



FINAL DECISION
United Energy distribution
determination
2016 to 2020

Attachment 7 – Operating
expenditure

May 2016

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Note

This attachment forms part of the AER's final decision on United Energy's distribution determination for 2016–20. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

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Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – f-factor scheme

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Shortened forms

Shortened form	Extended form
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
augex	augmentation expenditure
CAM	cost allocation method
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
MFP	multifactor productivity
MPFP	multilateral partial factor productivity
MRP	market risk premium
MTFP	multilateral total factor productivity
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider

Shortened form	Extended form
opex	operating expenditure
PFP	partial factor productivity
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
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
VBRC	Victorian Bushfire Royal Commission
WACC	weighted average cost of capital

7 Operating expenditure

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

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

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

7.1 Final decision

We are not satisfied that United Energy's forecast opex reasonably reflects the opex criteria.¹ We therefore do not accept the forecast opex United Energy included in its building block proposal.² We compare our substitute estimate of United Energy's opex for the 2016–20 regulatory control period with its initial regulatory proposal, our preliminary decision and United Energy's revised regulatory proposal in Table 7.1.³

Table 7.1 Our final decision on total opex (\$ million, 2015)

	2016	2017	2018	2019	2020	Total
United Energy's initial proposal	152.9	155.2	156.0	158.7	157.4	780.2
AER preliminary decision	127.3	128.8	130.8	132.7	134.5	654.0
United Energy's revised proposal	147.0	149.9	154.6	157.2	160.3	769.0
AER final decision	139.2	142.1	145.2	146.1	148.0	720.6

Source: AER analysis.

Note: Excludes debt raising costs.

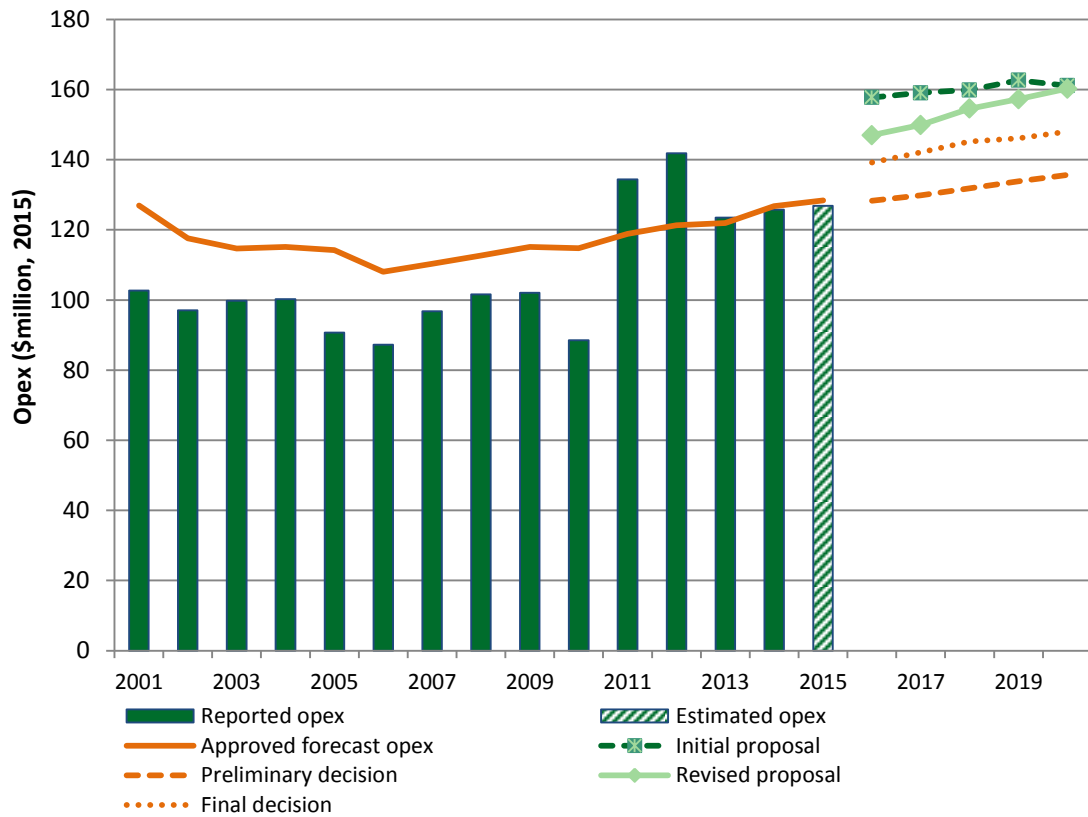
Figure 7.1 shows our final and preliminary decision compared to United Energy's past actual opex, previous regulatory decisions and its initial and revised proposals.

¹ NER, cl. 6.5.6(c).

² NER, cl. 6.5.6(d).

³ NER, cl. 6.12.1(4)(ii).

Figure 7.1 Our final decision and United Energy's past opex (\$ million, 2015)



Source: AER analysis.

Note: Includes debt raising costs.

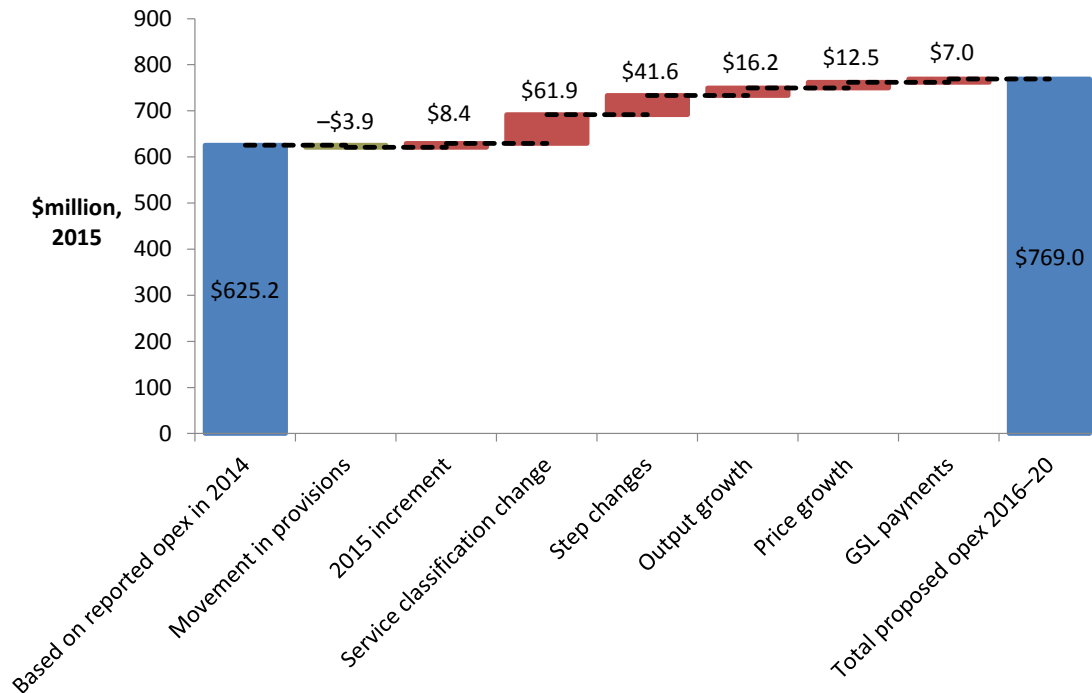
We note the main reason we and United Energy expect standard control services opex to increase in the 2016–20 regulatory control period is because of changes in the regulation of costs associated with the Advanced Metering Infrastructure (AMI) rollout. Previously these costs were regulated under an AMI Cost Recovery Order. From 2016 these costs are regulated under the NER.

7.2 United Energy's revised proposal and submissions

In its revised proposal, United Energy proposed a forecast opex of \$769.0 million (\$2015) for the 2016–20 regulatory control period. This is a 1.4 per cent decrease from the \$780.2 million (\$2015) it initially proposed.

In Figure 7.2 we separate United Energy's forecast opex into the different elements that make up its forecast.

Figure 7.2 United Energy's revised opex forecast (\$ million, 2015)



Source: AER analysis.

We describe each of these elements below:

- United Energy used the actual opex it incurred in 2014 as the base for forecasting its opex for the 2016–20 regulatory control period. This results in a base opex of \$625.2 million (\$2015) over the 2016–20 regulatory control period. This is \$4.5 million (\$2015) higher than our preliminary decision.
- United Energy's 2014 regulatory accounts include one-off accounting adjustments relating to provision changes. It adjusted base opex to remove the movement in provisions in 2014. The effect of this is to set the net forecast expenditure in this cost category to zero. This reduced United Energy's forecast by \$3.9 million (\$2015). This is consistent with our preliminary decision.
- To forecast the increase in opex between 2014 and 2015 United Energy added the difference between its opex allowances for 2014 and 2015. This is consistent with the approach set out in the *Expenditure Forecast Assessment Guideline* (the Guideline). This increased United Energy's forecast by \$8.4 million (\$2015). This is consistent with our preliminary decision.
- United Energy also adjusted its base opex to add opex that is classified as standard control services in the 2016–20 regulatory control period. This related to the reallocation of AMI costs. This increased United Energy's forecast by \$61.9 million (\$2015). This reflects different approaches to the allocation of AMI costs. In our preliminary decision we allocated these costs to alternative control services metering.

- United Energy included a category specific forecast for guaranteed service level (GSL) payments. This increased its forecast by \$7.0 million (\$2015). This is \$4.8 million (\$2015) more than our preliminary decision. The increase in GSL payments reflects new Electricity Distribution Code (EDC) requirements and a different forecasting approach to our preliminary decision.
- United Energy identified several step changes in opex for new regulatory obligations. This increased United Energy's forecast by \$41.6 million (\$2015). This is \$39.2 million (\$2015) higher than the step changes in our preliminary decision.
- United Energy adopted the forecast of output growth in our preliminary decision in its revised regulatory proposal. Output growth increased United Energy's opex forecast by \$16.2 million (\$2015). This is \$2.2 million (\$2015) higher than our preliminary decision because it was applied to a larger base opex.
- United Energy adopted the forecast of price growth in our preliminary decision in its revised regulatory proposal. Price growth increased United Energy's opex forecast by \$12.5 million (\$2015). This is \$2.2 million (\$2015) higher than our preliminary decision because it was applied to a larger base opex.

7.3 Assessment approach

This section sets out our general approach to assessment.⁴ Our approach to assessment of particular aspects of the opex forecast is set out in more detail in the relevant appendices.

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

There are two tasks that the NER requires us to undertake in assessing total forecast opex. In the first task, we form a view about whether we are satisfied a service provider's proposed total opex forecast reasonably reflects the opex criteria.⁵ If we are satisfied, we accept the service provider's forecast.⁶ In the second task, we determine a substitute estimate of the required total forecast opex that we are satisfied reasonably reflects the opex criteria.⁷ We only undertake the second task if we do not accept the service provider's forecast after undertaking the first task.

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

⁴ The discussion in this section, to the extent it differs from that set out in the preliminary decision, clarifies the assessment approach that we applied in both the preliminary decision and this final decision.

⁵ NER, cl. 6.5.6(c), 6.12.1(4).

⁶ NER, cl. 6.5.6(c), 6.12.1(4)(i).

⁷ NER, cl. 6.5.6(d), 6.12.1(4)(ii).

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:⁸

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

The opex criteria that we must be satisfied a total forecast opex reasonably reflects are:⁹

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]'.¹⁰

The service provider's forecast is intended to cover the expenditure that will be needed to achieve the opex objectives. The opex objectives are:¹¹

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.

Whether we are satisfied that the service provider's total forecast reasonably reflects the opex criteria is a matter for judgment. This involves us exercising discretion. However, in making this decision we treat each opex criterion objectively and as complementary. When assessing a proposed forecast, we recognise that efficient costs are not simply the lowest sustainable costs. They are the costs that an objectively prudent service provider would require to achieve the opex objectives based on realistic expectations of demand forecasts and cost inputs. It is important to

⁸ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. vii.

⁹ NER, cl. 6.5.6(c).

¹⁰ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113.

¹¹ NER, cl. 6.5.6(a).

keep in mind that the costs a service provider might have actually incurred or will incur due to particular arrangements or agreements that it has committed to may not be the same as those costs that an objectively prudent service provider requires to achieve the opex objectives.

Further, in undertaking these tasks we have regard to the opex factors.¹² We attach different weight to different factors. This approach has been summarised by the AEMC as follows:¹³

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

The opex factors that we have regard to are:

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period
- the actual and expected operating expenditure of the distribution network service provider during any preceding regulatory control periods
- the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the distribution network service provider in the course of its engagement with electricity consumers
- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure
- whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the distribution network service provider under clauses 6.5.8 or 6.6.2 to 6.6.4
- the extent the operating expenditure forecast is referable to arrangements with a person other than the distribution network service provider that, in our opinion, do not reflect arm's length terms
- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)
- the extent to which the distribution network service provider has considered and made provision for efficient and prudent non-network alternatives

¹² NER, cl. 6.5.6(c) and (d).

¹³ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

- any relevant final project assessment conclusions report published under 5.17.4(o),(p) or (s)
- any other factor we consider relevant and which we have notified the distribution network service provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.

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.

As we noted above, the two tasks that the NER requires us to undertake involve us exercising our discretion. In exercising discretion, the National Electricity Law (NEL) requires us to take into account the revenue and pricing principles (RPPs).¹⁴ In the overview we discussed how we generally have taken into account the RPPs in making this final decision. Our assessment approach to forecast opex ensures that the amount of forecast opex that we are satisfied reasonably reflects the opex criteria is an amount that provides the service provider with a reasonable opportunity to recover at least its efficient costs.¹⁵ By us taking into account the relevant capex/opex trade-offs, our assessment approach also ensures that the service provider faces the appropriate incentives to promote efficient investment in, and provision and use of, the network and minimises the costs and risks associated with the potential for under and over investment and utilisation of the network.¹⁶

Expenditure Forecast Assessment Guideline

After conducting an extensive consultation process with service providers, users, consumers and other interested stakeholders, we issued the Expenditure Forecast Assessment Guideline in November 2013 together with an explanatory statement.¹⁷ The Guideline sets out our intended approach to assessing opex in accordance with the NER.¹⁸

While the Guideline provides for regulatory transparency and predictability, it is not binding. We may depart from the approach set out in the Guideline but we must give reasons for doing so.¹⁹ For the most part, we have not departed from the approach set out in the Guideline in this final decision.²⁰ In our framework and approach paper, we

¹⁴ NEL, ss. 7A and 16(2).

¹⁵ NEL, s. 7A(2).

¹⁶ That is, the trade-offs that may arise having considered the substitution possibilities between opex and capex, and the relative prices of operating and capital inputs: NER, cl. 6.5.6(e)(6) and 6.5.6(e)(7); NEL, ss. 7A(3), 7A(6) and 7A(7).

¹⁷ AER, *Expenditure forecast assessment guideline - explanatory statement*, November 2013.

¹⁸ NER, cl. 6.5.6.

¹⁹ NER, cl. 6.2.8(c).

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

set out our intention to apply the Guideline approach in making this determination.²¹ There are several parts of our assessment:

1. We develop an alternative estimate to assess a service provider's proposal at the total opex level.²² We recognise that a service provider may be able to adequately explain any differences between its forecast and our estimate. We take into account any such explanations on a case by case basis using our judgment, analysis and stakeholder submissions.
2. We assess whether the service provider's forecasting method, assumptions, inputs and models are reasonable, and assess the service provider's explanation of how its method results in a prudent and efficient forecast.
3. We assess the service provider's proposed base opex, step changes and rate of change if the service provider has adopted this methodology to forecast its opex.

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

If we are not satisfied with the service provider's proposal, we approach our second task by using our alternative estimate as our substitute estimate. The AEMC expressly endorsed this approach in its decision on the major rule changes that were introduced in November 2012. The AEMC stated:²³

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 NSPs against others will provide an indication of both whether the proposal is reasonable and what a substitute should be. Both the consideration of 'reasonable' and the determination of the substitute must be in respect of the total for capex and opex.

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

Building an alternative estimate of total forecast opex

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

²¹ AER, *Stage 2 Framework and approach—NSW electricity distribution network service providers*, January 2014, p. 50.

²² AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

²³ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

Figure 7.3 How we build our alternative estimate



Underlying our approach are two general assumptions:

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

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model that a number of Australian regulators have employed over the last fifteen years. We refer to it as a 'revealed cost method' in the Guideline (and we have sometimes referred to it as the base-step-trend method in our past regulatory decisions).²⁴

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

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

Step 1—Base year choice

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

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

²⁴ AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

In choosing a base year, we need to make a decision whether to remove any categories of opex incurred in that year. For instance:

- If a material cost was incurred in the base year that is unrepresentative of a service provider's future opex, we may remove it from the base year in undertaking our assessment.
- Rather than use all of the opex that a service provider incurs in the base year, service providers also often forecast specific categories of opex using different methods. We must also assess these methods in deciding what the starting point should be. If we agree that we should assess these categories of opex 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). We designed the EBSS to achieve a fair sharing of efficiency gains and losses between a service provider and its consumers. Under the EBSS, service providers receive a financial reward for reducing their costs in the regulatory control period and a financial penalty for increasing their costs. The benefits of a reduction in opex flow through to consumers as long as base year opex is no higher than the opex incurred in that year. Similarly, the costs of an increase in opex flow through to consumers if base opex is no lower than the opex incurred in that year. If the starting point is not consistent with the EBSS, service providers could be excessively rewarded for efficiency gains or excessively penalised for efficiency losses in the prior regulatory control period.

Step 2—Assessing base opex

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

As we set out in the Guideline, to assess the service provider's actual expenditure, we use a number of different qualitative and quantitative techniques.²⁵ This includes benchmarking and detailed reviews.

Benchmarking is particularly important in comparing the relative efficiency of different service providers. The AEMC highlighted the importance of benchmarking in its changes to the NER in November 2012.²⁶

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.

²⁵ AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

²⁶ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 97.

