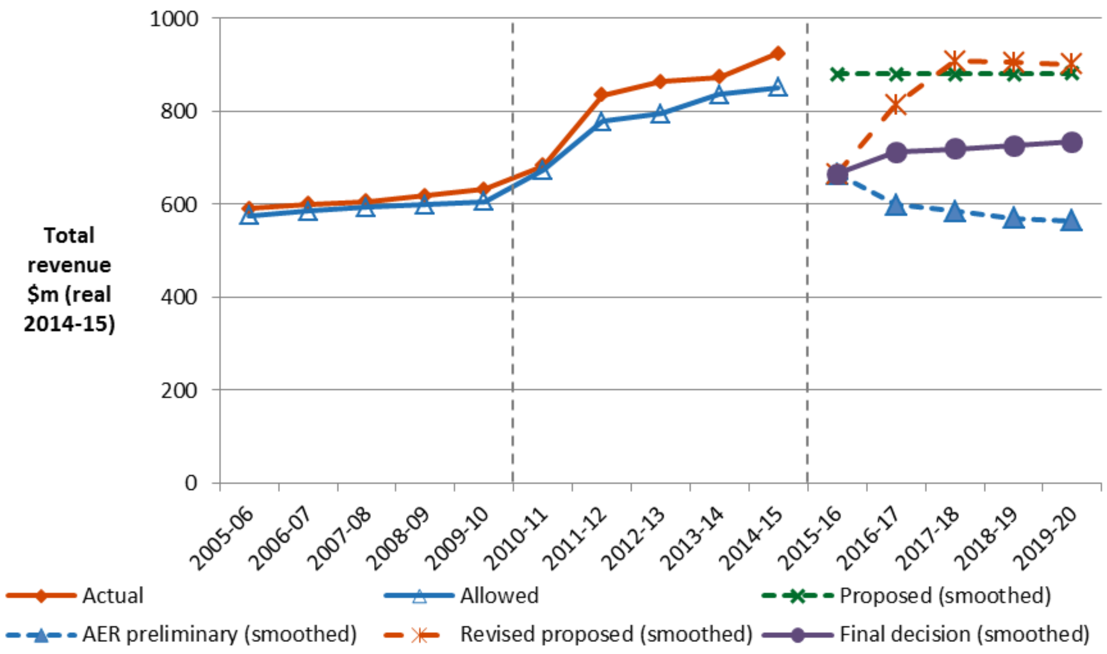
Our final decision is that SA Power Networks can recover $3837.5 million ($ nominal) from consumers over the 2015–20 regulatory control period. Our total revenue allowance is 19.1 per cent less than SA Power Networks' initial regulatory proposal and 15.4 per cent less than its revised regulatory proposal of $4534.5 million ($ nominal) for the 2015–20 regulatory control period.

Our final decisions provides for $626.3 million ($ nominal) more in allowed revenue over the 2015–20 regulatory control period than our preliminary decision set out. The reasons we depart from our preliminary decision are set out in this overview and subsequent attachment.

For the reasons set out in this final decision, we are satisfied our decision provides SA Power Networks with sufficient funding to maintain and operate its network safely and reliably for the 2015–20 regulatory control period.

The total revenue we have allowed SA Power Networks to recover from its customers in the 2015–20 regulatory control period is shown in figure 1. The difference between the total revenue set in our preliminary and final decisions can be explained largely by our decision to accept SA Power Networks' revised approach to depreciation, which better reflects actual asset lives. There has also been an increase to our preliminary decision rate of return.

Figure 1 SA Power Networks' total proposed revenue and AER final decision ($million, 2014–15)



Source: AER analysis.

We determine the revenue SA Power Networks may recover from its customers by assessing the costs we expect it to incur as an efficient and prudent service provider. The most important factors we see impacting on SA Power Networks' costs in the 2015–20 regulatory control period are:

- an improved investment environment compared to our 2010 decision, which translates to lower financing costs necessary to attract efficient investment. In our 2010 final decision we approved a rate of return of 9.76 per cent (nominal, vanilla).[10] This can be compared with the approved rate of return in this final decision of 6.17 per cent.[11]
- a revised approach to the calculation of depreciation proposed by SA Power Networks
- few changes to the operating environment facing SA Power Networks with respect to risk or regulatory obligations.
- forecast maximum demand, which is expected to remain reasonably flat over the 2015–20 regulatory control period, which reduces the requirement for growth-related capex. Annual maximum demand is forecast to decline by 0.32 per cent in each year of the period. Forecast changes in maximum demand are not uniform across the network. Some areas are expected to see stronger maximum demand growth and others stable or declining maximum demand.

Historically, SA Power Networks has been an efficient service provider compared to its interstate peers. SA Power Networks has proposed to increase its expenditure compared to the 2010–15 regulatory control period. If approved, we consider SA Power Networks' revised regulatory proposal would see it become less efficient than it has been.

We have approved capital expenditure (capex) and operating expenditure (opex) allowances that broadly reflect SA Power Networks' expenditure over the 2010–15 regulatory control period. In contrast, SA Power Networks proposed increases to capex and opex, most of which we have not accepted. SA Power Networks' opex forecast was materially higher than it has incurred in recent years due to its forecast step changes. We consider that many of these step changes reflected discretionary changes in programs (for example, programs that target bushfire areas that are in addition to SA Power Networks' legislative obligations) rather than new expenditure in response to changes in regulatory or legislative obligations. Capex and opex are discussed in detail in attachments 6 and 7.

SA Power Networks' initial and revised proposals included results of its customer engagement in support of its proposed increases in opex and capex, which we have had regard to in making this final decision. While we note the findings of the customer

[10] AER, *Final decision, South Australian distribution determination 2010–11 to 2014–15*, May 2010, p.132.

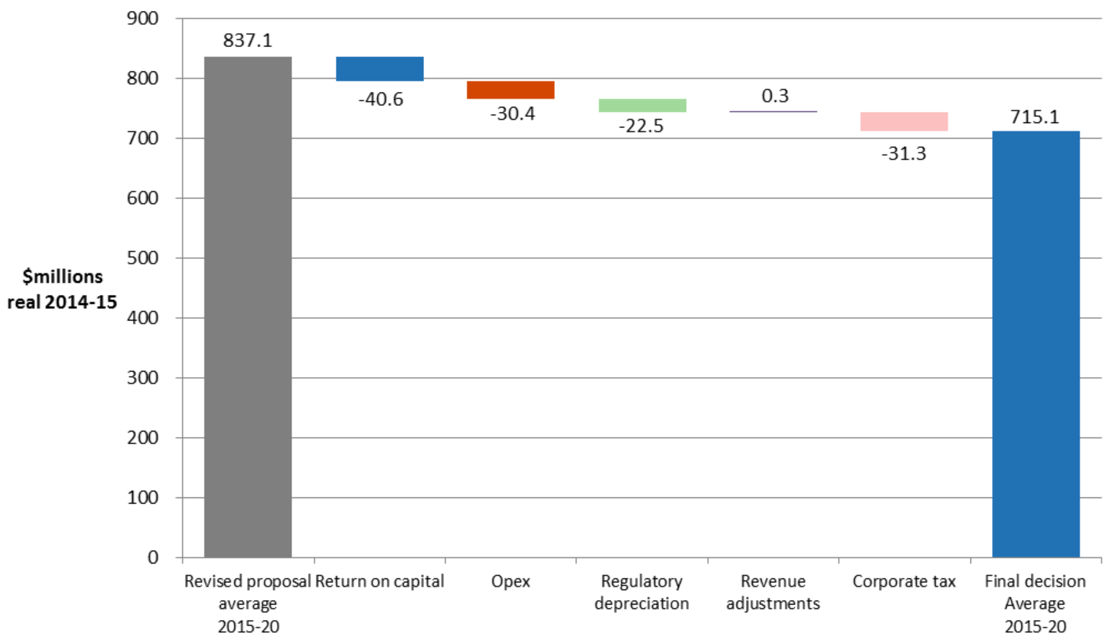
[11] Nominal, vanilla.

engagement program support elements of SA Power Networks' proposed expenditure, we do not find it sufficient in and of itself to justify the increases sought.

We have departed from our preliminary decision, by accepting the revised approach to calculating depreciation proposed by SA Power Networks in its revised regulatory proposal. The approach results in a higher depreciation allowance than the approach we set out in our preliminary decision. While SA Power Networks proposed approach results in a higher revenue recovery in the 2015–20 regulatory control period it more accurately reflects the economic life of assets and results in lower depreciation expense (and therefore lower revenue recovery) in future regulatory periods. Given that the revised approach more accurately tracks the economic life of assets, it is consistent with the requirements of the NER. A detailed discussion of depreciation is provided in section 3.5 and in attachment 5.

Overall, four constituent components of our decision drive the difference between SA Power Networks' revised regulatory proposal and our final decision: rate of return, opex, capex and corporate tax. The provision made for imputation credits (gamma), is the main driver of differences in the corporate tax allowance. Changes to the allowed rate of return also flow on to impact the corporate tax allowance (in addition to gamma) given the reduction in overall revenue requirements. Attachment 4 discusses this interrelationship in detail. Figure 2 illustrates the constituent components of our decision (which the NER refers to as building blocks). We discuss each of these further in the sections below.

Figure 2 AER's final decision and SA Power Networks' revised proposed annual building block costs ($million, 2014–15)



Source: AER analysis.

Note: Revenue adjustments include efficiency benefit sharing scheme amounts, shared asset amounts and forecast DMIA.

We consider SA Power Networks' revised proposal does not reflect the factors impacting on its cost drivers to a satisfactory extent. Consequently, we conclude that SA Power Networks has proposed to recover more revenue from its customers than is necessary for the safe and reliable operation of its network. It follows that we consider SA Power Networks' revised proposal does not contribute to the NEO to the greatest degree.

2.1 Impact of decision

Distribution charges—for standard control services—represent approximately 38 per cent, on average, of the annual electricity bill for SA Power Networks customers. Other factors may affect a customer's electricity bill, such as their consumption, their specific tariff, the wholesale price of electricity, or changes in the retail margin. In 2015–16 we expect a typical residential final bill will reduce by around 10 per cent. In 2016–17 we expect bills to increase by around 3 per cent. We expect bills to remain below the average annual residential customer bill paid in 2014–15.

Table 1 shows the estimated impact of our final decision on the average residential and small business customers' annual electricity bills in SA Power Networks' distributions area over the 2015–20 regulatory control period, compared with SA Power Networks' revised proposal.

Table 1 AER's estimated impact of its final decision on the average residential and small business customers' electricity bills in SA Power Networks' distribution area for the 2015–20 regulatory period ($ nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
AER final decision						
Residential annual bill[a]	2007	1803	1848	1870	1887	1905
Annual change[c]		–203 (–10.1%)	45 (2.5%)	22 (1.2%)	17 (0.9%)	19 (1.0%)
Small business annual bill[b]	3867	3475	3562	3603	3637	3673
Annual change[c]		–392 (–10.1%)	87 (2.5%)	42 (1.2%)	33 (0.9%)	36 (1.0%)
SA Power Networks' revised proposal						
Residential annual bill[a]	2007	1803	1936	2036	2047	2057
Annual change[c]		–203 (–10.1%)	133 (7.4%)	100 (5.2%)	10 (0.5%)	10 (0.5%)
Small business annual bill[b]	3867	3475	3732	3925	3945	3965
Annual change[c]		–392 (–10.1%)	257 (7.4%)	193 (5.2%)	20 (0.5%)	20 (0.5%)

Source: AER analysis; AER, Energy Made Easy, www.energymadeeasy.gov.au; *ESCoSA, South Australian Energy Retail Prices Ministerial Pricing Report 2014*, August 2014.

(a) Based on annual bill for typical consumption of 5000 kWh per year during the period 1 July 2014 to 30 June 2015. Sample postcode: 5015.

(b) Based on the annual bill sourced from Energy Made Easy for a typical consumption of 10000 kWh per year during the period 1 July 2014 to 30 June 2015. Sample postcode: 5015.

(c) Annual change amounts and percentages are indicative. They are derived by varying 2014–15 bill amounts in proportion with total annual regulated revenue divided by forecast demand. Actual bill impacts will vary depending on electricity consumption, tariff class and other variables.

2.2 Key issues raised in revised proposal

In its revised proposal, SA Power Networks raised a number of concerns with our preliminary decision. Three main concerns included:[12]

1. that we have maintained our stated position on rate of return and gamma notwithstanding that these positions are considered to be inconsistent with the NER and independent advice received by SA Power Networks.
2. that we misunderstood SA Power Networks' obligations under South Australian legislation to manage bush fire risk and in regard to work health and safety.
3. that we had not adequately considered SA Power Networks' customer engagement program that identified expenditure initiatives around bushfire risk management, tree trimming, network resilience to adverse weather and network investment to improve road safety.

In arriving at this final decision we have considered all the material before us. This includes SA Power Networks' revised regulatory proposal and stakeholder submissions. We have also reviewed the analysis we made in reaching our preliminary decision in light of the new information we have since received. Further, we have conducted additional analysis where required. While we have accepted some of the arguments raised by SA Power Networks, we do not agree with all of their concerns. While we have departed from our preliminary decision in a few respects, our positions in this final decision are broadly in line with our preliminary decision.

2.3 Structure of the overview

This overview provides a summary of our final decision and its constituent components and is structured as follows:

- Section 3 provides a break-down of our revenue decision into its key components.
- Section 4 sets out our final decision on classification of services, alternative control services, control mechanisms and incentive schemes that will apply to SA Power Networks. These are decisions we make in addition to the building block revenue determination.
- Section 5 explains our views on the regulatory framework.
- Section 6 outlines SA Power Networks customer engagement process.

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12 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 8 and 9.

