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

Attachment 7 − Operating expenditure

October 2015

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Note

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

Attachment 13 – Classification of services

Attachment 14 – Control mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Contents

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

7 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses, incurred in the provision of network services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's total revenue requirement.

This attachment provides an overview of our assessment of opex. Detailed analysis of our assessment of opex is in the following appendices:

- Appendix A—base opex
- Appendix B—rate of change
- Appendix C—step changes.

7.1 Final decision

We are not satisfied that SA Power Networks' forecast opex reasonably reflects the opex criteria.[1] We therefore do not accept the forecast opex SA Power Networks included in its building block proposal.[2] We compare our substitute estimate of SA Power Networks' opex for the 2015–20 regulatory control period with its initial regulatory proposal, our preliminary decision and SA Power Networks' revised regulatory proposal in Table 7.1.[3]

Table 7.1 Our preliminary and final decision on total opex ($ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' initial proposal	280.9	293.8	310.5	318.8	323.1	1527.2
AER preliminary decision	240.5	243.0	245.1	247.4	249.7	1225.8
SA Power Networks' revised proposal	269.8	281.1	284.8	290.8	295.5	1422.0
AER final decision	241.5	250.2	250.1	253.3	256.3	1251.4

Source: AER analysis.

Note: Excludes debt raising costs.

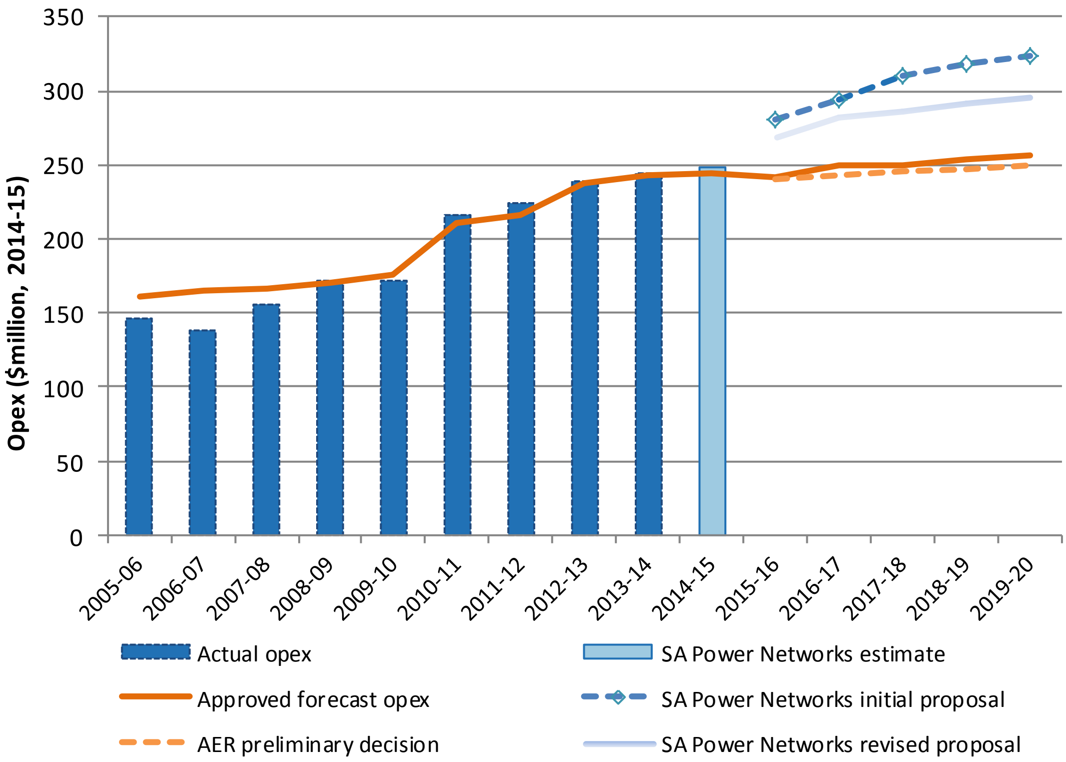
Figure 7.1 shows our final and preliminary decision compared to SA Power Networks' past actual opex, previous regulatory decisions and its initial and revised proposals.

1 NER, cl. 6.5.6(c).

2 NER, cl. 6.5.6(d).

3 NER, cl. 6.12.1(4)(ii).

Figure 7.1 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 21 11; AER analysis; SA Power Networks, *2015–20 revised regulatory proposal*, July 2015, p. 186

As outlined above, SA Power Networks proposed a significant increase in its opex forecast above recent historical levels. However, SA Power Networks did not identify any cost drivers which we consider will cause its opex to depart significantly from its historical opex. For instance:

- SA Power Networks faces few expected changes in its regulatory obligations in the 2015–20 regulatory control period.
- We would typically expect opex to materially increase if a service provider faced material increases in input prices and expected customer growth. However, we forecast that the price of the main input affecting opex, labour, will only be marginally above CPI in the 2015–20 regulatory control period. SA Power Networks' customer numbers are also not expected to change substantially in the 2015–20 regulatory control period either.
- We could not identify any other cost drivers likely to significantly affect the efficient opex required to operating and maintain SA Power Networks' poles and wires in the 2015–20 regulatory control period.

For these reasons we are not satisfied SA Power Networks' opex forecast would reasonably reflect the opex criteria. We consider an opex forecast which is more closely aligned with SA Power Networks' most recent audited actual opex would reasonably reflect the opex criteria. Our substitute opex forecast is based predominantly on SA Power Networks' actual audited opex in 2013–14.

7.2 SA Power Networks' revised proposal

In its initial proposal, SA Power Networks forecast opex of $1527.2 million ($2014–15) for the 2015–20 regulatory control period.[4]

SA Power Networks used the actual opex it incurred in 2013–14 as the base for forecasting its opex for the 2015–20 regulatory control period with some adjustments. SA Power Networks then:

- applied a trend to account for forecast output growth and forecast increases in labour and non-labour costs
- included step changes for activities carried out in delivery of standard control services opex which are not reflected in its base year.[5]

In its revised proposal, SA Power Networks proposed a forecast opex of $1422.0 million ($2014–15) for the 2015–20 regulatory control period. This is a 6.9 per cent decrease from the $1527.2 million ($2014–15) it initially proposed. The main changes from its initial proposal were

- reduced step changes by $76.8 million ($2014–15), and
- reduced estimate of the rate of change by $21.5 million ($2014–15)

In Figure 7.2 we separate SA Power Networks' forecast opex into the different elements that make up its forecast.

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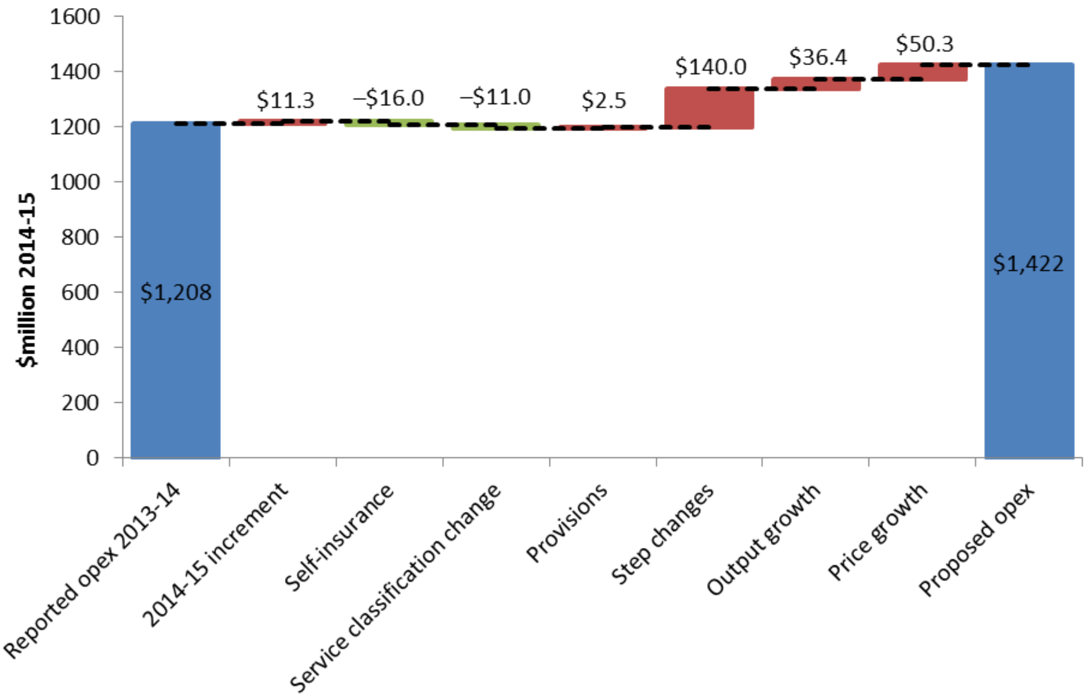
4 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 186

5 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 186.

Figure 7.2 SA Power Networks' opex forecast ($ million 2014–15)



Source: AER analysis

SA Power Networks did not agree with our preliminary position. It considered:

- it will face material and on-going increases in expenditure to meet demand, satisfy customer expectations, or comply with regulatory obligations and requirements
- it was already efficient and cannot improve efficiency to respond to growing costs
- the EBSS incentives are reduced by not allowing increases in expenditure allowances to meet growing costs.[6]

7.3 AER's assessment approach

This section sets out our general approach to assessment.[7] Our approach to assessment of particular aspects of the opex forecast is set out in more detail in the relevant appendices.

Our assessment approach, outlined below, is, for the most part, consistent with the Expenditure Forecast Assessment Guideline (the Guideline).

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6 SA Power Networks, *Revised regulatory proposal*, 3 July 2015, pp. 192–193.

7 The discussion in this section, to the extent it differs from that set out in the preliminary decision, clarifies the assessment approach that we applied in both the preliminary decision and this final decision.

There are two tasks that the NER requires us to undertake in assessing total forecast opex. In the first task, we form a view about whether we are satisfied a service provider's proposed total opex forecast reasonably reflects the opex criteria.[8] If we are satisfied, we accept the service provider's forecast.[9] In the second task, we determine a substitute estimate of the required total forecast opex that we are satisfied reasonably reflects the opex criteria.[10] We only undertake the second task if we do not accept the service provider's forecast after undertaking the first task.

In both tasks, our assessment begins with the service provider's proposal. We also develop an alternative forecast to assess the service provider's proposal at the total opex level. The alternative estimate we develop, along with our assessment of the component parts that form the total forecast opex, inform us of whether we are satisfied that the total forecast opex reasonably reflects the opex criteria.

It is important to note that we make our assessment about the total forecast opex and not about particular categories or projects in the opex forecast. The Australian Energy Market Commission (AEMC) has expressed our role in these terms:[11]

> It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

The opex criteria that we must be satisfied a total forecast opex reasonably reflects are:[12]

1. the efficient costs of achieving the operating expenditure objectives
2. the costs that a prudent operator would require to achieve the operating expenditure objectives
3. a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The AEMC noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[13]

The service provider's forecast is intended to cover the expenditure that will be needed to achieve the opex objectives. The opex objectives are:[14]

1. meeting or managing the expected demand for standard control services over the regulatory control period

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8 NER, cll. 6.5.6(c) and 6.12.1(4).

9 NER, cll. 6.5.6(c) and 6.12.1(4)(i).

10 NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

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

12 NER, cl. 6.5.6(c).

13 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113.

14 NER, cl. 6.5.6(a).

2. complying with all applicable regulatory obligations or requirements associated with providing standard control services
3. where there is no regulatory obligation or requirement, maintaining the quality, reliability and security of supply of standard control services and maintaining the reliability and security of the distribution system
4. maintaining the safety of the distribution system through the supply of standard control services.

Whether we are satisfied that the service provider's total forecast reasonably reflects the opex criteria is a matter for judgment. This involves us exercising discretion. However, in making this decision we treat each opex criterion objectively and as complementary. When assessing a proposed forecast, we recognise that efficient costs are not simply the lowest sustainable costs. They are the costs that an objectively prudent service provider would require to achieve the opex objectives based on realistic expectations of demand forecasts and cost inputs. It is important to keep in mind that the costs a service provider might have actually incurred or will incur due to particular arrangements or agreements that it has committed to may not be the same as those costs that an objectively prudent service provider requires to achieve the opex objectives.

Further, in undertaking these tasks we have regard to the opex factors.[15] We attach different weight to different factors. This approach has been summarised by the AEMC as follows:[16]

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

The opex factors that we have regard to are:

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period
- the actual and expected operating expenditure of the distribution network service provider during any preceding regulatory control periods
- the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the distribution network service provider in the course of its engagement with electricity consumers

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15 NER, cll. 6.5.6(c) and (d).

16 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure
- whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the distribution network service provider under clauses 6.5.8 or 6.6.2 to 6.6.4
- the extent the operating expenditure forecast is referable to arrangements with a person other than the distribution network service provider that, in our opinion, do not reflect arm's length terms
- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)
- the extent to which the distribution network service provider has considered and made provision for efficient and prudent non-network alternatives
- any relevant final project assessment conclusions report published under 5.17.4(o),(p) or (s)
- any other factor we consider relevant and which we have notified the distribution network service provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.

Consistent with the Guideline, we have used benchmarking to a greater extent than we did in regulatory determinations prior to the AEMC's 2012 rule changes. To that end, there are two additional operating expenditure factors that we have taken into account under the last opex factor above:

- our benchmarking data sets including, but not necessarily limited to:
  (a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN
  (b) any relevant data from international sources
  (c) data sets that support econometric modelling and other assessment techniques consistent with the approach set out in the Guideline

  as updated from time to time.
- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.[17]

For transparency and ease of reference, we have included a summary of how we have had regard to each of the opex factors in our assessment at the end of this attachment.

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[17] This is consistent with the approach we outlined in the explanatory statement to our Expenditure Forecast Assessment Guideline. See, for example, p. 131.

As we noted above, the two tasks that the NER requires us to undertake involve us exercising our discretion. In exercising discretion, the National Electricity Law (NEL) requires us to take into account the revenue and pricing principles (RPPs).[18] In the overview we discussed how we generally have taken into account the RPPs in making this final decision. Our assessment approach to forecast opex ensures that the amount of forecast opex that we are satisfied reasonably reflects the opex criteria is an amount that provides the service provider with a reasonable opportunity to recover at least its efficient costs.[19] By us taking into account the relevant capex/opex trade-offs, our assessment approach also ensures that the service provider faces the appropriate incentives to promote efficient investment in and provision and use of the network and minimises the costs and risks associated with the potential for under and over investment and utilisation of the network.[20]

Expenditure Forecast Assessment Guideline

After conducting an extensive consultation process with service providers, users, consumers and other interested stakeholders, we issued the Expenditure Forecast Assessment Guideline in November 2013 together with an explanatory statement.[21] The Guideline sets out our intended approach to assessing opex in accordance with the NER.[22]

While the Guideline provides for regulatory transparency and predictability, it is not binding. We may depart from the approach set out in the Guideline but we must give reasons for doing so.[23] For the most part, we have not departed from the approach set out in the Guideline in this final decision.[24] In our framework and approach paper, we set out our intention to apply the Guideline approach in making this determination.[25] There are several parts of our assessment:

1. We develop an alternative estimate to assess a service provider's proposal at the total opex level. [26] We recognise that a service provider may be able to adequately explain any differences between its forecast and our estimate. We take into account any such explanations on a case by case basis using our judgment, analysis and stakeholder submissions.

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18 NEL, ss. 7A and 16(2).

19 NEL, s. 7A(2).

20 That is, the trade-offs that may arise having considered the substitution possibilities between opex and capex, and the relative prices of operating and capital inputs: NER, cll. 6.5.6(e)(6) and 6.5.6(e)(7); NEL, ss. 7A(3), 7A(6) and 7A(7).

21 AER, *Expenditure forecast assessment guideline - explanatory statement*, November 2013.

22 NER, cl. 6.5.6.

23 NER, cl. 6.2.8(c).

24 We did not apply the DEA benchmarking technique. We outline the reasons why we did not apply this technique in appendix A of our all NSW distribution determinations for the 2015–20 regulatory control period.

25 AER, *Stage 2 Framework and approach - NSW electricity distribution network service providers*, January 2014, p. 50.

26 AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

2. We assess whether the service provider's forecasting method, assumptions, inputs and models are reasonable, and assess the service provider's explanation of how its method results in a prudent and efficient forecast.
3. We assess the service provider's proposed base opex, step changes and rate of change if the service provider has adopted this methodology to forecast its opex.

Each of these assessments informs our first task. Namely, whether we are satisfied that the service provider's proposal reasonably reflects the opex criteria.

If we are not satisfied with the service provider’s proposal, we approach our second task by using our alternative estimate as our substitute estimate. This approach was expressly endorsed by the AEMC in its decision on the major rule changes that were introduced in November 2012. The AEMC stated:[27]

> While the AER must form a view as to whether a NSP's proposal is reasonable, this is not a separate exercise from determining an appropriate substitute in the event the AER decides the proposal is not reasonable. For example, benchmarking the NSP against others will provide an indication of both whether the proposal is reasonable and what a substitute should be. Both the consideration of "reasonable" and the determination of the substitute must be in respect of the total for capex and opex.

We recognise that our alternative estimate may not exactly match the service provider's forecast. The service provider may have adopted a different forecasting method. However, if the service provider's inputs and assumptions are reasonable and efficient, we expect that its method should produce a forecast consistent with our estimate. We discuss below how we develop our alternative estimate.

Building an alternative estimate of total forecast opex

The method we use to develop our alternative estimate involves five key steps. We outline these steps below in Figure 7.3.

[27] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

Figure 7.3 How we build our alternative estimate

Step 1 - Start with service provider's base opex.

We typically use the service provider's actual opex in a single year as the starting point for our assessment. While categories of opex can vary from year to year, total opex is relatively recurrent. We typically choose a recent year for the base year. We call this base opex.

Step 2- Assess, and if necessary adjust, base opex

We assess whether the base opex forms the starting point of a total forecast opex that we would be satisfied reasonably reflects the opex criteria. We may do this by testing the base opex against a number of quantitative and qualtiative techniques. This includes economic benchmarking and detailed reviews. We adjust the base opex only to the extent that we find that it is materially inefficient.

Step 3 - Add a rate of change to base opex.

As the opex of an efficient service provider tends to change over time due to price changes, output and productivity we trend our estimate of base opex forward over the regulatory control period to take account of these changes. We refer to this as the rate of change.

Step 4 - Add or subtract any step changes

We then adjust our estimate to account for any forecast cost changes over the regulatory control period that would meet the opex critieria that are not otherwise captured in base opex or rate of change. This may be due to new regulatory obligations in the forecast period and efficient capex/opex trade-offs. We call these step changes.

Step 5 - Other opex

Finally we add any additional opex components which have not been forecast using this approach. For instance, we forecast debt raising costs based on the costs incurred by a benchmark efficient service provider.

This results in our alternative estimate. We use this in the first task to assess the service provider's proposal at the total opex level. We also use this as our substitute estimate, should we not be satisfied the service provider's proposal reasonably reflects the opex criteria.

Underlying our approach are two general assumptions:

1. the efficiency criterion and the prudency criterion in the NER are complementary
2. actual operating expenditure was sufficient to achieve the opex objectives in the past.

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model that has been employed by a number of Australian regulators over the last fifteen years. We refer to it as a 'revealed cost method' in the Guideline (and we have sometimes referred to it as the base-step-trend method in our past regulatory decisions).[28]

While these general steps are consistent with our past determinations, we have adopted a significant change in how we give effect to this approach, following the major changes to the NER made in November 2012. Those changes placed significant new emphasis on the use of benchmarking in our opex analysis. We will now issue benchmarking reports annually and have regard to those reports. These benchmarking reports provide us with one of a number of inputs for determining forecast opex.

We have set out more detail about each of the steps we follow in developing our alternative estimate below.

Step 1 — Base year choice

The starting point for our analysis is to use a recent year for which audited figures are available as the starting point for our analysis. We call this the base year. This is for a number of reasons:

- As total opex tends to be relatively recurrent, total opex in a recent year typically best reflects a service provider's current circumstances.
- During the past regulatory control period, there are incentives in place to reward the service provider for making efficiency improvements by allowing it to retain a portion of the efficiency savings it makes. Similarly, the incentive regime works to penalise the service provider when it is relatively less efficient. This provides confidence that the service provider did not spend more in the proposed base year to try to inflate its opex forecast for the next regulatory control period.
- Service providers also face many regulatory obligations in delivering services to consumers. These regulatory obligations ensure that the financial incentives a service provider faces to reduce its costs are balanced by obligations to deliver services safely and reliably. In general, this gives us confidence that recent historical opex will be at least enough to achieve the opex objectives.

[28] AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

In choosing a base year, we need to make a decision as to whether any categories of opex incurred in the base year should be removed. For instance:

- If a material cost was incurred in the base year that is unrepresentative of a service provider's future opex we may remove it from the base year in undertaking our assessment.
- Rather than use all of the opex that a service provider incurs in the base year, service providers also often forecast specific categories of opex using different methods. We must also assess these methods in deciding what the starting point should be. If we agree that these categories of opex should be assessed differently, we will also remove them from the base year.

As part of this step we also need to consider any interactions with the incentive scheme for opex, the Efficiency Benefit Sharing Scheme (EBSS). The EBSS is designed to achieve a fair sharing of efficiency gains and losses between a service provider and its consumers. Under the EBSS, service providers receive a financial reward for reducing their costs in the regulatory control period and a financial penalty for increasing their costs. The benefits of a reduction in opex flow through to consumers as long as base year opex is no higher than the opex incurred in that year. Similarly, the costs of an increase in opex flow through to consumers if base opex is no lower than the opex incurred in that year. If the starting point is not consistent with the EBSS, service providers could be excessively rewarded for efficiency gains or excessively penalised for efficiency losses in the prior regulatory control period.

Step 2 — Assessing base opex

The service provider's actual expenditure in the base year may not form the starting point of a total forecast opex that we are satisfied reasonably reflects the opex criteria. For example, it may not be efficient or management may not have acted prudently in its governance and decision-making processes. We must therefore test the actual expenditure in the base year.

As we set out in the Guideline, to assess the service provider's actual expenditure, we use a number of different qualitative and quantitative techniques.[29] This includes benchmarking and detailed reviews.

Benchmarking is particularly important in comparing the relative efficiency of different service providers. The AEMC highlighted the importance of benchmarking in its changes to the NER in November 2012:[30]

> The Commission views benchmarking as an important exercise in assessing the efficiency of a NSP and informing the determination of the appropriate capex or opex allowance.

[29] AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

[30] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 97.

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. For this decision we have used multilateral total factor productivity, partial factor productivity measures and several opex cost function models.[31]

We also have regard to trends in total opex and category specific data to construct category benchmarks to inform our assessment of the base year expenditure. In particular, we can use this category analysis data to identify sources of spending that are unlikely to reflect the opex criteria over the forecast period. It may also lend support to, or identify potential inconsistencies with, the results of our broader benchmarking.