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. For this decision we have used multilateral total factor productivity, partial factor productivity measures and several opex cost function models.²⁷

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

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

Step 3—Rate of change

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

- price growth
- output growth
- productivity growth.

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

Step 4—Step changes

Next we consider if any other opex is required to achieve the opex objectives in the forecast period. We refer to these as 'step changes'. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs. As the Guideline explains, we will typically include a step change only if efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.²⁸

²⁷ We discuss the benchmarking models in detail in appendix A.

²⁸ AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

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

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

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

7.3.1 Interrelationships

In assessing United Energy's 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 United Energy an incentive to reduce opex in the 2014 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 United Energy's proposed step change for its mobile radio costs
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- changes to the classification of services from standard control services to alternative control services
- concerns of electricity consumers identified in the course of its engagement with consumers.

7.4 Reasons for final decision

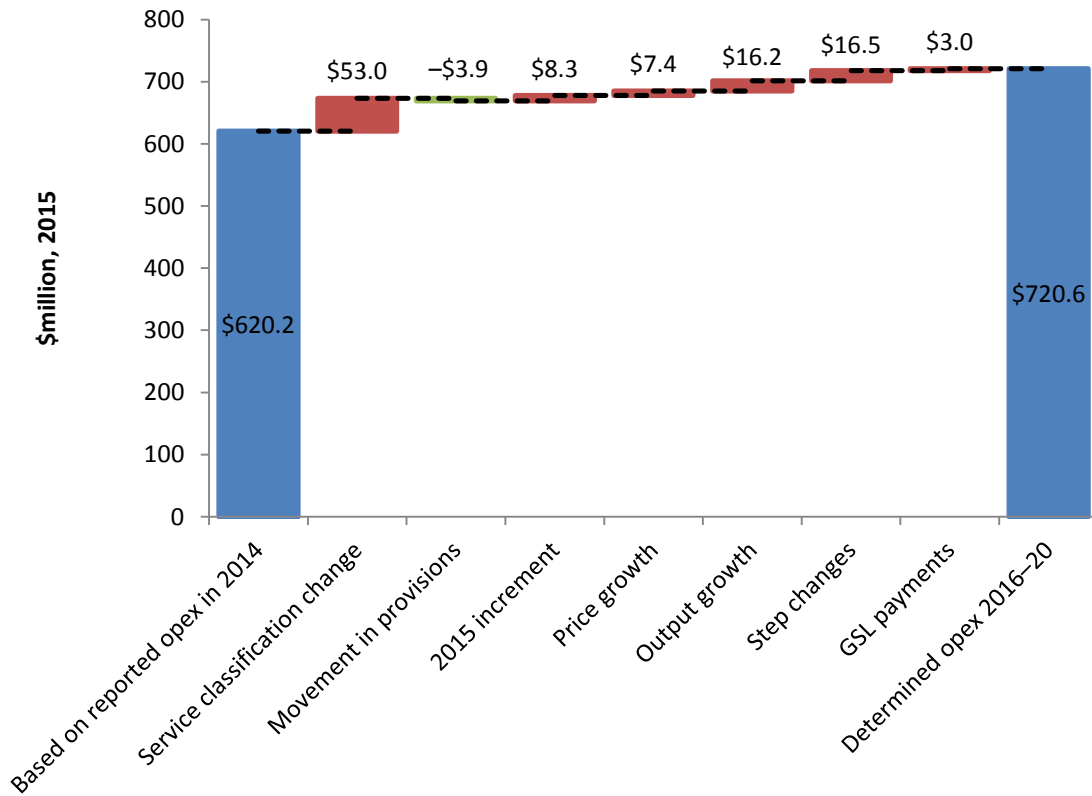
Generally we agree with United Energy on the approach to forecasting total opex. However, due to some differences with forecasts of the inputs used we are not satisfied United Energy's proposed total forecast opex of \$769.0 million (\$2015) reasonably reflects the opex criteria. We must not, therefore, accept United Energy's proposed total forecast opex.²⁹ As discussed above, we have used our alternative estimate of \$720.6 million (\$2015) as our substitute estimate.³⁰

Figure 7.4 illustrates how we constructed our forecast. The starting point on the left is what United Energy's opex would have been for the 2016–20 regulatory control period if it was set based on United Energy's reported opex in 2014.

²⁹ NER, cl. 6.5.6(d).

³⁰ NER, cl. 6.5.6(d) and 6.12.1(4)(ii).

Figure 7.4 AER final decision opex forecast (\$ million, 2015)



Source: AER analysis.

Table 7.2 outlines the quantum of difference between United Energy's revised proposed total opex and our final decision estimate for each year of the 2016–20 regulatory control period.

Table 7.2 Revised proposal and AER final decision on total forecast opex (\$ million, 2015)

	2016	2017	2018	2019	2020	Total
United Energy's revised proposal	147.0	149.9	154.6	157.2	160.3	769.0
AER final decision	139.2	142.1	145.2	146.1	148.0	720.6
Difference	-7.8	-7.8	-9.4	-11.2	-12.3	-48.3

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 United Energy's estimate below.

7.4.1 Base opex

Starting point for base opex

Consistent with our preliminary decision, we have based our opex forecast on United Energy's actual opex in 2014. We consider this leads to an opex forecast that reasonably reflects the opex criteria.

Our benchmarking indicates that the Victorian network service providers, including United Energy, are amongst the most efficient in the NEM. This suggests that it would be reasonable to rely on its actual opex when forecasting the base opex amount.

We also note that we regulate United Energy under an incentive-based regulatory framework. We would expect that United Energy, as a profit maximising service provider, would be responding to the financial incentives in the framework and would only incur cost increases where prudent. The incentive based framework gives us further confidence that in total United Energy's current opex is reasonably reflective of efficient levels.

We received some submissions that raised queries about the recent decline in productivity of the Victorian services providers and what it may mean for using actual opex in 2014 as the base opex.³¹

We have considered the recent productivity trend but it has not caused us to change our position on the efficiency of United Energy and the other Victorian service providers. We consider external drivers such as increases in bushfire mitigation obligations following the Black Saturday bushfires of 2009 and high labour price growth over the previous regulatory control period are the most significant drivers of the recent increases in opex for the Victorian service providers.

We outline our assessment of base opex in appendix A.

Adjustment for Advanced Metering Infrastructure (AMI) costs

We have included an adjustment to our base opex forecast of AMI IT and communications costs. This is a change in position from the preliminary decision.

Following the expiry of the AMI Order-in-Council, opex associated with AMI is to be regulated under the NER. In the preliminary decision we allocated all these costs to alternative control services. This was intended to be an interim position before we considered this issue in more detail through the development of the Distribution Ring Fencing Guideline.

³¹ VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 4, pp. 60-62; Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 25 February 2016, pp. 11-12.

We received a number of submissions which disagreed with our preliminary position. We reconsidered our approach in light of these submissions.

While there would be some benefit in waiting to consider this issue through the Ring Fencing Guideline process, given advanced meters have already been rolled out in Victoria, we acknowledge the cost allocation issues the Victorian service providers currently face are different to those that may potentially be faced by other service providers in other states. Therefore we agree that, on balance, there is no strong reason why we need hold all these costs in alternative control services until the Distribution Ring Fencing Guideline is completed. We therefore have developed a revised position on how such costs should be allocated. We have allocated shared AMI costs across standard control services and alternative control services in accordance with cost allocation principles consistent with our Cost Allocation Guidelines and the cost allocation principles in the NER.

By applying these principles we have made an adjustment to United Energy's base opex of \$10.6 million (\$2015). As discussed in Attachment 16 the revised approach leads to a commensurate reduction in metering opex from our preliminary decision.

Table 7.3 illustrates how we have constructed base opex.

Table 7.3 AER position on base opex (\$million, 2015)

	Our final decision
Reported 2014 opex	125.0
Remove debt raising costs	–
Remove movement in provisions	–0.8
Remove DMIA expenditure	–0.7
Remove GSL payments	–1.2
Remove licence fee (credit)	0.9
Service classification adjustment	10.6
Adjusted 2014 opex	133.9
2015 increment	1.7
Estimated 2015 opex	135.5

Source: AER analysis.

We outline our detailed assessment of the base year in appendix A.

7.4.2 Rate of change

The efficient level of expenditure required by a service provider in the 2016–20 regulatory control period may differ from that required in the final year of the 2011–15 regulatory control period. Once we have determined the opex required in the final year of the 2011–15 regulatory control period we apply a forecast annual rate of change to

forecast opex for the 2016–20 regulatory control period. This accounts for the forecast change in opex due to price, output and productivity growth.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than United Energy's over the forecast period. Table 7.4 below compares United Energy's and our overall rate of change in percentage terms for the 2016–20 regulatory control period.

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

	2016	2017	2018	2019	2020
United Energy's revised proposal	0.99	1.19	1.58	1.59	1.50
AER final decision	1.07	0.97	1.31	1.31	1.33
Difference	0.08	-0.22	-0.26	-0.28	-0.17

Source: AER analysis.

United Energy used the rate of change we determined in our preliminary decision in its revised regulatory proposal. However, it did not update its forecast of labour price growth to account for changes in economic conditions since we published our preliminary decision. Our preliminary decision used an average of the WPI growth rates forecast by Deloitte Access Economics (DAE) prepared in June 2015 and BIS Shrapnel prepared in November 2014. Our updated forecast uses an average of forecasts from DAE prepared in February 2016 and CIE prepared in November 2015. Consequently, our forecast of price growth is on average 0.22 percentage points lower than United Energy's forecast.

We have also updated our output growth forecasts to reflect the output weights in our latest benchmarking report. Consequently, we have forecast annual output growth 0.05 percentage points higher, on average, than United Energy did.

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

7.4.3 Step changes

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

- Power of Choice – metering competition
- Power of Choice – customer access to data
- regulatory information notice reporting
- vegetation management
- neutral testing
- pole top inspection
- National Energy Customer Framework (Chapter 5A).

In total these step changes contribute \$16.5 million (\$2015) or 2.3 per cent to our total opex forecast for United Energy for the 2016–20 regulatory control period.

We consider these step changes represent the efficient and prudent costs of meeting new regulatory obligations or represent an efficient capex/opex trade-off.

We were not satisfied there were reasons to change our opex forecast for other step changes.

Table 7.5 sets out our position on each of United Energy's proposed step changes.

Table 7.5 Step changes (\$ million, 2015)

	United Energy initial proposal	AER preliminary decision	United Energy revised proposal	AER final decision
Power of Choice – Metering competition	3.5	–	4.9	3.2
Power of Choice – Customer access to data	1.7	–	1.8	1.3
Power of Choice – Embedded network	0.7	–	Withdrawn	–
Power of Choice – Demand management IT Platform	1.6	–	1.6	–
Power of Choice – Network	3.5	–	Withdrawn	–
Regulatory Information Notice reporting	1.6	–	4.6	4.6
Energy Safe Victoria safety obligations	1.0	–	Withdrawn	–
Vegetation management	72.5 ³²	0.0	11.7	2.0
Effortless Customer Experience program	6.0	–	Withdrawn	–
Stakeholder engagement	1.3	–	1.3	–
Council trees	3.0	–	Merged with Vegetation management	–
Customer charter	0.7	–	Withdrawn	–
Regulatory submission	-5.2 ³³	–	Withdrawn	–

³² United Energy initially proposed \$8.7 million for this step change. United Energy updated its costs to reflect the final version of the Electric Line Clearance Regulations which was published after United Energy's initial proposal.

	United Energy initial proposal	AER preliminary decision	United Energy revised proposal	AER final decision
cost				
Neutral testing	0.4	–	2.3	2.3
Network planning and analytics – IT Capital Program	4.1	–	4.1	–
Guideline 11 EWOV direction	4.5	–	Withdrawn	–
IT security costs	4.0	–	3.9	–
Insurance premiums	2.3	–	Withdrawn	–
Pole top inspection	2.4	2.4	2.4	2.4
New pricing obligations	–	–	2.5	–
NECF	–	–	0.7	0.7
Real price escalations	0.5	–	–	–
Total	112.4³⁴	2.4	41.6	16.5

Source: United Energy, *Regulatory proposal, opex expenditure overview*, 30 April 2015, AER, United Energy *Preliminary decision attachment 7 operating expenditure*, October 2015, United Energy, *Revised regulatory proposal*, 6 January 2016, AER analysis.

We discuss each step change in more detail in appendix C.

7.4.4 Other costs not included in the base year

We have included debt raising costs and guaranteed service level payments in our final decision opex forecast. We have not included any other category specific forecast in our final decision opex forecast.

We discuss our assessment of GSL payments in appendix C and debt raising costs in attachment 3.

7.4.5 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.³⁵

³³ United Energy proposed a \$2.3 million step change for regulatory submission costs and removed \$1.5 million from its base opex. The net effect of this step change is -\$5.2 million over the forecast period relative to not making a base year adjustment.

³⁴ United Energy proposed \$53.8 million in its initial proposal. This total takes into account the updated vegetation management proposal and the net impact of regulatory submission costs.

³⁵ NER, cl. 6.5.6(e).

Table 7.6 summarises how we have taken the opex factors into account in making our final 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 United Energy's 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 United Energy's 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 Network Service Provider in the course of its engagement with electricity consumers.</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 regulatory proposals, such that they factor in the needs of consumers.³⁶</p> <p>We have considered the concerns of electricity consumers as identified by United Energy– particularly in considering United Energy's proposed step changes.</p>
<p>The relative prices of capital and operating inputs</p>	<p>We have considered capex/opex trade-offs in considering United Energy's proposed step changes. For instance we have provided a step change for pole top inspections on the basis that it is an efficient capex/opex trade-off. We considered the relative expense of capex and opex solutions in considering this step change.</p>

³⁶ AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

<p>The substitution possibilities between operating and capital expenditure.</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> <p>As noted above we considered capex/opex trade-offs in considering a step change for United Energy's pole top inspections. 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>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>	<p>The incentive scheme that applied to United Energy's 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 United Energy's opex for the 2016–20 regulatory control period.</p>
<p>The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.</p>	<p>Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.</p>
<p>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).</p>	<p>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 final decision.</p>
<p>The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.</p>	<p>We have not found this factor to be significant in reaching our final decision.</p>

Source: AER analysis.

A Base opex

A.1 Final decision

We have used a base opex amount of \$135.5 million (\$2015) in our final decision opex forecast. The comparison of the base opex amount in our preliminary decision, United Energy's revised proposal and our final decision is outlined below in Table A.1.

Table A.1 AER position on base opex (\$ million, 2015)

	Preliminary decision	Revised proposal	Our final decision
Reported 2014 opex	126.0	126.9	125.0
Remove movement in provisions	-0.8	-0.8	-0.8
Remove DMIA expenditure	-0.7	-0.7	-0.7
Remove GSL payments	-1.2	-1.2	-1.2
Remove licence fee (credit)	-	0.9	0.9
AMI cost reallocation	-	12.4	10.6
Adjusted 2014 opex	123.4	136.6	133.9
2015 increment	1.7	1.7	1.7
Estimated 2015 opex	125.0	138.3	135.5

Source: AER, United Energy preliminary decision opex model, October 2015; United Energy, United Energy - Opex - RRP, January 2016; AER, United Energy final decision opex model, May 2016.

A.2 United Energy's revised proposal and submissions

The main difference between our preliminary decision base opex amount and United Energy's revised proposal reflected a different allocation of AMI costs. In our preliminary decision we proposed to allocate all these costs to alternative control services opex. United Energy did not agree to this allocation in its revised proposal.

United Energy also proposed a revision to its reported 2014 opex for licence fee costs. The amount reported in 2014 was negative so this led to an increased base opex estimate.

The only other difference reflected different assumptions used to inflate base opex between 2014 and 2015.

We received several submissions in response to our preliminary decisions which either disagreed with our conclusions on base opex or requested further evidence to support our decision. In particular, VECUA considered there is extensive evidence of material inefficiencies in some Victorian distributors' opex. It considered this has been revealed

by the AER's benchmarking. As a result it considered using a revealed cost method to be flawed and a benchmarking approach should be used. It considered CitiPower to be the benchmark provider.³⁷

More generally, VECUA considered that in setting base opex we have had insufficient regard to:

- the decline in the Victorian distributors' productivity over the previous regulatory control period
- increases in the Victorian distributors' opex over the previous regulatory control period
- the opex reductions that should be realised from the Victorian distributors' major capex programs over the previous regulatory period.³⁸

The CCP was concerned we have presumed 2014 opex is efficient and that we have relied on it to set forecast expenditure in light of the forecast decline in productivity. It also urged we review this in detail. It was not convinced that increased bushfire mitigation expenditure and expansion of the network were driving the decline in productivity.³⁹

Further specific comments we received are addressed below.

A.3 Assessment approach

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

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

Where a service provider proposes adjustments to base opex then we assess whether those adjustments would lead to a total opex forecast that reasonably reflects the opex criteria.

³⁷ VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 60.

³⁸ VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 4, pp. 60-62.

³⁹ Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period.*, 25 February 2016, p. 11-12.

A.4 Reasons for final decision

Incentive regulation and the revealed cost forecasting approach

We have maintained our approach to setting United Energy's opex based on its actual opex in 2014. This approach is consistent with the approach we set out in the Guideline.

Network services are monopoly services with little scope in any given location for a competitor to duplicate the network efficiently.⁴⁰ Monopoly businesses do not have an incentive to set prices at an efficient level because there is no competitive discipline on their decisions. They do not need to consider how and whether or not rivals will respond to their prices. Monopolies' profits depend only on the behaviour of consumers, their cost functions, and their prices or the amount supplied.⁴¹

Without regulation, the resulting market power would lead to high prices and probably insufficient investment. Accordingly, we must regulate the prices and other aspects of these services to ensure reliable and affordable electricity.⁴²

Information asymmetries make it difficult for us to accurately assess the efficiency of the network businesses' proposals. We need to make judgements about 'efficient' costs.⁴³

Incentive regulation is used to partially overcome information asymmetries. We apply incentive-based regulation across all energy networks we regulate—consistent with the NER.⁴⁴ This is a fundamental aspect of the regime. As stated by the AEMC:

Set out in Chapter 6 of the NER, the incentive regulation framework is designed to encourage distribution businesses to spend efficiently and to share the benefits of efficiency gains with consumers. Specifically, it is designed to encourage distribution businesses to make efficient decisions on when and what type of expenditure to incur in order to meet their network reliability, safety, security and quality requirements.⁴⁵

⁴⁰ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 65.

