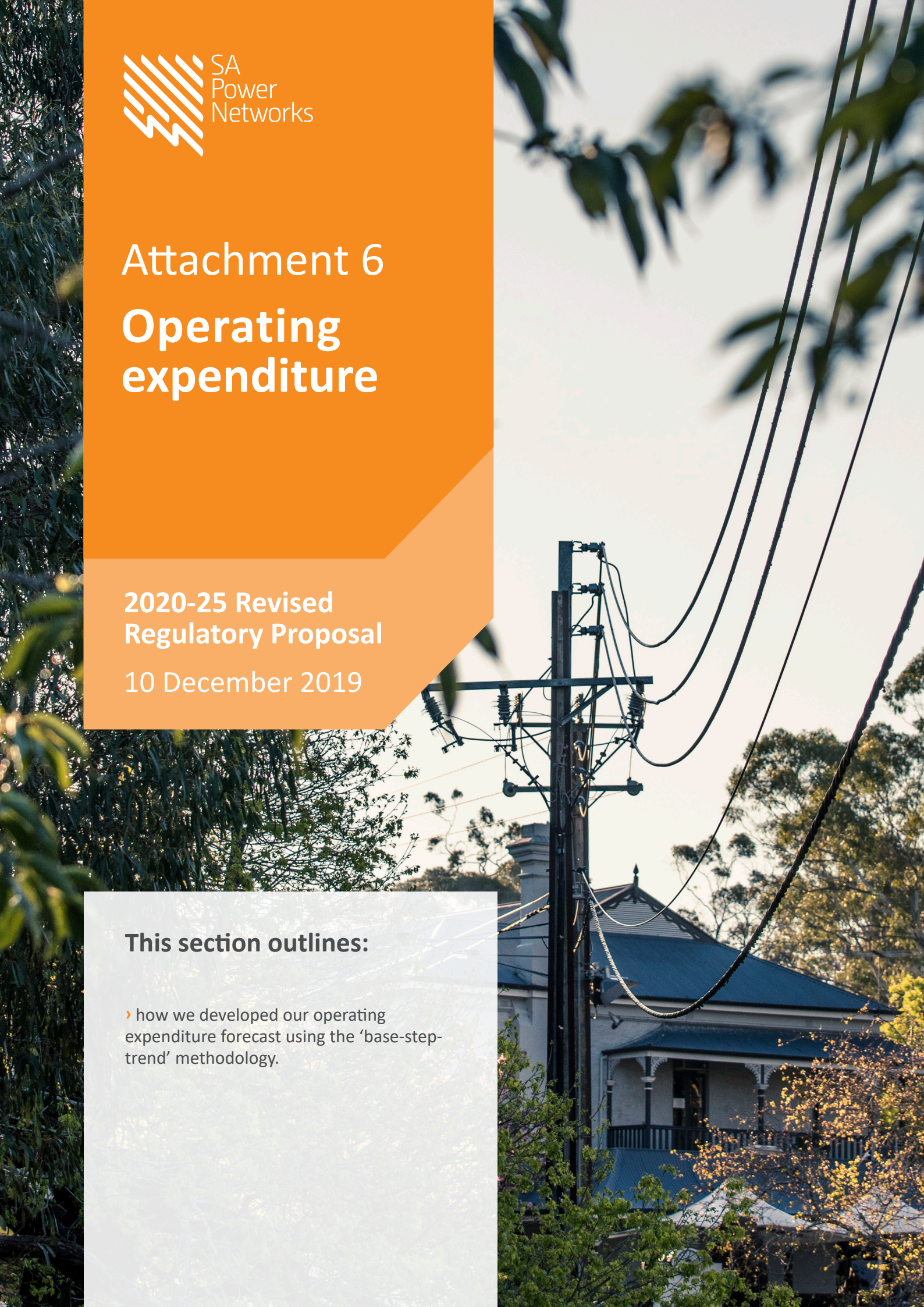
SA Power Networks

Attachment 6

Operating expenditure

2020-25 Revised Regulatory Proposal

10 December 2019



This section outlines:

› how we developed our operating expenditure forecast using the 'base-step-trend' methodology.

Company information

SA Power Networks is the registered Distribution Network Service Provider for South Australia.
For information about SA Power Networks visit sapowernetworks.com.au

Contact

For enquiries about this Revenue Proposal please contact:
Richard Sibly
Head of Regulation
SA Power Networks
GPO Box 77 Adelaide SA 5001
sapn2020proposal@sapowernetworks.com.au

Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal to the Australian Energy Regulator for the 1 July 2020 to 30 June 2025 regulatory control period. The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgement.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes and are therefore subject to ongoing change and development.

Whilst care was taken in the preparation of the information in this Regulatory Proposal, and it is provided in good faith, SA Power Networks, its officers and shareholders accept no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it for a different purpose or in a different context.

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Note

This attachment forms part of our Proposal for the 2020-25 Regulatory Control Period. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 18:

Document	Description
	Regulatory Proposal overview
Attachment 1	Annual revenue requirement and control mechanism
Attachment 2	Regulatory Asset Base
Attachment 3	Rate of Return
Attachment 4	Regulatory Depreciation
Attachment 5	Capital expenditure
Attachment 6	***Operating expenditure***
Attachment 7	Corporate income tax
Attachment 8	Efficiency Benefit Sharing Scheme
Attachment 9	Capital Expenditure Sharing Scheme
Attachment 10	Service Target Performance Incentive Scheme
Attachment 11	Demand management incentives and allowance
Attachment 12	Classification of services
Attachment 13	Pass through events
Attachment 14	Alternative Control Services
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Attachment 16	Connection Policy
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Attachment 18	List of Proposal documentation

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6 Operating Expenditure

6.1 Overview

SA Power Networks submitted its Regulatory Proposal (**Original Proposal**) for the 2020-25 regulatory control period (**RCP**) in January 2019.

In its draft decision on SA Power Networks' Original Proposal (**Draft Decision**), the Australian Energy Regulator (**AER**) did not accept SA Power Networks' proposed forecast operating expenditure (**opex**) of $1,530 million ($June 2020, excluding debt raising costs) for the provision of standard control services (**SCS**). The AER was not satisfied that that our proposed forecast opex reasonably reflected the opex criteria, as a result the AER determined an alternative estimate of $1,466 million ($June 2020, excluding debt raising costs), which represents a 4% reduction from SA Power Networks proposed opex forecast.

As with our Original Proposal, our 2020-25 Revised Regulatory Proposal (**Revised Proposal**) opex forecast has been developed in accordance with clause 6.5.6 of the National Electricity Rules (**NER**). Our forecast reflects the efficient and prudent costs of SA Power Networks achieving the opex objectives and a realistic expectation of the demand forecast, and cost inputs required to achieve those objectives. Our Revised Proposal opex forecast for the 2020-25 RCP is $1,442 million ($June 2020, excluding debt raising costs), taking into account our updates to actual base year costs and other factors as set out below.

Consistent with the approach we adopted in our Original Proposal, our forecast of total SCS opex has been designed to deliver optimal service provisions for our customers in both the short and long term. In preparing our opex forecast we have applied a top down assessment, using the AER's preferred 'Base-Step-Trend' methodology. Our Revised Proposal has been updated to reflect the actual results of our base year, along with updates to step changes and escalation factors. Table 6-1 and Figure 6-2 below show our original and (now) revised opex forecasts compared with the AER's Draft Decision.

Table 6-1: SA Power Networks opex proposals compared to AER Draft Decision for the 2020-25 RCP

Expenditure category (June 2020, $ million)	Original Proposal	AER Draft Decision	Revised Proposal
Base Year (including increment)	1,399.0	1,397.6	1,340.8
Step changes	75.1	53.6	76.2
Output Growth	30.6	25.6	24.7
Real Price Growth	25.7	9.7	20.4
Productivity Growth	-	(20.8)	(20.1)
Opex excluding debt raising	**1530.4**	**1465.7**	**1,442.0**
Debt raising costs[1]	20.5	7.2	11.3
Total opex	**1551.0**	**1,472.9**	**1453.3**

Note: totals may not add up due to rounding

This attachment provides an outline of our Original Proposal and the AER's Draft Decision, as well as our Revised Proposal opex forecast. Provided in Table 6-2 below, is a summary of the AER's decisions and our Revised Proposal responses.

[1] Our opex forecast referred to in this Attachment exclude debt raising costs which are dealt with in 'Attachment 3 - Rate of return and financing costs' and are not forecast using the base-step-trend approach.

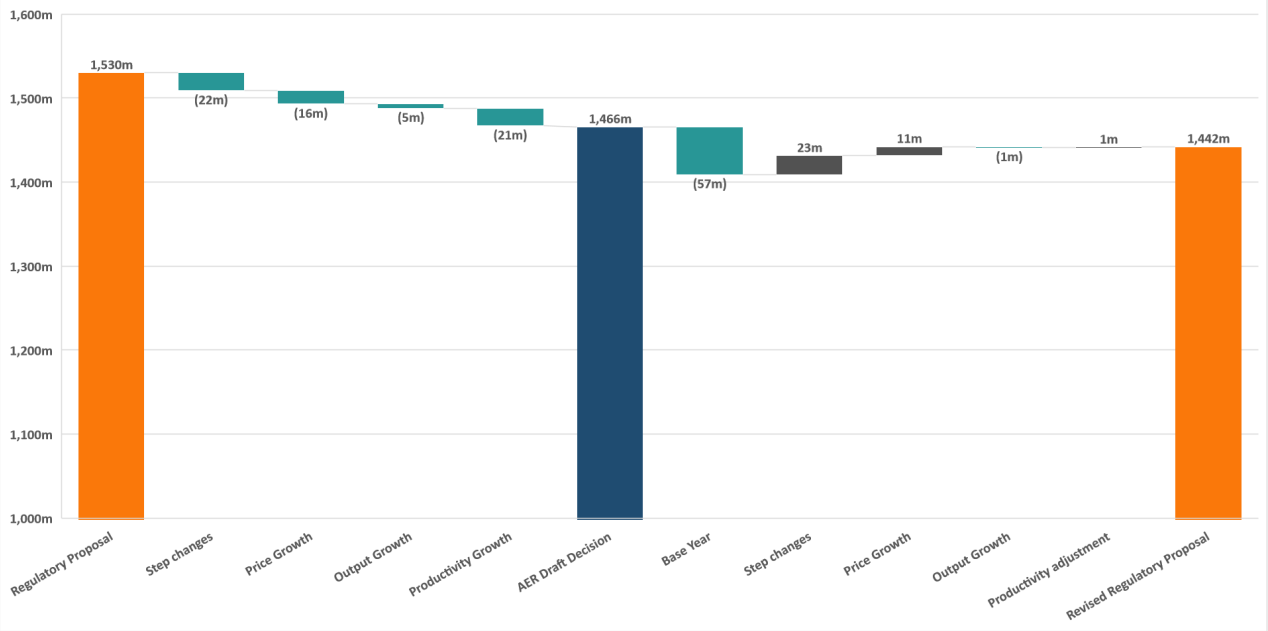
Table 6-2: Summary of feedback on SA Power Networks Regulatory Proposal on forecast opex