If we find that a service provider's base year expenditure is materially inefficient, the question arises about whether we would be satisfied that a total forecast opex predicated upon that expenditure reasonably reflects the opex criteria. Should this be the case, for the purposes of forming our starting point for our alternative estimate, we will adjust the base year expenditure to remove any material inefficiency.

Step 3 — Rate of change

We also assess an annual escalator that is applied to take account of the likely ongoing changes to opex over the forecast regulatory control period. Opex that reflects the opex criteria in the forecast regulatory control period could reasonably differ from the starting point due to changes in:

- price growth
- output growth
- productivity growth.

We estimate the change by adding expected changes in prices (such as the price of labour and materials) and outputs (such as changes in customer numbers and demand for electricity). We then incorporate reasonable estimates of changes in productivity.

Step 4 — Step changes

Next we consider if any other opex is required to achieve the opex objectives in the forecast period. We refer to these as 'step changes'. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs. As the Guideline explains, we will typically include a step change only if efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.[32]

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[31] The benchmarking models are discussed in detail in appendix A.

[32] AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

Step 5 — Other costs that are not included in the base year

In our final step, we assess the need to make any further adjustments to our opex forecast. For instance, our approach is to forecast debt raising costs based on a benchmarking approach rather than a service provider's actual costs. This is to be consistent with the forecast of the cost of debt in the rate of return building block.

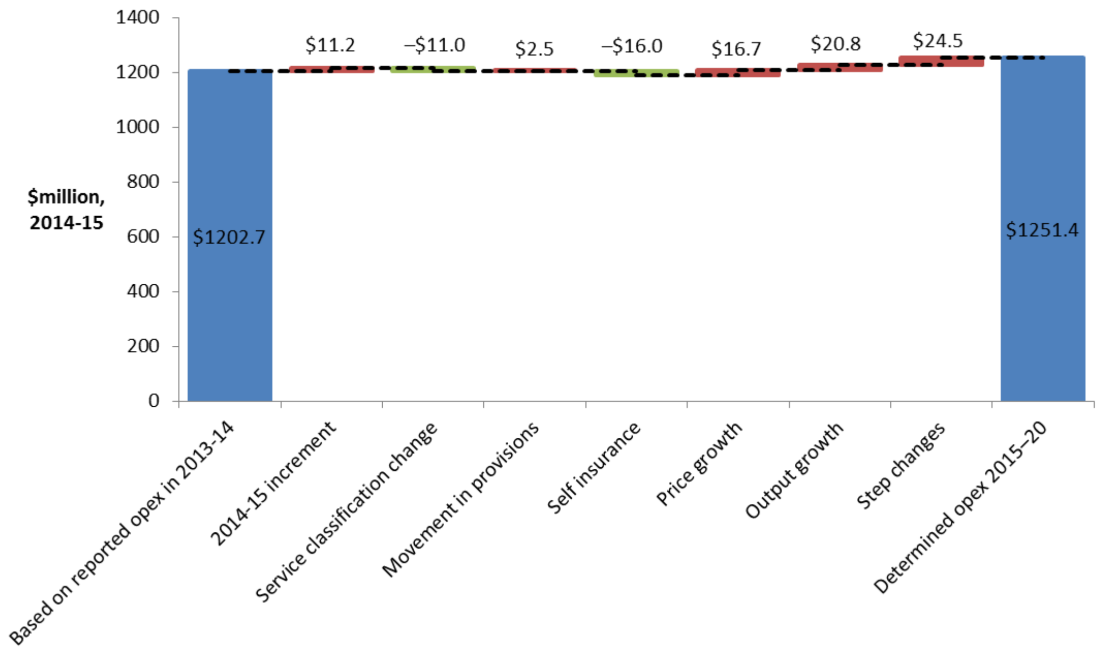
After applying these five steps, we arrive at our alternative estimate.

7.4 Reasons for final decision

We are not satisfied SA Power Networks' proposed total forecast opex of $1527.2 million ($2014–15) reasonably reflects the opex criteria.[33] As discussed above, we have therefore used our alternative estimate as our substitute estimate.[34]

Figure 7.4 illustrates how we constructed our forecast. The starting point on the left is what SA Power Networks' opex would have been for the 2015–20 regulatory control period if it was set based on SA Power Networks' reported opex in 2013–14.

Figure 7.4 AER final decision opex forecast



Source: AER analysis

33 NER, cl. 6.5.6(d).

34 NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

Table 7.2 Revised proposal vs final decision total forecast opex ($ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' revised proposal	269.8	281.1	284.8	290.8	295.5	1422.0
AER final decision	241.5	250.2	250.1	253.3	256.3	1251.4
Difference	–28.2	–30.9	–34.8	–37.5	–39.2	–170.5

Source: AER analysis.

Note: Excludes debt raising costs.

We outline the key elements of our alternative opex forecast and areas of difference between our estimate of opex and SA Power Networks' estimate below.

7.4.1 Base opex

Consistent with our preliminary decision, we have based our opex forecast on SA Power Networks' actual audited opex in 2013–14.

We received some submissions that disagreed with our position. They suggested we should either use a base opex amount from 2005 to 2010,[35] or make adjustments to forecast a lower amount of vegetation management expenditure.[36]

We do not agree with these submissions. Benchmarking suggests SA Power Networks is currently operating relatively efficiently to other service providers in the NEM. We have no evidence that would suggest SA Power Networks would efficiently incur materially lower opex in the 2015–20 regulatory control period. Therefore we consider that if we adjusted base opex in the way suggested by stakeholders, our opex forecast would not reasonably reflect the efficient costs of operating and maintaining SA Power Networks' poles and wires in the 2015–20 regulatory control period.

7.4.2 Rate of change

The efficient level of expenditure required by a service provider in the 2015–20 regulatory control period may differ from that required in the final year of the 2010–15 regulatory control period. Once we have determined the opex required in the final year of the 2010–15 regulatory control period we apply a forecast annual rate of change to forecast opex for the 2015–20 regulatory control period.

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35 Accolade Wines, *Submission on preliminary decision*, p. 5; CIT, *Submission on preliminary decision*, pp. 5-6; Renmark Irrigation Trust, *Submission on preliminary decision,* p. 1; Yatco, *Submission on preliminary decision* p. 1.

36 ECCSA, *Submission on preliminary decision*, p. 32; Government of South Australia, *Submission on preliminary decision,* p. 3; CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal,* p. 107.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than SA Power Networks' over the forecast period. Table 7.3 below compares SA Power Networks' and our overall rate of change in percentage terms for the 2015–20 regulatory control period.

Table 7.3 Forecast annual rate of change in opex (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
SA Power Networks	2.28	2.18	2.40	2.54	2.51
AER	0.88	0.85	1.19	1.35	1.47
Difference	1.40	1.33	1.20	1.19	1.04

Source: AER analysis.

The differences between our forecast rate of change and SA Power Networks' is driven by the following factors:

- To forecast labour price growth, SA Power Networks used wage price increases in its existing enterprise agreement for 2015–16 and 2016–17, then used Frontier Economics' recommended extrapolation of wage price increases in long term enterprise agreements from a comparator group of service providers. SA Power Networks' forecast is higher than ours, which we base on forecasts from Deloitte Access Economics and BIS Shrapnel. Our approach takes into account current market conditions which indicate that current wage growth is lower than historical wage increases. Under our approach we forecast utilities sector wage growth in South Australia will not return to average historical levels until the end of the 2015–20 regulatory control period.
- We forecast output growth using customer numbers, circuit length and ratcheted maximum demand from SA Power Networks' reset RIN. SA Power Networks largely adopted our preliminary decision output growth methodology but substituted ratcheted maximum demand for distribution transformer capacity and substation capacity. We consider our approach better reflects the increase in services SA Power Networks' customers require in the 2015–20 regulatory control period.

The differences in each forecast rate of change component are:

- our forecast of price growth is on average 0.81 percentage points lower than SA Power Networks' forecast
- our forecast of output growth is on average 0.41 percentage points lower than SA Power Networks' forecast

We outline our detailed assessment of the rate of change in appendix B.

7.4.3 Step changes

We have included step changes in our alternative opex forecast for the following proposals:

- New Regulatory Information Notice (RIN) requirements
- New National Energy Customer Framework (NECF) requirements
- Increased stakeholder engagement for new tariff structures
- New billing and customer related system
- Change in provision of mobile radio services
- Reduction in distribution licence fee.

In total these step changes contribute $24.4 million ($2014–15) or 1.9 per cent to our total opex forecast for SA Power Networks for the 2015–20 regulatory control period.

Our position on NECF and forecast changes to SA Power Networks' distribution licence fee is consistent with our preliminary decision. We forecast an additional increase in opex for mobile radio costs that was not included in our preliminary decision opex forecast. These costs were included in SA Power Networks' initial proposal but were classified as capex.

We have revised our position on stakeholder engagement for new tariffs, RIN compliance and SA Power Networks' billing and customer related IT system. We are satisfied that these costs are driven by new regulatory obligations.

A summary of our conclusions are in Table 7.4.

Table 7.4 Step changes ($ million, 2015)

	SA Power Networks initial proposal	AER preliminary decision	SA Power Networks revised proposal	AER final decision
Legal and regulatory	105.0	1.3	64.8	12.7
Capital program impacts	69.6	7.9	36.1	16.7
Customer driven initiatives	41.6	–	42.8	–
Financing related matters	0.6	–	–	–
Base year adjustments	–10.4	–5.0	–3.7	–5.0
Total	**206.4**	**4.2**	**140.0**	**24.4**

Source: AER analysis

Our forecast step changes in opex are significantly lower than the $140.0 million proposed by SA Power Networks. There were several common reasons for why we consider additional step changes in opex are not needed. We outline these below.

Our opex estimate already provides sufficient revenue for SA Power Networks to meet its existing regulatory obligations and service standards and maintain the reliability, safety and quality of supply of standard control services.

As outlined in the Guideline[37] and our preliminary decision,[38] actual past opex if efficient, should provide a good indicator of required funding in the future. If a service provider is operating efficiently, there should be few circumstances why we would expect its forecast opex to be significantly different to its recent opex.

We have determined that SA Power Networks' opex in 2013–14 is relatively efficient. In our view it provides a good basis for forecasting the total opex SA Power Networks would reasonably require to meet the opex criteria in the 2015–20 regulatory control period.

SA Power Networks included many step changes in its opex for new discretionary programs and projects it proposed to undertake. It did not identify any areas where its costs were expected to decline relative to 2013–14.

Expenditure on some categories of opex and some programs and projects will always increase relative to a recent year. However, a service provider can often adjust its opex to meet changing priorities. We consider that SA Power Networks, by including expenditure on new items of expenditure without considering other savings it can potentially make, has forecast a total opex amount that does not reasonably reflect the opex criteria.

Relatively few of SA Power Networks' step changes were to meet new or changed regulatory obligations or other external drivers. We are not convinced that an increase in expenditure is necessary for SA Power Networks to meet its existing regulatory obligations.

We allow increased funding for new or changed regulatory obligations that will lead to an increase in the level of opex. As a regulatory obligation is imposed on a service provider, it does not have an option as to whether it will incur expenditure to comply. In most cases it must incur additional expenditure to achieve the obligation. We do not consider it is reasonable for a service provider to have to find savings to fund changes in its obligations. We increased our opex forecast where there was evidence that SA Power Networks' opex would increase in the 2015–20 regulatory control period as a result of such changes.

SA Power Networks considered that while the obligations it faced had not changed, the actions it must take to meet its regulatory obligations had changed. For instance under section 60(1) of the *Electricity Act 1996* (SA) it must take reasonable steps to ensure that electricity infrastructure is safe and safely operated. It considered that the reasonable steps it must take have changed.[39] We were not persuaded by this argument. In our view, SA Power Networks did not demonstrate the total amount of opex it needs to ensure its electricity infrastructure is safe and safely operated will materially change in the 2015–20 regulatory control period when compared to the total opex it has recently incurred.

[37] AER, *Expenditure forecast assessment guideline*, November 2013, pp. 7-8.

[38] AER, *Preliminary decision, SA Power Networks 2015–20 regulatory control period, Attachment 7*, April 2015, p. 73.

[39] SA Power Networks, *Revised regulatory proposal*, 3 July 2015, p. 228.

SA Power Networks proposed a number of step changes labelled as 'customer driven'. We were not satisfied that SA Power Networks' 'customer driven initiatives' addressed consumer preferences

SA Power Networks submitted that several of the step changes it proposed were to address concerns expressed by consumers during its consumer engagement program.

However, we were not satisfied that SA Power Networks' customer driven initiatives did in fact address its consumers' preferences. We reached this conclusion after considering the particular consumer engagement initiatives SA Power Networks undertook, but also having regard to the consumer engagement we have undertaken in making this decision.

7.4.4 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. We forecast them using our standard forecasting approach for this category which sets the forecast equal to the costs incurred by a benchmark firm. Our assessment approach and the reasons for those forecasts are set out in the debt and equity raising costs appendix in the rate of return attachment (attachment 3).

7.4.5 Interrelationships

In assessing SA Power Networks' total forecast opex we took into account other components of its regulatory proposal, including:

- the operation of the EBSS in the 2010–15 regulatory control period, which provided SA Power Networks an incentive to reduce opex in the 2013–14 base year
- 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 capex and opex, for example, in considering SA Power Networks' proposed step change for its mobile radio costs
- 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
- concerns of electricity consumers identified in the course of its engagement with consumers.

7.4.6 Assessment of opex factors

In deciding whether we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.[40]

Table 7.5 summarises how we have taken the opex factors into account in making our final decision.

Table 7.5 AER consideration of opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark operating expenditure that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period. We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of SA Power Networks' proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.
The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of SA Power Networks' actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[41] We have considered the concerns of electricity consumers as identified by SA Power Networks– particularly in

40 NER, cl. 6.5.6(e).

41 AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

Opex factor	Consideration
	considering SA Power Networks' proposed step changes.
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering SA Power Networks' proposed step changes. For instance we have provided a step change for increased mobile radio costs on the basis that it is an efficient capex/opex trade-off. We considered the relative expense of capex and opex solutions in considering this step change. We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above we considered capex/opex trade-offs in considering a step change for SA Power Networks' mobile radio costs. We considered the substitution possibilities in considering this step change. Some of our assessment techniques examine opex in isolation – either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs. Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.
Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to SA Power Networks' opex in the 2010–15 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our estimate of base opex consistently in applying the EBSS and forecasting SA Power Networks' opex for the 2015–20 regulatory control period.
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
Whether the operating expenditure forecast includes an amount relating to a project that should more	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or

Opex factor	Consideration
appropriately be included as a contingent project under clause 6.6A.1(b).	programs). We did not identify any contingent projects in reaching our final decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be significant in reaching our final decision.

Source: AER analysis.

The NER require that we notify the service provider in writing of any other factor we identify as relevant to our assessment, prior to the service provider submitting its revised regulatory proposal.[42] Table 7.6 identifies these factors.

Table 7.6 Other factors we have had regard to

Opex factor	Consideration
Our benchmarking data sets, including, but not necessarily limited to: • data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN • any relevant data from international sources • data sets that support econometric modelling and other assessment techniques consistent with the approach set out in our Guideline as updated from time to time.	This information may potentially fall within opex factor (4). However, for absolute clarity, we are using data we gather from NEM service providers, and data from service providers in other countries to provide insight into the benchmark operating expenditure that would be incurred by an efficient and prudent distribution network service provider over the relevant regulatory period.
Economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.	This information may potentially fall within opex factor (4). For clarity, and consistent with our approach to assessment set out in our Guideline, we are have regard to a range of assessment techniques to provide insight into the benchmark operating expenditure that an efficient and prudent service provider would incur over the relevant regulatory control period.

42 NER, cl. 6.5.6(e)(12).

A Base opex

As opex is relatively recurrent, we typically forecast based on a single year of opex. We call this the base opex amount. In this section, we set out our assessment of SA Power Networks' base opex.

A.1 Position

We have used a base opex amount of $237.9 million ($2014–15) in our opex forecast.

The only change from our preliminary decision base opex forecast is a change in how we have inflated SA Power Networks' reported nominal opex to real 2014–15 dollars.

A.2 SA Power Networks' revised proposal and submissions

SA Power Networks' revised proposal used a base opex amount of $239.1 million ($2014–15). This was the same amount we used in our preliminary decision opex forecast.

We received several submissions which disagreed with our position on base opex. Many submissions highlighted the recent increase in SA Power Networks' opex and decline in productivity in the 2010 to 2015 regulatory control period.[43] As a result, some submissions were not convinced that we should base our forecast on 2013–14 opex.[44] Other submissions consider we should either:

- use a base opex amount from the 2005 to 2010 period[45], or
- adjust actual opex in 2013–14 to remove a positive pass through amount we allowed for vegetation management during the 2010–15 regulatory control period.[46]

A.3 Assessment approach

In the Expenditure Forecast Assessment Guideline (the Guideline), we explain that a 'revealed cost' approach is our preferred approach to assessing base opex. If actual expenditure in the base year reasonably reflects the opex criteria, we will set base

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43 Accolade Wines, *Submission on preliminary decision*, p. 5; CIT, *Submission on preliminary decision*, pp. 5-6; ECCSA, *Submission on preliminary decision*, pp. 29-31; CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal* , p. 107; SACOSS, *Submission on preliminary decision* , p. 2.

44 Business SA, Submission on preliminary decision, p. 2; ERAA, *Submission on preliminary decision* p. 1; CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal,* p. 107; Riverland Wine Association, *Submission on revised proposal* , p. 6; SAWIA, *Submission on preliminary decision,* p.4.

45 Accolade Wines, *Submission on preliminary decision*, p. 5; CIT, *Submission on preliminary decision*, pp. 5-6; Renmark Irrigation Trust, *Submission on preliminary decision,* p. 1; Yatco, *Submission on preliminary decision* p. 1.

46 ECCSA, *Submission on preliminary decision*, p. 32; Government of South Australia, *Submission on preliminary decision,* p. 3; CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal,* p. 107.

opex equal to actual expenditure for those cost categories forecast using the revealed cost approach.

We use a combination of techniques to assess whether base opex reasonably reflects the opex criteria. This includes economic benchmarking, partial performance indicators and category-based techniques. If economic benchmarking indicates a service provider's base opex is materially inefficient, our approach is to complement our benchmarking findings with other analysis such as PPIs, category-based techniques and detailed review.

A.4 Response to submissions

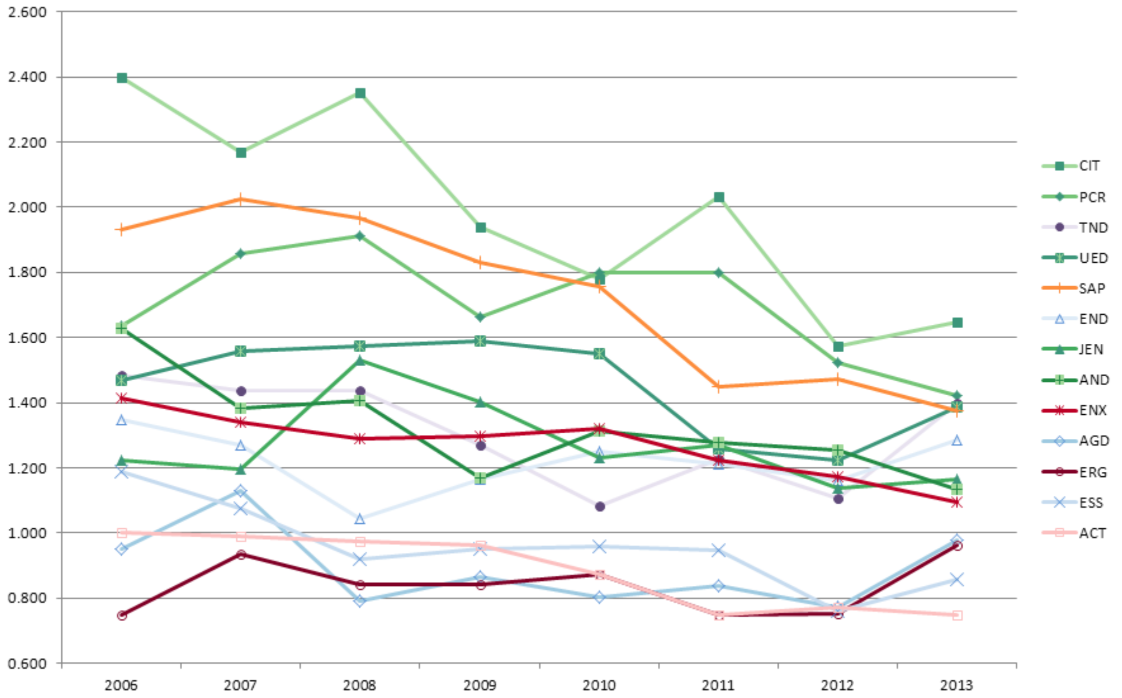
A.4.1 Assessment of base opex

We have not changed our preliminary position to use SA Power Networks' actual opex in 2013–14 as the base opex amount.

Benchmarking indicates that SA Power Networks operates relatively efficiently compared to other service providers in the NEM. Therefore we consider it appropriate to rely on its most recent actual opex to forecast its opex for the 2015–20 regulatory control period. The benchmarking we undertook in reviewing SA Power Networks' proposal is outlined in appendix A our preliminary decision.

While SA Power Networks has experienced declining opex productivity in recent years, this is not sufficient for us to conclude that SA Power Networks is operating at materially inefficient levels. For instance, as illustrated in Figure A.1 the opex MPFP benchmarking measure shows that declining opex productivity has been experienced by electricity distributors across the NEM. SA Power Networks' recent opex MPFP still compares relatively well to other service providers in the NEM. There is no evidence it is currently operating at materially inefficient levels. We consider it would be unrealistic to expect SA Power Networks to incur similar amounts of opex to what it incurred in the 2005 to 2010 period. The acronym for SA Power Networks in Figure A.1 is SAP.

Figure A.1 Opex MPFP of distributors over the benchmarking period



Source: AER, *Annual Distribution Benchmarking Report*, 2014, p. 34.

Nor do we consider it would be reasonable to make an adjustment to SA Power Networks' base opex to remove a pass-through amount we previously approved for vegetation management expenditure.

In July 2013, we approved a cost pass through amount for SA Power Networks which related to an increase in vegetation clearance costs following the breaking of the drought in 2010.[47] The opex forecast we originally approved for SA Power Networks for the 2010 to 2015 period which was made in May 2010 was based on the actual frequency and level of vegetation inspection and clearance undertaken during 2008–09.[48] The cost pass through amount we approved in July 2013 reflected our forecast of the incremental increase in vegetation management opex arising from an unexpected increase in vegetation growth rates. The approved amount for 2013–14 was $11.4 million ($nominal).[49] We did not consider the vegetation management expenditure that would be incurred by SA Power Networks beyond the 2010–15 regulatory control period in making this decision.

This cost pass through amount we approved reflected our estimate of the incremental increase in forecast opex that we did not account for when we originally forecast SA Power Networks' opex. The forecast was originally set based on the opex incurred by

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47 AER, *Final decision, SA Power Networks cost pass through application*, July 2013.