⁴¹ ACCC, *Submission to the Productivity Commission's inquiry into the economic regulation of airport services*, March 2011, p. 8.

⁴² Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 65.

⁴³ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 190.

⁴⁴ Clause 6.2.6(a) of the NER states that for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C (Building Block Determinations for standard control services). Further, the RPPs state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.

⁴⁵ AEMC, *Consultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, February 2015, p. 3.

Broadly speaking, incentive regulation is designed to align the commercial goals of the business to the goals of society or, in the case of energy regulation, the NEO.⁴⁶ It relies on the principle that the network businesses' objective is to maximise profits.⁴⁷ Businesses that are able to improve their efficiency are rewarded with higher profits.⁴⁸ Businesses that allow their efficiency to deteriorate earn lower-than-expected profits. The actual revenue allowance set by the regulator should not influence the basic incentive of network businesses to minimise costs and, thereby, maximise profits. The drive to maximise shareholder returns should in theory push the businesses to become more efficient and productive over time. This allows us to leave the minutiae of input and output decision-making to the businesses.⁴⁹

The revealed cost forecasting approach is consistent with this framework. As opex is relatively recurrent from year to year, the incentive framework gives us confidence that we can rely on a service provider's actual opex when forecasting their efficient opex for the next regulatory control period.

By using a revealed cost forecasting approach, we assume that any efficiencies which have occurred since our previous regulatory determination have already been reflected in a service provider's actual opex. For instance, to the extent there are any opex efficiencies that the businesses have realised through a recent capex program, we assume it would be reflected in its existing opex. Similarly, given the financial incentives these service providers face in avoiding unnecessary cost increases, we assume that any cost increases that have occurred since the last regulatory determination reflect a prudent and efficient response to particular changes in a service provider's operating environment.

For Victorian service providers, strong incentives have applied to opex for three regulatory control periods. We would expect a priori that in responding to these incentives, these service providers would already be delivering a service that is relatively efficient. As this provides a strong theoretical reason why the Victorian service providers would be operating relatively efficiently, to conclude one is in fact operating inefficiently, we would require a convincing alternative body of evidence across a number of sources. We are not aware of any such evidence.

The main tool we have to assess whether incentive regulation is working is benchmarking. However, all the benchmarking we have undertaken, which was presented in our preliminary decision⁵⁰ shows that, on the whole, the Victorian service providers are operating relatively efficiently when compared to their counterparts in

⁴⁶ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 188.

⁴⁷ Put simply, it is assumed that shareholders want the business to maximise profits because the greater the profits, the greater their income.

⁴⁸ As stated by the AER in its Expenditure Forecast Assessment Guideline explanatory statement, 'the ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's forecast) because network businesses can retain a portion of cost savings made during the regulatory control period.' (p. 42)

⁴⁹ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, pp. 27–28.

⁵⁰ AER, *Preliminary decision, Attachment 7*, October 2015, pp. 31-40.

New South Wales and Queensland.⁵¹ We do acknowledge the gap between the Victorian service providers and the NSW and Queensland service providers has narrowed in recent years on the MTFP and Opex MPFP benchmarks. However, as discussed in our annual benchmarking report⁵² and below, changes in bushfire mitigation requirements including vegetation management are a significant driver of this outcome.

On this basis we have continued to rely on each of the Victorian service providers' actual opex to forecast and we have chosen not to undertake a forensic review of each of their opex. We consider this is a reasonable position to take in undertaking our task in assessing opex under the NER.

We also note that VECUA has inferred that because CitiPower is the best performer on one benchmarking model, the opex of all other Victorian service providers should be deemed to be inefficient.⁵³ We do not agree with this finding. Because benchmarking models are subject to limitations regarding specification of outputs and inputs, data imperfections and other uncertainties, we consider it is preferable to interpret the findings of any benchmarking conservatively. We do not consider it is reasonable to conclude that because one service provider is ranked highest in one model then all other service providers must be inefficient.⁵⁴

Reasons for productivity decline/increase in opex in Victoria

In response to the VECUA and CCP submissions, we have considered the reasons for the decline in opex productivity across the Victorian service providers in the past period. This has not caused us to change our position on base opex from the preliminary decision.

In total the Victorian service providers' opex have, on average, increased by 3.8 per cent per annum in real terms since 2009. We have observed the opex partial factor productivity (PFP) of the five Victorian service providers has declined by an average of 2.5 per cent per annum in this time. The opex PFP measure takes into account changes in customer numbers, circuit length, ratcheted maximum demand, energy

⁵¹ Our preliminary decision was based on benchmarking we had presented in our most recent distribution benchmarking report published in November 2014 (AER, *2014 Annual benchmarking report*, November 2014). After releasing our preliminary decision in October 2015 we published an additional distribution benchmarking report in November 2015 (AER, *2015 Annual benchmarking report*, November 2015). The 2015 version of the report still indicates that the Victorian service providers are operating relatively efficiently compared to their counterparts in New South Wales and Queensland.

⁵² AER, *2015 Annual benchmarking report*, November 2015, p. 8.

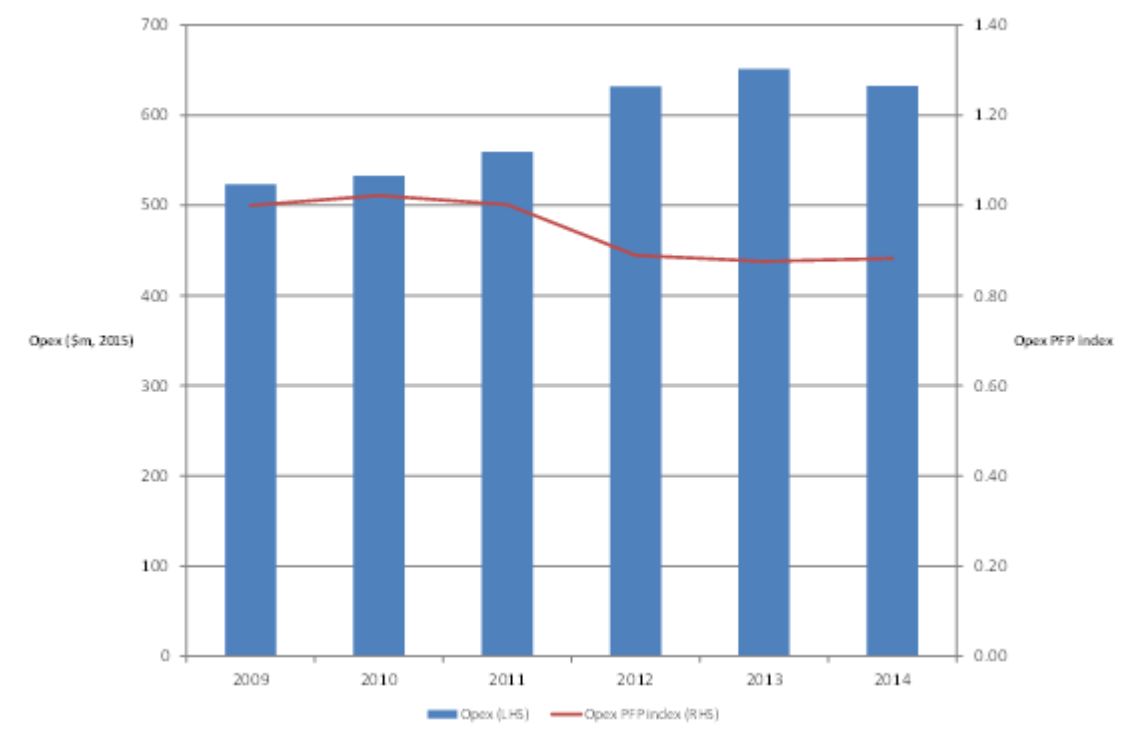
⁵³ VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 60

⁵⁴ We also note the model VECUA refers to measured average opex efficiency over an eight year period (2006 to 2013). For the purposes of setting base opex we are reaching a conclusion on efficient opex for 2014. As the costs facing the Victorian service providers are different in 2014 to the average costs they faced from 2006 to 2013, it is not possible to directly infer 2014 efficiency by assessing 2006 to 2013 efficiency.

delivered and customer minutes off supply. This suggests that a significant proportion of the growth in opex since 2009 is due to other cost drivers.

As outlined below in Figure A.1, the trend in opex and opex PFP has been relatively flat between 2009 and 2011. There is a significant increase in opex (and decline in opex PFP) across the Victorian service providers' between 2011 and 2012 and then a relatively flat trend in both opex and opex PFP between 2012 and 2014.

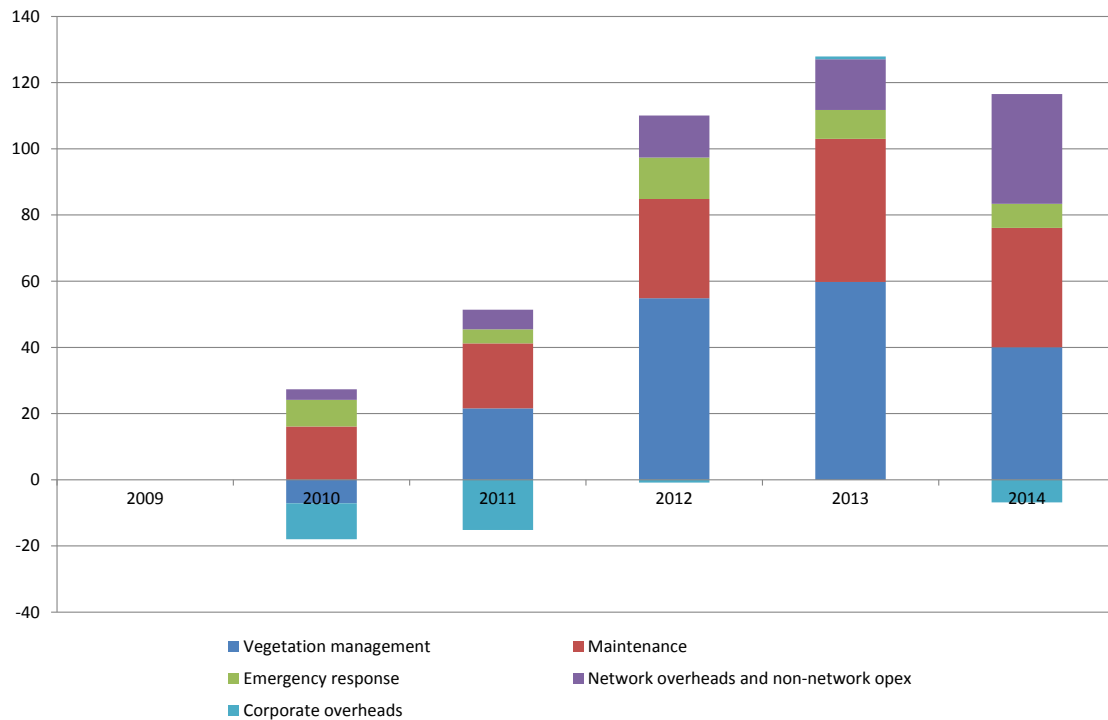
Figure A.1 Victorian service providers - trend in opex and partial factor productivity in opex - 2009 to 2014 (\$million, 2015)



Source: AER analysis

Figure A.2 aggregates total opex for each of the Victorian service providers by category and demonstrates the change in categories of opex in this time. It shows that increases in vegetation management opex followed by increases in maintenance opex are the main reasons why the Victorian service providers' opex has increased since our last determination.

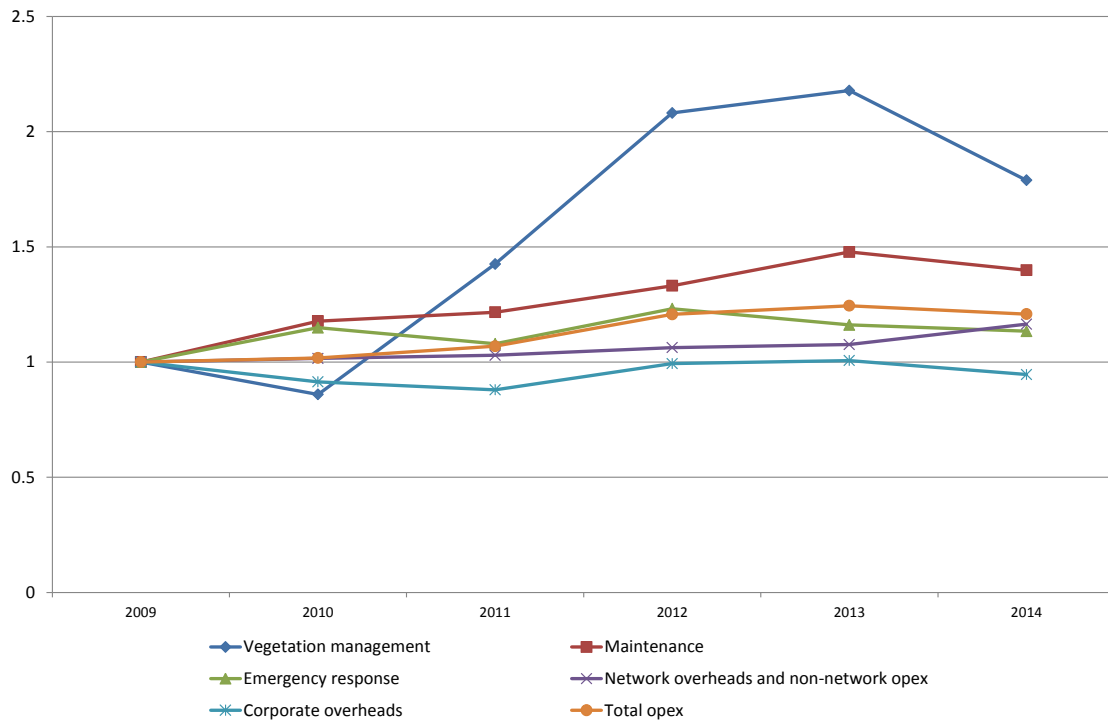
Figure A.2 Change in Victorian service providers opex relative to 2009 (\$ million, 2015)



Source: AER analysis.

Figure A.3 illustrates the growth of each category on an index based measure. Opex on vegetation management has increased proportionally by a much greater amount than other categories of opex. There has been a moderate increase in maintenance expenditure relative to 2009 levels. Network overheads allocated to opex and emergency response opex have increased only marginally relative to 2009 levels. Opex on corporate overheads has declined.

Figure A.3 Change in opex relative to 2009 - index measure (\$million, 2015)



Source: AER analysis.

A major driver of the increase in vegetation management opex across the industry is attributable to the changes in regulatory requirements as a result of the *Electrical Safety (Electric Line Clearance) Regulations 2010* which was introduced in June 2010 following the Black Saturday bushfires. These new regulations introduced the following key changes to the Victorian service provider's regulatory requirements.

- Minimum clearance spaces surrounding aerial bundled cable or insulated cable now applied to small tree branches. Under the previous version of the regulations, the minimum clearance spaces did not apply to small tree branches under specified conditions.
- Minimum clearance spaces surrounding powerlines in hazardous bushfire risk areas now applied to tree branches above a powerline of 22kV. Under the previous version of the regulations the minimum clearance space did not apply under specified conditions.⁵⁵

We signalled that the *Electrical Safety (Electric Line Clearance) Regulations 2010* would be a significant cost driver affecting the Victorian service providers' opex when we forecast large step changes in opex in our final decisions for the 2011 to 2015

⁵⁵ Victorian Competition and Efficiency Commission, *Proposed Electrical Safety (Electric Line Clearance) Regulations 2010 Regulatory Impact Statement*, p. xviii-xix.

regulatory control period.⁵⁶ At the time, we forecast increases in opex of \$206 million (\$2015) from 2011 to 2015 due to these new regulations.⁵⁷

Vegetation management expenditure across the industry was also likely affected by heavy rainfall during the period. The year 2010 was the fifth wettest year on record in Victoria following one of the wettest springs on record,⁵⁸ and 2011 was the twelfth wettest year on record.⁵⁹ While we have not collected evidence on the effects of this pattern on vegetation growth in Victoria, we did observe that above average rainfall in South Australia in 2010 and 2011 led to significant increases in vegetation growth and vegetation management expenditure.⁶⁰

The moderate increase in maintenance expenditure across the industry in part also reflects other increases in regulatory obligations following the Black Saturday bushfires. For instance, one of the Victorian Bushfire Royal Commission's recommendations was to mandate maximum thirty seven month inspection cycles of single wire earth return lines (SWER) and 22KV feeders in high bushfire risk areas.⁶¹ This came into force in the *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*⁶² and is now mandated by the *Electrical Safety (Bushfire Mitigation) Regulations 2013*.⁶³ This has contributed to the increase in pole inspection expenditure in Figure A.4.

⁵⁶ AER, *Victorian electricity distribution network service providers distribution determination 2011-15*, October 2010, p. 301; AER, *Opex step changes - final decision model*, AER analysis.

⁵⁷ Following an Australian Competition Tribunal decision, we reconsidered the amount we had forecast for Powercor and CitiPower. This led to a further increase in our forecast for Powercor and CitiPower of \$27 million (\$2015). See AER, *Vegetation management forecast operating expenditure step change 2011-15*.

⁵⁸ Bureau of Meteorology, <http://www.bom.gov.au/climate/current/annual/vic/archive/2010.summary.shtml>, 4 January 2011.

⁵⁹ Bureau of Meteorology, <http://www.bom.gov.au/climate/current/annual/vic/archive/2011.summary.shtml>, 3 January 2012.