	AER Draft Decision	Revised Proposal
Base opex	The AER accepted our 2018/19 base year forecast, considering it to be a relatively efficient forecast, as indicated by its benchmarking results.	Our base year forecast has been updated to include the actual results achieved for the 2018/19 regulatory year. These results were lower than the forecast provided in our Original Proposal and have resulted in a lower overall opex forecast for our Revised Proposal.
Step changes	The AER accepted the need for the six step changes that we proposed. However, it reduced the amounts proposed for minor cable and conductor repairs to reflect past actual expenditure and adjusted the Guaranteed Service Level (**GSL**) step change to use a longer historical averaging period. The AER acknowledged receiving a submission on an increase to the annual licence fee for our distribution licence (**Distribution Licence Fee**) imposed by the South Australian Government,[2] but due to timing it was not able to be considered as part of its Draft Decision.	We largely accept the AER decisions regarding the step changes included in our Original Proposal. We have updated (where applicable) the step changes in our Revised Proposal for the latest tendering outcomes, base year actual results and Consumer Price Index (**CPI**) escalations. We have also included additional step changes for the increase to our Distribution Licence Fee highlighted by the South Australian Government in its submission to our Original Proposal, changes to Utilities Cyber Maturity requirements and a negative change associated with savings from our Low Voltage (**LV**) Transformer Monitoring capital expenditure (**capex**) business case.
Rate of change – output growth	The AER applied its standard approach (using output weights from all four benchmarking models) to forecast expected increases in output growth. The AER recognised the concerns we raised regarding the output factors being used, specifically the use of energy throughput and the impacts of Distributed Energy Resources (**DER**) and will consider these as part of a wider periodic review. [3]	We have applied the AER's standard approach to our revised forecast for output growth. However, we do not agree that applying the weights from all four models is representative of the efficient costs required to provide SCS. We acknowledge that the AER is aware that more work will need to be done to properly assess this and it will be included as part of a wider periodic review into economic benchmarking.
Rate of change – real price growth	Following analysis performed by the AER on Wage Price Index (**WPI**) growth, it has changed its approach to forecasting real labour price growth for the utilities sector in South Australia. Instead of applying an average of two consultants' forecasts, real price growth has been based solely on forecasts prepared for the AER by Deloitte Access Economics (**DAE**).	We engaged BIS Oxford Economics to review the analysis on recent labour price growth raised by the AER. We identify, including analysis contained in this review, additional factors that should be considered when analysing forecast performance against actuals and the resulting implications if the AER's new approach was applied the future. Based on our analysis, we have again applied an average of the latest BIS Oxford Economics and DAE labour forecasts for the 2020-25 RCP.
Rate of change – productivity growth	The AER applied the 0.5% pa productivity growth forecast from its opex productivity growth review final decision.	We have applied a 0.5% pa productivity growth to our Revised Proposal forecast opex.

[2] AER, *Draft Decision on SA Power Networks Distribution Determination 2020 to 2025,* Attachment 6 – Operating expenditure (**Attachment 6**), pages 55 and 56.

[3] AER, Attachment 6, page 35.

Figure 6-1: Movement in opex forecast to 2020-2025 Revised Proposal ($June 2020)



In our 2018 customer engagement program, we provided our customer and stakeholder groups with a comparison between total historical, current period and a preliminary forecast opex, and their feedback helped refine our Original Proposal opex forecast. Figure 6-2 below shows our revised opex forecast compared to our historical performance, our Original Proposal and the AER's alternative estimate in its Draft Decision.

Figure 6-2: SA Power Networks historical and forecast opex ($June 2020)

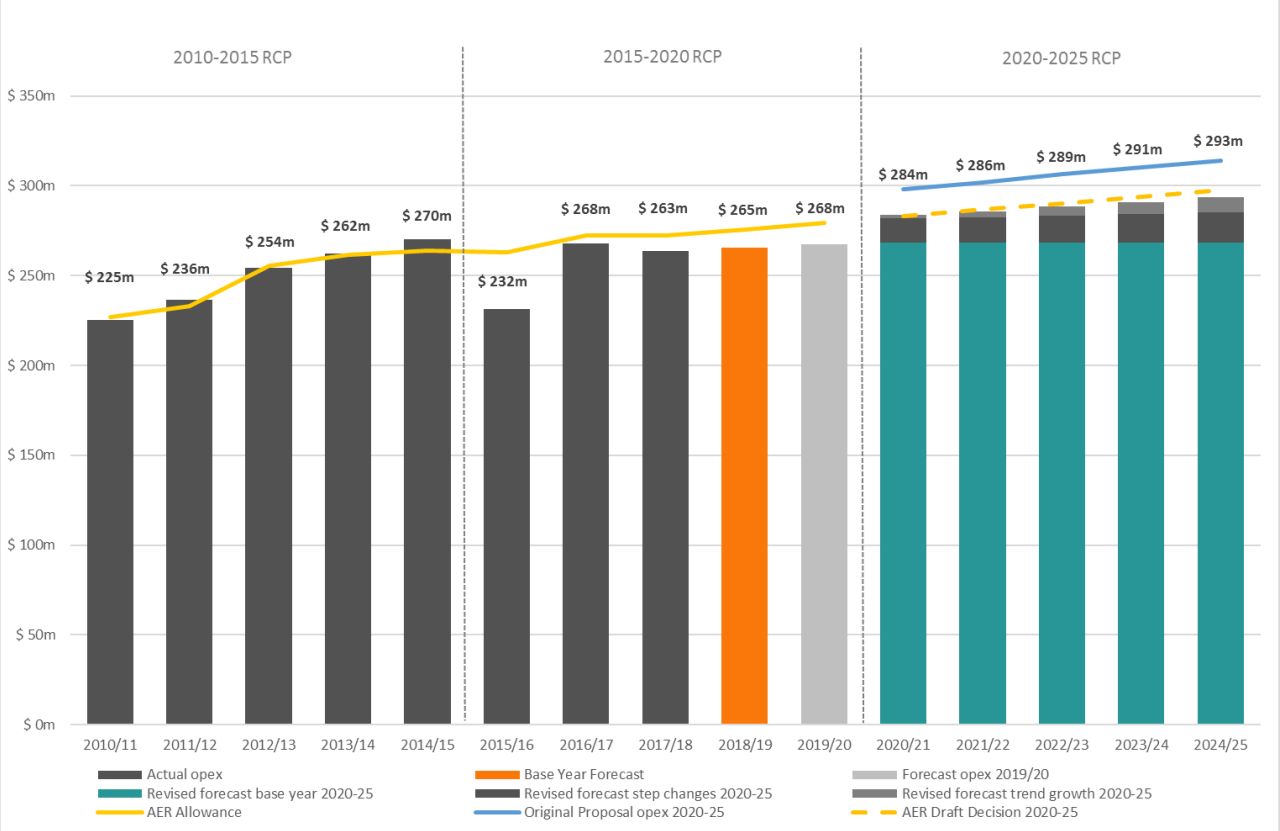
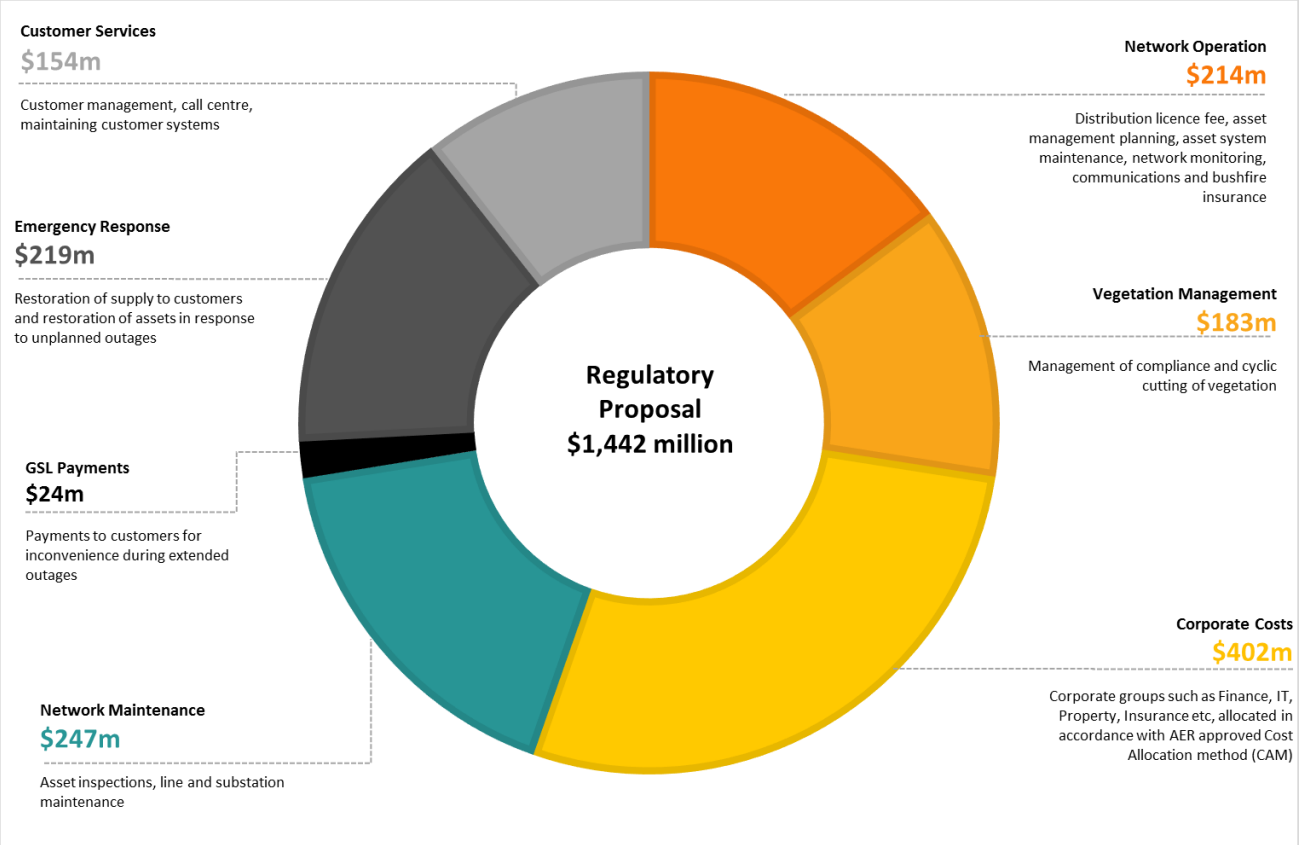


Figure 6-3, contains a summary of the individual opex components and the Revised Proposal cost forecasts for the 2020-25 RCP.

Figure 6-3: Forecast opex for the 2020-25 RCP by category ($June 2020)



6.2 Original Proposal

In our Original Proposal we explained that our opex forecast for the 2020-25 RCP had been developed in accordance with clause 6.5.6 of the NER. It reflected the efficient and prudent costs of SA Power Networks achieving the opex objectives[4] and a realistic expectation of the demand forecast, and cost inputs required to achieve those objectives.[5]

Our Original Proposal for the 2020-25 RCP, and consequently our opex forecast, had been formed by an extensive and rigorous customer engagement program. Throughout our engagement program, our customers and stakeholders have consistently told us that they value three key things, namely:

- keeping the prices down;
- maintaining a safe and reliable network; and
- prudently transitioning for the new energy future.

Our customers also told us that they support achieving an appropriate balance between these key objectives.

Our Original Proposal (and Revised Proposal) recognises that the electricity industry is being transformed by customer choices and technology and we need to achieve an appropriate and transparent balance between these key objectives when managing this transformation. We will do this by combining our experiences and perspective with the views of our customers and stakeholders.

In building our opex forecast we applied the AER's base-step-trend methodology and other requirements of the AER's Expenditure Forecast Assessment Guideline (**EFAG**)[6], where:

- the 'base' represents the efficient 2018/19 regulatory year forecast, plus the incremental change between the 2018/19 and 2019/20 allowances;
- the 'step' represents circumstances that change a business's fundamental opex requirements unavoidably and materially, such as a change in regulatory obligations for the delivery of SCS which were not reflected in the base year or a trade-off between capex and opex; and
- the 'trend' represents the forecast changes in scale (output growth) and the escalation of labour and non-labour costs (real price growth) applied to opex.

Table 6-3 sets out the Original Proposal SCS opex forecast of **$1,530** million ($June 2020, excluding debt raising costs) for the 2020-25 RCP.