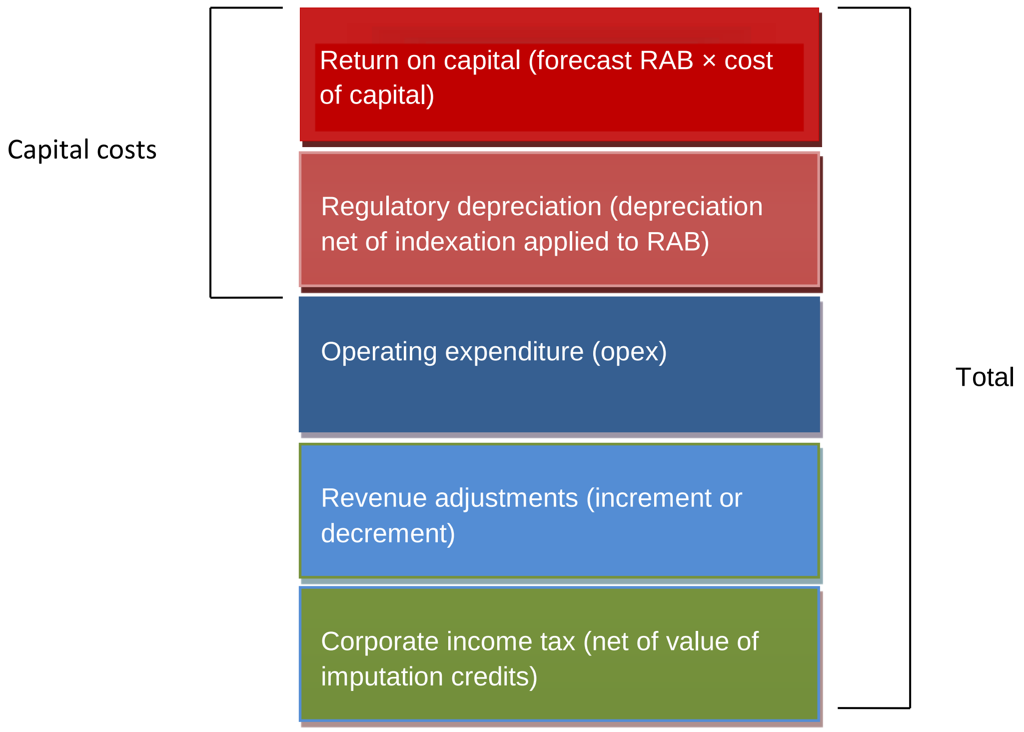
3 Key elements of the building blocks

We use the building block approach to determine SA Power Networks' annual revenue requirement. The building blocks, illustrated in figure 3, include:

- a return on the regulatory asset base (RAB) (return on capital)
- depreciation of the RAB (return of capital)
- forecast opex
- revenue increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of the RAB and therefore the revenue generated from the return on capital and return of capital building blocks.

Figure 3 The building block approach for determining total revenue



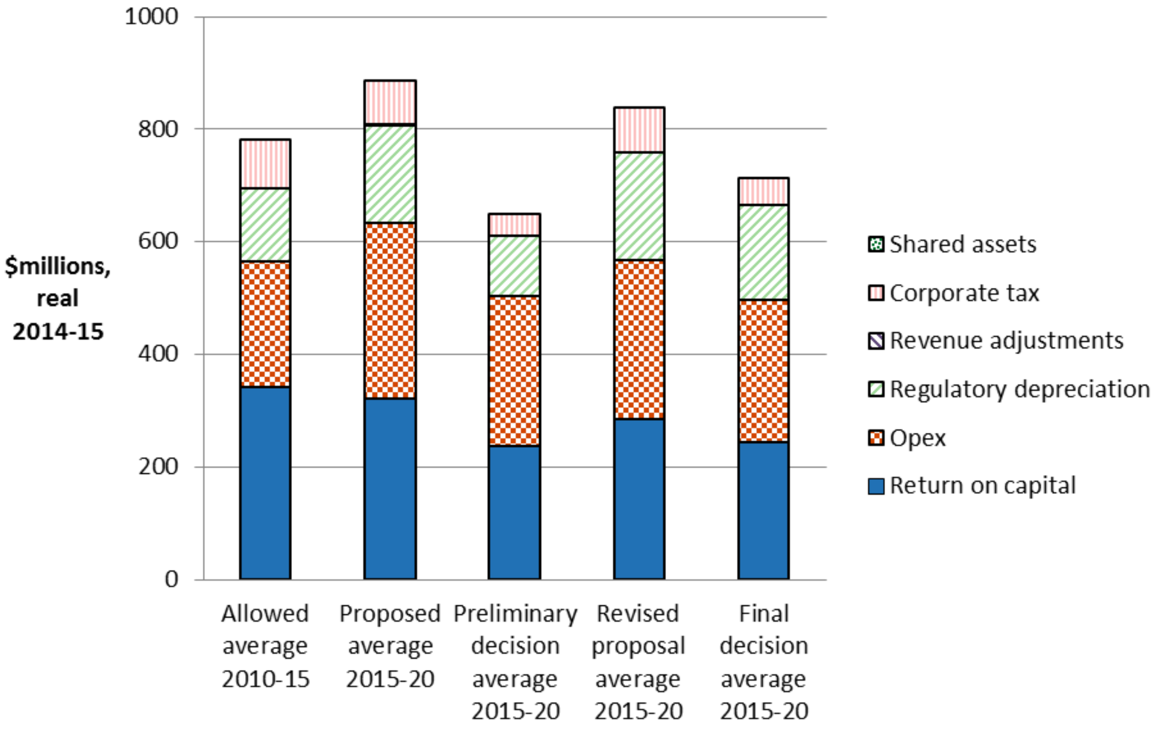
In setting the allowed revenue for SA Power Networks of $3837.5 million ($ nominal) for the 2015–20 regulatory control period, we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation Guidelines. We also consider information provided by SA Power Networks, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions.

- consider our total revenue allowance against section 16 of the NEL, including the constituent components set out in the NER, how they interrelate with each other and how those interrelationships have been take into account.

Figure 4 and table 2 show our final decision on SA Power Networks' revenue and the contribution of each building block.

Figure 4 AER's final decision on constituent components of total revenue ($ million, 2014–15)



Source: AER analysis.

Note: Revenue adjustments include efficiency benefit sharing scheme amounts, shared asset amounts and forecast DMIA.

Table 2 AER's final decision on SA Power Networks' revenues for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	233.0	250.7	263.9	276.5	288.7	1312.9
Regulatory depreciation	116.9	188.8	194.0	202.5	215.0	917.2
Operating expenditure	249.5	265.0	271.5	281.9	292.4	1360.3
Revenue adjustments[a]	–0.1	–4.8	–2.3	5.4	–0.1	–1.9
Net tax allowance	38.9	52.4	51.9	54.5	60.6	258.3
Annual revenue requirement (unsmoothed)	638.2	752.1	779.1	820.8	856.7	3846.9
Annual expected revenue (smoothed)	682.0	748.2	774.5	801.9	830.9	3837.5
X factor[b]	n/a	–7.02%	–1.00%	–1.00%	–1.10%	n/a

Source: AER analysis.

(a) Revenue adjustments include efficiency benefit sharing scheme carry-overs, shared asset amounts and forecast DMIA.

(b) The X factors from 2016–17 to 2019–20 will be revised to reflect the annual return on debt update.

(c) In our preliminary decision, we determined the expected revenue and associated X factor for 2015–16. In this final decision to update the 2015–16 revenue for our assessment of efficient costs, we maintained the preliminary decision expected revenue for 2015–16 and determined X factors for the final four years of the 2015–20 regulatory control period. This is to adjust SA Power Networks' total expected revenue requirement for the remaining four years in the 2015–20 regulatory control period for the difference between the preliminary decision revenue and our final decision on SA Power Networks' efficient costs for 2015–16.

3.1 Regulatory asset base

The RAB is the value of SA Power Networks' assets used to provide distribution network services. It is the value on which SA Power Networks earns a return on capital and a depreciation allowance (return of capital) on assets in its RAB. We assess SA Power Networks' proposed opening value for the RAB for each year of the 2015–20 regulatory control period.

Our final decision is to accept SA Power Networks' revised proposed opening RAB value of $3778.4 million ($ nominal) as at 1 July 2015. We had accepted in our preliminary decision the opening RAB in SA Power Networks' initial proposal, noting some updates would be required for the final decision. SA Power Networks' revised proposal made the following changes:[13]

- updating 2014–15 capex with more recent estimates
- updating the RAB roll forward with the actual inflation input for 2014–15.

[13] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 324.

SA Power Networks adopted our preliminary decision on the use of forecast depreciation for establishing the RAB at the commencement of the regulatory control period from 1 July 2020.[14]

Table 3 sets out our final decision on the roll forward of the RAB values for the 2010–15 regulatory control period.

Table 3 AER's final decision on SA Power Networks' RAB for the 2010–15 regulatory control period ($ million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15[a]
Opening RAB	2900.0	3096.8	3287.9	3502.0	3674.4
Capital expenditure[b]	271.0	325.7	335.2	291.3	335.4
Inflation indexation on opening RAB	96.6	48.9	82.2	102.6	48.9
Less: straight-line depreciation	170.7	183.6	203.3	221.5	242.0
Closing RAB	3096.8	3287.9	3502.0	3674.4	3816.7
Difference between estimated and actual capex (1 July 2009 to 30 June 2010)					–24.3
Return on difference for 2009–10 capex					–14.0
Closing RAB as at 30 June 2015					3778.4

Source: AER analysis.

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

(b) Net of disposals and capital contributions, and adjusted for CPI.

We determine a forecast closing RAB value at 30 June 2020 of $4882.4 million ($ nominal). This is $107.8 million (or 2.2 per cent) lower than the amount of $4990.2 million ($ nominal) in SA Power Networks' revised proposal. Our final decision on the forecast closing RAB reflects our adjustments to SA Power Networks' forecast capex (attachment 6), forecast regulatory depreciation (attachment 5) and the forecast inflation rate (attachment 3).

Table 4 sets out our final decision on the roll forward of SA Power Networks' forecast RAB for the 2015–20 regulatory control period.

14 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 324.

Table 4 AER's final decision on SA Power Networks' RAB for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20
Opening RAB	3778.4	4064.1	4279.3	4482.8	4680.9
Capital expenditure[a]	402.6	404.1	397.5	400.6	416.5
Inflation indexation on opening RAB	94.5	101.6	107.0	112.1	117.0
Less: Straight-line depreciation	211.3	290.4	301.0	314.6	332.0
Closing RAB	4064.1	4279.3	4482.8	4680.9	4882.4

Source: AER analysis.

(a) Net of forecast disposals and capital contributions.

Details of our final decision on the value of the RAB are set out in attachment 2.

3.2 Rate of return (return on capital)

The return on capital provides a distributor with revenue to service the interest on its loans and give a return on equity to shareholders. The return on capital building block is calculated as a product of the rate of return and the value of the RAB.[15]

The NER set out that the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services. The NER refers to this requirement as the 'allowed rate of return objective'.

We have determined an allowed rate of return of 6.17 per cent (nominal vanilla[16]). We have not accepted SA Power Networks' proposed 7.09 per cent return. In accordance with the Rate of Return Guideline, we will update the rate of return annually.[17] Table 5 sets out the parameters we have used to determine the rate of return.

15 NER, cl. 6.5.2(a).

16 The nominal vanilla rate of return formula combines a post-tax return on equity and pre-tax return on debt, for consistency with other building blocks.

17 NER, cl. 6.5.2(i)(2).

Table 5 AER's final decision on SA Power Networks' rate of return (nominal)

	AER previous decision (2010–15)	SAPN revised proposal (2015–16)[(a)]	AER final decision (2015–16)	Return over 2015–20 regulatory control period
Return on equity (nominal post–tax)	11.09%	9.8%	7.5%	Remains constant (7.5%)
Return on debt (nominal pre–tax)	8.87%	5.29%	5.28%	Updated annually
Gearing	60%	60%	60%	Remains constant (60%)
Nominal vanilla WACC	9.76%	7.09%	6.17%	Updated annually as return on debt is updated
Forecast inflation	2.52%	2.06%	2.50%	Remains constant (2.50%)

Source: AER analysis; SA Power Networks, *Revised regulatory proposal 2015-20*, July 2015; AER, *Final decision: South Australia distribution determination 2010–11 to 2014–15*, May 2010.

(a) SA Power Networks' revised proposal uses values derived from the placeholder averaging periods for risk free rate and rate on debt in its revised proposal. SA Power Networks' revised proposal: maintains the position in its (initial) regulatory proposal concerning the allowed rate of return on equity of 9.83 per cent; includes the 'hybrid' transition delivering a return of 5.29 per cent using the 'place holder' averaging period; and determines the inflation rate by using actual recorded inflation for that part of the regulatory period that has already elapsed and otherwise market based measures instead of the forecasts and mid-point targets of the Reserve Bank of Australia. SA Power Networks, *Revised regulatory proposal 2015-20*, 27 March 2015, p. 331.

Our approach

All NER requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective.[18] The NER recognises that there may be several plausible answers that could achieve the allowed rate of return objective. We agree with stakeholders that predictability in our approach to rate of return issues, consistent with prevailing market conditions materially benefits the long term interests of consumers and also benefits investors.[19]

We developed our approach prior to the submission of SA Power Networks' initial regulatory proposal. As required by the rate of return framework, in December 2013 we

[18] NER, cl. 6.5.2(b).

[19] ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p. 1; AER, *Better regulation: Explanatory statement Rate of Return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp. 185−186.

published the Guideline.[20] The Guideline was developed through extensive consultation and involved effective and inclusive stakeholder participation.[21]

Return on debt

Previously, we used an on-the-day approach to determine the return on debt.[22] This is the approach that many Australian regulators continue to use. We have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.[23] This is consistent with the approach most stakeholders supported during the Guideline development process.

In its initial proposal, SA Power Networks proposed a gradual transition from the on–the–day to trailing average approach. We accepted SA Power Networks' initial regulatory proposal. However, in its submission on the current determination processes, SA Power Networks purported to depart from its initial proposal on this issue. It proposed a hybrid transition to the trailing average approach.

We have not accepted SA Power Networks' revised approach on this issue. We consider that SA Power Networks' revised approach is backward looking and produces a biased estimate of the return on debt. We discuss this in attachment 3 ─ rate of return.

Return on equity

Our approach to determining the return on equity involves considering all of the information before us, through a six step process as set out in the Rate of Return Guideline (foundation model approach). This includes detailed consideration of a number of financial models for determining the return on equity.[24] Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective. However, SA Power Networks' proposed a multi-model approach to calculating the return on equity.