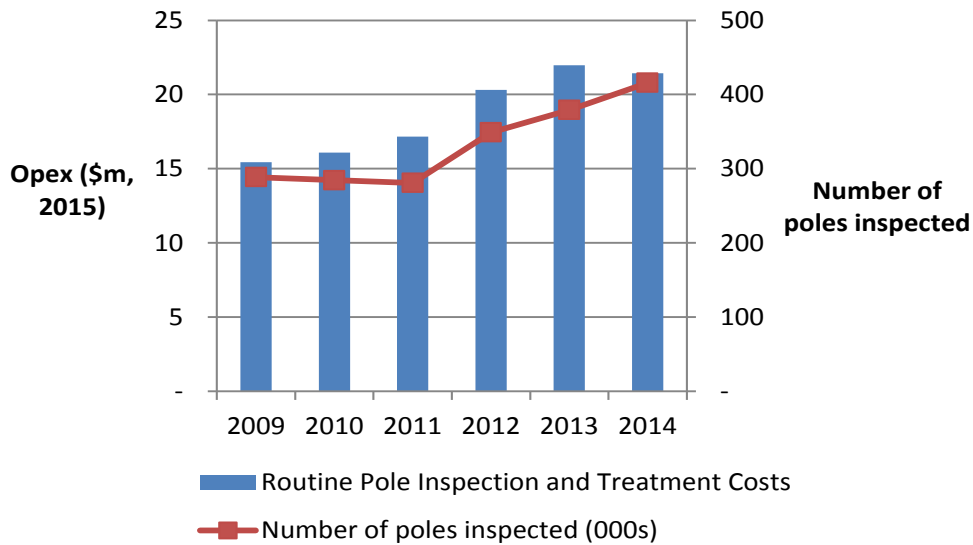
⁶⁰ AER, *SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation management*.

⁶¹ Victorian Bushfires Royal Commission, *Final Report - Summary*, July 2010, p. 29.

⁶² *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*, Cl. 5A(j); *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*, Cl. 5A(j);

⁶³ *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*, Cl. 6(i);

Figure A.4 Pole inspection and pole inspection expenditure (\$million, 2015)



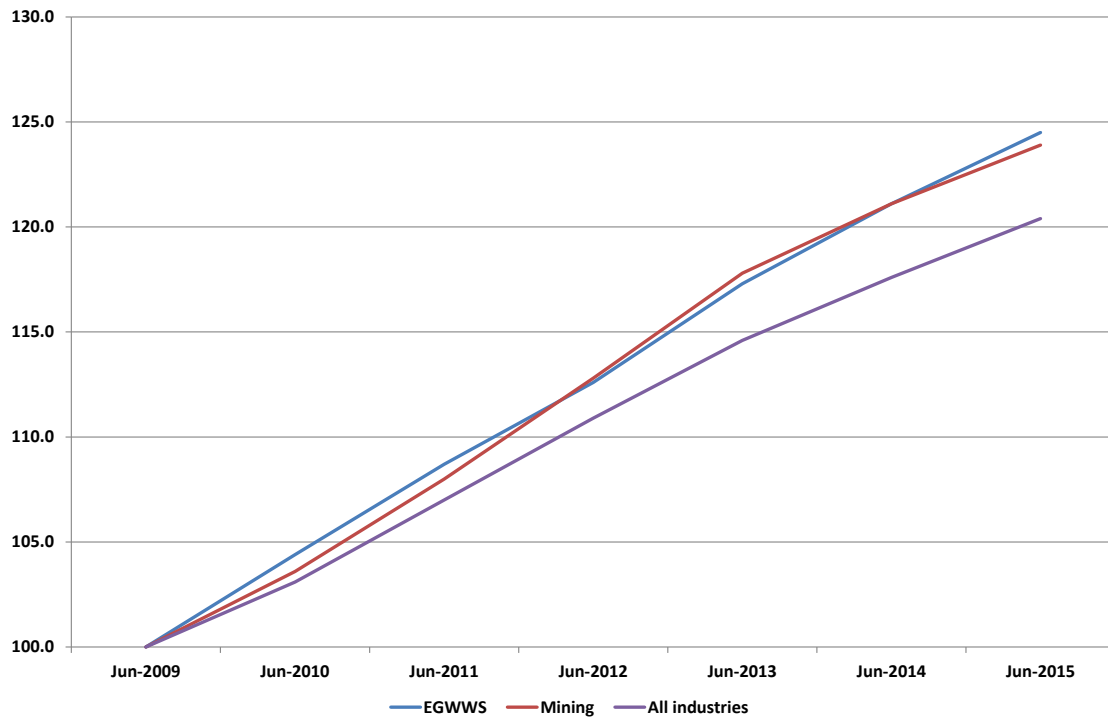
Source: AER analysis.

Another factor contributing to the increase in maintenance opex and opex more generally is the strength in wage growth across the industry. Labour costs are the most significant component of opex for utility businesses.

Since 2009, wage growth in the ABS' Electricity Gas Water and Wastewater (EGWWS) classification has been on average 3.7 per cent per annum in nominal terms. As indicated in Figure A.5, this has largely matched the rate of wage growth in the mining industry and has exceeded wage growth across the Australian economy. This, in part, is likely to reflect the impact of the mining boom on the EGWWS sector. The impact of the demand for mining labour has previously been recognised as a driver of utilities wages by Deloitte and BIS Shrapnel.⁶⁴

⁶⁴ Access Economics, *Forecast growth in labour costs: update of March 2010 report*, September 2010, p. vii; BIS Shrapnel, *Labour Cost Escalation Forecasts to 2016–17 - Australia and Queensland*, January 2012, p. 21.

Figure A.5 Wage growth - ABS classifications



Source: ABS, 6345.0 Wage price index, Table 9b, December 2015.

In our view, the above drivers do not suggest that the Victorian service providers' operating efficiency has materially declined over the previous regulatory period. In our view it suggests there are a number of changes in business conditions that help to explain the trend since our last revenue determination in Victoria.

Importantly, we do not expect these drivers to persist in the 2016–20 regulatory control period. For instance, the *Electrical Safety (Electric Line Clearance) Regulations 2015* led to relatively minimal changes to the Victorian service providers' regulatory requirements for vegetation management. As discussed in Appendix B, we also expect efficient wage growth in the utility sector to slow. This is in part attributable to the reduced competition for labour from the mining sector.⁶⁵

A.5 Allocation of AMI costs

Our final position on standard control services (SCS) base opex incorporates an adjustment of \$10.6 million (\$2015) for AMI costs. This is a change in position from our preliminary decision where we allocated all AMI costs to alternative control services (ACS). Our revised approach is based on advice on cost allocation principles for IT and communications systems from Energy Market Consulting Associates (EMCa). These

⁶⁵ Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, February 2016, p. 39.

principles are aligned with the cost allocation principles in our Cost Allocation Guidelines⁶⁶ and in the NER.⁶⁷

Preliminary decision approach and consideration of stakeholder views

During the 2011–15 regulatory control period, incremental costs associated with implementing and operating smart meters were regulated under the Advanced Metering Infrastructure Order in Council (AMI OIC). This included costs associated with new or upgraded IT systems.

With the expiry of the AMI OIC, opex associated with AMI is now to be regulated under the NER. United Energy initially proposed an adjustment to its SCS base opex of \$18.9 million (\$2015) for AMI opex previously regulated under the AMI OIC. Other opex associated with smart meters was allocated to ACS metering. United Energy's proposed base opex amount for ACS metering was \$5.2 million (\$2015). Under United Energy's approach it allocated all direct costs associated with the operation, repair and maintenance of type 5 and 6 meters to ACS metering. All shared costs were allocated to SCS opex.⁶⁸

In our preliminary decision we did not allocate any AMI costs to SCS. Each of the Victorian service providers had adopted a different approach to allocating AMI costs in their initial proposals. Presently, metering services are not subject to competition but, following NER changes, competition is scheduled to begin from December 2017.⁶⁹ We considered that a different approach to allocating costs across each of the Victorian service providers would not help in promoting effective competition for metering. We considered a consistent approach to be preferable which could be dealt with through our Distribution Ring Fencing Guideline in accordance with a national framework.⁷⁰ We are scheduled to publish a Distribution Ring Fencing Guideline by 1 December 2016.

In the interim, before this Guideline is developed, we considered it was preferable to allocate all AMI costs to ACS. As this is similar to the historical approach where AMI costs are recovered separately to most distribution network costs, we also considered this approach will help in promoting transparency around trends in metering and SCS opex.⁷¹

In its revised proposal United Energy's proposed SCS opex base year adjustment for AMI was \$12.4 million (\$2015). Its revised base opex amount for ACS metering was \$10.0 million (\$2015). The adjustment to SCS opex reflected 79 per cent of United Energy's IT costs formerly regulated under the AMI OIC.

⁶⁶ AER, *Electricity distribution network service providers - Cost allocation guideline*, June 2008.

⁶⁷ NER, cl.6.15.2.

⁶⁸ United Energy, *Revenue capped metering services overview paper*, 28 April 2015, p. 16.

⁶⁹ AEMC, National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2015, 26 November 2015, p. i.

⁷⁰ AER, *United Energy preliminary decision*, October 2015, Attachment 7, p.44.

⁷¹ AER, *United Energy preliminary decision*, October 2015, Attachment 7, p.44.

In response to our preliminary decision, all of the Victorian service providers disagreed with the AER's decision to allocate all AMI costs to metering ACS. All of the Victorian service providers maintained that certain AMI costs should be allocated to SCS.

The Victorian service providers' arguments to support their proposals to allocate some AMI costs to SCS can be summarised as follows:

- a number of the IT systems rolled out as part of the AMI metering service are needed even if the service providers did not provide a metering service, e.g. for customer billing and providing data to the market, and should therefore be considered to contribute to the distribution network SCS⁷²
- as some of these costs should be allocated to SCS, in the event of metering competition, they would be at an unfair disadvantage if all AMI costs are allocated to ACS⁷³
- costs must be correctly allocated now in line with the regulatory framework.⁷⁴ Several service providers considered costs should be allocated in accordance with their Cost Allocation Methods (CAM).⁷⁵
- different DNSPs adopted different approaches to the AMI roll out (e.g. purpose built IT systems compared to upgrades / lifecycle replacement of existing systems) and these differences limit the extent to which cost allocation between standard control services and alternative control services will or can be consistent across all DNSPs.⁷⁶

The Victorian Government also disagreed with our preliminary decision on this issue. It considered we must resolve this issue to the best of our ability now.⁷⁷ It considered that if all AMI costs are allocated to ACS then metering charges will be higher than they should be. It considered that there is a risk that this may encourage inefficient entry from new competitors.⁷⁸ The CCP agreed with our preliminary decision to allocate all AMI costs to ACS metering pending development of the Distribution Ring Fencing Guideline.⁷⁹

⁷² AusNet Services, *Revised regulatory proposal, Attachment 11-6*; CitiPower, *Revised regulatory proposal*, p. 151; Powercor, *Revised regulatory proposal*, pp. 150-151.

⁷³ AusNet Services, *Revised regulatory proposal, Attachment 11-7*; CitiPower, *Revised regulatory proposal*, p. 151; Jemena, *Revised regulatory proposal, Attachment 9-1*, p. 23; Powercor, *Revised regulatory proposal*, p. 151; United Energy, *Revised regulatory proposal*, p. 106.

⁷⁴ Jemena, *Revised regulatory proposal, Attachment 9-1*, p. 22; United Energy, *Revised regulatory proposal*, pp. 104-105.

⁷⁵ AusNet Services *Revised regulatory proposal, Attachment 11-7*; CitiPower, *Revised regulatory proposal*, pp. 152-153; Powercor, *Revised regulatory proposal*, pp. 152-153.

⁷⁶ CitiPower, *Revised regulatory proposal*, p. 152; Jemena, *Revised regulatory proposal, Attachment 9-1*, p. 24; Powercor, *Revised regulatory proposal*, p. 152; United Energy, *Revised regulatory proposal*, p. 105.

⁷⁷ Victorian Government, *Submission on preliminary decisions*, p. 10.

⁷⁸ Victorian Government, *Submission on preliminary decisions*, p. 10.

⁷⁹ CCP, *Report on AER preliminary decision*, p. 23.

In light of the several submissions we received from stakeholders that disagreed with our preliminary position, we reconsidered whether we should continue to hold all AMI costs in ACS metering until we considered this issue further in developing the Distribution Ring Fencing Guideline. We have determined that a change in position from our preliminary decision is appropriate. We note that the mandated AMI roll-out involved upgrades not just to metering services but also other network services, such as IT and other systems which previously were being recovered in aggregate under the AMI OIC regime, but are now regulated under the NER. This means certain systems should be seen as part of SCS.

While there would be some benefit in waiting to consider this issue through the Distribution Ring Fencing Guideline process, given advanced meters have already been rolled out in Victoria, the cost allocation issues the Victorian service providers currently face are different to those that may potentially be faced by other service providers in other states. Therefore, on balance, it is appropriate to consider the allocation of AMI costs between SCS and ACS, notwithstanding we have not yet completed the Distribution Ring Fencing Guideline. We therefore have developed a revised position on how such costs should be allocated for the 2016–2020 regulatory control period.⁸⁰

EMCa advice on cost allocation

We engaged EMCa to help develop a cost allocation approach that could be applied across the Victorian service providers. We asked EMCa to focus on IT and communications costs as this was the main area where the service providers proposed to allocate costs to SCS.

EMCa carried out a desktop review of the AMI information submitted by the Victorian service providers as part of their regulatory submissions. It also reviewed relevant AMI regulatory decision and guidance documents. It compared the allocation approach for AMI-related IT and communications expenditure and collated evidence on the key drivers and rationale provided by each business to justify the allocation approaches taken.⁸¹

EMCa also reviewed the allocations proposed by the businesses against our cost allocation framework, which include:

1. the cost allocation principles in the NER⁸²
2. our Cost Allocation Guideline,⁸³ and
3. approved Cost Allocation Methods for each service provider.⁸⁴

⁸⁰ We note that our decision to allocate these costs in this way for the 2016–2020 regulatory control period does not prevent us from re-considering this issue through the Ring Fencing Guideline process.

⁸¹ EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. 2.

⁸² NER, s.6.15.2.

⁸³ AER, *Electricity distribution network service providers - Cost allocation guideline*, June 2008.

EMCa agreed that it is reasonable that some proportion of the costs relating to AMI should be allocated to SCS as some aspects of AMI were geared towards providing greater network benefits beyond metering services.

While EMCa considered it reasonable to suggest that the allocation of AMI costs should be consistent with each service provider's CAM, for the most part it did not consider their CAMs are sufficiently prescriptive or granular as to provide a clear method for allocating AMI costs between metering ACS and SCS:

While noting the AER's Decisions approving the CAMs, given the high-level nature of the documents it is not possible to assess from the CAMs alone, whether the DNSPs have adopted a cost allocation approach for metering-related IT and communications that is consistent with NER's CAG. Moreover the variety of methods used by the DNSPs in allocating costs between SCS and metering ACS directly demonstrates the latitude in interpretation that has been applied in the CAMs.⁸⁵

EMCa considers it is more instructive to allocate such costs by direct reference to the NER's Cost Allocation Principles (CAP) and our Cost Allocation Guidelines (CAG). By basing the allocation of AMI costs on consistent principles with reference to the main reason the system was put in place (i.e. driver), EMCa considers this would provide a more reasonable platform for metering competition.⁸⁶

In line with our CAG and the NER's CAP, EMCa considers that costs should be directly attributed (to distribution network SCS or metering ACS) only where the relevant systems are solely used to provide that service or where use for the other services can be considered immaterial as defined by Australian accounting standards. Where costs are shared and material, EMCa recommends the costs be allocated on a causal basis.⁸⁷

On this basis EMCa would expect DNSPs to propose an attribution / allocation of IT opex and communications opex broadly as set out in Table A.2.

⁸⁴ AusNet Services, *Cost Allocation Method*, November 2014; CitiPower, *Cost Allocation Method*, April 2014; Jemena, *Cost Allocation Method*, July 2014; Powercor, *Cost Allocation Method*, April 2014; United Energy *Cost Allocation Method*, October 2014.

⁸⁵ EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. 22.

⁸⁶ EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

⁸⁷ EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

Table A.2 Proposed allocation of AMI IT and communications costs

Allocation between ACS/SCS	
Allocated solely to ACS metering	<ul style="list-style-type: none"> Communications infrastructure opex including Network Management Systems (NMS), Metering Management Systems (MMS), Network Operations and Control Centre (NOCC) Metering data management systems
Allocated solely to SCS	<ul style="list-style-type: none"> Field force mobility systems Network billing systems Customer Information Systems Outage management systems
Shared between ACS and SCS	<ul style="list-style-type: none"> B2B systems for managing AMI- related transactions with other market participants GIS Asset management systems Performance and reporting regulatory systems Middleware / integration bus technology Data analysis systems New / upgraded IT infrastructure to support the additional AMI functionality

Source: EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

Several service providers considered that a common allocation method would be challenging to apply given they implemented AMI at different stages of their IT lifecycles. However, EMCa did not afford this much weight given it had recommended the service providers apply a causal allocation method. This gives consideration to the reason the cost was incurred and recognises the different stage of the service providers' IT lifecycles. EMCa considered the service providers' arguments would only be relevant if it were advocating the same fixed allocation percentage be used across all service providers.⁸⁸

⁸⁸ EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

Application of cost allocation principles to United Energy's AMI costs

We invited United Energy to comment on EMCa's draft framework for allocating AMI costs to which it responded on 24 March.⁸⁹

United Energy supported many aspects of EMCa's proposed cost allocation approach. It disagreed with EMCa's findings in relation to communications costs. EMCa proposed to allocate these costs 100 per cent to alternative control services. United Energy proposed a 60 per cent allocation. It considered this reflected the contribution to standard control services data/services/development, although it noted that this only results in \$2 per annum change in its metering charge which it does not consider material. AusNet Services was the only other Victorian service provider that allocated the majority of its communications costs to standard control services. For instance, CitiPower and Powercor proposed to allocate 100 per cent of communications costs to alternative control services.⁹⁰

To identify whether a system should be solely related to the provision of metering services, EMCa considered the main reason the system was implemented (i.e. driver). It has advised that, on balance, a 100 per cent allocation of communications costs to ACS metering is reasonable given that the AMI communications network was put in place to provide for remote collection of interval metering data. EMCa advised that a high performance communications network was essential to meet this requirement.⁹¹

We have accepted EMCa's advice on the allocation of these costs. The cost allocation principles in the NER and our cost allocation guidelines specify that costs should be allocated in accordance with a causal allocator unless such an allocator cannot be established without undue cost and effort.⁹² We have interpreted the main reason United Energy incurs communications costs in operating its advanced meters is to support daily uploads of half-hourly interval metering data. These are metering services. Therefore we consider it reasonable to allocate these costs to ACS metering. As this is the same allocation proposed by CitiPower and Powercor, this demonstrates our approach is reasonable.⁹³

Table A.3 illustrates how the allocation of IT and communications costs has changed between United Energy's initial proposal, its revised proposal and our final decision.