48 AER, *Final decision, SA Power Networks cost pass through application*, July 2013, p. 5.

49 AER, *Final decision, SA Power Networks cost pass through application*, July 2013, p. 34.

SA Power Networks in 2008–09 during an extended period of below average rainfall and above average temperatures.[50]

If we removed the pass through amount from the base year in forecasting its opex for the 2015–20 period, we would be forecasting SA Power Networks should incur the same vegetation management opex that we originally forecast for the 2010–15 regulatory control period. In essence, we would be forecasting that SA Power Networks should incur similar vegetation management opex to what it did during the last drought. We have no evidence to support such a forecast.

More broadly, we note that in relying on a base year to forecast a service provider's future opex, we are not forecasting that opex on categories of opex will be similar to the base year. We are forecasting the total amount of opex we consider that a prudent service provider would need to reasonably reflect the opex criteria. In the forecast period we would expect that some categories of opex will decline relative to 2013–14 levels. Some categories of opex will increase. It would be inconsistent if we only considered making an adjustment to SA Power Networks' base opex for vegetation management but also did not consider the forecast opex SA Power Networks would require on all other discrete categories of opex.

A.4.2 **Response to SA Power Networks**

SA Power Networks also made a number of observations about its benchmarking and its relative efficiency. For instance, it considered it benchmarks well above what we determined to be the 'efficient frontier'.[51] It considered that if it had incurred much higher expenditure in the base year, it would have still been considered to be an efficient provider.[52]

We understand SA Power Networks' references to the 'efficient frontier' to be the benchmark comparison point we used in determining whether we would primarily use a benchmark instead of a service provider's revealed costs to forecast its opex. We used benchmarking to determine opex forecasts for three service providers in recent determinations ─ ActewAGL, Ausgrid, Essential Energy.[53] It was based on the results of one econometric benchmarking model, the Cobb Douglas Stochastic Frontier Analysis (SFA) econometric model.

SA Power Networks appears to be implying that for any service providers where we did not adjust their opex on the basis of benchmarking, they are at the 'efficient frontier'. This mischaracterises the conclusions we reached in benchmarking. We used a range of different sources, including benchmarking and detailed review to determine whether a service provider was or was not operating at 'materially inefficient' levels. We then primarily used one economic benchmarking model, the Cobb Douglas SFA model, to

50 AER, *Final decision, SA Power Networks cost pass through application*, July 2013, p. 6.

51 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 192.

52 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 192.

53 Also for our preliminary decision for Ergon Energy, published in April 2015.

measure the size of the inefficiency. Because of the possible forecasting error, data error and modelling issues, the benchmark comparison point was not chosen to be the best performing service provider in the model (i.e. the efficient frontier), it was a much lower point than the efficient frontier predicted by the model.[54] SA Power Networks' efficiency score was lower than the most efficient score predicted by the model, but above the benchmark comparison point we used. It is inaccurate to say that we concluded that SA Power Networks is operating above the efficient frontier.

SA Power Networks also suggested that had it incurred much higher expenditure in the base year, it would have still been considered to be efficient. SA Power Networks' comments appear to reflect a misunderstanding what the results of the Cobb Douglas SFA model showed. The efficiency scores from the model which we presented in our final decisions for the NSW/ACT service providers and SA Power Networks' preliminary decision are average efficiency scores over the 2006 to 2013 period.[55] It is correct to say that SA Power Networks ranks relatively well over the 2006 to 2013 period on this measure. However, while SA Power Networks' average efficiency score from 2006 to 2013 is relatively higher than most other service providers, as illustrated above, it also has relatively poor productivity over the 2006 to 2013 period. It is not clear that SA Power Networks has factored in the decline in its opex productivity over the 2006 to 2013 period in making this claim.

SA Power Networks also considered that had the AER considered environmental factors (such as capitalisation policy) it would have benchmarked well ahead of the 'efficient frontier'. Origin Energy also queried what operating environment factors had been taken into account in assessing SA Power Networks performance.[56] We would expect that some operating environment factors may advantage SA Power Networks while some may disadvantage SA Power Networks. Capitalisation policy differences are one of several potential cost drivers which are not accounted for in our benchmarking. We have only undertaken an analysis of all potential other operating environment factors that affect a service provider's benchmarking where we were explicitly considering an adjustment to base opex. For instance, we undertook this analysis for the NSW and QLD service providers. As SA Power Networks' benchmarking performance already suggested it was performing relatively well to other service providers, we chose not to undertake detailed analysis of all the detailed operating environment factors that may be affecting SA Power Networks' benchmarking performance.

A.5 Inflation of base opex

Our base opex for this final decision is different to the base opex amount we used in our preliminary decision, and SA Power Networks adopted in its revised proposal. This difference is due to the inflation used to convert nominal amounts to real 2014–15

54 AER, *Final Decision Ausgrid 2014–19, Attachment 7*, 30 April 2015, p. 79.

55 AER, *Final Decision Ausgrid 2014–19, Attachment 7*, 30 April 2015, p. 108.

56 Origin Energy, *Submission to AER preliminary decision SA Power Networks*, 3 July 2015, p. 8.

dollars. For our preliminary decision we estimated the annual inflation rate to June 2015 would be 2.0 per cent, based on the RBA's forecast in its statement on monetary policy.[57] For this final decision we have use the actual inflation rate of 1.5 per cent as reported by the ABS.[58] This actual inflation rate was not available at the time of our preliminary decision.

57 Reserve Bank of Australia*, Reserve Bank of Australia statement of monetary policy*, November 2014.

58 ABS catalogue 6401.0 Tables 3 and 4.

B Rate of change

Our forecast of total opex includes an allowance to account for efficient changes in opex over time.

There are several reasons why forecast opex that reflects the opex criteria might differ from expenditure in the base year.

As set out in the Expenditure Forecast Assessment Guideline (the Guideline), we have developed an opex forecast incorporating the rate of change to account for:[59]

- price growth
- output growth
- productivity growth.

This appendix contains our assessment of the opex rate of change for use in developing our estimate of total opex.

B.1 Position

We have applied the same rate of change methodology to derive our alternative estimate of opex as we used in our preliminary decision. We do not agree with SA Power Networks' criticisms of our rate of change forecasting methodology. We consider our rate of change forecasting methodology for the 2015–20 regulatory control period leads to a forecast rate of change in opex an efficient service provider would require to meet the opex objectives.

We have updated our estimate of the rate of change in opex to reflect the most recent forecasts of labour price growth in the South Australian utilities industry from Deloitte Access Economics (DAE) and BIS Shrapnel. The net impact of these changes results in an annual rate of change that is on average 0.36 per cent higher than our preliminary decision estimate.

Our average annual estimated rate of change for the 2015–20 regulatory control period is 1.15 per cent (see table B.1).

[59] AER. *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

Table B.1 SA Power Networks and AER rate of change (per cent real)[60]

	2015–16	2016–17	2017–18	2018–19	2019–20
SA Power Networks revised proposal					
Price growth	1.21	1.21	1.44	1.50	1.58
Output growth	1.05	0.96	0.94	1.02	0.92
Productivity growth	–	–	–	–	–
Overall rate of change	2.28	2.18	2.40	2.54	2.51
AER					
Price growth	0.31	0.28	0.62	0.78	0.90
Output growth	0.57	0.57	0.57	0.57	0.57
Productivity growth	–	–	–	–	–
Overall rate of change	0.88	0.85	1.19	1.35	1.47
Overall difference	1.40	1.33	1.20	1.19	1.04

Source: AER analysis.

B.2 Preliminary position

For our preliminary decision, we did not adopt SA Power Networks' forecast growth in price and output in our forecast rate of change and thus our alternative estimate of opex. We outline our preliminary position for each rate of change component below.

- **Price growth:** for labour price growth we adopted DAE's wage price index (WPI) forecast for the South Australian electricity, gas, water and waste services (utilities) industry. For non-labour we adopted the forecast change in the CPI. We applied Economic Insights' benchmark opex price weightings for labour and non-labour.
- **Output growth**: we applied the weighted average forecast change in customer numbers, circuit length and ratcheted maximum demand from SA Power Networks' reset RIN. We based the weights of each of these outputs on Economic Insights' opex cost function analysis.
- **Productivity growth**: we applied a zero per cent productivity growth estimate. We based this estimate on our considerations of recent productivity trends and whether this would be applicable to the forecast period. This was also consistent with Economic Insights' recommendations.

Refer to section B of attachment 7 in our preliminary decision for a detailed explanation of our considerations.

60 The rate of change = (1+ price growth) x (1+ output growth) * x (1+ productivity growth) - 1.

B.3 SA Power Networks' revised proposal and submissions

SA Power Networks made several adjustments to its rate of change methodology from its initial proposal. In its revised proposal SA Power Networks adopted:

- a utilities industry labour forecast for contracted services instead of a forecast using the construction industry[61]
- CPI for 'other' price growth[62]
- our output growth specification but substituted the ratcheted maximum demand output measure with distribution transformer and substation capacity growth.[63]

These changes have resulted in a decrease in the average annual rate of change estimate of 2.57 per cent in its initial proposal to 2.38 per cent in its revised proposal.

SA Power Networks raised concerns regarding our approach to forecasting:

- labour price growth[64]
- non-labour price growth[65]
- output growth,[66] and
- productivity growth.[67]

B.4 Reasons for position

We are not satisfied SA Power Networks' proposed rate of change for the 2015–20 regulatory control period reasonably reflects the efficient costs a prudent service provider would require to meet the opex objectives.

We consider our forecast reasonably reflects the opex criteria because:

- our labour price growth measure reasonably reflects current market conditions
- our labour and non-labour price weightings reasonably reflect the benchmark efficient mix of labour services and other costs required to provide distribution services
- our output growth measure reasonably reflects the forecast increase in services that customers require.

61 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 221.
62 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 221.
63 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 201.
64 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 204–218.
65 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 219–223.
66 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 200–201.
67 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 224–225.

We note that we and SA Power Networks have applied a zero estimate of forecast productivity growth.

In the sections below we discuss the reasons why we consider our approach is preferable to SA Power Networks' approach.

B.4.1 Labour price growth

To forecast labour price growth we have adopted an average of BIS Shrapnel and Deloitte Access Economics' utilities sector labour price growth forecasts.

In our preliminary decision we outlined that we prefer an average of BIS Shrapnel's and DAE's labour price growth forecasts. However, SA Power Networks' initial proposal did not include labour price growth forecasts for the utilities industry from BIS Shrapnel. SA Power Networks' revised proposal included utilities sector forecasts from BIS Shrapnel to forecast its contracted services price growth.

SA Power Networks maintained the approach it used to forecast labour price growth in its initial proposal. It used wage increases in its own EA until 2016–17. From 2017–18 to 2019–20 it used a historical average of private electricity network EA wage increases forecast by Frontier Economics. In this decision we refer to Frontier Economics' benchmark five year historical average of private electricity network EA wage increases as the 'benchmark EA' and we refer to SA Power Networks' overall labour price growth forecasting approach as the 'hybrid EA approach'.

We raised several issues regarding SA Power Networks' hybrid EA approach in our preliminary decision. We did not consider SA Power Networks' hybrid EA approach reflected current market conditions and thus its forecast increase in labour prices did not reflect an efficient forecast of labour prices.[68]

SA Power Networks' revised proposal included consultants' reports from Frontier Economics[69] and NERA.[70] To the extent that these reports have raised issues that are relevant to our forecast we have addressed them in this appendix.

We do not consider SA Power Networks' revised proposal has raised any issues that would cause us to depart from the approach used in our preliminary decision. The sections below discuss why we have not departed from our labour price growth forecasting approach.

Current market conditions

We consider our use of the utilities industry WPI leads to an opex forecast that reasonably reflects the opex criteria. We prefer our approach to SA Power Networks'

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68 AER, *Preliminary decision attachment 7*, April 2015, p. 50.

69 Frontier Economics, *Review of AER's preliminary decision on labour escalation rates*, July 2015.

70 NERA, *Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs*, 23 June 2015.

approach because it reflects current market conditions and SA Power Networks approach does not.

In our preliminary decision we noted that the nominal average annual wage increase in Frontier Economics' benchmark sample was 4.5 per cent in 2014–15 and 4.4 per cent in 2013–14. This was higher than ABS' measure of wages in the utilities sector of 3.0 per cent from June 2013 to June 2014. We also noted that SA Power Networks' proposed wage increases did not reflect current market conditions because overall wage growth is at record lows.[71]

In its revised proposal SA Power Networks considered that its labour price growth forecast reflects current market conditions for electricity workers in South Australia. SA Power Networks raised two key issues in support of its proposal.

1. SA Power Networks' current EA is efficient because it was negotiated at arm's length and in a commercial manner.[72]
2. SA Power Networks' current EA and Frontier Economics' benchmark EA wage increases are similar to wage increases in historical EAs.[73]

SA Power Networks' approach has focussed on the efficiency of its EA negotiations and how it considered its hybrid approach reflects historical wage increases in the utilities sector.

We do not agree that the historical level of wage increases is a reasonable basis to forecast labour price growth if it does not reflect current market conditions. All current and forecast macroeconomic indicators for the Australian, South Australian and utilities sectors are below historical levels. We are not satisfied SA Power Networks' forecast labour price growth of between 2.15 per cent to 2.26 per cent per annum above CPI is efficient when current wage increases for the utilities sector reported by the ABS are similar to CPI. The wage increases set out in Frontier Economics' benchmark EA do not reflect these conditions.

Annual wage growth in Australia and South Australia is currently the lowest it has been since the ABS began recording this series. A labour price growth forecast based on historical price growth without taking into account current market conditions that are different to historical levels is not reasonable.

The historical annual average wage growth in the utilities sector from September 1997 to September 2014 was 4.1 per cent. Meanwhile recent wage data from the ABS shows the following:

- annual nominal Australian wage growth from June 2014 to June 2015 was 2.3 per cent[74]

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[71] AER, *Preliminary decision attachment 7*, April 2015, p. 53.

[72] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 205.

[73] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 206.

[74] ABS 6345.0 Wage price index Table 9B.

- annual nominal South Australian wage growth from June 2014 to June 2015 was 2.5 per cent [75]
- annual nominal utilities industry wage growth from June 2014 to June 2015 was 2.7 per cent.[76]

DAE considered that its forecasts of wage growth in the South Australian utilities sector reflect the weakness expected in both South Australia's economy and in broader wage growth across all industries over the next few years.[77]

An indicator of the softening in the labour market in South Australia is an unemployment rate of 7.9 per cent as at July 2015 in South Australia compared to the national unemployment of rate of 6.1 per cent.[78] Evidence of the current pressures on South Australia's utilities sector include Alinta Energy announcing it will close its Northern and Playford B power stations as well as its Leigh Creek coal mine around 31 March 2016.[79]

The CCP also identified similar macroeconomic data which showed that wages in utilities, construction and administrative and support industries grew at level below SA Power Networks' forecasts.[80] The CCP also notes that both the private and public sectors have seen similar declines in wage growth.[81] We agree with the CCP that the supporting macroeconomic evidence suggests that wage growth should be lower than the average historical level.

In response to our use of macroeconomic data in the preliminary decision, SA Power Networks considered our comparison of the benchmark EA wage increase (4.5 per cent) to the national utilities WPI in 2013–14 (3.2 per cent) was misleading.[82] Frontier Economics considered we should have compared the utilities WPI with all electricity EA wage increases in 2013–14 (3.6 per cent) which would show that EA wage increases are similar to the utilities WPI.[83]

We disagree with Frontier Economics. The appropriate point of comparison is the forecast proposed by SA Power Networks and the national utilities WPI. It is unclear why we should be comparing the utility industry WPI to a subset of EAs which it did not use as its forecast.

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75 ABS 6345.0 Wage price index Table 8A.

76 ABS 6345.0 Wage price index Table 9B.

77 Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 69.

78 ABS 6202.0 Labour Force Table 7.

79 Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 69. and https://alintaenergy.com.au/about-us/news/flinders-operations-update accessed 7 October 2015.

80 Consumer Challenge Panel, *Advice to the AER, AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal CCP panel 2*, August 2015, p. 121.

81 Consumer Challenge Panel, *Advice to the AER, AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal CCP panel 2*, August 2015, p. 121.

82 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 207.

83 Frontier Economics, *Review of AER's preliminary decision on labour escalation rates*, July 2015, p. 11.

Supply and demand imbalance for specialist labour

In support of its proposed labour price growth forecasts, SA Power Networks also highlighted the specialist nature of electricity network labour.

We do not consider the specialist nature of electricity network labour is a reason for wage increases in excess of general utilities labour because there is no evidence of a supply and demand imbalance for electricity network labour.

In our preliminary decision we noted that the only reason for electricity networks to have efficient wage increases above other industries is due to a supply and demand imbalance for electricity labour. We did not consider there was any evidence of such an imbalance.[84]

In its revised proposal, SA Power Networks considered that supply and demand imbalances may be a contributor to EA labour price increases above other industries.[85] To support this, SA Power Networks considered that:

- a study undertaken by SA Power Networks and the South Australian Centre for Economics Studies (SACES) in 2012 identified shortages and difficulties in recruiting for several occupations.[86] The SACES report identified the Olympic Dam expansion and the mining boom as drivers of shortages for the types of workers SA Power Networks requires.[87] SA Power Networks also identified a shortage of linesworkers in regional areas as an example of the shortage of labour it requires.[88]
- electricity labour is not substitutable with the rest of the utilities sector.[89] Further, Frontier Economics considered excess mining labour is no more likely to be absorbed by the utilities industry than other industries.[90]

Neither of these points identifies a supply and demand imbalance for electricity labour.

DAE considered there is little evidence of a shortage of skilled labour in South Australia for distribution networks so the pressure on wages due to specialised labour supply is correspondingly weak.[91]

DAE also considered that in the context of a large workforce, the effect on wage growth due to a shortage in regional linesworkers is not likely to be significant in South

84 AER, *Preliminary decision attachment 7*, April 2015, p. 54.

85 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 210.

86 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 209.

87 South Australian Centre for Economic Studies, *Shortages in the electricity utilities sector: a brief overview*, August 2012, p. 11.

88 Department of Employment, *ANZSCO 3422-11 Electrical Linesworker*, November 2014, p. 1.

89 Frontier Economics, *Review of AER's preliminary decision on labour escalation rates*, July 2015, p. 16.

90 Frontier Economics, *Review of AER's preliminary decision on labour escalation rates*, July 2015, p. 18.

91 Deloitte Access Economics, *A response to submission on AER's preliminary decision for a regulatory proposal*, 11 September 2015, p. 8.

Australia.[92] In any case, although the Department of Employment identified a regional shortage for linesworkers, it stated that the national shortage for electrical linesworkers largely abated in 2014.[93] It considered the applicants in 2014 were more suitable applicants than in 2013 and there was 40 per cent fewer vacancies advertised compared to the peak in September 2013. [94] It also stated that South Australian employers attracted the largest field of suitable applicants.[95]

We also note the Olympic Dam expansion did not eventuate and DAE considered the mining boom is over due to Australian businesses spending less on big construction projects and falls in commodity prices.[96] This means the two key factors SACES identified as causing the shortage in electrical labour no longer exist.

We also consider current market conditions in other similar industries such as the mining industry and non-electricity labour in the utilities industry have an impact on electrical labour wages. This is consistent with previous comments by SA Power Networks and the views of other labour forecasters;

- in its regulatory proposal for the 2010–15 regulatory control period SA Power Networks identified other industries as having an impact on the supply and demand of its labour. For example it identified the construction of the national broadband network as a related industry requiring similar skills.[97] SA Power Networks also engaged BIS Shrapnel to forecast labour cost growth. A key driver of wage growth in BIS Shrapnel's forecast was the influence of the mining and construction sectors.[98]
- Jacobs noted that the construction and mining industry are relevant to labour cost pressures facing Ergon Energy as many employees or contractors have the potential to work in those sectors.[99]
- Independent Economics noted wages in occupations that the utilities sector employ have been supported by strong demand in the rapidly expanding mining sector.[100]
- The CIE's wage growth model takes into consideration the linkages and interactions between industries such as the mining industry and construction sectors.[101]

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92 Deloitte Access Economics*, A response to submission on AER's preliminary decision for a regulatory proposal*, 11 September 2015, p. 6.

93 Department of employment, *Labour market research – electrotechnology and telecommunications trades*, 2014 p. 3.

94 Department of Employment, *ANZSCO 3422-11 Electrical Linesworker*, November 2014, p. 3.

95 Department of employment, *Labour market research – electrotechnology and telecommunications trades*, 2014 p. 3.

96 Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 12.

97 ETSA Utilities, *ETSA Utilities regulatory proposal 2010–2015*, 1 July 2009, p. 103.

98 BIS Shrapnel, *Update of outlook for wages and contract services to 2014/15: South Australia*, December 2009.

99 Jacobs, *2015/20 regulatory submission Ergon Energy*, 10 October 2014, p. 33.

100 Independent Economics, *Labour cost escalators for NSW, the ACT and Tasmania*, 18 February 2014, p. vi.

101 CIE, *Labour price forecasts*, 17 December 2014, p. 14.

SA Power Networks also considered electricity labour was not substitutable with other utilities labour.[102]

We consider the utilities industry is an appropriate comparison point because the electricity industry makes up a majority of the ABS' utilities classification. We also consider the change in labour price in other industries can influence wages in the electricity industry.

In our preliminary decision we noted that electricity workers make up 56.5 per cent of the utilities industry.[103] We recognised that the utilities industry is a broad measure that includes other workers but it captured all electricity workers.

Deloitte Access Economics considered that electricity labour is large component of the utilities sector therefore it would have a notable impact on the WPI series. It also considered that a difference between electricity labour and non-electricity labour does not mean electricity labour would necessarily have higher wage growth.[104]

SA Power Networks' EA wage increases

We also consider SA Power Networks' annual wage increase of 4.25 per cent set out in its EA is above the efficient market rate.

SA Power Networks and its consultants Frontier Economics and NERA considered SA Power Networks' EA was efficient for the following reasons:

- Frontier Economics considered that SA Power Networks' EA is in line with the historical average EA outcomes of privately owned electricity networks.[105] The final EA wage increases of 4.25 per cent per annum was below the 7.00 per cent per annum proposed originally by the single bargaining unit of unions (SBU). Therefore, Frontier submitted SA Power Networks was able to achieve pay reductions relative to the SBU's original log of claims.[106]
- SA Power Networks considered that its EA negotiations balanced needs between paying lowest costs, paying workers sufficiently to retain high skills, and maintaining productivity and minimising the threat of industrial action. SA Power Networks also submitted that the electricity industry is highly unionised and SA Power Networks' current EA is in line with its competitors.[107]

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102 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 212.

103 AER, *Preliminary decision attachment 7*, April 2015, p. 52.

104 Deloitte Access Economics, *A response to submissions on AER's preliminary decision for a regulatory proposal*, 11 September 2015, p. 11.

105 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 205.

106 Frontier Economics, *Forecasting labour cost escalation rates using EBA outcomes*, August 2014, pp. 25–27.

107 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 205.