Table 6-3: SA Power Networks Original Proposal opex forecast for the 2020-25 RCP

Expenditure category ($ June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Base Year (including increment)	279.8	279.8	279.8	279.8	279.8	**1,399.0**
Step changes	14.3	14.3	15.3	15.5	15.8	**75.1**
Output Growth	2.4	4.5	6.2	7.9	9.6	**30.6**
Real Price Growth	1.3	3.1	5.2	7.2	8.9	**25.7**
Productivity Growth	-	-	-	-	-	**-**
Opex excluding debt raising	**297.9**	**301.7**	**306.5**	**310.3**	**314.0**	**1530.4**
Debt raising costs	4.0	4.1	4.1	4.1	4.1	**20.5**
Total opex	**301.9**	**305.8**	**310.6**	**314.5**	**318.1**	**1551.0**

Note: totals may not add up due to rounding

[4] *NER 6.5.6(a).*
[5] *NER 6.5.6(c).*
[6] AER*, Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution,* November 2013.

6.3 AER's Draft Decision

The AER, in its Draft Decision, determined an alternative estimate of $1,466 million ($June 2020, excluding debt raising costs), which represents a $64 million or 4% reduction from SA Power Networks proposed opex forecast.

In making its Draft Decision, the AER accepted our proposed 2018/19 base year as the starting point for its alternative estimate. The AER highlighted that its benchmarking results show that SA Power Networks has consistently been amongst the most productive and efficient distributors in the National Electricity Market (**NEM**) over the last eleven years.[7] In response to stakeholder submissions, the AER also noted that once a decision is made regarding the efficiency of the revealed year opex, it does not matter which year is chosen as the base year. The combined effect of the Efficiency Benefit Sharing Scheme (**EBSS**) would result in little impact on the total revenue allowance for the business.[8]

The AER's lower Draft Decision for 2020-25 RCP opex is primarily as a result of changes to two step changes and rate of change movements. The following factors are the main contributors to the difference between SA Power Networks' opex proposal in its Original Proposal and the AER's decision on that proposed opex in its Draft Decision:

- Step changes reduced by the AER by $22 million ($June 2020). While the AER accepted the need for all proposed step changes, updated forecasts were applied to the cable and conductor minor repairs and GSL step changes to reflect past actual expenditure and the use of a longer historical averaging period.
- Price growth reduced by the AER by $16 million ($June 2020). This reflected a new approach by the AER to forecasting labour price growth from its previous determinations. Following an analysis performed by the AER for the period of 2007 to 2018, it considered that DAE's real WPI growth forecasts have been more accurate than the results obtained from averaging the forecasts over the period 2012-18.
- Output growth reduced by the AER by $5 million ($June 2020). The AER applied its standard approach (using output weights from all four benchmarking models) to forecast the expected increases in output.
- Productivity growth (negative) adjustment by the AER of $21 million ($June 2020). This represented the 0.5% pa productivity growth forecast from the AER's opex productivity growth final decision in March 2019.

Table 6-4 below outlines the AER Draft Decision opex for the 2020-25 RCP.

Table 6-4: AER Draft Decision opex forecast for the 2020-25 RCP

Expenditure category (June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Base Year (including increment)	279.5	279.5	279.5	279.5	279.5	**1,397.6**
Step changes	9.5	10.1	11.1	11.3	11.6	**53.6**
Output Growth	2.0	3.8	5.2	6.6	8.1	**25.6**
Real Price Growth	0.7	1.3	1.9	2.6	3.4	**9.7**
Productivity Growth	(1.4)	(2.8)	(4.2)	(5.6)	(7.0)	**(20.8)**
Opex excluding debt raising	**290.3**	**291.9**	**293.5**	**294.5**	**295.6**	**1,465.7**
Debt raising costs	1.4	1.4	1.4	1.4	1.4	**7.2**
Total opex	**291.7**	**293.3**	**294.9**	**296.0**	**297.0**	**1,472.9**

Note: totals may not add up due to rounding

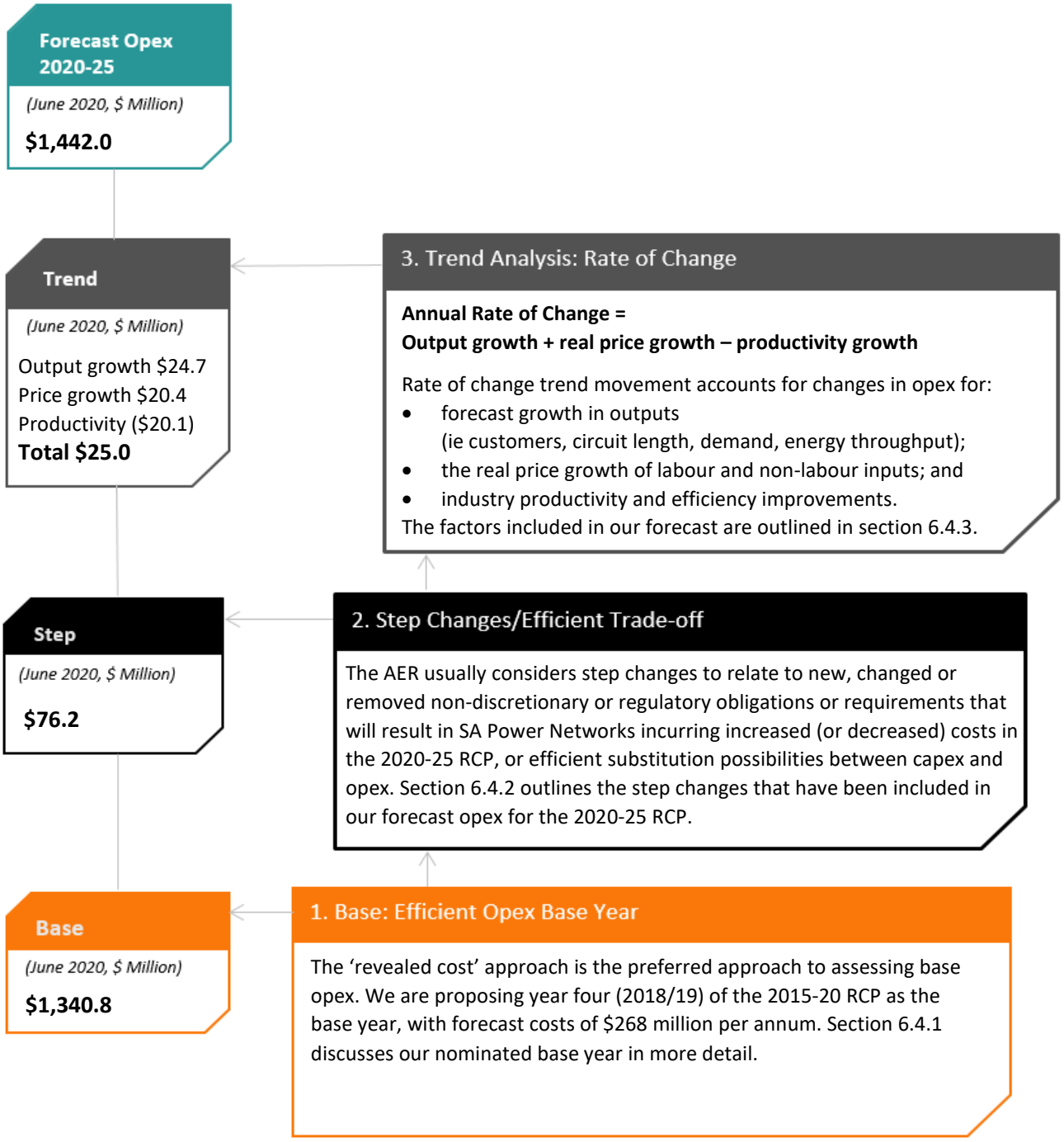
[7] AER, Attachment 6, page 24.

[8] AER, Attachment 6, page 23.

6.4 SA Power Networks' response to AER Draft Decision

The EFAG sets out the AER's intended approach to assessing opex in accordance with the NER. We have again applied the AER base-step-trend methodology as outlined in the EFAG to prepare our revised opex forecast for the 2020-25 RCP (Figure 6-4).[9]

Figure 6-4: Opex base-step-trend methodology



[9] Forecasts for category specific opex using an alternative method to the base-step-trend methodology (eg debt raising costs) are discussed in Attachment 3 - Rate of Return, Revised Proposal.

6.4.1 Base year

In making its Draft Decision, the AER accepted our nominated 2018/19 regulatory year as our base year, considering it to be a relatively efficient forecast, as indicated by its benchmarking results.[10]

Most stakeholder submissions on our Original Proposal also considered our opex to be relatively efficient but did note that, due to declining opex productivity and the higher proposed opex in 2018/19, the base year costs should be examined closely. The AER used a variety of economic benchmarking tools to test the efficiency of our opex for use as our base year. Its results showed that SA Power Networks has consistently been amongst the most productive and efficient distributors in the NEM over the last eleven years.[11]

Our Revised Proposal base year forecast has been updated to reflect our 2018/19 audited results. [12] The actual opex incurred in our 2018/19 base year of $272 million ($June 2020) was lower than we previously forecast and contributes to the lower opex forecast in our Revised Proposal. Contributing to our lower actual expenditure compared to our original forecast were lower GSL inconvenience payments. Due to the volatility in our GSL inconvenience payments, resulting from unpredictable weather outcomes, our estimate of GSL expenditure for the 2018/19 base year was forecast using a five-year average of historical payments. In our Original Proposal we raised the possibility of applying a non-recurrent efficiency gain to account for variances in our GSL costs should they be abnormally high or low in the base year compared to average. In our Revised Proposal we have not opted to take this approach but have instead retained the actual GSL expenditure incurred in the base year, consistent with how the AER made its Draft Decision. The lower base year GSL expenditure also impacts the amount we have proposed for our GSL step change, discussed further in section 6.4.2.6.

In line with the EFAG and the application of the EBSS requirements we have further adjusted our base year expenditure to apply the following:

- a reduction of $7 million ($June 2020) to remove movements in provisions; and
- an addition of $3 million ($June 2020) for the incremental adjustment for final regulatory year (2019/20) expenditure in the 2015-20 RCP.

Our base year opex complies with the requirements of the Reset Regulatory Information Notice (**RIN**) and has been calculated in accordance with our approved Cost Allocation Method.

6.4.2 Step changes

In our Original Proposal, we submitted step changes totalling $75 million ($June 2020). The AER accepted the need for all six step changes that we proposed. While all changes were accepted, the AER reduced the amounts for the reclassification of cable and conductor repairs to reflect past actual expenditure. It also updated the change relating to GSL reliability payments to use a longer historical averaging period to forecast future payments.

We have updated our proposed step changes to reflect feedback from the AER's Draft Decision, customer and stakeholder submissions, and updates to CPI escalation factors. The main updates were applied to the following step changes:

- Critical Infrastructure Centre (**CIC**) compliance costs updated to reflect tender outcomes;
- GSL step change forecast reduced to reflect lower actual GSL expenditure in 2018/19; and
- the inclusion of a new step change for SA Government imposed increases to our Distribution Licence Fee and a new step change for Utilities Cyber Maturity Uplift requirements.

[10] AER, Attachment 6, page 23.

[11] AER, Attachment 6, page 24.

[12] At the time of submitting our Original Proposal the actual results for the 2018/19 regulatory year were not available, so we instead applied a combination of year to date actuals and budgets to develop our forecast base year.

Table 6-5 provides a comparison of our original step changes, the AER's Draft Decision on those step changes and our revised step changes, for the 2020-25 RCP.

Table 6-5: SA Power Networks summary of step changes for the 2020-25 RCP

(June 2020, $ million)	Original Proposal	AER Draft Decision	Revised Proposal
LV Management	3.8	3.8	3.7
Cloud Transition – Hosting	7.2	7.2	7.2
Cloud Transition – Scheduling	3.8	3.8	3.7
Cable and Conductor minor repair	68.2	49.7	49.7
Critical Infrastructure Compliance	12.1	12.1	10.1
GSL Reliability	(19.9)	(23.0)	(1.8)
Distribution Licence Fee	-	-	3.2
Utilities Cyber Maturity Uplift	-	-	1.7
LV Transformer Monitoring	-	-	(1.3)
Step Change	**75.1**	**53.6**	**76.2**

6.4.2.1 LV Management – Enabling the energy transition

We proposed our LV management step change in alignment with our new project within our capital expenditure program. This program is to develop new operational systems and business processes to actively manage the integration of solar, battery storage and virtual power plants (**VPPs**) into the distribution network.