⁸⁹ United Energy, *AER information request – United Energy - #054 – Advanced Metering Infrastructure costs* [email to AER], 24 March 2014.

⁹⁰ CitiPower, *AER information request – CitiPower - #044 – Advanced Metering Infrastructure costs.pdf* [email to AER], 24 March 2016; Powercor, *AER information request – Powercor - #050– Advanced Metering Infrastructure costs.pdf* [email to AER], 24 March 2016.

⁹¹ EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. 35.

⁹² NER, cl. 6.5.2(3)(ii); AER, *Electricity distribution network service providers, Cost allocation guideline*, June 2008, s.2.2.4(a).

⁹³ CitiPower, *AER information request – CitiPower - #044 – Advanced Metering Infrastructure costs.pdf* [email to AER], 24 March 2016; Powercor, *AER information request – Powercor - #050– Advanced Metering Infrastructure costs.pdf* [email to AER], 24 March 2016.

Table A.3 Allocation of IT and communications costs (per cent)

Initial proposal		Revised proposal		Final decision	
SCS	ACS	SCS	ACS	SCS	ACS
100	0	79	21	68	32

Source: United Energy, *Regulatory proposal*, United Energy, *Revenue capped metering Services Overview Paper*, 28 April 2015; United Energy, *Response to AER Information Request 54 CROIC allocation – Final.pdf* [email to AER], 24 March 2016; AER analysis.

A.6 Other adjustments to base opex

Licence fee adjustments

We have accepted United Energy's adjustment to its base opex for licence fees.

In its revised proposal, United Energy made an adjustment to its reported 2014 opex for licence fees. United Energy's 2014 opex included a reversal of \$0.9 million relating to its licence fees. This was a reversal of accruals made during the 2006 to 2010 period, which were only reversed out in 2014. It reported that the delay in timing was due to an accounting error.

Licence fees are recovered through a tariff variation adjustment, so we agree with United Energy that these costs should not be included in base opex. We have made an equivalent adjustment to United Energy's 2014 opex when estimating its EBSS carryover amounts.

Inflation

The other change to our base opex estimate reflects an update of how we have inflated base opex from nominal dollars to real \$2015. For our preliminary decision we estimated the annual inflation rate to December 2015 would be 2.5 per cent, based on the RBA's forecast in its statement on monetary policy.⁹⁴ For this final decision we have used the actual inflation rate of 1.7 per cent as reported by the ABS.⁹⁵ This actual inflation rate was not available at the time of our preliminary decision.

⁹⁴ Reserve Bank of Australia, *Reserve Bank of Australia statement of monetary policy*, August 2015, p. 67.

⁹⁵ ABS catalogue 6401.0, December 2015

B Rate of change

Once we have determined the efficient opex required in 2015 we apply a forecast annual rate of change to forecast opex for the 2016–20 regulatory control period. We do this to account for likely changes in demand and cost inputs for each year of the forecast period. As set out in the Expenditure Forecast Assessment Guideline (the Guideline), the rate of change accounts for forecast:⁹⁶

- price growth
- output growth
- productivity growth.

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

B.1 Position

We are not satisfied United Energy's proposed rate of change for the 2016–20 regulatory control period reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.⁹⁷ United Energy adopted the rate of change forecast from our preliminary decision. We consider this forecast should be updated to reflect the most up to date available information. We think this is required for our alternative estimate of opex to reasonably reflect the efficient and prudent costs faced by United Energy given a realistic expectation of demand forecasts and cost inputs. We discuss our reasons for this in the sections below.

We have applied the same rate of change methodology as we used in our preliminary decision. However, we have updated our estimate of the rate of change in opex to reflect the most recent forecasts of labour price growth in the Victorian utilities industry from Deloitte Access Economics (DAE) and the Centre for International Economics (CIE).⁹⁸ The net impact of these changes results in an annual rate of change of 1.20 per cent, which is on average 0.17 per cent lower than our preliminary decision estimate.

We note that we and United Energy have forecast similar output growth and have both applied a zero estimate of forecast productivity growth.

⁹⁶ AER. *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

⁹⁷ NER, cl. 6.5.6(c)(3).

⁹⁸ We used DAE and BIS Shrapnel in our preliminary decision but none of the DNSPs submitted an up to date forecast from BIS Shrapnel with their revised regulatory proposals.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than United Energy's over the forecast period. Table B.1 shows United Energy's and our overall rate of change in percentage terms for the 2016–20 regulatory control period.

The difference in the forecast rate of change is because our forecast of annual price growth is on average 0.17 percentage points lower than United Energy's

We discuss the reasons for the difference between us and United Energy for the rate of change components below.

Table B.1 United Energy and AER rate of change (per cent)

	2016	2017	2018	2019	2020	Average
United Energy	0.99	1.19	1.58	1.59	1.50	1.37
AER	1.07	0.97	1.31	1.31	1.33	1.20
Difference	0.08	-0.22	-0.26	-0.28	-0.17	-0.17

Source: AER analysis.

B.2 Preliminary position

For our preliminary decision, we did not adopt United Energy's forecast growth in price and output in our forecast rate of change and thus our alternative estimate of opex. We have summarised our preliminary position for each rate of change component below:

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

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

B.3 United Energy's revised proposal and submissions

United Energy adopted the forecast rate of change from our preliminary decision in its revised regulatory proposal.⁹⁹ This resulted in a decrease in the average annual rate of change estimate from 2.14 per cent in its initial proposal to 1.37 per cent in its revised proposal.

B.4 Reasons for position

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

B.4.1 Overall rate of change

United Energy adopted the rate of change from our preliminary decision in its revised regulatory proposal. Our forecast rate of change is lower than United Energy's because we have updated our forecast. Specifically, we have updated our forecast of price change to reflect the latest labour market information. We have also updated our output weights to match those in our latest benchmarking report.

United Energy adopted the output growth forecast from our preliminary decision in its revised regulatory proposal, which is also consistent with our forecast output growth for this final decision. United Energy forecast zero productivity growth for the 2016–20 regulatory control period. This is consistent with our forecast of productivity growth.

Table B.2 shows United Energy's and our overall rate of change and each rate of change component for each regulatory year of the 2016–20 regulatory control period.

In estimating our rate of change, we considered United Energy's proposed forecast growth in prices, output and productivity and the methodology used to forecast these.

We discuss the reasons for the differences between United Energy's revised proposal and our preliminary decision for each rate of change component below.

⁹⁹ United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 62–64.

Table B.2 United Energy and AER rate of change (per cent real)¹⁰⁰

	2016	2017	2018	2019	2020	Average
United Energy revised proposal						
Price growth	0.22	0.50	0.79	0.92	0.85	0.66
Output growth	0.77	0.69	0.78	0.67	0.64	0.71
Productivity growth	–	–	–	–	–	–
Overall rate of change	0.99	1.19	1.58	1.59	1.50	1.37
AER						
Price growth	0.25	0.23	0.49	0.59	0.63	0.44
Output growth	0.82	0.74	0.82	0.71	0.69	0.76
Productivity growth	–	–	–	–	–	–
Overall rate of change	1.07	0.97	1.31	1.31	1.33	1.20
Overall difference	0.08	–0.22	–0.26	–0.28	–0.17	–0.17

Source: AER analysis.

B.4.2 Forecast price growth

We are not satisfied United Energy's proposed average annual price growth of 0.7 per cent for the 2016–20 regulatory control period reasonably reflects the increase in prices a prudent and efficient service provider would require to achieve the opex objectives. We forecast an average annual price growth of 0.4 per cent for the 2016–20 regulatory control period.

We forecast price growth based on the forecast growth in labour and non-labour prices. We used the forecast change in the wage price index (WPI) for the electricity, gas, water and waste services industry (the utilities industry) as the forecast change in the labour price.¹⁰¹ We assumed non-labour prices grow with CPI. We applied input price weights of 62 per cent for labour and 38 per cent for non-labour.

¹⁰⁰ The rate of change = (1+ price growth) × (1+ output growth) × (1+ productivity growth) – 1.

¹⁰¹ We recognise that the utilities industry is a broad measure that includes other workers but captures all electricity distribution workers. However, we are satisfied that it is an appropriate comparison point. DAE considered that electricity labour is a large component of the utilities sector and therefore it has a notable impact on the WPI

United Energy adopted the forecast of price growth in our preliminary decision in its revised regulatory proposal but it did not update its forecast of labour price growth to account for changes to economic conditions since we published our preliminary decision. We discuss our consideration of this below.

Labour price growth

As noted above we used a forecast of WPI growth for the Victorian utilities sector to forecast labour price growth. We consider the average of the utilities WPI growth forecasts from DAE and CIE represents a realistic expectation of the cost inputs required to achieve the opex objectives.

We are satisfied that this approach to forecasting labour price growth reasonably reflects a realistic expectation of the labour price growth faced by a prudent and efficient firm. This forward looking approach draws on available current market information from multiple sources, including from enterprise agreements, on the expected changes to the drivers of labour price. This is particularly important when labour drivers have changed significantly in recent times and wage price growth, for both the economy as a whole, and the utilities industry more specifically, is at the lowest level on record.¹⁰²

United Energy adopted the forecast of price growth in our preliminary decision in its revised regulatory proposal. However, our standard practice is to update our forecast of price growth in our final decisions to reflect the most up to date information practicably available at the time of our final decision.

For our preliminary decision we used an average of the WPI growth rates forecast by DAE and BIS Shrapnel. DAE prepared its forecast in June 2015. BIS Shrapnel prepared its forecasts in November 2014. Consequently the forecasts we used are now, on average, over a year old.

We received updated forecasts from DAE in February 2016. However, none of the Victorian DNSPs provided updated WPI forecasts from BIS Shrapnel. Consequently the only forecasts we have from BIS Shrapnel are those it produced in November 2014.

Consequently we considered alternative sources of WPI forecasts. AusNet Services, CitiPower and Powercor all provided WPI growth forecasts from CIE with their revised regulatory proposals, as they did with their initial proposals. In our preliminary decision for AusNet Services we raised a number of concerns with CIE's WPI growth forecasts. Specifically, we stated that CIE WPI growth forecasts looked inconsistent with the prevailing labour market conditions in that they peaked in 2016 and remained above

series. It also considered that a difference between electricity labour and non-electricity labour, if true, is neutral as to wage implications. It may point to wage pressures being either higher or lower than the utilities industry more generally.

¹⁰² ABS, 6345.0 *Wage price index*, Table 9b.

the historic average over the entire forecast period.¹⁰³ However CIE has addressed these concerns in its revised forecasts. We compare the Victorian utilities WPI forecasts from all three forecasters in Table B.3.

Table B.3 Forecast annual WPI growth, Victoria, EGWS (per cent)

	2016	2017	2018	2019	2020	Average
BIS Shrapnel (November 2014)	0.9	1.3	1.8	2.1	1.8	1.6
DAE (February 2016)	0.1	-0.2	0.5	0.9	1.1	0.5
CIE (November 2015)	0.7	1.0	1.1	1.0	1.0	0.9

Source: DAE, *Forecast growth in labour costs in NEM regions of Australia*, 22 February 2016, p. 8; CIE, *Labour price forecasts*, 23 November 2015, p.76; BIS Shrapnel, *Real labour and material cost escalation forecasts to 2020*, November 2014, p. ii.

The forecast Victorian utilities WPI growth rates from BIS Shrapnel are higher on average than the historic average rate at the national level of 1.2 per cent per annum. By contrast, the forecast utilities WPI growth rates from both DAE and CIE are lower, on average, than the historic average rate. We noted in our preliminary decision that WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, were at their lowest level on record.¹⁰⁴ WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, have since fallen further.¹⁰⁵

We note that CIE's revised forecasts are significantly lower than its initial forecasts from December 2014. Its revised average annual WPI growth forecasts are 0.8 per cent lower. CIE stated that the primary driver of this reduction was a downgrade to its forecast GDP growth and an upgrade to its forecast labour supply growth.¹⁰⁶ Consequently it is clear that CIE considered changes in economic conditions between December 2014, when it released its initial forecasts, and November 2015, when it released its revised forecasts, have had a significant impact on wage growth expectations. BIS Shrapnel's December 2014 forecasts do not account for these changed conditions. Consequently we consider BIS Shrapnel's outdated forecasts should not be included in our average. Instead we have used CIE's forecasts because they reflect up to date economic information.

B.4.3 Forecast output growth

The forecast output growth rate we have applied in our estimate of the overall rate of change averages 0.8 per cent per annum. We consider this reasonably reflects the

¹⁰³ AER, *Preliminary decision: AusNet Services, Attachment 7*, October 2015, p. 56.

¹⁰⁴ AER, *Preliminary decision, Attachment 7*, October 2015, p. 57.

¹⁰⁵ ABS, *6345.0 Wage price index*, Table 9b.

¹⁰⁶ CIE, *Labour price forecasts*, 23 November 2015, p. 25.

increase in output a prudent and efficient service provider would require to achieve the opex objectives. There is only a small difference between United Energy's forecast output growth rate, which averaged 0.7 per cent per annum. The difference is because we updated our output weights to match those in our latest benchmarking report.

Our approach to forecasting output growth

We have maintained our preliminary decision methodology to forecast output growth.¹⁰⁷ We updated our output weights to match those in our latest benchmarking report. The output growth factors we used and their respective weights are:

- customer numbers (73.9 per cent)
- circuit line length (8.7 per cent)
- ratcheted maximum demand (17.4 per cent).

United Energy adopted our approach to forecasting output growth in its revised regulatory proposal.

We used the customer numbers forecasts adopted by United Energy in its revised regulatory proposal opex model, which were consistent with our preliminary decision and United Energy's initial regulatory proposal. This produces an average annual growth rate of 0.97 per cent for customer numbers.

We used the forecast circuit length adopted by United Energy in its revised regulatory proposal opex model, which was consistent with our preliminary decision and United Energy's initial regulatory proposal. This produces an average annual growth rate of 0.46 per cent for circuit length.

For our preliminary decision we used AEMO's maximum demand forecasts. For this final decision we have updated our forecasts of maximum demand to reflect the most recently available forecasts from AEMO. We ratchet the maximum demand we use as an output measure in our output specification. Ratcheted maximum demand is the highest value of maximum demand observed up to the year in question. It recognises capacity United Energy used to satisfy demand and gives it credit for this capacity in subsequent years, even if annual maximum demand is lower in subsequent years.

United Energy's weather corrected peak demand hit a local peak of 2162.1 MW in 2013.¹⁰⁸ AEMO did not forecast peak demand to surpass this level in the 2016–20 regulatory control period. Consequently we set ratchet peak demand to this level for all years in the 2016–20 regulatory control period. This produces an average annual growth rate of zero for ratcheted maximum demand, consistent with United Energy's revised regulatory proposal and our preliminary decision.

¹⁰⁷ AER, *Preliminary decision, Attachment 7*, pp. 49–50.

¹⁰⁸ Consistent with our preliminary decision and United Energy's revised regulatory proposal, we used non-coincident summated weather adjusted system annual maximum demand with a 50 per cent probability of exceedance measure at the transmission connection point in MW.

B.4.4 Forecast productivity growth

We have applied a zero per cent productivity growth forecast in our estimate of the overall rate of change. This reflects 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 other distribution network service providers such as Ergon Energy.¹⁰⁹ This is also consistent with our preliminary decision.

United Energy also included forecast productivity growth of zero in its rate of change.

The Guideline states 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.¹¹⁰

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 considered Economic Insights' economic benchmarking, United Energy's 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 discuss these further in our preliminary decision.¹¹¹

VECUA, however, stated that our decision to apply zero productivity growth 'is illogical and is not supported by the evidence'. It stated that we need to forecast positive productivity growth for the Victorian distributors to bring their productivity back into line with their previous productivity levels and into line with the levels the electricity transmission, gas distribution and other asset intensive industry sectors achieve.¹¹²

VECUA asserted that a key reason for the distributors' productivity declines during the previous regulatory period was our provision of excessive opex allowances. It considered these been a strong driver of the networks' inefficient labour practices. It stated that such factors must not be used to justify poor productivity outcomes in future years.¹¹³ VECUA, however, provided no evidence to support these assertions. Productivity declines, however, have not been unique to Australian electricity distribution networks. We have seen similar declines in productivity in Ontario and New Zealand, which operate different regulatory frameworks. Further, we are unaware of any incentive for the Victorian DNSPs to increase their actual opex when it is not

¹⁰⁹ Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 7 October 2015, p. 29.

¹¹⁰ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

¹¹¹ AER, *Preliminary decision*, Attachment 7, October 2015, pp. 68–73.

¹¹² VECUA, *Submission to the AER*, 6 January 2016, p. 5.

¹¹³ VECUA, *Submission to the AER*, 6 January 2016, p. 67.

efficient to do so. We consider the drivers of recent productivity declines in our assessment of CitiPower's base opex in appendix A.