- NERA considered that the electrical trades union (ETU) has a monopoly over employee labour supply which has allowed it to extract higher wages.[108]

Our position is that EAs are inappropriate to use to forecast labour price growth, for the following reasons:

- If regulators compensate a business for the actual outcome of its commercial negotiations with employees, then this would remove an important incentive for businesses to become more productive over time. This is not the long term efficient outcome for electricity consumers. This point was also raised by DAE.[109]
- It is not efficient for a prudent firm to pay more than the utilities industry market rate for its labour without improving productivity. Otherwise the marginal cost for each unit of labour exceeds the market rate. SA Power Networks has not identified any benefits to consumers that would flow from its EA that would offset its labour price increases.
- If we were to apply a historical average EA for the years without an EA then our decision may impact on the negotiations. This is because bargaining representatives may interpret this position as endorsing the historical average EA as the appropriate wage increase. This may not be appropriate if one of the parties has been able to use its bargaining power to negotiate higher wage increases.

The CCP also considered adopting the EA wage rates would undermine the incentive nature of the regulatory framework.[110] We agree with the CCP. As noted above if we were to adopt the EA wage rates to forecast labour price growth then this may affect future negotiations if the service provider and employees can reasonably expect the costs to be passed through to consumers.

EAs as a regulatory obligation

SA Power Networks also considered its EA was a regulatory obligation in its revised proposal for the following reasons:

- its EA is a regulatory obligation under section 2D of the NEL
- the EA is an instrument issued under an Act of a participating jurisdiction that materially affects the provision of electricity network services.

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108 NERA, *Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs*, 23 June 2015, pp. 15–16 and Rick Catanzariti, *Enterprise Bargaining Agreements*, 26 March 2015, para. 30.

109 Deloitte Access Economics, *A response to submission on AER's preliminary decision for a regulatory proposal*, 11 September 2015, p. 7.

110 Consumer Challenge Panel, *Advice to the AER, AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal CCP panel 2*, August 2015, p. 119.

- its EA is certified by the Fair Work Act 2009 and this act is, by virtue of section 6 of the Australian Energy Market Act 2004, a 'participating jurisdiction' under the NEL.[111]

As a result, it considered its forecast labour price growth based on EA wage increases are the efficient costs of meeting this obligation.[112]

We consider EA's are not a 'regulatory obligation or requirement' as defined in section 2D of the NEL.[113]

The fact that the EA requires certification under the Fair Work Act 2009 does not make it an instrument "made or issued by or under" that Act. Likewise, the fact that the Fair Work Act 2009 contains provisions regulating certain procedures by which an enterprise and its employees may make an EA does not mean that EAs are "made under" the Act. Section 182 specifies than an EA is made when a majority of employees vote to approve the agreement. It follows that an EA is made by agreement between the enterprise and its employees but regulated by an Act. The agreement made between parties is not made or issued under an Act.

We also note an EA is not an instrument that 'materially affects the provision of electricity network services' within the meaning of section 2D. The EA itself has no effect on the provision of network services. There is no necessary connection between the terms of the EA and the nature, quality or quantity of network services supplied by a DNSP. An EA is not a requirement to provide electricity network services and a DNSP may arrange labour on many bases that do not involve an EA.

Other issues

SA Power Networks also raised several other issues in support of its approach. We do not consider any of these issues are reasons for us to depart from our approach used in our preliminary decision.

First SA Power Networks considered DAE's forecast lacks transparency and consistency and therefore should not be relied upon. It noted that macroeconomic modelling entails numerous assumptions and methodological choices which the DAE has not divulged.[114]

We consider a consultant's forecasting performance is the key factor in selecting an appropriate forecast. We have adopted the best forecast available of the South

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111 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 206.

112 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 206.

113 Section 2D sets out a multifaceted definition of 'regulatory obligation or requirement'. The part of the definition that has been argued to capture EAs is s 2D(1)(b)(v), which describes "any instrument made or issued under or for the purposes of an Act of a participating jurisdiction … that materially affects the provision … of electricity network services". The EA in question is not an instrument issued for the purposes of any Act, nor does it "materially affect the provision … of electricity network services".

114 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 212.

Australian utilities sector WPI. This is a forecast SA Power Networks has also used to forecast price growth in contracted services.

DAE has had regard to the following information in its forecast:

- the overall economic conditions for Australia and South Australia, and
- economic outlook for the utilities sector for Australia and South Australia.[115]

We consider DAE has provided sufficient information on the drivers of its forecast in its report. All economic forecasters adopt their own assumptions and methodologies. Transparency is important but we recognise that all labour forecasters have proprietary methodologies. We recognise the need for economic forecasters, such as DAE and BIS Shrapnel, to have proprietary information. The transparency of forecasts is only a key issue if the forecast results in a systematic bias compared to the ABS' data.

SA Power Networks adopted forecasts from its own consultant BIS Shrapnel to forecast price growth in contracted services. BIS Shrapnel also adopts its own assumptions and methodologies. So SA Power Networks' concerns about transparency should also be relevant to its own forecast.

We also consider DAE's forecasts are more accurate than BIS Shrapnel's. When comparing the forecasts with actual data we found that DAE under forecast and BIS Shrapnel over forecast the utilities sector WPI. Overall DAE forecasts were closer to the actual data than BIS Shrapnel but an average of the two consultants was the closest.[116]

Second, SA Power Networks considered a key consideration in our preliminary decision was that EAs were not representative of overall electricity workers wage increases. SA Power Networks considered this was incorrect because its EA covers 95 per cent of its employees.[117]

The proportion of staff covered by SA Power Networks EA is a key consideration in our final decision assessment of SA Power Networks labour price growth.

In our preliminary decision we considered private sector EAs represented wage increases for approximately half of the labour employed by privately owned service providers.[118] We noted that Frontier Economics' benchmark EA represents the labour price of only a subset of its total labour price forecast because more than half of the staff employed by private service providers are not covered by an EA.

We accept the EA covers and represents the wage increases for most of SA Power Networks' employees. However, this is not a key consideration in our assessment

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115 Deloitte Access Economics*, Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, pp. 12,19.

116 AER, *Powerlink transmission determination 2012–13 to 2016–17*, April 2012, p. 54.

117 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 210.

118 AER, *Preliminary decision SA Power Networks – attachment 7*, April 2015, p. 51.

because we consider SA Power Networks' forecast is not efficient based on current macroeconomic factors discussed above.

Lastly, SA Power Networks demonstrated empirically that wage growth less labour productivity in the utilities sector does not equal CPI.[119]

We agree that empirically this relationship has not held for the utilities industry even though its holds at the overall industry level. However it is reasonable to expect, in a competitive labour market, over the long term, more expensive labour should be relatively more productive than less expensive labour. Otherwise a service provider is paying more without receiving any productivity benefits.

B.4.2 Price weightings

We weight the forecast price growth to account for the proportion of opex that is labour and non-labour. We adopted a 62 per cent weighting for labour and 38 per cent for non-labour. We forecast the labour component based on the utilities WPI and we base the non-labour component on the CPI. These weightings are consistent with the weightings used in Economic Insights' benchmarking analysis.

SA Power Networks' revised proposal considered our price weightings were out of date and not reflective of SA Power Networks' actual price weightings.[120]

SA Power Networks adopted the following opex price weightings:

- labour – 46.1 per cent
- contracted services – 43.5 per cent
- materials –10.4 per cent.[121]

What we have included as labour is different to what SA Power Networks has included as labour. Our labour component includes both labour directly employed by a benchmark efficient service provider and contracted labour employed to provide field services. We do not include labour employed by contractors who provide non-field services in the labour weighting. Non-field services include services such as legal, accounting, IT and other administrative services that are not unique to providing electricity distribution services. We base this classification on Economic Insights' recommended approach to classifying labour and non-labour.[122]

We define labour in this way so we only include the productivity related to providing field services in the productivity component of the opex cost function. This is true for both our measurement of historic productivity change and the forecast productivity

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[119] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 215.

[120] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 220.

[121] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 222.

[122] Economic Insights, *Response to Ergon Energy's consultants' reports on economic benchmarking*, 7 October 2015, p. 30.

change in our opex forecast. We do this because when we measure historic productivity change we are interested in the productivity change achieved by the service providers rather than the productivity change achieved by contractors providing services that are not unique to electricity distribution.

SA Power Networks has allocated a narrower set of costs to non-labour which includes costs such as distribution licence fee and insurance premiums. Our non-labour proportion includes materials costs as well as contract costs for non-field services.

In response to submissions from SA Power Networks, Ergon Energy and the CCP we have investigated whether we could update the benchmark weightings. To do so we considered opex data from a sample of the most efficient service providers according to our opex benchmarking analysis, specifically:

- AusNet Services
- CitiPower
- Jemena
- Powercor
- SA Power Networks
- United Energy.

We assessed the proportion of the total opex of these service providers that was labour, contracts and other. That is, we divided the labour opex of the six service providers by their combined total opex for 2014.[123] We did the same for contracts and other. The resulting weights are in Table B.2.

Table B.2 Opex price weightings (per cent)

	Labour	Contracts	Other
SA Power Networks	46	44	10
Benchmark	43	40	17

Source: SA Power Networks, *Revised regulatory proposal*, July 2015, p. 82; AER analysis.

However, we note that the data available to us does not differentiate between expenditure for contracts that provide field services and contracts that provide non-field services. Further, for those contracts that provide field services, only the labour-related expenses attributable to these contracts should be allocated to the labour price weighting. Consequently, the 2014 data provided by the service providers only enables us to identify that the labour weighting should be somewhere between 43 per cent and

123 We used 2013–14 for SA Power Networks, which operates on a financial year basis.

83 per cent. The 62 per cent weight for labour is in the middle of the estimated 43 per cent to 83 per cent labour weighting range. In the absence of more precise information we are satisfied that the 62 per cent weighting for labour remains appropriate.

SA Power Networks considered our 62 per cent labour and 38 per cent non-labour weighting was not reflective of SA Power Networks because it assumes only one third of SA Power Networks' contracts would receive price growth greater than CPI.[124]

We consider that we should not use a service provider's own base year opex price weightings to forecast price change. Doing so would provide the service provider an incentive to use more than the efficient proportion of internal labour in the base year to increase its forecast price change. Consequently we cannot assume an individual service provider's opex price weightings are efficient, even if our benchmarking analysis finds the service providers' base opex to be efficient.

Notwithstanding this, we do not consider our approach is necessarily detrimental to SA Power Networks.

The remainder of our analysis on opex price weightings contains confidential information which we have removed from the public version of this document.

Other (materials, land and non-labour services)

SA Power Networks' revised its approach to forecasting materials, land and non-labour contract services price growth which is collectively referred to as 'other'.[125] SA Power Networks applied no real price growth to 'other'. This approach is consistent with our preliminary decision and we have adopted a forecast of CPI for 'other' in our final decision.

B.5 Output growth

We have maintained our preliminary decision methodology to forecast output growth consistent with our economic benchmarking analysis.[126] Our output growth factors and their respective weights are:

- customer numbers (67.6 per cent),
- circuit line length (10.7 per cent), and
- ratcheted maximum demand (21.7 per cent).

SA Power Networks considered our approach to forecasting output growth does not take into account the installation of new assets (in terms of additional circuit length and

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124 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 220.

125 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 221–222

126 AER, *Preliminary decision SA Power Networks – attachment 7*, April 2015, p. 61.

capacity installed) during a period where it forecasts ratcheted maximum demand at the aggregate level will not increase.[127]

SA Power Networks substituted ratcheted maximum demand with the following output growth factors:

- distribution transformer capacity (10.8 per cent)
- substation capacity (10.8 per cent).

SA Power Networks referred collectively to these two output growth factors as spatial growth.[128]

In our preliminary decision we considered that ratcheted maximum demand represents the actual capacity a service provider must have to meet its customers' needs whereas zone substation capacity and transformers represent the amount of infrastructure a service provider must build to meet the capacity.[129]

Our measure is a demand side measure that better represents the increase in service customers require. A supply side measure may reflect the number of assets SA Power Networks maintains but does not necessarily align with an increase in service to customers. For instance, if a service provider built additional capacity that customers do not require then its customers will have to pay more for maintenance even though they would not receive a greater level of service.

Based on this, we consider our measure reflects the opex objective to meet or manage the expected demand for standard control services over the regulatory control period.[130] This is because customers should not have to pay more if expected demand remains the same. SA Power Networks' capacity measure includes an increase in opex even though overall there is no increase in services to its customers. Therefore, we do not consider SA Power Networks' measure would lead to an opex forecast that reasonably reflects the opex criteria.

We based our approach on advice from Economic Insights. Economic Insights considered ratcheted maximum demand better considers the demand side functional output and only gives credit for network capacity actually used and not for capacity that may be installed that is excess to users' requirements. Further, the customer number and line length components of output growth recognise ongoing growth in the network.[131]

Economic Insights also noted that SA Power Networks' substitution of one output growth factor with another would not be consistent with the weights used in forming the

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[127] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 201.

[128] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 201.

[129] AER, *Preliminary decision SA Power Networks – attachment 7*, April 2015, p. 63.

[130] NER, cl. 6.5.6(a).

[131] Economic Insights, *Response to Ergon Energy's consultants' reports on economic benchmarking*, 15 September 2015, p. 27.

overall output growth derived in the econometric model because the weights are based on using ratcheted maximum demand, not installed transformer capacity.[132] The output weights are dependent on the elasticities from the econometric cost function and specific to that model specification. The elasticities would be different for different model specifications.

We also note the driver of SA Power Networks' spatial growth is localised demand growth in residential areas to meet customer growth.[133] We consider the customer numbers and circuit length output growth factors already capture this source of growth.

The CCP also considered ratcheted maximum demand is a better approach because it is based on the capacity actually used by consumers.[134] The CCP also noted the following issues with SA Power Networks' methodology:

- SA Power Networks did not provide any statistical analysis to suggest that capacity build is a better measure of efficient investment than ratcheted maximum demand
- our approach already provides opex compensation for spatial demand growth because the growth in customer numbers and circuit line length both capture much of the costs associated with servicing new pockets of growth.[135]

B.6 Productivity growth

We have maintained our preliminary decision approach of zero forecast productivity growth.

In its revised proposal SA Power Networks also forecast zero productivity growth. However, it considered we should have adopted negative productivity growth in our alternative estimate of opex for the follow reasons:

1. Economic Insights identified negative productivity growth between 2006 and 2013. SA Power Networks considered step changes only partially explain the negative growth across the industry. It considered we provided little conclusive evidence to support why we expect productivity growth to not continue to be negative in the 2015–20 regulatory control period.
2. Other regulators have adopted a negative productivity growth rate. Specifically it identified the New Zealand Commerce Commission (NZCC) adopted a negative 0.25 per cent productivity forecast.
3. SA Power Networks identified several factors where it will have to find productivity improvements in the 2015–20 regulatory control period.[136] This

132 Economic Insights, *Response to Ergon Energy's consultants' reports on economic benchmarking*, 15 September 2015, p. 27.

133 SA Power Networks, *Regulatory proposal 2015–20*, 31 October 2014, p. 217.

134 Consumer Challenge Panel, *Advice to the AER, AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal CCP panel 2*, August 2015, p. 116.

135 Consumer Challenge Panel, *Advice to the AER, AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal CCP panel 2*, August 2015, p. 116.

includes asset aging, spatial network growth, increasing weather events, demand for data, increasing safety requirements and increasing customer expectation and services.

We do not consider adopting negative productivity in the 2015–20 regulatory control period would be reasonable and in the long term interests of SA Power Networks' consumers.

First, we consider forecast productivity growth should capture forecast productivity driven by technical change and economies of scale.[137] The past is not necessarily the best measure of forecast productivity if these two types of productivity did not drive historical productivity. We have not identified all potential sources of negative productivity from 2006 to 2013. However, SA Power Networks did not provide evidence for why negative productivity will continue in the 2015–20 regulatory control period. We do not consider negative productivity in the past is determinative of negative productivity in the figure. For example our historical measure includes the impact of increased vegetation management costs in Victoria and South Australia vegetation clearance pass through.[138] It is not reasonable to include the impact of these past events in our forecast productivity.

Second, the NZCC adopted a different assessment approach to us. Although the NZCC adopt a labour cost index and producer price index to forecast price growth.[139] The NZCC does not include step changes in its opex forecast. The NZCC also includes an economies of scale adjustment to its output growth forecast.[140] When compared on a like with like basis our approach results in a higher opex forecast because economies of scale and step changes more than offsets –0.25 per cent negative productivity growth.

We note that the Ontario Energy Board adopted a productivity forecast of zero because it did not consider it was appropriate to entrench declining productivity expectations into the future.[141] OFGEM also accepted positive forecast productivity proposed by its regulated distribution businesses.[142]

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136 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 225. This includes asset aging, spatial network growth, increasing weather events, demand for data, increasing safety requirements and increasing customer expectation and services.

137 AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 189 AER, *Preliminary decision attachment 7*, April 2015, p. 65.

138 AER, *Preliminary decision attachment 7*, April 2015, p. 66.

139 New Zealand Commerce Commission, *Default price quality paths for electricity distributors from 1 April 2015 to 31 March 2020 low cost forecasting approaches*, 28 November 2014, p. 27.

140 New Zealand Commerce Commission, *Default price quality paths for electricity distributors from 1 April 2015 to 31 March 2020 low cost forecasting approaches*, 28 November 2014, p. 22.

141 Ontario Energy Board, *Rate setting parameters and benchmarking under the renewed regulatory framework for Ontario's Electricity Distributors*, 21 November 2013, p. 17.

142 OFGEM, *RIIO-ED1 final determinations for the slow track electricity distribution companies*, 28 November 2014, p. 31.

Lastly, the other factors identified by SA Power Networks do not actually relate to productivity growth. We have already incorporated efficient increases in price growth and output growth. We consider increases in costs driven by other factors if proposed as a step change.

Nor do we consider the age of SA Power Networks' assets will result in an increase in total opex. SA Power Networks estimated residual asset lives are not materially different to the residual asset lives in 2013–14.[143] More information on our assessment of SA Power Networks' asset age is in appendix 6 of our preliminary decision.

The CCP noted that SA Power Networks' starting point that negative productivity in the past means that the default assumption is negative productivity in the future does not reflect a competitive market.[144] We agree with the CCP and we do not consider past negative productivity necessarily means that productivity should continue to be negative.

143 AER, *Preliminary decision attachment 6*, April 2015, p. 107.

144 Consumer Challenge Panel, *Advice to the AER, AER's preliminary decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal CCP panel 2*, August 2015, p. 123.

C Step changes

In assessing a service provider's forecast, we recognise that there may be changed circumstances in the forecast period that may impact on the service provider's expenditure requirements. We consider those changed circumstances as potential 'step changes'.

We typically allow step changes for changes to ongoing costs in the forecast period associated with new regulatory obligations and for efficient capex/opex trade-offs. Step changes may be positive or negative. We would not include a step change if the opex that would otherwise be incurred to reasonably reflect the opex criteria, is already covered in another part of the opex forecast, such as base opex or the rate of change.

This appendix sets out our consideration of step changes in determining our opex forecast for SA Power Networks for the 2015–20 regulatory control period.

C.1 Final position

In our final decision opex forecast we have included step changes for the following proposals:

- new Regulatory Information Notice (RIN) requirements
- new National Energy Customer Framework (NECF) requirements
- increased stakeholder engagement for new tariff structures
- new billing and customer related system
- change in provision of mobile radio services
- reduction in distribution licence fee.

In total these step changes contribute $24.4 million ($2014–15) or 1.9 per cent to our total opex forecast for SA Power Networks for the 2015–20 regulatory control period.

C.2 Preliminary position

In its initial regulatory proposal SA Power Networks proposed fifty four step changes above its base opex equal to $216.8 million ($2014–15). It listed its step changes under the following categories:

- legal and regulatory
- capital program impacts
- customer driven and changing community expectations
- finance related.[145]

[145] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 256.

We included two proposed step changes in our preliminary decision opex forecast. We included a step change in opex for SA Power Networks to access the South Australian Government's mobile radio network. This was proposed as a capital program impact step change. We were satisfied this proposal reflected an efficient capex/opex trade-off. [146] We also agreed with SA Power Networks that it would face increased opex as a result of full compliance with NECF.[147] This was proposed as a legal and regulatory step change.

In addition we assessed four proposed base year adjustments equal to –$10.4 million ($2014–15) as step changes. We included one proposed base year adjustment in our forecast. This was for a forecast reduction in SA Power Networks' distribution licence fee.[148]

We did not include other step changes or base year adjustments proposed by SA Power Networks in our forecast. There were several common themes for our preliminary decision.

We considered our estimate of opex already reflected the efficient cost of meeting SA Power Networks' existing regulatory obligations and maintaining levels of service.

SA Power Networks' step changes in its initial proposal represented an 18 per cent increase above a forecast based on the opex it incurred in 2013–14. New programs of opex that SA Power Networks states it did not undertake in the base year, primarily drove this increase.

We did not consider variation in the expenditure on SA Power Networks' new programs of opex to be a reason for increasing the revenue it can recover from electricity network consumers. We forecast that SA Power Networks would be able to efficiently operate and maintain its network with little change from current revealed opex levels.

Several proposed step changes were for initiatives designed to achieve efficiencies. Under our assessment framework we do not include additional funding for efficiency.

SA Power Networks is subject to an incentive based regime whereby if it achieves efficiencies it will be rewarded through incentive payments which are additional to its opex and capex allowances. It would be inconsistent with the incentive based regulatory framework if SA Power Networks was funded to carry out programs or projects to generate efficiencies and receive a reward through the incentive schemes.

We found insufficient evidence of changes in SA Power Networks' regulations or requirements.

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[146] AER, *Preliminary decision, Attachment 7*, p. 93.

[147] AER, *Preliminary decision, Attachment 7*, p. 84.

[148] AER, *Preliminary decision, Attachment 7*, p. 105.

SA Power Networks quoted a variety of regulations and laws in its proposal. However, we could find little evidence that the regulations or laws it faced had materially changed since 2013–14, or if they had, how this was likely to materially affect the cost of providing regulated network services.

We were not satisfied we needed to increase forecast opex for SA Power Networks' customer driven initiatives or changes in community expectations.

SA Power Networks also proposed step changes labelled as customer driven initiatives or to meet changes in community expectations.

We recognise from time to time that a service provider will need to change the way it provides services to meet customer or community needs. However, while customers may express a preference for certain services, it does not necessarily mean that an increase in total forecast opex is required. Customers and the community also expect to only pay efficient costs to receive a safe and reliable electricity supply. A service provider will need to balance these objectives when deciding what total expenditure to incur.

Without compelling evidence that the expenditure to meet customer or community expectations would be required to achieve a service provider's regulatory obligations, meet or manage expected demand, or to maintain the reliability, safety and quality of supply of the service, we will not approve increases in forecast opex. We did not consider SA Power Networks had demonstrated that its proposed step changes labelled as customer driven or for meeting community expectations warranted an increase in forecast opex.

C.3 SA Power Networks' revised proposal and submissions

SA Power Networks proposed $140.0 million ($2014–15) in step changes in its revised proposal. SA Power Networks' revised step changes contribute 9.8 per cent to its total opex forecast. It did not specify why it did not repropose many step changes it proposed in its initial proposal. SA Power Networks' revised proposal on step changes is set out below in Table C.1 to Table C.5.