The AER is satisfied that the LV Management step change represents prudent and efficient expenditure to manage high voltage conditions in low voltage feeders and other constraints on our network arising from DER.[13] Typically the AER would not provide a step change to operate and maintain a new asset, instead it would look to apply a standard approach allowing for increases in line with the output growth forecast. However, due to the significant demands to manage the network and address customers' needs that SA Power Networks is facing with regard to DER, the AER recognised there is a likelihood, at least in the short term, that the output growth forecast may not fully compensate for the higher opex required to address DER. On this basis, the AER has considered it appropriate to allow an opex step change in this case.[14]

We accept the AER's Draft Decision but have reduced this step change in our Revised Proposal to $3.7 million ($June 2020) to reflect the latest CPI escalations in our modelling.

6.4.2.2 Cloud Transition – Cloud hosting

Our cloud hosting step change reflects the constant changes occurring in the information and communications technology (**ICT**) environment. ICT businesses are now only providing software applications through cloud subscription services, meaning that they can no longer be 'owned' and installed locally. This change represents a transfer of costs from businesses purchasing internal capital hardware, to a subscription-based operating environment.

The AER's Draft Decision accepted our proposed step change for cloud hosting, considering the capex/opex trade-off to result in forecast expenditure that is prudent and efficient.[15]

We accept the AER's Draft Decision and have updated this step change in our Revised Proposal to $7.2 million ($June 2020) to reflect the latest CPI escalations in our modelling (noting no reduction to values represented in Table 6-5 due to rounding).

[13] AER, Attachment 6, page 48.
[14] AER, Attachment 6, page 50.
[15] AER, Attachment 6, page 43.

6.4.2.3 Cloud Transition – Work scheduling

Our Digital Strategy outlines key focus areas to enable the organisation to achieve its prudent and strategic outcomes in an increasingly digital world. As mentioned above, the constantly changing ICT environment now means that more ICT businesses are only providing access to their software applications through cloud subscription services. Our work scheduling step change is an example of an application that has reached the end of its life and the replacement option is only available through a cloud service.

The AER's Draft Decision accepted our proposed step change for cloud work scheduling, considering the capex/opex trade-off will result in forecast expenditure that is prudent and efficient.[16]

We accept the AER's Draft Decision and have updated this step change in our Revised Proposal to $3.7 million ($June 2020) to reflect the latest CPI escalations in our modelling.

6.4.2.4 Cable and conductor minor repair costs – reclassification from capex to opex

Our Original Proposal included a change to reclassify the treatment of cable and conductor minor repairs from capex to opex. The nature of cable and conductor minor repairs are more akin to repairs and maintenance rather than refurbishment and are better represented as opex. In proposing this step change we removed this expenditure from our replacement capex (**repex**) forecast and included a capex/opex trade-off in our opex forecast.

The AER indicated in its Draft Decision that it was satisfied that it is appropriate to reclassify our cable and conductor minor repair costs as opex rather than repex. Advice provided to the AER from Energy Market Consulting associates (**EMCa**) also considered the proposed treatment of this expenditure to be consistent with that which it typically observes in other distributors.[17]

However, the AER's Draft Decision indicated that it was not satisfied that the magnitude of the proposed step change reasonably reflected the efficient costs of a prudent firm. Since lodging our Original Proposal in January 2019, we have engaged with the AER and EMCa to provide updated estimates of the cable and conductor repair expenditure for 2018/19. Using these revised estimates, EMCa considered that an average of actual expenditure from 2014/15 to 2018/19 reasonably reflects the total expenditure that we will require for minor cable and conductor repairs. Further analysis by the AER on the volumes and unit rates reflected in our Original Proposal, supported the conclusion made by EMCa and provided the basis to approve our cable and conductor minor repair cost step change.

We accept the AER's Draft Decision and have updated this step change in our Revised Proposal to $49.7 million ($June 2020).

6.4.2.5 Critical Infrastructure Compliance

In 2017, a series of requirements were introduced to address the national security risks associated with foreign involvement in relation to critical infrastructure. SA Power Networks' distribution system is classified as a high priority Australian critical infrastructure asset under the new critical infrastructure system and data control obligations. To meet our requirements of these new obligations we are required to develop and implement risk mitigation strategies with the CIC through a 'treatment plan'. While the capex aspects of our treatment plan have been implemented in the current 2015-20 RCP, under the terms of the treatment plan and agreed compliance dates there are several ongoing opex components that are required to be implemented in the 2020-25 RCP.

[16] AER, Attachment 6, page 46.
[17] AER, Attachment 6, page 39.

In its Draft Decision, the AER accepted this step change and was satisfied that it is required to meet new obligations that SA Power Networks faces, and that the expenditure proposed is efficient.[18] The AER also considered that this proposed expenditure meets the EFAG expectations for a step change associated with new and major regulatory obligations and the definition of 'regulatory obligations or requirements' as defined in the National Electricity Law (**NEL**).[19]

At the time of proposing this expenditure we were actively testing the market through a competitive tender for services that would enable us to meet the new requirements. We have now finalised this tender process and are able to provide updated costs estimates in line with the AER's expectations expressed in its Draft Decision. These revised cost estimates and updates on the agreement process with the Commonwealth and other aspects of our revised proposed step change can be found in Supporting document 6.1.

We accept the AER's Draft Decision and have applied the outcome of the tender process to our revised CIC step change forecast of $10.1 million ($June 2020) for the 2020-25 RCP.

6.4.2.6 GSL Reliability Duration Payments

Our Original Proposal included a negative step change for GSL inconvenience payments. This change was driven by the review by the Essential Services Commission of South Australia (**ESCoSA**) of our reliability service standards.[20] Prior to the commencement of each new RCP, ESCoSA reviews the reliability service standards that will apply to SA Power Networks. To better target customers with ongoing, persistent reliability issues, ESCoSA has reviewed and amended the GSL scheme to apply to SA Power Networks for the 2020-25 RCP.

The new standards do not take effect until 1 July 2020 and the costs of the current GSL scheme are included in our 'revealed year' costs. To determine an efficient adjustment to be applied to the base year opex, we re-calculated what the last five years of our GSL expenditure would have been had the new regulatory obligations applied. By applying this approach, we proposed a negative step change of $19.9 million ($June 2020) in our Original Proposal to account for the changes to our GSL regulatory obligations for the 2020-25 RCP.

While the AER was satisfied that there will be a change in our GSL obligations and that our forecasting approach to using actual historical GSL payments was appropriate, it did not accept our proposed forecast. Applying the changes proposed by ESCoSA, the AER examined our actual GSL payments since 2005/06, and how much would have been paid out had the new scheme been applicable over this time. The alternative methodology applied by the AER in calculating the impact of these changes on our opex, was to apply a longer averaging period. Rather than the five-year period that we applied; the AER applied a 10-year period from 2008/09 to 2017/18. As explained below, SA Power Networks accepts the AER's use of a longer term averaging period for the 2020-25 RCP, but has used the period from 2009/10 to 2018/19 as we now have actual data for the 2018/2019 regulatory year which, of course, was not available when we lodged our Original Proposal.

The current, and the 2020-25 RCP, GSL scheme, is heavily dependent on the number and severity of major weather events. SA Power Networks has experienced a significant increase in the number and severity of major weather events since 1 July 2010. This increase is reflected in the more than doubling of the number of Major Event Days (**MEDs**) and MED Unplanned System Average Interruption Duration Index (**USAIDI**) average per annum.[21] As a result, it would be more reflective of actual experience for the long-term

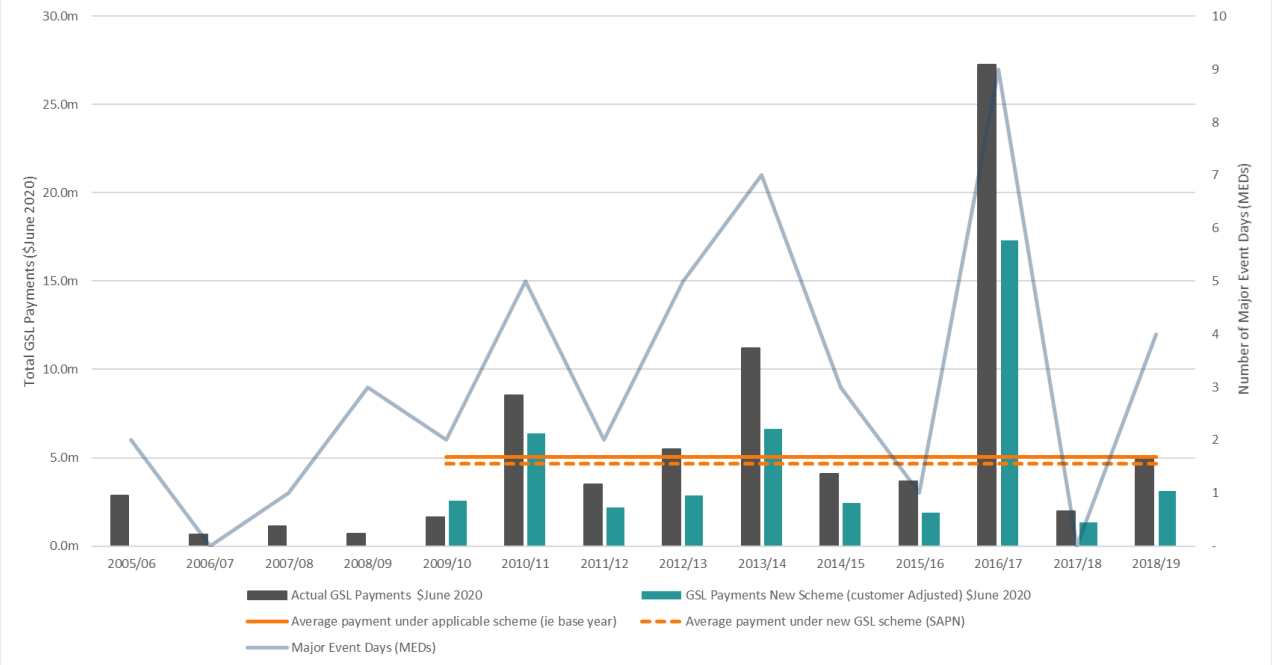
[18] AER, Attachment 6, page 41.
[19] AER, Attachment 6, page 42.
[20] ESCoSA, *SA Power Networks reliability standards review, Final decision,* January 2019, page 35.
[21] The average MEDs since 1 July 2010 have increased from 1.6 to 4 per annum and MED USAIDI has increased from 14 to 83 minutes on average per annum.

average to apply from 1 July 2010 (ie a total of 9 years rather than 10). However, as noted above, our Revised Proposal accepts the AER's approach of using a 10-year average to calculate the GSL reliability duration payment step change, but on the basis that the average is updated to include the latest year of actual data for 2018/19.[22] By applying a longer historical average period (10 years compared with five years) the changes in customer numbers applicable for GSL payments, over the averaging period, has a greater impact on the application of the new scheme. To account for this, the average GSL payments to apply from 1 July 2020 have been adjusted to account for the changes in customer numbers over the same 10-year period.

In its Draft Decision, the AER implied that the higher GSL expenditure we experienced in 2016/17, was related to the South Australia state-wide blackout triggered by severe weather that damaged transmission and distribution assets.[23] This is incorrect. The costs of the GSL reliability duration payments associated with this state-wide event was only 7% of the duration payments in 2016/17. The main causes of the higher GSL expenditure that we experienced during the 2016/17 regulatory year were six other separate major weather events (representing nine MEDs) that occurred on other days during the year, which contributed 90% of the cost of reliability duration payments in 2016/17. The remaining 3% of GSL payments were not associated with severe major weather events.