Although it stated that forecast productivity growth should be positive, VECUA did not suggest a basis on which to forecast positive productivity growth. VECUA did state that some of its participants operate in asset intensive industries that have delivered positive productivity growth during the 2006–13 period.¹¹⁴ However it did not identify which industries it was referring to or why those industries would be an appropriate benchmark for electricity distribution. The CCP also considered forecast productivity should be positive. However, it did suggest we should consider the approach IPART uses to forecast productivity growth for the industries it regulates.¹¹⁵ The approach the CCP referred to was the approach used by IPART to regulate rural and regional buses and local council rates. IPART forecast productivity based on the 15-year average of the ABS market sector value-added multifactor productivity (MFP) based on quality adjusted hours worked. It set forecast productivity growth to zero when the 15 year average is negative.¹¹⁶ The 15 year average productivity growth for the EGWWS industry is –3.3 per cent. Consequently IPART's approach to forecasting productivity also results in a forecast growth of zero.

Consistent with previous submissions, the Victorian Department of Economic Development, Jobs, Transport and Resources (DEDJTR) stated that:¹¹⁷

... with the rollout of smart meters in Victoria substantially complete, the AER should expect the Victorian DNSPs to realise efficiency gains from the rollout. These efficiency gains should be passed through to customers as the benefits are realised, as it is their customers, rather than the DNSPs, that have funded the investment in smart meters through a cost recovery regulatory regime.

We stated in our preliminary decision that DEDJTR had not identified or quantified the 'value added benefits' or the further benefits it expected to be realised over the 2016–20 regulatory control period. We stated that without this information we could not incorporate them into our opex forecast. We also noted that DEDJTR had not provided us the independent assessment of the benefits of the AMI program that it had referred to.¹¹⁸

DEDJTR stated in its submission on our preliminary decisions that Deloitte forecast the benefits associated with the rollout of smart meters in a public report it prepared in 2011 for the Department of Treasury and Finance.¹¹⁹ The most significant benefits identified in this report relate to capex and metering expenditure. Deloitte also identified some 'other smaller benefits' that may be relevant to standard control

¹¹⁴ VECUA, *Submission to the AER*, 6 January 2016, p. 67.

¹¹⁵ CCP, *Report on AER Preliminary Decisions and DNSPs' Revised Proposals*, 25 February 2016, p. 30.

¹¹⁶ IPART, *IPART cost indices—productivity factor*, Fact sheet, October 2014, pp. 1–2.

¹¹⁷ DEDJTR, *Submission*, 14 January 2016, p. 1.

¹¹⁸ AER, *Preliminary decision, Attachment 7*, October 2015, p. 72.

¹¹⁹ Deloitte, *Advanced metering infrastructure cost benefit analysis*, 2 August 2011.

services opex. Of these smaller benefits, the most material reductions in standard control services opex were from:¹²⁰

- the avoided cost of investigation of customer complaints about voltage and quality of supply
- the avoided cost of investigation of customer complaints about loss of supply which turn out not to be a loss of supply
- reduction in calls to faults and emergencies lines
- reduced cost of network loading studies for network planning.

DEDJTR stated that a recent review it undertook indicates that the DNSPs are in the early stages of realising these benefits and therefore their revealed 2014 operating expenditure would not reflect them.¹²¹ DEDJTR did not provide this review. It also did not identify how the savings are allocated across the DNSPs and the extent to which these savings are reflected in base opex.

United Energy stated that it is already delivering many network benefits to its customers and its 2014 base year expenditure reflects these efficiencies. It stated that, where possible, it will continue to realise further benefits and it would share the associated efficiencies with its customers through the EBSS. It considered removing efficiency savings before they are realised would undermine the EBSS.¹²² We disagree with United Energy that removing the efficiencies from forecast opex would undermine the EBSS. Including the efficiencies in the forecast opex, or not, simply determines who receives those forecast efficiencies. If we remove efficiencies from forecast opex then consumers would receive 100 per cent of the forecast efficiencies. If we do not remove them then United Energy would receive the efficiencies and then share them with its customers through the revealed cost forecasting framework and the EBSS. United Energy has the same incentive to reduce opex under both scenarios.

It also stated that the benefits set out in the Deloitte report were outdated. It stated that there had been significant changes since the report was published in 2011.

We have considered the evidence provided to us and are satisfied that any future benefits arising from the AMI rollout will not materially impact standard control services opex. We are satisfied that base opex sufficiently captures the benefits of the AMI rollout, as they relate to standard control services opex, because the AMI meters were largely rolled out by the start of the base year. We also note that any benefits that have not yet been realised will be shared with consumers through our revealed cost forecasting framework and the EBSS.

¹²⁰ DEDJTR, *Submission*, 14 January 2016, p. 3.

¹²¹ DEDJTR, *Submission*, 14 January 2016, p. 3.

¹²² United Energy, *Submission*, 4 January 2016, p. 2.

C Step changes

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

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

This appendix sets out our consideration of step changes in determining our opex forecast for United Energy for the 2016–20 regulatory control period.

C.1 Final position

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

- Power of Choice metering competition
- Power of Choice customer access to data
- Regulatory Information Notice reporting
- Vegetation management
- Neutral testing
- Pole top inspection
- National Energy Customer Framework (NECF).

In total these step changes contribute \$16.5 million (\$2015) or 2.3 per cent to our total opex forecast for United Energy for the 2016–20 regulatory control period.

Table C.1 Step changes (\$million, 2015)

	United Energy initial proposal	AER preliminary decision	United Energy revised proposal	AER final decision
Power of Choice – Metering competition	3.5	–	4.9	3.2
Power of Choice – Customer access to data	1.7	–	1.8	1.3
Power of Choice – Embedded network	0.7	–	Withdrawn	–
Power of Choice – Demand management IT	1.6	–	1.6	–

	United Energy initial proposal	AER preliminary decision	United Energy revised proposal	AER final decision
Platform				
Power of Choice – Network	3.5	–	Withdrawn	–
Regulatory Information Notice reporting	1.6	–	4.6	4.6
Energy Safe Victoria safety obligations	1.0	–	Withdrawn	–
Vegetation management	72.5 ¹²³	0.0	11.7	2.0
Effortless Customer Experience program	6.0	–	Withdrawn	–
Stakeholder engagement	1.3	–	1.3	–
Council trees	3.0	–	Merged with Vegetation management	–
Customer charter	0.7	–	Withdrawn	–
Regulatory submission cost	-5.2 ¹²⁴	–	Withdrawn	–
Neutral testing	0.4	–	2.3	2.3
Network planning and analytics – IT Capital Program	4.1	–	4.1	–
Guideline 11 EWOV direction	4.5	–	Withdrawn	–
IT security costs	4.0	–	3.9	–
Insurance premiums	2.3	–	Withdrawn	–
Pole top inspection	2.4	2.4	2.4	2.4
New pricing obligations	–	–	2.5	–
NECF	–	–	0.7	0.7
Real price escalations	0.5	–	–	–
Total	112.4¹²⁵	2.4	41.6	16.5

¹²³ United Energy initially proposed \$8.7 million for this step change. United Energy updated its costs to reflect the final version of the Electric Line Clearance Regulations which was published after United Energy's initial proposal.

¹²⁴ United Energy proposed a \$2.3 million step change for regulatory submission costs and removed \$1.5 million from its base opex. The net effect of this step change is -\$5.2 million over the forecast period relative to not making a base year adjustment.

¹²⁵ United Energy proposed \$53.8 million in its initial proposal. This total takes into account the updated vegetation management proposal and the net impact of regulatory submission costs.

Source: United Energy, *Regulatory proposal, opex expenditure overview*, 30 April 2015, AER, United Energy *Preliminary decision attachment 7 operating expenditure*, October 2015, United Energy, *Revised regulatory proposal*, 6 January 2016, AER analysis.

Note: Numbers may not add due to rounding

C.2 Preliminary position

In its initial proposal and subsequent submissions to its initial proposal United Energy proposed 19 step changes above its base opex equal to \$112.4 million (\$2015).¹²⁶

In our preliminary decision, we included one step change in our opex forecast. We were satisfied that additional opex associated with United Energy's pole top inspection program reflected an efficient capex/opex trade-off.

C.3 United Energy's revised proposal and submissions

In its revised proposal, United Energy proposed \$41.6 million (\$2015) in step changes.

As shown in Table C.1 United Energy withdrew or merged several step changes. United Energy also proposed new step changes for:

- new pricing obligations
- implementation of the national energy customer framework (NECF)

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

- Consumer Challenge Panel (CCP)
- Victorian Energy Consumer and User Alliance (VECUA).

We received general comments about our consideration of step changes from VECUA and the CCP. While VECUA has some residual concerns with the step changes we allowed in our preliminary decision, overall, it agreed with our assessments of the Victorian service providers' proposed step changes.¹²⁷ The CCP considered we were correct to reject most of the step changes in the Victorian service providers' proposals. It considered there is a tendency for the service providers to present a range of small cost increases without considering the overall ups and downs from year to year. It considered this results in a cumulative bias in the DNSPs' proposals.¹²⁸

¹²⁶ United Energy, *Regulatory proposal, Operating expenditure overview*, 30 April 2015, p. 23.

¹²⁷ VECUA, *Submission to the AER Preliminary Decision 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 63.

¹²⁸ Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 10 February 2016, p. 17.

The Victorian Government submitted that in our preliminary decisions we did not accept step changes in operating expenditure that were not considered material. It stated it expects us to adopt the same approach in assessing the operating expenditure forecasts in the revised regulatory proposals.¹²⁹

C.4 Assessment approach

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

Our assessment of proposed step changes must be understood in the context of our overall method of assessing total required opex using the "base step trend" approach. When assessing a service provider's proposed step changes, we consider whether they are needed for the total opex forecast to reasonably reflect the opex criteria.¹³⁰ Our assessment approach is specified in the Guideline¹³¹ and is more fully described in section 7.3 of this attachment.

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

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

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

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output, then step changes that relate to

¹²⁹ Victorian Government, *Submission on the revised regulatory proposals, Victorian EDPR 2016–20*, 12 February, p. 4.

¹³⁰ NER, cl. 6.5.6(c).

¹³¹ AER, *Expenditure forecast assessment guideline*, November 2013, pp.11, 24.

forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of new office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year) to account for forecast network growth.¹³²

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 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 opex items where the price may be forecast to increase by less than CPI. If we add a step change to account for higher insurance premiums we might provide a more accurate forecast for the insurance category in isolation; however, our forecast for opex as a whole will be too high.

Further, to assess whether step changes are captured in other elements of our opex forecast, we will assess the reasons for, and the efficient level of, the incremental costs (relative to that funded by base opex and the rate of change) that the service provider has proposed. In particular, we have regard to:¹³³

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

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

¹³² AER, *Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p.73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp. 164-5.

¹³³ AER, *Expenditure forecast assessment guideline*, November 2013, p. 11.

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.¹³⁴ 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 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.¹³⁵ For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.

C.5 Reasons for position

C.5.1 Power of Choice

We have included a \$4.4 million step change for the AEMC's Power of Choice reforms. We have included costs relating to the introduction of metering competition and customer access to data requirements.

In its initial proposal, United Energy proposed \$11.0 million for the implementation of the AEMC's Power of Choice reforms.¹³⁶

In our preliminary decision, we recognised that there was still some uncertainty around the AEMC's final Power of Choice rule changes and considered that if the rules were not finalised by the time of our final decision, United Energy could apply for a cost pass through. This was consistent with our capex decision which accounted for the majority of United Energy's Power of Choice related costs.

In its revised proposal, United Energy amended its forecast and withdrew some Power of Choice related opex costs. United Energy proposed a total of \$8.3 million for this step change. The proposed costs related to the following Power of Choice components:

- Metering competition (\$4.9 million)

¹³⁴ AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

¹³⁵ AER, *Expenditure forecast assessment guideline*, November 2013, pp. 24 and 51–52.

¹³⁶ United Energy, *Operating expenditure overview*, 30 April 2015, p. 23.

- Customer access to data (\$1.8 million)
- Demand Management IT Platform (\$1.6 million).¹³⁷

United Energy also proposed \$33.5 million in capex for Power of Choice related projects. Our assessment of United Energy's Power of Choice capex is in attachment 6.

We discuss each component of United Energy's Power of Choice opex below.

Metering competition

We have included \$3.2 million (\$2015) for metering competition in our opex forecast.

In its initial proposal United Energy proposed \$3.5 million in opex related to the AEMC's rule change on metering competition.

As discussed above, we did not assess the efficiency of United Energy's costs as the final rule change had not yet been finalised.

On 26 November 2015, the AEMC released its final determination on metering competition. In its revised proposal United Energy proposed \$4.9 million (\$2015) in opex and \$18.0 million in capex for metering competition.

For opex, United Energy proposed costs for network, customer, data and meter management. United Energy considered it required an additional 16 FTEs to comply with its metering competition obligations.

Under the rule change, a Metering Coordinator, appointed by a retailer, has primary responsibility for the provision of metering services. The 'Responsible Person' previously performed this task. The Metering Coordinator also has the responsibility to engage with the Metering Provider and Metering Data Provider.¹³⁸

Since these new roles relate to competition in metering, it is not reasonable to include the costs related to these roles in our assessment of standard control opex.

Although United Energy identified an extensive list of tasks it needed to undertake as part of the rule change, it was unclear how the tasks identified by United Energy related to its proposed costs. Further, it was also not clear under what role United Energy was to perform these tasks.

We asked United Energy to identify under which NER role it was undertaking its metering competition tasks and to provide a reconciliation with the activities identified in its proposal and its FTE requirement forecast.¹³⁹

¹³⁷ United Energy, *Revised regulatory proposal*, January 2016, p. 175.

¹³⁸ AEMC, *Competition in metering services overview*, 26 November 2015, p. 4.

¹³⁹ AER, *Information request 48* [email to United Energy], 25 February 2015.

In response to our information request, United Energy noted that it was to perform all of these tasks as a local network service provider (LNSP).

United Energy reiterated the tasks it was required to undertake and did not provide a reconciliation of each task with its FTE requirement forecast. United Energy also did not provide any additional breakdown of its FTE requirement beyond what was already included in its revised regulatory proposal.

We have the following concerns with United Energy's proposal and its information request responses on metering competition:

- United Energy already performs some of the tasks identified. United Energy noted that it had to perform extra tasks as the default Metering Coordinator. However, in the case where United Energy will act as the default Metering Coordinator, it already undertakes these tasks as the 'Responsible Person'. As noted above the Metering Coordinator is a new role separate to United Energy's role as a LNSP.
- It was not clear under which role United Energy was performing each task. United Energy's response to our information request noted that it was performing all these tasks as a LNSP. However, this is inconsistent with its revised proposal where some of the tasks were Metering Coordinator tasks.
- Some activities are already recovered through other fees. For example, United Energy already recovers the costs of managing its field crews through Alternative Control fee based services.¹⁴⁰
- United Energy based its forecast FTE requirement on the annual volume of meters it expects to be competitive and the average handling time for type 1-4 meter issues.¹⁴¹ However, United Energy did not provide the forecast volumes for each task and there was no clear relationship between United Energy's FTE forecast and the tasks it identified.
- United Energy identified an increase in the interaction with third parties like Metering Data Providers. However, this is the role of the Metering Coordinator rather than the LNSP and as noted above United Energy already performs these tasks as the 'Responsible Person'.

We recognise that United Energy will incur additional costs to comply with the metering competition rule change. However, United Energy did not provide a cost build up that identified the costs related to its competition in metering obligations. In the absence of robust information from United Energy, we have considered on what other basis we can develop a forecast cost that reflects a prudent and efficient quantum of costs.

Since United Energy and AusNet Services have proposed a labour based approach to forecast their opex for metering competition obligations and both networks have similar

¹⁴⁰ <https://www.unitedenergy.com.au/wp-content/uploads/2015/09/2016-Summary-of-UE-Schedule-of-Charges-1.pdf>

¹⁴¹ United Energy, *Response to information request 48* [email to AER], 3 March 2016, p. 5.

customer numbers,¹⁴² we consider United Energy should not incur materially different costs to AusNet Services to meet its metering contestability obligations.

AusNet Services' proposal included new business process and increased volumes related to coordinating with Metering Coordinators, exception management for new connections and new exit fee processes. AusNet Services also proposed costs related to providing data consistent with the AEMC's minimum service specification. We assessed AusNet Services' cost build-up and we consider AusNet Services' proposed cost for metering contestability is efficient and prudent.

Given the similarity in customer bases between AusNet Services and United Energy, we consider the costs AusNet considers it will incur are a reasonable estimate of the costs that United Energy would incur. We have, therefore, adopted AusNet Services' forecast of \$3.1 million in our alternative forecast for United Energy's metering contestability costs.

Customer access to data

We have included \$1.3 million for customer access to data in our opex forecast.

United Energy proposed \$1.8 million (\$2015) for its customer access to data step change.

On 6 November 2014, the AEMC made a final determination on the Customer Access to Data rule change which required AEMO to publish a Data Provision Procedure effective from 1 March 2016.¹⁴³

To comply with the rule change, United Energy proposed two FTEs for:

- business operations to provide data to customers (one FTE)
- IT operations to support its upgraded IT system (one FTE).

United Energy noted that it was expanding its customer portal to have increased capacity for self-service and timely access to data.

We have assessed United Energy's proposed costs and we have:

- not included an additional FTE in business operations to provide data to customers
- included an additional FTE in IT operations to support its upgraded IT system.

We consider United Energy is likely to incur additional compliance costs to comply with AEMO's new Meter Data Provision Procedures data formats. To facilitate this new data

¹⁴² As at 2015, AusNet Services has 680,000 customers and United Energy has 667,000 customers. AusNet Services has forecast higher customer growth compared to United Energy over the 2016–20 regulatory control period.

¹⁴³ Australian Energy Market Commission, *National Electricity Amendment (Customer access to information about their energy consumption) Rule 2014*, 6 November 2014, p. i.

gathering format, we have included the additional costs of IT operations to support United Energy's upgraded IT system.

However, we do not consider United Energy requires additional resources in business operations to provide this data to customers. United Energy already has an existing customer portal in place. United Energy should be able to use these existing resources in conjunction with its additional resources in IT operations to provide its customers with the data in the correct format.

Demand management IT platform

We have not included a step change for United Energy's demand management IT platform.

Consistent with its initial proposal, United Energy proposed \$1.6 million for its demand management IT platform in its revised proposal. These costs are for application support, hardware maintenance and software maintenance associated with its proposed \$5.4 million capex program.

