PRELIMINARY DECISION
United Energy distribution determination
2016 to 2020

Attachment 7 – Operating expenditure

October 2015

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Note

This attachment forms part of the AER's preliminary decision on United Energy's revenue proposal 2016–20. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 - Annual revenue requirement

Attachment 2 - Regulatory asset base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency benefit sharing scheme

Attachment 10 - Capital expenditure sharing scheme

Attachment 11 - Service target performance incentive scheme

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Attachment 18- f-factor scheme

Contents

Shortened forms

Shortened form	Extended form
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
DAE	Deloitte Access Economics
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DNSP	distribution network service provider
DUoS	distribution use of system
EA	enterprise agreement
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
GSL	guaranteed service level
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

Shortened form	Extended form
NSP	network service provider
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
SFA	stochastic frontier analysis
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital
WPI	wage price index

7 Operating expenditure

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

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

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

7.1 Preliminary decision

We are not satisfied that 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] Our alternative estimate of United Energy's opex for the 2016–20 regulatory control period, which we consider reasonably reflects the opex criteria, is outlined in Table 7.1.[3]

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

	2016	2017	2018	2019	2020	Total
United Energy's 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
Difference	**–25.6**	**–26.4**	**–25.2**	**–26.0**	**–22.9**	**–126.1**

Source: AER analysis.

Note: Excludes debt raising costs and DMIA.

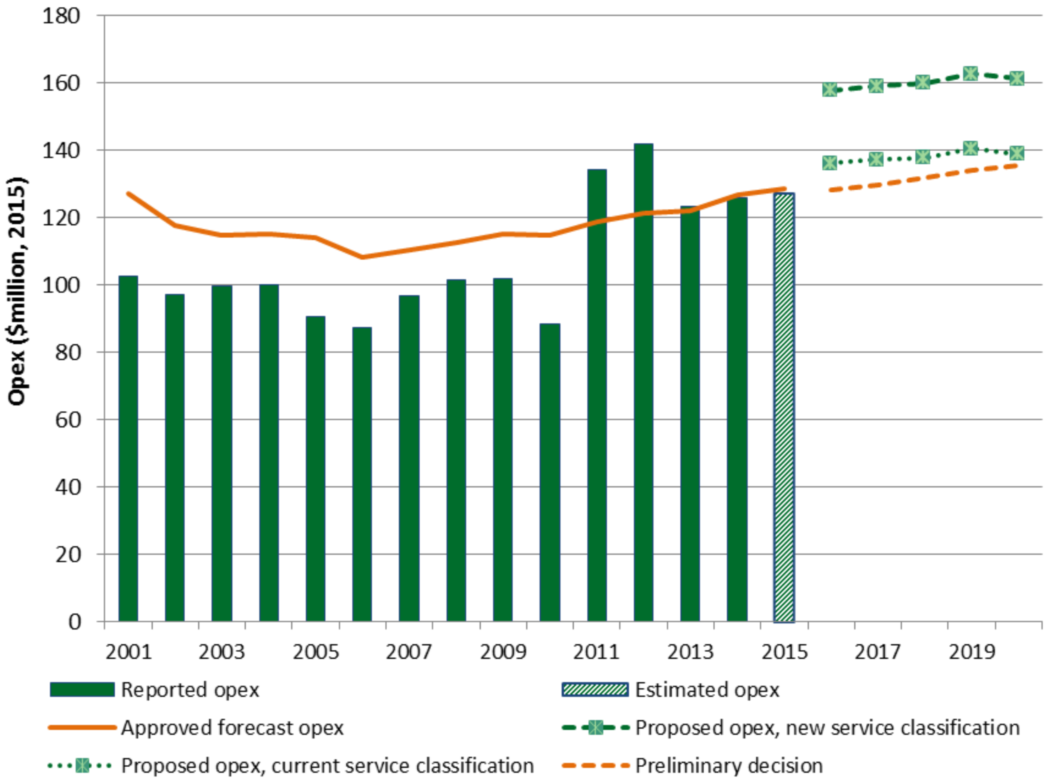
Figure 7.1 shows our preliminary decision compared to United Energy's proposal, its past allowances and past actual expenditure.

