



**PRELIMINARY DECISION  
SA Power Networks  
determination 2015–16 to  
2019–20**

**Attachment 7 – Operating  
expenditure**

April 2015

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## Note

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

The preliminary 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

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## Shortened forms

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

Shortened form	Extended form
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 Preliminary decision

We are not satisfied that SA Power Networks' forecast opex reasonably reflects the opex criteria.<sup>1</sup> We therefore do not accept the forecast opex SA Power Networks included in its building block proposal.<sup>2</sup> Our alternative estimate of SA Power Networks' opex for the 2015–20 period, which we consider reasonably reflects the opex criteria, is outlined in Table 7.1.<sup>3</sup>

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

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' proposal	280.9	293.8	310.5	318.8	323.1	1527.2
AER draft decision	240.5	243.0	245.1	247.4	249.7	1225.8
Difference	-40.4	-50.8	-65.4	-71.4	-73.4	-301.3

Source: AER analysis.

Note: Excludes debt raising costs.

Figure 7.1 shows our preliminary decision compared to SA Power Networks' proposal, its past allowances and past actual expenditure.

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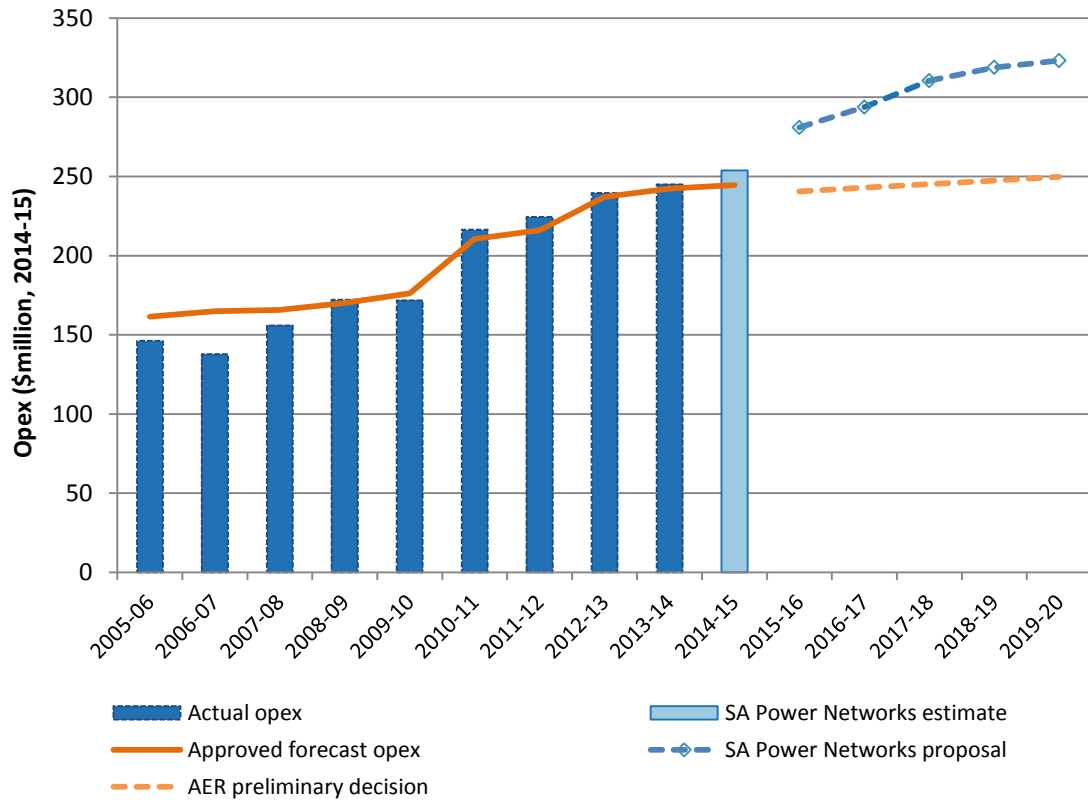
<sup>1</sup> NER, clause 6.5.6(c).

<sup>2</sup> NER, clause 6.5.6(d).

<sup>3</sup> NER, clause 6.12.1(4)(ii).



**Figure 7.1 Our preliminary decision compared to SA Power Networks' past and proposed opex (\$ million, 2014–15)**

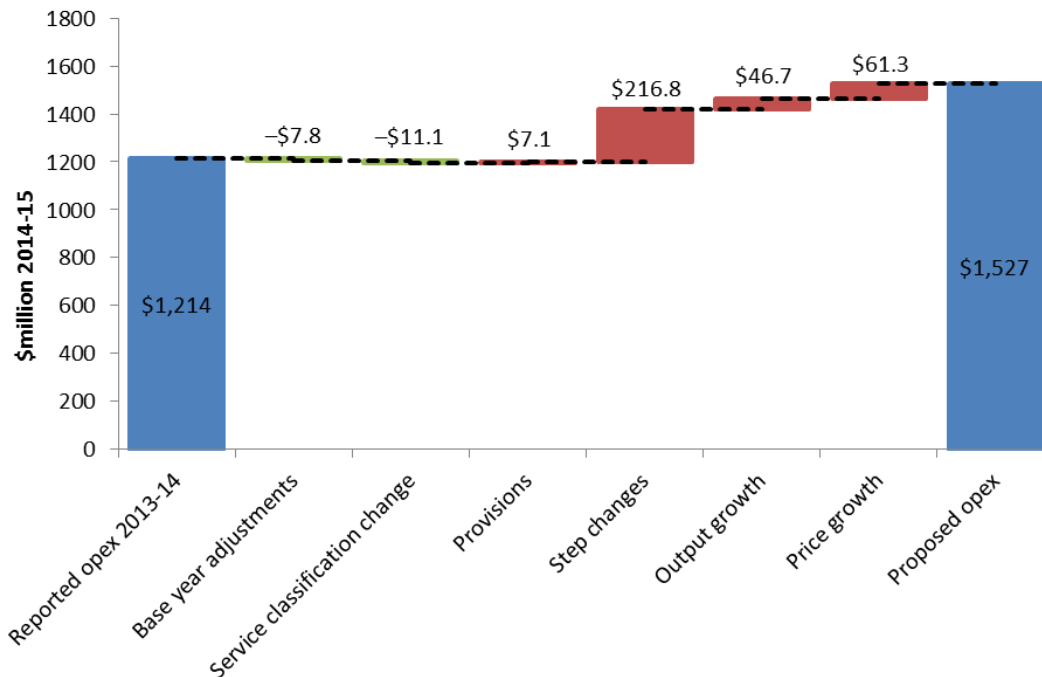


Source: SA Power Networks, Regulatory accounts 2010–11 to 2013–14; SA Power Networks, Economic benchmarking - Regulatory Information Notice response 2005–06 to 2012–13; SA Power Networks, Regulatory proposal for the 2015–20 period - Attachment 211.11a PUBLIC; AER analysis.

## 7.2 SA Power Networks' proposal

SA Power Networks proposed total forecast opex of \$1527 million (\$2014–15) for the 2015–20 period (excluding debt raising costs, totalling \$27 million). In Figure 7.2 we separate SA Power Networks' forecast opex into the different elements that make up its forecast.

**Figure 7.2 SA Power Networks' opex forecast (\$ million, 2013–14)**



Source: AER analysis.

We describe each of these elements below:

- 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. Its reported expenditure for 2013–14 would lead to base opex of \$1214 million (\$2014–15) over the 2015–20 regulatory control period.
- SA Power Networks adjusted its base opex downward to reflect that some costs in 2013–14 were higher than average, for example, costs associated with preparing a regulatory proposal. Upward adjustments were also made for ongoing costs that commenced during the 2013–14 base year and therefore were not fully accounted for. The net adjustment reduces SA Power Networks' forecast by \$7.8 million (\$2014–15).
- SA Power Networks also adjusted its base opex to remove opex on metering services. These services have been reclassified as alternative control services so need to be removed from SA Power Networks' standard control services opex. This reduced SA Power Networks' forecast by \$11.1 million (\$2014–15).
- SA Power Networks 2013–14 regulatory accounts include one-off accounting adjustments relating to provision changes. It adjusted base opex to remove the negative movement in provisions in 2013–14. The effect of this is to set the net forecast expenditure in this cost category to zero. This increased SA Power Networks' forecast by \$7.1 million (\$2014–15).
- SA Power Networks identified step changes in costs it forecast to incur during the forecast period, which were not incurred in 2013–14. These costs broadly related

to changes in regulatory and legal obligations, operating costs arising from capital program impacts, and delivering on customer expectations identified during its customer engagement program. This increased SA Power Networks' forecast by \$216.8 million (\$2014–15).

- SA Power Networks proposed network growth, customer growth and workforce size as output drivers in its opex forecast. Forecast increases in these drivers increased SA Power Networks' opex forecast by \$46.7 million (\$2014–15).
- SA Power Networks accounted for forecast changes in prices related to labour price increases, contracted service price increases, materials and land price increases. These forecast price changes increased SA Power Networks' opex forecast by \$61.3 million (\$2014–15).

### 7.3 AER's assessment approach

We decide whether or not to accept the service provider's total forecast opex. We accept the service provider's forecast if we are satisfied that it reasonably reflects the opex criteria.<sup>4</sup> If we are not satisfied, we replace it with a total forecast of opex that we are satisfied does reasonably reflect the opex criteria.<sup>5</sup>

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:<sup>6</sup>

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

The service provider's forecast is intended to cover the expenditure that will be needed to achieve the operating expenditure objectives. These objectives are:<sup>7</sup>

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

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<sup>4</sup> NER, clause 6.5.6(c).

<sup>5</sup> NER, clause 6.5.6(d).

<sup>6</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. vii.

<sup>7</sup> NER, clause 6.5.6(a).

We assess the proposed total forecast opex against the opex criteria set out in the NER. The opex criteria provide that the total forecast must reasonably reflect:<sup>8</sup>

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]'.<sup>9</sup>

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.<sup>10</sup> We attach different weight to different factors when making our decision to best achieve the National Electricity Objective. This approach has been summarised by the AEMC as follows:<sup>11</sup>

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 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
- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure

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<sup>8</sup> NER, clause 6.5.6(c).

<sup>9</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113.

<sup>10</sup> NER, clause 6.5.6(e).

<sup>11</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

- 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 Revenue Proposal under clause 6.10.3, is an operating expenditure factor.

For this determination, there are two additional operating expenditure factors that we will take 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 our 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.<sup>12</sup>

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.

More broadly, we also note in exercising our discretion, we take into account the revenue and pricing principles which are set out in the National Electricity Law.<sup>13</sup>

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<sup>12</sup> This is consistent with the approach we outlined in the explanatory statement to our Expenditure Forecast Assessment Guideline. See, for example, p. 131.

<sup>13</sup> NEL, s. 16(2); s. 7A.

## *The Expenditure Forecast Assessment Guideline*

After conducting an extensive consultation process with service providers, users, consumers and other interested stakeholders we issued an Expenditure Forecast Assessment Guideline (our Guideline) in November 2013 together with an explanatory statement.<sup>14</sup> Our Guideline sets out our intended approach to assessing operating expenditure in accordance with the NER.<sup>15</sup>

We may depart from the approach set out in our Guideline but if we do so we give reasons for doing so. In this determination we have not departed from the approach set out in our Guideline. In our Framework and Approach paper for each service provider, we set out our intention to apply our guideline approach in making this determination.

Our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves.<sup>16</sup> By doing this we form a view on whether we are satisfied that the service provider's proposed total forecast opex reasonably reflects the criteria. If we conclude the proposal does not reasonably reflect the opex criteria, we use our estimate as a substitute forecast. 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:<sup>17</sup>

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.

Our estimate is unlikely to exactly match the service provider's forecast because the service provider may not adopt the same forecasting method. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate.

If a service provider's total forecast opex is materially different to our estimate and there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not reasonably reflect the opex criteria. Conversely, if our estimate demonstrates that the service provider's forecast reasonably reflects the expenditure criteria, we will accept the forecast.<sup>18</sup> Whether or not we accept a service provider's forecast, we will provide the reasons for our decision.<sup>19</sup>

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<sup>14</sup> AER, *Expenditure forecasting assessment guideline - explanatory statement*, November 2013.

<sup>15</sup> NER, clause 6.5.6.

<sup>16</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

<sup>17</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

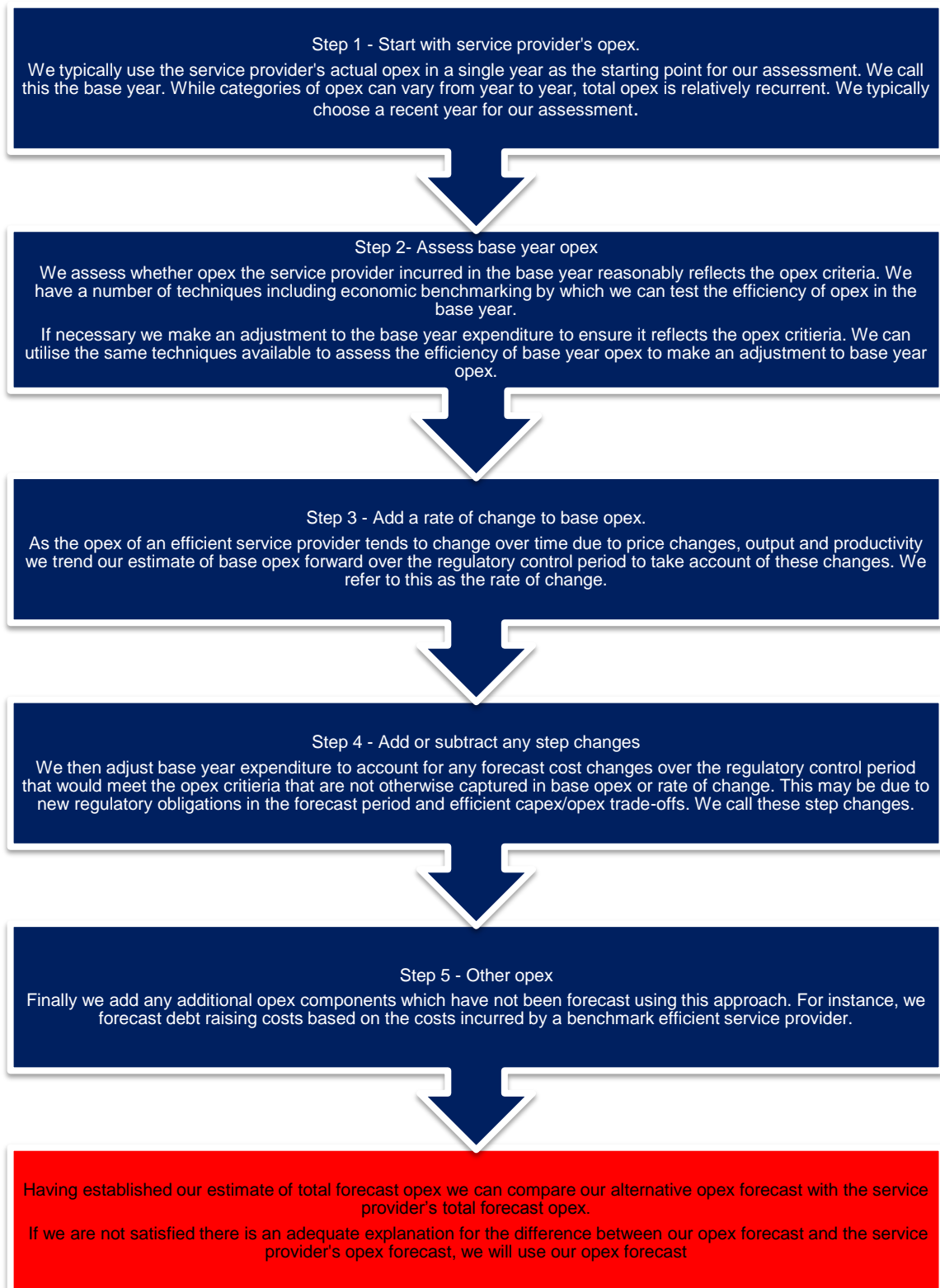
<sup>18</sup> NER, clause 6.5.6(c).

<sup>19</sup> NER, clause 6.12.1(3)(ii).

### ***Building an alternative estimate of total forecast opex***

Our approach to forming an alternative estimate of opex involves five key steps which we outline below Figure 7.3.

**Figure 7.3 Our assessment approach**





Underlying our approach are two general assumptions:

- the efficiency criterion and the prudence criterion in the NER are complementary
- actual expenditure was sufficient to achieve the expenditure 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 our Guideline (and we have sometimes referred to it as the base-step-trend method in our past regulatory decisions).

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 expenditure 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 the benchmark efficient costs of providing opex.

We have set out more detail about each of the steps we follow in constructing our forecast below.

### ***Step 1—Starting point—base year expenditure***

We prefer 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, we have 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, we penalise the service provider when it is relatively less efficient. This gives us 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.

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 remove it from the base year in undertaking our assessment. For instance, for this draft decision we removed metering and

ancillary network services which will be reclassified as alternative control services in the 2015–20 regulatory control period.

- Rather than use all opex 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 these reductions 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 year 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 year expenditure***

Regardless of the base year we choose, the service provider's actual expenditure may not reflect 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 test whether actual expenditure in that year should be used to forecast efficient opex in the next regulatory control period.

As we set out in our Guideline, to assess the efficiency of a service provider's actual expenditure, we use a number of different techniques.<sup>20</sup> For instance, we may undertake a detailed review of a service provider's actual opex.

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:<sup>21</sup>

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.

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

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<sup>20</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

<sup>21</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 97.

Total Factor Productivity, Partial Factor Productivity and several opex cost function models to assess SA Power Networks' efficiency.<sup>22</sup>

We also have regard to trends in total opex and category specific data to construct category benchmarks. We have used this information to inform our assessment of the efficiency of base year expenditure. In particular, we can use this category analysis data to diagnose potential sources of inefficiency. It may also lend support to, or identify potential inconsistencies with, our broader benchmark modelling.

If we determine that a service provider's base year expenditure does not reasonably reflect the opex criteria, we will not use it as our starting point for our estimate of total forecast opex. Rather, we will adjust it so it reflects an efficient, recurrent level of opex that does reflect the opex criteria. To arrive at an adjustment, we use the same techniques we used to assess the service provider's efficiency.

### ***Step 3—Rate of change***

Once we have chosen an efficient starting point, we apply an annual escalator to take account of the likely ongoing changes to efficient opex over the forecast regulatory control period. Efficient opex in the forecast regulatory control period could reasonably differ from the efficient starting point due to changes in:

- prices
- outputs
- productivity.

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***

We then consider if there is other opex needed 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 our Guideline explains, we will typically compensate a service provider for step changes only if efficient base year opex and the rate of change in opex of an efficient service provider do not already compensate for the proposed costs.<sup>23</sup>

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

In our final step, we make any further adjustments we need for our opex forecast to achieve the opex objectives. For instance, our approach is to forecast debt raising

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<sup>22</sup> The benchmarking models are discussed in detail in Appendix A, which details our assessment of base opex.

<sup>23</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

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 total opex forecast.

### ***Comparing the service provider's proposal with our estimate***

Having established our estimate of total forecast opex we can test the service provider's proposed total forecast opex. This includes comparing our alternative total with the service provider's total forecast opex. However, we also assess whether the service provider's forecasting method, assumptions, inputs and models are reasonable, and assess the service provider's explanation of how that method results in a prudent and efficient forecast.

The service provider may be able to adequately explain any apparent differences between its forecast and our estimate. We can only determine this on a case by case basis using our judgment.

This approach is supported by the AEMC's decision when implementing the changes to the NER in November 2012. The Commission stated:<sup>24</sup>

the AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

If we are not satisfied there is an adequate explanation for the difference between our opex forecast and the service provider's opex forecast, we will use our opex forecast in determining a service provider's total revenue requirement.

## **7.4 Reasons for our preliminary decision**

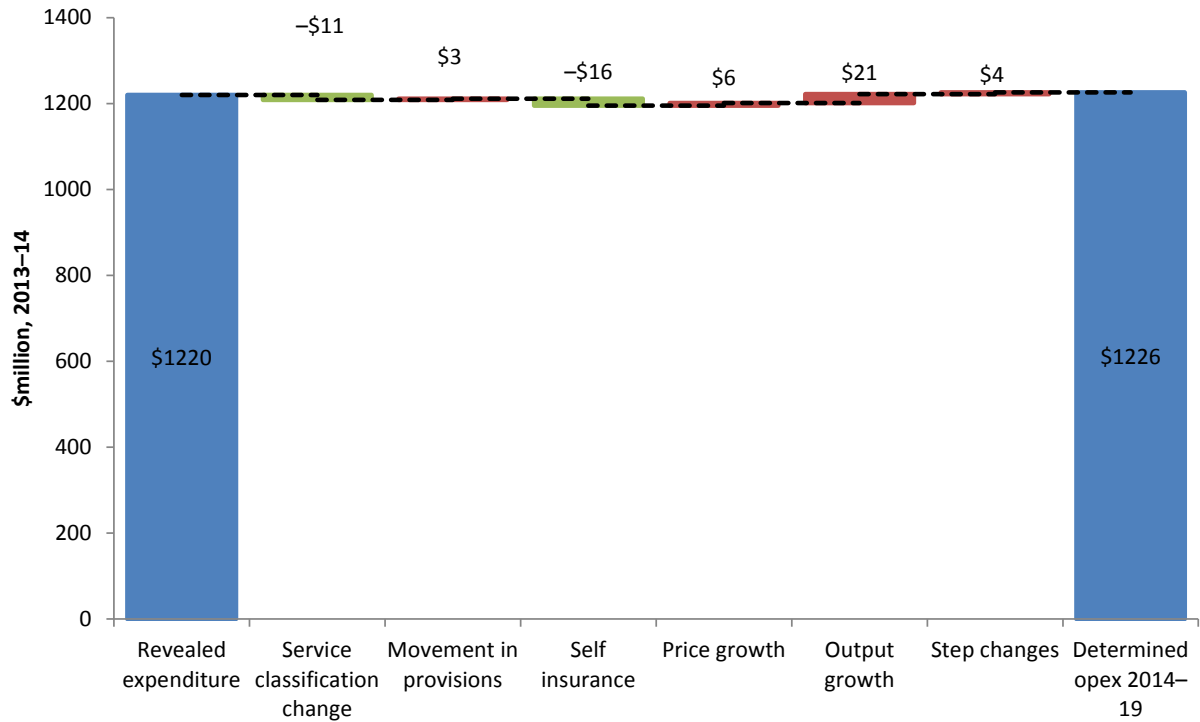
We are not satisfied SA Power Networks' total forecast opex reasonably reflects the opex criteria. We compared SA Power Networks' opex forecast to an opex forecast we constructed using the method outlined above. Our estimate is of the efficient opex a prudent operator would require to achieve the opex objectives. SA Power Networks' proposal is higher than ours and we are satisfied that it does not reasonably reflect the opex criteria. For this reason, we have substituted SA Power Networks' total opex forecast with our total opex forecast.