We received several submissions supporting our preliminary position on most step changes. These included submissions from:

- Business SA[149]
- Consumer Challenge Panel[150]
- Energy Consumers Coalition of South Australia (ECCSA)[151]

[149] Business SA, *Submission on AER preliminary decision*, p. 2.

[150] Consumer Challenge Panel, *Submission on AER preliminary decision and SA Power Networks revised proposal*, p. 21; pp. 131–132.

[151] Energy Coalition Consumers of South Australia submission, *Submission on AER preliminary decision*, pp. 32–33.

- Energy Retailers Association of Australia (ERAA)[152]
- Origin Energy[153]
- South Australian Council of Social Services (SACOSS).[154]

Business SA agreed there are few changes to the operating environment facing SA Power Networks during 2015–20 with respect to regulatory obligations. It submitted that while customers may express a preference for certain services, it does not necessarily mean that an increase in total forecast expenditure is required.[155]

The Consumer Challenge Panel (CCP) agreed that most step changes SA Power Networks proposed were already captured by base opex or output growth.[156] It also considered there should be a negative step change for vegetation management.[157]

Table C.1 Legal and regulatory step changes ($ million, 2014–15)

Proposal	SA Power Networks initial proposal	AER preliminary decision	SA Power Networks revised proposal	AER final decision
Asset inspections - no access poles	23.4	-	21.9	-
Asset inspections - underground cables	3.1	-	-	-
Asset inspections - bushfire inspection frequency	15.6	-	12.9	-
WH&S - Asset inspections 2 person crews	2.8	-	2.8	-
WH&S - Network operations	4.0	-	-	-
WH&S - Fleet monitoring	2.2	-	2.2	-
WH&S - Fleet inspections	3.9	-	3.9	-
New RIN requirements	9.2	-	6.4	6.4
National Energy Retail Law Regulations	4.3	-	-	-
National Energy Customer Framework	1.3	1.3	1.3	1.3
Demand Side Participation	33.8	-	13.3	5.1
Environmental Management	1.4	-	-	-
Total	**105.0**	**1.3**	**64.8**	**12.7**

152 Energy Retailers Association of Australia, *Submission on preliminary decision*, p. 1.
153 Origin Energy, *Submission on preliminary decision*, p. 8.
154 SACOSS, *Submission on preliminary decision*, p. 2.
155 Business SA, *Submission on preliminary decision*, p. 2.
156 Consumer Challenge Panel, *Submission on AER preliminary decision and SA Power Networks revised proposal*, pp. 131–132.
157 Consumer Challenge Panel, *Submission on AER preliminary decision and SA Power Networks revised proposal*, pp. 154–156.

Source: SA Power Networks, Reset RIN 2015–20; AER, Opex model for SA Power Networks - preliminary decision; SA Power Networks, Revised Reset RIN 2015–20; AER, Opex model for SA Power Networks – final decision.

Table C.2 Capital program impact step changes ($ million, 2014–15)

Proposal	SA Power Networks initial proposal	AER preliminary decision	SA Power Networks revised proposal	AER final decision
Information Technology	43.9	-	19.4	4.0
Mobile radio	7.9	7.9	12.8	12.8
Carrier costs, radio licensing and planning	5.1	-	-	-
Network Management Centre	3.6	-	-	-
Data quality	3.9	-	3.9	-
Substation maintenance - disconnectors	2.4	-	-	-
Flexible load management	1.0	-		-
Total	69.6	7.9	36.1	16.7

Source: SA Power Networks, Reset RIN 2015–20; AER, Opex model for SA Power Networks - preliminary decision; SA Power Networks, Revised Reset RIN 2015–20; AER, Opex model for SA Power Networks - final decision.

Table C.3 Customer driven initiatives and changing community expectations ($ million, 2014–15)

Proposal	SA Power Networks initial proposal	AER preliminary decision	SA Power Networks revised proposal	AER final decision
Change in NBFRA trimming cycle	13.5	-	13.5	-
Tree removal and replacement - BFRA	9.2	-	10.5	-
Tree removal and replacement - NBFRA	6.1	-	6.1	-
Advanced tree trimming practices	1.9	-	1.9	-
Community engagement and consultation - vegetation management	1.2	-	1.2	-
Customer education and consultation	1.7	-	1.7	-
Self-service products	1.0	-	1.0	-
Customer service team	1.6	-	1.6	-
Bushfire education campaign	2.6	-	2.6	-
Extreme weather education campaign	1.9	-	1.9	-

Farmers and sailors - education campaign	0.9	-	0.9	-
Total	41.6	-	42.8	-

Source: SA Power Networks, Reset RIN 2015–20; AER, Opex model for SA Power Networks - preliminary decision; SA Power Networks, Revised Reset RIN 2015–20; AER, Opex model for SA Power Networks — final decision.

Table C.4 Finance related operating expenditure ($ million, 2014–15)

Proposal	SA Power Networks initial proposal	AER preliminary decision	SA Power Networks revised proposal	AER final decision
Insurance premiums	3.0	-	-	-
Superannuation	–2.4	-	-	-
Total	**0.6**	**-**	**-**	**-**

Source: SA Power Networks, Reset RIN 2015–20; AER, Opex model for SA Power Networks - preliminary decision; SA Power Networks, Revised Reset RIN 2015–20; AER, Opex model for SA Power Networks — final decision.

Table C.5 Base year adjustments ($ million, 2014–15)

Proposal	SA Power Networks initial proposal	AER preliminary decision	SA Power Networks revised proposal	AER final decision
Regulatory proposal	–8.2	-	-	-
Distribution licence fee	–5.5	–5.0	–5.0[158]	–5.0
Non network solution	1.3	-	1.3[159]	-
Property	2.0	-	-	-
Total	–10.4	–5.0	–3.7	–5.0

Source: SA Power Networks, Reset RIN 2015–20; AER, Opex model for SA Power Networks - preliminary decision; SA Power Networks, Revised Reset RIN 2015–20; AER, Opex model for SA Power Networks — final decision.

C.4 Assessment approach

We have adopted the same assessment approach we used in our draft decision. This was set out in section C.3 of the preliminary decision.

158 Listed as a legal and regulatory step change in revised proposal.

159 Listed as a capital program impact step change in revised proposal.

Our assessment of proposed step changes must be understood in the context of our overall method of assessing total required opex using the "base step trend" approach. When assessing a service provider's proposed step changes, we consider whether they are needed for the total opex forecast to reasonably reflect the opex criteria.[160] Our assessment approach specified in the Guideline[161] and is more fully described in section 7.3 of this attachment.

As a starting point, we consider whether the proposed step changes in opex are already compensated through other elements of our opex forecast, such as base opex or the 'rate of change' component. Step changes should not double count costs included in other elements of the opex forecast.

We generally consider an efficient base level of opex (rolled forward each year with an appropriate rate of change) is sufficient for a prudent and efficient service provider to meet all existing regulatory obligations. This is the same regardless of whether we forecast an efficient base level of opex based on the service provider's own costs or the efficient costs of comparable benchmark providers. We only include a step change in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.

We forecast opex by applying an annual 'rate of change' to the base year for each year of the forecast regulatory control period. The annual rate of change accounts for efficient changes in opex over time. It incorporates adjustments for forecast changes in output, price and productivity. Therefore, when we assess the proposed step changes we need to ensure that the cost of the step change is not already accounted for in any of those three elements included in the annual rate of change. The following explains this principle in more detail.

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output then step changes that relate to forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of new office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year) to account for forecast network growth.[162]

By applying the rate of change to the base year opex, we also adjust our opex forecast to account for real price increases. A step change should not double count price increases already compensated through this adjustment. Applying a step change for costs that are forecast to increase faster than CPI is likely to yield a biased forecast if

[160] NER, cl. 6.5.6(c).

[161] AER, *Expenditure forecast assessment guideline*, November 2013, pp. 11, 24.

[162] AER, *Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp. 164–5.

we do not also apply a negative step change for costs that are increasing by less than CPI. A good example is insurance premiums. A step change is not required if insurance premiums are forecast to increase faster than CPI because within total opex there will be other items opex where the price may be forecast to increase by less than CPI. If we add a step change to account for higher insurance premiums we might provide a more accurate forecast for the insurance category in isolation; however, our forecast for opex as a whole will be too high.

Further, to assess whether step changes are captured in other elements of our opex forecast, we will assess the reasons for, and the efficient level of, the incremental costs (relative to that funded by base opex and the rate of change) that the service provider has proposed. In particular, we have regard to:[163]

- whether there is a change in circumstances that affects the level of expenditure a prudent service provider requires to meet the opex objectives efficiently
- what options were considered to respond to the change in circumstances
- whether the option selected was the most efficient option—that is, whether the service provider took appropriate steps to minimise its expected cost of compliance
- the efficient costs associated with the step change and whether the proposal appropriately quantified all costs savings and benefits
- when this change event occurs and when it is efficient to incur expenditure, including whether it can be completed over the regulatory period
- whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.

One important consideration is whether each proposed step change is driven by an external obligation (such as new legislation or regulations) or an internal management decision (such as a decision to use contractors). Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control in order to be expenditure that reasonably reflects the opex criteria. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken. As noted above, the opex forecasting approach may capture these costs elsewhere.

Usually increases in costs are not required for discretionary changes in inputs.[164] Efficient discretionary changes in inputs (not required to increase output) should normally have a net negative impact on expenditure. For example, a service provider may choose to invest capex and opex in a new IT solution. The service provider should not be provided with an increase in its total opex to finance the new IT since the outlay should be at least offset by a reduction in other costs if it is efficient. This means we will not allow step changes for any short-term cost to a service provider of

[163] AER, *Expenditure forecast assessment guideline*, November 2013, p. 11.

[164] AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

implementing efficiency improvements. We expect the service provider to bear such costs and thereby make efficient trade-offs between bearing these costs and achieving future efficiencies.

One situation where a step change to total opex may be required is when a service provider chooses an operating solution to replace a capital one.[165] For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.

C.5 Reasons for position

We have included step changes in our alternative opex forecast for the following proposals:

- new Regulatory Information Notice (RIN) requirements
- new National Energy Customer Framework (NECF) requirements
- increased stakeholder engagement for new tariff structures
- new billing and customer related system
- change in provision of mobile radio services
- reduction in distribution licence fee.

Our position on NECF and forecast changes to SA Power Networks' distribution licence fee is consistent with our preliminary decision. We forecast an additional increase in opex for SA Power Networks to access the South Australian Government's mobile radio network that was not included in our preliminary decision opex forecast. These costs were included in SA Power Networks' initial proposal but were classified as capex.

We have revised our position on stakeholder engagement for new tariffs, RIN compliance and SA Power Networks' billing and customer related system. We are satisfied that these cost increases are driven by new regulatory obligations.

Our reasons for each of these positions are described in more detail below in sections relating to each step change proposal.

There were several common themes to our reasons for not including proposed step changes in our forecast. These themes are consistent with our preliminary decision. We have set out these themes below.

[165] AER, *Expenditure forecast assessment guideline*, November 2013, p. 24; AER, *Explanatory statement: Expenditure forecast assessment guideline*, November 2013, pp.51–52.

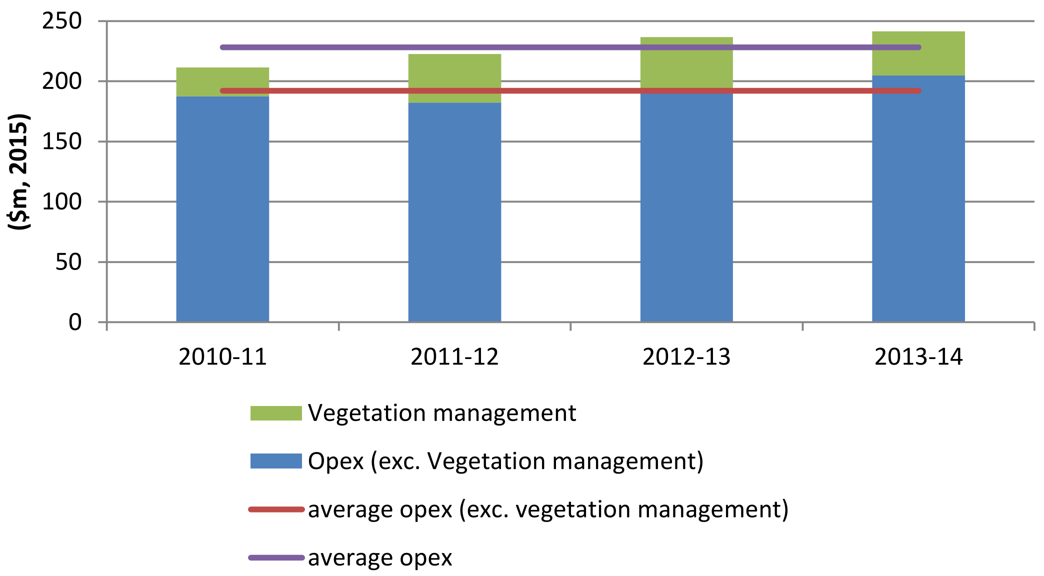
Our opex estimate already provides sufficient revenue for SA Power Networks to meet its existing regulatory obligations, and maintain the reliability, safety and quality of supply of standard control services.

As outlined in the Guideline[166] and our preliminary decision,[167] actual past opex, if efficient, should provide a good indicator of required funding in the future. If a service provider is operating relatively efficiently, there are relatively few circumstances why we would expect to forecast significantly different opex to a service provider's recent opex.

We have determined that SA Power Networks' opex in the base year is relatively efficient. In our view it provides a good basis for forecasting the total opex SA Power Networks would reasonably require to meet the opex criteria over the 2015–20 regulatory control period.

Figure C.1 illustrates that the total actual opex SA Power Networks incurred in its proposed base year, 2013–14, was similar to the previous year, 2012–13. When excluding opex on vegetation management, which increased materially in 2011–12 following above average rainfall in South Australia in 2010 and 2011, it has incurred a similar total amount of opex in each year of the most recent regulatory control period.

Figure C.1 SA Power Networks – actual opex from 2010–15 regulatory control period



Source: SA Power Networks, Economic Benchmarking Regulatory Information Notice responses 2010–11 to 2013–14; AER analysis.

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166 AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

167 AER, *Preliminary decision, Attachment 7*, p. 73.

However, while there is some consistency in SA Power Networks' total opex in recent years, there has been variation in the type of opex it has undertaken. For instance, between 2012–13 and 2013–14, vegetation management opex fell from $43.6 million to $36.7 million and inspections opex fell from $13.6 million to $11.7 million. As opex on these categories fell, opex on other categories increased. For instance:

- Guaranteed Service Level payments increased from $5.0 million in 2012–13 to $10.1 million in 2013–14.
- Corporate and other operating costs increased from $61.7 million in 2012–13 to $66.2 million in 2013–14.
- Network operating costs increased from $24.3 million in 2012–13 to $27.9 million in 2013–14.
- Substation property maintenance increased from $4.9 million in 2012–13 to $6.7 million in 2013–14.[168]

This variation is not surprising. If we analysed opex at a more granular level we would expect even greater variation. For instance, the projects and programs that drive all categories of opex would not be the same in 2012–13 as in 2013–14.

This illustrates that while new priorities may emerge for SA Power Networks, this expenditure can be funded as priorities change and the cost of other programs and projects decline. SA Power Networks has the flexibility to reallocate resources from year to year to meet changing priorities. SA Power Networks, if acting prudently, would always consider what mix of opex it needs in each year and how it needs to adjust its opex to meet changing priorities.

In relying on a base year to forecast a service provider's future opex, we are not forecasting that the cost of each of the projects and programs a service provider undertook in the base year would be representative of the cost of each of the projects and programs it will undertake in the forward regulatory control period. Nor are we forecasting that opex on each category of opex will be similar to the base year. We are forecasting the *total* amount of opex we consider that a prudent service provider would need to meet the opex criteria. While expenditure on projects and categories of opex varies from year to year, a service provider can often adjust its opex to meet changing priorities.

In its revised proposal, SA Power Networks proposed twenty eight increases in opex which it classified as a step change. For many of these increases, it is not expenditure that is as a result of a new or changed regulatory obligations or another external driver. It is new discretionary expenditure it is proposing to undertake in the 2015–20 regulatory control period. It identified only one area, a reduction in the cost of its

168 SA Power Networks, *Economic Benchmarking Regulatory Information Notice responses 2010–11 to 2013–14*; AER analysis.

licence fee, where it forecast lower opex in the 2015–20 regulatory control period. It forecast no productivity improvements in opex.

SA Power Networks' approach to defining step changes is different to ours. It appears to focus on whether the forecast cost of the discrete project or program is different to that incurred in the base year, and whether it considered an increase in expenditure in that particular project or program would be consistent with the opex objectives.[169] There is no evidence it considered potential savings or potential reprioritisation of costs relative to what it incurred in the base year.

We acknowledge that some new projects or programs SA Power Networks proposed to undertake in the 2015–20 regulatory control period may be prudent in isolation. However our task relates to forecasting the total opex a prudent service provider would require to achieve the opex objectives efficiently. SA Power Networks, by including expenditure on new items of expenditure, without considering other savings it can potentially make, has forecast a *total opex* amount that does not reasonably reflect the opex criteria. This is a major reason why we have not accepted its opex forecast.

We have increased SA Power Networks' opex allowance for the cost of new or changed regulatory obligations. However, relatively few of SA Power Networks' proposed step changes were to meet new or changed regulatory obligations. We were not convinced that an increase in opex is necessary for SA Power Networks to meet its existing regulatory obligations.

We will allow increased funding for new or changed regulatory obligations that will lead to an increase in the level of opex. As a regulatory obligation is imposed on a service provider, it does not have an option as to whether it will incur expenditure to comply. In most cases it must incur additional expenditure to achieve the obligation. We do not consider it is reasonable for a service provider to have to find savings to fund increases in its obligations.

In its revised proposal, SA Power Networks disagreed with this distinction. It considered that to recognise the validity of a step change to fund a material increase in the cost of complying with a changed ('black letter law') regulatory obligation, while denying the validity of a step change in other circumstances to be inconsistent.[170] It outlined several areas where it did not agree with the approach we had taken.

- Regulatory obligations can evolve over time. For instance under section 60(1) of the *Electricity Act 1996* (SA) SA Power Networks must take reasonable steps to ensure that electricity infrastructure is safe and safely operated. It considered the 'reasonable steps' it must take will change.[171]
- Where a service provider is not found to be compliant with its regulatory obligations, it may need to increase its opex to improve compliance.[172]

[169] SA Power Networks, *Initial proposal, Attachment 21.13*, October 2014, p. 4.
[170] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 229.
[171] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 228.
[172] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 228.

As outlined in our preliminary decision, we agree that, over time, expectations about what steps a service provider must undertake in discharging its duties will change. However, a service provider must provide persuasive evidence to support that such a change in legal standards has occurred and why expenditure in the forward regulatory period would need to depart from its historical expenditure as a result.

The requirements of SA Power Networks to take 'reasonable steps' to ensure that electricity infrastructure is safe and safely operated is a general requirement which has been in place for some time.[173] If the 'reasonable steps' SA Power Networks must take changes in a way that has a material impact on SA Power Networks' opex over time, we would expect SA Power Networks to provide evidence to demonstrate this. It is not enough for SA Power Networks to simply state that the reasonable steps it must take will change in the 2015–20 period. It must demonstrate this with evidence. We are not convinced that SA Power Networks has demonstrated that the total amount of opex it needs to ensure its electricity infrastructure is safe and safely operated will materially change in the 2015–20 regulatory control period when compared to 2013–14.

Similarly, there were also several step changes SA Power Networks proposed under the title of 'changing community expectations'. These programs were new proposed communications campaigns which would inform the community about risks associated with electricity and powerlines. However, SA Power Networks did not provide any evidence to substantiate its view that community expectations around informing the public about such risks had changed. As such there is no evidence that an increase in total opex is required for SA Power Networks to deliver such messages. We consider informing the public about risks associated with electricity infrastructure is a business as usual expense for a network service provider. As such we have not allowed any increase in funding for these programs. Like any discretionary expenditure, we expect SA Power Networks to reprioritise its opex if it wishes to undertake this expenditure. We do not wish to direct SA Power Networks to determine what discretionary expenditure it carries out. It is for it to decide whether to spend slightly more on public education campaigns and slightly less in other areas.

If a service provider is not compliant with its regulatory obligations, then we would need to consider whether a step change in opex would be needed. We need to ensure a service provider has sufficient revenue to be able to efficiently achieve its regulatory obligations. Where a finding of non-compliance with regulatory obligations results from a new legal precedent, or a change in enforcement policy by a regulatory body, we are more likely to consider that to be a change in exogenous circumstances justifying a step change. However, we must also be cautious about potentially providing an incentive for service providers to breach their regulatory obligations. In some circumstances, approving increases in opex where a service provider is not compliant

173 For instance, see *Electricity Act 1996* s.(60(1)) as at 1 January 1998.

with existing regulatory obligations could have perverse incentive effects. To provide it with such an incentive would not be consistent with the NEO.[174]

However, this is a moot point in SA Power Networks' case. It has not provided any evidence of where it is in breach of its regulatory obligations. It has only referred to one regulatory obligation it considered it had breached (the inspection of "no access poles"). SA Power Networks considered that this was a requirement of its Safety Reliability Maintenance and Technical Management Plan (SRMTMP).[175] However, there is no evidence this is a prescriptive requirement. We discuss our position on this step change in further detail below.

SA Power Networks proposed a number of step changes labelled as 'customer driven'. We were not satisfied that SA Power Networks' 'customer driven initiatives' addressed consumer preferences. In any case, SA Power Networks' consumer engagement is one of a number of factors to which we have had regard in assessing its proposal.

SA Power Networks submitted that several of the step changes it proposed were to address concerns expressed by consumers during its customer engagement program. It submitted that this program was both representative of its customer base and of the South Australian population, as well as being robust and academically sound in design and implementation. It submitted that we would err by not allowing step changes relating to its customer engagement programs.[176]

SA Power Networks' customer driven initiatives mostly related to new vegetation management programs. In particular, SA Power Networks proposed new tree removal and replacement programs and a shorter tree trimming cycle in non-bushfire risk areas. SA Power Networks' key justification for these programs was community concerns about the aesthetics of SA Power Networks' current vegetation management practices.[177] Amongst the customer engagement it undertook was a willingness to pay study which assessed its consumers' willingness to pay for different vegetation management initiatives.[178]

We are not convinced that the customer engagement that SA Power Networks undertook did in fact demonstrate that consumers of its standard control services valued these new initiatives. In particular, the study only surveyed a sample of residential consumers and not commercial consumers. We also consider that the consumers that were surveyed were not fully informed about the benefits associated with each option. We discuss SA Power Networks' willingness to pay study in further detail in this attachment.

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174 That is, it would not promote efficient operation and use of electricity services in the long term interests of consumers with respect to safety.

175 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 238.

176 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 231.

177 SA Power Networks, *Initial proposal*, October 2014, p. 21.

178 The NTF Group, *Targeted Willingness to Pay Research*, July 2014.

We have also undertaken consumer engagement as part of our consideration of the preliminary decision and final decision. A common issue raised by stakeholders was SA Power Networks' current level of opex.[179] Several stakeholders identified vegetation management as an area where SA Power Networks could potentially reduce its expenditure.[180] Significantly, this included the South Australian Government. Therefore, increased expenditure on vegetation management is inconsistent with the views expressed in several of the submissions we received.