Unlike some other jurisdictions, ESCoSA's GSL scheme requires payments to be made for outages on MEDs. Figure 6-5 below shows the actual and equivalent GSL payments under the existing and new schemes, as well as the number of MEDs that have occurred over the same period. While the new scheme will reduce the value of overall GSL payments, the volatility of extreme weather events and the inclusion of MEDs in the scheme is likely to still see considerable fluctuations in GSL payments year on year.

Figure 6-5: Actual and equivalent GSL payments under the existing and new schemes ($June 2020)



A combination of the lower GSL expenditure in our base year and updating the average calculation to include the latest year of actual data, has reduced our Revised Proposal GSL step change. We are now proposing a step change of minus $1.8 million ($June 2020) for the 2020-25 RCP. The assumptions and calculations for this step change can be found in Supporting Document 6.2 GSL opex 2020-25.

[22] We have applied a 10-year average based on the retrospective expenditure for GSL payments from 2009/10 to 2018/19.

[23] AER, Attachment 6, page 55.

6.4.2.7 Distribution Licence Fee

We are proposing a new step change for increases to our annual Distribution Licence Fee. This change was not included in our Original Proposal because, at the time of submitting our Original Proposal, we were not aware of any increase to our annual Distribution Licence Fee.

The increase was first brought to our attention in May 2019, when the Government of South Australia advised the AER of the increase in its submission to the AER on our Original Proposal. SA Power Networks only received a letter from the South Australian Energy and Technical Regulation Division about this increase in June 2019. That letter confirmed an increase in our Distribution Licence Fee from $2,257,600 to $2,935,000 per annum for the 2020-25 RCP. SA Power Networks wrote to the AER in August 2019 requesting that the AER consider the increased Distribution Licence Fee as a step change in its Draft Decision. A copy of our letter has been included as Supporting Document 6.3.

The AER did not examine the expected increase in our Distribution Licence Fee when developing its alternative estimate for the Draft Decision. The AER noted that it was not possible to consider this late request as part of the Draft Decision but that it would consider it as part of its final decision for the 2020-25 RCP.

The AER also noted in its Draft Decision that it typically would require there to be a new regulatory obligation for a step change to be allowed. However, in comparable circumstances, and as noted in our supporting documentation, the AER made an allowance for a negative step change in the 2015-20 RCP to reflect a reduction in SA Power Networks' annual Distribution Licence Fee for that RCP. For the 2015-20 RCP, we applied a base year cost reduction to reflect advice from the Minister of that reduced Distribution Licence Fee and, in its 2015-20 preliminary decision, the AER approved and included an adjustment for that reduction in its alternative forecast and stated that this adjustment was due to 'a reduced cost incurred by SA Power Networks in delivering its regulatory obligations and therefore classified as a step change'.[24]

In these circumstances, and as further elaborated in our supporting documentation, we submit that an allowance for an increase in our Distribution Licence Fee should be made for the upcoming 2020-25 RCP. For this reason, we have included a step change of $3.2 million ($June 2020) in our Revised Proposal opex forecast for the costs associated with the increase in our Distribution Licence Fee for the 2020-25 RCP.

6.4.2.8 Utilities Cyber Maturity Uplift

Our Utilities Cyber Maturity Uplift step change proposes new expenditure on non-network ICT to implement processes and systems to ensure that SA Power Networks can comply with new cyber security related regulatory obligations during the 2020-25 RCP. The obligations arise from work initiated by the Australian Energy Market Operator (**AEMO**) in developing the Australian Energy Cyber Security Framework. The work is at a progressed state and decisions on exact implementation timing are currently before Commonwealth and jurisdictional governments and energy market bodies via the Council of Australian Governments Energy Council (**CoAG-EC**).

Proposed expenditure over the 2020-25 RCP is primarily comprised of 'non-recurrent' capex of $5.15m (Dec $2017), with a step increase in opex of $1.59m (Dec $2017). The business case for this proposed expenditure has been included as Supporting Document 5.30 - Utilities Cyber Maturity Uplift business case, and it sets out, among other things:

- why this matter requires consideration in the AER's final decision for the 2020-25 RCP, despite forecast expenditures not being included in our Original Proposal and therefore also not having been allowed for in the AER's Draft Decision;
- the identified need for the proposed expenditures;
- the regulatory compliance options (and specific initiatives) considered by SAPN and how costings for these options were reasonably derived; and
- the engagement SAPN undertook with our customers and stakeholders on this matter.

[24] AER, Attachment 7 – Operating Expenditure | SA Power Networks' determination 2015–20, page 105.

While we recognise that this is a new step change that was not included in our Original Proposal, we propose that both the capex and opex step change should be subject to the same assessment approach on the basis that:

- the proposed capex and opex are both required for SA Power Networks to implement the initiatives required to address the identified need set out in the business case;
- the business case shows that the recommended option is a prudent response to regulatory compliance and is shown to be the least cost means of ensuring compliance over the 2020-25 RCP;
- the identified need is to comply with regulatory obligations which, based on reasonable expectations, SA Power Networks will have to comply with over the 2020-25 RCP. While the regulatory requirements are not yet enacted, there is sufficient information before SA Power Networks to form a view that:
  - it is reasonable to expect that we will need to incur expenditure to comply with new regulatory obligations over the 2020-25 RCP; and
  - there is reasonable clarity on the specifications of the regulatory obligations under development and the compliance actions we will need to take. Therefore, there is a reasonable basis upon which to form a realistic expectation of the costs required to implement the compliance actions;
- the NER require SA Power Networks to propose forecast expenditure for a RCP that is required to achieve the opex and capex objectives.[25] One of the objectives is to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services; and
- the Revenue and Pricing Principles in the NEL require that the AER provide SAPN with a reasonable opportunity to recover at least our efficient costs of providing (regulated) direct control network services and complying with regulatory obligations.[26]

When we discussed this topic with our customers and stakeholders, they told us that cyber security was an important consideration but needed to be addressed at least cost. A detailed explanation of our engagement with customers and stakeholders on this topic and how our revised proposal responds, is set out in Supporting Document 5.30. For the reasons outlined above, we have included a step change of $1.7 million ($June 2020) in our Revised Proposal opex forecast for the costs associated with Utilities Cyber Maturity uplift.

6.4.2.9 LV Transformer Monitoring

Our Original Proposal included a capital program of work related to LV Transformer Monitoring. This program of work was to roll-out permanent LV transformer monitors across the metropolitan area to implement a new LV load forecasting methodology. The AER did not approve this expenditure in its Draft Decision, finding that:

(a) we had not adequately justified why monitoring at the LV transformer level is required; and
(b) that we did not appear to have taken into account the efficiency benefits, which would be expected to reduce business-as-usual operating costs in our Quality of Supply program.

We have reviewed the AER's Draft Decision feedback and have amended our capex business case accordingly in our Revised Proposal. The analysis that was performed in the preparation of that business case identified benefits through opex savings within our LV monitoring capital program. To incorporate these savings into our opex forecast for the 2020-25 RCP, we are proposing to include a negative step change.

Unlike our LV Management step change which is looking at the development of new operational systems and business processes to actively manage the integration of solar, battery storage and virtual power plants

[25] NER clauses 6.5.6 and 6.5.7

[26] NEL, Section 7A Revenue and Pricing Principles

(**VPPs**) into the distribution network, LV Monitoring is focused on developing a program to improve our capacity planning on the LV network. Although state-wide peak demand in South Australia is forecast to remain relatively flat over the next 15 years, we continue to experience localised areas of peak demand growth across the distribution network, particularly in the metropolitan area, primarily due to infill development. One of the functions of network planning is to forecast, each year, which local LV transformers are reaching capacity so that transformer replacements or other augmentation works can be undertaken prior to the summer peak demand season.

We rely today on the installation of temporary load and voltage loggers to conduct temporary load surveys and to investigate customer-reported issues. In order to forecast load growth, we conduct load surveys on individual transformers over the course of each year by installing temporary loggers to record load data over a period of one week. At the end of each survey, a crew returns to the site to un-install and recover the logger, and the logged data is then analysed to predict whether the transformer is likely to become overloaded during summer peak conditions. We are proposing to move away from this approach and to install and commission a sample set of permanent remote monitoring on multi-customer LV distribution transformers in the metropolitan area to improve capacity planning in the LV network.

Our revised opex proposal includes a step change of minus $1.3 million ($June 2020) to recognise the efficiency savings that will be delivered by our LV Transformer Management capital program. However, these efficiency savings are contingent on the approval of the LV Transformer Monitoring capex. Our customers and stakeholders supported this revised approach to LV Transformer Monitoring. A copy of the LV Transformer Monitoring business case is included as Supporting Document 5.15, Revised Proposal.

6.4.3 Rate of change

Our Revised Proposal continues to adopt a rate of change approach which is consistent with the rate of change formula in the EFAG.[27] Outlined below are the approaches that we have applied to forecasting output growth, real price growth and productivity growth.

6.4.3.1 Output growth

Our Original Proposal raised concerns with the 'refined' approach to forecasting annual output growth taken by the AER in its recent distribution determinations, specifically, the application of an average of the weightings from all four econometric models used to benchmark Distribution Network Service Providers (**DNSPs**). Concerned that we would not have the opportunity to recover our efficient costs of achieving the opex objectives required under the opex criteria,[28] we engaged NERA Economic Consulting (**NERA**) to review the AER's approach and its proposed changes to output weightings. [29] As a result of the findings provided by NERA, we did not apply the AER's latest methodology in the build-up of our Original Proposal opex forecast. Instead, our proposed output growth forecast applied an average of the weightings from two of the four benchmarking models used by the AER (eg the two Cobb-Douglas models).

The AER did not accept the changes we proposed to forecasting output growth. Economic Insights, engaged by the AER, reviewed NERA's report and outlined some areas of concern in relation to NERA's analysis and proposed approach.[30] The AER accepted the analysis of NERA's arguments by Economic Insights, and determined that its current output forecasting approach remains appropriate and that it would continue to forecast output growth using an average of all its benchmarking models.[31] Table 6-6 below, represents the output growth factors from the 2018 Annual Benchmarking Report used by the AER in its Draft Decision and by SA Power Networks in our Revised Proposal.

[27] AER*, Expenditure Forecast Assessment Guideline for Electricity Distribution,* November 2013, page 23.
[28] *NER, clause 6.5.6(c).*
[29] Supporting Document 6.5, NERA, *Review of the AER's proposed output weightings*, December 2018.
[30] Economic Insights, *Review of NERA report on output weights*, 30 April 2019.
[31] AER, Attachment 6, page 34.

Table 6-6: AER Draft Decision output specifications and weights applied[32]

Output*	MPFP	SFACD	LSECD	LSETLG
Customer Numbers	31.00%	71.71%	68.71%	57.74%
Circuit length	29.00%	12.65%	10.76%	11.27%
Ratcheted maximum demand	28.00%	15.64%	20.53%	30.99%
Energy throughput	12.00%			

*MPFP = Multilateral partial factor productivity, SFACD = Cobb Douglas stochastic frontier analysis, LSECD = Cobb Douglas least squares estimation, LSETLG = Translog least squares estimation.

While we have applied the AER's 'refined' approach in our Revised Proposal, we do not believe that the weights from all four models are representative of the efficient costs required to provide SCS. The significant transformation that the electricity industry is undergoing means that the output drivers used by the AER are not appropriately tracking the underlying input drivers of distributors' operating costs. As highlighted in our Original Proposal,[33] for SA Power Networks, this is particularly the case with ratcheted maximum demand and energy throughput.