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<sup>24</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

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 preliminary decision opex forecast**



Source: AER analysis

Table 7.2 summarises the quantum of the difference between SA Power Networks' proposed total opex and our preliminary decision estimate.

**Table 7.2 Proposed vs preliminary decision total forecast opex (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
SA Power Networks' proposal	280.9	293.8	310.5	318.8	323.1	<b>1527.2</b>
AER draft decision	240.5	243.0	245.1	247.4	249.7	1225.8
Difference	-40.4	-50.8	-65.4	-71.4	-73.4	-301.3

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 Forecasting method assessment

As noted above, our estimate of total opex is unlikely to exactly match SA Power Networks' forecast. Broadly, differences between the two forecasts can be explained by differences in the forecasting methods adopted and the inputs and assumptions used to apply the method. We have reviewed SA Power Networks' forecast method and found only minor differences between its method and our own. We found these minor differences did not explain why SA Power Networks' forecast opex is higher than our own estimate.

## 7.4.2 Base opex

We tested the efficiency of SA Power Networks' base opex in 2013–14 using a number of different techniques. We are satisfied it represents opex incurred by an efficient and prudent service provider. The techniques we used to test the efficiency of SA Power Networks' opex are outlined in Table 7.3. All evidence suggests SA Power Networks' actual opex does not appear to be materially inefficient.

**Table 7.3 Assessment of the efficiency of SA Power Networks' opex**

Technique	Description of technique	Findings
	Economic benchmarking measures the efficiency of a service provider in the use of its inputs to produce outputs.	Our benchmarking across the 2006–13 period indicates that SA Power Networks performs well against its peers.
Economic benchmarking	The economic benchmarking techniques we used to test SA Power Networks' efficiency included Multilateral Total Factor Productivity, Multilateral Partial Factor Productivity and opex cost function modelling. We compared SA Power Networks' efficiency to other service providers in the NEM.	Over the benchmarking period we have observed that SA Power Networks' operating expenditures have increased significantly, however we observed a decrease in opex productivity across almost all other service providers.

Source: AER analysis.

Following examination of the quantitative and qualitative evidence, we do not consider it is appropriate to adjust SA Power Networks' base year opex.

We outline our assessment of SA Power Networks' base opex in appendix A.

## 7.4.3 Rate of change

The efficient level of expenditure required by the services providers 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 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.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than SA Power Network's over the forecast period. Table 7.4 below compares SA Power Network's and our overall rate of change in percentage terms for the 2015–20 regulatory control period.

**Table 7.4 Forecast annual rate of change in opex (per cent)**

	2015–16	2016–17	2017–18	2018–19	2019–20
SA Power Networks	2.14	2.40	2.66	2.76	2.89
AER	0.50	0.82	0.83	0.89	0.92
Difference	-1.64	-1.59	-1.84	-1.87	-1.98

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 its existing enterprise agreement for 2015–16 and 2016–17, then used Frontier Economics' recommended extrapolation of 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. SA Power Network's labour price growth methodology, which is on average 1.52 per cent above CPI, did not take into account the decline in productivity as a result of SA Power Network's forecast price growth. We would expect SA Power Networks to also forecast productivity growth to offset some of its forecast price increases. Our methodology has taken into account the interaction between price growth and productivity growth.
- SA Power Networks proposed different output growth drivers to ours. SA Power Networks' output growth drivers include network growth, customer growth and workforce size. SA Power Networks forecast using historical growth rates rather than using its forecasts from its reset RIN. We forecast a lower output growth, using the same output growth measures and weightings as used in Economic Insight's economic benchmarking report and using data from SA Power Networks' reset RIN.<sup>25</sup> We consider our approach is preferred because it takes into account SA Power Networks' actual forecasts of output growth for the 2015–20 regulatory control period rather than an extrapolation of historical growth rates.

The differences in each forecast rate of change component are:

- our forecast of price growth is on average 1.30 percentage points lower than SA Power Networks' forecast
- our forecast of output growth is on average 0.47 percentage points lower than SA Power Networks' forecast
- our forecast of productivity growth is the same as SA Power Networks'

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

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<sup>25</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 40–41.

## 7.4.4 Step changes

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

- National Energy Customer Framework
- mobile radio costs
- forecast changes to SA Power Networks' distribution licence fee

We are not satisfied that other cost changes SA Power Networks identified require a change to an efficient base level of opex, escalated by the forecast rate of change. A summary of the revenue impact from SA Power Networks' proposed step changes, and those we accept, are outlined in Table 7.5.

**Table 7.5 Forecast step changes (\$ million, 2014–15)**

	SA Power Networks proposal	AER position
Legal and regulatory	105.0	1.3
Capital program impacts	69.6	7.8
Customer driven initiatives	41.6	–
Financing related matters	0.6	–
<b>Total</b>	<b>216.8</b>	<b>9.1*</b>

Source: AER analysis

\* This does not include forecast changes to SA Power Networks' distribution licence fee which we included as a negative step change of –\$5.0 million. SAPN did not label this as a step change.

There were several common reasons why we consider additional step changes in opex are not needed. We outline these below.

### ***Base opex already reflects the cost of meeting existing regulatory obligations and service standards***

SA Power Networks' proposed step changes represent 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 drive this increase.

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



### ***Several proposed step changes are for initiatives designed to achieve efficiencies***

SA Power Networks has proposed a number of different step changes in opex where it considers the program or projects will generate efficiencies. We have not included these programs or projects in our alternative opex forecast.

SA Power Networks is subject to 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 received a reward through the incentive schemes.

### ***We could find little evidence of changes in SA Power Networks' regulations or requirements***

SA Power Networks quoted a variety of regulations and laws in its proposal. However, we could find little evidence that the regulation 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 have outlined our detailed assessment of step changes in Appendix C.

## **7.4.5 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.

## **7.4.6 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 the assessing 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.

### 7.4.7 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.<sup>26</sup> Table 7.6 summarises how we have taken the opex factors into account in making our preliminary decision.

**Table 7.6 AER consideration of opex factors**

Opex factor	Consideration
<p>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.</p>	<p>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.</p> <p>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.</p> <p>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.</p>
<p>The actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods.</p>	<p>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.</p>
<p>The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution</p>	<p>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</p>

<sup>26</sup> NER, clause 6.5.6(e).

Opex factor	Consideration
Network Service Provider in the course of its engagement with electricity consumers.	<p>regulatory proposals, such that they factor in the needs of consumers.<sup>27</sup></p> <p>We have considered the concerns of electricity consumers as identified by SA Power Networks— particularly in considering SA Power Networks' proposed step changes.</p>
The relative prices of capital and operating inputs	<p>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-offs. We considered the relative expense of capex and opex solutions in considering this step change.</p> <p>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.</p>
The substitution possibilities between operating and capital expenditure.	<p>As noted above we considered capex/opex trade-offs in considering step change for SA Power Networks' mobile radio costs. We considered the substitution possibilities in considering this step change.</p> <p>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.</p> <p>In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs.</p> <p>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.</p> <p>Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.</p>
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.	<p>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.</p> <p>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.</p>
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total

<sup>27</sup> AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

Opex factor	Consideration
Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	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 appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our preliminary 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 preliminary 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.<sup>28</sup> Table 7.7 identifies these factors.

**Table 7.7 Other factors we have had regard to**

Opex factor	Consideration
<p>Our benchmarking data sets, including, but not necessarily limited to:</p> <ul style="list-style-type: none"> <li>• data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN</li> <li>• any relevant data from international sources</li> <li>• data sets that support econometric modelling and other assessment techniques consistent with the approach set out in our Guideline</li> </ul> <p>as updated from time to time.</p>	<p>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.</p>
<p>Economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.</p>	<p>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.</p>

<sup>28</sup> NER, clause 6.5.6(e)(12).

## A Base opex

We consider that SA Power Networks' base opex is an appropriate starting point for our revealed cost opex forecast as SA Power Networks' base year opex does not appear materially inefficient. We have come to this conclusion based upon the results of our benchmarking analysis and having reviewed SA Power Networks' regulatory proposal and submissions.

Under our overall benchmarking SA Power Networks appears to be amongst the more efficient service providers. SA Power Networks has also provided benchmarking analysis which it considers demonstrates that it is efficient.<sup>29</sup> The results of our overall benchmarking are comparable with SA Power Networks' benchmarking.

However, SA Power Networks' efficiency appears to have declined across the period due to increases in its operating expenditure. This is evident in our opex MPFP analysis. SA Power Networks considers that the decline in performance is attributable to changes in operating environment factors over the benchmarking period. Notwithstanding this, we have decided that SA Power Networks' base opex is not materially inefficient because:

- SA Power Networks is still amongst the more efficient networks in the NEM at the end of the period and
- the decline in the measured productivity is not unique to SA Power Networks.

### A.1 Benchmarking results

In this section we set out in greater detail our analysis of the overall benchmarking techniques we have used to test to see whether SA Power Networks' base year opex is efficient. The techniques, developed by our consultant Economic Insights, measure either the overall efficiency of service providers or how efficiently they use opex in particular. They are:

- multilateral total factor productivity (MTFP) – is an index that measures the ratio of inputs used for output delivered
- opex multilateral partial factor productivity (MPFP), which is an index-based technique that measures the ratio of output quantity index to opex input quantity index.<sup>30</sup>

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<sup>29</sup> SA Power Networks, Regulatory Proposal 2015–20, 2014, p. 13.

Huegin Consulting, The Australian Energy Regulator's new approach to benchmarking, An indication of how SA Power Networks will benchmark against other DNSPs within the National Electricity Market, September 2014, p. 14. (Hue)

<sup>30</sup> At the time of developing the Expenditure forecast assessment guideline, we had not received data from service providers so we considered data envelopment analysis (DEA) may be another technique we could apply. However, we have been able to apply stochastic frontier analysis. This is a superior technique to DEA. Economic Insights, 2014, p. 7.

- econometric modelling techniques:
  - Cobb Douglas stochastic frontier analysis (SFA)—this estimates the efficient level of opex required for a service provider by constructing an efficient frontier and compares this to the actual opex used by the service provider
  - Cobb Douglas least squares estimation—is similar to the above in modelling opex cost function but uses least squares estimation method to estimate an industry-average technology, and include dummy variables for Australian DNSPs to capture firm-specific efficiency
  - Translog least squares estimation—this is similar to the Cobb Douglas least squares estimation technique but assumes more flexible functional form regarding the relationship between opex and outputs.

Each benchmarking technique compares the relative efficiency of service providers to its peers. They may differ in terms of estimation method or model specification and accounting for operating environment factors (factors that may differentiate service providers) to differing degrees. Despite this, Economic Insights found.<sup>31</sup>

The efficiency scores across the three econometric models are relatively close to each other for each DNSP and they are, in turn, relatively close to the corresponding MPFP score. This similarity in results despite the differing methods used and datasets used reinforces our confidence in the results.

We also consider partial performance indicators benchmarking in our annual benchmarking report. The partial performance indicators are a simpler form of benchmarking.

### **A.1.1 MTFP and MPFP findings**

Economic Insights' MTFP and MPFP modelling indicates that SA Power Networks is efficient overall and also in the use of its opex.

#### ***Methodology***

Multilateral total factor productivity allows for the comparison of productivity levels between service providers and across time. Productivity is a measure of the quantity of output produced from the use of a given quantity of inputs. When there is scope to improve productivity, this implies there is productive inefficiency.

In this section we consider the MTFP and total factor productivity MPFP indexes developed by Economic Insights. MTFP measures total output relative to an index of all inputs used. MPFP measures total output relative to one particular input (e.g. opex partial productivity is the ratio of total output quantity index to an index of opex quantity).

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<sup>31</sup> Economic Insights, 2014, pp. 46–47.

For further detail on MTFP and index number benchmarking approaches we direct readers to our previous publications.<sup>32</sup>

We note that there has been debate regarding our use of benchmarking in our determinations for the ACT, NSW and Queensland service providers. The ACT, NSW and Queensland service providers have made a number of submissions on our use of benchmarking in the NSW and ACT distribution determinations. We have considered these submissions and have concluded that the benchmarking we have relied upon is appropriate. We have published these submissions along with our consideration of them on our website.<sup>33</sup>

## **Results**

Figure A.1 presents the relative efficiency of the service providers. A score of 100 per cent indicates that the service provider is 100 per cent efficient (they are producing the highest ratio of outputs to inputs). A score of 50 per cent indicates that a service provider is half as efficient as the frontier networks and can reach the frontier by halving its inputs.

The MTFP results indicate that, on average SA Power Networks is amongst the more productive.

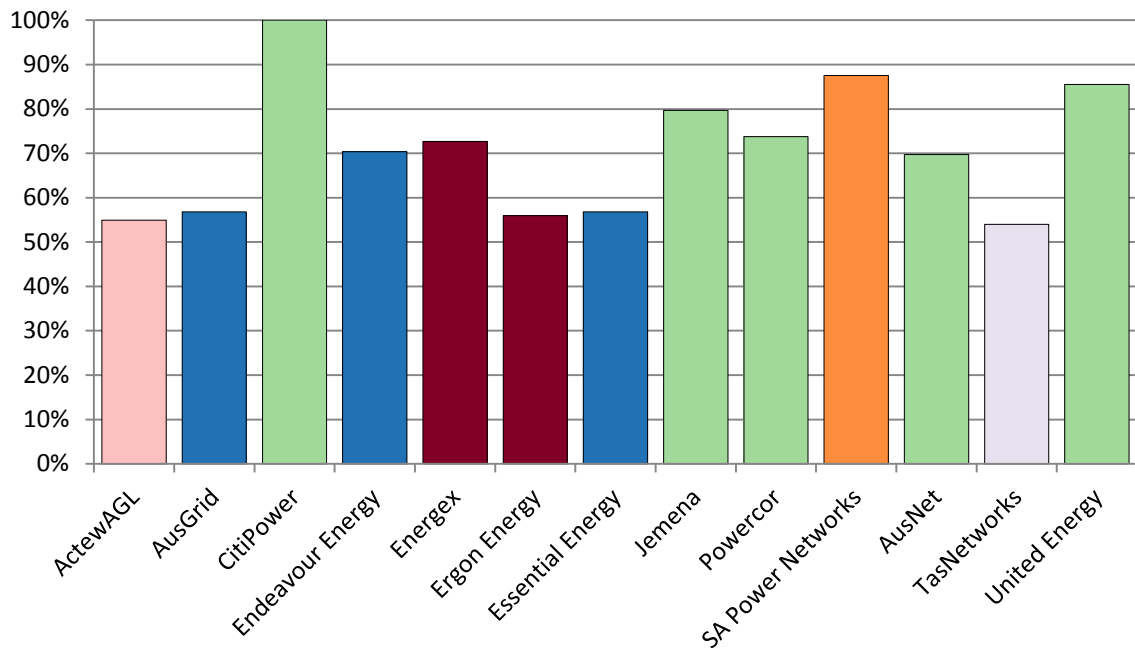
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<sup>32</sup> These include: Economic Insights, 2014 and AER, Electricity distribution network service providers, Annual benchmarking report, November 2014, and our draft determinations for the NSW and ACT distribution network service providers.

AER, Better Regulation, Explanatory Statement Expenditure Forecast Assessment Guideline, November 2013  
ACCC/AER, Benchmarking Opex and Capex in Energy Networks, Working Paper no.6, May 2012.

<sup>33</sup> <http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements>

**Figure A.1 MTFP Performance (average 2006–2013)**

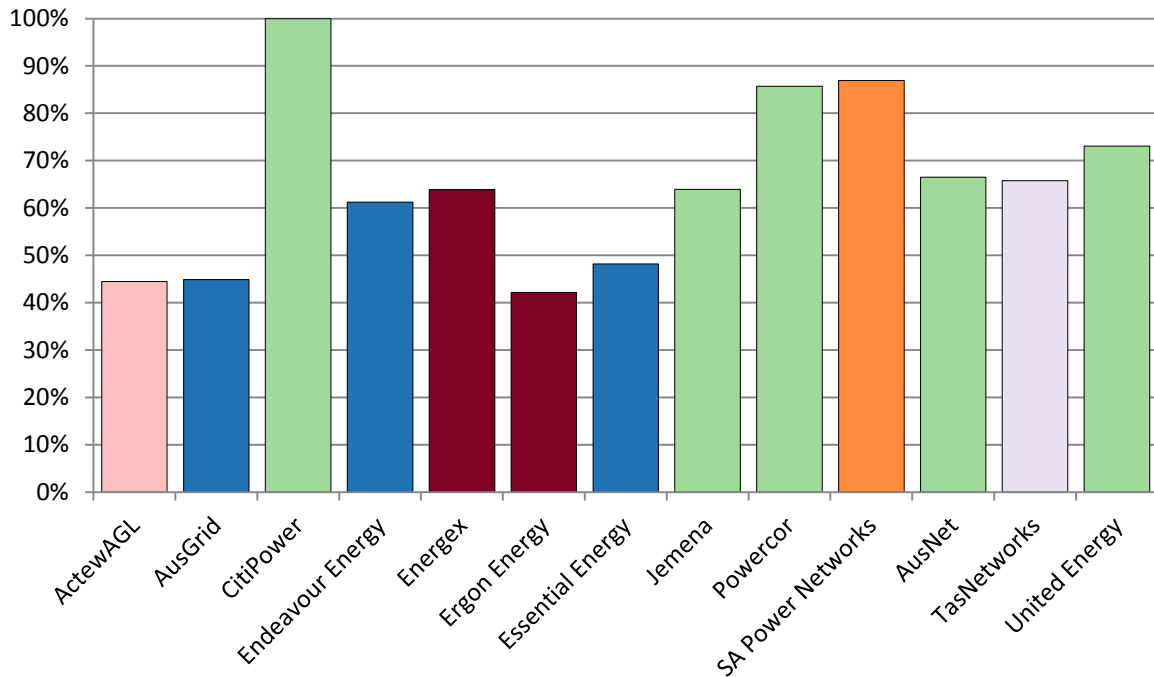


Source: AER analysis.

Figure A.2 presents the opex multilateral partial factor productivity (MPFP) results. As would be expected, the performance of the service providers changes somewhat under these results, reflecting the different combination of opex and capital used by the service providers to deliver network services. Under both measures SA Power Networks is amongst the most efficient.



**Figure A.2 Opex MPFP performance (average 2006–13)**



Source: AER analysis.

SA Power Networks engaged Huegin to undertake benchmarking analysis. The findings of Huegin's benchmarking indicate that SA Power Networks has the highest productivity score in 2013 after the effects of customer density have been removed.<sup>34</sup> There are some differences between Huegin's benchmarking model specification and our own. These are as follows:

- Huegin uses a system capacity output measure. We instead use ratcheted maximum demand and circuit line length.<sup>35</sup>
- Huegin applies output weights of 75per cent on customer connections and 25 per cent on system capacity (with reliability weights derived Value of Customer Reliability measures from the AER's service target performance incentive scheme of \$95,700/MWh for CBD network segments and \$47,850/MWh for other network segments adjusted from September 2008).<sup>36</sup>

<sup>34</sup> Huegin Consulting, The Australian Energy Regulator's new approach to benchmarking, An indication of how SA Power Networks will benchmark against other DNSPs within the National Electricity Market, September 2014, p. 14. (Hue)

<sup>35</sup> Huegin consulting.

<sup>36</sup> Huegin consulting.

The reasons for the adoption of ratcheted maximum demand and circuit line length are outlined in Economic Insights report.<sup>37</sup> Instead of applying a 75/25 per cent weighting, Economic Insights has estimated the cost-based weightings for outputs using a Leontief cost function.<sup>38</sup> We consider that this approach is preferential to applying a given set of output weights as Huegin has done because it is based upon the objective results of a cost model. Further, Economic Insights has adopted the most recent valuation of customer reliability as developed by AEMO. We consider that this measure is preferential to the September 2008 measure as it is a more recent estimate.

## **A.1.2 Findings from econometric modelling of the opex cost function**

Economic Insights has chosen to model the opex cost function of the service providers using three models.<sup>39</sup> These models are Cobb Douglas SFA, Cobb Douglas least squares estimation (CD LSE) and Translog least squares estimation (TLG LSE). The findings from these models support each other. Like the opex MPFP analysis, these models indicate that SA Power Networks is one of the more efficient networks.

### ***Methodology***

The TLG LSE and CD LSE models are econometric modelling of Translog and Cobb Douglas opex cost functions, respectively.<sup>40</sup> They are parametric techniques, which means that they model the underlying cost function of the service providers as specified. Further, these models allow for the direct incorporation of relevant operating environment factors into the analysis.

The Cobb Douglas SFA method is the more advanced technique because it directly estimates the efficient frontier and efficiency scores for the networks. It also retains the benefits of the LSE models. In the Cobb Douglas SFA method, the composite error term is decomposed into a white noise term and a cross-sectional one-sided disturbance term, which is interpreted as a measure of firm-specific inefficiency. For these reasons the Cobb Douglas SFA method is Economic Insights' preferred model. We agree and have adopted Economic Insights' recommendations. Economic Insights' report provides a detailed explanation of these modelling approaches.<sup>41</sup>

Figure A.3 presents the benchmarking results for each of the econometric cost functions. This figure also presents the opex MPFP results. Figure A.3 shows that the benchmarking models, despite employing different efficiency measurement techniques, produce consistent results. Further, these models are consistent with the opex MPFP results. This gives us confidence that the models provide an accurate indication of the efficiency of base year opex.

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<sup>37</sup> Economic Insights, 2014, pp. 9–12.

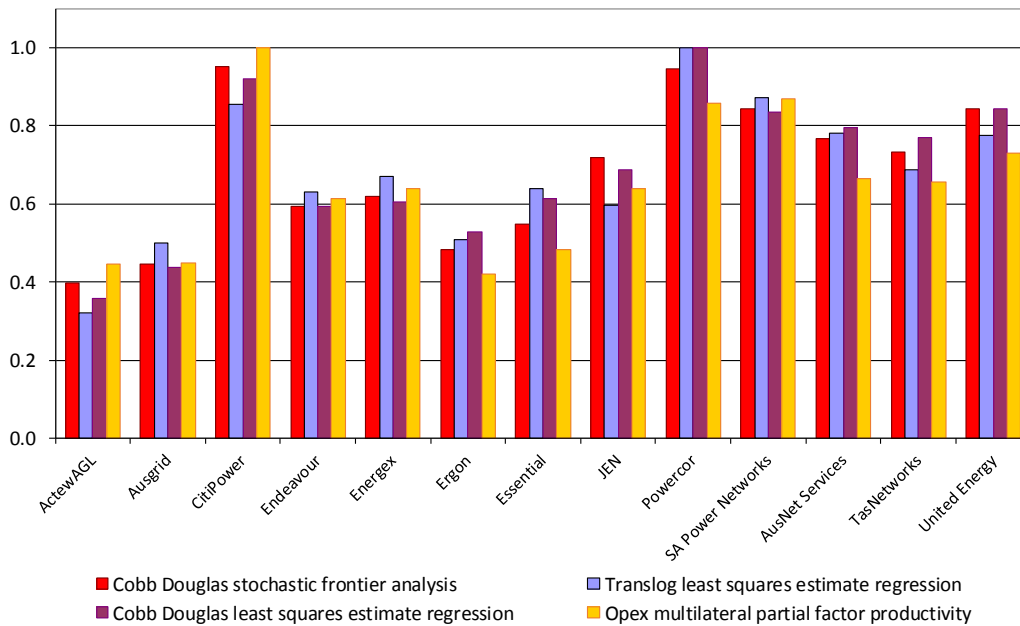
<sup>38</sup> Economic Insights, 2014, p.12.