We consider that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. We are persuaded by the expert evidence before us that also indicates that, on balance, employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.[25]

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20 NER, cl. 6.5.2(m).

21 http://www.aer.gov.au/node/18859

22 This involved determining the return on debt by reference to the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the regulatory control period.

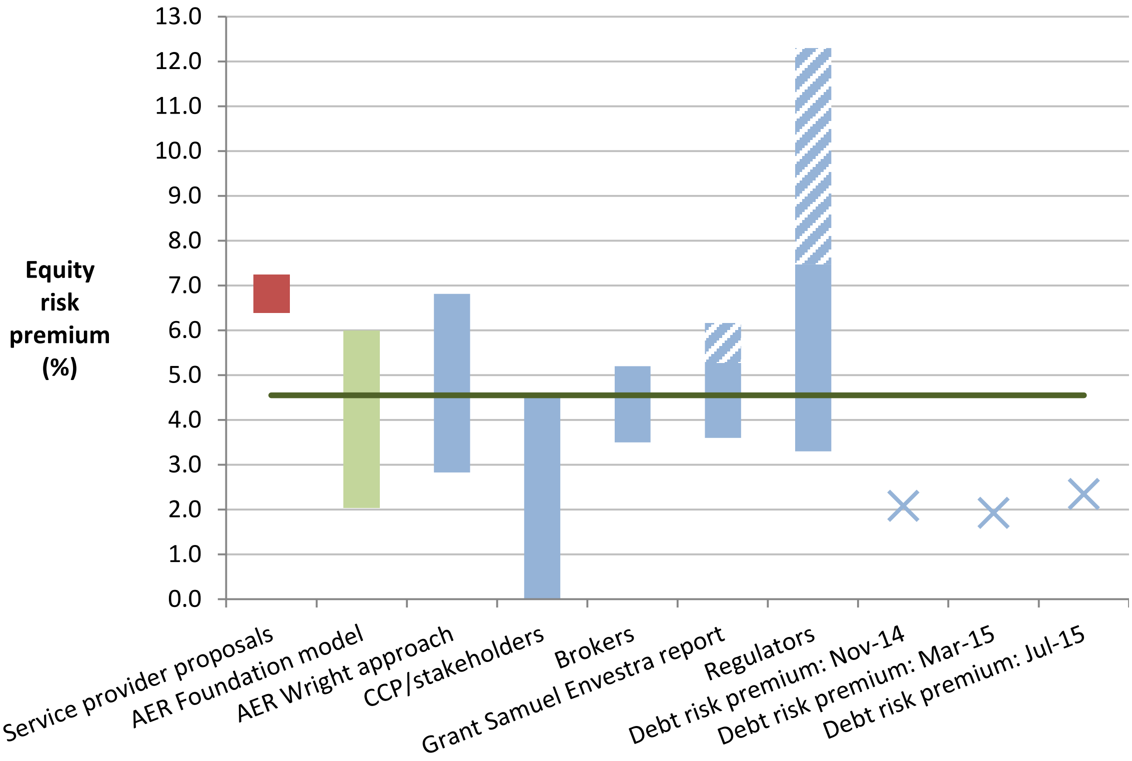
23 In broad terms, this means that the return on debt for any year will represent the average return on debt over the previous ten years.

24 NER, cl.6.5.2(e)(1).

25 McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p. 13; John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p. 3.

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at any given time.[26] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within the range of other information available to inform the return on equity (see figure 5). A detailed explanation of our findings on return on equity and this figure can be found attachment 3: Rate of return.

Figure 5 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports.

Notes: The AER foundation model equity risk premium (ERP) range uses the range and point estimate for MRP and equity beta as set out in step three. The calculation of the Wright approach, debt premium, brokers, and other regulators ranges is outlined in Appendices E.1, E.2, E.4, and E.5 respectively.

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel made no explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.

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[26] Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

The shaded portion of the other regulators range represents the impact of rail decisions on the range. We consider rail networks are unlikely to be comparable to the benchmark efficient entity.

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in October-December 2015. Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in October-December 2015. The lower bound is based on the Alliance of Electricity Consumers submission on Energex and Ergon Energy revised proposals. The upper bound is based on Origin Energy's submission on the preliminary decision for SA Power Networks.

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[27] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NER requires that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[28] That is, the revenue a service provider recovers from customers in respect of its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

Our final decision is to adopt a value of imputation credits of 0.4. This differs from SA Power Networks' proposed value of imputation credits of 0.25.

Although we have broadly maintained the approach to determining the value of imputation credits set out in the Rate of Return Guideline, we have re-examined the relevant evidence and estimates since our preliminary decision. This re-examination, and new evidence and advice considered for the first time since the Guideline, led us to depart from the value of 0.5 in the Guideline. Most notably, our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate in the Guideline.

Estimating the value of imputation credits is a complex and somewhat imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a

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27 *Income Tax Assessment Act 1997*, parts 3–6.

28 NER, cll. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3.

widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate. There is a range of evidence relevant to the utilisation rate:

- the proportion of Australian equity held by domestic investors (the 'equity ownership approach')
- the reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics')
- implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics
- less reliance upon implied market value studies.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range of 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- the equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.29 and 0.42 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.42.
- the evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- an estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance on SFG's dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this study (0.31) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

3.4 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). We are required to decide on whether to approve the depreciation schedules submitted by SA Power

Networks.[29] In doing so, we make a determination on the indexation of the RAB and depreciation building blocks for SA Power Networks' 2015−20 regulatory control period. The regulatory depreciation allowance is the net total of straight-line depreciation less the indexation of the RAB.

Our final decision is to determine a regulatory depreciation allowance of $917.2 million ($ nominal) for SA Power Networks. This amount represents a decrease of $122.2 million ($ nominal) (or 11.8 per cent) of the $1039.5 million ($ nominal) SA Power Networks proposed for the 2015–20 regulatory control period.[30]

We have departed from our preliminary decision. In coming to our final decision:

- we accept SA Power Networks' revised proposed asset classes, its straight-line depreciation method, and the standard asset lives used to calculate the regulatory depreciation allowance.
- we accept SA Power Networks' revised proposal approach to determining depreciation associated with existing assets compared to its initial proposal. However, we have made some changes to the implementation of the approach for clarity and to prevent a distortion in the depreciation profile.
- we made determinations on other components of SA Power Networks' revised proposal which affect the forecast regulatory depreciation allowance—that is, forecast inflation (attachment 3) and forecast capex (attachment 6).[31]

Table 6 sets out our final decision on SA Power Networks' depreciation allowance for the 2015–20 regulatory control period.[32]

Table 6 AER's final decision on SA Power Networks' depreciation allowance for the 2015−20 regulatory control period ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Straight-line depreciation	211.3	290.4	301.0	314.6	332.0	1449.4
Less: inflation indexation on opening RAB	94.5	101.6	107.0	112.1	117.0	532.1
Regulatory depreciation	**116.9**	**188.8**	**194.0**	**202.5**	**215.0**	**917.2**

Source: AER analysis.

Details of our final decision on the regulatory depreciation allowance are set out in attachment 5.

29 NER, cl. 6.12.1(8).

30 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 411–412.

31 NER, cl. 6.5.5(a)(1).

32 NER, cl. 6.5.5(b).

3.5 Capital expenditure

Capex refers to the capital expenses incurred in the provision of network services. The return on and return of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

We estimate total capex of $1845.8 million ($2014–15) for SA Power Networks' 2015–20 regulatory control period. This is a reduction of 10.9 per cent on SA Power Networks' revised capex forecast of $2070.8 million ($2014–15). We are satisfied our substitute estimate of SA Power Networks' total forecast capex reasonably reflects the capex criteria. Table 7 outlines our final decision compared to SA Power Networks' revised proposal.

Table 7 AER final decision on SA Power Networks' total capex ($ million 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' revised proposal	409.1	444.4	423.6	411.7	382.0	2,070.8
AER final decision	376.5	380.5	364.7	358.8	365.4	1845.8
Difference	-32.7	-63.9	-58.9	-53.0	-16.6	-225.0
%	-8.0	-14.4	-13.9	-12.9	-4.3	-10.9

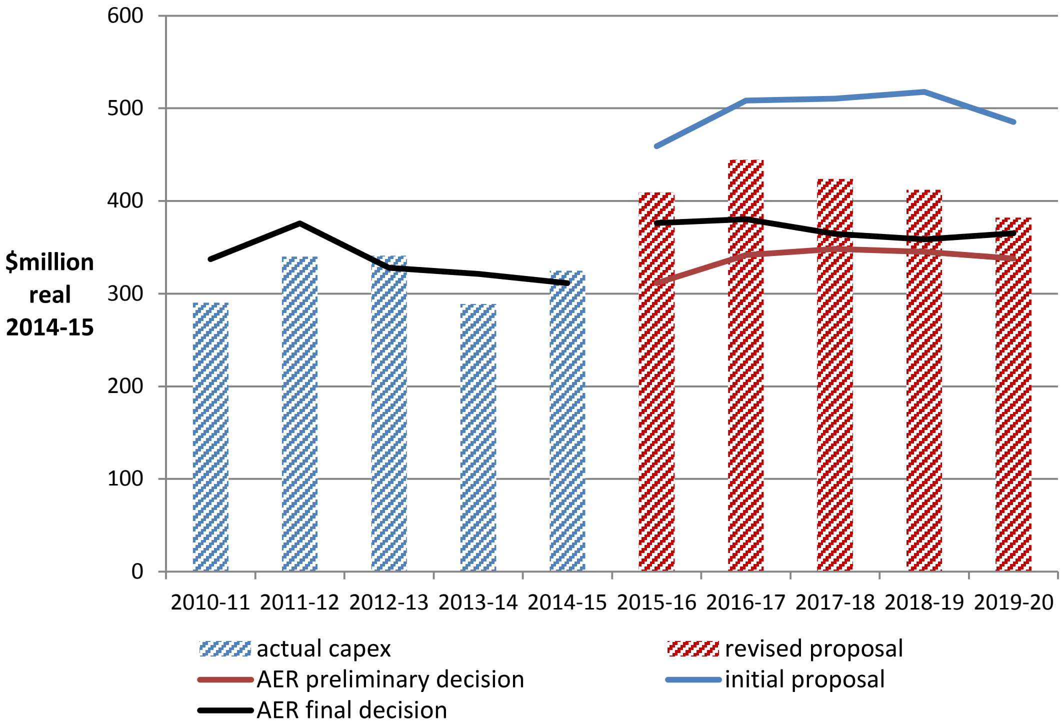
Source: AER analysis.

Note: Numbers may not add up due to rounding.

Note: Total capex excludes capital contributions.

Figure 6 shows SA Power Networks' initial proposal, its revised proposal and our preliminary and final decisions for capex for the 2015−20 regulatory control period. It also shows the actual capex that SA Power Networks spent during the 2010−15 regulatory control period.

Figure 6 AER final and preliminary decisions compared to SA Power Networks' actual and forecast capex



SA Power Networks submitted a revised total capex forecast 16.5 per cent lower than its initial regulatory proposal. The main reasons for the lower capex forecast in SA Power Networks' revised proposal are:

- lower expenditure for bushfire mitigation and network monitoring
- removed expenditure for road safety
- lower proposed replacement expenditure (repex)
- lower capex for unmodelled SCADA and "other" capex.

Attachment 6 sets out our detailed reasons for our final decision on SA Power Networks' revised capex forecast. In our final capex decision, we accept a number of components of SA Power Networks' revised total capex forecast, including capex for:

- meeting forecast demand growth in some areas and maintaining power quality
- improving security of supply by hardening the network against severe weather events and establishing a second undersea cable to Kangaroo Island
- undergrounding power lines (as part of the power line environment committee) and network control and monitoring equipment at rural substations
- SA Power Networks' core bushfire safety program.

However, we consider that overall SA Power Networks' revised capex proposal did not reflect the capex criteria.

The key points of our capex estimate for SA Power Networks are:[33]

- Our substitute estimate of total capex includes $655.1 million ($2014–15) for repex. This is 4 per cent lower than SA Power Networks' revised repex forecast of $681.9 million ($2014–15). Our repex estimate is lower because we used updated data in our repex model. We consider the forecast for pole top repex to be excessive. We consider SA Power Networks' actual pole top repex from the 2010–15 regulatory control period better reflects an appropriate forecast that meets the capex criteria than SA Power Networks' forecast.

- Our substitute estimate of total capex includes $481.1 million ($2014−15) for augmentation expenditure (augex). This is 19 per cent lower than SA Power Networks' revised augex forecast of $592.1 million. We accept SA Power Networks' core bushfire safety program. However, our augex estimate is lower primarily because we do not accept SA Power Networks' proposals for bushfire mitigation measures that were incremental to its core bushfire safety program. We are satisfied that SA Power Networks is currently complying with, and is expected to continue to meet, its regulatory safety obligations over the 2015─20 regulatory control period. Also, we do not accept some of SA Power Networks' proposals to further improve reliability levels beyond current compliant levels and for further network monitoring because it is not necessary to meet its service obligations.

- Our substitute estimate of total capex includes $723.0 million ($2014–15) for connections capex.[34] Our connections capex estimate includes a forecast of customer contributions of $522.5 million ($2014–15). Our preliminary decision accepted SA Power Networks' forecasts for connections and customer contributions. Our final decision is also to accept SA Power Networks' forecasts, which are unchanged. We accepted the forecasts after considering long term trends and assessing them as consistent with expected construction activity in South Australia. SA Power Networks' revised proposal included slight upward revisions to gross expenditure and customer contributions. SA Power Networks noted these reflect revisions to augmentation charges included in SA Power Network's amended Connection Policy. We are satisfied lower augmentation charge rates will reduce expenditure SA Power Networks may recover through customer contributions.

- We estimate SA Power Networks requires $511.2 million ($2014–15) for non–network capex. This is 9 per cent lower than SA Power Networks' revised non–network capex forecast of $562.6 million ($2014–15). We accept SA Power Networks' revised forecast capex for motor vehicles, communications and other non-network capex. Our estimate of total non–network capex is lower than SA

[33] We obtained these figures from SA Power Networks' RIN. Our assessment used information subsequently provided by SA Power Networks.

[34] Total connections capex includes customer contributions.