We did not consider United Energy's proposed capex was reasonable because it did not address a new regulatory obligation and United Energy did not provide a robust business case. United Energy also expects this project to provide capex efficiencies and we consider customers should not fund these productivity improvements.

We discuss our assessment of United Energy's demand management IT platform capex in attachment 6.

Since United Energy linked its opex to its capex, for the same reasons we have also not included this expenditure in our opex forecast.

C.5.2 Regulatory information notice reporting

We have included a step change of \$4.6 million (\$2015) in our final decision opex forecast for RIN compliance. We are satisfied this step change is driven by a regulatory change.

As of 2015, we require economic benchmarking (EB) and category analysis (CA) regulatory information notice (RIN) reporting to be based on actual rather than estimated data. All the Victorian network service providers, except AusNet Services, proposed increases in opex and capex to make changes to their IT systems and business processes to meet our requirements for actual data.

In its initial proposal, United Energy proposed a mostly capex solution of \$24.3 million (\$2015) capex and \$1.6 million opex to comply with the requirement to provide actual RIN data.¹⁴⁴

¹⁴⁴ United Energy, *Regulatory proposal, Operating expenditure overview*, 30 April 2015, p. 29.

In our preliminary decision, we were not satisfied the magnitude of United Energy's proposed capex for RIN compliance costs was prudent and efficient.¹⁴⁵ As the proposed step change in opex depended on the forecast increase in capex, we did not include the step change in our opex forecast.

In its revised proposal, United Energy proposed reduced RIN compliance capex of \$16.3 million (\$2015) for IT system changes, together with an opex step change of \$4.6 million.¹⁴⁶ United Energy's total revised RIN compliance IT costs of \$20.9 million (\$2015) reflected a reduction of \$5.0 million or 19 per cent from its initial proposal.

In assessing the need for any RIN compliance costs, we must be satisfied that they reflect the efficient costs that a prudent operator would require to comply with its regulatory obligations.¹⁴⁷ This will maximise the net benefits of RIN reporting to consumers in terms of enhanced transparency and data availability. We have assessed the proposed opex and capex together as a total project. We discuss United Energy's forecast RIN compliance capex in more detail in attachment 6 of this final decision.

United Energy's revised proposal for the RIN compliance project reflects a new approach to meeting RIN reporting obligations. United Energy stated it reduced the scope of the project by retaining some manual processes, only capturing data that is essential for RIN reporting, and deferring some IT changes until required for asset management purposes.¹⁴⁸

Our assessment of the opex step change is dependent on our final position on United Energy's proposed capex.

As discussed in attachment 6 of this final decision, we are not satisfied United Energy's revised proposal RIN compliance capex of \$16.3 million (\$2015) reflects a reasonable estimate of the efficient costs of a prudent operator.¹⁴⁹ This is for the following reasons:

- We maintain the concern expressed in our preliminary decision that United Energy's forecast for RIN compliance appears to reflect a risk averse assessment of possible costs, and are therefore likely to be overstated.
- The business case submitted by United Energy does not fully support the efficiency of the forecast costs.
- United Energy's proposed RIN compliance capex of \$16.3 million (\$2015) exceeds the investment requirements identified by other service providers.

¹⁴⁵ AER, *Preliminary decision, CitiPower distribution determination 2016–20 - Attachment 6 - Capital expenditure*, October 2015, pp. 6-102 to 6-103.

¹⁴⁶ United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 55 and 66.

¹⁴⁷ NER, cl. 6.5.7(c).

¹⁴⁸ United Energy, *Revised regulatory proposal*, 6 January 2016, p. 56.

¹⁴⁹ NER, cl. 6.5.7(c).

- United Energy submitted that the \$16.3 million figure included in its revised regulatory proposal was a typographical error.¹⁵⁰ Its business case identified RIN compliance capex of \$14.7 million.

We consider forecast capex of \$11.0 million reasonably reflects the efficient costs for United Energy to achieve RIN reporting compliance. We consider this level of capex is commensurate with United Energy's need for system investment given past asset management practices.

We have included an opex step change of \$4.6 million (\$2015) in our final decision opex forecast. In coming to this decision we assessed the proposed opex step change both as a component of totex (opex and capex) and separately:

- We consider a total RIN compliance forecast of \$15.6 million aligns with those of other Victorian distributors (specifically CitiPower/Powercor) which we consider to be efficient. Therefore, we are satisfied that a combined total capex and opex cost of \$15.6 million (\$2015) for new RIN reporting requirements reflects the efficient costs of a prudent operator¹⁵¹
- United Energy's proposed RIN compliance opex step change is less than that proposed by the other Victorian distributors, except AusNet Services. Therefore, we are satisfied the proposed opex of \$4.6 million (\$2015) reflects the efficient opex of a prudent operator.

C.5.3 Changes to Electrical Safety (Electric Line Clearance) Regulations

We have included a step change for vegetation management of \$2.0 million (\$2015) for new vegetation management requirements. We are satisfied that these costs are driven by a new regulatory obligation.

This includes the costs to comply with new amenity tree standards and advice provided to local councils.

United Energy initially proposed \$8.7 million (\$2015) for additional costs it expected to incur to comply with changes to *Electricity Safety (Electric Line Clearance) Regulations 2015 (ELC 2015)*.¹⁵² It based its initial proposal on expected draft changes to the ELC regulations. Following the release of the final version of ELC 2015, United Energy updated its proposal to \$72.5 million (\$2015).¹⁵³

In our preliminary decision, we considered the change in costs to comply with ELC 2015 was uncertain and we did not include a step change. We based this on advice from Energy Safe Victoria (ESV) which indicated that the costs proposed by United

¹⁵⁰ United Energy, *Response to AER information request 046* [email to AER], 23 February 2016.

¹⁵¹ NER, cl. 6.5.7(c).

¹⁵² United Energy, *Regulatory proposal, Operating expenditure overview*, 30 April 2015, p. 31.

¹⁵³ United Energy, *Response to information request 9 – Part 2* [email to AER], 21 July 2015, p. 1.

Energy did not reflect the final regulations and ESV intended to issue guidance notes to all Victorian DNSPs.¹⁵⁴

In its revised proposal, United Energy revised its forecast step change to \$11.7 million (\$2015). United Energy stated that it based its revised forecast on advice from ESV.¹⁵⁵

United Energy considered it needed costs to comply with the following changes:

- application of amenity tree standard AS 4373
- additional notification requirements
- assistance provided to councils.¹⁵⁶

We discuss our position on each of these changes and potential offsetting costs in the sections below.

Amenity tree standards

United Energy considered it would require \$0.45 million (\$2015) to engage Certificate 3 Arborists for inspections to be compliant with amenity tree standard AS 4373.

We have assessed the changes to ELC 2015 regarding amenity tree standards and we consider United Energy's proposed changes are consistent with AS 4373. We have also assessed United Energy's cost build up and we agree that the changes in the obligations relating to amenity tree cutting practices will require United Energy to incur additional costs to engage more qualified labour. We consider the proposed costs are prudent and efficient.

Notification requirements

United Energy proposed \$4.16 million (\$2015) to comply with ELC 2015 notification requirements. United Energy considered it was required to include a notice in local newspapers, on a weekly basis, to advise the public of the intended cutting areas and the date when cutting may take place. United Energy considered this was consistent with ESV guidance.

We note ESV's guidance to United Energy stated the following:

When administering the 2015 regulations, ESV would have no issue with a direct notice to the properties close to the tree/s instead of a notice in a newspaper, as an equivalent safety outcome.¹⁵⁷

¹⁵⁴ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 66.

¹⁵⁵ United Energy, *Revised regulatory proposal*, January 2016, p. 194.

¹⁵⁶ United Energy, *Revised regulatory proposal*, January 2016, p. 193.

¹⁵⁷ Energy Safe Victoria, *Electric Safety (Electric Line Clearance) Regulations 2015 – guidance information*, 27 November 2015, p. 3.

We consider the advice provided by ESV to United Energy indicates that it does not require notices in local newspapers if United Energy already sends direct notice to its customers. As noted in United Energy revised regulatory proposal, its existing practice is to send notices to directly affected person(s).¹⁵⁸

Based on this we do not consider there to be a change in United Energy notification obligations.

Assistance provided to councils

We consider the requirement for United Energy to provide assistance to local councils represents a new regulatory obligation. Under ELC 2015, if requested by a local council, United Energy is required to provide advice on:

- safe limits of approach to electric lines for cutting or removing a tree
- methods for cutting or removing a tree.¹⁵⁹

We have included \$1.6 million of the \$7.1 million (\$2015) in opex proposed by United Energy.

In its guidance to Victorian DNSPs, ESV stated:

For many years now the DB's have had in place resources to support their stakeholders when electrical safety concerns were raised about work in the vicinity of their power lines. Despite the absence of this clause in previous ELC regulations, it has always been ESV's expectation that the DB's would have provided the same or similar support on request.

We note that United Energy does not currently provide these resources.¹⁶⁰ Although ESV considers providing support to local councils is good industry practice, we consider this represents a new obligation for United Energy.

However, we do not consider the costs proposed by United Energy are efficient.

United Energy included the following cost components in its forecast:

- two FTEs to provide assistance and the required sag and sway information (\$1.6 million (\$2015))
- assisting local councils, private property owners and occupiers to facilitate more effective clearing of vegetation, which will involve United Energy cutting the trees (\$5.5 million (\$2015)).¹⁶¹

¹⁵⁸ United Energy, *Revised regulatory proposal*, January 2016, p. 193.

¹⁵⁹ United Energy, *Revised regulatory proposal*, January 2016, p. 193.

¹⁶⁰ United Energy, *Revised regulatory proposal*, January 2016, p. 193.

¹⁶¹ United Energy, *Revised regulatory proposal*, January 2016, p. 194.

We note ELC 2015 requires United Energy to provide assistance only for sag and sway information and safe cutting methods.¹⁶² We have included \$1.6 million in costs related to this assistance.

However, ELC 2015 does not require United Energy to undertake the cutting on behalf of local councils and private property owners. This is not a standard control service.

We addressed this issue in our preliminary decision. United Energy proposed tree cutting costs on behalf of local councils as a separate step change in its initial proposal. We noted that the cutting of council trees is not United Energy's responsibility. The costs associated with providing assistance to councils to cut their trees would be an unregulated service.¹⁶³

In response to our preliminary decision, the Victorian Greenhouse Alliances considered there to be a disconnect between United Energy's stakeholder engagement requirements and our decision to not approve United Energy's trial of dedicated vegetation management crews to work with councils. It also considered that this step change would foster engagement between stakeholders that will result in the identification of initiatives that meet the long term needs of all parties.¹⁶⁴

We do not consider the costs of United Energy providing tree cutting services is a requirement under ELC 2015 nor is it a requirement in our Consumer Engagement Guidelines. In this case United Energy is proposing to provide an additional service to local councils to cut trees. These trees are local councils' responsibility and United Energy's customers should not bear the costs for local councils' trees cutting.

However, we have assessed United Energy's forecast costs of United Energy providing information to local councils on how the local councils can cut their own trees safely. We consider this is a new obligation in ELC 2015 and United Energy's forecast to provide information on safe cutting methods and sag and sway information is efficient and prudent.

Offsetting costs

In our preliminary decision, we identified potential cost savings due to the reintroduction of exceptions for structural branches. Since we provided United Energy with a step change for the removal of these exceptions in ELC 2010 in our previous regulatory determination, we considered there may be potential cost savings as these exceptions are reintroduced in ELC 2015.

In its submission to our preliminary decision, the Victorian Government identified increases in vegetation management expenditure under ELC 2010 (in 2013) compared

¹⁶² Energy Safe Victoria, *Electricity Safety (Electric Line Clearance) Regulations 2015, Sections 20 and 21*. 28 June 2015.

¹⁶³ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 70.

¹⁶⁴ Victorian Greenhouse Alliances, *Submission to Victorian Electricity Distribution Price Review 2016–20 Preliminary Decision October 2015*, 6 January 2016, p. 3.

ELC 2005 (in 2009) for AusNet Services, Powercor and United Energy. It considered that the AER should assess both negative and positive step changes associated with the introduction of ELC 2015.¹⁶⁵

United Energy did not address this issue in its revised proposal. In its response to submissions, United Energy noted that it has taken into account any savings arising from the removal of any regulations or the introduction of less onerous obligations.¹⁶⁶

However, United Energy did not identify what cost savings it had taken into account. In response to our information request requesting United Energy to identify the savings it had taken into account, United Energy noted that the new clearance provisions would not decrease its pruning costs.¹⁶⁷

United Energy also explained its vegetation management processes and noted that the 2010 regulations specified absolute compliance with maintaining the clearance space and it manages vegetation management on a two year cycle.¹⁶⁸

Since United Energy operates on a two year cutting cycle, by 2014 it would have already been compliant with ELC 2010.

We are satisfied that its base year opex reflects vegetation management costs related to structural branches in the 2016–20 regulatory control period.

C.5.4 Stakeholder engagement

We have not included a step change in our opex forecast for stakeholder engagement.

United Energy initially proposed a \$1.3 million (\$2015) step change for stakeholder engagement.

United Energy noted this was in response to the AEMC's 2012 rule changes and our Consumer Engagement Guidelines. The additional opex allowed for two new roles for:

- a relationship manager for the fifteen local councils in United Energy's service area, and
- a second role focused on engaging stakeholders about future capital projects.¹⁶⁹

We did not include this step change in our preliminary decision. We considered that a prudent service provider would already have programs in place to engage with consumers. We noted that the changes to the NER in 2012 required service providers to describe how it engaged with consumers, and how it sought to address any relevant concerns identified as a result of that engagement. United Energy was required to

¹⁶⁵ Victorian Government, *Submission on AER preliminary decision VIC EDPR 2016–20*, 14 January 2016, p. 7.

¹⁶⁶ United Energy, *Submission on United Energy's revised regulatory proposal 2016 to 2020*, 4 February 2016, p. 3.

¹⁶⁷ United Energy, *Response to information request 47* [email to AER], 24 February 2016, p. 3.

¹⁶⁸ United Energy, *Response to information request 47* [email to AER], 24 February 2016, p. 3.

¹⁶⁹ United Energy, *Operating expenditure overview*, 30 April 2015, p. 35.

present this information in an overview report with its regulatory proposal.¹⁷⁰ We did not consider this requirement was onerous.¹⁷¹

This position was supported in a submission by VECUA which considered that the distributors' base year opex allowance provides them with sufficient funds to fulfil the expectations of the AER's consumer engagement guideline.¹⁷²

In response to our preliminary decision, United Energy maintained the same stakeholder engagement step change. It considered that:

- the 2012 changes to the NER and the AER's Consumer Engagement Guidelines introduced new regulatory requirements for United Energy to engage its customers and other stakeholders
- our preliminary decision was inconsistent with the expectations set out in the AER's Consumer Engagement Guidelines which may require service providers to change how they run their business
- United Energy is not resourced to meet stakeholder engagement requirements throughout the 2016–20 regulatory control period because its base opex did not include provisions for within period stakeholder engagement resources.¹⁷³

We do not consider a change in regulatory obligations for United Energy is a driver of its proposed stakeholder engagement costs.

As outlined in our preliminary decision, we expect a prudent service provider would already have programs in place to engage with consumers. The Consumer Engagement Guidelines clarify what is good practice consultation and considers the service providers should use their judgement in how to engage. The Consumer Engagement Guideline states that it cannot compel any particular form of consumer engagement by service providers, however the quality of the engagement will be a factor and whether the service provider considered and responded to consumer views.¹⁷⁴

Based on this, we maintain our preliminary position for the final decision to not include a step change for stakeholder engagement.

C.5.5 Neutral testing

We have included a step change of \$2.3 million (\$2015) for neutral testing requirements in our opex forecast. We are satisfied these costs are driven by a regulatory obligation that is currently not included in the base opex forecast for SCS.

¹⁷⁰ The new NER clause relevant to United Energy is 6.8.2(c1)(2).

¹⁷¹ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, pp. 69 – 70

¹⁷² Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian distribution networks' 2016–20 revenue proposals*, 13 July 2015, p. 38.

¹⁷³ United Energy, *Revised regulatory proposal*, January 2016, p. 196.

¹⁷⁴ AER, *Consumer engagement guideline for network service providers*, November 2013, p. 12.

In its initial proposal, United Energy forecast additional opex of \$0.4 million for neutral testing. United Energy noted that under regulation 27(2) of the Electricity Safety (Network Assets) Regulations 1999 it is required to inspect earthing systems every 10 years. United Energy noted that it previously undertook neutral testing as part of its advanced metering program so these costs are not included in its base year opex.

In our preliminary decision we considered there was no change to United Energy's neutral testing obligation and that there was productivity benefits associated with this program.¹⁷⁵

In its revised proposal, United Energy proposed \$2.3 million (\$2015) and clarified that previously it recovered the costs of meeting its obligations under the Advanced Metering Infrastructure (AMI) Cost Recovery Order in Council (CROIC) which is not a part of SCS opex.¹⁷⁶ In response to our information request, United Energy also clarified that the costs relating to neutral testing are not included in its forecast alternative control services (ACS) metering costs for the 2016–20 regulatory control period.¹⁷⁷

We accept that this step change represents a shift from costs previously recovered as a part of AMI to SCS. Although the obligation has not changed, United Energy has not recovered the costs related to these obligations from standard control services since 2009. These costs have not been included in our base year forecast and United Energy has not included these costs elsewhere in its forecast.

We also consider United Energy's forecast costs for this step change is reasonable, as it represents office staff to monitor its remote systems. We have assessed the inputs required by United Energy to comply with its obligations and we consider the proposed costs reflect an efficient and prudent amount.

C.5.6 Network planning and analytics

We have not included a step change in our opex forecast for United Energy's proposed network planning and analytics step change.

United Energy initially proposed a \$4.1 million (\$2015) step change for network planning and analytics. United Energy noted that the driver of this step change is opex associated with network planning and analytics capex. United Energy considered this would enable it to maintain the quality, reliability and security of the supply of standard control services. United Energy also noted that this program will avoid increased network opex by removing the need for manual neutral integrity testing for all connection points on its network.¹⁷⁸

¹⁷⁵ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 71.