In any case, consumer engagement is one of number of different factors we take into account in assessing a service provider's proposal. We only approve a total opex forecast that reasonably reflects the opex criteria. As a starting point, we can only approve opex that will achieve an opex objective(s).[181] Consumers may express a preference for particular expenditure but this does not necessarily mean that proposed opex would reasonably reflect the opex criteria. For instance, the Local Government Association of South Australia supports SA Power Networks' vegetation management programs.[182] However, there are already other funding arrangements in place if local councils wish to fund SA Power Networks to provide vegetation management services. Given there are other funding sources available to SA Power Networks to provide these services, we do not consider this is expenditure that should be recovered from all electricity consumers.

In addition to vegetation management, SA Power Networks proposed several smaller initiatives which it submitted were justified by information from its customer engagement program. However, on reviewing SA Power Networks' customer engagement program we were not satisfied there was a direct link between the views expressed in SA Power Networks' customer engagement and the proposed initiatives. Consistent with our views on other discretionary expenditure SA Power Networks proposed, whether SA Power Networks undertakes this expenditure is a matter for it when considering all priorities it faces.

We analyse the discrete customer driven initiatives SA Power Networks has proposed in this appendix. A more comprehensive discussion of our views on SA Power Networks' customer engagement program is outlined in the Overview of this decision.

Interaction with incentive schemes

One reason why we did not include several proposed step changes in our opex forecast in the preliminary decision is because of the interactions they would have with

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179 Accolade Wines, *Submission on preliminary decision*, p. 5; Business SA, *Submission on preliminary decision*, p. 2; CIT, *Submission on preliminary decision*, pp. 5-6; ECCSA, *Submission on preliminary decision*, pp. 29-31; ERAA, *Submission on preliminary decision*, p. 1; CCP, *Submission on preliminary decision and revised proposal*, p. 107; Renmark Irrigation Trust, *Submission on preliminary decision*, p. 1; SACOSS, *Submission on preliminary decision*, p. 2; SAWIA, *Submission on preliminary decision*, p. 4; Yatco, *Submission on preliminary decision*, p. 1.

180 ECCSA, *Submission on preliminary decision*, p. 32; Government of South Australia, *Submission on preliminary decision*, p. 3; CCP, *Submission on preliminary decision and revised proposal*, p. 107.

181 NER, cll. 6.5.6(a), 6.5.6(c).

182 Local Government Association of South Australia, *Submission on preliminary decision*, 3 July 2015.

the EBSS. Forecast opex must be consistent with any incentive scheme or schemes that apply to SA Power Networks.[183] We considered it would inconsistent with the incentive-based regulatory framework if SA Power Networks was funded to carry out programs or projects to generate efficiencies and it received a reward through an incentive scheme. Consumers would pay for the incremental cost of the initiative as well as pay SA Power Networks rewards for becoming more efficient. We considered this was relevant for a number of proposed step changes, including:

- inspections of underground cables[184]
- 10 separate IT step changes[185]
- carrier costs, radio licensing and planning[186]
- condition monitoring and network planning.[187]

SA Power Networks did not repropose these step changes in its revised proposal so this issue is less relevant for our final decision.

However, ElectraNet raised concerns about rejecting an efficient step change if it had an expected payback period longer than the regulatory period. It considered that if an initiative does not return efficiencies until the next regulatory period then the service provider would be unable to recover the cost of the initiative and therefore would have not have an incentive to fund it.[188]

We do not agree that a service provider has no incentive to fund longer term investments. If an expected payback period is longer than the regulatory control period then we acknowledge it increases the uncertainty about whether it can fully recover the cost. However, this is typical of investments with longer payback periods. If, overall, the investment would lower the service provider's costs in a subsequent regulatory control period then a service provider can expect to benefit from the investment in that period.

We discuss our final position on each proposed step change below.

[183] NER, cl. 6.5.6(e)(8).

[184] AER, *Preliminary decision, Attachment 7*, pp. 78-79.

[185] AER, *Preliminary decision, Attachment 7*, pp. 89-90.

[186] AER, *Preliminary decision, Attachment 7*, p. 94.

[187] AER, *Preliminary decision, Attachment 7*, p. 94.

[188] ElectraNet, *Submission on preliminary decision*, p. 3.

Increased asset inspections ─ no access poles, bushfire risk areas

We have not included any step changes related to asset inspections in our opex forecast. We would expect SA Power Networks' base level of opex would provide a sufficient level of opex to recover the prudent and efficient cost of meeting all regulatory obligations ─ including asset inspections. This is consistent with the position we outlined in our preliminary decision.

In its revised proposal, SA Power Networks included an increase in opex of $21.8 million ($2014–15) for asset inspections on 'no access poles'[189] and an increase in $12.9 million ($2014–15) for increased frequency of asset inspections in bushfire risk areas.[190]

'No access poles' refers to poles supporting electrical lines, the footings of which are covered at ground level with bitumen, concrete or paving. Inspecting a 'no access' pole involves a visual examination of the pole footings. This requires an asset inspector to remove the ground covering from around the pole to expose the steel just below ground level, take measurements, calculate and assess the level of corrosion in the pole and then reinstate the ground covering around the pole.

SA Power Networks stated that it undertook limited inspections of 'no access' poles during the 2010–15 regulatory control period. It previously assumed the below ground condition of each pole was similar to the above ground condition. It claims this approach was technically in breach of its Safety, Reliability, Maintenance and Technical Management Plan.[191] It states that during the 2010–15 regulatory control period, Western Power was directed by its safety regulator to inspect all such poles.[192] This triggered SA Power Networks to test whether its assumption about the below ground condition of these poles was correct in a sample of them. It subsequently found that the below ground condition of its poles could not be inferred from the above ground condition. It proposed to inspect all 'no access poles' in the 2015–20 regulatory control period to further determine the extent of any deterioration in their condition.

In bushfire risk areas, SA Power Networks currently inspects its assets every five or ten years depending on the corrosion zone. In the next regulatory control period, upon advice from a consultant, it proposed to inspect all assets in bushfire risk areas every five years. It considered its current practices do not align with inspection cycles of other service providers in the NEM.[193]

As outlined above, in assessing whether to provide a step change or not, we assess the drivers of the project. We typically only approve an increase in funding for new or

189 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 240.

190 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 244.

191 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 237.

192 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 238.

193 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 241.

changed regulatory obligations, or efficient capex/opex trade-offs. For expenditure that is discretionary, we would expect a prudent and efficient service provider to fund it without increasing total opex. As outlined above, SA Power Networks' opex has remained relatively stable in recent years although the mix of opex it has undertaken has changed. There is evidence that it is able to change the programs and projects it undertakes to deliver new or changed programs. We see no convincing reason why increased inspections of no access poles and increased inspections of assets in bushfire risk areas need to be treated differently.

Further specific comments about SA Power Networks' proposed step changes for asset inspections are outlined below.

Inspections of no access poles

SA Power Networks claims that its failure to inspect no access poles was in breach of its SRMTMP and therefore was not in compliance with its regulatory obligations. It considered that rectifying this non-compliance will require SA Power Networks to incur material and ongoing costs. It considered this assessment is critical because these poles are largely located in urbanised areas where they are in close proximity to the public and their failure poses a significant safety hazard.[194]

Sections 6.2 and 6.3 of SA Power Networks' Network Maintenance Manual outlines the inspection cycles SA Power Networks adopts.[195] The Network Maintenance Manual is referred to in SA Power Networks' SRMTRP which SA Power Networks is required to prepare under the *Electricity Act 1996* (SA).[196]

We were unclear as to whether inspection cycles were in fact dictated by regulatory obligations as SA Power Networks claimed. Business SA[197] and the Consumer Challenge Panel[198] also raised queries about what the SRMTRP requires.

We consulted with the Office of the Technical Regulator (OTR) to clarify what the SRMTRP required. It considered the SRMTRP to be a high level document and clarified that it did not require or approve specific work programs when recommending the SRMTRP for approval.[199]

As there is no specific regulatory obligation to inspect no access poles, SA Power Networks has flexibility about what below ground inspections it undertakes. A discretionary business decision to carry out a program should only be made after considering a range of different factors ─ including cost. Our position is not to provide increases in funding for discretionary changes in business practices.

194 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 238.

195 SA Power Networks, *Network Maintenance Manual*, October 2012, Sections 6.2 and 6.3.

196 Electricity Act (SA) 1996 s.23(c)(i).

197 Business SA, *Submission on initial proposal*, p. 25.

198 CCP, *Submission on preliminary decision and revised proposal*, p. 13.

199 Email from the Office of the Technical Regulator (SA), 31 August 2015.

In any case, SA Power Networks' claims about the urgency of this new program also do not appear to align with the speed of the actions it has taken to address this risk. For instance, the Western Australian safety regulator, EnergySafety, publicly released its findings about Western Power's pole inspection practices in May 2009[200], not in the 2010–15 regulatory control period as SA Power Networks' proposal states.[201] SA Power Networks first commenced a trial of 'no access pole' inspections in 2013–14.[202] Following the trial, it planned to undertake some additional inspections in 2014–15 followed by an accelerated program commencing in 2015–16.[203] If the EnergySafety review raised concerns for SA Power Networks as serious as it claims, then we would expect it would have acted with more urgency to address this issue.

SA Power Networks also claims that it has demonstrated its practices are not aligned with practices of other service providers.[204]

The remainder of our analysis on inspections of no access poles contains confidential information which we have removed from the public version of this document.

Inspections in bushfire risk areas

In our preliminary decision, we agreed that increased inspections of assets in areas subject to bushfire risk would align SA Power Networks more closely with the practices of other providers. However, we were not persuaded that SA Power Networks would require additional funding to implement this change in practice. In particular, we considered SA Power Networks' forecasting approach was not transparent. Its forecast was contained in a complex inspections forecasting model with line-by-line estimates of every pole inspection SA Power Networks plans to undertake over the 2015–20 regulatory control period.[205] We did not consider SA Power Networks provided sufficient clarity about the assumptions underlying its forecast.

SA Power Networks provided a limited explanation of its inspections forecasting model in its revised proposal.[206] A more detailed response was provided in response to an information request on 24 August following an unrelated question.[207]

Following the information provided by SA Power Networks on 24 August, we now have a better understanding of how the forecast is constructed in its forecasting model. However this has raised further concerns about SA Power Networks' forecast.

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200 EnergySafety, *2008 Distribution Wood Pole Audit Review*, May 2009.

201 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 238.

202 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 14.

203 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 15.

204 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 238.

205 SA Power Networks, *Initial proposal, Attachment 21.40: Multivariable Inspection Forecasting Model*, October 2014.

206 SA Power Networks, *Revised regulatory proposal, Attachment H.6*, July 2015.

207 SA Power Networks, *Revised regulatory proposal, Attachment H.6*, July 2015; SA Power Networks, *Multi Variable Inspection Forecasting Model Explanation.pdf,* 24 August 2015.

The remainder of our analysis on inspections in bushfire risk areas contains confidential information which we have removed from the public version of this document.

Workplace Health and Safety

We have not included any step changes related to workplace health and safety in our alternative opex forecast. We would expect a prudent service provider would already be meeting its regulatory obligations in relation to workplace health and safety.

In its initial proposal, SA Power Networks included four step changes for workplace health and safety in its opex forecast. These were:

- Asset inspections—For pre-bushfire season patrols, SA Power Networks uses single person patrols. Citing the distances that its employees must travel as part of these patrols, and the risk of motor vehicle accidents, SA Power Networks proposed to use two person patrols. It forecast additional opex of $2.8 million ($2014–15) over the 2015–20 regulatory control period for this step change.[208]
- Fleet monitoring—SA Power Networks propose to introduce an in-vehicle monitoring system to monitor driver behaviour.[209] It forecast additional opex of $2.2 million ($2014–15) for this step change.
- Fleet inspections—Following an independent review, SA Power Networks has identified some additional inspections of elevated working platforms and cranes it needs to undertake to comply with Australian standards related to cranes, hoists and winches.[210] It forecast an additional $3.9 million ($2014–15) for this step change.
- Network operations—Given forecast increases in connections such as embedded generation, SA Power Networks considered there is increasing demand for monitoring of the distribution system. As a result it considered that it needs to increase the resources it devotes to monitoring the distribution system after business hours.[211] It forecast additional opex of $4.0 million ($2014–15) for this step change.

For all these proposed step changes, SA Power Networks cited compliance with the requirements of sections of the *Work Health and Safety Act 2012* (SA) (WHS Act). Under the WHS Act that commenced on 1 January 2013, SA Power Networks must ensure that, so far as reasonably practicable, workplaces are without risk to the health and safety of any person.[212] In our preliminary decision we acknowledged that the WHS Act had changed. However, this did not materially change the workplace health and safety obligations SA Power Networks faced. For instance, SafeWork SA

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208 SA Power Networks, *Revised regulatory proposal, Attachment 21.13*, July 2015, p. 38.

209 SA Power Networks, *Revised regulatory proposal, Attachment 21.13*, July 2015, p. 48.

210 SA Power Networks, *Revised regulatory proposal, Attachment 21.13*, July 2015, p. 53.

211 SA Power Networks, *Revised regulatory proposal, Attachment 21.13*, July 2015, p. 44.

212 Workplace Health and Safety Act 2012(SA), s. 17.

considered that most of the new Work Health and Safety Regulations 2012 are consistent with the former occupational health, safety and welfare legislation. The regulations which changed are unrelated to SA Power Networks' proposed step changes. [213]

We also recognised that standards of what risks are acceptable do change over time. However, SA Power Networks had not demonstrated how this is relevant to these particular step changes it proposed. When considering a step change we analyse whether the circumstances facing a service provider will be different to the circumstances it faced in the base year. It was not clear to us why the measures that were reasonably practicable in the base year, 2013–14, are likely to be materially different to what is reasonably practicable in the 2015–20 regulatory control period. As such we were not satisfied that a prudent service provider's opex in meeting its WH&S obligations should be materially different in the 2015–20 regulatory control period when compared to the base year. We therefore did not include a step change for any of these proposals in our forecast.[214]

In its revised proposal SA Power Networks re-proposed three of the four initiatives it proposed in its initial proposal. It did not re-propose the initiative relating to network operations. It considered it would be covered by output growth.[215] SA Power Networks states that it is continually reviewing its workplace practices to identify if any of those workplace practices need to be modified in order to discharge its duties. It considered the measures it has identified are reasonably practicable at this point in time. As the activities were not undertaken in the base year, and it considered the costs to be efficient, it submitted that we should provide a step up in funding for the new measures it has identified.[216]

We see no reason to change our position from our preliminary decision. We must forecast a sufficient amount of total opex for a prudent service provider to efficiently deliver all of its regulatory obligations. Meeting workplace health and safety requirements is a business as usual expense for a network service provider. We consider a prudent service provider would already be meeting its obligations under current workplace health and safety legislation. As the change in workplace, health and safety legislation commenced on 1 January 2013, a prudent service provider would have already been compliant with these changes before the base year, 2013–14 had even commenced. In any case, this change in legislation did not fundamentally change the obligations facing SA Power Networks. For these reasons we do not agree there is sufficient evidence that SA Power Networks would require an increase in total forecast opex to comply with its workplace, health and safety obligations.

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213 SafeWork SA, http://www.safework.sa.gov.au/uploaded_files/WHSTransitionalSummary.pdf, 2014.

214 AER, *Preliminary decision, Attachment 7*, April 2015, p. 94.

215 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 246.

216 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 246.

New RIN requirements

We have included a step change of $6.4 million ($2014–15) for new regulatory information notice (RIN) requirements in our opex forecast. We are satisfied that these costs are driven by a new regulatory obligation.

In its initial proposal, SA Power Networks forecast additional opex of $9.2 million in systems and business processes to provide actual data whereas previously we required estimated information to comply with our RIN requirements.[217] SA Power Networks considered its existing systems and processes were not configured or designed to capture the information required by the RINs.

In our preliminary decision we did not consider SA Power Networks had put forward persuasive evidence as to why its RIN reporting costs would increase in the 2015–20 regulatory control period.[218]

In its revised proposal, SA Power Networks provided additional evidence to demonstrate that producing actual data costs materially more than estimated data.[219] SA Power Networks stated the amount of opex it will incur to comply with the new regulatory obligation will depend on whether we accept its revised RIN-related IT capex forecast in our final determination.[220] It stated if we do not accept its revised RIN-related IT capex forecast, the cost of collecting and providing actual data for the RINs using its existing manual systems will be materially higher. It proposed a step change of:

- $6.4 million ($2014–15) if we accept its revised RIN-related IT capital expenditure forecast, or [221]
- $16.6 million ($2014–15) if we do not approve its increase in capex.[222]

We accept that the changed RIN requirements will impose some additional burden on SA Power Networks. We have accepted SA Power Networks' revised RIN-related IT capex forecast in our final determination. We discuss this capex project in section B.6 of attachment 6. The additional opex relates to introducing new procedures, systems and training and ongoing internal governance and audit costs necessary to collect and confirm actual rather than estimated data.

217 SA Power Networks, *Regulatory proposal, Attachment 20.39 RIN Business Case.* We require actual information for the economic benchmarking RIN from 2014–15 and for the category analysis RIN from 2015–16.

218 AER, *SA Power Networks Preliminary determination 2015–20*, Attachment 7, 30 April 2015, p. 7-82.

219 SA Power Networks*, Revised Regulatory Proposal, Attachment G.22 EAM and RIN Reporting*, 3 July 2015; SA Power Networks, *Revised regulatory proposal*, July 2015, p. 251.

220 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 251.

221 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 254.

222 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 255

NECF

Consistent with its initial proposal, SA Power Networks proposed an increase in opex of $1.3 million for full NECF compliance. We included this step change in our initial proposal.

The South Australian Government partially adopted the NECF on 1 February 2013, with the intention of full adoption from 1 July 2015 with the inclusion of the NECF connection charging obligations. With full adoption of the NECF, SA Power Networks states that it expects a greater number of additional or expanded activities relating to connection charges and rebates. SA Power Networks states it has updated its Connection Policy to reflect NECF requirements. It forecasts it will need two additional FTEs at a cost of $1.3 million ($2014–15) over the 2015–20 regulatory control period to undertake the additional or expanded activities.[223] We considered the assumptions underlying SA Power Networks' proposal to be reasonable. ECCSA also considered that two additional staff was a reasonable assumption of the additional workload associated with full implementation of NECF.[224]

We have not changed our position to include this as a step change.

We note the South Australian Government considered that a step change for NECF was not justified. It considered the changes to the AER's Connection Charging Guideline are not too dissimilar to the current connection charging regime.

While the two regimes are similar, they are not identical. For instance:

- Under SA Power Networks' previous Connection Policy which is based on ESCOSA guidelines the minimum rebate for a new customer (residential and non-residential) connection is $3,000.[225] Under the new SA Power Networks Connection Policy, which is based on the AER's Connection Charge Guidelines, there is no minimum requirement. As a result, SA Power Networks have forecast an increase in the individual rebates it will process.
- In accordance with SA Power Networks' previous Connection Policy, connections that are presently treated as 'developer' projects do not receive a rebate under the upstream rebate scheme. Under its new Connection Policy developers need to be assessed under a 'Pioneer Scheme' to see if they qualify for a rebate.[226] This will lead to an increase in the number of assessments SA Power Networks will need to undertake.

We consider additional estimated costs of $1.3 million over five years to be a reasonable estimate of the additional burden associated with the change in requirements.

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[223] SA Power Networks, *Initial proposal, Attachment 21.13*, p. 68.

[224] ECCSA, *Submission on preliminary decision*, p. 33.

[225] ESCOSA, *Electricity Distribution Code 07, December 2009,* A-36.

[226] AER, *Connection Charging Guideline*, June 2012, p. 22.

Demand side participation

In its revised proposal SA Power Networks included three step changes labelled as demand side participation:

- transition to cost reflective tariffs ($5.1 million)
- metering contestability ($5.1 million)
- low voltage network monitoring ($3.0 million).

We have included a step change for the transition to cost reflective tariffs proposal but not the other proposals. We discuss our position on each proposal below.

Transition to cost reflective tariffs

In its initial proposal SA Power Networks forecast additional opex of $11.9 million ($2014–15) for customer and retailer engagement costs to assist with the introduction of new tariff structures.[227] Most of this proposed step change ($8.0 million) was attributable to new customer support staff. SA Power Networks estimated it would need to employ 26 additional FTEs by 2020 to assist with consumer queries in relation to new tariff arrangements.[228]

In our preliminary decision we recognised SA Power Networks may incur some additional costs in developing and implementing new tariff structures. For instance, the AEMC noted that as a result of a rule change, there will be more consultation with consumers and retailers in the development of network price structures, and the process for setting network prices will be more transparent.[229] The AEMC considered consultation with consumers and retailers was required for distribution businesses to develop prices that best suit the particular circumstances of their network and their customers.[230] Further, distribution businesses are required demonstrate how stakeholder views have been taken into account in their new tariff structure.[231]

However, SA Power Networks' based its increase in costs on its proposal to install 'smart ready meters' in its network. We did not accept the installation of 'smart ready meters' so we did not accept its proposed stakeholder engagement costs.[232] We also noted concerns about the large number of additional consumer support staff SA Power Networks proposed to employ. We did not consider this to be a reasonable estimate of the additional volume of work.

In its revised proposal, SA Power Networks revised its forecast down to $5.1 million ($2014–15). Its revised forecast comprised of:

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227 SA Power Networks, *Initial proposal, Attachment 14.3*, p. 7.

228 SA Power Networks, *Response to Information Request AER 025*, 18 February 2015.

229 AEMC, *National electricity amendment (distribution network pricing arrangements) Rule 2014*, p. 10.

230 AEMC, *National electricity amendment (distribution network pricing arrangements) Rule 2014*, p. viii.

231 AEMC, *National electricity amendment (distribution network pricing arrangements) Rule 2014*, p. 13.

232 AER, *Preliminary decision, Attachment 7*, p. 86.

- an additional four FTEs to provide support and education to small and medium businesses to help them manage the transition to cost-reflective tariffs. ($1.9 million)[233]
- production and distribution of education materials, including customer information packs ($1.7 million)[234]
- additional customer support staff ($1.5 million).[235]

We agree a prudent service provider would incur additional costs in helping consumers to transition to new tariff structures required by the network pricing rule change. We consider SA Power Networks has addressed our preliminary decision concerns by placing greater reliance on retailers for customer education and support. This has resulted in lower forecast increase for call centre costs of $1.5 million relative to $8.0 million in SA Power Networks' initial proposal. We consider SA Power Networks' revised estimate of additional customer support staff to be a reasonable estimate.

We note SA Power Networks did not include the support costs for small to medium businesses in its initial proposal. In response to an information request SA Power Networks provided additional evidence to support these costs.[236] We are satisfied that SA Power Networks will receive a greater number of queries from businesses relating to tariffs. We are also satisfied that queries from business customers are different to standard residential customers and may benefit from specialist advice. As such we consider this would reflect a reasonable estimate of the additional in the work to provide education and consult with business customers on new tariff structures.