Power Networks' forecast because we consider its forecasts for non–network IT capex projects are higher than the efficient costs required to meet the identified needs. Also, we are not satisfied SA Power Networks' business cases for major property projects reflect prudent and efficient expenditure.

- We do not accept SA Power Networks' proposed capitalised overheads of $89.4 million ($2014–15). We have instead included in our substitute estimate of overall total capex an amount of $83.8 million ($2014–15) for capitalised overheads. This reduction in forecast overheads reflects our direct capex forecast that is expected to attract overhead expenditure.

3.6 Operating expenditure

Opex is non-capital expenditure incurred in the provision of distribution network services. It includes labour and other non-capital costs that SA Power Networks is likely to require to operate and maintain its network during the 2015–20 regulatory control period.

SA Power Networks forecast total opex of $1432.1 million ($2014–15) over the 2015–20 regulatory control period. Our final decision is we are not satisfied SA Power Networks' revised forecast opex as submitted reasonably reflects the opex criteria. Where we find that a distributors' forecast opex does not reasonably reflect the opex criteria, the NER instructs us to not accept it and replace it with a forecast that we are satisfied reasonably reflects the opex criteria.

We accept SA Power Networks' forecast opex as a starting point to the 2015–20 regulatory control period. SA Power Networks has been operating efficiently. The incentive framework will continually encourage SA Power Networks to find further efficiencies. We do not however accept the forecast increments to opex that SA Power Networks set out in its revised proposal.

Attachment 7 sets out our detailed reasons for our final decision on SA Power Networks' total forecast opex. We compare our estimate with SA Power Networks' proposal in table 8.

Table 8 AER final decision on total opex ($ million, 2014–15)

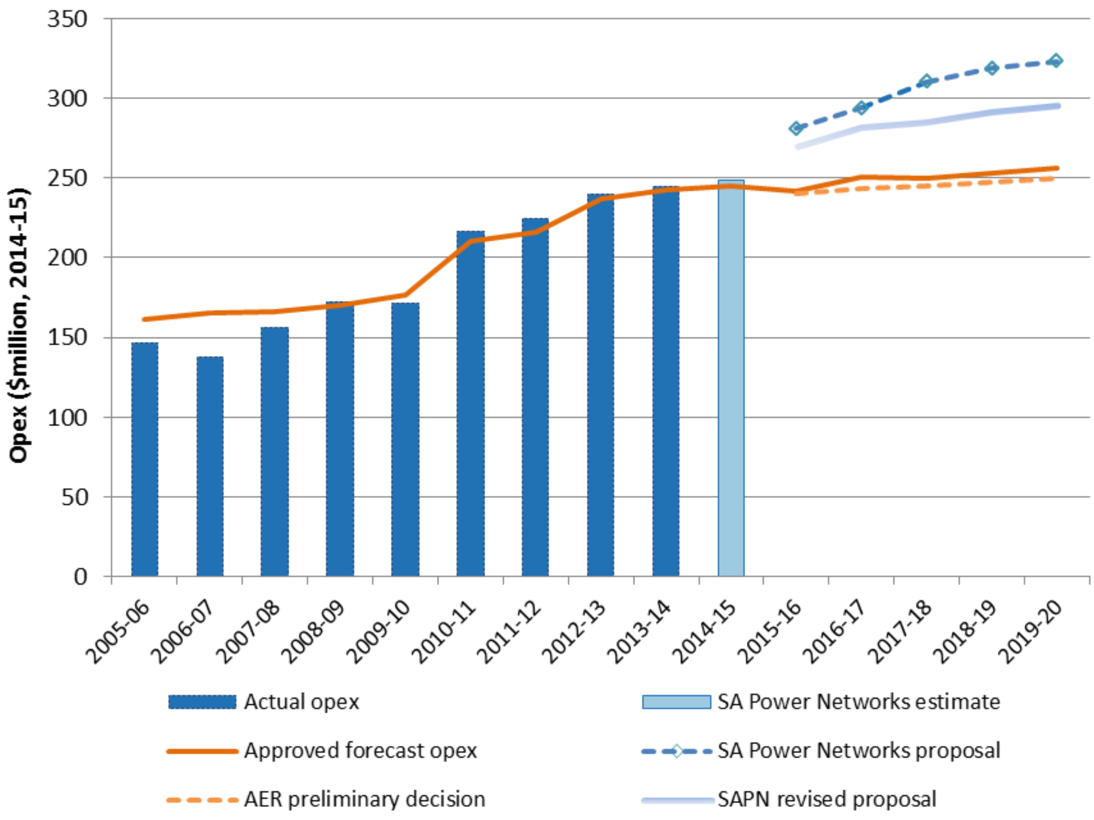
Year ending 30 June	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' revised proposal	271.6	283.0	286.9	292.9	297.7	**1432.1**
AER final decision	243.4	252.2	252.1	255.4	258.5	**1261.6**
Difference	**–28.2**	**–30.8**	**–34.8**	**–37.5**	**–39.2**	**–170.4**

Source: AER analysis.

Note: Includes debt raising costs.

Figure 7 shows our final decision compared to SA Power Networks' proposal, its past allowances and past actual expenditure.

Figure 7 AER final decision compared to SA Power Networks' past and proposed opex ($million, 2014–15)



Source: SA Power Networks, Regulatory accounts 2010–11 to 2013–14; SA Power Networks, Economic benchmarking - Regulatory Information Notice response 2005–06 to 2012–13; SA Power Networks, *Regulatory proposal for the 2015–20 period* - Attachment 211.11a PUBLIC; SA Power Networks, 2015–20 revised regulatory proposal, July 2015, p. 186; AER analysis.

We have used SA Power Networks' reported opex for 2013–14 as the basis for forecasting total opex. The difference between our forecast opex and SA Power Networks' proposal reflects our views on step changes and the rate of change.

3.6.1 Step changes

We have included six step changes in our opex forecast:

- New Regulatory Information Notice (RIN) requirements
- National Energy Customer Framework (NECF)
- Demand side participation - stakeholder engagement for new tariff structures
- Mobile radio
- Information Technology - Billing and customer related system
- Distribution licence fee.

We are satisfied that changes in opex associated with these step changes arise due to new regulatory requirements or efficient capex/opex trade-offs. We are not, however, satisfied there are reasons to change our opex forecast for any other step changes proposed by SA Power Networks in its revised proposal.

In particular, we have determined that SA Power Networks is currently operating relatively efficiently. Its base opex provides a good indicator of the total opex it should need in each year of the 2015–20 regulatory control period. The main reason why SA Power Networks' opex forecast in its revised proposal was materially higher than it has incurred in recent years was due to its forecast step changes. We consider that many of the proposed step changes reflect discretionary changes in programs and projects rather than new expenditure in response to external drivers. We consider that changes in discretionary expenditure should be managed by SA Power Networks within its current level of funding for opex.

3.6.2 Rate of change

The difference between our forecast of the rate of change and SA Power Networks' proposal reflects our views on price growth and output growth:

- we have forecast lower labour price growth than SA Power Networks and we have adopted different opex price weights
- our approach to forecasting output growth used information from Economic Insights and SA Power Networks' reset RIN, which produced a lower forecast than that proposed by SA Power Networks.

3.7 Corporate income tax

The NER requires us to make a decision on the estimated cost of corporate income tax for SA Power Networks' 2015–20 regulatory control period. The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for SA Power Networks over the 2015–20 regulatory control period. It enables SA Power Networks to recover the costs associated with the estimated corporate income tax payable during that period.

Our final decision is to determine the estimated cost of corporate income tax of $258.3 million ($ nominal) for SA Power Networks over the 2015–20 regulatory control period as shown in table 9. We do not accept SA Power Networks' revised proposed cost of corporate income tax allowance of $426.5 ($ nominal). This represents a reduction of $168.2 million (or 39.4 per cent) from SA Power Networks' revised proposal.

Table 9 AER's final decision on SA Power Networks' tax allowance for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Tax payable	64.8	87.4	86.5	90.9	101.0	430.6
Less: value of imputation credits	25.9	34.9	34.6	36.4	40.4	172.2
Corporate income tax allowance	**38.9**	**52.4**	**51.9**	**54.5**	**60.6**	**258.3**

Source: AER analysis.

Our final decision reflects our amendment to one of SA Power Networks' revised proposed inputs for forecasting the cost of corporate income tax. This is due to some changes to the implementation of its revised proposed tax depreciation approach for existing tax assets, which we accept. It also reflects our final decision on the value of imputation credits (gamma) as discussed in attachment 4. Changes to the building block costs also affect revenue, which in turn impacts the tax calculation. The changes affecting revenue are discussed in attachment 1.

Details of our final decision on the corporate income tax allowance are set out in attachment 8.

4 Service classification, incentive schemes and other issues

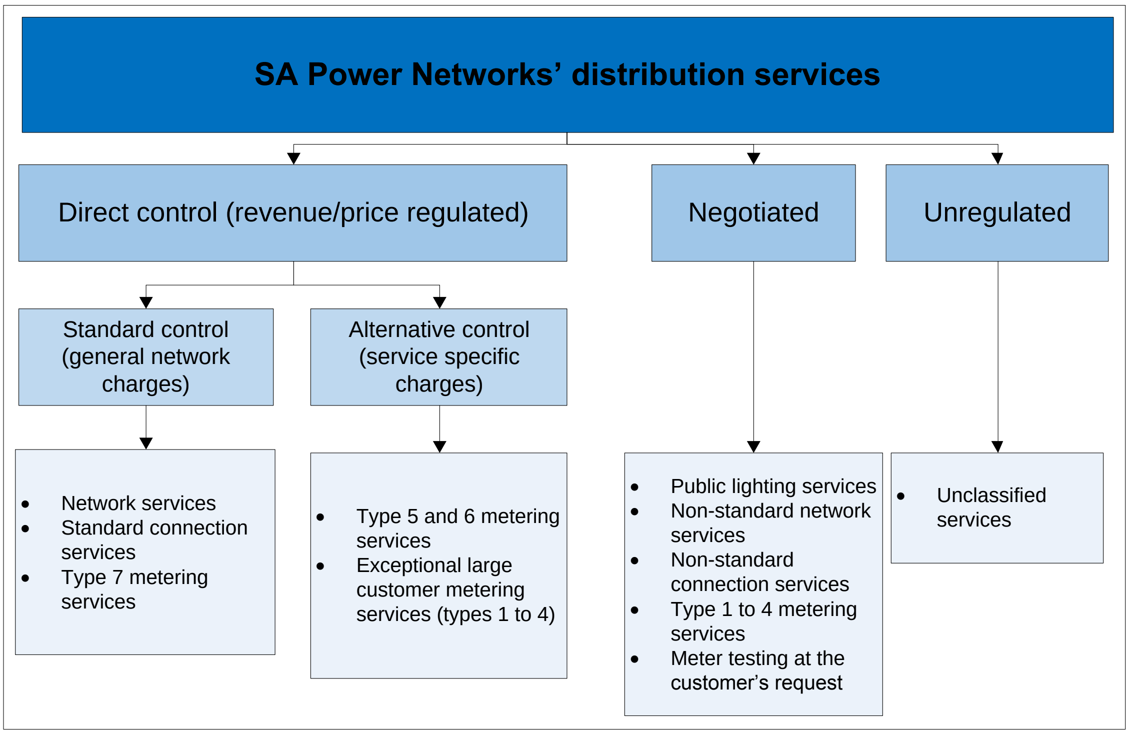
A range of factors, in addition to the building blocks, affect SA Power Networks' revenue. These include service classification, control mechanism, our approach to services charged to individual consumers and incentive schemes to promote efficiency. This section sets out final decision on these issues.

4.1 Service classification and control mechanism

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our final decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Our final decision is to retain the classification structure as set out in our preliminary decision. Figure 8 summarises our final decision on service classifications for the 2015–20 regulatory control period.

Figure 8 AER's final decision on 2015–20 service classifications for SA Power Networks



Consistent with our preliminary decision, SA Power Networks will be subject to a 'revenue cap' form of control for standard control services over the 2015–20 regulatory control period. The control mechanism (which describes how revenue will vary from year to year) is discussed in attachments 14 and 16. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap.

4.2 Alternative control services

Alternative control services do not form part of SA Power Networks' revenue cap. Rather, the prices of these services are set individually. Our final decision is to maintain the approach adopted in our preliminary decision, that the form of control mechanism to apply to SA Power Networks' alternative control services will be price caps. SA Power Networks must demonstrate compliance with the control mechanism through an annual pricing proposal.

Our final decision approves a structure of metering charges which has a capital and non–capital component. This “two–part tariff” gives effect to a regulatory regime that is robust enough to transition to competition. In accordance with an AEMC draft determination and draft rule, competition in metering and related services is scheduled to occur on 1 July 2017.[35]

The approved two part tariff structure is largely unchanged from our preliminary decision. This is with the exception of a reallocation of SA Power Networks’ recovery of its tax liability costs, from the non–capital to the capital component. We approved this change in response to SA Power Networks’ revised proposal. For more information about the approved structure of metering charges refer to attachment 16 (appendix B).

4.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to SA Power Networks are the:

- efficiency benefit sharing scheme (EBSS)
- capital expenditure sharing scheme (CESS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme (DMIS).

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. Incentives for opex and capex are balanced (approximately 30 per cent) and constant. They are also balanced with the incentives under our service target performance incentive scheme. This encourages businesses to make efficient decisions on when and what type of expenditure to incur, in order to meet or exceed service reliability targets.

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35 AEMC, *Draft Rule Determination, National Electricity Amendment (Expanding competition in metering related services) Rule 2015*, 26 March 2015.

4.3.1 Efficiency benefit sharing scheme

The EBSS provides an additional incentive for service providers to pursue efficiency improvements in opex.

As opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period (step changes provide for increases where this is not the case). Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period to forecast opex for the next regulatory control period. We call this the 'revealed cost approach'.

To encourage a service provider to become more efficient during the regulatory control period it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the service provider to retain efficiency savings and efficiency losses for a longer period of time.[36] In total these rewards and penalties work together to provide a continuous incentive for a service provider to pursue efficiency gains over the regulatory control period. The combined effect of our revealed cost forecasting approach and the EBSS is that opex efficiency savings or losses are shared approximately 30:70 between the network businesses and consumers. For example, for a one dollar saving in opex the network business gets 30 cents of the benefit while consumers get 70 cents of the benefit.