<sup>39</sup> Economic Insights, 2014, p. iii.

<sup>40</sup> Economic Insights describes the opex cost functions in detail. Economic Insights, 2014, pp. 27–31.

<sup>41</sup> Economic Insights, 2014, pp. 25–28.

**Figure A.3 Econometric modelling and opex MPFP results**



Source: Economic Insights, 2014.

All the models indicate that SA Power Networks is amongst the more efficient networks.

We consider that it is important to examine a broad range of benchmarking techniques. As such, we have also conducted partial performance indicator benchmarking.

### A.1.3 Partial performance indicators

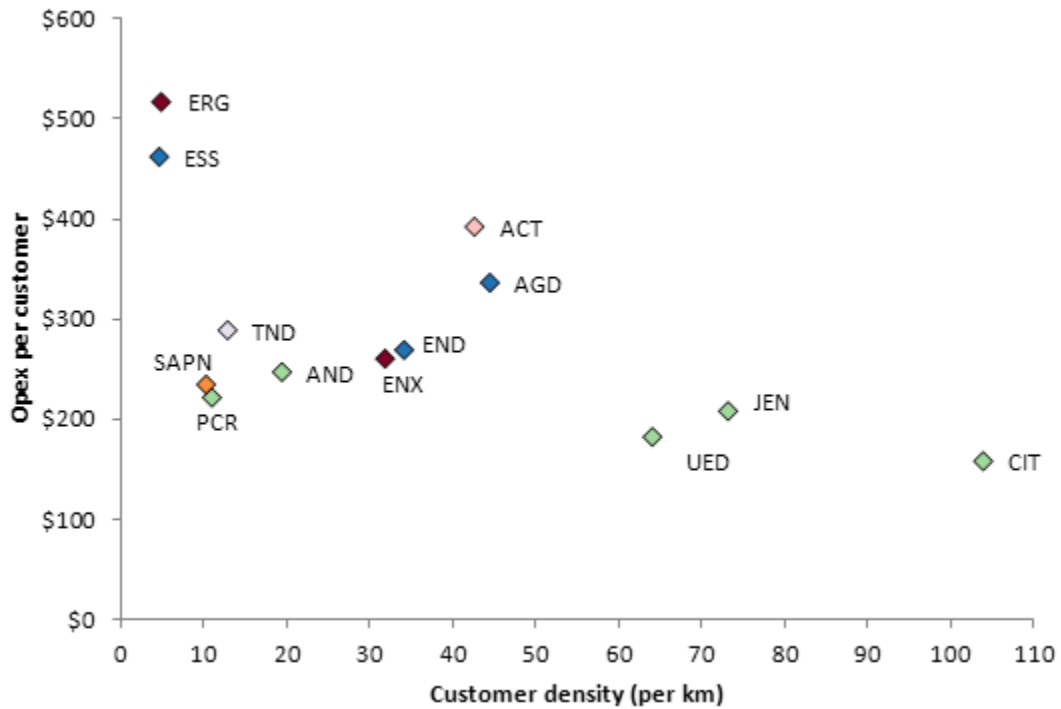
In our annual benchmarking report we present a number of partial performance indicators of SA Power Networks' performance.<sup>42</sup> These indicators examine SA Power Networks' use of assets, opex and total inputs in delivering its distribution services. Under these metrics SA Power Networks appears to be one of the more efficient networks. As such, we consider that this benchmarking supports the findings of the econometric benchmarking discussed in sections A.1.1 and A.1.2.

Though a number of PPIs are presented in this report we consider that the most relevant is opex per customer. This is because customer numbers appears to be the most material driver of costs for service providers.<sup>43</sup> Figure A.4 presents this PPI. This figure shows that relative to other service providers with comparable customer densities SA Power Networks has low or comparable opex per customer.

<sup>42</sup> AER, Electricity distribution network service providers, Annual benchmarking report, November 2014

<sup>43</sup> The number of customer connections has the highest coefficient in Economic Insights econometric models and its SFA Cobb Douglas Model. Economic Insights, 2014, pp. 33–35.

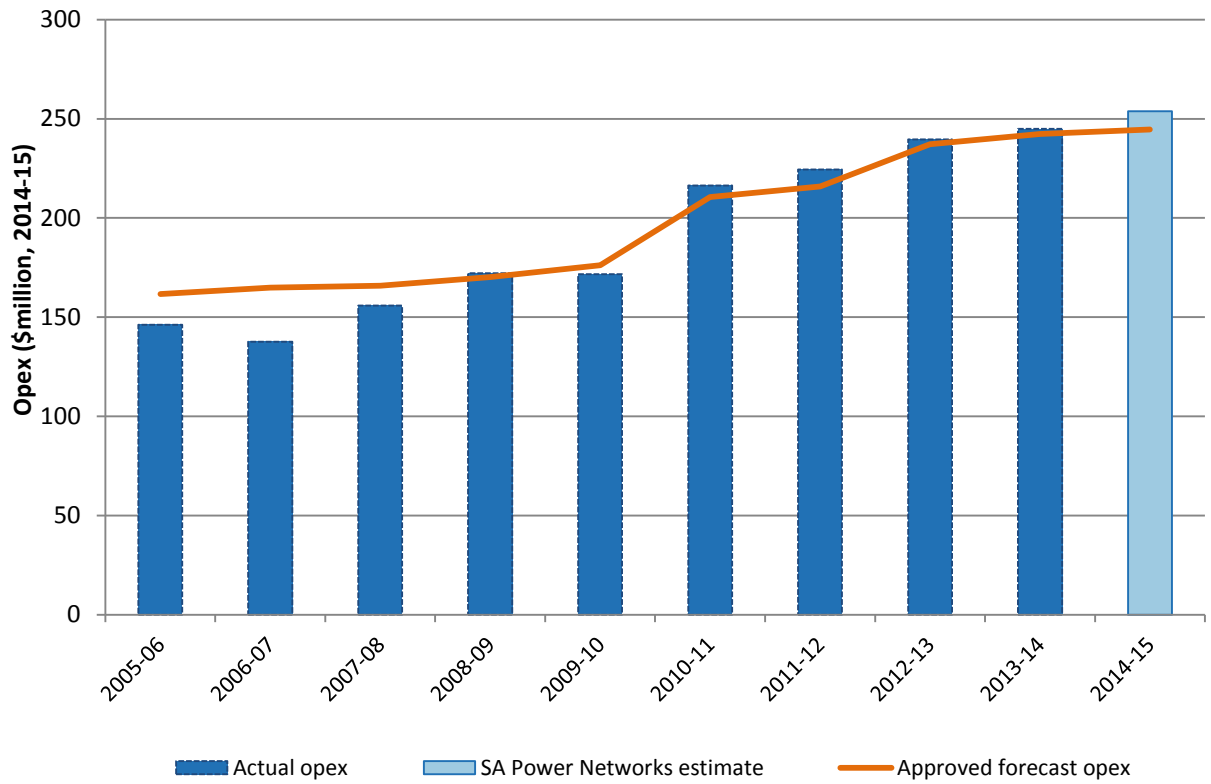
**Figure A.4 PPI of operating expenditure per customer**



## A.2 Base year assessment

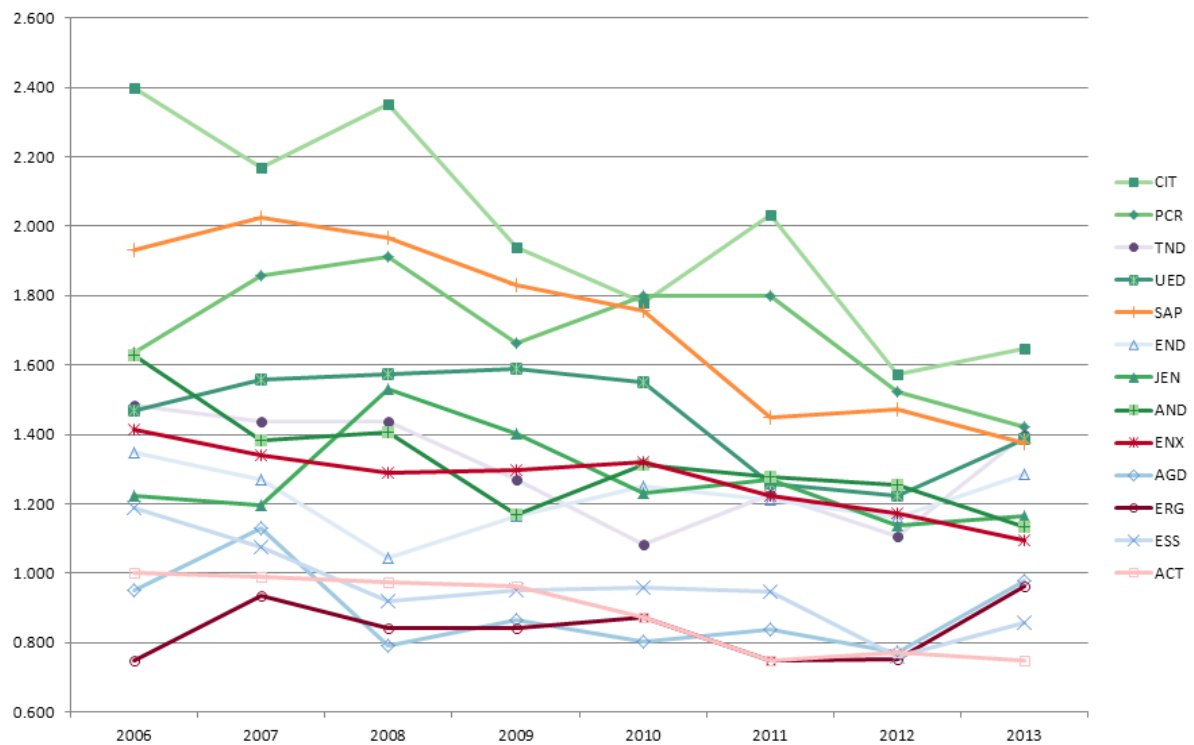
Our benchmarking across the 2006–13 period indicates that SA Power Networks performs well against its peers. However, over the benchmarking period we observe that SA Power Networks' operating expenditures have increased significantly. In real terms, SA Power Networks' opex in 2012–13 is 31 per cent higher than the average over the benchmarking period (Figure A.5).

**Figure A.5 SA Power Networks' opex compared to our forecasts**



This increase in opex has contributed to a decline in opex MPFP over the period. This is illustrated in Figure A.6.

**Figure A.6 MPFP of distributors over the benchmarking period**



We note that, despite SA Power Networks' opex of MPFP falling over the period, SA Power Networks remains amongst the five most efficient networks.

SA Power Networks' decrease in opex MPFP over the benchmarking period is the result of increasing opex over the period. This seems to be consistent with the trend decline in the opex MPFP results and technical regress found in the opex cost modelling. On average, the MPFP of distributors across Australia has declined by 2.21 per cent per annum. This decline in productivity is, in part, attributable to increasing regulatory obligations and pass-throughs which have not been removed from our opex data.<sup>44</sup>

SA Power Networks also notes the decline in productivity in its regulatory proposal. We requested that SA Power Networks provide information on the reasons for its increased opex which has contributed to the decline in its productivity across the benchmarking period. SA Power Networks provided a list of drivers for the increase in expenditures across the period.<sup>45</sup>

Further, over the benchmarking period SA Power Networks has been subject to incentive schemes which provide an incentive to reduce opex. This includes our EBSS

<sup>44</sup> Economic Insights, Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs, 17 November 2014, p. 62.

<sup>45</sup> SAPN, AER SAPN 004, Opex Environmental Factors, January 2015

under which it has incurred a penalty. The application of our EBSS and the calculation of the penalty to SA Power Networks is set out in attachment 9.

On balance, in light of SA Power Networks' good performance in the benchmarking metrics over the historical period, but also in the recent years of the opex MPFP series we have decided that SA Power Networks' base opex is not materially inefficient.

### **A.3 Adjustments to base year expenditure**

SA Power Networks made a number of adjustments to its base year expenditure to forecast its expenditure for the 2015–20 regulatory control period. We considered these adjustments when we derived our alternative estimate.

#### **A.3.1 Self-insurance**

SA Power Networks' base year expenditure included \$5.1 million (\$2014–15) for self-insurance. This is \$3.2 million (\$2014–15) higher than the average over the first four years of the 2010–15 regulatory control period. Normally we do not adjust base year expenditure if an individual opex category is atypically high or low. However, self-insurance was excluded from the EBSS for the 2010–15 regulatory control period.<sup>46</sup> Consequently we have adjusted base year expenditure to be equal to the average over the first four years of the period. This is consistent with SA Power Networks proposal.

#### **A.3.2 Reclassification of metering services**

In our framework and approach paper we reclassified type 5 and 6 metering related services as alternative control services. SA Power Networks' base year expenditure included \$2.2 million (\$2014–15) for these services. We have removed this expenditure from SA Power Networks' base year expenditure to develop our alternative opex forecast. This is consistent with SA Power Networks' proposal.

#### **A.3.3 Demand management innovation allowance**

We provided SA Power Networks a demand management innovation allowance (DMIA) in the 2010–15 regulatory control period. We also stated in our framework and approach that we would provide another allowance in the 2015–20 period. This allowance is provided separately to the opex allowance. Consequently we have removed \$1.5 million (\$2014–15) of opex funded by the DMIA from SA Power Networks' base year expenditure to develop our alternative opex forecast. We provide

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<sup>46</sup> A non-recurrent increase (decrease) in expenditure results in a negative carryover amount if it is subject to the EBSS. If the opex forecast based on this abnormally high (low) opex it will be higher (lower) than the efficient amount. However, the negative (positive) EBSS carryover offsets this, sharing the efficiency loss between the service provider and its network users. Clause 6.5.6(e)(8) of the NER requires us to have regard to whether the opex forecast is consistent with the EBSS when deciding whether we are satisfied that the proposed opex forecast reasonably reflects the opex criteria.

SA Power Networks a DMIA allowance of \$0.6 million (\$2014–15) separate to its opex allowance.

Further, SA Power Networks inflated its proposed DMIA allowance above the allowed for by the demand management incentive scheme. SA Power Networks included the DMIA in its proposal by reducing base year expenditure funded by the DMIA from \$1.5 million (\$2014–15) to \$0.6 million (\$2014–15), the annual allowance it will receive in the 2015–20 period. However, SA Power Networks then adjusted base year DMIA funded expenditure for forecasted price changes, increasing the forecast DMIA above the amount allowed for by the demand management incentive scheme.

### **A.3.4 Proposed base year adjustments considered as step changes**

SA Power Networks proposed further base year adjustments that we have assessed as step changes:

- regulatory proposal
- distribution licence fee
- non-network solution
- property.

We state in our Guideline that we may add (or subtract) step changes for any costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria.<sup>47</sup> SA Power Networks proposed these base year adjustment because the amount of expenditure in the base year was not representative of its expectation of expenditure in the 2015–20 regulatory control period. Consequently, if these adjustments are required for the opex forecast to meet the opex criteria, we would add (or subtract) them as step changes in our alternative forecast. We consider whether these adjustments are required as step changes in appendix C.

## **A.4 Estimate of final year expenditure**

To derive our alternative opex estimate we used the adjusted base year expenditure to estimate final year expenditure.

Our Guideline states we estimate final year expenditure to be equal to:

$$A_f^* = F_f - (F_b - A_b) + \text{non-recurrent efficiency gain}_b$$

where:

$A_f^*$  is the best estimate of actual opex for the final year of the preceding regulatory control period

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<sup>47</sup> AER, Expenditure forecast assessment guideline for electricity distribution, November 2013, p. 24.



$F_f$  is the determined opex allowance for the final year of the preceding regulatory control period

$F_b$  is the determined opex allowance for the base year

$A_b$  is the amount of actual opex in the base year

*non-recurrent efficiency gain<sub>b</sub>* is the non-recurrent efficiency gain in the base year.

The estimate of final year opex should be consistent in both our opex forecast and the EBSS in order to share SA Power Networks' efficiency gains made in 2014–15 with its network users as intended by the EBSS. Version one of the EBSS for distribution businesses does not allow estimated final year expenditure to be adjusted for non-recurrent efficiency gains (version two, which will apply in the 2015–20 regulatory control period does). We are required to have regard to whether the opex forecast is consistent with the EBSS when deciding whether we are satisfied that the proposed opex forecast reasonably reflects the opex criteria.<sup>48[5]</sup> To ensure consistency with estimated final year expenditure in the EBSS, we have not adjusted our estimate of final year expenditure for any non-recurrent efficiency gains.

We applied this equation to derive an estimated opex of \$241.9 million (\$2014–15) for 2014–15. We then applied our forecast rate of changes, and added step changes, to derive our alternative estimate of opex for the 2015–20 period.

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<sup>48</sup> NER, cl. 6.5.6(e)(8).

## 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 opex that reflects the opex criteria for each year of a regulatory control period might differ from expenditure in the base year.

As set out in our Expenditure forecast assessment guideline (our Guideline), we have developed an opex forecast incorporating the rate of change to account for the following factors:<sup>49</sup>

- price growth
- output growth
- productivity growth.

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

### B.5 Position

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 B.1 shows SA Power Networks' and our overall rate of change in percentage terms for the 2015–20 period. We consider that applying our methodology to derive an alternative estimate of opex will result in a forecast that reasonably reflects the efficient and prudent costs faced by SA Power Networks given a realistic expectation of demand forecasts and cost inputs.

The differences in each forecast rate of change component are:

- our forecast of annual price growth is on average 1.30 percentage points lower than SA Power Networks'
- our forecast of annual output growth is on average 0.47 percentage points lower than SA Power Networks'
- our forecast productivity growth is the same as SA Power Networks'.

SA Power Network's use of its Enterprise Agreement (EA) for 2015–16 to 2016–17 and benchmarked EAs for 2017–18 to 2019–20 to forecast labour price growth is the primary difference between SA Power Networks' and our forecast price growth. SA Power Networks also proposed different output growth drivers to ours.

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<sup>49</sup> AER. *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

We discuss the reasons for the difference between us and SA Power Networks for each rate of change component below.

**Table B.1 SA Power Networks and AER rate of change (per cent)**

	2015–16	2016–17	2017–18	2018–19	2019–20
SA Power Networks	2.14	2.40	2.66	2.76	2.89
AER	0.50	0.82	0.83	0.89	0.92
Difference	-1.64	-1.59	-1.84	-1.87	-1.98

Source: AER analysis

## B.6 SA Power Networks proposal

Table B.2 shows SA Power Network's proposed cumulative change in opex for each rate of change component reported in SA Power Network's reset RIN.

SA Power Networks' rate of change methodology is different to ours because it applied different output growth drivers and adopted a labour price measure based on benchmarked Enterprise Agreements (EAs). Further SA Power Networks' output growth includes economies of scale factors. We consider economies of scale in our assessment of productivity. This is consistent with the approach set out in our Guideline.<sup>50</sup>

We discuss each of these components below.

**Table B.2 SA Power Networks proposed opex by rate of change drivers (\$'000, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20
Base opex	247 412	247 412	247 412	247 412	247 412
Price growth	2 989	6 884	11 705	16 984	22 785
Output growth	3 022	6 110	9 367	12 563	15 638
Productivity growth	–	–	–	–	–

Source: SA Power Networks reset RIN table 2.16.1

### *Forecast price growth*

SA Power Networks proposed price growth for the following categories:

- labour
- contracted construction and labour services

<sup>50</sup> AER, *Explanatory statement draft expenditure forecast assessment guidelines for electricity transmission and distribution*, August 2013, p. 36.

- materials
- land.

Table B.3 outlines the consultants SA Power Networks engaged for each price growth category and the methodology proposed by each consultant. Table B.4 shows SA Power Network's annual percentage change for each of its proposed price growth categories.

**Table B.3 SA Power Networks forecast price growth consultants and proposed methodology**

Price growth	Consultant	Methodology
Labour	Frontier Economics	SA Power Network's existing EA for 2015–16 to 2016–17. For the years where there is no EA, 2017–18 to 2019–20, Frontier Economics recommended the extrapolation of long term Enterprise Bargaining Agreements from a comparator group of distribution service providers.
Contracted construction and labour services	BIS Shrapnel	Average of BIS Shrapnel and Deloitte Access Economics forecast of the contracted construction and labour services industry.
Materials	Competition Economic Group and Jacobs	Based on the forecast commodity prices and the mix of components used in constructing and/or maintaining the distribution network.
Land	Maloney Field Services	Use of long term Australian Bureau of Statistics data to forecast unimproved land values in South Australia.

Source: SA Power Networks, *Regulatory proposal*, pp. 265–268.

**Table B.4 SA Power Network's proposed real price growth (per cent)**

Price growth category	2015–16	2016–17	2017–18	2018–19	2019–20
Labour	1.66	1.66	1.77	1.77	1.77
Contracted construction and labour services	0.50	0.90	1.10	1.40	1.80
Materials	0.71	0.12	0.01	–0.02	0.02
Land	5.96	5.96	5.96	5.96	5.96

Source: SA Power Networks, *Regulatory proposal*, p. 178.

### ***Forecast output growth***

SA Power Networks proposed network growth, customer growth and workforce size as output drivers in its opex forecast.<sup>51</sup>

The network growth driver is the average of the growth in lines, distribution transformers and installed substation capacity weighted by their depreciated capital value.<sup>52</sup>

SA Power Networks used data provided in its Economic benchmarking and Category analysis RINs to calculate output growth for the 2015–20 regulatory control period.

It applied the network growth and customer growth drivers to operational and customer service activities. It applied the workforce size driver to back-office and support functions.

It then applied an economies of scale factor to each operating cost group.

### ***Forecast productivity growth***

SA Power Networks did not apply a productivity adjustment to its rate of change. It considers our benchmarking is not sufficiently robust to apply deterministically.<sup>53</sup>

SA Power Networks engaged Huegin Consulting to conduct modelling to determine SA Power Networks' relative efficiency.