In its Draft Decision the AER recognised that 'NERA raised fair concern about whether energy throughput fully accounts for the impact of DER and considers that it will likely be appropriate to review the output specification used in its benchmarking models'.[34] Furthermore, the AER recognised that, currently, the energy throughput variable only captures amounts delivered to customers over the distribution network and not the energy delivered into the network via DER, such as residential roof-top solar panels. An increase in roof-top solar could potentially involve a substitution of different energy sources amongst the same customers without changing the total energy consumed or materially changing the existing network in terms of circuit length or maximum demand. However, a distributor may be required to incur higher opex and/or capital to manage the safety and reliability of its network. This creates material increases in the inputs without a corresponding increase to any or all of the outputs as currently measured.[35]

A similar point was also made by the AEMC in its recent report, Integrating Distributed Energy Systems for the Grid of the Future, where it stated:

> "*In particular, how the electricity distribution network is operated and the services provided by distribution network service providers (DNSPs) could change. A high DER environment could mean that DNSPs need to alter aspects of their operation, from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and facilitating efficient access for DER so that they can provide the greatest benefits to system as a whole. This change is likely to have implications on aspects of the regulatory framework*."[36]

The AER acknowledged that, under these circumstances, the existing output measures would not allow a distributor to recover prudent and efficient costs associated with a significant change to its operating environment and that more work is required to properly assess this impact.[37] In the meantime, recognising the current output specification does not fully account for growing DER, the AER has considered and allowed a step change related to this matter. That is, the AER assessed and accepted our proposed step change relating to LV Management that is driven by increasing use of DER on our network. Specifically, the AER stated:

> "*Overall, we accept this opex step change given that … [t]here is a likelihood that, at least in the short term, the output growth forecast may not fully compensate for the higher opex required to address DER*".[38]

[32] AER, Attachment 6, page 36.
[33] SA Power Networks, *2020-25 Regulatory Proposal, Attachment 6 Operating Expenditure*, January 2019, page 30.
[34] AER, Attachment 6, page 34.
[35] Ibid.
[36] Australian Energy Market Commission, *Integrating Distributed Energy Resources for the Grid of the Future*, 26 September 2019, page v
[37] AER, Attachment 6, page 35.
[38] AER, Attachment 6, page 50.

In both the AER's Draft Decision and its latest benchmarking report[39], the AER has acknowledged that more work is required to be performed to properly assess the impacts of DER. The AER has also highlighted that it would be appropriate to review the specifications of the outputs to appropriately account for the relationship between changes in inputs and growth in DER. As stated in our submission to the AER on its draft benchmarking report, SA Power Networks supports the AER's pending review of its benchmarking specifications to consider the impact of DER, among other matters relevant to output measurement. We have provided several submissions to the AER and AEMC on this matter in recent years.[40] We acknowledge the complexity of the review into DER and, noting this complexity, encourage the AER to commence this review at the earliest opportunity.

Table 6-7 below shows the output growth factors that have been used to develop our Revised Proposal forecast opex for the 2020-25 RCP.

Table 6-7: SA Power Networks forecast output growth for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Average/ Total
Ratcheted maximum demand %	-	-	-	-	-	-
Circuit line length %	0.37%	0.37%	0.38%	0.38%	0.39%	0.38%
Customer numbers %	1.17%	0.98%	0.78%	0.77%	0.76%	0.89%
Energy Throughput (GWh)	-0.56%	0.26%	0.24%	0.51%	0.84%	0.26%
Weighted output growth %	**0.71%**	**0.63%**	**0.51%**	**0.52%**	**0.52%**	**0.58%**
Output growth ($m)	**$1.9**	**$3.6**	**$5.0**	**$6.4**	**$7.8**	**$24.7**

6.4.3.2 Real price growth

A real price change adjusts the base opex to account for forecast changes in input costs above or below CPI. Customers and stakeholders did not support any increase above CPI for price inputs during our customer engagement process. In our Original Proposal, we accepted this view for non-labour costs only and included a real increase in labour price growth, based on an average of independent expert forecasts.

Consistent with our Original Proposal and the AER's Draft Decision, our Revised Proposal adopts the AER's forecast price growth weightings of 59.7 per cent labour and 40.3 per cent non-labour. Table 6-8 below displays the real price growth included in our forecast opex based on these weightings. Further detail on how we have derived these forecasts is contained in the next section.

Table 6-8: SA Power Networks revised forecast real price growth for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Average/ Total
Labour price growth %	0.76%	0.83%	0.89%	1.02%	0.89%	0.88%
Non-labour price growth %	-	-	-	-	-	-
Weighted real price growth%	0.45%	0.49%	0.53%	0.61%	0.53%	0.52%
Real price growth ($m)	**$1.2**	**$2.6**	**$4.0**	**$5.6**	**$7.0**	**$20.4**

6.4.3.2.1 Labour price growth

SA Power Networks operates in a dynamic industry, providing a complex range of electricity services to customers. Our workers have diverse skills. Much of our work is performed on or near energised electricity assets in a high-risk environment, where public and worker safety is paramount. As the services that

[39] AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.
[40] These include our submissions on various reports and reviews including to the AER's 2018 Benchmarking Report, the AER's 2018 Productivity Review, the AER's OEF review in 2017, the AEMC's Network Regulation Framework Review in 2019, and the AER's 2019 Benchmarking Report.

customers demand have evolved, and continue to evolve, with technology, so too must the skill set of the workers we seek to retain and/or acquire from labour markets.

The prices we pay for labour (wages) are influenced by the market for labour, that is, by factors such as competition from other firms and industries for staff with particular skills. To ensure we cover our likely labour costs, we must predict how future movements in labour markets will affect labour prices, over the length of a five-year RCP. Given the complexity of predicting market movements and, given that these are matters beyond SA Power Networks' control, our current practice is to:

- seek the perspectives of expert independent labour market forecasters, consistent with the approach of all regulated network businesses; and
- not depend solely on a single forecaster's approach, consistent with what has been the regulatory practice.

Original Proposal

For the purposes of our Original Proposal:

- we engaged expert independent forecasters, BIS Oxford Economics (**BISOE**) to forecast real labour price movements (escalations) for South Australia. The measure was the Wage Price Index (**WPI**) for the utilities sector titled, 'Electricity, Gas, Water and Waste Services' (**EGWWS**) ;
- rather than rely solely on the expectations of our own forecaster, we proposed that the AER apply an average of BISOE's forecast and that of the forecaster engaged by the AER, DAE; and
- our proposed real labour price growth forecasts were those set out in Table 6-9.

Table 6-9: SA Power Networks Original Proposal - real labour escalators for the 2020-25 RCP

	2020/21	2021/22	2022/23	2023/24	2024/25
BIS Oxford Economics %	1.16%	1.53%	1.72%	1.62%	1.36%
Deloitte Access Economics %	0.40%	0.60%	0.70%	0.57%	0.57%
Average %	**0.78%**	**1.07%**	**1.21%**	**1.09%**	**0.96%**

AER Draft Decision and stakeholder views

In their submissions to the AER on our Original Proposal, some stakeholders questioned if SA Power Networks' real labour price growth forecasts were reasonable, given their views that wages growth in South Australia had recently been and were likely to remain subdued.[41] That was based on their opinions, with no alternative forecasts being provided to the AER.

In its Draft Decision the AER did not approve SA Power Networks' proposal of continuing to apply the AER's standard approach from previous regulatory determinations of using an average of two forecasters (in this case, the forecasts of BISOE and DAE), and instead determined that it would rely solely on the forecasts of its own consultant, DAE.

The AER reached the decision to only use the forecasts of its own consultant after noting there was a difference in the 2020-25 RCP forecasts for the South Australian utilities sector (EGWWS) produced by DAE and BISOE, which difference had been queried by some stakeholders. The AER then analysed the historic performance of the two forecasters. However:

- as estimates of actual labour price movements for the South Australian utilities sector are not produced by the Australian Bureau of Statistics (**ABS**), the AER compared DAE and BISOE historic forecasts from previous documents, against estimates of actuals, but on the basis of the WPI for the national utilities sector (Australia-wide) and not South Australia; and
- noted that, in the years 2007-11, the performance of DAE and BISOE was similar but, based on its calculation method, the AER viewed DAE as having been more accurate in the period 2012-18.

[41] See the summary of stakeholder submissions provided in the AER's Draft Decision, Attachment 6, pp.9-30.

Our further engagement with customers and stakeholders

Since the publication of the AER's Draft Decision, we have engaged further on this topic with customers and stakeholders for the purposes of our Revised Proposal, via two meetings with our Customer Consultative Panel (**CCP**).[42] The general feedback we received, particularly from stakeholders representing vulnerable customers, was that they felt many South Australians had not experienced real wage increases.[43]

We appreciate there is general complexity in understanding the drivers of labour price movements in South Australia, particularly for specific and specialist skilled sectors like ours as compared to other parts of the State's economy. We are also conscious of ensuring that the costs of service provision to our customers are no higher than they need to be.

Our views with respect to labour costs are that:

- SA Power Networks needs to at least be able to recover our reasonably expected efficient costs over the 2020-25 RCP; and
- because this involves predicting movements in complex labour markets, the least risky and more accurate approach to enable cost recovery, while at the same time minimising costs, is to seek the views of an independent expert labour market forecaster, and to have regard to more than one forecast as we have proposed to do.

SA Power Networks Revised Proposal

To address the AER's concerns about the accuracy of forecasts, we engaged independent experts BISOE to comment on the methodology applied by the AER in arriving at its Draft Decision, in a report titled, '*Review of AER Forecast Comparison'*.[44] BISOE's report contains the detailed analysis and recommendations supporting our Revised Proposal and has been included as Supporting Document 6.4.

SA Power Networks does not accept the AER Draft Decision to solely use the forecasts of DAE, and we maintain our position that the AER should apply an average of the real labour growth forecasts for the South Australian utilities sector produced by BISOE and DAE.

The AER Draft Decision to rely solely on DAE's forecast is:

1) generally inconsistent with best practice regulation;
2) an imprudent approach to predicting SA Power Networks' reasonably expected costs, given there is no direct evidence on the performance of the two forecasters with respect to the South Australian utilities sector; and
3) likely to result in less accurate forecasts, given several flaws and omissions in the AER's analysis of the historical performance of the forecasts for the national utilities sector produced by DAE and BISOE.

[42] Meetings held on 22 November 2019 and 27 November 2019.

[43] This is based on SA Power Networks' recollection of views expressed at those meetings, as no formal minutes of those meetings were taken.

[44] BISOE, *Review of AER Forecast Comparison: Report prepared for SA Power Networks*, November 2019.

Inconsistency with best practice regulation

Forecasting is an inherently complex art. Best practice in dealing with complexity is to not rely solely on one statistical/econometric method and model. The AER is aware of this from past direction from the Australian Competition Tribunal (**Tribunal**). It is imprudent for the AER to now rely solely on one forecast for labour prices, contrary to the Tribunal's direction which the AER follows in other aspects of regulatory forecasting. There is no apparent reason why labour price growth forecasting warrants an inconsistent approach—it is no less complex than other forecasting and forms a material part of SA Power Networks' reasonably required costs.

We note:

- The AER previously, in its April 2015 electricity distribution determinations for New South Wales (**NSW**), sought to rely on a single model (for benchmarking) to determine forecast opex allowances.[45] This decision was subject to a merits review, in which the Tribunal raised concerns with reliance on a single model and remitted the NSW decisions, directing the AER to use a broader range of modelling and benchmarking to derive alternative opex forecasts.[46]
  - Since that explicit Tribunal direction, the AER has, in a number of other regulatory forecasts and economic measures, relied on several statistical/econometric models and methods, and at each specific time quoted these decisions as seeking to give effect to the Tribunal's direction. These include the following examples:
    - Forecasting opex productivity growth—the AER had regard to seven different measures to forecast opex productivity growth, using more than ten statistical/econometric methods;[47]
    - Forecasting opex output growth—the AER applied an average of the output weights from four models to forecast opex output growth for the NSW distribution determinations,[48] a decision it has sought to also now apply to SA Power Networks' opex output growth; and
    - Annual Benchmarking—the AER decided in its annual benchmarking reports for 2018 and just recently in its November 2019 report (released after its Draft Decision for SA Power Networks), to base its benchmarking on even more statistical/econometric models, now using five different measures.[49]
- The Tribunal's direction and current AER general practice as noted above, is supported by economic literature. The AER has previously (and correctly) observed that there is a significant body of economic literature drawing on strong empirical evidence, concluding that forecast accuracy can be substantially improved by combining multiple individual forecasts.[50]

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[45] See AER, *Final Decision for Ausgrid Distribution Determination, Attachment 7: Operating expenditure; Final Decision for Endeavour Energy Distribution Determination 2019-24, Attachment 6: Operating expenditure and Draft Decision for Essential Energy Distribution Determination 2019-24, Attachment 6: Operating expenditure*.