Introduction of full competition in metering

In its revised proposal, SA Power Networks proposed a step change of $5.1 million ($2014–15) related to the introduction of full competition in metering. These costs related to the implementation of new business process and systems and increased staffing levels to manage the replacement of SA Power Networks' regulated Type 6 meters with third party meters.[237]

Even though the AEMC is yet to make a rule change related to competition in metering SA Power Networks submitted that it has sufficient confidence in the outcome of the rule change process to estimate the impact. SA Power Networks also noted that we would be able to take account of the final rule when making this final decision.[238]

Since SA Power Networks submitted its revised proposal, the AEMC has extended the timeframe for publication of the final rule determination on the Competition in Metering

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233 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 258.

234 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 258.

235 SA Power Networks, *Revised regulatory proposal*, Attachment H.8, July 2015, 2 July 2015, p. 14.

236 SA Power Networks, *Response to information request 049*, 24 July 2015, p. 4.

237 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 259.

238 SA Power Networks, *Revised regulatory proposal*, Attachment H.8, July 2015, p. 7.

rule change in order to consider complex issues around the details of implementing a competitive framework for metering.[239] In these circumstances, we consider that uncertainty remains around the nature of the Competition in Metering rule change and the details of its implementation. We do not consider we are in a position to consider possible opex associated with a future rule change when the regulatory obligation or requirement is yet to be made. We note the SA Power Networks may be eligible to apply for a pass through amount when the rule changes are confirmed.

We further discuss the uncertainty that exists around the nature of the applicable regulatory obligation, the possible system changes required, and the quantum of costs which may be incurred in our capex assessment of SA Power Networks' metering in attachment 6.

Low voltage network monitoring

SA Power Networks' revised proposal includes $3.0 million ($2014–15) relating to a low voltage network monitoring trial. This is a decrease compared to the $12.4 million ($2014–15) it proposed in the initial proposal.

In its initial proposal, SA Power Networks proposed a trial of network monitoring in its low voltage network. SA Power Networks' expenditure related to additional communications and IT devices that it proposed to install in smart meters to facilitate the trial. As we did not approve the installation of smart ready meters, we did not approve additional opex. We also noted in our capex attachment that SA Power Networks had effectively managed power quality over 2010–15 in the presence of significant uptakes in solar PV connections. We did not consider that SA Power Networks provided sufficient evidence to demonstrate that it would not be able to maintain supply voltage without additional capex for monitoring. See our preliminary decision for more detail on our reasoning.[240]

SA Power Networks' revised proposal retained its network monitoring program, but instead proposed a 'staged approach' that will defer the majority of expenditure to the 2020–25 regulatory control period. The trial proposed for the 2015–20 regulatory control period included a monitoring trial in the Unley Park areas of South Australia.[241]

We recognise that solar PV will likely continue to play a large role in the South Australian energy market and this will have implications for power quality. As parts of the network experience higher amounts of solar rooftop generation, this can lead to voltage fluctuations on the network (in particular voltage spikes) that may need to be addressed by SA Power Networks. We recognised this in our preliminary decision.[242]

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239 AEMC, *Additional consultation on specific issues National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 and National Energy Retail Amendment (Expanding competition in metering and related services Rule 2015),* 17 September 2015, p. 1.

240 AER, *Preliminary decision, Attachment 6*, pp. 44–48.

241 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 136.

242 AER, *Preliminary decision, Attachment 6*, p. 48.

However, SA Power Networks appear to argue that its existing practices — receiving customer complaints, thoroughly investigating those complaints, and taking action as appropriate to resolve voltage issues — is no longer the most prudent and efficient practice to the management of power quality complaints. As set out in our capex attachment, we are not satisfied that a change in practice is warranted. As such we have not included any capex or opex associated with this trial in our final decision expenditure forecasts.

IT

In its revised proposal, SA Power Networks included four step changes for IT:

- Data Centre Consolidation ($4.5 million)
- Enterprise Information Security ($9.0 million)
- SAP Foundation ($2.3 million)
- Customer Information System ($3.6 million).

We have included a step change for the SA Power Networks' customer information system, but not the other IT proposals. We discuss our position on each IT project below.

Data Centre Consolidation

Consistent with its initial proposal, SA Power Networks proposed $4.5 million in opex for its data centre consolidation. SA Power Networks stated that its data centres are running out of capacity due to increased volumes of data and the increased portfolio of business systems and supporting infrastructure.[243]

In our preliminary decision we considered that this proposal was related to SA Power Networks' incremental business needs which are already compensated through the output growth factor we apply to base opex. We considered it would be double counting to apply an additional step change.[244]

In its revised proposal, SA Power Networks stated the following:

> It is clear from this reasoning that the AER assumed that the increase in the volume of data required to be collected by SA Power Networks as a result of various recent (e.g. the AEMC's Distribution Network Pricing Arrangements Rule change) and imminent (e.g. the AEMC's Expanding Competition in Metering and Related Services Rule change) changes to regulatory obligations, was the only driver for the step change. However, this is incorrect. This step change and the related data centre consolidation project is actually an efficient

[243] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 263.

[244] AER, *Preliminary decision, Attachment 7*, p. 94.

> capex/opex trade-off which was inadequately described in the Original Proposal.[245]

SA Power Networks have misunderstood the reason why we did not include this step change in our alternative opex forecast. We did not assume that this step change was linked to AEMC rule changes.

As explained in our preliminary decision, the reason we did not include this step change in our forecast was because we consider SA Power Networks is already appropriately compensated through the forecast rate of change in opex.[246]

The output growth factor in the rate of change factor compensates SA Power Networks as the outputs it is expected to service grow. For instance, if SA Power Networks' customers are forecast to increase and/or its network grows, forecast output growth will be higher. Correspondingly the forecast opex we consider is required to efficiently operate and maintain SA Power Networks' network will need to increase. We account for this through the forecast output growth factor in the rate of change estimate.

Inevitably, as a service provider grows, it will face capacity constraints in some parts of its network. When a business grows, the data required to run an efficient network will also increase. However, the compensation for additional expenditure to expand capacity is provided through forecast output growth. We risk overcompensating a business if we provide additional expenditure for output growth through a rate of change adjustment to base opex and through a step change to expand its capacity.

While it may well be more efficient for SA Power Networks incur opex rather than capex in meeting this expanded capacity, this does not change our position. Even if an opex solution is more efficient than a capex solution, forecast output growth is the means by which we compensate a business for incremental opex needs.

Enterprise Information Security

SA Power Networks proposed a step change a $9.0 million to improve its information security capabilities, a decrease from the $10.2 million it proposed initially.

We did not include this proposal in our preliminary decision opex forecast. Information security is a discretionary business decision. As outlined in our preliminary decision, we do not typically fund a service provider to fund discretionary business decisions. New programs or project may, in isolation, be prudent. However, new programs and projects can often be funded as the cost of other programs and projects in the base year decline.[247]

We also considered that the need for increased information security capabilities was unclear. The business case provided very general information about SA Power

[245] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 263.

[246] AER, *Preliminary decision, Attachment 7*, p. 92.

[247] AER, *Preliminary decision, Attachment 7*, p. 93.

Networks' current information security capabilities and outlined broad options for improving these capabilities. We considered SA Power Networks did not clearly put forward a case as to why it would require an increase in its total opex for this program. In particular we considered that the business case did not identify:

- the specific information security risks SA Power Networks faces
- whether those risks caused incidents for SA Power Networks in the 2010–15 regulatory control period
- the cost to SA Power Networks from those incidents
- how those risks are expected to change in the 2015–20 regulatory control period from the risks it faced in the 2010–15 regulatory control period
- what options SA Power Networks considered to deal with those specific risks
- how those options do or do not address the specific risks SA Power Networks has identified
- why the preferred options need to be funded through an increase in SA Power Networks' total opex budget.[248]

In response to our preliminary decision, SA Power Networks stated that information security presented c-i-c risks related to:

- interruptions to customer facing services and/or loss of data resulting in non-compliance with our regulatory or legal obligations, financial penalties and potential loss of life
- disclosure of corporate information to unauthorised parties resulting in increased vulnerability to future attacks, potential reputational damage and financial consequences
- disclosure of private and sensitive information held by SA Power Networks in relation to its customers, staff and contractors resulting in potential financial or reputational consequences to those parties and financial penalties to SA Power Networks
- potential power outages
- potential damage to power networks
- potential loss of life.[249]

In the next regulatory control period, SA Power Networks considered these risks will increase due to:

- increased terrorist and cyber criminal activity

[248] AER, *Preliminary decision, Attachment 7*, p. 93.

[249] SA Power Networks, *Revised regulatory proposal, Attachment G.18*, July 2015, p. 4.

- convergence between information technology, operational technology and telecommunications environments due to implementation of its recent advanced distribution management system
- greater number of external suppliers that are allowed access to its network
- greater use of devices and applications that use the network.[250]

The remainder of our analysis on enterprise information security contains confidential information which we have removed from the public version of this document.

SAP foundation

In its initial proposal SA Power Networks proposed a step change listed as SAP foundation. It considered the existing hardware and associated technologies providing the SAP Enterprise Resource Planning and associated database systems are coming to the end of their service life and need to be replaced.[251] It forecast increased opex of $2.4 million ($2014–15). The costs included the provision of maintenance and licence fees to SAP and Oracle and an uplift in ongoing support.[252]

In our preliminary decision, we noted that periodically a service provider will need to replace systems and/or its software. However, we did not consider a step change in total opex is needed where this is the case. We noted that we approve opex to maintain the same level of service to consumers. We were not convinced that a prudent service provider's costs should be increasing if there is no change in service to consumers.[253]

In response to our preliminary decision, SA Power Networks emphasised the need to upgrade its aging technology and that the costs associated with this particular platform were forecast to increase.

We have not changed our position on this step change from our preliminary decision.

Our view is that any additional opex associated with periodic upgrades of IT systems are business as usual expenses. A prudent service provider should manage these costs within its existing level of funding. We are only forming a view on the total opex we consider a prudent service provider would reasonably require to meet the opex criteria. Our opex forecasting approach is largely top-down. We have relied predominantly on the total opex SA Power Networks incurred in the base year for forecasting opex and have used this amount to predict the future total opex we consider a prudent service provider would require. We consider that incremental changes in a service provider's opex for discretionary projects and programs should be managed by a prudent service provider without requiring an increase in the total

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[250] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 264.

[251] SA Power Networks, *Revised regulatory proposal*, Attachment G.20, July 2015, p. 1.

[252] SA Power Networks, *Revised regulatory proposal*, Attachment G.18, July 2015, p. 36.

[253] AER, *Preliminary decision, Attachment 7*, p. 92.

funding it would require from consumers. There does not appear to be anything unique about this proposal which would cause us to reach a different view.

Billing and customer related system

In its initial proposal, SA Power Networks included a step change in its opex associated with its new billing and customer related system. It considered its system was aging and needed replacing. It forecast a net increase in opex of $6.9 million.[254]

In our preliminary decision, our reasoning was consistent with the SAP foundation step change. We recognised that periodically a service provider will need to replace systems and/or its software. However, we did not consider a step change in total opex is needed where this is the case. We were not convinced that the costs of operating a new system would be higher to maintain the same level of service.

In its revised proposal, SA Power Networks revised its forecast step change down to $3.6 million. The revisions to the forecast reflected a delay in implementation by one year, and reduced software and maintenance costs.

SA Power Networks agreed that if it were implementing a like for like upgrade then significant increases in opex would not be required. However, in this instance it considered current and future planned regulatory obligations were the main driver for the additional capability. It referred to new obligations regarding rule changes regarding customer access to data and metering, and tariffing.[255]

For instance, on 6 November 2014 the AEMC made a rule change which will make it easier for customers to access their data. While the specifics of the format for the provision of data will be determined by the Australian Energy Market Operator in its data provision procedures, the determination sets out that, at a minimum, the data should include the customer nature and extent of energy usage for daily time periods including:

- usage or load profile over a specified period
- a diagrammatic representation of the above information.[256]

SA Power Networks considered that with its existing system, it can only meet the requirements with manual reports.[257]

In regards to tariffing, on 27 November 2014 the AEMC also made a rule change requiring tariffs to be set based on the long run marginal costs of providing the service. SA Power Networks has identified that it could not implement a demand tariff based on limited functionality of its existing billing system. For instance, a recent trial confirmed

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[254] SA Power Networks, *Initial proposal, Attachment 21.13*, p. 92.

[255] SA Power Networks, *Revised regulatory proposal, Attachment G.21*, July 2015, p. 4.

[256] NER, cl. 7.16.

[257] SA Power Networks, *Revised regulatory proposal, Attachment G.21*, July 2015, p. 4.

that the limitations of its current software do not allow automation of the billing process based on such a tariff.[258]

Based on the additional clarification SA Power Networks have provided, we have reconsidered our preliminary decision. While the main driver of the replacement of the SA Power Networks' billing system is to replace an aging system, we accept that key drivers of the additional capability of its proposed new system are changed regulatory requirements. As such we are satisfied that the forecast step up meets our definition of a step change.

However we have forecast the step up in opex should be slightly higher to what SA Power Networks proposed. The $3.6 million ($2014–15) step change was SA Power Networks' estimated net increase in opex if it implemented Option 2a in its business case. Under this option, SA Power Networks would operate and manage its new customer relationship management system itself.

Nous Group, which we engaged to review SA Power Networks' IT capex program, recommended SA Power Networks implement Option 2b in its business case.[259] This is a cloud based option whereby a third party would provide the customer relationship management system and SA Power Networks would subscribe to it. SA Power Networks forecast that implementing this option would require materially less capex than Option 2a but marginally more opex.[260]

To estimate the opex step change associated with this option, we requested SA Power Networks apply the same revisions it applied when re-estimating Option 2a for its revised proposal.[261] SA Power Networks estimated the additional step up in opex would be $4.0 million ($2014–15) by applying these changes.[262] The majority of the costs reflect the incremental costs of the actual licenses associated with the new system.[263] We are satisfied that this is a reasonable estimate of the additional costs of operating and maintaining its new customer billing system.

Mobile radio

Consistent with our preliminary decision, we have included a step change in our opex forecast for mobile radio costs.

Currently SA Power Networks owns and operates a state wide mobile radio communications network for the provision of voice communications between its network operations centre and its field staff. SA Power Networks has identified that due to the age of its network it is preferable to look at alternative solutions. Its preferred option is to migrate all users to the South Australian Government's Radio Network. The

258 SA Power Networks, *SAPN 064*, 25 September 2015, p. 1.
259 Nous Group, *Review of SA Power Networks ICT Expenditure 2015-20*, July 2015, p. 17.
260 Nous Group, *Review of SA Power Networks ICT Expenditure 2015-20*, July 2015, p. 17.
261 AER, *Information request SAPN 064*, 25 September 2015, p. 1.
262 SAPN, *BC01 Reconciliation All Options V.101.xlsx*, 25 September 2015.
263 SA Power Networks, *Revised proposal, Attachment G.21*, p. 8.

migration to the new network will occur in 2016–17.[264] SA Power Networks initially only proposed a step change in opex of $7.8 million. The residual expenditure was specified as capex. This included a once-off fee to access the network.

As outlined in our assessment approach we consider step-changes for efficient capex/opex trade-offs generally meet the opex criteria. On the basis of the confidential business case provided by SA Power Networks we accept that it would be a prudent and efficient business decision to migrate SA Power Networks' mobile radio users to the South Australian Government's Radio Network. We included SA Power Networks' proposed step change in our alternative opex forecast.

Our conclusion in the preliminary decision was based on all forecast expenditure on mobile radio costs. SA Power Networks considered the $5.0 million in capex should have been allocated as opex. Capex is incurred to acquire or create additional assets of a permanent nature or which increases the value, life or capacity of an existing asset.[265] As the forecast fee is part of the payment to access the service rather than to acquire or create a new asset, we agree with SA Power Networks that it should be classified as opex. As our initial assessment of this proposal was based on all proposed expenditure, then the reallocation of this fee to opex rather than capex does not affect our views on the prudency or efficiency of this proposal. We have therefore included the full $12.8 million ($2014–15) as a step change in our final decision opex forecast.

We note that ECCSA did not agree with our decision as it is not driven by external requirements.[266] While this is true, we consider the alternative option to what SA Power Networks proposed would be to invest in a capital solution which we expect would be higher cost in NPV terms. On this basis we consider its proposed step change reflects a prudent and efficient business decision.

Non network solution

We have not included a step change in our opex forecast for SA Power Networks' non network solution.

SA Power Networks initially proposed a base year adjustment for $1.3 million ($2014–15) for a non-network solution. Its step change in its revised proposal is consistent with its initial proposal.

SA Power Networks has previously implemented non-network solutions to reinforce supply in the Bordertown region. It signed a contract with a third party supplier which entails payments until 2021. Those network support payments increase annually based on the annual forecast demand at the time the contract was signed. Prior to implementing the solution, SA Power Networks (then ETSA utilities) went through a

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264 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 268.

265 SA Power Networks, *Accounting Practices and Guideline Manual*, April 2009, Section 3.1.1.

266 ECCSA submission, *Submission on AER preliminary decision*, p. 33.

public process (ESCoSA Guideline 12) to determine the most cost effective solution for addressing increased demand. It considered the ESCOSA process was similar to our RIT-D process.[267]

In our preliminary decision opex forecast, we did not include a step change for this proposal. Our position is not to forecast opex at the category level but at the total opex level.[268] We considered a step change for this particular proposal would be inconsistent with our broader opex forecasting approach.[269]

In its revised proposal, SA Power Networks considered that not to provide a step change would decrease confidence in the RIT-D process, and provide a disincentive for a service provider to seek demand management solutions.

We disagree with SA Power Networks that this should be a step change. In the future, SA Power Networks will face a more balanced incentive to implement non-network rather than network solutions. With the CESS in place, a service provider will receive a 30 per cent reward for any capex underspend in the 2015–20 regulatory control period, and a 30 per cent penalty for any capex overspend. This will lead to a higher marginal cost of incurring capex than it has previously faced. This will provide a stronger incentive for SA Power Networks to defer capex ─ including network augmentation. We are unclear how not providing an opex step change in this instance materially affects its incentives to undertake non-network solutions.

We also note SA Power Networks is forecasting a step change for non-network solution because it forecasts the contractual costs it has with the non-network provider will increase. We compensate SA Power Networks for forecast increases in the price of contracted services through the estimated rate of change in opex. The estimated rate of change is a global estimate of the forecast increase in opex we consider an efficient service provider would incur. While some contracted services may increase faster than the rate of change we forecast, some contracted services will increase at a slower rate, or may decrease. We are not confident that our forecast would reasonably reflect the opex criteria if we singled out one particular contract that will increase at a relatively higher rate.

Data quality

We have not included a step change in our opex forecast for data quality.

Consistent with its initial proposal, SA Power Networks proposed an increase in opex of $3.9 million ($2014–15) for improved data quality. This was for several different initiatives.

[267] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 269.

[268] AER, *Preliminary decision, Attachment 7*, p. 105.

[269] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 270.

We did not include this step change in our preliminary decision opex forecast. In its business case SA Power Networks noted that problems with data quality can lead to potentially incorrect decisions which may lead to increased maintenance costs and outages, and administrative overheads to correct the issue.[270] If the cost associated with data errors and correcting those errors is greater than cost associated with new data management systems designed to correct those errors, then we would expect SA Power Networks' opex should be lower as a result of its data quality program. As such we were not convinced that a higher opex forecast is needed.[271]

In its revised proposal, SA Power Networks considered it may not have accurately explained its data quality program in its initial proposal.

In support of its revised proposal it referred to a number of regulatory obligations which rely on adequate data quality:

- The Australian Energy Market Operator's (AEMO) Market Settlement and Transfer Solutions (MSATS) Procedures: Consumer Administration and Transfer Solution (CATS) procedures, principles and obligations. Specifically, Section 2.2(i) of those MSATS Procedures provides that 'CATS Participants must ensure, as required under specific obligations within the CATS Procedures, that all new and existing standing data in MSATS is kept current and relevant, for the National Metering Identifier (NMIs) they are responsible for'.[272]
- Under clause 90(1) of the National Energy Retail Rules (NERR), SA Power Networks must, as a DNSP, notify all affected customers of a planned interruption at least four days before the date of interruption.[273]
- Under clause 125 of the NERR it faces obligations regarding life support customers. It considered this highlights utmost importance of DNSPs having accurate customer information in order to contact and advise affected customers of planned interruptions.[274]

It also considered that governments are continuing to outline further obligations with respect to data quality. SA Power Networks referred to the ongoing AEMC power of choice program that has 'created a number of data quality issues that must be addressed'. It referred to an AEMO work program that seeks to address cleansing of NMI standing data and the review of the effectiveness of the MSATS procedures.[275]

As a result of all these drivers, SA Power Networks proposed to increase resourcing levels by 11 FTEs reducing to 7 FTEs in the latter half of the regulatory control period.

We see no reason to change our position on this step change.

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270 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 122, 123.

271 AER, *Preliminary decision, Attachment 7*, p. 96.

272 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 272.

273 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 272.

274 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 272.

275 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 273.

SA Power Networks has not addressed our criticisms of its initial proposal. SA Power Networks business case identifies efficiency gains that can be made by improving data quality. In its initial proposal, SA Power Networks stated:

> Thousands of notifications are now issued to customers each month to provide important information about the state of their power supply, either through bulk mail outs or SMS messaging. These notifications rely on the accuracy of postal addresses and phone numbers that SA Power Networks store for each customer. A single error or omission can result in a day of field work being cancelled and a complaint to manage from an unsatisfied customer. **These outcomes generate unnecessary costs and inefficiencies for the business that could be avoided if the data was accurate**.[276]

SA Power Networks has itself identified efficiencies that may arise from its data quality initiatives. If this is the case then we expect that the initiative may be able to fund itself. It is not clear why it needs a higher opex forecast.

We also note the regulatory obligations SA Power Networks referred to (MSATS, NERR) are existing regulatory obligations. A prudent service provider would already be compliant with its existing regulatory obligations. It would not need to seek more funding from its consumers to become compliant. While AEMO may be seeking to further improve NMI data quality, we are not aware that AEMO has imposed additional obligations on SA Power Networks. SA Power Networks did not provide any information in its revised proposals as to what these obligations might be. We see no reason why we should increase forecast opex when SA Power Networks has not articulated how it would be affected.

Finally, SA Power Networks considered improved data quality is important in delivering its customer service strategy.[277] We consider the initiatives a service provider carries out in delivering internal business strategies is a matter for it to consider when weighing up all the priorities it faces. As such, we are not convinced this is a reason to include a step change in our opex forecast either.

Vegetation management

We have not included any of SA Power Networks' proposed step changes for vegetation management in our alternative forecast of opex.

SA Power Networks initially proposed several step changes for vegetation management:

- In non-bushfire risk areas, SA Power Networks is required to inspect and clear vegetation at regular intervals which cannot exceed more than three years. SA Power Networks considered there is ongoing concern from Councils and communities, particularly in metropolitan areas, of clearances based on a three

276 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 118.