SA Power Networks considers itself to be on the efficient frontier so a 'catch up' productivity factor is not applicable.<sup>54</sup>

### ***Overall rate of change***

The rate of change approach applies a percentage change to the previous year's opex. Table B.2 above expresses the impact of each rate of change component in dollar terms. To allow a like with like comparison, we have expressed each of SA Power Network's rate of change components in annual percentage terms below in Table B.5.

The values in Table B.5 represent the incremental change in percentage terms of each rate of change component from the previous year's opex.

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<sup>51</sup> SA Power Networks, Regulatory proposal, p. 264.

<sup>52</sup> SA Power Networks attachment 21.4 scale escalation model.

<sup>53</sup> SA Power Networks, Regulatory proposal, p. 269.

<sup>54</sup> SA Power Networks, Regulatory proposal, p. 269.

**Table B.5 SA Power Networks opex rate of change (per cent)**

	2015–16	2016–17	2017–18	2018–19	2019–20
Price growth	1.06	1.33	1.58	1.72	1.89
Output growth	1.07	1.05	1.06	1.02	0.98
Productivity growth	–	–	–	–	–
Overall rate of change	2.14	2.40	2.66	2.76	2.89

Source: SA Power Networks, *Regulatory proposal*; AER analysis.

## B.7 Assessment approach

As discussed above, we assess the annual change in expenditure in the context of our assessment of SA Power Networks' proposed total forecast opex.

The rate of change itself is a build-up of various components to provide an overall holistic number that represents our forecast of annual change in overall opex during the 2015–20 regulatory control period. We consider the rate of change approach captures all drivers of changes in efficient base opex except for material differences between historic and forecast step changes. The rate of change approach takes into account inputs and outputs, and how well the service provider utilises these inputs and outputs.

The rate of change formula for opex is:

$$\Delta Opex = \Delta price + \Delta output - \Delta productivity$$

Where  $\Delta$  denotes the proportional change in a variable.

Our starting point for assessing the service provider's proposed change in annual expenditure is to disaggregate the service provider's proposal into the three rate of change components. This enables us to identify where there are differences in our estimate and the service provider's estimate of the components of the rate of change. While individual components in the service provider's proposed annual change in expenditure may differ from our rate of change component forecasts, we will form a view on the overall rate of change in deciding what to apply to derive our alternative opex forecast.

We also take into account whether the differences in the rate of change components are a result of differences in allocation or methodology. For example, a service provider may allocate economies of scale to the output growth component of the rate of change, whereas we consider this is productivity growth. Irrespective of how a service provider has built up or categorised the components of its forecast rate of change, our assessment approach considers all the relevant drivers of the opex rate of change.

Since our rate of change approach is a holistic approach we cannot make adjustments to one component without considering the interactions with other rate of change

components. For example, if we were to adjust output to take into account economies of scale, we must ensure that economies of scale have not already been accounted for in our productivity growth forecast. Otherwise, this will double count the effect of economies of scale.

### **B.7.1 Price growth**

Under our rate of change approach we escalate opex by the forecast change in prices. Price growth is made up of labour price growth and non-labour (which includes materials) price growth. The growth in prices accounts for the price of key inputs that do not move in line with the CPI and form a material proportion of SA Power Networks' expenditure.

To determine the appropriate forecast change in labour prices we assessed forecasts from Frontier Economics, BIS Shrapnel and Deloitte Access Economics. We discuss our consideration of the choice of labour price forecast below in section B.8.2.

### **B.7.2 Output growth**

'Output growth' captures the change in expenditure due to changes in the level of outputs delivered, such as increases in the size of the network and the customers serviced by that network. An increase in the quantity of outputs is likely to increase the efficient opex required to service the outputs.

Under our rate of change approach, a proportional change in output results in the same proportional change in expenditure. For example, if the only output measure is maximum demand, a 10 per cent increase in maximum demand results in a 10 per cent increase in expenditure. We consider any subsequent adjustment for economies of scale as a part of our assessment of productivity.

To measure output growth, we select a set of output measures and apply a weighting to these measures. We have chosen the same output growth measures and weightings as used in Economic Insight's economic benchmarking report.<sup>55</sup> This ensures we measure output growth consistently through time and across service providers.

We obtained the historical output growth for SA Power Networks from our Economic Benchmarking RIN. The Economic Benchmarking RIN provides a consistent basis to benchmark the inputs and outputs of each service provider. This allows us to consistently compare the change in output overtime and across service providers.

We calculated the forecast output growth based on forecasts obtained from the reset RIN which was prepared on the same basis as the Economic Benchmarking RIN.

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<sup>55</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 40–41.

We have assessed each of SA Power Networks' output growth drivers and compared its forecast output growth with ours at the overall level.

We discuss in greater detail how we have estimated output growth in section B.8.5.

### **B.7.3 Productivity**

We forecast our change in productivity measure based on our expectations of the productivity an efficient service provider in the distribution industry can achieve. We based forecast productivity on analysis from Economic Insights' economic benchmarking analysis.<sup>56</sup> However, we have also assessed whether the historical productivity from 2006–13 reflects a reasonable expectation of the benchmark productivity that can be achieved for the forecast period.

If inputs increase at a greater rate than outputs then a service provider's productivity is decreasing. Changes in productivity can have different sources. For example, changes in productivity may be due to the realisation of economies of scale or technical change, such as the adoption of new technologies. We expect efficient service providers to pursue productivity improvements over time.

In the explanatory statement to our Guideline we noted that we would apply a rate of change to our estimate of final year opex (taking into account an efficiency adjustment, if required), to account for the shift in the productivity frontier over the forecast period.<sup>57</sup>

Since forecast opex must reflect the efficient costs of a prudent firm, it must reflect the productivity improvements it is reasonable to expect a prudent service provider can achieve. All else equal, a price taker in a competitive market will maintain constant profits if it matches the industry average productivity improvements reflected in the market price. If it is able to make further productivity improvements, it will be able to increase its profits until the rest of the industry catches up, and this is reflected in the market price. Similarly, if a service provider is able to improve productivity beyond that forecast, it is able to retain those efficiency gains for a period.<sup>58</sup>

Since we take both outputs and inputs into account, our productivity measure accounts for labour productivity and economies of scale. The effect of industry wide technical change is also included.

We discuss how we have estimated productivity growth in more detail in section B.8.6

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<sup>56</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 38.

<sup>57</sup> AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

<sup>58</sup> AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 66.



## B.7.4 Other considerations

### *Interaction with our base opex and step changes*

As noted above, we use the rate of change approach in conjunction with our assessment of base opex and step changes to determine total opex. We cannot make adjustments to base opex and step changes without also considering its effect on the opex rate of change, and, in particular, productivity.

For example, if we adjust an inefficient service provider's base we must also set forecast productivity growth to reflect an efficient service provider's productivity growth.

This interrelationship is also important for our step change assessment. Historical data influences our forecast rate of change. Our measured productivity will include the effect of past step changes which typically increase a service provider's inputs. This will lower our measured productivity. If we include an allowance for step changes in forecast opex and we don't take this into account in our productivity forecast, there is a risk that a service provider will be overcompensated for step changes.<sup>59</sup>

### *Comparison with our previous cost escalation approach*

Under our previous approach to setting the trend in opex, we assessed real cost escalations (this is similar to price growth) and output growth separately. We assessed any productivity growth based on labour productivity for real cost escalations and economies of scale for output growth.

This approach was less robust than our opex rate of change approach because accounting for both labour productivity and economies of scale separately could result in double counting productivity effects.

In practice, this meant that we could either apply labour productivity or economies of scale but not both. In our recent determinations we applied an adjustment for economies of scale rather than labour productivity. However, we noted this approach did not account for all sources of productivity growth and that a single productivity measure would be more accurate.<sup>60</sup>

## B.8 Reasons for position

We have separated the sections below into the three rate of change components. Where relevant we compare these components to SA Power Network's rate of change using information provided in the reset RIN and opex model.

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<sup>59</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 42.

<sup>60</sup> AER, *Final decision SP AusNet Transmission Determination 2014–15 to 2016–17*, January 2014, pp. 64–65.

## B.8.1 Overall rate of change

We have adopted a lower rate of change to forecast our alternative estimate of opex than SA Power Networks' forecast rate of change. SA Power Networks' higher labour price forecasts are the primary driver of this difference. SA Power Networks also escalates a higher proportion of opex for labour price growth.

Our forecast output growth is also lower than SA Power Network's. SA Power Network's use of historical averages to forecast output growth is the primary driver of this difference. We base our forecast output growth on SA Power Network's forecasts of the output drivers in its reset RIN.

We, like SA Power Networks, did not include a forecast change in productivity for the 2015–20 regulatory control period.

SA Power Networks considered our economic benchmarking models were not robust enough to measure and forecast productivity growth. We base our productivity growth forecast on our expectations of the change in productivity for an efficient distribution network service provider in the short to medium term. We also take into account the interaction between price, output and productivity growth.

Table B.6 shows SA Power Networks' and our overall rate of change and each rate of change component for each regulatory year of the 2015–20 regulatory control period.

In estimating our rate of change, we considered SA Power Networks' proposed forecast changes in prices, output and productivity and the methodology used to derive these changes.

**Table B.6 AER and SA Power Networks' overall rate of change (per cent)**

	2015–16	2016–17	2017–18	2018–19	2019–20
<b>SA Power Networks</b>					
Price growth	1.06	1.33	1.58	1.72	1.89
Output growth	1.07	1.05	1.06	1.02	0.98
Productivity growth	–	–	–	–	–
<b>Overall rate of change</b>	<b>2.14</b>	<b>2.40</b>	<b>2.66</b>	<b>2.76</b>	<b>2.89</b>
<b>AER</b>					
Price growth	–0.07	0.25	0.26	0.31	0.35
Output growth	0.57	0.57	0.57	0.57	0.57
Productivity growth	–	–	–	–	–
<b>Overall rate of change</b>	<b>0.50</b>	<b>0.82</b>	<b>0.83</b>	<b>0.89</b>	<b>0.92</b>
<b>Difference</b>	<b>–1.64</b>	<b>–1.59</b>	<b>–1.84</b>	<b>–1.87</b>	<b>–1.98</b>

Source: AER analysis.

We discuss the reasons for the differences between SA Power Networks' proposal and our preliminary decision for each rate of change component below.

## **B.8.2 Labour price and productivity**

Forecast labour price growth is the main driver of the difference between SA Power Networks and our rate of change.

We consider Deloitte Access Economics' (DAE's) forecast of the electricity, gas, water and wastes services (EGWWS) industry reflects current expectations of the market conditions for the forecast period and represents a more reasonable forecast of the labour price for the rate of change than the forecast proposed by SA Power Networks.

SA Power Networks' use of its EA and benchmark EAs did not account for the corresponding impact on its opex productivity. We consider a reasonable forecast labour price measure should also take into account forecast productivity.

We discuss in the sections below:

- the use of enterprise agreements versus an industry wide measure of the labour price
- how these price measures should be accounted for in the productivity component of the rate of change
- the reasonable measure for a forecast labour price to forecast the rate of change.

### ***Use of enterprise agreements versus an industry wide measure***

SA Power Networks proposed to use the labour price rise in its 2014–16 EA of 1.66 per cent in real terms for the first two years of the forecast period. For the remaining years following the expiry of its current EA, SA Power Networks proposed an extrapolation of benchmarked EA outcomes of 1.77 per cent in real terms from similar businesses based on analysis from Frontier Economics.<sup>61</sup>

To select the group of comparator EAs, Frontier Economics selected all privately owned transmission and distribution service providers in Australia.<sup>62</sup>

Either an EGWWS wage price index (WPI) forecast or SA Power Networks' use of benchmark EAs could be reasonable forecasts of the labour price. SA Power Networks' methodology captures a subset of its electricity labour meanwhile our measure captures all electricity labour in addition to labour from other similar industries. In this circumstance there is no clearly preferable methodology to forecast the labour price. However, the labour price is one component in the rate of change. We must also consider the interaction between price growth and other components in the

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<sup>61</sup> SA Power Networks, Regulatory proposal, p. 266.

<sup>62</sup> Frontier Economics, Forecasting labour cost escalation rates using EBA outcomes, August 2014, p. 28. We note Frontier Economics included Energex which we recognise as a public business rather than a private business.

rate of change such as productivity. We have maintained our approach of using the EGWWS WPI because it also takes into account the interaction between price growth and productivity growth. For this reasons we consider our labour price growth methodology produces the best estimate of the overall rate of change.

In considering whether EAs are a reasonable measure of labour price growth we have considered the following:

- whether the proportion of staff covered by EAs or the EGWWS WPI is representative of overall electricity labour
- whether EA rates are reflective of current market conditions

#### *Proportion of staff covered by each measure*

The choice of labour price measure should reflect the annual change in labour price for electricity distribution workers. Neither a private service provider's EA nor a utilities industry wide labour price is a perfect measure of the electricity industry's labour price.

Based on our analysis we consider in general a privately owned distribution service providers' benchmark EA does not reflect a significant proportion of its in-house labour. We based this on our analysis of each distribution service provider's Category Analysis RINs and the number of staff covered in its EA. We note less than half of the staff of CitiPower, Powercor and AusNet Services staff are employed under their respective EAs. Further, the privately owned distribution service providers outsource a large proportion of their opex.<sup>63</sup>

Outsourced labour is not covered by the service providers' EAs, but it is still an input used to provide operating and maintenance services required by the service provider, thus forming part of its opex.

We consider a benchmark private service provider's EA represents the labour price of only a subset of its total labour price and overall labour costs. This is because the proportion of a private service provider's staff that is covered by its EA is less than the proportion of labour that is outsourced or employed directly but not covered by an EA.

In contrast, our forecast of the EGWWS WPI captures all electricity distribution workers. However, this industry wide measure also captures other utilities industries. Table B.7 shows the proportion of each industry that makes up the EGWWS service classification.

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<sup>63</sup> Deloitte Access Economics, *NSW distribution network service providers labour analysis – final draft addendum to 2014 report*, 9 April 2015. p. 29

**Table B.7 EGWS proportions (per cent)**

Electricity	Gas	Water	Waste Services
56.5	1.8	23.3	18.4

Source: ABS table 5209.0.55.001, AER analysis. Calculated from each industry's proportion of total employee compensation.

SA Power Networks' labour price measure is a narrower than ideal measure of the labour price for electricity workers. This is because it excludes a majority of electricity workers that private businesses either directly or indirectly employ.

In contrast, our industry wide measure is a broader than ideal measure of the labour price for electricity workers, because it includes workers from other utilities, as well as the electricity industry. Although electricity workers make up a majority of the EGWS, the change in the labour price in other industries can influence the labour price.

These two approaches are two different sampling methodologies to capturing electricity labour. They have distinct advantages and disadvantages, so we consider neither approach is clearly preferable to the other on the basis of sampling accuracy for identifying electricity labour price growth.

#### *EA wage rates and current market conditions*

We do not consider the benchmark EA wage increases for private electricity service providers represents the current market conditions for electricity workers.

The average EA in used Frontier Economics' benchmark sample contains wage increases of 4.5 per cent for 2013–14 and 4.4 per cent for 2014–15. This is higher than the 3.0 percent for the EGWS WPI from June 2013 to June 2014.<sup>64</sup>

We consider the difference between the benchmark EA wage increases and the EGWS WPI could be due to wages in other EGWS industries and/or electricity workers not covered by an EA rising less than workers under an EA.

We do not consider wage increases in other EGWS industries are likely to be sufficiently different to the electricity industry to fully account for the 1.5 per cent difference between the EA and EGWS WPI. This would require average wage increases in these industries to be less than 1.5 per cent for 2013–14, which we consider to be unlikely. This is because there is no evidence that wages in these other industries are significantly below CPI.

We consider it is more likely that the private sector EAs in Frontier Economics' comparator group is not representative of wage increases in the electricity sector. As

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<sup>64</sup> Frontier Economics, *AER SAPN 014 Frontier Economics – Forecast calculations.xlsx*. We have excluded Energex's EA of 3.5 per cent because it is not a privately owned service provider.

discussed above, electricity workers covered by a private electricity service provider's EA represent only a subset of total electricity workers.

Business SA submitted that the wage increases in SAPN's EA of 4.25 per cent are not reflective of the wage constraints across both public and private sectors and current economic conditions in South Australia. Business SA also does not anticipate any demand side pressures in the labour market which substantiate wage increases significantly above CPI.<sup>65</sup>

South Australian Wine Industry Association (SAWIA) submitted that SA Power Networks' proposed labour price growth was extremely generous in comparison to the 3 per cent increase experienced in other industries.<sup>66</sup>

We agree with Business SA and SAWIA that SA Power Networks' EA wage increases are higher than wage growth in other industries. DAE noted that Australian wage growth is at record lows but wage gains in the utilities sector are still above national wage gains.<sup>67</sup>

DAE expects wage growth to fall in the utilities sector in the near term but remain above national wage growth until late 2016. DAE also notes that the skill shortages which underpinned strong wage growth in utilities in the past decade have diminished.<sup>68</sup>

DAE also noted that wage growth for existing EBA agreements in utilities fell from 3.7 per cent to 3.5 per cent in the last quarter and this downward trend is set to continue.<sup>69</sup>

The Consumer Challenge Panel (CCP) did not consider SA Power Networks' labour forecast above CPI to be reasonable. It noted that there was minimal wage pressure in the current Australian economy due to the end of the mining boom and skilled labour is more readily available. Further, it considered that if the cost of labour was rising at more than 2 per cent above CPI then it would be reasonable to expect that employers would deliver productivity improvements.<sup>70</sup>

SA Power Networks' proposal did not convincingly explain why it required opex for labour price growth in excess of CPI. Frontier Economics noted that SA Power Networks' EA represented an efficient outcome since all parties acted commercially and at arm's length from each other.<sup>71</sup> Frontier Economics also noted that SA Power Networks' wage increase set out in its EA was 2.75 per cent below the Single Bargaining Unit's (SBU) original Log of Claims of 7 per cent per annum. Frontier

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<sup>65</sup> Business SA, *SA Power Networks Regulatory proposal*, January 2015, p. 28.

<sup>66</sup> South Australian Wine Industry Association, *Submission in response to SA Power Networks' regulatory proposal 2015–20*, January 2015, p. 4.

<sup>67</sup> Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, p. 41

<sup>68</sup> Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, p. 44.

<sup>69</sup> Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, p. 45.

<sup>70</sup> Consumer Challenge Panel, *Submission by Consumer Challenge Panel 2 to the AER in response to SA Power Networks regulatory proposal for 2015–20*, January 2015, p. 29.

<sup>71</sup> Frontier Economics, *Forecasting labour cost escalation rates using EBA outcomes*, August 2014, p. 24.

Economics considers this demonstrated that SA Power Networks was able to negotiate a reduction in pay rates relative to the SBU's original claim. Overall we consider SA Power Networks' forecast labour price is not reflective of market conditions in the utilities sector and the overall Australian economy. If we were to apply SA Power Network's EA and Frontier Economics' benchmarked EA across all electricity labour, this is likely to lead to opex forecasts that do not reflect the opex objectives. There is no evidence to suggest that there is a supply and demand imbalance in electricity labour. We agree with the CCP that productivity gains should offset labour price increases. We discuss further the interaction between labour price and productivity in the next section below.

### ***Interaction between labour price and productivity***

We consider SA Power Networks EA wage increases, which are higher than current market conditions, are only efficient if they are to compensate labour productivity gains. Our benchmarking analysis uses the EGWWS WPI to measure both historical opex price growth and productivity growth. We consider a consistent measure is required when forecasting price growth and productivity growth.

In isolation, SA Power Networks labour price growth based on its EA may accurately reflect SA Power Networks' wage increases, but this measure does not account for the impact of its labour prices on its productivity. We must consider the effect of SA Power Networks' EA on its productivity forecast.

Since our rate of change approach is holistic, we cannot make a change to one component without considering the impact on other rate of change components. We do not consider SA Power Networks' labour price growth is consistent with our forecast of productivity growth.

This section discusses how the productivity component of the rate of change should account for the labour price measure used.

SA Power Networks forecast wages for staff on its EA to increase by an average of 1.73 per cent each year from 2014–15 to 2019–20 in real terms. We would expect there to be an increase in productivity to offset this real increase in prices. However, SA Power Networks forecast zero productivity. We consider zero productivity in conjunction with SA Power Networks' labour forecast is not likely to lead to an estimate consistent with the opex criteria.

This is because over the long term labour price growth adjusted for labour productivity is equal to the change in the CPI. Professor Borland demonstrates this in analysis that shows that, on average from 1997–98 to 2009–10, CPI plus labour productivity matched the average weekly ordinary time earnings (AWOTE).<sup>72</sup>

Jacobs also considered that over an extended period, growth in labour price will tend to average within the RBA's target range for CPI. The wages for the average worker

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<sup>72</sup> Professor Jeff Borland, *Labour cost escalation: choosing between AWOTE and LPI*, March 2012, p. 6.

tend to grow faster than CPI, equivalent to the sum of labour price growth and productivity growth.<sup>73</sup>

Since labour costs make up a majority of opex, we consider the rate of change excluding output growth should be approximately equal to CPI unless there is a decline in non-labour productivity.

SA Power Networks submitted that a productivity adjustment was not appropriate based on the maturity of our economic benchmarking models.<sup>74</sup> However, SA Power Networks did not adequately explain why it could justify an increase in its real labour price without a corresponding increase in its labour productivity. We consider a service provider at the efficient frontier should be able to at least maintain its current level of productivity provided there are no changes to external factors, such as a supply and demand imbalance for labour, in the forecast period. However, SA Power Network's forecast of labour in conjunction with zero productivity effectively results in a decline in its productivity.

### *Compositional productivity*

Australian PV institute submitted that it is unclear why SA Power Networks expects labour costs to increase, especially as it expects older staff members to be replaced by younger ones over the coming 5 years and labour costs are static or falling in real terms.<sup>75</sup>

The Australian PV institute has identified a change in labour composition. We note the WPI measure of the labour price does not account for shifts in labour composition. Other price measures such as the AWOTE capture compositional change which we would then account for in our productivity forecast. As noted above, the difference between different labour price measures is offset if a matching productivity adjustment is applied.

## **B.8.3 Forecast labour price**

As noted above we have used the EGWWS WPI to forecast the labour price. We consider the EGWWS WPI forecast by DAE to be a reasonable forecast of the labour price which takes into account current market conditions. This measure is also consistent with our productivity forecast methodology.

Where a consultant is used to forecast labour prices, we consider an averaging approach that takes into account the consultant's forecasting history, if available, to be the best methodology for forecasting labour price growth.

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<sup>73</sup> Jacobs, *Cost escalation factors 2015–20*, 10 October 2014, p. 32.

<sup>74</sup> SA Power Networks, *Regulatory proposal*, p. 269.

<sup>75</sup> Australian PV institute, *APVI submission to the AER on the Issues Paper on SA Power Network's Regulatory Proposal*, December 2014, p. 4.