The EBSS also discourages a service provider from incurring opex in the expected base year in order to receive a higher opex allowance in the following regulatory control period.[37]

Our final decision for the EBSS carryover amounts from the 2010–15 regulatory control period is outlined in table 10. The difference between SA Power Networks' revised proposal and our final decision mostly reflects an adjustment we have made for Regulatory Information Notice reporting costs.

Table 10 AER's final decision on SA Power Network's EBSS carryover amounts ($ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' revised proposal	-0.7	-5.0	-2.7	3.8	0.0	-4.7
Our final decision	0.1	-4.4	-1.9	5.0	0.0	-1.2

Source: AER analysis; SA Power Networks, PTRM in revised proposal for the 2015–20 regulatory control period.

[36] Without this, the incentive would be greatest to make savings in the first year of the regulatory control period.

Our final decision is to apply the EBSS to SA Power Networks in the 2015–20 regulatory control period.[38] Our final decision on the EBSS for SA Power Networks is discussed in attachment 9.

4.3.2 Capital expenditure sharing scheme

The CESS provides a network service provider with the same reward for an efficiency saving and same penalty for an efficiency loss regardless of which year they make the saving or loss. Consumers benefit from improved efficiency through lower regulated prices.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

For capex, the sharing of underspends and overspends happens at the end of each regulatory control period when we update a network service provider's RAB to include new capex. If a network service provider spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the service provider had spent the full amount of the capex forecast.

Our final decision is to apply the CESS, as set out in version 1 of the Capital Expenditure Incentives Guideline, to SA Power Networks in the 2015–20 regulatory control period.[39] Attachment 10 sets out our reasons for our final decision on the CESS.

4.3.3 Service target performance incentive scheme

In its regulatory proposal, SA Power Networks supported our framework and approach proposal to apply the national STPIS for the 2015–20 regulatory control period. SA Power Networks was subject to a variant of the national STPIS scheme in the 2010–15 regulatory control period. SA Power Networks submitted a proposal to transition from its current application of the STPIS to the national STPIS. Our final decision, consistent with our preliminary decision, is to adopt SA Power Networks' proposed transition approach. Attachment 11 sets out our final decision on SA Power Networks' service component parameter values.

The national STPIS is intended to balance the incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing appropriate financial incentives to distributors to maintain and improve service performance (at the level where customers are willing to pay for these

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[38] AER *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

[39] AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, pp. 5–9.

improvements).[40] Hence, the STPIS also provides an incentive for distributors to invest in further reliability improvements (via additional capex or opex) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate beyond the acceptable level valued by customers. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

Distributors can only retain their rewards for sustained and continuous improvements to the reliability of supply to customer. Once improvements are made, the benchmark performance targets will be tightened in future years.

In conjunction with the EBSS and CESS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex are achieved efficiently, rather than at the expense of service levels to customers.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

4.3.4 Demand management incentive scheme

The DMIS includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

We have determined to continue Part A of the DMIS for SA Power Networks in the 2015–20 regulatory control period (that is, the DMIA component). We will not apply Part B of the DMIA to SA Power Networks for the 2015–2020 regulatory control period because we have decided to apply a revenue cap form of control. This is consistent with our preliminary decision.[41] SA Power Networks accepted our preliminary decision on this issue.[42]

The current innovation allowance amount of $0.6 million ($2014–15) per annum will continue in the 2015–20 regulatory control period.

Attachment 12 sets out our final decision on SA Power Networks' DMIS.

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[40] AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009.

[41] AER, *Preliminary decision SA Power Networks distribution determination 2015-16 to 2019-20, Attachment 12 – Demand management incentive scheme*, April 2015, pp. 6–7.

[42] SA Power Networks, *SA Power Networks Revised Regulatory Proposal,* July 2015, pp. 316–317.

5 Understanding the NEO

The NEO is the central feature of the regulatory framework. The NEO is to:

> promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.[43]

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.[44] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[45]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[46] We have also considered the quality and reliability of services provided to consumers. For example, opex allowances have been set so SA Power Networks may meet existing and new regulatory requirements. Repex allowances take into account the age and condition of assets. We have allowed sufficient augex and connections capex to cater for expected areas of growth. Our capex allowance is based on a contemporary estimate of the value of customer reliability. And the STPIS encourages maintenance, and indeed improvement of, service quality.

The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[47] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would.

For example, we do not consider that the NEO would be advanced if the allowed revenue encourages overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[48] This could have significant longer term pricing implications for those consumers who continue to use network services.

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43 NEL, s. 7.

44 Hansard, *SA House of Assembly*, 9 February 2005, pp. 1451–1460.
Hansard, *SA House of Assembly*, 27 September 2007, pp. 963–972.
Hansard, *SA House of Assembly*, 26 September 2013, pp. 7171–7176.

45 Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

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

47 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50.

48 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if the allowed revenue result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[49] and could have adverse consequences for safety, security and reliability of the network.

The NEL also includes the revenue and pricing principles (RPP), [50] which support the NEO. As the NEL requires,[51] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
> - as the case requires, distribution determination or transmission determination; or
> - determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
> - in the Rules.
>
> A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks

49 NEL, s. 7A(6).

50 NEL, s. 7A.

51 NEL, s. 16(2).

> involved in providing the direct control network service to which that price or charge relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all elements of the NEO and consider each of the RPPs.[52] For example:

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide SA Power Networks with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a network service provider in our assessment of SA Power Networks' forecast capital expenditure and operating expenditure proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of SA Power Networks' distribution system in our demand forecasting and augmentation determinations (Refer to capex attachment 6).
- Our application of the EBSS, CESS, STPIS and DMIS in this determination provides SA Power Networks with effective incentives which we consider will promote economic efficiency with respect to the direct control services that SA Power Networks provides throughout the regulatory control period. (Refer to attachments 9, 10, 11 and 12).
- We have determined SA Power Networks' opening RAB taking into account the RAB adopted in the previous distribution determination. (Refer to attachment 2, regulatory asset base).
- The allowed rate of return objective reflects the revenue and pricing principle in s. 7A(5). We have determined a rate of return that we consider will provide SA Power Networks with a return commensurate with the regulatory and commercial risks involved in providing direct control services. (Refer to attachment 3, rate of return).
- Our financing determinations provide the distributor with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

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52 Hansard, *SA House of Assembly*, 27 September 2007, p. 965; Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, we are also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the determination are each set too conservatively.[53] The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[54]

5.1 Achieving the NEO to the greatest degree

A distribution determination is a complex decision and must be considered as such. In most instances, 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. For example, chapter 6 of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several point estimates within a range.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. Where this is the case, our role is to

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53 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2016, p. 52.

54 NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* p. 8.

make an overall decision that we are satisfied contributes to the achievement of the NEO to the *greatest* degree.[55]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NEO, 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.

Also, in coming to this final decision we have considered SA Power Networks' initial and revised proposals. We have examined each of the building block components of the proposals and the incentive mechanisms that will apply across the next regulatory control period. We have considered the submissions we received in regard to SA Power Networks' proposals and our preliminary decision. We have conducted our own analysis and engaged expert consultant to help us better understand if and how SA Power Networks' proposals contribute to the achievement the NEO. We have also considered how our constituent decisions relate to each other, the impact that particular constituent decisions have on other constituent components of our decision, and have described these interrelationships in this final decision. We have undertaken an extensive and consultative regulatory review process to ensure we have canvassed stakeholder issues and made as much of this information publicly available as practicable. We have had regard to and weighed up all the information assembled before us in making this final decision.

Therefore, we are satisfied that among the options before us our final decision on SA Power Networks' distribution determination for the 2015–20 regulatory control period contributes to the achieving the NEO to the greatest degree.

5.1.1 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[56] Interrelationships can take various forms, including:

- 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 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

[55] NEL, s. 16(1)(d).

[56] SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013, p. 6.

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, 4 and 8).

- 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 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our final decision. These considerations are explored in the relevant attachments. We include a table of interrelationships, including the impacts of particular constituent decision on other constituent components of our distribution determination, in appendix D.

6 SA Power Networks' consultation

This section provides an overview and commentary on the consultation processes undertaken by SA Power Networks. Our specific assessment of the expenditure initiatives proposed by SA Power Networks arising from its stakeholder and consumer engagement can be found in the opex and capex assessments in attachments 6 and 7.

6.1 Summary of SA Power Networks' customer engagement program

Prior to submitting its initial regulatory proposal, SA Power Networks undertook a customer engagement program (CEP) titled 'TalkingPower'. The key elements of the program are shown in figure 9.

Figure 9: SA Power Networks' TalkingPower customer engagement program

Source: SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 19.

According to SA Power Networks, its CEP was designed and commenced in 2013 with advice from independent experts and consultants. SA Power Networks reported that over 13,000 electricity consumers actively participated in its CEP and that it was representative of SA Power Networks' customer base, including all customer segments and geographical regions.[57] SA Power Networks submitted that its CEP was unbiased and gave rise to statistically significant outcomes and results.[58]

TalkingPower involved three stages of engagement with stakeholders: research, strategy and regulatory. The first two stages were focused on identifying issues of concern to customers and the extent of support for initiatives to address those issues. These included a number of workshops, an online survey and publication of a report

[57] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 15.

[58] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 15.

for consultation titled 'Directions and Priorities 2015 to 2020'. SA Power Networks also engaged ‘The NTF Group’ to conduct discrete willingness to pay (WTP) study. The study was aimed at identifying the extent of customers’ financial support for a subset of the programs that were identified as part of the CEP.[59] The regulatory stage focussed on our preliminary decision, and included ongoing consumer engagement and consultation with the majority of stakeholders who provided submissions to us.[60]

SA Power Networks relied on the outcomes of its CEP to justify total expenditures of around $400 million in its initial regulatory proposal.[61] In response to our preliminary decision, SA Power Networks subsequently reduced or removed some of these 'customer supported/driven' programs in its revised proposal. For example, SA Power Networks stated that despite findings of its CEP that consumers supported its proposed bushfire safety program, it revised down its proposed expenditure. This was to address our concerns outlined in the preliminary decision over the inadequacy of the CEP for the purpose of supporting the level of expenditures proposed and that the cost of the initiative was inefficient.[62]

In its revised regulatory proposal, SA Power Networks outlined its disagreement with our consideration of its CEP and broader stakeholder submissions.[63] SA Power Networks contends that:

- we should place little or no weight on the stakeholder submissions and CCP advice which were critical of SA Power Networks’ CEP, because they were either largely anecdotal in nature, unsubstantiated or technically lacking[64]
- we had failed to properly ‘have regard to’ the concerns raised by its customers as identified during SA Power Networks’ CEP in the manner required under the NER in assessing proposed opex[65] and capex[66][67]
- we focused on the WTP research and did not have sufficient regard to SA Power Networks’ CEP as a whole.[68]

Further, SA Power Networks engaged the NTF Group to critique our preliminary decision, CCP advices and stakeholder submissions.[69]

59 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 20.
60 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 20.
61 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 23.
62 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 105.
63 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 15.
64 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 28, 30 and 34.
65 NER, cl. 6.5.6(e)(5A).
66 NER, cl. 6.5.7(e)(5A).
67 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 16.
68 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 33–34.
69 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, attachments C.2 (NTF Review of SACOSS) C. 3 (NTF Review of Business SA), C.4 (NTF Review of CCP2), C.5 (NTF Response to SACOSS WTP assertions), C.6 (NTF Response to AER), C.7 (NTF Review of Oakley Greenwood report).

6.2 NER requirements regarding consumer engagement

SA Power Networks submitted that the AEMC's 2012 rule changes were amended to give added focus to promoting the long term interests of consumers.[70] We agree. Chapter 6 of the NER was amended to, among other things, require:

- distributors to submit an overview with their regulatory proposal which describes how they have engaged with consumers and sought to address any relevant concerns identified by that engagement.[71]
- the AER, when determining whether to accept distributors' proposed capex and opex forecasts, to have regard to the extent to which the forecast includes expenditure to address the concerns of consumers as identified by the distributor in the course of its engagement with consumers.[72]

Our obligation to have regard to the extent to which a distributor's forecast includes expenditure to address the concerns of consumers forms part of our overall task of determining whether the distributor's proposed forecasts reasonably reflect the efficient and prudent costs of achieving the capex (or opex) objectives.[73] Therefore, if proposed expenditure is not required to achieve one or more of the capex (or opex) objectives, even with evidence of consumer support we will not be satisfied that the proposed expenditure reasonably reflects the capex and opex criteria.

Furthermore, the extent to which the proposed forecasts include expenditure to address the concerns of consumers during the course of its engagement with consumers is only one of nine or more factors that we must have regard to in determining whether we are satisfied that the proposed capex (or opex) reasonably reflects the capex (or opex) criteria.[74] In this sense, the factor relating to consumer engagement alone is not determinative. [75]

If a distributor submits that particular expenditure programs will address the concerns of consumers identified through its consumer engagement, we will consider whether such claims are supported by solid evidence of the preferences of affected consumers. This may include consideration of whether the engagement was sufficient to identify key areas of consumer concern, whether consumers have been adequately informed of relevant price implications, and how the expenditure proposed would address those customer concerns. We outline our assessment of SA Power Networks' CEP in the following section.

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70 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*.

71 NER, cll. 6.8.2(c1)(2).

72 NER, cll. 6.5.6(e)(5A) and 6.5.7(e)(5A).

73 NER, cll. 6.5.6(c)(1) to (3) and 6.5.7(c)(1) to (3) and cll. 6.5.6(a) and 6.5.7(a).

74 NER, cll. 6.5.6(e)(5A) and 6.5.7(e)(5A).

75 AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, pp. 36–37.

6.3 Our assessment

Consistent with the views expressed in our preliminary decision, we commend SA Power Networks for its proactive approach to consumer engagement.

Our expectations regarding a service provider's engagement with consumers were set out in our Consumer Engagement Guideline, released in 2013. The Guideline presents a framework for service providers to establish a consumer engagement strategy and to develop processes that best fit their business. We expect electricity and gas service providers to engage meaningfully with consumers as part of their usual way of doing business across a range of business activities.