277 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 273.

year cutting cycle. It considered a shift to a shorter inspection and cutting cycle in metropolitan areas and rural townships would allow more frequent tree trimming to be undertaken in areas where high value is placed on street trees and visual amenity. It forecast increased opex of $13.5 million ($2014–15) to implement this program.[278]

- In both bushfire and non-bushfire risk areas, SA Power Networks proposed an increase in opex for a tree removal and replacement program to remove inappropriate, fast growing or large trees. It forecast increased opex of $9.2 million ($2014–15) in Bushfire Risk Areas (BFRAs) and $6.1 million ($2014–15) in Non Bushfire Risk Areas (NBFRAs).[279]
- SA Power Networks considered there is a need for it to consider alternative pruning techniques to improve the visual aesthetics, as well as the health, structure and growth rates of trees identified for clearance. To address these issues it proposed to engage a number of arborists at a cost of $1.9 million ($2014–15) to provide expert advice and input into tree trimming practices.[280]
- SA Power Networks proposed $1.2 million ($2014–15) for a communications plan targeted towards customers in council areas most affected by vegetation management activities. The plan will contain messages about what can and cannot be planted under powerlines, the rationale and detail of SA Power Networks' tree trimming practices.[281]

In our preliminary decision we did not include any step changes for vegetation management expenditure in our opex forecast. We outlined a range of different reasons for our position. For instance:

- We did not consider willingness to pay (WTP) research SA Power Networks submitted in support of its proposals provided persuasive evidence that consumers supported its vegetation management expenditure.
- The proposed change in the tree trimming cycle and tree removal and replacement programs appeared to be primarily aimed at addressing community concerns around the aesthetics of vegetation. We considered the amenity of SA Power Networks' tree trimming practices is a policy issue that goes beyond our remit. If SA Power Networks' practices which are required as part of its legislative obligations no longer reflects community expectations then this is something for the relevant legislators to consider. If local Councils were of the view that amenity needs to be addressed, then they can potentially enter into agreements with SA Power Networks to fund the additional services they require.
- For SA Power Networks' tree removal and replacement programs, it considered the programs were to address a safety and bushfire risk but SA Power Networks did

[278] SA Power Networks, *Initial proposal, Attachment 21.13*, pp. 145–149.
[279] SA Power Networks, *Initial proposal, Attachment 21.13*, pp. 150–160.
[280] SA Power Networks, *Initial proposal, Attachment 21.13*, pp. 161–165.
[281] SA Power Networks, *Initial proposal, Attachment 21.13*, pp. 166–171.

not provide evidence as to what these risks were. The expenditure was not related to a new or changed regulatory requirement.

SA Power Networks' revised proposal is mostly consistent with its initial proposal. The only change is an increase in the estimated cost of tree removal and replacement in BFRAs by $1.3 million ($2014–15). The initial estimate included cost savings relating to undergrounding of 135km of line in BFRAs. SA Power Networks did not propose undergrounding in BRFAs in its revised proposal so it removed the forecast cost savings it included in its initial proposal.

SA Power Networks disagreed with our preliminary position not to include this expenditure in our revised opex forecast. In particular it considered:

- we had reached inaccurate conclusions about the validity of its WTP research. In doing this it considered we had not adequately considered the consumer engagement factor in the NER.[282]
- it is not reasonable to wait until Councils are willing to enter into funding arrangements under the Electricity Act in relation to vegetation management. If that was the position taken by SA Power Networks, it considered that concerns in relation to visual amenity and safety aspects of vegetation management may never be addressed.[283]
- amenity is part of the quality of service that consumers receive. Therefore it did not agree the opex objectives did not refer to amenity. It considered that if consumers are willing and prepared to pay for a higher quality of service (such as amenity) then it is efficient.[284] By not including expenditure that is valued by consumers in our decision, it also considered we had not adequately considered allocative efficiency in assessing its proposal.[285]
- its proposed tree removal and replacement programs is required to maintain the safety, reliability, quality of electricity supply from its electricity distribution system.[286]

Reasons for final position

Consistent with our preliminary decision, we have not included a step change in our opex forecast for vegetation management.

In considering whether total opex is consistent with the opex criteria, we must consider whether forecast opex reasonably reflects the efficient costs a prudent operator would require to achieve the opex objectives.[287] One of the opex objectives is to comply with

282 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 278.
283 SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 278-279.
284 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 277.
285 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 229.
286 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 279.
287 NER, cl. 6.5.6(c)(1).

applicable regulatory obligations or requirements.[288] Therefore to be consistent with the opex criteria, forecast opex must reasonably reflect the efficient cost of complying with all regulatory obligations or requirements.

SA Power Networks is currently only required to trim trees at a minimum every three years in non-bushfire risk areas. Therefore its proposed step change to move from a three year trimming cycle to a two year trimming cycle would go beyond its regulatory obligations. It increases the cost of achieving its regulatory obligations. Similarly, SA Power Networks' tree removal and replacement programs are not mandatory requirements. SA Power Networks is therefore proposing to increase the expenditure beyond what is strictly required to comply with its regulatory obligations or requirements. We do not see any strong reason to include step changes in our opex forecast for these discretionary programs.

Our assessment of these proposals is outlined below.

Consideration of consumer engagement

SA Power Networks is relying to a large degree on its view that its willingness to pay study has demonstrated its consumers' preferences.

We do not agree with the weight SA Power Networks has placed on this study.

The survey conducted by The NTF Group aimed to determine what combination of price and network service improvements should be offered to residential SA Power Networks consumers. In the survey, 895 South Australian residents were presented with different pairs of service options, with an estimated impact on their quarterly bill.[289]

The network service options related to vegetation management as well as network undergrounding. In relation to vegetation management there were different options in bushfire risk areas and non-bushfire risk areas.

- In bushfire risk areas, residents were asked to express a willingness to pay for either 0%, 2.5%, 5%, 8% or 10% of trees that are removed or replaced.
- In non-bushfire risk areas, residents were asked to express a willingness to pay for
    - a tree removal or replacement program where 0%, 2.5% or 5% of trees are removed or replaced, and
    - a two year or three year cutting cycle.

In bushfire risk areas, 2.5% removal or replacement of trees received the most support amongst all options. In non-bushfire risk areas, 2.5% removal or replacement of trees combined with a two year trimming cycle received most support. SA Power Networks subsequently included each of these options as step changes in its proposal.

288 NER, cl. 6.5.6(a)(2).

289 The NTF Group, *Targeted Willingness to Pay Research Findings*, July 2014, p. 4.

We have not placed strong reliance on this study for several reasons.

First, the WTP survey is not the only source of information we must use in reaching a position on these proposals.

Electricity consumers do not pay for discrete initiatives such as tree replacement or removal or a tree trimming cycle. They pay for a range of different services. We determine the total amount of opex SA Power Networks can recover for all the services it provides to its consumers.

In taking consumer engagement into account, we must not only consider consumer feedback on discrete initiatives proposed by SA Power Networks but also a wide range of other information including consumer feedback we receive about SA Power Networks' proposal in consulting with consumers.

The findings of the WTP survey which suggested that consumers are willing to pay for additional vegetation management initiatives was in contrast with other stakeholder feedback we received on SA Power Networks' proposal. For instance:

- Many stakeholders have expressed concerns about SA Power Networks' proposed opex.[290]
- Several stakeholders including the South Australian Government and the Consumer Challenge Panel considered SA Power Networks should receive a *negative* step change for vegetation management expenditure.[291] These stakeholders noted the significant increase in SA Power Networks' vegetation management expenditure in the 2010–15 regulatory control period.
- SACOSS noted in its submission that the WTP survey was conducted in the first quarter of 2014 which was before SA Power Networks increased its tariffs for a cost-pass through for increased vegetation management expenditure.[292] The decision on the cost pass through was made on 30 July 2013 but did not affect tariffs of South Australian consumers until 1 July 2014. SACOSS queried whether SA Power Networks would have received the same response from consumers if the survey had been conducted after consumers were aware they would already face increased tariffs as a result of increased vegetation management expenditure.

Second, the WTP survey only provided survey respondents with limited information about the benefits of each option. As outlined in our preliminary decision, we commissioned Oakley Greenwood to review the NTF Group study. It found the decision made by consumers did not reflect informed choices given the limited

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290 Accolade Wines, *Submission on preliminary decision*, p. 5; CIT, *Submission on preliminary decision*, pp. 5-6; ECCSA, *Submission on preliminary decision*, pp. 29-31; CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal*, p. 107; SACOSS, *Submission on preliminary decision*, p. 2.

291 ECCSA, *Submission on preliminary decision*, p. 32; Government of South Australia, *Submission on preliminary decision,* p. 3; CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal,* p. 107.

292 SACOSS, *Submission on initial proposal*, p. 32.

information provided to consumers about the benefits of each of the options. For instance, Oakley Greenwood found that:

> In each case the customer can choose based on what they think of the bundle of service levels and the price, and in doing so they can express a preference for those service levels as compared to price. In this sense, the DCE approach will provide a preference function.
>
> However, the choice that is being provided is about inputs, not outcomes. Presumably, the objective of these service activities is to reduce the incidence of fires in bushfire risk areas. What is lacking is the likely relative reduction in fire risk that could reasonably be associated with each service bundle. **In effect, the respondent is being asked to choose between different cost levels without understanding what the benefit level is likely to be.**
>
> This problem also characterises the choice options posed concerning the number of traffic blackspots at which consumers would be willing to pay to underground electricity lines, and the frequency of tree trimming and the removal and replacement of inappropriate vegetation in relevant NBFRAs that consumers would be willing to pay for.
>
> In these cases, there is no relationship between the relative amounts of money paid and:
>
> - the likely reduction in traffic accidents and associated property damage and injury/death (in the case of the traffic blackspots), or
> - the risk of fires and unplanned outages resulting from trees contacting or bringing down powerlines.
>
> **In each of these cases, the consumer is being asked to make a choice on either a best guess or emotional basis. The analysis will provide a result, but it will not be the result of an informed choice**.[293]

Consistent with Oakley Greenwood's findings we do not see how consumers can make reasoned decisions between the value they receive from various vegetation management options if they have incomplete information about the likely benefits that would arise from such options.

In response to these concerns in the preliminary decision, the NTF Group acknowledged that the safety and reliability benefits were not quantified. It stated this was because SA Power Networks could not draw objective, verifiable links between the initiatives and the outcomes that could be achieved.[294]

While we agree that it would not be appropriate to draw links between initiatives and outcomes that could not be verified, this limits the conclusions one can draw from the

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[293] Oakley Greenwood, *Peer review of the willingness to pay research submitted by SA Power Networks,* April 2015, p. 6.

[294] The NTF Group, *Report on AER Discussion of Willingness to Pay Research*, July 2015, p. 5.

study. If survey respondents do not know what the likely benefits of the different vegetation management options are then they do not have full information when deciding whether they are willing to pay for such options. For instance, the survey asked consumers whether they were willing to pay for trees to be removed in bushfire risk areas. SA Power Networks considered this will improve visual amenity[295] as well as mitigate safety and bushfire risks[296]. It is not clear how a typical consumer could make an informed decision whether they are willing to pay for 2.5%, 5%, 8% or 10% of trees to be removed or replaced in bushfire risk areas without any information as to how any of those options contribute to reducing bushfire risk.

Lastly, the WTP survey was only aimed at measuring the willingness to pay of South Australian residential consumers.[297] It did not assess whether non-residential consumers would be willing to pay for increased vegetation management expenditure. Tariffs levied on non-residential customers provide approximately 50 per cent of SA Power Networks revenue.[298] Therefore the survey is not representative of SA Power Networks' entire customer base. We note that Business SA, South Australia's Chamber of Commerce and Industry and the Energy Users Association of Australia both expressed concern about the reliance SA Power Networks had placed on its WTP survey.[299]

Consideration of other funding arrangements

As outlined in our preliminary decision, there are other funding arrangements available to SA Power Networks if it wishes to carry out vegetation management expenditure that goes beyond its regulatory obligations. We do not consider it would be efficient for all of SA Power Networks' consumers to fund this expenditure when it is not clear SA Power Networks has fully explored all other funding options.

Under the *Electricity Act 1996* (SA) and *Electricity (Principles of Vegetation Clearance) Regulations 2010* (SA) there is already provision for local Councils to sign up to Vegetation Clearance Agreements with SA Power Networks in non-bushfire risk areas. These agreements may govern the way in which vegetation is kept clear of public powerlines on land (other than private land) within both the council's area and a prescribed area. These agreements may:

- require SA Power Networks to do more than what it currently does to inspect and clear vegetation
- may confer responsibility for vegetation management in relation to low voltage powerlines on Councils

295 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 151.

296 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 150.

297 The NTF Group, *Report on AER Discussion of Willingness to Pay Research*, July 2015, p. 5.

298 SAPN, Economic Benchmarking RIN 2013-14, Template 3.1.

299 Business SA, *Submission on preliminary decision*, p, 2; EUAA, *Submission on initial proposal*, pp. 16-17.

- provide for payments by the council to SA Power Networks or by SA Power Networks to the council.[300]

SA Power Networks acknowledged that other funding provisions exist but considered that Councils have limited resources to fund these initiatives.[301] The Local Government Association of South Australia also highlighted its resource constraints in its submission.[302]

We do not consider the possible resource constraints of local Councils to be a convincing reason why electricity consumers should fund this expenditure. If local Councils are unwilling to fund initiatives to enhance the beautification of their streets, then we are not convinced that this burden should fall on all electricity consumers instead. As noted by the CCP:

> Different local councils will have different priorities and if some councils want a higher standard of vegetation management in their region than is required to deliver a reliable, quality and safe electricity network and network services, then it is appropriate that that council contributes to this rather than put that burden on all electricity consumers in the state.[303]

If local Councils consider that a two year trimming cycle is preferable, but are unable to fund this change in practice directly, then we consider it would be preferable for them to raise this issue directly with the relevant legislator in South Australia. We determine the funding for service providers to efficiently achieve their regulatory obligations. We do not determine what those obligations should be. It is not for us to decide that an alternative minimum tree trimming requirement (such as a two year trimming cycle) is preferable.

Consideration of other drivers for of tree removal and replacement program

SA Power Networks has also outlined in its revised proposal that its tree removal and replacement programs are needed to address safety and fire risks. It outlines two areas where it considered this is the case.

- The accumulation of legacy trees that are now in, or are entering, senescence (i.e. over-mature and decaying), and the emergent cohort of 'problem' trees that has resulted, in significant part, from the trend in recent decades to plant trees, particularly near power lines.

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300 *Electricity Act 1996*, cl. 55A; *Electricity (Principles of Vegetation Clearance) Regulations 2010*, cl. 8.

301 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 278.

302 LGSAA submission, p. 3.

303 CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal*, p. 153.

- It considered there has been, and will continue to be, an increase in the scale of sapling emergence because of the uncommonly experienced 'pulse regeneration' event which has followed the 2010–11 record rainfall period.[304]

In response to an information request it provided a breakdown of how the forecast removal of legacy trees and saplings contributed to the forecast cost of the step change (table C.8).[305]

Table C.6 Tree removal and replacement step changes ($ million, 2014–15)

	BFRA	NBFRA
Removal - Legacy Trees	14.9	7.6
Removal - Saplings	1.7	0.8
Tree replacement	1.2	0.8
Reduced Cutting (and scoping)	(7.3)	(3.2)
Total	**10.5**	**6.1**

Source: SAPN, AER SAPN 049 Opex Step Changes.pdf, July 2015, p. 13.

As outlined above, the main contributor to the step change is the proposed removal of legacy trees. We acknowledge that as trees age, the risk of the tree falling (in part or whole) will increase. However, we fund SA Power Networks to maintain the safety and reliability and quality of supply. SA Power Networks has provided no evidence to demonstrate how the risks from legacy trees are expected to change over the 2015–20 regulatory control period. We are therefore not convinced it would need additional expenditure to manage these trees in the 2015–20 regulatory control period.

As there was heavy rainfall in 2010 and 2011, there is some explanation as to why there might be a greater number of sapling trees in South Australia.[306] However, it is still not clear from SA Power Networks' proposal what risks these trees present in the 2015–20 regulatory control period when compared to now. In any case, as indicated in Table C.6, the proposed increase in opex to remove these trees is relatively minor. Consistent with our approach to step changes discussed throughout this attachment, we are not convinced that an increase in one program of opex is a necessary reason to change our views on the total amount of opex we consider would reasonably reflect the opex criteria. Total opex is relatively recurrent so expected variation in opex at the program level is not a sufficient reason to provide a step change.

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304 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 279.

305 SA Power Networks, *AER SA Power Networks 049*, July 2015, p. 13.

306 GHD, *SA Power Networks - Vegetation Management Program Regulatory Proposal 2015-20*, June 2015.

Customer services and community education

We have not included a step change in our opex forecast for proposed customer service or community education initiatives.

SA Power Networks initially proposed a range of different customer service and community safety initiatives in its forecast:

- a program to educate customers on the electricity industry so they better understand who SA Power Networks are and what they do and how they benefit from changes in the industry ($1.7 million)[307]
- implementation of a tailored digital advertising strategy to support the launch and communication of new self-service options ($1.0 million)[308]
- a new customer service experience improvement team ($1.6 million)[309]
- a new summer time media campaign to better educate customers about bushfire dangers with respect to powerlines and outages ($2.6 million)[310]
- a new media campaign to educate customers about the dangers and implications of extreme weather outages and powerlines ($1.9 million)[311]
- a program that targets farmers and sailors with respect to the risks of coming in contact with powerlines ($0.9 million).[312]

We did not include any of these proposals in our preliminary decision opex forecast.

We considered that all of these proposed campaigns are discretionary activities. The number and type of communications campaigns that SA Power Networks runs is a matter for it to consider when weighing up all the priorities it faces. They are not matters for which we increase a service provider's funding.

In response to our preliminary decision, SA Power Networks maintained the same customer services and community education step changes. It considered that:

- it has a regulatory obligation under its SRMTRP to raise awareness about the role of SA Power Networks in the electricity industry to raise the public's awareness of risks that are inherent in the electricity industry. It considered it must undertake these initiatives to comply with its regulatory obligations.
- consumers have overwhelmingly indicated that they want more information about SA Power Networks and the service they provide and they value safety very highly

307 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 166.
308 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 172.
309 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 182.
310 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 189.
311 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 195.
312 SA Power Networks, *Initial proposal, Attachment 21.13*, p. 200.

> They want SA Power Networks to undertake additional steps and programs of work to ensure ongoing community safety.[313]

We have not changed our position since the preliminary decision.

Section 3.19 of SA Power Networks' SRMTRP provides an indication of some of the areas which SA Power Networks provides information to the public to raise awareness. It states that 'SA Power Networks responds as the need arises to many other needs or perceived needs'.[314] As noted in our assessment of the no access poles step change, the SRMTRP does not impose specific requirements on SA Power Networks.

As there is no specific change in requirement about what SA Power Networks must do in raising public awareness, we consider it is for it to decide how to prioritise this within its existing level of funding. As noted above, we do not approve funding for projects and programs. To the extent that SA Power Networks needs to alter its mix of opex to address changing priorities, then this is for it to consider by weighing up all the priorities it faces. A network service provider carries out a range of different discretionary projects and programs every year. We do not see why these programs and projects should be treated differently.

We have also considered SA Power Networks' consumer engagement but we are not convinced there is a need to increase its funding as a result of its proposed customer service and community safety initiatives. As set out in our preliminary decision, where there is no regulatory obligation, we determine the efficient opex to meet or managed expected demand and maintain the reliability, safety and quality of supply of the service.[315] Without robust evidence about why a service provider needs more funding to achieve unchanged objectives then we do not provide a step change. We consider informing and educating customers to be business as usual expenses. In our view, SA Power Networks has not demonstrated why it needs increased funding for any of these programs. We see no reason why the total opex SA Power Networks incurs would need to increase for these initiatives.

While we note that SA Power Networks has used its consumer engagement program to justify these initiatives, we do not consider there is evidence that the consumer engagement it undertook does support these initiatives.

The findings of the engagement which SA Power Networks used to support its proposals were general, high level observations about what it considered its customers want. For instance, in support of its customer driven and community safety initiatives SA Power Networks states that its customer engagement has shown that: [316]

> customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;

[313] SA Power Networks, *Revised regulatory proposal*, July 2015, pp. 286-87.

[314] SA Power Networks, *SRMTRP*, August 2014, Section 3.19

[315] AER, *Preliminary decision, Attachment 7*, p. 103.

[316] SA Power Networks, *Initial proposal, Attachment 21.13*, October 2014, p. 172-173; 189.

customers have made it clear that they are not all the same and while there is a basic common service they do have differing needs and expectations for other services;

customers want more choice in how they interact with us;

61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them

customers clearly expressed a need for education on new technologies and changes to the industry;

raising community awareness through engagement, education and partnerships is essential.

customers rated the top three community safety and reliability initiatives as:

- inspecting, maintaining and upgrading the network;
- bushfire prevention activities; and
- hardening the network against lightning and storms;

customers strongly supported initiatives that would result in the prevention of bushfires, safety hazards and provide valued support for the community in emergency situations;

As outlined above, the findings are very broad and there is no clear link between the views expressed in engagement and the initiatives SA Power Networks proposed. Other than SA Power Networks' vegetation management program, (addressed above) consumers were not asked to express a preference on the specific initiatives SA Power Networks proposed.

SA Power Networks' consumer engagement program was predominantly focused on seeking its consumers input about the view about the services they value and not the price they are prepared to pay for these services. Throughout our engagement as part of this process, many consumers highlighted recent increases in electricity network prices in South Australia as a concern.[317] In light of these concerns we are not

317 AlmondCo Australia, Submission on preliminary decision; Angove Family Winemakers, Submission on preliminary decision; Australian Olive Association, Submission on revised proposal; Berri Resort Hotel submission; Business SA submission, p. 1; Central Irrigation Trust submission, Submission on revised proposal; Century Orchards Irrigation Trust, Submission on revised proposal; Knispel Brothers, Submission on revised proposal; Lowana Fruits, Submission on preliminary decision; M&N Cerrachi Family Trust, Submission on preliminary decision; Olga Black, Submission on preliminary decision; Omega Orchards, Submission on preliminary decision; Riverland Energy Association, Submission on preliminary decision; Renmark Irrigation Trust, Submission on preliminary decision; SACOSS, Submission on preliminary decision, p. 1; SA Financial Counsellors Association, Submission on preliminary decision; TGP Almonds, Submission on preliminary decision; The Better Drinks Co. Submission on preliminary decision; TWG Australia, Submission on preliminary decision. (All submissions received in July 2015 and available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020.

confident that increasing the revenue SA Power Networks can recover from its consumers to deliver these specific initiatives would necessarily reflect its consumers' views.

Our preliminary position on these step changes was supported by the CCP. It agreed that SA Power Networks should not be funded for a discretionary business decision, and found that information available from SA Power Networks and other sources to be sufficient.[318] It also recommended that SA Power Networks work with the South Australian Government and the Country Fire Service to explain risks during bushfires, rather than take a unilateral approach.[319]

318 CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal,* p. 146.

319 CCP, *Submission on AER preliminary decision and SA Power Networks revised proposal,* p. 146.