We note SA Power Networks proposed an average of BIS Shrapnel and DAE forecasts for its contracted construction and labour services price growth. As noted below in our "Contracted construction and labour services" section, we consider only the EGWWS sector should be included for labour price growth.

Since we do not have an alternative SA EGWWS WPI forecast to average with our consultant's forecast we have adopted DAE's forecast WPI for utilities.

SA Power Networks did not consider the SA EGWWS WPI was a reasonable forecast of its labour price for the following reasons:

- EGWWS WPI is not representative of the labour costs of an electricity distribution business
- The Australian Bureau of Statistics (ABS) does not release data for the South Australian EGWWS WPI due to its small sample size. As a result, forecasts of the EGWWS WPI for SA are based on imputed values.
- Splicing together current EA outcomes with consultant's forecasts is likely to lead to a large unwarranted discontinuity in the forecast of labour costs over the RCP.<sup>76</sup>

As noted above, a measure of all electricity distribution workers is not available. We note either a narrower than ideal subset of electricity workers or a broader than ideal sample of all utilities workers can be a reasonable alternative where there is no measure of all electricity distribution workers.

We consider a state based forecast of the labour price will better reflect the cost inputs required to achieve the opex objectives. We recognise that the ABS does not publish EGWWS WPI figures for South Australia. However, our consultant DAE does not solely rely on ABS data to forecast its South Australian WPI. Although the forecast is based on imputed values it still represents the best forecast of the South Australian EGWWS industry available to us.

We recognise that there is a discontinuity between splicing EA and consultant forecasts. However, this is not relevant to our approach because we have applied the WPI throughout the whole forecast period.<sup>77</sup>

We also noted that EAs do not necessarily only reflect the labour price. For example a NSP may negotiate a lower increase in salary but change redundancy provisions. This may result in a lower price increase but may also affect the quantity of labour a NSP employs which will impact its labour productivity. This means EAs may affect both labour price and productivity.

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<sup>76</sup> SA Power Networks, Regulatory proposal, p. 266

<sup>77</sup> AER, *Draft decision Ausgrid distribution determination 2014–19 attachment 7: operating expenditure*, p. 221.

## B.8.4 Overall price growth

This section discusses the weightings we have applied to each price growth category and the reasons why we have adopted the CPI for non-labour price growth. We discuss why we have adopted the EGWWS WPI for the labour price above in section B.8.2.

We adopted a 62 per cent weighting for labour price and 38 per cent non-labour for our forecast opex price growth. We based our forecast of the labour price growth on forecasts of the EGWWS. Our forecast for non-labour price growth is the forecast change in the CPI. Table B.8 shows SA Power Networks' and our forecast annual price growth for each price growth driver.

**Table B.8 Forecast real price growth (per cent)**

	2015–16	2016–17	2017–18	2018–19	2019–20
<b>SA Power Networks</b>					
Labour	1.66	1.66	1.77	1.77	1.77
Contracted construction and labour services	0.50	0.90	1.10	1.40	1.80
Materials	0.71	0.12	0.01	-0.02	0.02
Land	5.96	5.96	5.96	5.96	5.96
Overall	1.06	1.33	1.58	1.72	1.89
<b>AER</b>					
Labour	-0.11	0.40	0.42	0.51%	0.56
Non-labour	-	-	-	-	-
Overall	-0.07	0.25	0.26	0.31	0.35

Source: SA Power Networks Regulatory proposal pp. 265–268; AER analysis.

As discussed above, SA Power Network's used its EA and benchmarked EA's to forecast labour price growth. This is higher than DAE's forecast labour price growth for the utilities sector.

In addition to this, SA Power Network's overall price growth is also different to ours for the following reasons:

- SA Power Networks escalates 97.9 per cent of its annual forecast opex by either its EA rate or contracted construction and labour services. Meanwhile, we apply a 62 per cent weighting to labour.
- SA Power Networks distinguishes between labour supplied by its own employees and contracted services. We do not distinguish between these labour types in our labour price growth.

- SA Power Networks forecast for materials and land is higher than our non-labour forecast.

We discuss these factors in detail below.

### ***Opex price weightings***

We weight the forecast price growth to account for the proportion of opex that is labour and non-labour.

We have adopted a 62 per cent weighting for labour and 38 per cent for non-labour. We forecast the labour component based on the EGWWS and we base the non-labour component on the CPI.

We have based these weightings on Economic Insight's benchmarking analysis which applied weight of 62 per cent EGWWS WPI for labour and 38 per cent for five producer price indexes (PPIs) for non-labour. The five PPI's cover business, computing, secretarial, legal and accounting, and public relations services.<sup>78</sup> These opex weightings are based on Pacific Economic Group's (PEG) analysis of Victorian electricity distribution service providers regulatory accounts data.<sup>79</sup>

Based on the available evidence, we consider the weightings from PEG's analysis represent reasonable benchmark weightings for efficient frontier.

SA Power Networks did not provide price weightings for its overall opex. Rather, its opex model applied a base - step - trend approach at the cost category level to each of its 65 opex cost categories.

Our analysis of SA Power Networks' opex model indicates that its overall opex weightings for each price category are:

- labour—43.8 per cent
- contracted constructions and labour services—54.1 per cent
- materials—0.7 per cent
- land—1.5 per cent

We consider the difference between SA Power Networks' opex weightings and ours to be a material driver of the difference between SA Power Networks' and our overall price growth. This is because SA Power Networks forecasts its labour and contractor expenditure, which accounts for 97.9 per cent of its opex, to change by more than CPI. Meanwhile, our price growth escalates only 62 per cent of opex above CPI.

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<sup>78</sup> Economic Insights, *Measurement of Inputs for Economic Benchmarking of Electricity Network Service Providers*, 22 April 2013, p. 4.

<sup>79</sup> Pacific Economics Group, *TFP research for Victoria's Power Distribution Industry*, Report prepared for the Essential Services Commission, 2004.

Under our price growth methodology only electricity related labour receives a price growth greater than CPI. The non-labour component of price growth includes contracted services. SA Power Networks' methodology assumes that the change in its contracting arrangements will be in line with forecast wage increases for the corresponding labour. As noted above, we consider the contracted services based on the PPI's are similar to the CPI so for forecasting purposes we consider contracting costs will move in line with the CPI.

Changing the opex weightings may result in a different price growth. However the impact on the overall rate of change is offset by a change in the productivity measure.

For example, Economic Insights conducted sensitivity analysis using the AWOTE and WPI and it found that the AWOTE, which on average is higher than the WPI, resulted in higher measured productivity levels.<sup>80</sup>

So if SA Power Networks were to include the labour price growth for its contracted services it would also have to include the productivity gains for its contracted workers in its productivity growth forecast.

We discuss the interaction between the price growth and productivity growth in detail above in section B.8.2.

#### *Forecast of producer price indices and CPI*

For the purposes of forecasting we have applied the forecast change in the CPI rather than the PPI's used by Economic Insights in its economic benchmarking of past opex. We recognise that the use of PPI's for historical purposes and CPI for forecasts may be inconsistent. However, sensitivity analysis from Economic Insights showed there to be no material difference between using the CPI or PPI in the economic benchmarking results. This is because the change in PPI's follows a similar trend to the change in CPI.<sup>81</sup>

We adopt the Reserve Bank of Australia's (RBA's) CPI forecasts in the Statement of Monetary Policy. For the years beyond those forecast by the RBA we apply the mid-point of their target band. We consider forecasts of the CPI to be more robust than forecasts of the PPI's because the CPI is a more aggregated measure and forecasts of the CPI are more readily available. Further the CPI is subject to the RBA's inflation target band which provides a more robust basis for economists to produce their forecasts. For this reason we have used forecast CPI, rather than PPI's, to forecast the non-labour component of price growth. Economic Insights noted that while the use of these PPIs is likely to be more accurate for historic analysis, it is unlikely to be practical for applications requiring forecasts of the opex price index such as the rate of change.

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<sup>80</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 17 November 2014, p. 23.

<sup>81</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 13.

This is because it is very difficult to obtain price forecasts at a finely disaggregated level other than by simple extrapolation of past trends.<sup>82</sup>

If the forecasts of the five PPI's can be forecast with similar accuracy to the CPI, then we would consider the five PPI's to also be a reasonable opex price deflator. However, at this stage we do not consider robust forecasts of the five PPI's are available.

### ***Materials and land***

We have not included explicit price categories for materials and land. These categories are included in our non-labour price growth.

SA Power Networks' based its proposed price growth for materials on the change in the forecast price of the following commodities:

- aluminium
- copper
- steel
- crude oil.<sup>83</sup>

SA Power Networks proposed real land cost escalation because the costs related to the properties it owns increase at a rate above CPI.<sup>84</sup>

We consider only price growth categories that are not already included in the CPI and have a material effect on opex input prices should be separately included in the rate of change.

We recognise that materials and land tax may change at a different rate to CPI. However, this is true of many other opex cost items. If we were to separately forecast materials and land costs because we expect them to change in price at a different rate to CPI, then we must also separately forecast price growth for other categories that increase in price less rapidly to avoid forecasting bias. Not doing so will systematically exceed the forecast opex required to meet the opex criteria.

For land price growth, we note the CPI includes both rental and house purchase costs in the basket.<sup>85</sup>

Further, we note the inclusion of a price growth category that increases at a rate greater than CPI will result in a higher productivity measure in our economic benchmarking. However, the inclusion of additional variables which do not have a material impact on the overall rate of change will result in a less parsimonious model.

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<sup>82</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 13.

<sup>83</sup> Competition Economists Group, *Materials cost escalation factors: a report for SA Power Networks*, August 2014, p. 2.

<sup>84</sup> SA Power Networks, *Regulatory proposal* p. 268.

<sup>85</sup> <http://www.abs.gov.au/websitedbs/webfaq.nsf/home/Consumer+Price+Index+FAQs> Accessed 9 February 2015.

For this reason we have included only two price growth categories which broadly reflect an efficient service provider's price growth.

### ***Contracted construction and labour services***

We consider we should only apply EGWWS labour for the labour component of price growth.

SA Power Networks commissioned labour forecasts for the following industries:

- electricity distribution
- contracted construction and labour services

The ABS previously advised:

... regardless of the type of job, if the job was selected from a business classified to the electricity, gas, water and waste services industry, the jobs pay movements contributes to this industry.<sup>86</sup>

The ABS takes into account the nature of the business, not the nature of the work undertaken, when allocating a job to an industry. The ABS labour price statistics for the EGWWS industry reflects both specialised electricity distribution network related labour and general labour.

We consider regardless of the nature of the task, if labour is employed by a business that operates in the utilities industry, then it should be escalated by the EGWWS industry forecast. For this reason we have adopted the EGWWS classification for all labour.

## **B.8.5 Output growth**

We are not satisfied SA Power Network's proposed average annual output growth of 1.04 per cent for the 2015–20 regulatory control period reflects the increase in output an efficient service provider requires to meet its opex objectives. We consider our weighted average output measure using economic benchmarking variables to be more reflective of the change in outputs SA Power Networks must meet. This results in an average network growth of 0.57 per cent for the 2015–20 regulatory control period.

We have adopted the following output growth measures and their respective weightings:

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

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<sup>86</sup> ABS, *Email from Kathryn Parlor to Fleur Gibbons*, 8 July 2010.

These output measures are consistent with the output variables used in our opex cost function analysis undertaken by Economic Insights to measure productivity. This approach is consistent with our Guideline.<sup>87</sup>

To develop the opex cost function Economic Insights selected the outputs, in consultation with stakeholders, using the following three selection criteria.

First, the output aligns with the NEL and NER objectives. The NER expenditure objectives for both opex and capex are to:

- meet or manage the expected demand for standard control services over that period
- comply with all applicable regulatory obligations or requirements associated with the provisions of standard control services
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
  - the quality, reliability or security of supply of standard control services
  - the reliability or security of the distribution system through the supply of standard control services

to the relevant extent:

- maintain the quality, reliability and security of supply of standard control services
- maintain the reliability and security of the distribution system through the supply of standard control services
- maintain the safety of the distribution system through the supply of standard control services.

Second, the output reflects services provided to customers.

Third, only significant outputs should be included. While service providers provide a wide range of services, a few key outputs dominate costs. Only those key outputs should be included to keep the analysis consistent with the high level nature of economic benchmarking.<sup>88</sup>

We discuss the process for selecting the output specification in our base opex appendix A and Economic Insights' benchmarking report.<sup>89</sup>

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<sup>87</sup> AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 23.

<sup>88</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 9.

<sup>89</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 9–12.

Our rate of change approach assumes any change in output results in the same proportional change in opex. For example, a 10 per cent increase in weighted average output growth results in a 10 per cent increase in opex.

We used the customer numbers, circuit length and maximum demand reported in SA Power Networks reset RIN. This produces an average annual growth rate of 0.75 per cent for customer numbers, 0.59 per cent for circuit length and no growth for ratcheted maximum demand. Our overall weighted average output growth is 0.57 per cent per annum.

The following three main drivers make up SA Power Networks' forecast output growth:

1. network growth (1.59 per cent per annum)
2. customer growth (1.34 per cent per annum)
3. workforce size (4.47 per cent per annum).<sup>90</sup>

SA Power Networks used the average historical growth rates from 2006–07 to 2012–13 for network growth and customer growth to forecast output growth. For workforce size, SA Power Networks applied the average from 2009–10 to 2012–13.<sup>91</sup>

The average historical growth rates are different to SA Power Network's proposed forecast growth rates for network growth and customer growth.

We consider the forecasts of line length and customer numbers in the reset RIN to be a better reflection of forecast output growth than SA Power Networks' historical growth rates, since historical growth rates do not take into account current and future market conditions. We also note that since SA Power Network's forecasts growth is different to its historical growth, this indicates that its own expectations for the forecast period are different to historical growth rates.

Economic Insights considers ratcheted maximum demand to be a better measure of the output a service provider must provide rather the level of assets such as distribution transformers and installed substation capacity. This is because the assets to provide capacity may be in excess to customer's requirements. Meanwhile ratcheted maximum demand takes into account network capacity actually used even if maximum demand may be lower in subsequent years.<sup>92</sup>

We note SA Power Networks maximum demand is lower in the forecast period than in 2014–15, so our forecast of ratcheted demand is zero. It is not reasonable to increase opex to allow for SA Power Networks to increase its network capacity when there is no increase in forecast maximum demand.

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<sup>90</sup> SA Power Networks, *Regulatory proposal*, p. 265.

<sup>91</sup> SA Power Networks, *21.4 Scale Escalation model 2015–20*, worksheets G1, G2 and G3.

<sup>92</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 17 November 2014, p. 11.



In regards to SA Power Networks' workforce size growth driver, we consider the number of staff employed to be an input rather than an output. SA Power Networks may require more staff as its network grows and our output growth measure will account for this increase.

We also note SA Power Networks has included economies of scale in its output growth measure. Although this reduces SA Power Networks' overall output growth, it still exceeds our output growth measure. We have considered economies of scale in our productivity assessment.

AGL noted that SA Power Networks proposed an increase in its opex even though there is no growth in overall energy consumption and peak demand.<sup>93</sup>

We note our output growth measure does not include overall energy consumption and uses a ratcheted maximum demand measure which does not include the decrease in forecast maximum demand. Over the 2015–20 regulatory control period ratcheted maximum demand is unchanged. Our weighted average output growth measure also includes the growth in customers and line length as the drivers of the output growth component in our rate of change measure.

### **B.8.6 Forecast productivity**

We have applied a zero per cent productivity growth in estimating our overall rate of change. We base this on our expectations of the forecast productivity for an efficient service provider in the short to medium term. This is consistent with Economic Insights' recommendation to apply zero forecast productivity growth for the distribution network service providers.<sup>94</sup>

Although our forecast productivity adjustment for SA Power Networks is zero, this reflects our price growth and output growth measures. We consider labour productivity and economies of scale to be sources of productivity and are linked to the labour and output measures.

SA Power Networks did not apply a productivity adjustment in its rate of change. It submitted that there was an inadequate basis for estimating and applying a productivity adjustment in the rate of change. However, SA Power Networks did apply economies of scale factors to its output growth which we consider to be a form of productivity.<sup>95</sup>

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<sup>93</sup> AGL, *SA Power Networks– regulatory proposal Jul 2015 to June 2020 – AGL submission to the Australian Energy Regulator*, 30 January 2015, p. 12.

<sup>94</sup> Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 8 September 2014, p. 52 and Economic Insights, *Response to consultants' reports on economic benchmarking of electricity DNSPs*, 13 April 2015, p. 74.

<sup>95</sup> SA Power Networks, *Regulatory proposal*, p. 269

Our Guidelines state that we will incorporate forecast productivity in the rate of change we apply to base opex when assessing opex. Forecast productivity growth will be the best estimate of the shift in the productivity frontier.<sup>96</sup>

We consider past performance to be a good indicator of future performance under a business as usual situation. We have applied forecast productivity based on historical data for the electricity transmission and gas distribution industries where we consider historical data to be representative of the forecast period.

To reach our best estimate of forecast productivity we have taken into account all available information. This includes Economic Insights' economic benchmarking, SA Power Networks' proposal, our expectations of the distribution industry in the short to medium term, and observed productivity outcomes from electricity transmission and gas distribution industries.

We have applied a zero productivity forecast for SA Power Networks for the following reasons:

- While data from 2006–13 period indicates negative productivity for distribution network service providers on the efficient frontier, we do not consider this is representative of the underlying productivity trend and our expectations of forecast productivity in the medium term. The increase in the service provider's inputs, which is a significant factor contributing to negative productivity, is unlikely to continue for the forecast period.
- Measured productivity for electricity transmission and gas distribution industries are positive for the 2006–13 period and are forecast to be positive.

We must also consider the interaction between our productivity, price growth and output growth.

We discuss each of these reasons in detail in the sections below.

### ***Forecast outlook and historical productivity***

As noted above, the forecast productivity is our best estimate of the shift in the frontier for an efficient service provider. Typically we consider the best forecast of this shift would be based on recent data. However, this requires a business as usual situation where the historical data is representative of what is likely to occur in the forecast period.<sup>97</sup>

Analysis from Economic Insights using MTFP and opex cost function models showed that from 2006 to 2013, the distribution industry experienced negative productivity

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<sup>96</sup> AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

<sup>97</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 41.

growth.<sup>98</sup> This means that for the distribution industry inputs specified under the models increased at a greater rate than the measured outputs.

According to Economic Insights' modelling, the average annual output growth from 2010 to 2013 for the distribution industry was 0.6 per cent. During this period, the output measures of customer numbers and circuit length grew by 1.2 per cent and 0.5 per cent respectively. Maximum demand decreased by 4.1 per cent from its peak in 2009.<sup>99</sup>

However, total input quantity increased by 2.8 per cent per annum from 2010 to 2013.<sup>100</sup> This has been driven by substantial increases in both opex and capital inputs.

We note past step changes will also decrease measured productivity. Since a step change will increase a service provider's opex without necessarily increasing its outputs. For example, a change in a regulatory obligation may increase a service provider's compliance costs without increasing its ratcheted maximum demand, line length or customer numbers.

We note that in Victoria for the 2011–2015 period, the increase in regulatory obligations related to bushfires was forecast to be 9.0 per cent of total opex.<sup>101</sup>

We consider the increase in bushfire safety requirements to be a one off step increase in the cost of compliance. We do not expect there to be a similar increase in the cost of bushfire safety requirements in the forecast period.

We also approved a \$35.5 million (\$2009–10) step change for SA Power Network's vegetation clearance pass through as a result of changing weather conditions.<sup>102</sup>

If we used historical productivity to set forecast productivity, this would incorporate the effect of past step changes which as shown above have negatively impacted on measured opex productivity. We do not consider past step changes should affect

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<sup>98</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 20, p. 40.

<sup>99</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 44–45.

<sup>100</sup> Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 45.

<sup>101</sup> AER, *Final decision: CitiPower Ltd and Powercor Australia Ltd vegetation management forecast operating expenditure step change*, August 2012, p. 2. AER, *CitiPower Pty Distribution determination 2011-15*, September 2012, p. 17. AER, *Powercor Australia Ltd Distribution determination 2011-15*, October 2012, p. 26. AER, *Final decision: Powercor cost pass through application of 13 December 2011 for costs arising from the Victorian Bushfire Royal Commission*, May 2011, p. 96. AER, *Final decision - appendices: Victorian electricity distribution network service providers - Distribution determination 2011-2015*, October 2011, p. 301-304. AER, *Final Decision: SP AusNet cost pass through application of 31 July 2012 for costs arising from the Victorian Bushfire Royal Commission*, 19 October 2012, p. 3. AER, *SPI Electricity Pty Ltd Distribution determination 2011-2015*, August 2013, p. 20. AER, *Jemena Electricity Network (Victoria) Ltd: Distribution determination 2011-2015*, September 2012, p. 22. AER, *United Energy Distribution: Distribution determination 2011-2015*, September 2012, p. 19.

<sup>102</sup> AER, *SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation growth rates*, July 2013, p. 6.

forecast productivity. We assess any new step changes in our step change assessment.

### ***Other industries and proposed productivity***

In estimating forecast productivity for the distribution industry we have also had regard to the electricity transmission and gas distribution industry, and distribution network service provider's productivity forecasts.<sup>103</sup>

Measured declines in productivity in the electricity distribution sector are unlikely to reflect longer term trends. Economic Insights notes:

We also note that a situation of declining opex partial productivity is very much an abnormal situation as we normally expect to see a situation of positive technical progress rather than technical regress over time. While we acknowledge the distinction between the underlying state of technological knowledge in the electricity distribution industry and the impact of cyclical factors that may lead to periods of negative measured productivity growth, the latter would be expected to be very much the exception, step change issues aside.

Further both the electricity transmission and gas distribution industries experienced positive opex productivity growth during the 2006–13 period.<sup>104</sup> For electricity transmission network service providers average industry productivity was 0.85 per cent and for gas distribution Jemena Gas Networks proposed an average opex productivity of 0.95 per cent of which 0.83 per cent was attributed to the shift in the frontier.<sup>105</sup>

Cyclical factors and regulatory obligations for the distribution sector may be the reason for the lower measured productivity in the distribution industry compared to the transmission and gas distribution industries. Over the medium to long term, however, we expect the distribution network service providers to have underlying productivity growth rates comparable to the electricity transmission and gas distribution industries. This is because the specific factors that have resulted in declining productivity for the distribution industry are unlikely to apply over the medium to long term and the distribution industry should be broadly similar to other energy networks.

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<sup>103</sup> This includes productivity forecasts from Endeavour Energy, Essential Energy, ActewAGL, Ausgrid, Ergon Energy, Energex and SA Power Networks.

<sup>104</sup> AER, *TransGrid transmission determination – draft decision*, Attachment 7, Appendix A, November 2014; AER, *JGN gas distribution determination – draft decision*, Attachment 7, Appendix A, November 2014.