The overarching expectation of our Guideline is for distributors to engage genuinely and meaningfully with consumers and undertake a process of continuous improvement. Our preliminary decision was supportive of SA Power Networks' efforts to improve its consumer engagement activities, including WTP studies. We consider surveys and WTP studies can be a useful means by which a service provider could measure its expenditure proposals against the interests of consumers. We agree with SA Power Networks' assertion that it has embraced the NER changes requiring service providers to better engage with their customers.[76] Prior to lodging its initial regulatory proposal, SA Power Networks presented the AER with an overview of its CEP in 2014. At the time, our feedback to SA Power Networks was positive insofar as its efforts to engage with consumers represented an encouraging start and set a benchmark for other network businesses to follow.

However, we did not accept certain expenditures that SA Power Networks included in its initial proposal that it sought to justify relying to a significant extent on its CEP and the WTP study.[77]

As noted above, in its revised proposal, SA Power Networks has reduced the amount of expenditure it proposes based on its CEP, but continues to rely on its CEP to justify some aspects of its proposed expenditure. This includes vegetation management and customer driven opex, the Bushfire Safer Places undergrounding and reliability and hardening the network capex. We have had regard to this material in our assessment of SA Power Networks' expenditure proposals in attachments 6 and 7 to this final decision. We acknowledge that the CEP information provided by SA Power Network identifies a number of customer concerns and that SA Power Networks has sought to address some of those concerns in its expenditure proposals. However, as discussed in attachments 6 and 7, we have some reservations regarding the CEP material and the conclusions that SA Power Networks sought to draw from it. This has led us to disagree with the weight SA Power Networks has placed on some aspects of its CEP material.

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76 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 15.

77 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 23.

Our concerns are underlined by comments in submissions that conflict with some findings of SA Power Networks' CEP as noted below.

6.4 Submissions on SA Power Networks' customer engagement

We consider the submissions from stakeholders to be an important part of the regulatory review process. The NER require us to seek submissions on the distributor's regulatory proposals and to have regard to them in making our decision. However, considering submissions is not just a matter of complying with the NER, it is good regulatory practice. Submissions inform our view but are not determinative in themselves. We consider these submissions alongside the proposals and the requirements of the NER. We received 31 submissions from stakeholders in response to SA Power Networks' initial proposal and a further 74 submissions in response to our preliminary decision and SA Power Networks' revised proposal. In addition to commenting on SA Power Networks' initial and revised proposals and our preliminary decision, some submissions commented on SA Power Networks' CEP. We have had regard to SA Power Networks' CEP as well as other submissions regarding customer preferences.

Some of the issues raised by stakeholders generally regarding SA Power Networks' engagement are set out below.

In response to SA Power Networks' Directions and Priorities Statement, Council of the Aging SA (COTA SA) submitted that the price implications of projects had not been properly explained in the document or during the preceding consultations. COTA SA also submitted that the consultation process was undermined by a lack of transparency about how information gathered would be used by SA Power Networks.[78]

We received several comments of concern in response to SA Power Networks' initial regulatory proposals:

- SACOSS submitted SA Power Networks did not adequately convey information about price and cost implications of proposed expenditure options during its CEP.[79]
- We received a number of submissions criticising SA Power Networks' WTP study conducted by The NTF Group, including:
    - Energy Users Association of Australian (EUAA) stated that customers were not given options to elect bill reductions to avoid additional spending (above 2010–15 levels)[80]

[78] COTA SA, *Submission on SA Power Networks Directions and Priorities Statement*, 6 June 2014, pp. 2–4.

[79] SACOSS, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 23; COTA SA, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 3; Central Irrigators Trust, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 9. EUAA, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 15.

[80] EUAA, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 17.

- Business SA submitted the survey provided a discrete series of questions and did not give participants visibility of the totality of their selected responses[81]
- AGL questioned if consumers, when being asked to pay to mitigate particular scenarios, were presented with the probabilities of the events actually occurring as part of the WTP study. On this basis, it asked us to consider the robustness of the WTP findings. [82]

In response to SA Power Network's revised proposal:

- The South Australian Council of Social Service (SACOSS) indicated it represented a large and diverse group of South Australians and did not accept the view of SA Power Networks that comments in submissions critical of its consumer engagement were anecdotal, and should therefore be given little or no weight. SACOSS also raised a number of concerns in regard to the methods used by The NTF Group. SACOSS submitted that Banarra (a consultant engaged by SA Power Networks) raised concerns as to how the CEP had been conducted.[83]
- Energy Consumers Coalition of South Australia (ECCSA) submitted that the CEP has been conducted without providing the full context of how the information given to CEP participants would be used. It recommended the findings of the CEP be disregarded.[84]
- EUAA considered that SA Power Networks' CEP was not comprehensive or robust as had been claimed and suggested business consumers were not adequately represented in the CEP. EUAA suggested that we should disregard the findings of the CEP.[85]

The following examples provide an indication of consumer views that do not align with SA Power Networks' CEP findings. Some of the examples relate to SA Power Networks' proposed road safety or other expenditure which it has removed from its revised proposal. However, these examples informed our views regarding the customer engagement process SA Power Networks undertook and we note them for this reason. In particular:

- SA Power Networks' Directions and Priorities Statement
    - Of the nine submissions SA Power Networks received (three from residential consumers, two from Government and Council, two from business and two from welfare groups), all raised concerns about SA Power Networks'

81 Business SA, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 20.

82 AGL, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 3.

83 SACOSS, *Submission on SA Power Networks' revised regulatory proposal*, July 2015, pp. 2–10;

84 ECCSA, *Submission on SA Power Networks' revised regulatory proposal*, July 2015, p. 5;

85 EUAA, *Submission on SA Power Networks' revised regulatory proposal*, July 2015, p. 7;

indicated future direction.[86] In particular, Business SA noted that some of SA Power Networks' initiatives, like the road safety program, should not be included in the regulatory proposal as there were alternative means of funding such projects through the South Australian Government.[87]

- Concerns raised in stakeholder submissions in January 2015 on SA Power Networks' regulatory proposal.
  - The South Australian Government acknowledged SA Power Networks' efforts to understand consumer issues, however the Government was concerned that the results presented did not align with the concerns expressed by South Australian electricity consumers at large.[88]
  - ECCSA also questioned whether more cost effective options were considered by SA Power Networks.[89]
  - Business SA acknowledged that SA Power Networks' proposal to improve road safety is well intentioned but akin to measures being taken to improve bushfire mitigation, it submitted that setting the appropriate level of road safety risk, and the optimum policy response to achieve this, are matters for Government.[90]
  - The CCP submitted that investment in undergrounding electricity lines should be as a result of a comprehensive plan agreed to by all stakeholders, including councils, road departments and tourism bodies. The CCP stated that this is not an economic regulatory matter, but rather a community issue of which SA Power Networks is but one part.[91]
  - The CCP and South Australian Government pointed to an alternative source of funding for undergrounding of cables based on advice from Power Line Environment Committee.[92]
  - SACOSS raised concerns that SA Power Networks CEP resulted in households expressing a willingness to pay beyond their capacity to pay.[93]

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86 Submissions on SA Power Networks' Directions and Priorities Statement were received from Business SA, Central Irrigation Trust, South Australian Government, Kangaroo Island Council, G Goland, Peter, Tim D, Consumers SA and COTA SA in June 2014. Submissions available at http://talkingpower.com.au/your-views/directions-priorities/.

87 Business SA, *Submission on SA Power Networks Directions and Priorities Statement*, 6 June 2014, pp. 5–6.

88 Government of South Australia, *Submission on SA Power Networks' regulatory proposal*, 30 January 2015, p. 13.

89 Energy Consumers Coalition of South Australia, *Submission on SA Power Networks' regulatory proposal*, December 2014, p. 37.

90 Business SA, *Submission on SA Power Networks' regulatory proposal*, January 2015, pp. 16–18.

91 CCP2 Advice, *Response to SA Power Networks' regulatory proposal*, January 2015, p. 22.

92 CCP2 Advice, *Response to SA Power Networks' regulatory proposal*, January 2015, p. 23; Government of South Australia, *Submission on SA Power Networks' regulatory proposal*, 30 January 2015, p. 4.

93 SACOSS, *Submission on SA Power Networks' regulatory proposal*, January 2015, p. 33.

6.5 Consultants' advice

In light of the concerns identified in submissions, we engaged Oakley Greenwood to conduct a review of SA Power Networks' WTP study. We also asked Oakley Greenwood to address the concerns SA Power Networks raised in its revised regulatory proposal in response to our preliminary decision.

Oakley Greenwood raised a number of issues about the extent to which we could rely on the consumer information SA Power Networks submitted. In particular, Oakley Greenwood suggested that customers were asked to make choices in the WTP study without adequate information of the consequences of those choices. Oakley Greenwood concluded that this runs the risk of informing policy, investment or pricing decisions that may not turn out to be popular once the consequences are better understood by consumers.[94] Further, Oakley Greenwood suggested that a range of alternative options were not tested in the WTP research. For example, the presentation of the undergrounding and vegetation management scenarios in high bushfire risk areas and bushfire risk areas were not conducive to respondents making trade-off decisions that were appropriately informed.[95]

Oakley Greenwood also considered that the way in which WTP survey results 'were used to determine preferred service options should have been more carefully considered…to minimise the financial impact on customers (and specific customer segments) that were unwilling (whether due to lack of interest or lack of ability) to pay for the service initiative'.[96]

SA Power Networks engaged Banarra to conduct a 'gap analysis' of its CEP; comparing it to good practice principles including those set out in our Consumer Engagement Guideline.[97] Banarra identified that SA Power Networks could improve its CEP in line with the best practice principles contained in our Guideline by:

- expanding the range of stakeholder groups it considered[98]
- using a broader range of stakeholder characteristics and interests and consider those consumers' capacity and capability to engage[99]

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94 Oakley Greenwood, *Response to comments on the peer review of WTP research submitted by SA Power Networks*, September 2015, p. 4.

95 Oakley Greenwood, *Response to comments on the peer review of WTP research submitted by SA Power Networks*, September 2015, p. 5.

96 Oakley Greenwood, *Response to comments on the peer review of WTP research submitted by SA Power Networks*, September 2015, p. 7.

97 Banarra, *Stakeholder engagement assessment, Final gap analysis report for SA Power Networks*, 24 April 2015 and listed as Attachment C.1 to SA Power Networks revised regulatory proposal, 3 July 2015.

98 Banarra, *Stakeholder engagement assessment, Final gap analysis report for SA Power Networks*, 24 April 2015, p. 10.

99 Banarra, *Stakeholder engagement assessment, Final gap analysis report for SA Power Networks*, 24 April 2015, p. 10.

- involving consumers in the upfront design of the process including identification of priorities and key issues[100]
- developing specific performance indicators and measurable objectives to evaluate the effectiveness of its programs and the quality of the engagement delivered.[101]

We consider the issues in submissions noted above and in SA Power Networks' own assessment of its CEP (which includes but is not limited to WTP studies) give further support to Oakley Greenwood's findings. In particular, that where information obtained from the CEP is used to support or form the basis for expenditure, it is important that the activities to be funded be shown to be aligned with the customers' priorities and expectations, and the drivers of satisfaction identified in the CEP research.[102] Without this alignment, we consider the proposed expenditure may not address the concerns of consumers.

We encourage SA Power Networks to continue to engage with its consumers and address concerns that are identified through the course of its engagement. However SA Power Networks should note that the outcomes of any CEP will be assessed along with other expenditure factors, in ensuring that the expenditure forecast reasonably reflects the opex and capex criteria and is in the long term interests of consumers.

Appendix B sets out our consultation in reaching our final decision.

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100 Banarra, *Stakeholder engagement assessment, Final gap analysis report for SA Power Networks*, 24 April 2015, p. 14.

101 Banarra, *Stakeholder engagement assessment, Final gap analysis report for SA Power Networks*, 24 April 2015, p.14.

102 Oakley Greenwood, *Response to comments on the peer review of WTP research submitted by SA Power Networks*, September 2015, p. 11.

A Constituent decisions

Our final distribution determination is predicated on the following decisions (constituent decision):[103]

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to SA Power Networks for the 2015–20 regulatory control period (listed by service group): • Standard control services include network services, standard connection services and type 7 metering services • Alternative control services include metering types 5 and 6 provision, maintenance, reading, data services and exceptional large customer metering services • Negotiated distribution services include public lighting, non-standard network services, non–standard connection services, non–standard metering services, type 1 to 4 metering services and meter testing at a customer's request.
In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in SA Power Networks' building block proposal. Our final decision on SA Power Networks' annual revenue requirement for each year of the 2015–20 regulatory control period is set out in attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves SA Power Networks' proposal that the regulatory control period will commence on 1 July 2015. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves SA Power Networks' proposal that the length of the regulatory control period will be five years from 1 July 2015 to 30 June 2020.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER does not accept SA Power Networks' proposed total forecast capital expenditure of $2070.8 million ($2014–15). Our substitute estimate of SA Power Networks' total forecast capex for the 2015–20 regulatory control period is $1845.8 million ($2014–15). This is discussed in attachment 6 of the final decision.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept SA P14–ower Networks' proposed total forecast operating expenditure inclusive of debt raising costs of $1432.1 million ($2015). Our final estimate of SA Power Networks' total forecast opex for the 2015–20 regulatory control period is $1261.6 million ($2014–15).This is discussed in attachment 7 of the final decision.
In accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination.
SA Power Networks did not include any proposed contingent projects in its regulatory proposal or revised regulatory proposal for the 2015–20 regulatory control period. Therefore, • in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors • in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects • in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.
In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept SA Power Networks' proposal of 7.09 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 6.17 per cent as set out in table 3.1 of attachment 3 of the final decision. This rate of return will be updated annually because

[103] NER, cl. 6.12.1.

Constituent decision
our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 (appendix I) of the final decision.
In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in attachment 4 of the final decision.
In accordance with clause 6.12.1(6) the AER's decision on SA Power Networks' regulatory asset base as at 1 July 2015 in accordance with clause 6.5.1 and schedule 6.2 is $3778.4 million ($ nominal). This is set out in attachment 2 of the final decision.
In accordance with clause 6.12.1(7) the AER does not accept SA Power Networks' proposed corporate income tax of $426.5 million ($nominal). Our decision on SA Power Networks' corporate income tax is $258.3 million ($nominal). This is set out in attachment 8 of the final decision.
In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by SA Power Networks. This is set out in attachment 5 of the final decision.