[46] See Applications by Public Interest Advocacy Centre Ltd and Endeavour Energy [2016] ACompT 2 and Applications by Public Interest Advocacy Centre Ltd and Essential Energy [2016] ACompT 3.

[47] The AER stated: *"…this broader approach of drawing on a wider range of information sources is also consistent with the recommendations of the Australian Competition Tribunal…".* AER, *Final decision paper—Forecasting productivity growth for electricity distributors,* page 10.

[48] The AER stated: *"…using an average of the output weights from the four models, helps to address concerns raised by the Australian Competition Tribunal…the Tribunal raised concerns about our reliance on a single model…".* AER, *Draft Decision for Ausgrid Distribution Determination 2019-24*, Attachment 6, Operating Expenditure, page 39.

[49] The AER stated: "*In 2018 and 2019 we made a number of improvements…these addressed some of the concerns raised by the Australian Competition Tribunal."* AER, *Annual Benchmarking Report–Electricity distribution network service providers*, November 2019, page 41.

[50] See AER 2012 Final Decision for Powerlink's transmission determination. AER, Final Decision—Powerlink Transmission determination 2012-13 to 2016-17, p.54. The key seminal literature that the AER pointed to in that decision was the work by Clemens (1989) which states: "*…results have been virtually unanimous: combining multiple forecasts leads to increased forecast accuracy…this has been the result whether the forecasts are judgmental or statistical, econometric or extrapolation. Furthermore, in many cases one can make dramatic performance improvements by simply averaging the forecasts…*". Clemen RT, *Combining forecasts: a review and annotated bibliography*, International Journal of Forecasting 5, 1989, p.559.

- It is also incongruous for the AER, in the case of labour price forecasting, to suggest that there is only one source of truth (ie its own forecaster) when, for opex output growth, it continues to use a measure (opex MPFP) which the AER acknowledges is mis-specified[51] and may inadequately reflect distributors' costs[52], but justifies this on the basis of consistency with the Tribunal's direction to rely on more, rather than fewer, models.

There is no direct evidence to warrant reliance on a single forecast for South Australia

As estimates of actual movements in labour prices for the South Australian utilities sector are not produced, it is even more imprudent and risky to rely on a single forecast and arrive at this decision via inferences garnered by historical performance in forecasting labour price growth for the national utilities sector:

- The revenue and pricing principles[53] and the NER both require the AER to approve a reasonably expected forecast of costs required by SA Power Networks as a distributor operating in South Australia.
- There is no direct evidence (ie South Australian specific data) available on the historical performance of either DAE or BISOE to suggest that only one of these forecasters will present the accurate view of forecast labour price growth in South Australia.
- Given the lack of direct evidence, it is also unreasonable for SA Power Networks to be treated differently to the six distributors[54] for which the AER has relatively recently accepted the use of an average of two labour price growth forecasts, particularly when estimates of actuals are produced for NSW.
- There is also no evidence that forecast growth in real labour prices for the national utilities sector is useful to indicate forecast growth in the real labour prices for the utilities sector in South Australia. We observe that the AER's practice over a long time has been to determine a labour price growth forecast specific to a network businesses' jurisdiction, rather than applying a national sector forecast to these businesses.

Sole reliance on DAE would likely result in less accurate forecasts

As noted above, following the Draft Decision, we engaged BISOE to comment on the AER's proposed 'sole reliance' methodology. [55]

[51] The AER stated in its Draft Decision for SA Power Networks for the 2020-25 RCP: "*We recognise that NERA* (SAPN's consultant at the time) *raised a fair concern about whether energy throughput* (an output factor in the AER's opex MPFP model*) fully accounts for the impact of Distributed Energy Resources and consider that it will likely be appropriate to review the output specification used in our benchmarking models*." Further, the AER stated: "*…a distributor may be required to incur higher opex and or capital to manage the safety and reliability of its network"*, a subject which holds particularly true for SA Power Networks given the high penetration of DER technologies in South Australia. AER, *Draft decision—SA Power Networks 2020-25: Attachment 6—Operating Expenditure*, pp.6-34 and 6-35

[52] For example, in the AER's Draft Decision on SA Power Networks' proposed opex for the 2020-25 RCP, the AER accepted our proposed opex step change for LV management (ie management of impacts of Distributed Energy Resources on the network) partly on the basis of noting that that the AER's models for opex output growth do not fully reflect the fact that DER is increasing costs for distributors but without corresponding outputs being measured in the AER's current models. Further to this point, the AER also acknowledged that it accepted the need to undertake a review of how its models measure outputs as part of its annual benchmarking review process. AER, *Draft Decision—SA Power Networks 2020-25: Attachment 6—Operating Expenditure*, pp.6-34-35

[53] NEL, section 7A.

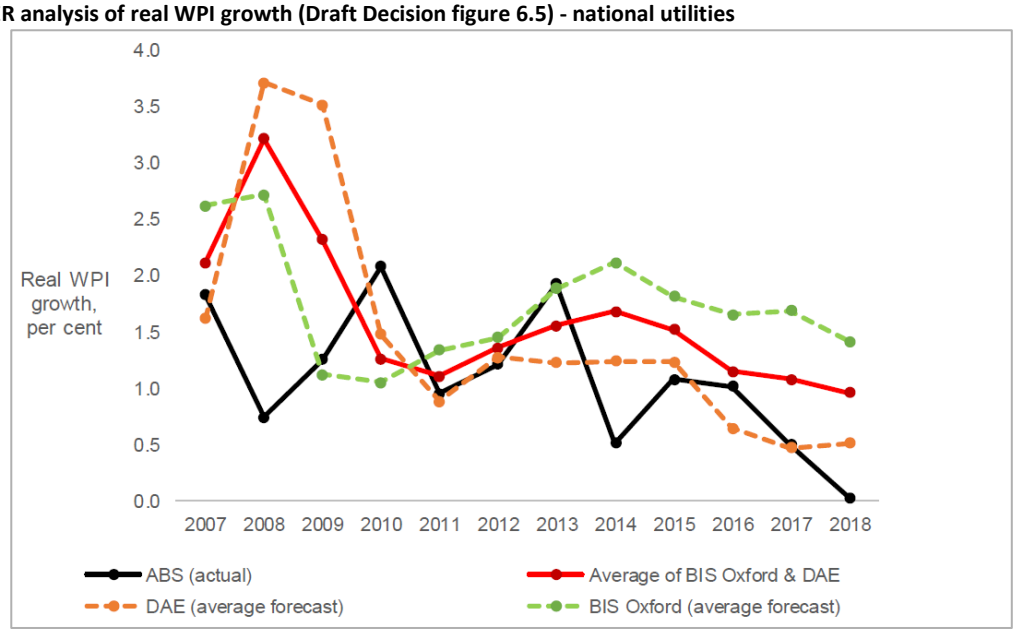
[54] AER, *Final Decision for Ausgrid Distribution Determination,* Overview, page 34; *Final Decision for Endeavour Energy Distribution Determination 2019-24,* Attachment 6: Operating expenditure, page 6; *Draft Decision for Essential Energy Distribution Determination 2019-24,* Attachment 6: Operating expenditure, page 27; *Final Decision for Evoenergy Distribution Determination 2019-24*, Attachment 6: Operating expenditure, page 6; *Final decision for Power and Water Corporation Distribution Determination,* Attachment 6: Operating expenditure, page 8; and *Final Decision for TasNetworks Distribution Determination 2019-24*, Attachment 6: Operating expenditure, page 7.

[55] BISOE, *Review of AER Forecast Comparison: Report prepared for SA Power Networks*, November 2019.

BISOE's detailed analysis is contained in its report. However, in summary, BISOE's key findings are that:

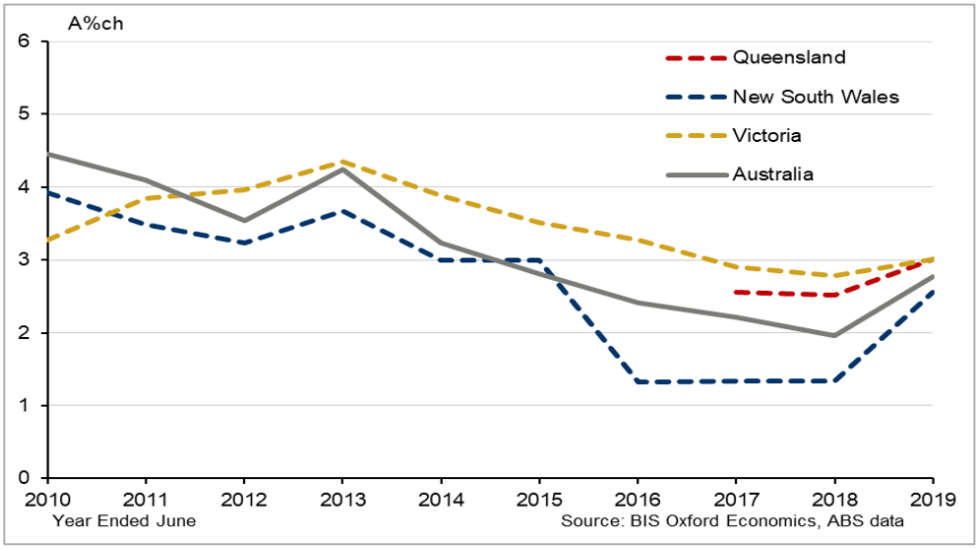
- The AER's method of calculating the historic performance of DAE and BISOE with respect to labour price growth for the national utilities sector requires corrections to avoid biased and misconstrued results:
  - Performance of a forecast must be measured with specific regard to the horizon of the forecast rather than giving equal weight to all forecast years—performance of forecasts typically vary over the length of a forecast period (accuracy of earlier years differs to latter years).
  - Forecasts by DAE and BISOE must not be compared asymmetrically—using forecasts from the same firm from consecutive months results in these forecasts having a higher than average weight in calculations.
  - It is important to not only consider performance against the national utilities sector but also against the national 'all-industries' sector WPI and the gap between the two—DAE and BISOE begin their projections with forecasts for all-industries and then consider the gap, and offsetting forecast errors in both of these could be misconstrued as being a more accurate forecast of performance for the utilities sector.
- DAE's historic forecasting performance for the national utilities sector has not been superior to that of BISOE:
  - The AER's analysis only shows DAE's forecasts (compared to BISOE's forecasts) for the national utilities sector to have been closer to estimated actuals in a recent period rather than the longer-term, as shown in Figure 6-6.