<sup>105</sup> AER, *JGN gas distribution determination – draft decision*, Attachment 7, Appendix A, November 2014.

## C Step changes

In developing our alternative opex forecast, we recognise that there may be changed circumstances in the forecast period that may impact on the expenditure requirements of a service provider. 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 our alternative forecast, such as our estimate of 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 Position

We have included some step changes SA Power Networks labelled as legal and regulatory costs, capital program impacts and base year adjustments in our alternative opex forecast. We summarise the revenue impact in Table C.1.

**Table C.1 Summary of draft position on step changes (\$ million, 2014–15)**

	SA Power Networks proposal	AER position
Legal and regulatory	105.0	1.3
Capital program impacts	69.6	7.8
Customer driven initiatives	41.6	–
Financing related matters	0.6	–
Base year adjustments*	–10.4	–5.0
<b>Total</b>	<b>206.4</b>	<b>4.1</b>

Source: AER analysis; SA Power Networks, *Regulatory proposal*, pp. 253, 256.

\* This only includes the expenditure that SA Power Networks classified as a base year adjustment that we assessed as a step change. We consider other proposed base year adjustments in the base opex appendix.

### C.2 SA Power Networks' proposal

SA Power Networks identified step changes in costs it forecasts it will incur during 2015–20 which were not incurred in the proposed base year, 2013–14. It stated that these costs related to:

- changes in regulatory and legal obligations

- operating costs arising from capital program impacts
- delivering on customer expectations identified during its customer engagement program
- financing related matters.<sup>106</sup>

Each category of step change was further categorised into sub-categories and then into programs or projects. Table C.2 to Table C.5 identifies and summarises SA Power Networks' proposal at the sub-category level.

**Table C.2 Legal and regulatory step changes (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Asset inspections	8.5	8.9	8.9	8.9	6.9	42.1
Workplace health and safety	2.2	2.4	2.7	2.8	2.8	12.9
Energy laws and regulations	4.6	5.3	11.8	13.0	13.9	48.6
Environmental management	0.2	0.3	0.3	0.3	0.3	1.4
<b>Total</b>	<b>15.5</b>	<b>16.9</b>	<b>23.7</b>	<b>25.0</b>	<b>23.9</b>	<b>105.0</b>

Source: AER analysis; SA Power Networks, *Regulatory proposal*, p. 256.

**Table C.3 Capital program impact step changes (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Information technology	6.6	11.2	11.3	8.1	6.7	43.9
Telecommunications	1.9	3.2	3.6	3.9	4.0	16.6
Data quality	1.0	0.8	0.7	0.7	0.7	3.9
Substation maintenance	0.4	0.5	0.5	0.5	0.5	2.4
Condition monitoring	0.2	0.4	0.4	0.4	0.4	1.8
Flexible load management	0.2	0.2	0.2	0.2	0.2	1.0
<b>Total</b>	<b>10.3</b>	<b>16.3</b>	<b>16.7</b>	<b>13.8</b>	<b>12.5</b>	<b>69.6</b>

Source: AER analysis; SA Power Networks, *Regulatory proposal*, p. 258.

<sup>106</sup> SA Power Networks, *Regulatory proposal*, October 2014, p. 255

**Table C.4 Customer driven and changing community expectations step changes (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Vegetation management	8.0	7.1	6.5	5.6	4.8	31.9
Customer services	1.0	0.7	1.0	0.6	1.0	4.3
Community safety	1.7	1.2	0.8	0.9	0.8	5.4
<b>Total</b>	<b>10.7</b>	<b>9.0</b>	<b>8.2</b>	<b>7.1</b>	<b>6.6</b>	<b>41.6</b>

Source: AER analysis; SA Power Networks, *Regulatory proposal*, p. 260.

**Table C.5 Financing related step changes (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Insurance premiums	0.3	0.4	0.6	0.8	0.9	3.0
Superannuation	-0.9	-0.6	-0.4	-0.3	-0.2	-2.4
<b>Total</b>	<b>-0.6</b>	<b>-0.2</b>	<b>0.2</b>	<b>0.5</b>	<b>0.7</b>	<b>0.6</b>

Source: AER analysis; SA Power Networks, *Regulatory proposal*, p. 262.

In addition, SA Power Networks removed costs from its base year for opex incurred in 2013–14 for expenditures of an unusual nature that it considers is likely to understate/overstate its long term efficient costs.

Table C.6 summarises SA Power Networks' proposed base year adjustments.

**Table C.6 Base year adjustments (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Self- insurance	-3.2	-3.2	-3.2	-3.2	-3.2	-16.0
Metering reclassification	-2.2	-2.2	-2.2	-2.2	-2.2	-11.0
Regulatory proposal	-3.0	-3.2	-1.5	0.7	-1.2	-8.2
Distribution licence fee	-1.1	-1.1	-1.1	-1.1	-1.1	-5.5
DMIA	-0.9	-0.9	-0.9	-0.9	-0.9	-4.5
Non-network solution	0.2	0.2	0.3	0.3	0.4	1.4
Property	0.4	0.4	0.4	0.4	0.4	2.0
Finance adjustments	1.4	1.4	1.4	1.4	1.4	7.0
<b>Total</b>	<b>-8.4</b>	<b>-8.6</b>	<b>-6.8</b>	<b>-4.6</b>	<b>-6.4</b>	<b>-34.8</b>

Source: AER analysis, SA Power Networks, *Regulatory proposal*, p. 254.

### C.3 Assessment 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.<sup>107</sup> Our assessment approach is consistent with the approach specified in our *Expenditure forecast assessment guideline* (Guideline).<sup>108</sup>

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 the base efficient 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 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.

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. For 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.<sup>109</sup>

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 we do not also apply a negative step change for costs that are increasing by less than

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<sup>107</sup> NER, clause 6.6.5(c).

<sup>108</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 11, 24.

<sup>109</sup> AER, *Explanatory guide: Expenditure assessment forecast 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. 164–165.



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 categories whose price is 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 total opex as a whole will be too high.

Further to assessing 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:<sup>110</sup>

- whether there is a change in circumstances that affects the service provider's efficient forecast expenditure
- 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 making 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 increase maintenance opex). Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control. 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.<sup>111</sup> 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 implementing efficiency improvements. We expect the service provider to bear such

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<sup>110</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

<sup>111</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 24.

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.<sup>112</sup> 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.4 Reasons for position

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

- National Energy Customer Framework
- Mobile radio
- Forecast changes to SA Power Networks' distribution licence fee

There were several common themes why we have not considered additional step changes in opex were needed.

**Base opex already reflects the cost of meeting existing regulatory obligations, and maintaining the reliability, safety and quality of supply of standard control services.**

As outlined in our Guideline, actual past expenditure, if efficient, should provide a good indicator of required funding in the future.<sup>113</sup> Opex tends to be stable or recurrent both on a year by year basis and when comparing opex across regulatory control periods. If a service provider is operating efficiently, there should be few reasons why its forecast opex in a regulatory control period should be much different to its past spending in the previous regulatory control period. Reasons why we do forecast an increase in opex include:

- changes in input prices and output growth which we account for through the rate of change,
- a new or changed regulatory obligation, which represents an increase in what a service provider must undertake, or
- an efficient opex/capex trade-off which represents a change in the inputs a prudent service provider would use to provide an efficient distribution network service

SA Power Networks' proposed step changes represent an 18 per cent increase above a forecast based on the opex it incurred in 2013–14. The increase is primarily driven by

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<sup>112</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 24; AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, pp. 51–52.

<sup>113</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 22.

new programs or projects of opex that SA Power Networks states it did not undertake in the base year.

We acknowledge that some types of projects and programs of expenditure a service provider undertakes will differ between years and between regulatory control periods. However, we do not consider variation in the expenditure on projects and programs is a reason to increase the revenue it can recover from electricity network consumers. What matters is whether the cost of these programs is likely to affect the total efficient opex a prudent service provider would require to meet all existing regulatory obligations, meet or manage expected demand, and maintain the reliability, safety and quality of supply.

A new program 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. Alternatively, efficiency improvements can fund new programs and projects. In considering whether a step change is required we have regard to whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts. SA Power Networks has not demonstrated this to us. In many cases it has just identified a need at the program or project level and then added it to the total opex it incurred in 2013–14. It did not demonstrate whether it had considered the increase in the cost of the program could be met by other savings or by re-prioritising its opex budget. We would expect a prudent service provider acting efficiently would undertake a rigorous process to determine not only whether the particular projects and programs need to be undertaken but how it had sought to determine whether an increase in its total opex forecast would be needed.

We note that several stakeholders questioned the drivers behind SA Power Networks' proposed increase in opex:

- The Energy Consumers Coalition of South Australia commented that a number of proposed step changes are not driven by external forces but a desire for SA Power Networks to do more work.<sup>114</sup>
- The South Australian Financial Counsellors Association saw no reason for SA Power Networks' increase in opex given that demand is falling, SA Power Networks is a long established business and newer technologies should be increasing its efficiency.<sup>115</sup>

**Several proposed step changes are for initiatives designed to achieve efficiencies. An increase in funding for such initiatives would be inconsistent with the incentive based regulatory framework**

SA Power Networks has proposed a number of different step changes in opex where it considers the program or projects will generate efficiencies. We have not included these programs or projects in our alternative opex forecast.

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<sup>114</sup> ECCSA, *SA Electricity Distribution Revenue Reset*, p. 56.

<sup>115</sup> SAFCA, *Submission to SA Power Networks' regulatory proposal*, p. 14.

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. For instance;

- If it can achieve efficiencies in delivering opex it will keep the difference between forecast and actual opex within a regulatory period, and also receive some Efficiency Benefit Sharing Scheme (EBSS) payments in the next period. Our approach to implementing the EBSS is outlined in Attachment 9.<sup>116</sup>
- If it can achieve efficiencies in delivering capex it will keep the return on the RAB within the regulatory control period based on what we forecast would be an efficient capex spend. It will also receive Capital Expenditure Sharing Scheme (CESS) payments. Our approach to implementing the CESS is outlined in Attachment 10.<sup>117</sup>
- If it can reduce the frequency and duration of unplanned outages it will receive Service Target Performance Incentive Scheme (STPIS) payments. Our approach to implementing the STPIS is outlined in Attachment 11.

Forecast opex must be consistent with any incentive scheme or schemes that apply to SA Power Networks.<sup>118</sup> 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 or increased reliability and it received a reward through the incentive schemes. Consumers would pay for the incremental cost of the initiative as well as pay SA Power Networks rewards for becoming more efficient and/or more reliable. Its customers could end up paying more for a service which costs less.

We expect a service provider to weigh up the expected benefits it would receive from an efficiency initiative against the expected cost of the initiative and decide itself whether that initiative is worth funding. In our view, there is no compelling reason why SA Power Networks should receive additional funding from its customers to pursue efficiencies.

### **We could find little evidence of changes in SA Power Networks' regulations or requirements**

As outlined in the assessment approach section, we may consider a step change in opex where there has been a change in a regulatory or legal obligation facing a service provider.

In considering whether this is the case, we consider first whether the obligation has changed since the base year. If it has not changed then a service provider's base level of opex should be sufficient to meet its regulatory obligations. If it has changed we

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<sup>116</sup> Also see AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers- Explanatory Statement*, November 2013.

<sup>117</sup> Also see AER, *Capital Expenditure Sharing Scheme for Electricity Network Service Providers- Explanatory Statement*, November 2013.

<sup>118</sup> NER, s.6.5.6(e)(8)

consider whether there is evidence that the obligation is likely to lead to increased costs in delivering regulated network services.

SA Power Networks has quoted a variety of regulations and laws in its proposal. However, we could find little evidence that the regulation 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. This view was also expressed by Business SA which considered that SA Power Networks had made repeated references to costs associated with new standards and regulations without specifying what those changes are.<sup>119</sup> The EUAA also noted that SA Power Networks does not face significant changes to its compliance regime so did not consider many step changes to be justified.<sup>120</sup>

In supporting some step changes, SA Power Networks considers that expectations of what a reasonable service provider would do in meeting its regulatory obligations or requirements may change over time. We do not dispute this as an overarching principle but there was little evidence that these expectations had changed since 2013-14, the base year for SA Power Networks' opex forecast.

### **There was no compelling evidence to support increases in 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 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 expenditure to undertake.

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 do not approve increases in forecast opex.

We do not consider SA Power Networks has demonstrated that its proposed step changes labelled as customer driven or for meeting community expectations warranted an increase in forecast opex. This was for a variety of reasons:

- Many of the proposed programs were discretionary. We consider discretionary programs should be managed within SA Power Networks' existing budget.

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<sup>119</sup> Business SA, *SA Power Networks Regulatory Proposal*, p. 24.

<sup>120</sup> EUAA, *Submission to SA Power Networks' regulatory proposal*, p. 11.

- There was little evidence about why SA Power Networks would need additional opex for these programs to maintain the reliability, safety and quality of supply of the service it provides.
- SA Power Networks was seeking to undertake activities which could be provided by other organisations, or funded by other sources.

We address our position on each step change proposed by SA Power Networks below.

## C.4.1 Legal and regulatory step changes

### *Asset inspections*

SA Power Networks proposed three step changes for asset inspections. We did not include any step changes for asset inspections in our alternative forecast of opex. Our reasons for this position are outlined below.

#### *Inspections of pole footings*

SA Power Networks forecast an increase in opex of \$23.4 million (\$2014–15) to inspect poles that it previously considered were not accessible ('no access' poles). Previously SA Power Networks undertook limited inspections of pole footings where there were access issues such as bitumen or concrete paving. SA Power Networks considered such poles would not be susceptible to the degree of corrosion and degradation of poles in other locations. During 2013–14 it tested whether this assumption was valid but identified that these assets do suffer below ground corrosion. It proposed a step change for a program commencing in the 2015–20 regulatory control period to inspect these poles.<sup>121</sup>

We do not consider an increase in opex is needed for this program of expenditure. This is for a range of different reasons.

SA Power Networks' proposed program to inspect no access poles is not a response to a new regulatory obligation. It is a new program it has identified to help meet its existing regulatory obligations. As outlined above, we recognise that a service provider will alter its expenditure over time on specific programs and projects. Inspecting no access poles may be one area where SA Power Networks needs to devote additional resources in the 2015–20 regulatory control period. However, we do not forecast opex on individual programs and projects. We forecast total opex. Total opex is relatively recurrent. As opex on some programs and projects increases, opex on other programs and projects will decrease. It is a prudent service provider's responsibility to reallocate its opex budget to meet these changing priorities. It generally should not need an increase in its budget to meet existing regulatory obligations. We see no reason why we should make a distinction for this proposed program of expenditure.

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<sup>121</sup> SA Power Networks, *Attachment 21.13*, p. 13.

SA Power Networks states that inspecting no access poles will avoid reactive emergency response to unplanned failures and it will avoid the higher costs of emergency replacement of failed poles relative to planned replacement.<sup>122</sup> These are efficiencies. Forecast opex must be consistent with any incentive scheme or schemes that apply to SA Power Networks.<sup>123</sup> As outlined above, we do not provide step changes for programs that aim to improve efficiency. We would expect SA Power Networks to weigh up the increased inspection costs with the likely reductions in replacement capex and emergency response opex, when deciding whether to undertake this program. However, it should not require an increase in funding to implement programs that will achieve efficiencies. If this program is efficient, the benefits that flow to SA Power Networks through the EBSS through lower emergency replacement opex and/or the CESS) through lower replacement capex costs should outweigh the additional cost it faces.

We also note that if this program of expenditure is expected to help reduce the likelihood of emergency replacement of failed poles, it may also help to improve reliability. SA Power Networks is rewarded for improvements in reliability through the STPIS. Forecast opex must also be consistent with the STPIS.<sup>124</sup> It would be inconsistent with how the STPIS is intended to operate if consumers paid for an increase in opex to improve reliability but also funded STPIS payments for improved reliability to SA Power Networks.

#### *Inspections of underground cables*

SA Power Networks forecast an increase in opex of \$3.1 million (\$2014–15) to inspect underground cables. SA Power Networks states that in the past its underground network has not been condition monitored as it considered there is no method of prudently performing this inspection. This has resulted in a reactive maintenance where cables are fixed when they fail and cable sections are replaced following multiple failures. It has recently purchased new cable fault finding technology which has the capability of determining the condition of underground cables. It proposes a new program to determine the condition of 62 per cent of its underground cables. Without this program SA Power Networks considers the number of unplanned outages will increase above historic levels.<sup>125</sup>

We do not consider an increase in opex is needed for this program of opex.

Similar to the no access poles program, by undertaking this program SA Power Networks has also stated that it will:

- avoid reactive emergency response to unplanned failures, and

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<sup>122</sup> SA Power Networks, *Attachment 21.13*, p. 17.

<sup>123</sup> NER, s.6.5.6(e)(8)

<sup>124</sup> NER, s.6.5.6(e)(8)

<sup>125</sup> SA Power Networks *Attachment 21.13*, p. 20.

- the higher costs of emergency replacement of failed cables relative to planned replacement.<sup>126</sup>

We would expect SA Power Networks to weigh up all the costs and benefits when deciding whether to implement this program. That is, SA Power Networks should consider the additional costs that may arise from the increased inspections of underground cables and planned maintenance costs to repair faulty cables against the EBSS, CESS and STPIS benefits that will arise from reductions in:

- emergency replacement capex of failed cables,
- reactive maintenance opex to repair faulty cables, and
- unplanned outages.

As outlined above, forecast opex must be consistent with any incentive scheme or schemes that apply to SA Power Networks. The incentive schemes will provide SA Power Networks with benefits where it can reduce its opex, capex and unplanned outages. If efficient, the benefits should be sufficient to cover any incremental costs associated with inspecting underground cables. On the other hand if the expected benefits of the program do not outweigh the expected costs, then it would not be cost efficient for SA Power Networks to increase its opex for inspecting underground cables. Under either scenario we are not satisfied that a step change in our alternative opex forecast is needed.

#### *Inspections of assets in bushfire risk areas*

SA Power Networks forecasts an increase in opex of \$15.6 million (\$2014–15) to increase the inspection frequency of assets in bushfire risk areas. SA Power Networks commissioned an independent review by Jacobs to review and recommend strategies to reduce the likelihood of fire starts. Jacobs recommended reducing the visual inspection cycle from ten years in all Bushfire Risk Areas to five years, and to extend thermographic inspections to all sections of feeders. SA Power Networks included a step change in its opex to give effect to Jacobs' recommendations.<sup>127</sup>

We have not included SA Power Networks' forecast of increased asset inspections in bushfire risk areas in our alternative opex forecast.

Based on the comparative asset inspection practices in the NEM, we accept that it would be prudent to increase the frequency of assets in bushfire risk areas. SA Power Networks notes in its proposals that bushfire risk area inspection practices of other DNSPs. It showed that other service providers inspect assets every two and a half to five years.<sup>128</sup> Based on this information we consider it would be good practice for SA Power Networks inspect its assets in bushfire risk areas more frequently than ten years.

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<sup>126</sup> SA Power Networks, *Attachment 21.13*, p. 24.

<sup>127</sup> SA Power Networks, *Attachment 21.13*, p. 29.

<sup>128</sup> SA Power Networks, *Attachment 21.13*, p. 37.



However, we are not persuaded that SA Power Networks requires additional funding to implement these practices.

As noted above, our task is to determine the total amount of funding SA Power Networks needs to carry out its regulatory obligations. While it may be prudent for SA Power Networks to change one particular business practice, this is not sufficient evidence that it needs additional funding. The cost of individual programs and projects often change over time, but these changes can be accommodated without increasing total spending. SA Power Networks has not persuaded us that this change cannot be accommodated without a step change.

We also have concerns with SA Power Networks' approach to estimating the cost of its proposed step change. SA Power Networks has forecast its asset inspections expenditure from 2010–15 using a bottom-up approach. It estimated the step change as the difference between SA Power Networks' bottom-up forecast of opex on pole inspections over the 2015–20 period and the actual opex it spent on pole inspections in 2013–14. We consider that any step change should relate to the estimated incremental cost of total opex that would not have otherwise occurred without the change in practice. It is not clear why pole inspection expenditure in 2013–14 should be the baseline. For instance, SA Power Networks' forecasting model illustrates its annual pole inspection expenditure was not consistent during the 2010–15 period. We would require additional evidence in SA Power Networks' revised proposal to justify 2013–14 as the baseline for pole inspection expenditure.

SA Power Networks' bottom-up approach to forecasting pole inspections over the 2015–20 regulatory period was contained in a complex forecasting model which contains line-by-line estimates of every pole inspection SA Power Networks plans to undertake over the 2015–20 regulatory control period.<sup>129</sup> SA Power Networks did not provide sufficient clarity about the underlying assumptions supporting its forecast. In all forecasts we expect service providers to clearly outline all the main assumptions and inputs used and demonstrate how these affect the relevant forecast.

### ***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.

SA Power Networks included four step changes for workplace health and safety in its opex forecast. These are:

- 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

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<sup>129</sup> SA Power Networks, *Attachment 21.40 - Multivariable inspection forecasting model*

proposes to use two person patrols. It forecasts additional opex of \$2.8 million (\$2014–15) over the 2015–20 regulatory control period for this step change.<sup>130</sup>

- Network operations—Given forecast increases in connections such as embedded generation, SA Power Networks considers there is increasing demand for monitoring of the distribution system. As a result it considers that it needs to increase the resources it devotes to monitoring the distribution system after business hours.<sup>131</sup> It forecasts additional opex of \$4.0 million (\$2014–15) for this step change.
- Fleet monitoring—SA Power Networks propose to introduce an in-vehicle monitoring system to monitor driver behaviour.<sup>132</sup> It forecasts 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.<sup>133</sup> It forecasts an additional \$3.9 million (\$2014–15) for this step change.

For all these proposed step changes, SA Power Networks has cited compliance with the requirements of sections the Work Health and Safety Act 2012 (SA) (WHS Act). The Energy Consumers Coalition of South Australia (ECCSA) considered that it was not clear if the proposed enhancements are mandated by law or reflect SA Power Networks' interpretation of the legal requirements. It considered that if there is no mandated change then SA Power Networks should not be granted an increase in opex.<sup>134</sup>

The WHS Act commenced on 1 January 2013. We consider a prudent service provider would already be compliant with its obligations under the WHS Act by that date. It would not need to introduce substantial new measures to ensure compliance in the 2015–20 regulatory control period. We note that SafeWork SA considers that most of the new Work Health and Safety Regulations 2012 are consistent with the former occupational health, safety and welfare legislation.<sup>135</sup> The regulations which have changed were unrelated to SA Power Networks' proposed step changes.

In support of its proposals, SA Power Networks cite section 17 of the WHS Act that provides that SA Power Networks must eliminate the risks to health and safety so far as is reasonably practicable, and if it is not reasonably practicable to do so, minimise

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<sup>130</sup> SA Power Networks, *Attachment 21.13*, p. 38.