In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply:
• In accordance with clause 6.12.1(9) of the NER, the AER's final decision is to apply version two of the EBSS to SA Power Networks in the 2015–20 regulatory control period. This is set out in attachment 9 of the final decision.
• In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the capital expenditure incentives guideline to SA Power Networks in the 2015–20 regulatory control period. CESS is discussed in attachment 10 of the final decision.
• In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to SA Power Networks for the 2015−20 regulatory control period. STPIS is discussed in attachment 11 of the final decision.
  ○ We will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as SA Power Networks must comply with its existing SA jurisdictional guaranteed service level scheme.
  ○ A beta of 2.5 will be used to calculate the major event day boundary.
  ○ Our decision on the SAIDI and SAIFI incentive rates and performance targets to apply to SA Power Networks for the 2015–20 regulatory control period are set out in tables 11.1 and 11.2 of attachment 11 of this final decision.
  ○ Our decision on the customer service incentive rate and performance target are set out in section 11.1 of attachment 11 of this final decision.
  ○ The revenue at risk for SA Power Networks will be capped at ±5.0 per cent. Within this there will be a cap of ±0.5 per cent on the telephone answering parameter for performance.
  Note: The meaning for year "t" under the price control formula for this determination is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.
• The AER has determined to continue Part A of the Demand Management Innovation Scheme (DMIS) for SA Power Networks in the 2015–20 regulatory period (that is, the DMIA component). DMIS is discussed in attachment 12 of the final decision.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.
In accordance with clause 6.12.1(11) the AER's 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 (TAR) calculated using the formula in attachment 14 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14 of the final decision.

Constituent decision
In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps. This is discussed in attachment 16 of the final decision.
In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is SA Power Networks must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 14 of the final decision.
In accordance with clause 6.12.1(14) the AER's decision on the additional pass through events that are to apply is to not accept the nominated pass through events as drafted by SA Power Networks. The AER substitutes its own definitions for the following events: • natural disaster event • insurance cap event • insurer credit risk event • terrorism event.
In accordance with clause 6.12.1(15) the AER's decision is to vary SA Power Networks' proposed negotiating framework for the 2015–20 regulatory control period.[104] Specifically, our final decision is to delete the word 'classification' at section 3 and schedule 1 of the negotiating framework and replace it with 'category'. The negotiating framework that is to apply to SA Power Networks is set out at attachment 17 of the final decision.
In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in November 2014 to SA Power Networks. This is set out is at attachment 17 of the final decision.
In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes for SA Power Networks is set out at attachment 14 of the final decision.
In accordance with clause 6.12.1(18) the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of SA Power Networks regulatory control period (1 July 2020). This is discussed in attachment 2 of the final decision.
In accordance with clause 6.12.1(19) the AER's 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 are discussed in attachment 14 of the final decision.
In accordance with clause 6.12.1(20) the AER's decision is we 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 14 of the final decision.
In accordance with clause 6.12.1(21) the AER approves the connection policy submitted by SA Power Networks on 3 July 2015 in relation to its revised proposal. This is set out in attachment 18 of the final decision.

104 NER, cl. 6.12.1(15).

B Our consultation process

This section summaries our consultation and engagement with stakeholders, interested parties and SA Power Networks in coming to this final decision.

We recognise that stakeholder participation in decision making processes is an important element of achieving the NEO by better understanding the long term interests of consumers. The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of the decision before it is made.[105]

Below we set out the consultation process we have followed leading up to this final decision. We have considered the views presented to us at each stage in reaching our final decision.

Effective consultation with stakeholders is essential to the performance of our regulatory functions. In summary, our consultation and engagement with stakeholders through the process that has led to this final determination can be summarised as follows:

- holding regular meetings with SA Power Networks to discuss issues relevant to this decision. These meetings commenced in August 2013 to discuss the framework and approach. The meetings continued throughout our decision making process.
- establishing the CCP to assist us to make better regulatory determinations by providing input on issues of importance to consumers.
- considering 31 submissions on SA Power Networks' regulatory proposal and 74 submissions on our preliminary decision and SA Power Networks' revised proposal. A list of submissions to the latter is at appendix C.
- publishing an issues paper on 5 December 2014 to help stakeholders engage with, and meaningfully respond to issues in SA Power Networks' regulatory proposal that we considered material to consumers.
- hosting a public forum in Adelaide on 10 December 2014 and 27 May 2015 so stakeholders could question the AER, the CCP and SA Power Networks on its regulatory proposal.
- having SA Power Networks present its proposal to the AER Board on 23 January 2015 and 31 July 2015, so questions could be raised and key issues explained.
- having the CCP present its advice in response to SA Power Networks' initial and revised regulatory proposals and our preliminary decision to the AER Board.
- convening monthly meetings between the CCP and AER staff to discuss key issues.

[105] NEL, s. 16 (1)(b).

- ongoing formal and informal jurisdictional consumer forums that commenced in November 2013.
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of SA Power Networks' regulatory proposal.
- discussions with SA Power Networks about its regulatory proposal. In particular, our consultants and AER staff met with SA Power Networks to discuss expenditure proposals. During this process, AER staff considered over 60 responses to information requested from SA Power Networks.
- releasing a consultation paper on recovering the residual metering capital costs through an alternative control service charge and considering 19 submissions in response.

This process builds on the extensive consultation undertaken by the AER as part of the Better Regulation program. Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[106] The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[107]

The resulting Guidelines support our decision making framework. Our consultation and engagement gives us confidence the approaches set out in the Guidelines, which we have applied in this decision unless otherwise noted, will result in decisions that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation Guidelines are available on our website and include:[108]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline for Network Service Providers
- Shared Assets Guideline
- Confidentiality Guideline.

Our consultation processes, which go well beyond the minimum requirements of the NER, provide us with a range of stakeholder views.

106 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

107 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

108 www.aer.gov.au/Better-regulation-reform-program.

C List of submissions

We received 74 submissions in response to SA Power Networks' revised proposal and our preliminary decision as listed below:

	Submission from	Date received	Submission on
1	Almond Co Australia	22 June 2015	AER preliminary decision
2	Angove	3 July 2015	AER preliminary decision
3	AusNet Services	3 July 2015	AER preliminary decision
4	Berri Estates	19 June 2015	AER preliminary decision
5	Business SA	6 July 2015	AER preliminary decision
6	Byrne Vineyards	26 June 2015	AER preliminary decision
7	CCW Co-operative Ltd	25 June 2015	AER preliminary decision
8	Central Irrigators Trust	17 June 2015	AER preliminary decision
9	Commissioner for Kangaroo Island	26 June 2015	AER preliminary decision
10	Consumers SA	2 July 2015	AER preliminary decision
11	D & F Ceracchi Family Trust	3 July 2015	AER preliminary decision
12	Energy Consumers Coalition of South Australia	3 July 2015	AER preliminary decision
13	ElectraNet	3 July 2015	AER preliminary decision
14	Energy Retailer's Association of Australia	3 July 2015	AER preliminary decision
15	Mr John Herbst	3 July 2015	AER preliminary decision
16	Knispel Bros Pty Ltd	22 June 2015	AER preliminary decision
17	Local Government Association of South Australia	3 July 2015	AER preliminary decision
18	Lowana Fruits	3 July 2015	AER preliminary decision
19	M & N Ceracchi Family Trust	3 July 2015	AER preliminary decision
20	Olga Black	3 July 2015	AER preliminary decision
21	Omega Orchards Pty Ltd	23 June 2015	AER preliminary decision
22	Origin	3 July	AER preliminary decision
23	Professionals Australia	2 July 2015	AER preliminary decision
24	Riverland Energy Association	2 July 2015	AER preliminary decision
25	Renmark Irrigation Trust	3 July 2015	AER preliminary decision
26	South Australian Council of Social Services	2 July 2015	AER preliminary decision
27	South Australian Government, Minister for Mineral Resources and Energy	10 July 2015	AER preliminary decision

	Submission from	Date received	Submission on
28	South Australian Wine Industry Association	3 July 2015	AER preliminary decision
29	Solar Depot	2 July 2015	AER preliminary decision
30	Spark	3 July 2015	AER preliminary decision
31	TGP Almonds	23 June 2015	AER preliminary decision
32	The Better Drinks	2 July 2015	AER preliminary decision
33	Treenet	10 June 2015	AER preliminary decision
34	TWG Australia	2 July 2015	AER preliminary decision
35	United Energy	3 July 2015	AER preliminary decision
36	Vector Limited	3 July 2015	AER preliminary decision
37	Winkie Heights	24 June 2015	AER preliminary decision
38	Yatco	3 July 2015	AER preliminary decision
39	South Australian Financial Counsellors	3 July 2015	AER preliminary decision
40	Almond Co Australia	8 July 2015	SA Power Networks' revised proposal
41	Business SA	20 July 2015	SA Power Networks' revised proposal
42	Century Orchards	9 July 2015	SA Power Networks' revised proposal
43	CitiPower and Powercor	9 July 2015	Current regulatory determination processes
44	City of Marion	28 July 2015	SA Power Networks' revised proposal
45	District Council of Elliston	17 July 2015	SA Power Networks' revised proposal
46	Flinders Rangers Council	16 July 2015	SA Power Networks' revised proposal
47	Jemena	24 July 2015	Current regulatory determination processes
48	Mr John Herbst	24 July 2015	SA Power Networks' revised proposal
49	Jubilee Almonds	10 July 2015	SA Power Networks' revised proposal
50	Multinet Gas	24 July 2015	Current regulatory determination processes
51	QFM Production Pty Ltd	10 July 2015	SA Power Networks' revised proposal
52	Renmark Irrigation Trust	24 July 2015	SA Power Networks' revised proposal

	Submission from	Date received	Submission on
53	Riverland Wind	24 July 2015	SA Power Networks' revised proposal
54	South Australian Council of Social Services	24 July 2015	SA Power Networks' revised proposal
55	South Australian Wine Industry Association	24 July 2015	SA Power Networks' revised proposal
56	TGP Almonds	14 July 2015	SA Power Networks' revised proposal
57	United Energy	24 July 2015	Current regulatory determination processes
58	UnitingCare	24 July 2015	SA Power Networks' revised proposal and AER preliminary decision
59	Wakefield Regional Council	24 July 2015	SA Power Networks' revised proposal
60	Yatco	24 July 2015	SA Power Networks' revised proposal
61	Central Irrigation Trust	10 July 2015	SA Power Networks' revised proposal
62	Energy Consumers Coalition of South Australia	22 July 2015	SA Power Networks' revised proposal
63	District Council of Loxton Waikerie	29 July 2015	SA Power Networks' revised proposal
64	Yorke Peninsula Council	24 July 2015	SA Power Networks' revised proposal
65	Knispel Bros Pty Ltd	9 July 2015	SA Power Networks' revised proposal
66	Ms Fran Newby	23 July 2015	SA Power Networks' revised proposal
67	Berri Resort Hotel	22 July 2015	SA Power Networks' revised proposal
68	Australian Olive Association	13 July 2015	SA Power Networks' revised proposal
69	District Council of Karoonda East Murray	21 July 2015	SA Power Networks' revised proposal
70	Dad's Olive Oil	16 July 2015	SA Power Networks' revised proposal
71	Riverland Energy Association	20 July 2015	SA Power Networks' revised proposal
72	Energy Users Association of Australia	24 July 2015	SA Power Networks' revised proposal and AER preliminary decision
73	South Australian Government, Minister for	4 August 2015	SA Power Networks' revised

	Submission from	Date received	Submission on
	Mineral Resources and Energy		proposal
74	AGL	31 July 2015	SA Power Networks' revised proposal

D Interrelationships in the AER's final decision for SA Power Networks

Interrelationships in the AER's final decision for SA Power Networks	
Page Ref.	**Explanation**
Overview	
Final decision Overview p. 43	Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past. Interrelationships can take various forms, including: • 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 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 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, 4 and 8). • 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 6 and 7). • trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the network service provider has more assets to maintain leading to higher opex requirements (see attachments 6 and 7). • the network service provider's approach to managing its network. The network service provider's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6). We have considered interrelationships, including those above, in our analysis of the constituent components of our final decision. These considerations are explored in the relevant attachments.
Attachment 1: Annual Revenue Requirement	
	Smoothing profile (X factors) is affected by the overall annual revenue requirement based on all building block decisions, including rate of return and capex. Further, the smoothing profile is affected by the removal of alternative control services assets for changes in classification of services.
Attachment 2: Regulatory asset base	
Preliminary decision p. 2–11	The RAB is an input into the determination of the return on capital and depreciation (return of capital) building block allowances. Factors that influence the RAB will therefore flow through to these building block components and the annual revenue requirement. Other things being equal, a higher RAB increases both the return on capital and depreciation allowances.