Figure 6-6: AER analysis of real WPI growth (Draft Decision figure 6.5) - national utilities



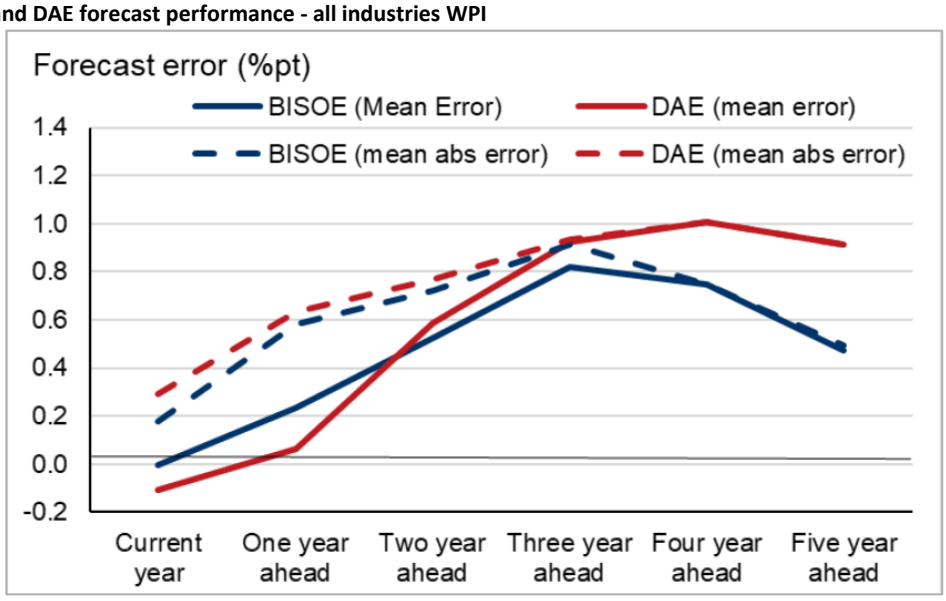
  - This recent period reflected a 'one off' aberration, as actuals for the national utilities sector were dragged down by influences specific to the NSW electricity network businesses before, during and after their privatisation, as shown in Figure 6-7. These NSW influences were not relevant to South Australia.

Figure 6-7: BISOE analysis of utilities sector by jurisdiction



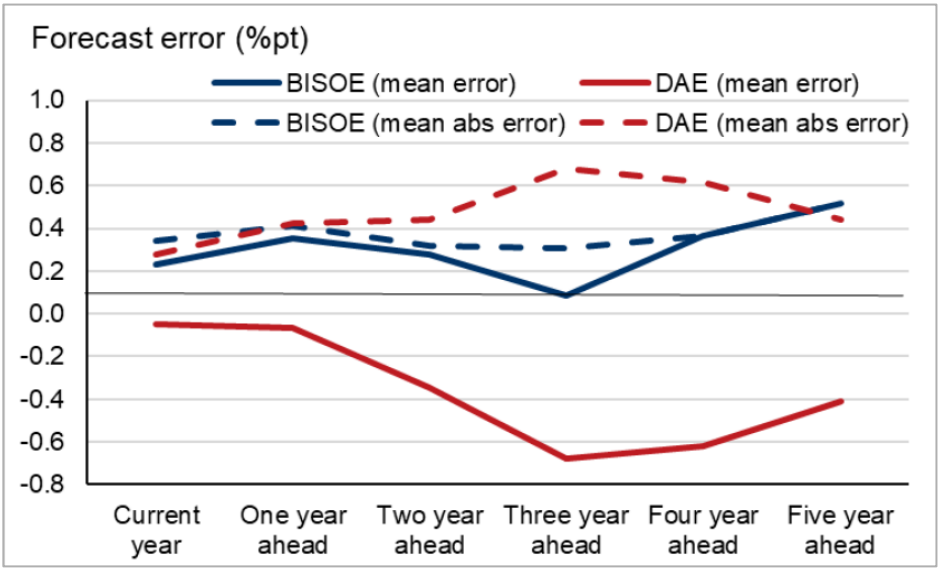
- Correcting the AER's approach, BISOE's analysis finds that:
  - DAE's model contains apparent misspecifications. DAE usually has utilities growth outpacing all-industries in the first 1-2 years then subsequently falling below all-industries. Despite this, the actual long-term trend for utilities outpaces all-industries.
  - As Figure 6-8 shows — for the all-industries sector, the near-term mean error in DAE's forecasts is smaller than BISOE's on average, but the mean absolute error is larger. In the medium/long-term DAE performs worse than BISOE as measured by the mean error and mean absolute error.

Figure 6-8: BISOE and DAE forecast performance - all industries WPI



  - As Figure 6-9 shows — for the forecast gap between the all-industries and utilities sectors, in the early years DAE's forecast has a smaller mean error than BISOE's, although the mean absolute error is the same for both firms. In the out years, DAE's forecast performance is worse than BISOE's on both the mean error and mean absolute error. Examining the mean error and mean absolute error together, BISOE's forecasts show some upward bias while DAE's show a larger downward bias.

Figure 6-9: BISOE and DAE forecast performance - all industries and utilities WPI gap



- Sole reliance on DAE's forecast will likely result in more inaccuracy and increase the risk of SA Power Networks not being afforded a reasonable opportunity to recover at least its efficient costs relative to the use of an average of the DAE and BISOE forecasts. This is noting that:
  - DAE's apparent better performance in forecasts for the national utilities sector during a period containing a 'one-off' aberration, is not the result of superior modelling, but rather the inadvertent result of two offsetting errors. Its error / bias in forecasting that growth for the utilities sector would be materially lower than the all-industries sector, was offset by its error in over-estimating the growth of the all-industries sector, making DAE's utilities sector forecast appear more accurate than BISOE's. That is, DAE's incorrect modelling of the relationship between the utilities and all-industries sectors wages was compensated by over-estimating the all-industries sector wages.
  - There is no basis upon which to expect that, in future, these historic circumstances will be repeated, noting that:
    - both DAE and BISOE have improved their forecasts for the all-industries sector over time;
    - the general trend to overstate/understate the all-industries/utilities gap by BISOE and DAE respectively has remained but has been declining over time. It should not be assumed that biases seen historically will remain the same over the forecast 2020-25 RCP;
    - as BISOE's analysis demonstrates, an individual forecaster is unlikely to outperform another forecaster for all series and at every point in time over a forecast horizon, as any number of unforeseeable events influence the outcome for any given series, as occurred with the NSW specific influences mentioned above. Therefore, using more than one forecast (via an average or other statistical technique) will reduce the risks of a particular approach to forecasting or view of economic growth (positive or negative) unduly influencing proposed wages growth; and
    - BISOE's overall conclusion is that an average of DAE's and BISOE's forecasts is statistically likely to produce the most accurate result for labour price increases over the 2020-25 RCP.

In summary

For the reasons set out above and detailed in BISOE's report, our Revised Proposal is to apply an average of DAE's and BISOE's forecasts for the utilities sector in South Australia, as this is more likely to afford SA Power Networks a reasonable opportunity to recover at least our efficient forecast labour costs over the 2020-25 RCP as required by the NEL and NER.

Our proposed forecast has been updated since our Original Proposal to reflect the latest economic conditions, as summarised in Table 6-10 and detailed in an updated labour escalation report from BISOE (Supporting Document 6.5, Revised Proposal).

Table 6-10: SA Power Networks Revised Proposal – real labour escalators for the 2020-25 RCP

	2020/21	2021/22	2022/23	2023/24	2024/25
BIS Oxford Economics %	1.11%	1.28%	1.44%	1.60%	1.33%
Deloitte Access Economics %[56]	0.41%	0.37%	0.34%	0.45%	0.44%
Average %	**0.76%**	**0.83%**	**0.89%**	**1.02%**	**0.89%**

6.4.3.2.2 Non-labour price growth

In our Revised Proposal we have forecast that non-labour costs will increase in line with CPI (ie no real price increase).

6.4.3.3 Productivity growth

At the time of submitting our Original Proposal, the AER had only published a draft decision setting out its proposed approach to forecasting productivity growth for DNSPs in November 2018.[57] The AER's final decision paper was not released until March 2019. For this reason, and consistent with our submissions in response to the AER's draft decision, we included a proposed opex productivity growth factor of 0.0% in our opex forecast.

While customers and stakeholders suggested that a positive productivity growth factor should be considered for the 2020-25 RCP, we formed the view that this could not be justified on the available evidence and the other issues raised in our submission in response to the AER's draft decision.

We maintain that the productivity growth forecast must be carefully measured in order to not deny distributors the ability to at least recover our reasonably forecast costs. Productivity measurement must reflect the productivity improvements that all efficient and prudent DNSPs can reasonably achieve, by focussing on whether the productivity 'frontier' is shifting, rather than reflecting the performance of inefficient DNSPs 'catching-up' to the frontier, and ensuring that other factors that may skew productivity measures are accounted for.[58] We have applied the 0.5% productivity growth adjustment to our Revised Proposal in line with the AER's Final Decision Paper.[59]

Table 6-11: SA Power Networks forecast productivity growth for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Average/ Total
Productivity growth %	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Productivity growth ($m)	**($1.3)**	**($2.7)**	**($4.0)**	**($5.4)**	**($6.7)**	**($20.1)**

[56] DAE's forecasts are based on the values applied in the AER's Draft Decision. We expect that the AER will update these figures in its Final Decision.

[57] AER, *Draft decision paper: Forecasting productivity growth for electricity distributors,* November 2018.

[58] SA Power Networks, Submission to AER draft decision: Forecasting productivity growth for distributors, 21 December 2018. Accessible on the AER website: [https:www.aer.gov.au].

[59] AER, *Final decision paper: Forecasting productivity growth for electricity distributors,* March 2019.

6.5 Revised Proposal

Our revised SCS operating expenditure forecast is $1,442 million ($June 2020) and is summarised in Table 6-12. This combined with debt raising costs of $11 million ($June 2020), results in a total operating cost of $1,453 million ($June 2020) for the 2020-25 RCP.

Table 6-12: SA Power Networks Revised Proposal opex forecast for the 2020-25 RCP

Expenditure category (June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Base Year (including increment)	268.2	268.2	268.2	268.2	268.2	**1,340.8**
Step changes	13.7	14.0	15.4	16.1	17.0	**76.2**
Output Growth	1.9	3.6	5.0	6.4	7.8	**24.7**
Real Price Growth	1.2	2.6	4.0	5.6	7.0	**20.4**
Productivity Growth	(1.3)	(2.7)	(4.0)	(5.4)	(6.7)	**(20.1)**
Opex excluding debt raising	**283.6**	**285.7**	**288.5**	**290.9**	**293.3**	**1,442.0**
Debt raising costs	2.2	2.2	2.3	2.3	2.3	**11.3**
Total opex	**285.8**	**287.9**	**290.7**	**293.1**	**295.5**	**1,453.3**

Note: totals may not add up due to rounding

Shortened Forms

ABS	*Australian Bureau of Statistics*
AEMO	*Australian Energy Market Operator*
AER	*Australian Energy Regulator*
BISOE	*BIS Oxford Economics*
capex	*Capital expenditure*
CCP	*Customer Consultative Panel*
CIC	*Critical Infrastructure Centre*
CoAG-EC	*Council of Australian Governments Energy Council*
CPI	*Consumer Price Index*
DAE	*Deloitte Access Economics*
DER	*Distributed Energy Resources*
DNSP	*Distribution Network Service Provider*
Draft Decision	*AER 2020-25 Draft Decision*
EBSS	*Efficiency Benefit Sharing Scheme*
EFAG	*Expenditure forecast assessment guideline*
EGWWS	*Electricity, Gas, Water and Waste Services*
EMCa	*Energy Market Consulting associates*
ESCoSA	*Essential Services Commission of South Australia*
GSL	*Guaranteed Service Level*
ICT	*Information communication technology*
LSECD	*Cobb Douglas least squares estimation*
LSETLG	*Translog least squares estimation*
LV	*Low Voltage*
MEDs	*Major event days*
NEL	*National Electricity Law*
NEM	*National Electricity Market*
NER	*National Electricity Rules*
NERA	*NERA Economic consulting*
opex	*Operating expenditure*
Original Proposal	*2020-25 Regulatory Proposal*
repex	*Replacement capital expenditure*
Revised Proposal	*2020-25 Revised Regulatory Proposal*
RIN	*Regulatory Information Notice*
SCS	*Standard control services*
SFACD	*Cobb Douglas stochastic frontier analysis*
USAIDI	*Unplanned System Average Interruption Duration Index*
VPPs	*Virtual power plants*
WPI	*Wage Price Index*