<sup>131</sup> SA Power Networks, *Attachment 21.13*, p. 44.

<sup>132</sup> SA Power Networks, *Attachment 21.13*, p. 48.

<sup>133</sup> SA Power Networks, *Attachment 21.13*, p. 53.

<sup>134</sup> ECCSA, *SA Electricity Distribution Revenue Reset*, p. 57.

<sup>135</sup> SafeWork SA, [http://www.safework.sa.gov.au/uploaded\\_files/WHSTransitionalSummary.pdf](http://www.safework.sa.gov.au/uploaded_files/WHSTransitionalSummary.pdf), 2014.

those risks as far as reasonably practicable. It considers what is 'reasonably practicable' will change over time.<sup>136</sup>

The term 'reasonably practicable' means what could reasonably be done at a particular time to ensure health and safety measures are in place. In other words, what can reasonably be done will change over time. In determining what is reasonably practicable, SA Power Networks is required to weigh up all relevant matters prescribed by the WHS Act but cost may only be considered after assessing the extent of the risk and the available ways of eliminating or minimising the risk.<sup>137</sup>

As outlined above we recognise that standards of what risks are acceptable do change over time. However, SA Power Networks has 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 is not clear to us why the measures that were 'reasonably practicable' in the base year, 2013–14, are likely to be materially different in the 2015–20 regulatory control period. As such we are 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 to the base year. Therefore, we do not consider a step change in opex is appropriate for a prudent service provider to comply with its WH&S obligations.

## ***Energy laws and regulations***

### *RIN requirements*

We have not included a step change in our alternative opex forecast for Regulatory Information Notice requirements. We do not accept SA Power Networks' claim that it will incur higher costs in the 2015–20 regulatory control period in meeting its RIN requirements.

SA Power Networks forecast additional opex of \$9.2 million (\$2014–15) in systems and business processes to provide actual data for the AER's RIN requirements. It considers that each RIN now seeks a more granular level of information. It also notes the RIN requirements going forward will require a greater proportion of actual information whereas previously we required estimated information.

SA Power Networks considers its existing systems and processes are not configured or designed to capture the information required by the RINs.

SA Power Networks has not put forward persuasive evidence as to why its RIN reporting costs will increase in the 2015–20 regulatory control period. For instance:

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<sup>136</sup> SA Power Networks, *Attachment 21.13*, p. 39.

<sup>137</sup> SA Power Networks, *Attachment 21.13*, p. 39.

- SA Power Networks has not demonstrated to us why producing actual data rather than estimated data for some cost categories will lead to a materially greater cost burden to it in the 2015–20 regulatory control period.
- In each year of the 2015–20 regulatory control period, SA Power Networks will only provide data to the AER from the most recent year. The information that SA Power Networks collected and provided to the AER in 2013–14 for economic benchmarking was for eight years. The information we collected for category analysis was for five years. Some of this information was reported to us for the first time. The volume of data we will collect annually in the 2015–20 regulatory control period will be far less than we collected in 2013–14. We would expect this is a reason the annual costs SA Power Networks will incur in complying with our notices will be less than it incurred in 2013–14.
- As 2013–14 was the first year that we collected this data then we also expect that there would be some upfront costs incurred in initially identifying and collecting the data. By the 2015–20 regulatory control period, SA Power Networks would have had collected the data for two years. With two years experiencing in collecting the data we require, we would also expect SA Power Networks would develop more efficient practices in identifying, collecting and reporting the data. We would expect these efficiencies would only increase over the 2015–20 regulatory control period. This would also lead to a potential decrease in SA Power Networks' RIN reporting costs.
- In the 2013–14 regulatory year, SA Power Networks would also have incurred costs in completing its regulatory RIN. As these costs are typically only incurred towards the end of a regulatory control period, we would expect that SA Power Networks' regulatory reporting costs would fall in the first few years of the 2015–20 regulatory control period. This would help to further offset any forecast cost increase that would arise from reporting a greater amount of information on an actual rather than an estimated basis.

We also note Origin Energy, the EUAA and ECCSA did not support this step change.<sup>138</sup> Origin Energy considered these costs would not be material as it anticipates that the majority of this information would already be captured as a matter of course.<sup>139</sup> The EUAA noted that SA Power Networks prepared its RIN for the current regulatory determination process and was able to spend less than forecast opex for the current regulatory control period.<sup>140</sup>

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<sup>138</sup> Origin Energy, *Submission on SA Power Networks' regulatory proposal*, p. 7.; ECCSA, *Submission on SA Power Networks' regulatory proposal*, pp. 57-58; EUAA, *Submission on SA Power Networks' regulatory proposal*, p. 11.

<sup>139</sup> Origin Energy, *Submission on SA Power Networks' regulatory proposal*, p. 7.

<sup>140</sup> EUAA, *Submission on SA Power Networks' regulatory proposal*, p. 11.

### *National Energy Retail Law*

We have not included a step change in our alternative opex forecast for this proposed step change.

Clause 90 of the National Energy Retail Rules requires that a distributor provide customers with four business days prior notice of a planned interruption regardless of its duration.<sup>141</sup> At the time it submitted its proposal, SA Power Networks is exempt from this requirement. However, the derogation was due to terminate on 1 July 2015. Without an extension of the derogation, SA Power Networks would have needed to provide customers with four business days' notice where the duration of the planned interruption is less than 15 minutes. It forecast increased standard control services opex of \$4.3 million (\$2014–15) and \$6.2 million in alternative control services opex (\$2014–15) for the cost of meeting this obligation.<sup>142</sup>

The South Australian Government have since advised us that an extension of the derogation has been granted until 30 June 2020.<sup>143</sup> As such a step change is not required.

### *National Energy Customer Framework*

We have included a step change in our alternative opex forecast regarding full adoption of the NECF.

SA 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 greater a 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 (\$2013–14) over the 2015–20 regulatory control period to undertake the additional or expanded activities.<sup>144</sup>

We have considered the assumptions underlying SA Power Networks' proposal. On the whole we consider an additional 2 FTEs at an average total cost per employee of \$129 000 to be a reasonable estimate of the additional cost associated with full adoption of the NECF.

### *Demand side participation*

We have not included any forecast opex for demand side participation as proposed by SA Power Networks in our alternative opex forecast.

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<sup>141</sup> National Energy Retail Rules, s. 90(1).

<sup>142</sup> SA Power Networks, Attachment 21.13, p. 63.

<sup>143</sup> South Australian Government, Submission on SA Power Networks' regulatory proposal, p. 12.

<sup>144</sup> SA Power Networks, Attachment 21.13, p. 68.

SA Power Networks forecast an additional \$33.8 million (\$2014–15) for a demand side participation step change. This step change was linked to a number of different aspects of SA Power Networks' proposal:

- SA Power Networks' proposal to transition new small market customers to a new tariff based on maximum demand. SA Power Networks plans to offer the tariff on an opt-in basis from July 2015 to July 2017 before it becomes mandatory for all new customers and all customers upgrading their supply arrangements.
- SA Power Networks' proposal to install upgradable 'smart ready' interval meters as the standard replacement meter for regulated metering services. The installation of smart meters in SA Power Networks' network will facilitate SA Power Networks' proposed tariff arrangements.
- SA Power Networks' proposal to institute monthly billing. SA Power Networks currently charges customers quarterly. It considers that monthly billing will improve the effectiveness of the new tariff arrangements as consumers will receive more regular feedback about their electricity usage.
- SA Power Networks' proposal to introduce a trial of power quality monitoring. With increased growth in solar PV penetration, the grid is subject to increased two way flows. SA Power Networks is concerned that it may be affecting voltage at the customer supply point. If smart meters are installed in its network, it can monitor the quality of power at the customer supply point.

The elements of the proposed step change are:

- An additional \$12.4 million (\$2014–15) in communications and IT costs to facilitate SA Power Networks' power quality monitoring trial.<sup>145</sup>
- An additional \$11.9 million (\$2014–15) in customer and retailer engagement costs to assist with the introduction of new tariff arrangements.<sup>146</sup> Most of this proposed step change (\$8.0 million) is attributable to new customer support staff. SA Power Networks estimates it will need to employ 26 additional FTEs by 2020 to assist with consumer queries in relation to new tariff arrangements.<sup>147</sup>
- An additional \$6.0 million (\$2014–15) in billing costs as a result of the proposed change to monthly meter reading.<sup>148</sup>
- An additional \$3.7 million (\$2014–15) in IT costs to support SA Power Networks' new interval meters and additional forecast activity that will arise from metering contestability.<sup>149</sup>

As outlined in Attachment 16, we do not accept SA Power Networks' proposal to install 'smart ready meters' in its network or its proposal to change to monthly meter reading

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<sup>145</sup> SA Power Networks, *Attachment 14.3*, p. 7.

<sup>146</sup> SA Power Networks, *Attachment 14.3*, p. 7.

<sup>147</sup> SA Power Networks, *Response to Information Request AER 025*, 18 February 2015.

<sup>148</sup> SA Power Networks, *Attachment 14.3*, pp. 31–32.

<sup>149</sup> SA Power Networks, *Attachment 14.3*, p. 7.

and billing. As a result we have not included any step changes in communications, IT and billing costs in our alternative opex forecast.

We accept that SA Power Networks may incur some additional consultation costs in developing its new tariff structures. For instance, the structure of its tariff must be reasonably capable of being understood by retail customers so SAPN may incur some additional costs in meeting this requirement.<sup>150</sup> However, as with other elements of this proposal, SA Power Networks' estimate of additional consumer and retailer engagement costs are based on its assumption that all new consumers will be subject to a new capacity tariff from 1 July 2017. SA Power Networks states that this tariff will require a more advanced meter than its standard residential Type 6 meter. As we have not agreed to SA Power Networks' proposal to install smart ready meters in its network, we also have not included its consumer and retailer engagement proposal in our alternative opex forecast

In considering this proposed step change, we also assessed SA Power Networks' proposed forecast for additional consumer call centre staff. We note:

- As at March 2015 SA Power Networks only employs 17 FTEs in its call centre to answer general enquiries and building and contractors.<sup>151</sup> We do not consider hiring an additional 26 call centre FTEs by 2020 is a reasonable estimate given that all that may change is the tariff structure.<sup>152</sup>
- SA Power Networks considers indicators of the reasonableness of its customer call centre costs are:
  - the volume of calls it received when it trialled its capacity based tariff with some consumers, and
  - the forecast volume of calls it typically receives from PV customers.<sup>153</sup>

We question whether these are good indicators. For instance, retailers were not involved in SA Power Networks' capacity tariff trial. We would expect that when tariffs are changed the retailer would be the first point of contact for the customer and only complex calls would be referred to SA Power Networks. We would also expect PV customers would typically contact SA Power Networks on a range of different matters - not just tariffs. This was confirmed by SA Power Networks in a response to an information request.<sup>154</sup>

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<sup>150</sup> NER, cl. 6.18.5(i).

<sup>151</sup> SA Power Networks, *Response to Information Request AER 032*, 6 March 2015, p. 3.

<sup>152</sup> Noting that any additional staffing requirements because of customer growth will be accounted for through the rate of change in opex.

<sup>153</sup> SA Power Networks, *Response to Information Request AER 025*, 18 February 2015, pp. 2–3.

<sup>154</sup> SA Power Networks, *Response to Information Request AER 032*, 6 March 2015, p. 5.

## ***Environmental management***

We have not included a step change in our alternative opex forecast for environmental management costs as proposed by SA Power Networks.

SA Power Networks forecasts additional opex of \$1.4 million (\$2014–15) in the 2015–20 regulatory control period to meet obligations under environmental laws and community expectations. This is to cover the cost of two environmental advisors.<sup>155</sup>

There is not sufficient evidence for us to conclude that SA Power Networks will face new or changed environmental obligations or requirements in the 2015–20 regulatory control period. We note that the submission from ECCSA also considered that SA Power Networks had not provided evidence that environmental obligations would change after 2013-14 (the opex base year).<sup>156</sup>

In its proposal, SA Power Networks cited a range of different environmental obligations it must meet. However these obligations are either current (e.g. National Environment Protection (Assessment of Site Contamination) Measure 1999, Environment Protection Act 1993) or potentially could be introduced or revised during the 2015–20 regulatory control period (e.g. *Guidelines for the assessment and remediation of site contamination*).

When considering whether a step change in opex is needed we consider whether there are any new regulatory obligations a business is likely to face in the next regulatory control period. If a service provider's regulatory obligations are unchanged, we consider it is reasonable to assume that the cost of meeting those obligations will be similar to the cost incurred in the base year. A prudent service provider should not require increased funding to meet an unchanged obligation. Many of the obligations SA Power Networks referred to were already in place in 2013–14 so it is unclear why SA Power Networks would require additional funding above its actual opex in 2013–14 to meet those obligations.

If an obligation is forecast to change, then we require specific evidence about how that obligation will affect the cost of providing standard control services. We do not approve additional funding where a service provider has not specifically identified how this affects the cost of providing services. SA Power Networks has referred to some guidelines that may be introduced or revised in the 2015–20 regulatory control period. However, it is not clear from SA Power Networks' proposal how these new or revised guidelines would lead to increased obligations and costs for SA Power Networks.

SA Power Networks has also cited the introduction of an Environmental Management System to monitor, mitigate and manage environmental risks as a reason why environmental management costs are expected to increase. SA Power Networks'

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<sup>155</sup> SA Power Networks, Attachment 21.13, pp. 80–86.

<sup>156</sup> ECCSA, *SA Electricity Distribution Revenue Reset*, p. 59.



decision to introduce such a system is discretionary business decision for SA Power Networks. As such, it is not something we provide an increase in funding for.

## C.4.2 Capital program impact step changes

### *Information technology*

We have not included any step changes in our alternative opex forecast relating to IT.

SA Power Networks included 22 individual step changes in its proposal relating to IT changes. Many of these changes were related to proposed changes in capex. In total SA Power Networks' proposal led to increases in forecast IT opex of \$43.9 million (\$2014–15) over the 2015–20 regulatory control period.

A summary of SA Power Networks' proposal and its forecast incremental increase in opex is outlined below in Table C.7.

**Table C.7 Proposed IT step changes**

Step change	Description	Amount
New Customer information system and Customer relationship management system	Replace legacy billing and customer related systems and consolidate for a single view of a customer	6.9
Customer facing technologies	Refresh and consolidate the customer-facing web based systems and enable customers to get their information in a single view	1.9
Customer call management system replacement	Replace the legacy Customer Contact Centre call management system	1.2
Project program and portfolio management	Refresh and extend the enterprise-wide capabilities to view and manage all components of portfolios, programs and projects (i.e. scheduling, resource capacity planning)	2.9
Enterprise asset management	Refresh, consolidate and enhance capabilities into an integrated enterprise approach to asset management, including vegetation management and enabling RIN reporting compliance	-5.5
Field force mobility	Significantly enhance existing field mobility capabilities	1.5
Intelligent Design Management System	Consolidate design tools and implement a standardised design tool and processes	-3.2
Supply chain	Enable the visibility and management of inventory across depots and warehouses. Extend analytics and supplier management capabilities	-4.4
Enterprise information security	Foundation enterprise security control capabilities	10.2
Enterprise mobility	Consolidate and extend mobility management and development platforms and approaches	5.9
IT management and operations	Replace legacy IT Service Desk and Asset management system and refresh the management processes	2.3
HR systems	Consolidate and upgrade the existing HR systems to provide a single view of employees and extend to provide additional capabilities required for managing employees and skills	0.8

Step change	Description	Amount
Financial management	Upgrade and extend the current financial management systems for compliance and capabilities (i.e. existing General Ledger, Fixed Asset register)	1.8
Governance, risk, regulation and compliance	Upgrade and consolidate the existing systems to deliver an enterprise wide, integrated solution to manage governance, risk and compliance processes	0.5
Enterprise integration	Simplify our enterprise technical capabilities for integration for data and systems	6.2
Data centre consolidation	Rationalisation of data centres, increase good practice disaster recovery and governance practices	4.4
Data management	Implement a standard foundation Data Management toolsets (i.e. Enterprise, Quality, Lifecycle)	2.8
Unified communications	Upgrade the legacy telephony and business communications system and implement new integrated communications channels	1.1
SAP foundation	Refresh and upgrade the SAP hardware platform (incl. Oracle database systems and User Interface for ERP system)	2.4
Enterprise architecture tools	Enterprise Architecture repository based toolset	1.8
Enterprise information management	Implement a standard foundation to enable efficient management of documents, records and web content	1.6
Business intelligence enablement	Upgrade technical capabilities to enable robust business, customer and regulatory reporting including data, analytics and information management	0.7

Source: SA Power Networks, Attachment 21.13, pp. 92–97.

There are several reasons why we do not consider a step change to be justified.

**Several proposals were aimed at achieving cost efficiencies. We would expect these proposals would lead to lower opex rather than higher opex**

As outlined throughout this attachment, we do not approve increases in opex where an initiative is designed to reduce the costs facing a service provider. We would expect an initiative that is designed to make business processes more efficient would lead to reduced opex.

For instance, a number of proposed step changes were intended to help support other business processes. For instance there was proposed IT to help:

- manage programs and projects (Project Program and Portfolio Management)
- manage assets (Enterprise Asset Management)

- manage inventory (Supply Chain)
- manage documents, records and web content (Enterprise Information Management)
- manage data and systems (Enterprise Integration) manage business processes (Enterprise Architecture Tools)
- assist with customer and regulatory reporting (Business Intelligence Enablement)
- improve the mobility of staff (Enterprise Mobility, Field Force Mobility)
- implement video and instant messaging capability (Unified Communications).

All these initiatives appear to be aimed at developing more efficient business practices. However, for many of these IT step changes, SA Power Networks forecast higher opex.<sup>157</sup> If SA Power Networks can successfully invest in better systems to help manage assets, projects, documents, businesses process and data, then we would expect this would, overall, lower the cost of doing business. If staff can be become mobile then this will increase the number of tasks that can be performed remotely. Video and instant messaging services will, according to SA Power Networks, result in cost savings.<sup>158</sup>

SA Power Networks is subject to an incentive based regulatory framework whereby if it invests an initiative that reduces its costs, it will be rewarded accordingly. The reward is in net terms approximately 30 per cent of the saving. Under this framework SA Power Networks has an incentive to pursue efficiencies without receiving an increase in funding. If SA Power Networks did receive an increase in funding then consumers would fund efficiency payments to a service provider as well as funding the full cost of a project. This would be inconsistent with the incentive scheme and therefore inconsistent with the opex factor that requires forecast opex to be consistent with any incentive scheme or schemes that apply to SA Power Networks.<sup>159</sup>

**Several proposals were focussed on achieving compliance with existing legislative obligations. Other proposals referred to compliance requirements that were not clearly identified.**

For a number of step changes, SA Power Networks consider the driver to be supporting SA Power Networks' RIN reporting obligations (Enterprise Asset Management, People and Culture Improvements, Data Management, Enterprise Asset Management, Business Intelligence Enablement). As noted in the specific step change SA Power Networks submitted for RIN compliance, these requirements are not expected to materially change SA Power Networks' obligations in the 2015–20 regulatory control period. On the basis that these requirements have not changed we do not accept that a step change is needed. If SA Power Networks wish to invest in

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<sup>157</sup> For the enterprise asset management, supply chain and intelligent design management system step changes, SA Power Networks forecast lower opex.

<sup>158</sup> SA Power Networks, Attachment 21.13, p. 96.

<sup>159</sup> NER, cl.6.5.6(e)(8).

systems to make RIN reporting more efficient, then this is a matter for it, and not something we provide an increase in funding for.

For two other proposals (Enterprise Information Security, Data Management), SA Power Networks listed privacy laws in its proposal as a drivers.<sup>160</sup> SA Power Networks did not identify how changes in privacy laws this would impact on the costs that SA Power Networks would face. Nevertheless we understand the changes should have taken effect by 12 March 2014.<sup>161</sup> We would have expected that the costs of achieving compliance would be reflected in SA Power Networks' base opex.

For several proposals, SA Power Networks listed greater compliance requirements in the description of drivers. For instance, for the Intelligent Design Management System proposal, SA Power Networks stated that the driver was greater compliance and reporting requirements around safety in design.<sup>162</sup> In the People and Culture business case, it stated the driver was compliance with the skills and training accreditation requirements.<sup>163</sup> SA Power Networks did not:

- provide specific references of what these requirements were,
- explain how or why these requirements were expected to change since 2013–14 or
- explain why changes in these requirements were expected to represent a greater burden to SA Power Networks.

**Several proposals were related to replacement systems and/or software. We are not satisfied that these proposals would require an increase in total opex.**

SA Power Networks cited lifecycle replacement of software and systems as justification for several step changes including:

- Customer Information System and Customer Relationship Management System
- Customer Call Management System Replacement
- IT Management and Operations
- Financial Management
- Enterprise Resource Planning
- Unified communications

We recognise that periodically a service provider will need to replace systems and/or its software. However, we do not consider a step change in total opex is needed where this is the case.

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<sup>160</sup> SA Power Networks, Attachment 21.13, p. 94, 96.

<sup>161</sup> <http://www.oaic.gov.au/privacy/privacy-act/privacy-law-reform>,

<sup>162</sup> SA Power Networks, Attachment 21.13, p. 94.

<sup>163</sup> SA Power Networks, Attachment 21.13, p. 95.

As with many IT initiatives, upgrades in software and/or systems are only undertaken if the benefits of doing so would lower the costs that a service provider would otherwise face. In many cases, we would expect upgrades to lower the costs of doing business. As outlined above, total opex should not increase for efficiency improvements.

From time to time, replacement of some systems and/or software may lead to higher opex. However, our role is to provide sufficient funding in total to achieve regulatory obligations. Where there is no new regulatory obligation total opex must:

to the relevant extent:

(3)(iii) maintain the quality, reliability and security of supply of standard control services; and

(3)(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.<sup>164</sup>

Therefore, when considering the cost of replacement of software and systems, we would expect that incremental increase in the cost of particular systems would reflect the cost to achieve the same level of quality, reliability and security of service. In isolation, there may be programs or projects that cost more from one year to the next. However, when forecasting opex, we do not aggregate the forecast cost associated with individual projects and projects. We forecast total opex. We are not convinced that the total opex of an efficient business in providing the same quality, reliability and security of service would be much different in the 2015–20 regulatory control period to the base year, 2013–14.

### **Rate of change approach is designed to provide a business with incremental opex relating to business growth**

For the Data Centre consolidation step change, 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.<sup>165</sup>

This proposed step change relates to the estimated costs of SA Power Networks' incremental business needs which are already compensated for through our rate of change adjustment to base opex through output growth. It would double count these costs to provide a step change in addition to adjusting base opex for the rate of change.

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<sup>164</sup> NER, cl.6.5.6.

<sup>165</sup> SA Power Networks, *Attachment 21.13*, p. 97.