Interrelationships in the AER's final decision for SA Power Networks	
	The RAB is determined by various factors, including: • the opening RAB (meaning the value of existing assets at the beginning of the regulatory control period) • net capex • depreciation • indexation adjustment – so the RAB is presented in nominal terms, consistent with the rate of return. The opening RAB depends on the value of existing assets and will depend on actual net capex, actual inflation outcomes and depreciation in the past. The RAB when projected to the end of the regulatory control period increases due to both forecast new capex and the indexation adjustment. The size of the indexation adjustment depends on expected inflation (which also affects the nominal rate of return) and the size of the RAB at the start of each year. Depreciation reduces the RAB. The depreciation allowance depends on the size of the opening RAB and the forecast net capex. By convention, the indexation adjustment is also offset against depreciation to prevent double counting of inflation in the RAB and rate of return, which are both presented in nominal terms. This reduces the apparent depreciation building block that feeds into the annual revenue requirement. Maintaining the RAB in real terms by adding inflation is required by the NER and generally helps to promote smoother prices over the life of an asset. If the RAB was unindexed for inflation, the offsetting indexation adjustment applied to depreciation would also have to be removed. On balance, this means more depreciation would be returned to the business resulting in higher prices early in an asset life and lower prices later in its life. Even if allowed under the NER, moving to an unindexed RAB would lead to a price increase over the short to medium term and when new lumpy assets are added to the RAB. The depreciation amount also largely depends on the opening RAB (which in turn depends on capex in the past).
Attachment 3: Rate of return	
Final decision p. 3–29	This section notes the key interrelationships in the rate of return decision in the context of the rule requirements to apply a rate of return. Where we have had regard to these in developing our approach, they are more fully described in the Guideline. The manner in which these are taken into account in making this decision is set out as part of our reasoning and analysis in section 3.4 and the rate of return appendices. We estimate a rate of return for a benchmark efficient entity which is then applied to a specific service provider rather than determining the returns of a specific service provider based on its specific circumstances. This is the same whether estimating the return on equity or return on debt as separate components. We set a rate of return that is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as the service provider in respect of the provision of standard control services. This provides a reasonable opportunity to recover at least the efficient costs. The network service provider's actual returns could be higher or lower compared to the benchmark depending on how efficiently it operates its business. This is consistent with incentive regulation. That is, our rate of return approach drives efficient outcomes by creating the correct incentive by allowing network service providers to retain (fund) any additional income (costs) by outperforming (underperforming) the efficient benchmark. We are mindful that we apply a benchmark approach and an incentive regulatory framework. Any one component or relevant parameter adopted for estimating the rate of return should not be solely viewed in isolation. In developing our approach and implementing it to derive the overall rate of return we are cognisant of a number of interrelationships relating to the estimation of the return on equity and debt and underlying input parameters.

Interrelationships in the AER's final decision for SA Power Networks

Single benchmark

We adopt a single benchmark efficient entity across all service providers. In deciding on a single benchmark we considered different types of risks and different risk drivers that may have the potential to lead to different risk exposures. We also noted that the rate of return compensates investors only for non–diversifiable risks (systematic risks) and other types of risks are compensated via cash flows and some may not be compensated at all. These interrelationships between the types of risk and the required compensation via the rate of return are an important factor. Our view is that the benchmark efficient entity would face a similar degree of risk irrespective of the:

- energy type (gas or electricity)
- network type (distribution or transmission)
- ownership type (government or private)
- size of the service provider (big or small).

Domestic market

We adopt the Australian market as the market within which the benchmark efficient entity operates. This recognises that the location of a business determines the conditions under which the business operates and these include the regulatory regime, tax laws, industry structure and broader economic environment. As most of these conditions will be different from those prevailing for overseas entities, the risk profile of overseas entities is likely to differ from those within Australia. Consequently, the returns required are also likely to differ. This is an important factor in estimating the rate of return and we therefore adopt a domestic approach. Hence, when estimating input parameters for the Sharpe–Lintner capital asset pricing model (SLCAPM) we place most reliance on Australian market data whilst, using overseas data informatively.

Benchmark gearing

We apply a benchmark efficient level of gearing of 60 per cent. This benchmark gearing level is used:

- to weight the expected required return on debt and equity to derive the overall rate of return using the WACC formula
- to re-lever asset betas for the purposes of comparing the levels of systematic risk across businesses which is relevant for the equity beta estimate.

We adopt a benchmark credit rating which is BBB+ or its equivalent for the purposes of estimating the return on debt. To derive this benchmark rating and the gearing ratio, we reviewed a sample of regulated networks. Amongst a number of other factors, a regulated service provider's actual gearing levels have a direct relationship to its credit ratings. Hence, our findings on the benchmark gearing ratio of 60 per cent and the benchmark credit rating are interrelated given that the underlying evidence is derived from a sample of regulated network service providers.

Term of the rate of return

We adopt a 10 year term for our overall rate of return. This results in the following economic interdependencies that impact on the implementation of our return on equity and debt estimation methods:

- The risk free rate used for estimating the return on equity is a 10 year forward looking rate
- The market risk premium (MRP) estimate is for a 10 year forward looking period

Interrelationships in the AER's final decision for SA Power Networks	
	• We adopt a 10 year debt term for estimating the return on debt.
Attachment 4: Value of imputation credits	
Preliminary decision p. 4–13	The NER recognise that a service provider's allowed revenue does not need to include the value of imputation credits. The NER adjust for the value of imputation credits via the revenue granted to a service provider to cover its expected tax liability. This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors. The value of imputation credits is also interrelated with the MRP. As discussed in attachment 3, the definition of the MRP in the SLCAPM should account for the capitalised value of imputation credits. Accordingly, in our determination of the return on equity in attachment 3 we adjust estimates of the MRP in a manner consistent with our determination of the value of imputation credits in this attachment. This is also required by the NER/NGR.
Attachment 5: Regulatory depreciation	
Preliminary decision p. 5–10	The regulatory depreciation allowance is a building block component of the annual revenue requirement. Higher (or quicker) depreciation leads to higher revenues over the regulatory control period. It also causes the RAB to reduce more quickly (assuming no further capex). This outcome reduces the return on capital allowance, although this impact is usually secondary to the increased depreciation allowance. Ultimately, however, a service provider can recover only once the capex that it incurred on assets. The depreciation allowance reflects how quickly the RAB is being recovered, and it is based on the remaining and standard asset lives used in the depreciation calculation. It also depends on the level of the opening RAB and the forecast capex. Any increase in these factors also increases the depreciation allowance. To prevent double counting of inflation through the WACC and the RAB, the regulatory depreciation allowance also has an offsetting reduction for indexation of the RAB. Factors that affect forecast inflation and/or the size of the RAB will affect the size of this indexation adjustment.
Attachment 6: Capital expenditure	
Final decision p. 6–29	There are a number of interrelationships between total forecast capex and other components of the distribution. We considered these interrelationships in coming to our final decision on total forecast capex. **Capex and opex** Elements of total forecast opex relate to total forecast capex. These include the forecast labour price growth included in our opex forecast. The price of labour affects both total forecast capex and total forecast opex. More generally, our total opex forecast will provide sufficient opex to maintain network reliability. Although we do not approve opex on specific opex categories such as maintenance, the total opex we approve will in part influence the required repex. **Capex and demand**

Interrelationships in the AER's final decision for SA Power Networks	
	Forecast demand is related to total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability. **Capex and CESS** The CESS is related to total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient and that it reasonably reflects the capex criteria. As we note in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from the network service provider regulatory asset base. In particular, the CESS will ensure that the network service provider bears at least 30 per cent of any overspend against the capex allowance. Similarly, if the network service provider can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, the network service provider risks having to bear the entire overspend. **Capex and STPIS** The STPIS is interrelated to the total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to the network service provider systematically under or over performing against its targets. **Capex and contingent projects** A contingent project is interrelated to total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of the total forecast capex.
Attachment 7: Operating expenditure	
Final decision p. 7–25	In assessing total forecast opex we take into account other components of the regulatory proposal, including: • The operation of the EBSS. • The impact of cost drivers that affect both forecast opex and forecast capex. For instance forecast maximum demand affects forecast augmentation capex and forecast output growth used in estimating the rate of change in opex. • The inter-relationship between the RAB and opex. • The approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block. • Changes to the classification of services from standard control services to alternative control services. • Consistency with the application of incentive schemes.

Interrelationships in the AER's final decision for SA Power Networks	
	• Concerns of electricity consumers.
Attachment 8: Corporate income tax	
Preliminary decision p. 8–9	The cost of corporate income tax building block feeds directly into the annual revenue requirement (ARR). This allowance is determined by four factors: • pre-tax revenues • tax expenses (including tax depreciation) • the corporate tax rate • gamma—the expected proportion of company tax that is returned to investors through the utilisation of imputation credits—which is offset against the corporate income tax allowance. This is discussed further at attachment 4. Of these four factors, the corporate tax rate is set externally by the Government. The higher the tax rate the higher the required tax allowance. The pre-tax revenues depend on all the building block components. Any factor that affects revenue will therefore affect pre-tax revenues. Higher pre-tax revenues can increase the tax allowance. Depending on the source of the revenue increase, the tax increase may be equal to or less than proportional to the company tax rate. The tax expenses (or deductions) depend on various building block components and their size. Some components give rise to tax expenses, such as opex, interest payments and tax depreciation of assets. However, others do not, such as increases in return on equity. Higher tax expenses offset revenues as deductions in the tax calculation and therefore reduce the cost of corporate income tax allowance (all things being equal). Tax expenses include: • Interest on debt – Interest is a tax offset. The size of this offset depends on the ratio of debt to equity and therefore the proportion of the RAB funded through debt. It also depends on the allowed return on debt and the size of the RAB. • General expenses – In the main these expenses will match the opex allowance. • Tax depreciation – A separate tax asset base (TAB) is maintained for the businesses reflecting tax rules. This TAB is affected by many of the same factors as the RAB, such as capex, although unlike the RAB value it is maintained at its historical cost with no indexation. The TAB is also affected by the depreciation rate and asset lives assigned for tax depreciation purposes. A 10 per cent increase in the corporate income tax allowance causes revenues to increase by about 0.7 per cent. The proposed gamma of 0.25, compared to the value in our preliminary decision of 0.40, would increase the corporate income tax allowance by 32.3 per cent and total revenues by about 1.2 per cent.
Attachment 9: Efficiency benefit sharing scheme (EBSS)	
Final decision p. 9–8	The EBSS is intrinsically linked to a revealed cost forecasting approach for opex. Under this forecasting approach, the EBSS has two specific functions: To mitigate the incentive for a service provider to increase opex in the expected 'base year' to increase its approved opex forecast for the following regulatory control period. To provide a continuous incentive for a service provider to make efficiency gains - network service providers receive the same reward for an underspend and the same penalty for an overspend in each year of the regulatory control period.

Interrelationships in the AER's final decision for SA Power Networks	
	Incentives to reduce opex may also affect a service provider's incentives to undertake capex. We take into account these interactions in developing and implementing the EBSS as well as developing the capital expenditure sharing scheme (CESS). For instance: in developing and implementing the EBSS, we must have regard to any incentives that network service providers may have to capitalise operating expenditure as well as the possible effects of the scheme on incentives for the implementation of non-network alternatives. in developing the CESS, we must take into account the interaction of the scheme with other incentives that network service providers may have in relation to undertaking efficient opex or capex as well as the capex objectives and, if relevant, the opex objectives.
Attachment 10: Capital expenditure sharing scheme (CESS)	
Final decision p. 10–7	The CESS relates to other incentives to incur efficient opex, conduct demand management, and maintain or improve service levels. We aim to incentivise network service providers to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.
Attachment 11: Service target performance incentive scheme	
Final decision p. 11–8	In applying the STPIS we must consider any other incentives available to the network service provider under the NER or relevant distribution determination. One of the objectives of the STPIS is to ensure that the incentives are sufficient to offset any financial incentives the network service provider may have to reduce costs at the expense of service levels. The STPIS interacts with the Capital Expenditure Sharing Scheme (CESS) and the opex Expenditure Benefit Sharing Scheme (EBSS). The rewards and penalties amounts under STPIS (the incentive rates) are determined based on the average customer value for the improvement, or otherwise, to supply reliability (the VCR). This is aimed at ensuring that the network service provider's operational and investment strategies are consistent with customers' value for the services that are offered to them. Our capex and opex allowances are set to reasonably reflect the expenditures required by a prudent and efficient business to achieve the capex and opex objectives. These include complying with all applicable regulatory obligations and requirements and, in the absence of such obligations, maintaining quality, reliability, and security outcomes. The STPIS, on the other hand provides, an incentive for network service providers to invest in further reliability improvements (via additional STPIS rewards) where customers are willing to pay for it. Conversely, the STPIS penalises network service providers where they let reliability deteriorate. Importantly, the network service provider will only receive a financial reward after actual improvements are delivered to the customers. In conjunction with CESS and EBSS, the STPIS will ensure that: • any additional investments to improve reliability are based on prudent economic decisions • reductions in capex and/or opex are achieved efficiently, rather than at the expense of service levels to customers.
Attachment 12: Demand management incentive scheme	
Final decision p. 12–7	We have regard to several factors and interrelationships in developing and implementing a DMIS. These are: Benefits to consumers

Interrelationships in the AER's final decision for SA Power Networks	
	• the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme • the willingness of customers or end users to pay for increases in costs resulting from implementing DMIS. Balanced incentives • the effect of a particular control mechanism (i.e. price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives • the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections • the extent the distributor is able to offer efficient pricing structures • the possible interactions between DMIS and other incentive schemes.
Attachment 13: Classification of services	
Final decision p. 13–9	In assessing what services we classify, we are setting the basis for the charges that can be levied on those services. To allow charges to be recovered for standard control services, assets associated with delivering those services are added to the regulatory asset base (RAB). A separate RAB may also be constructed for the capital costs associated with an alternative control service. There will usually be operating costs associated with the provision of a service as well. The assets that make up the RAB and the operating costs that relate to any standard control service form a starting point for our assessment of the distributor's proposal for recovering revenues through charges for their services. Classification of services will therefore influence all revenue components of our decision. There are assets and operating costs associated with the services provided by distributors. We set the revenues the distributor may collect from customers to recover their asset and operating costs. That revenue is recovered through tariffs the distributor develops to charge to its customers. The regulatory regime establishes incentives such as the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) to encourage the provision of services as efficiently as possible. All of these factors interrelate with each other. We must be cognisant of these interrelationships when we make our determinations. The incentive schemes do not apply to services classified alternative control. As such, classifying services alternative control from standard control means the incentive schemes are no longer applied to expenditure associated with these services.
Attachment 14: Control mechanism	
	We considered the interrelationship between the control mechanism pass through amounts and the reclassification of metering services as alternative control services.
Attachment 15: Pass through events	
Final decision p. 15–10	Nominated pass through events are interrelated with the opex and capex forecasts. These interrelationships require us to balance a decision to accept nominated pass through events with the need to maintain appropriate incentives in other aspects of the decision.
Attachment 16: Alternative control services	

Interrelationships in the AER's final decision for SA Power Networks	
Final decision p. 16–22	We apply the same rate of return parameters for all direct control services (standard and alternative control services). Our decision on alternative control services therefore interrelates with our decision on rate of return and imputation credits. Please refer to Attachments 3 and 4 for the WACC and gamma values we accept for direct control services, along with our reasons.