¹⁷⁶ United Energy, *Revised regulatory proposal*, January 2016, p. 199.

¹⁷⁷ United Energy, *Response to information request 40* [email to AER], 10 February 2016, p. 2.

¹⁷⁸ United Energy, *Operating expenditure overview*, 30 April 2015, p. 40.

In our preliminary decision, we did not include a step change for this. We considered the driver of this step change was not a change in regulatory obligation but rather enabling United Energy to maintain its current services and avoid increased opex. We considered base opex is sufficient for United Energy to maintain the quality, reliability and security of the supply of standard control services. We expect this should be a business as usual expense for a prudent and efficient service provider.¹⁷⁹

In its revised proposal, United Energy combined its discussion on neutral testing and network planning and analytics step changes. However, it did not address the issues, we raised in the preliminary decision, relating to the network planning and analytics portion of the step change.

Although United Energy has combined its discussion on neutral testing and network analytics in its revised regulatory proposal we have assessed these two step changes separately consistent with United Energy's initial proposal. This is because the neutral testing step change relates specifically to United Energy's neutral testing obligations but the network analytics step change relates to using network analytics to maintain its network.

We note the network planning and analytics portion of its business case referred to in United Energy's revised proposal states the following:

- Network planning analytics will enable United Energy to maintain the quality, reliability and security of the supply of standard control services.
- The overall objectives are to cost-effectively improve the decision making capabilities for network operations whilst still maintaining United Energy's safety obligation.¹⁸⁰

Consistent with our preliminary decision, we consider the driver of this step change is not a change in regulatory obligation but rather enabling United Energy to maintain its current services.

As outlined in the Guideline¹⁸¹ and preliminary decision¹⁸² we consider an efficient base level of opex provides a sufficient amount of opex to meet existing regulatory obligations and to maintain the level of service United Energy provides to its consumers. We do not consider an increase in opex for discretionary spending should be needed where a service provider wants to change the way it provides these services.

We expect this should be a business as usual expense for a prudent and efficient service provider.

¹⁷⁹ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 72.

¹⁸⁰ United Energy, *Project Justification – Network Analytics*, 25 February 2015, p. 7.

¹⁸¹ AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

¹⁸² AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 61.

C.5.7 IT security costs

We have not included a step change in our opex forecast for United Energy's IT security costs.

United Energy initially proposed a step change of \$4 million. The step change in its revised proposal is consistent with its initial proposal. However, due to rounding, United Energy proposed \$3.9 million in its revised proposal.

United Energy considered it required additional ICT security resources and services to counter external threats to its network.

In its revised proposal, United Energy did not accept our preliminary decision for the following reasons:

- IT security is an escalating risk and provided examples of IT security threats to other Australian organisations.
- did not consider it could meet its IT security costs from its base year opex or the rate of change
- IT security is not a discretionary business decision and noted that we accepted United Energy's IT security capex proposal.

We have not changed our position on this step change.

For opex, we typically provide a step change in funding where there is some change in circumstance from the base year to warrant an increase in total opex. Areas where we commonly provide a step change in funding are where the scope of services a service provider must provide increases due to a new or changed regulatory obligation, or where the efficient mix of inputs it uses to provide network services changes. For instance a service provider may require more opex but less capex to undertake an activity.

United Energy considers the prevalence and risk of cyber attacks have increased, recent cyber security threats - for instance to the Bureau of Meteorology. It also provided information from the Australian Government Security Centre's Cyber Threat Report, PricewaterhouseCoopers Security Survey and ASIC Cyber Resilience Health Check that showed an increase in IT security threats.

While the Bureau of Meteorology cyber attack highlights a recent known cyber security breach and the reports referenced above highlights information security threats, information security threats to the utilities industry are not new. For instance in 2008, a CIA official reported that cyber attackers had hacked into the computer systems of utility companies outside the United States made demands, in at least one case causing a power outage that affected multiple cities.¹⁸³ In 2003 a software flaw contributed to a widespread blackout across Northeastern USA and Canada. The

¹⁸³ Washington Post, *Hackers Have Attacked Foreign Utilities, CIA Analyst Says*, 19 January 2008.

Australian Government recognised the threat of cyber security as early as 1999. This suggests that information security risks have presented a risk to utility providers for some time.

We have also not put much weight on the Australian Government Security Cyber Security Threat report provided by United Energy. This report does not identify the cyber security risks facing electricity distributors or identify the specific measures an electricity distributor should take to address these risks.

United Energy noted that the ASIC Cyber Resilience Health Check identified IT security as a potential matter of regulatory compliance.¹⁸⁴ We note the relevant legal and compliance requirements identified in the document are not new and are existing requirements in the Corporations Act. Further, these requirements do not relate specifically to IT security but to general disclosure requirements.¹⁸⁵

United Energy also noted that its proposed IT security program of \$3.9 million (\$2015) was reasonable because it represented 2.6 per cent of its IT opex budget and is below the 4.0 per cent industry average referred to in the PwC report.¹⁸⁶

These numbers are incorrect. Based on its reset RIN,¹⁸⁷ United Energy's forecast IT security represents 4.2 per cent of its forecast IT opex rather than 2.6 per cent.

Further, the calculation reported by United Energy implies that it currently does not undertake any IT security expenditure as a part of its IT opex. Based on this we consider United Energy has actually forecast above the industry average rather than below.

We also consider United Energy did not provide sufficient information to support its cost build up. All of the reasons for why it required additional expenditure referred to a business case that did not include the actual opex proposed by United Energy.¹⁸⁸

In response to our information request, United Energy noted that it omitted to include these costs in its business case and identified the following tasks for its new security services which accounts for \$3.6 million (89 per cent) of its proposed step change:

- maintaining and managing our information management system (including policies, processes and systems)
- providing management and governance over security related services, processes, activities, projects and systems applied and managed by other service providers
- providing security testing services

¹⁸⁴ United Energy, *Revised regulatory proposal*, January 2016, p. 201.

¹⁸⁵ ASIC, *Report 429: Cyber resilience health check*, March 2015, p. 43.

¹⁸⁶ United Energy, *Revised regulatory proposal*, January 2016, p. 201.

¹⁸⁷ United Energy, *Initial proposal reset RIN response*. April 2015, United Energy proposed forecast IT opex of \$93 million.

¹⁸⁸ United Energy, *PJ23 – Security Program*, February 2015.

- providing security training and awareness services across our organisation, and
- working with other service providers to manage and maintain operational effectiveness of all security controls and technology across our environments.¹⁸⁹

We consider a prudent service provider in addressing risks to its network should already undertake the tasks identified by United Energy.

We are not satisfied that United Energy's forecast costs are reasonable. Since the cost build up explicitly refers to the business case which only accounts for \$428,000 of the total step change, United Energy did not provide a cost build-up for why it required an additional \$3.6 million for additional security services from external service providers.

We note that we did not accept United Energy's forecast IT capex related to IT security monitoring. In our capex assessment, we did not assess individual IT capex projects. In our preliminary decision we assessed United Energy's overall IT capex. We did not accept United Energy's initial proposal for overall IT capex.

For our final decision, we have not included additional capex for IT security because there was insufficient evidence to support its business case. We discuss our assessment of United Energy's IT security capex in attachment 6.

C.5.8 National Energy Customer Framework (United Energy)

We have included a \$0.7 million (\$2015) step change for the implementation of NECF connections arrangements in Victoria.

In its revised proposal, United Energy proposed a new step change of \$0.7 million (\$2015) related to the implementation of Chapter 5A of the NER.

United Energy noted that the Victorian Energy Minister introduced a Bill into Victorian Parliament on 8 December 2015 – the National Electricity (Victoria) Further Amendment Bill 2015.¹⁹⁰

To comply with its new obligations United Energy would need to undertake additional or expanded activities to manage changes to connection processes.¹⁹¹

We are satisfied that the intention of the Victorian Government to adopt Chapter 5A of the rules to apply no later than 1 January 2017 will result in a change in regulatory obligation for United Energy.

United Energy's forecast comprises start-up costs and an ongoing one FTE to provide performance tracking and ongoing connection management. We have assessed the

¹⁸⁹ United Energy, *Response to information request 40* [email to AER], 10 February 2016, p. 1.

¹⁹⁰ United Energy, *Revised regulatory proposal*, January 2016, p. 204.

¹⁹¹ United Energy, *Revised regulatory proposal*, January 2016, p. 205.

cost build up and we consider the costs are efficient and prudent. These costs are also broadly comparable to Jemena, CitiPower and Powercor's proposed costs.¹⁹²

C.5.9 Pole top inspections

Consistent with our preliminary decision, we have included a step change of \$2.4 million (\$2015) for pole top inspections in our opex forecast. We are satisfied that these costs represent an efficient capex/opex trade-off for the reasons explained in our preliminary decision.¹⁹³

We have maintained our preliminary decision because there have been no changes to UE's forecast capex and opex for pole top structures and we have received no further submissions on this step change.

C.5.10 New pricing obligations (United Energy)

We have not included a step change in our opex forecast for United Energy's new pricing obligations step change.

In its revised proposal, United Energy proposed a new \$2.5 million (\$2015) step change for operating expenditure related to the introduction of new pricing obligations in Victoria.¹⁹⁴

In November 2014, the Australian Energy Market Commission (AEMC) made a new rule to require network businesses to set prices that reflect the efficient cost of providing network services to individual consumers.¹⁹⁵ Prices based on these new rules were to apply in Victoria from 1 January 2017.

United Energy noted that the AEMC's Distribution Network Pricing Arrangements rule change required it to comply with new network pricing objective and principles and it was also required to produce a tariff structure statement (TSS).

United Energy considered it required additional opex to prepare its TSS, communicate and consult with customers and assess the impact on customers. United Energy noted that its tasks were similar to those we approved in Jemena's preliminary decision. However, United Energy did not provide a cost build up for these tasks.

We do not consider the costs associated with developing a TSS is relevant to the forecast cost of complying with this obligation because United Energy published its TSS on 25 September 2015. As part of this TSS United Energy outlined its extensive

¹⁹² CitiPower, *Revised regulatory proposal*, January 2016, p. 185. Powercor, *Revised regulatory proposal*, January 2016, p. 178, Jemena, *Attachment 8-2 Operating expenditure step changes*, January 2016, p. 76.

¹⁹³ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 74

¹⁹⁴ United Energy, *Revised regulatory proposal*, January 2016, p. 202.

¹⁹⁵ AEMC, *National Electricity Amendment (Connecting Embedded Generators Under Chapter 5A) Rule 2014*, 13 November 2014.

stakeholder engagement and produced an indicative pricing schedule.¹⁹⁶ We do not consider it is necessary to incur ongoing educational costs because this is the retailer's responsibility. We also consider the development of the new tariffs for the TSS is a one off event and any future TSS can be released without a material increase in costs.

Jemena's preliminary decision

United Energy noted that we approved a step change for new pricing obligations in our preliminary decision for Jemena.

As a part of final decision assessment, we have reassessed our position for Jemena's step change and we have not included Jemena's proposed costs related to mail outs and customer enquiries.

The new rule requires distribution businesses to consult with consumers and retailers to develop a tariff structure statement that outlines the price structures that they will apply for the regulatory period. The businesses will also publish an indicative pricing schedule each year to provide consumers and retailers with up to date information on likely price levels throughout the regulatory control period.

However, the AEMC rule change does not oblige United Energy to conduct its customers of the new tariffs. Rather, the onus will be on the retailers to offer the new tariff structures as part of their product offerings. Similarly customers will direct most of their inquiries to retailers. Nor does the rule change require United Energy to promote the new tariffs to its customers.

Information request response

In response to our information request notifying United Energy of our change in position for Jemena, United Energy maintained its forecasting approach because it must comply with the cost-reflective pricing principles and the NER requires it to take steps to encourage customers to adopt cost-reflective tariffs. United Energy noted that it would achieve this through a combination of customer engagement, mail outs and responding to queries.¹⁹⁷

We agree with United Energy on the importance of consumer awareness regarding cost-reflective tariffs. However, United Energy did not explain why it had to undertake these activities when it is the responsibility of retailers to pass on these tariffs to their customers. We consider distributors are not best placed to promote the take-up of cost reflective tariffs for the following reasons:

- The cost reflective tariff will not necessarily be reflected in retail electricity offers. Consequently, it is uncertain whether or not the distributor's cost reflective tariffs will have the impact on the retail offers that the distributor claims.

¹⁹⁶ United Energy, *Tariff structure statement 2017–20*, 25 September 2015, p. 21 and appendix 6.

¹⁹⁷ United Energy, *Response to information request 50* [email to AER], 7 March 2016.

- The way in which consumers will see the networks tariffs will depend on how energy retailers choose to represent the new tariffs in their bills.

The AEMC in its final determination also noted retailers rather than distributors are the key stakeholder in consumer awareness. It stated:

Most consumers will gain an understanding of pricing signals through the retail tariffs they are charged. This is because for most consumers, their primary relationship will be with the retailer. As such, the role of retailers in providing information to facilitate understanding of pricing signals is critical.¹⁹⁸

The AEMC also noted that retailers have a significant incentive to pass on network price signals in some form when deciding how to structure their retail prices.¹⁹⁹

As noted above United Energy is not obligated to notify its customers and we consider the retailer has primary responsibility to pass on changes in tariffs through their own retail tariffs.

Other submissions

The Victorian Government submitted that customers must opt in to, rather than opt out from, cost reflective network tariffs and that the AER must assess whether the DNSPs' proposals are consistent with an opt-in approach.²⁰⁰

In this circumstance, the impact of an opt-in arrangement does not affect our assessment because we have not included costs related to the new pricing obligations in our opex forecast.

C.5.11 Other costs not included in the base year

Guaranteed Service Levels

We have forecast guaranteed service level (GSL) payments for the 2016–20 regulatory control period using an average of GSL payments made by United Energy between 2010 and 2014. Our forecast also reflects changes in the Electricity Distribution Code (EDC).²⁰¹

We have included \$3.0 million (\$2015) for GSL payments in our opex forecast.

In its initial proposal, United Energy forecast GSL payments of \$5.7 million (\$2015). United Energy used a single base year to forecast GSL costs over the forthcoming

¹⁹⁸ AEMC, *Rule determination National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. 67

¹⁹⁹ AEMC, *Rule determination National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. viii

²⁰⁰ Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016–20*, p. 6.

²⁰¹ Essential Services Commission, *Electricity Distribution Code Version 9*, December 2015, p. 19-20.

regulatory period.²⁰² United Energy did not account for regulatory changes to GSL obligations because the new EDC rules were not finalised at the time.

In our preliminary decision, we included in total forecast opex \$2.2 million (\$2015) for GSL payments over the 2016-20 regulatory control period. We forecast GSL payments as the average of GSL payments made by United Energy between 2010 and 2014. We adopted the historical averaging approach to maintain consistency with our GSL payment forecasting method for previous regulatory control periods. Further, the incentives provided by this forecasting approach are consistent with adopting a single year revealed cost approach and applying the EBSS.²⁰³

In its revised proposal, United Energy forecast GSL payments of \$7.0 million (\$2015). United Energy did not accept our preliminary determination and adopted the following forecasting method:

- used a single base year forecast on the basis that this is the method used for other opex forecasts; however, it did not propose GSL payments be included in the EBSS as for other opex categories.
- increased their forecast to reflect anticipated increases in the size and the frequency of GSL payments under the new EDC.²⁰⁴

We discuss each component of United Energy's forecast in the sections below.

Single base year forecast method

GSL costs are volatile from year to year. Normally volatility is not a problem when we forecast opex because the EBSS applies. However, United Energy did not propose applying the EBSS to the GSL category. The EBSS functions in such a way as to ameliorate windfall gains or losses that may accrue from using a high/low base year forecast. We consider it would be inappropriate to use a single base year forecast for a category which is not subject to the EBSS. All other distributors submitted revised proposals using an historical average as the basis for their GSL forecasts. Given that GSL payments in the base year proposed by United Energy were relatively high, United Energy's customers will be disadvantaged compared to the customers of other distributors. As GSL payments are part of a regulatory obligation designed to benefit customers, we consider it more reasonable to continue to use a five year average.

Electricity Distribution Code

We note that it was difficult to determine whether the basis for United Energy's revised proposal was the draft EDC rules or the final EDC rules. The final version of the code requires lower/fewer GSL payments in some circumstances. United Energy responded to our information request by providing a new forecast based on the final version of the

²⁰² United Energy, *Initial Regulatory proposal, Operating expenditure overview*, April 2015, p. 46.

²⁰³ AER, *United Energy preliminary decision attachment 7: operating expenditure*, 29 October 2015, p. 24.

²⁰⁴ United Energy, *Revised Regulatory Proposal*, January 2016, p. 67.

code. United Energy's analysis demonstrates that the EDC rule changes increase their GSL costs by 27 per cent.²⁰⁵

We have assessed United Energy's proposed change in costs for each type of GSL payment and the forecast volume of payments. We are satisfied this forecast increase in GSL payments to reflect changes to the EDC code are prudent and efficient.

We have maintained our preliminary position that using a five-year average is the most appropriate way to forecast GSL payments and revised our forecast upward by 27 per cent to reflect the new EDC.

Other submissions

The CCP noted the increased GSL payment forecast and suggested that the AER examine the forecast.²⁰⁶ The CCP also suggested that GSL costs "could be recovered during the course of the regulatory period".²⁰⁷ Realised GSL costs may be either higher or lower than forecast as they depend on the frequency of unplanned outages. Recovering GSL costs as the CCP suggests may also remove the incentive for the distributor to maintain service levels.

²⁰⁵ United Energy, *Response to information request 47* [email to AER], 25 February 2016.

²⁰⁶ Consumer Challenge Panel Sub Panel 3, *Submission to the Australian Energy Regulator (AER)*, 25 February 2016, p. 33.

²⁰⁷ Consumer Challenge Panel Sub Panel 3, *Submission to the Australian Energy Regulator (AER) an overview*, 22 February 2016, p. 16.