## **The need for increased funding for enterprise information security was not clear**

For the enterprise information security step change, SA Power Networks proposed to implement initiatives to improve information security with respect to:

- security monitoring
- threat management
- vulnerability management
- security awareness
- identity management
- information security management system.<sup>166</sup>

The business case provides very general information about SA Power Networks' current information security capabilities and considers broad options for improving these capabilities. We consider SA Power Networks has not clearly put forward a case as to why it would require an increase in its total opex budget for this program. In particular we consider that the business case did not identify

- the specific information security risks SA Power Networks faces.
- whether those risks have 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 has 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.

## ***Telecommunications***

### *Mobile radio*

We have included a step change in our alternative opex forecast for increased mobile radio costs. On the basis of the information SA Power Networks provided, we consider this to be an efficient capex/opex trade-off.

We consider this proposed step change in our confidential appendix.

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<sup>166</sup> SA Power Networks, *Attachment 20.02 Public SA Power Networks IT BC Information Security Foundation*, pp. 36–39.

### *Carrier costs, radio licensing and planning*

We have not included a step change in our alternative opex forecast for increased carrier costs, radio licensing and planning costs as proposed by SA Power Networks.

SA Power Networks has forecast increased telecommunications carrier costs, radio licensing costs and planning costs. It has attributed these increased costs to more intelligent networks and greater automation. This has led to an increase in connected devices in areas such as SCADA to substations, grid devices and asset monitoring and corporate data requirements for depots and data centres. In total SA Power Networks has forecast increased opex of \$5.1 million (\$2013–14) in these three areas.<sup>167</sup>

We do not accept that increased use of technological solutions would lead to an increase in opex for an efficient business. Technological growth may well lead to increased opex in certain areas for an efficient business (such as telecommunications). However we would expect that increased use of intelligent networks and greater automation would help reduce opex and capex across the network and/or improve reliability. These benefits should more than outweigh the additional carrier, radio licensing and planning costs. As such no step up in total opex should be needed.

### *Network Management Centre*

We have not included a step change in our alternative opex forecast for costs associated with SA Power Networks' network management centre.

SA Power Networks forecast an increase in FTEs in its network management centre. It identified three main drivers for this step change:

- increased safety focus in line with recent Work health and safety legislation.
- the establishment of a dedicated security role that will provide a consistent approach in security across all technologies.
- the establishment of a helpdesk as single point of contact for planned and unplanned outages and restoration, records management, fault recording and tracking.

In total SA Power Networks forecast it would need 6 additional FTEs by the end of 2020.<sup>168</sup>

We do not consider any of these drivers present compelling reasons for an increase in opex.

As we discuss throughout this attachment we consider an efficient base amount of opex should be enough for SA Power Networks to achieve its regulatory obligations. We generally do not consider additional opex is needed if there are no new regulatory

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<sup>167</sup> SA Power Networks, *Attachment 21.13*, p. 107.

<sup>168</sup> SA Power Networks, *Attachment 21.13*, p. 113.

obligations. The drivers SA Power Networks identified do not constitute a reason for an increase in its total opex forecast. For instance:

- As discussed above, workplace health and safety legislation changed in South Australia on 1 July 2013. We would expect a prudent service provider would already be compliant with its legislative obligations so it is not clear to us why SA Power Networks requires an increase in its opex in response to this driver.
- As discussed above in relation to the enterprise information security step change, we do not consider SA Power Networks has established the case for why it needs increase funding to manage information security issues.

We consider the third driver is not a reason for a step change. How SA Power Networks manages its staff in responding to calls about planned and unplanned and outages and restoration, records management, fault recording and tracking is a discretionary matter for SA Power Networks. This is not something we include as a step change in forming an opex forecast.

### *Other*

SA Power Networks also included in its opex forecast step changes for various other programs where there was a capital program impact. This included:

- Data quality—SA Power Networks proposed to implement a series of initiatives to improve data quality (\$3.9 million).<sup>169</sup>
- Maintenance of substation disconnectors—SA Power Networks proposed additional maintenance of two substation disconnectors which were installed in the last regulatory control period (\$2.4 million).<sup>170</sup>
- Condition monitoring and network planning—SA Power Networks proposed to further implement a condition/risk based replacement method rather than relying principally on asset age as a measure of remaining asset life (\$1.8 million).<sup>171</sup>
- Flexible load management—SA Power Networks proposed opex for a new database to track devices compliant with the Australian Standard for electric vehicles, battery storage and air conditioning and for an advertising campaign to promote take up of products where the load can be controlled dynamically (\$1.0 million).<sup>172</sup>

For the reasons below, we have not included any of these proposals in our forecast of total opex.

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<sup>169</sup> SA Power Networks, Attachment 21.13, pp. 117–128.

<sup>170</sup> SA Power Networks, Attachment 21.13, pp. 129–133.

<sup>171</sup> SA Power Networks, Attachment 21.13, pp. 134–138.

<sup>172</sup> SA Power Networks, Attachment 21.13, pp. 139–143.



### *Data quality*

Consistent with the reasoning we have outlined for IT related step changes, SA Power Networks' data quality program, if efficient, should lead to reduced opex not increases.

For instance, in its business case SA Power Networks notes 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.<sup>173</sup> 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 are not convinced that a higher opex forecast is needed.

### *Maintenance of substation disconnectors*

It may be the case that SA Power Networks will face increased maintenance costs for these particular assets. However, increased maintenance on individual assets should be funded out an efficient base level of opex. Maintenance costs on each individual asset will often vary from year to year. For instance, there are likely to be other assets which SA Power Networks maintains where the costs it incurs are expected to decrease during the regulatory control period. It is inconsistent to consider the incremental maintenance costs only on particular assets when assessing total opex.

We would also expect increased maintenance costs driven by new substation disconnectors relates to increased output growth. We account for incremental opex driven by output growth through our estimate of the rate of change. It would be double counting to also increase SA Power Networks' opex through a step change.

### *Condition monitoring and network planning*

SA Power Networks has referred to a range of different benefits of improved condition monitoring and network planning. If these benefits arise, we would expect SA Power Networks to receive a commensurate reward through our incentive schemes.

For instance SA Power Networks has cited the following benefits of improved condition monitoring:

- Optimised asset replacement expenditure would lead to increased asset deferral. If this occurs we would expect SA Power Networks to receive CESS benefits.
- Supports to move to an optimised maintenance strategy for substation plant. For instance SA Power Networks have stated that the historical maintenance strategy has resulted in many repeat visits and outages at substations over relatively short

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<sup>173</sup> SA Power Networks, *Attachment 21.13*, p. 122, 123.

periods of time.<sup>174</sup> Reducing the number of site visits will help to reduce opex, which will help to provide benefits through the EBSS.

When forecasting opex, we do not approve increases in opex for initiatives that expect to deliver efficiency benefits and/or service improvements. We expect initiatives that help a service to become more efficient to be self-funding. If the benefits of an initiative outweigh the costs then the benefits a service provider will receive through the incentive schemes should be sufficient to cover the incremental costs of the project. No increase in forecast opex is required.

#### *Flexible load management*

SA Power Networks' business case does not clearly identify the benefits to network consumers of a new database. If the new database is to track industry developments, SA Power Networks should be the beneficiary. For example the database may identify new opex or capex saving initiatives. In this scenario the costs of the database area matter for it to manage within its total opex budget. It is not clear why SA Power Networks would need additional funding.

SA Power Networks' proposed load management advertising campaign does not appear to be required to meet its regulatory obligations. One reason for advertising load control programs is to limit peak demand growth. However, SA Power Networks would be a beneficiary through lower opex and capex requirements. It is a matter for SA Power Networks to weigh up the costs and benefits of the advertising program in the context of its total expenditure program.

Alternatively if there are expected environmental benefits from this advertising program, then this is the type of initiative that government agencies may be interested in funding. It is not clear why SA Power Networks' consumers should be expected to fund this initiative in the absence of a regulatory obligation on SA Power Networks.

### **C.4.3 Customer driven initiatives and changing community expectations**

#### *Vegetation management*

SA Power Networks proposed several step changes for vegetation management. We did not include any of these proposed step changes in our alternative forecast of opex.

- 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 considers there is ongoing concern from Councils and communities, particularly in metropolitan areas, of clearances based on a three year cycle. SA Power Networks considers, in engagement with local community, there is support for a two year cutting cycle to improve visual amenity, lessen the

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<sup>174</sup> SA Power Networks, *Attachment 21.13*, p. 136.

amount of growth to trim and lead to less customer complaints. It forecasts increased opex of \$13.5 million (\$2014–15) to implement this program.<sup>175</sup>

- In both bushfire and non-bushfire risk areas, SA Power Networks proposes an increase in opex for a tree removal and replacement program to remove inappropriate, fast growing or large trees. It forecasts 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 ) for this step change.<sup>176</sup>
- SA Power Networks also considers 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 proposes 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.<sup>177</sup>
- SA Power Networks proposes \$1.2 million (\$2014–15) for a communications plan targeted towards customers in council areas most affected by vegetation 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.<sup>178</sup>

We have not provided an increase in opex for any of these programs. We address the first three programs below. We have considered SA Power Networks' proposed communications plan along with its proposed customer service and community safety programs.

#### *Cost drivers supporting proposed step changes in vegetation management*

Several of these programs are aimed at addressing community concerns about the amenity of SA Power Networks' tree trimming practices.<sup>179</sup> We determine the required funding for SA Power Networks to achieve its regulatory obligations. Where there are no regulatory obligations, we determine funding that that would maintain the reliability, safety and quality of supply. Improved amenity is not an objective we are directed to consider when determining SA Power Networks' funding requirements.

The amenity of SA Power Networks' tree trimming practices is a broader policy issue that goes beyond our remit. If legislation no longer reflects community expectations in respect to amenity then we would consider that this is for relevant policy makers to consider. In our role we do not consider we should determine what these changes should be.

We also note that under the *Electricity Act 1996 (SA)* and *Electricity (Principles of Vegetation Clearance) Regulations 2010 (SA)* there is already provision for local

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<sup>175</sup> SA Power Networks, *Attachment 21.13*, pp. 145–149.

<sup>176</sup> SA Power Networks, *Attachment 21.13*, pp. 150–160.

<sup>177</sup> SA Power Networks, *Attachment 21.13*, pp. 161–165.

<sup>178</sup> SA Power Networks, *Attachment 21.13*, pp. 166–171.

<sup>179</sup> SA Power Networks, *Attachment 21.13*, pp. 145, 151, 156, 161.

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,
- provide for payments by the council to SA Power Networks or by SA Power Networks to the council.<sup>180</sup>

Councils and the Local Government Association of South Australia indicated support for SA Power Networks' request for funding in relation to these proposals.<sup>181</sup> If South Australian local Councils are of the view that increased resources need to be devoted to enhancing amenity in non-bushfire risk areas, then, they can potentially fund changes through these agreements. There are already other sources of funding available to SA Power Networks than regulated electricity revenues.

We also note that consumer preferences for amenity and concerns about current tree trimming practices are likely to vary between different communities. Central Irrigation Trust submitted that if communities would like visual amenities improved they should recover the cost from those communities and not all users.<sup>182</sup>

For the tree replacement and removal programs SA Power Networks has listed amenity as a factor but also safety and bushfire risk and reduced costs. We do not consider SA Power Networks provided sufficient evidence to justify an increase in opex for the other drivers it listed.

Based on the evidence available to us, we consider SA Power Networks' base opex should already provide a sufficient source of funding for it address safety and bushfire risks. For instance, SA Power Networks is already required to adhere to strict legislative requirements regarding vegetation clearance distances in bushfire risk areas. It is not clear why removing or replacing trees would lower the risk of bushfires and improve safety relative to SA Power Networks' current practices.

In any case, SA Power Networks has stated that this program would be expected to deliver cost savings:

There are a number of Councils, particularly Councils in areas with high average rainfall and fast growing species, where it may be necessary to cut

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<sup>180</sup> Electricity Act 1996, s. 55A; Electricity (Principles of Vegetation Clearance) Regulations 2010, s. 8.

<sup>181</sup> Local Government Association of South Australia, Submission to SA Power Networks regulatory proposal, p. 2. We also received support from Treenet on behalf of a Reference Group for Vegetation Management near Powerlines.

<sup>182</sup> CIT, *CIT Submission to SA Power Networks Regulatory Proposal (2015 – 2020)*, p. 9.

trees multiple times in a year to meet legislative requirements. In these situations tree removal is the most appropriate solution over the long-term as regular and ongoing clearance is required for compliance.

A tree removal and replacement program is a long term investment with a payback period of between approximately 7-8 years with most of the benefit accruing in rural areas.<sup>183</sup>

As discussed throughout this attachment, we do not approve increases in funding for programs that we expect to deliver efficiencies. We expect a service provider to weigh up the cost and benefits before deciding to invest in a project or program. If the program is efficient, then the service provider will be rewarded appropriately through the regulatory framework.

### *Willingness to pay research commissioned by SA Power Networks*

We also note that SA Power Networks has referred to willingness to pay research it had conducted to support several of its proposed vegetation management programs.<sup>184</sup> We do not consider this study provides persuasive evidence that SA Power Networks' consumers support SA Power Networks' program.

In that study, Discrete Choice Experiment (DCE) design in which different pairs of service options and their impacts on the quarterly bill of an average customer were presented to the respondent who was then asked in each case to select the option he or she preferred. In respect to vegetation management, respondents were asked to choose between

- A two year or three year cutting cycle in NBRFAs
- A tree removal or replacement program in NBRFAs where respondents were asked to choose between either 0%, 2.5% or 5% of trees that were removed or replaced
- A tree removal or replacement program in BFRAs where respondents were asked to choose between either 0%, 2.5%, 5%, 8% or 10% of trees that were removed or replaced.

The study also considered different undergrounding options to deal with bushfire risk and traffic options. It found that the most preferred options amongst respondents were

- in high bushfire risk and bushfire risk areas, 135kms of undergrounding combined with 2.5% tree removal and replacement
- in non-bushfire risk areas, 2.5% removal and replacement of inappropriate vegetation, associated with a 2 year trimming cycle without undergrounding powerlines
- undergrounding powerlines surrounding 30 Traffic Blackspots

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<sup>183</sup> SA Power Networks, *Attachment 21.13*, p. 152.

<sup>184</sup> SA Power Networks, *Attachment 6.8, The NTF Group: SAPN Targeted Willingness to Pay Research*, July 2014.

We commissioned Oakley Greenwood to review SA Power Networks' study. It found the decision made by consumers did not reflect informed choices given the limited information provided to consumers about the benefits of each of the options. On this basis, we do not consider the findings of the report indicate there is customer support for SAPN's programs.

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 NBFRA 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.<sup>185</sup>

### *South Australian Government submission*

In considering these proposals we also considered a submission from the South Australian Government. It did not support SA Power Networks' increased vegetation management expenditure and considered that we should forecast lower vegetation management allowance than the amount it incurred in 2013–14.<sup>186</sup> It considered the actual vegetation clearance in 2008–09 would be a better indicator of its forecast needs. One of the reasons it cited was that actual vegetation management expenditure in 2013-14 was likely to be higher because it was driven by wet conditions in 2010 and 2011.

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<sup>185</sup> Oakley Greenwood, *Peer review of the willingness to pay research submitted by SAPN*, p. 6

<sup>186</sup> South Australian Government, *Submission to SA Power Networks' regulatory proposal*, p. 10.

We have not changed our position in response to the South Australian Government's comments. As noted throughout this appendix we have forecast opex based on total opex incurred in a single year. We consider total opex incurred in a recent year is a reasonable basis for forecasting total opex needs in future years. As outlined in the base opex appendix we consider SA Power Networks' actual opex to be relatively efficient. While vegetation management expenditure could be one category of expenditure that declines relative to 2013-14 levels, there possibly will be other categories of opex that will increase. We consider it is generally preferable to adopt a consistent forecasting approach across all categories of opex.

In any case we also do not consider vegetation management expenditure incurred in 2008–09 to be a reasonable indicator of annual vegetation management expenditure in the 2015–20 regulatory control period. As noted in the South Australian Government submission, the period from 2004 to 2009 was the longest period of below average rainfall in South Australia in 33 years.<sup>187</sup> We do not consider it would be reasonable to re-forecast SA Power Networks' vegetation management expenditure based on expenditure it incurred in drought conditions.

### ***Customer service and community safety***

We also have not included a step change in our alternative opex forecast to fund SA Power Networks' proposed customer service and community safety programs.

SA Power Networks 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)<sup>188</sup>
- Implementation of a tailored digital advertising strategy to support the launch and communication of new self-service options (\$1.0 million)<sup>189</sup>
- A new customer service experience improvement team (\$1.6 million)<sup>190</sup>
- A new summer time media campaign to better educate customers about bushfire dangers with respect to powerlines and outages (\$2.6 million)<sup>191</sup>
- A new media campaign to educate customers about the dangers and implications of extreme weather outages and powerlines (\$1.9 million)<sup>192</sup>
- A program that targets farmers and sailors with respect to the risks of coming in contact with powerlines (\$0.9 million)<sup>193</sup>

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<sup>187</sup> South Australian Government, *Submission to SA Power Networks' regulatory proposal*, p. 10

<sup>188</sup> SA Power Networks, *Attachment 21.13*, p. 166.

<sup>189</sup> SA Power Networks, *Attachment 21.13*, p. 172.

<sup>190</sup> SA Power Networks, *Attachment 21.13*, p. 182.

<sup>191</sup> SA Power Networks, *Attachment 21.13*, p. 189.

<sup>192</sup> SA Power Networks, *Attachment 21.13*, p. 195.

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. Discretionary expenditure should be managed within a service providers existing budget.

As noted throughout this attachment, where there is no regulatory obligation, we provide efficient opex to meet or managed expected demand and maintain the reliability, safety and quality of supply of the service. Without clear and robust evidence about why a service provider needs more funding to achieve these objectives then we do not provide a step change. In our view, SA Power Networks has not demonstrated this in relation to any of these programs. We see no reason why the forecast cost SA Power Networks incurs in communicating with its consumers would need to increase in the 2015–20 regulatory control period relative to what it incurred in the base year, 2013–14.

For instance, in support of its proposed community safety programs, SA Power Networks referred to its consumer engagement program. In it, it stated that consumers considered that public safety is a key priority area SA Power Networks must address across the entire State.<sup>194</sup> Public safety should and would always be a priority for SA Power Networks. However, what matters in determining a total opex forecast is whether the total opex SA Power Networks spends on public safety needs to increase. SA Power Networks has not provided any compelling evidence that any of these campaigns necessitate a total increase in funding in activities directed towards public safety.

In relation to its proposed customer service programs, we also note SA Power Networks is proposing to educate consumers about the electricity industry and changes in the industry. We do not consider this to be SA Power Networks' role. It is its role to provide a safe and reliable network service. There are already a range of sources available to help explain to consumers about how the electricity industry works and what tariffing options are available.

#### **C.4.4 Finance-related opex**

##### ***Insurance premiums***

We have not included a step change in our alternative opex forecast for increased insurance premiums.

SA Power Networks has forecast a \$3.0 million (\$2014–15) increase in its insurance premiums based on advice from AoN.

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<sup>193</sup> SA Power Networks, *Attachment 21.13*, p. 200.

<sup>194</sup> SA Power Networks, *Attachment 21.13*, p. 189; SA Power Networks, *Attachment 21.13*, p. 195; SA Power Networks, *Attachment 21.13*, p. 200.



SA Power Networks' prices are already updated annually for changes in the Consumer Price Index (CPI). CPI includes a basket of representative goods, including household insurance. Our approach when dealing with proposed insurance increases is to assume that the service provider will be appropriately compensated for changes in insurance costs through CPI adjustments. We risk overcompensating a service provider for changes in insurance if we update its network prices for CPI and approve an increase in insurance premiums for the particular service provider.

### ***Superannuation***

We have not included a step change in our alternative opex forecast for forecast superannuation contributions.

SA Power Networks are required to make contributions to the Electricity Industry Superannuation Scheme (EISS) and other superannuation schemes. The EISS actuary, in conjunction with the EISS Board, independently sets the required employer contributions to ensure that the EISS is appropriately funded, based on assumptions reflecting their actuarial standards. SA Power Networks forecasts that its contributions will be \$2.4 million (\$2014–15) per annum lower than incurred in the base year, 2013-14.

As outlined elsewhere in this appendix, we have not forecast opex at a category level. While superannuation costs may decline over the period, there may be other costs which increase. To be consistent with our broader approach, we have not included this proposed negative step change in our alternative opex forecast.

### **C.4.5 Base year adjustments**

We have included a step change in our alternative forecast for changes in SA Power Networks' distribution licence fee.

SA Power Networks included seven base year adjustments in its proposal. We consider three of these proposed adjustments (service classification change, provisions for self-insurance and DMIA) elsewhere in this decision. Under our assessment approach we consider changes in service classification, and provisions to be base year issues. Accordingly we discuss our approach to these issues in appendix A. We discuss DMIA expenditure in attachment 12.

Under our assessment approach we considered the remaining adjustments as step changes.

- Forecast changes for the costs of preparing SA Power Networks' regulatory proposal.

These costs are larger towards the end of a regulatory control period. In the base year, 2013–14 SA Power Networks incurred costs in preparing its regulatory proposal. If SA Power Networks forecast its total opex with these costs included, it considered it would overestimate its required opex. SA Power Networks forecast a negative adjustment of \$8.4 million (\$2014–15) in making this change.

- Forecast changes in the distribution licence fee

The SA Minister for Mineral Resources and Energy advised SA Power Networks that its annual licence fee will be reduced from 1 July 2015. SA Power Networks forecast a negative adjustment to its opex forecast of \$5.3 million (\$2014–15) in making this change. Subsequent to releasing its proposal it revised this downwards to \$5.0 million (\$2014–15). This reflected the fact that the new licence fee would not apply until 11 October 2015.

- Non network solution

This relates to the Bordertown non-network solution, previously implemented in 2013 to address capacity constraints in the Bordertown region. SA Power Networks forecast an additional \$1.3 million associated with the ongoing generation standby capacity and associated operational fees.

- Property

SA Power Networks have leased a new depot. This depot will improve customer service and ease safety issues due to congestion at other depots.

SA Power Networks entered into a lease arrangement because it could not purchase a suitable property in the timeframe required. The lease commenced in the latter part of the 2013–14 year.

We have included SA Power Networks' adjustment for the changes in the distribution licence fee in our alternative opex forecast. This is a reduced cost incurred by SA Power Networks in delivering its regulatory obligations and therefore classified as a step change. The forecast amount payable in the 2015–20 regulatory control period has been confirmed by the South Australian Minister for Mineral Resources and Energy.<sup>195</sup>

We have not included other adjustments proposed by SA Power Networks in our alternative opex forecast. As outlined elsewhere in this appendix our approach is not to forecast opex at the category level. We have not attempted to determine incremental changes in these categories.

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<sup>195</sup> Government of South Australia, *Submission to SA Power Networks' regulatory proposal*, p. 11.