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 preliminary decision compared to United Energy's past and proposed opex ($ million, 2015)

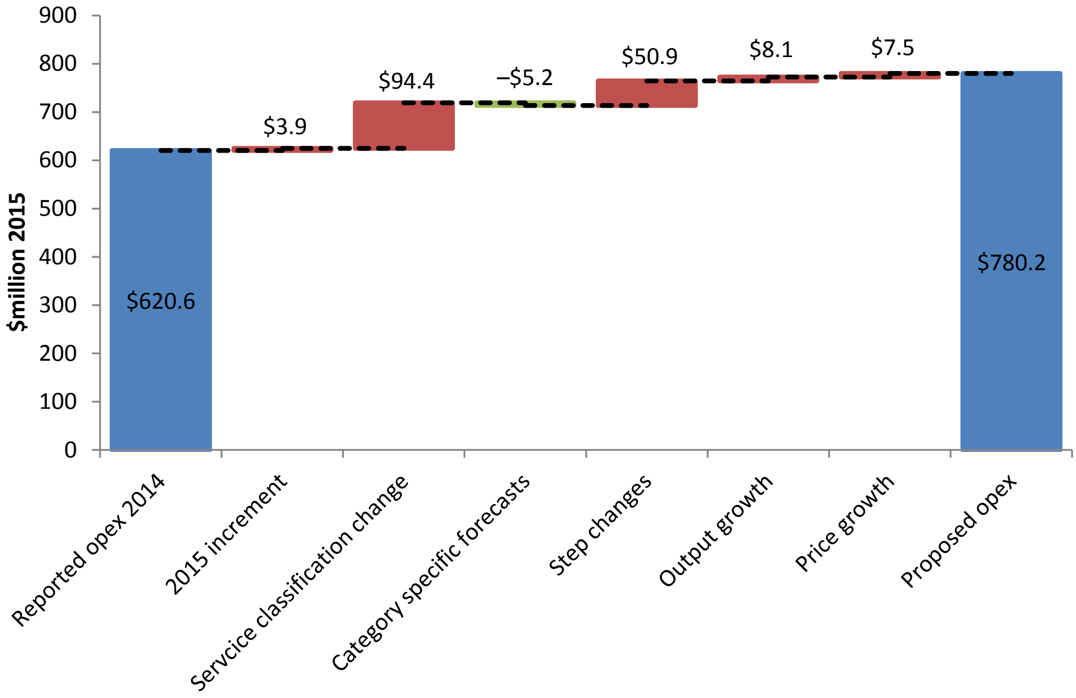


Source: United Energy, Regulatory accounts 2011 to 2014; United Energy, Economic benchmarking - Regulatory Information Notice response 2006 to 2013; AER analysis.

7.2 United Energy's proposal

United Energy proposed total forecast opex of $780.2 million ($2015) for the 2016–20 regulatory control period (excluding debt raising costs, totalling $13.7 million). 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 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. Its reported expenditure for 2014 would lead to base opex of $620.6 million ($2015) over the 2016–20 regulatory control period.
- 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 Guideline.[4] This increased United Energy's forecast by $3.9 million ($2015).
- United Energy also adjusted its base opex to add opex that it proposed to be classified as standard control services in the 2016–20 regulatory control period. This increased United Energy's forecast by $94.4 million ($2015).
- United Energy included category specific forecasts for guaranteed service level payments. This reduced its forecast by $5.2 million ($2015).
- United Energy identified step changes in costs it forecast to incur during the forecast period, which were not incurred in 2014. These costs broadly related to changes in regulatory and legal obligations, operating costs arising from capital program impacts, and delivering on customer expectations identified during its

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

customer engagement program. This increased United Energy's forecast by $50.9 million ($2015).

- United Energy proposed output growth forecast using our approach to accounting for forecast output growth. This increased United Energy's opex forecast by $8.1 million ($2015).
- United Energy accounted for forecast growth in prices related to labour and non-labour price increases. These forecast price changes increased United Energy's opex forecast by $7.5 million ($2015).

7.3 AER's assessment approach

This section sets out our general approach to assessment. 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.

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]

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

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

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

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

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 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]

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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).

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.

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

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

- our benchmarking data sets including, but not necessarily limited to:
  - (a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN

(b) any relevant data from international sources

(c) data sets that support econometric modelling and other assessment techniques consistent with the approach set out in the Guideline

as updated from time to time.

- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.[14]

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).[15] 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.[16] 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.[17]

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.[18] The Guideline sets out our intended approach to assessing opex in accordance with the NER.[19]

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.[20] For the most part, we have not departed from the approach set

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

[15] NEL, ss. 7A and 16(2).

[16] NEL, s. 7A(2).

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

[18] AER, *Expenditure forecast assessment guideline - explanatory statement*, November 2013.

[19] NER, cl. 6.5.6.

[20] NER, cl. 6.2.8(c).

out in the Guideline in this final decision.[21] In our Framework and Approach paper, we set out our intention to apply the Guideline approach in making this determination.[22] 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. [23] 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. This approach was expressly endorsed by the AEMC in its decision on the major rule changes that were introduced in November 2012. The AEMC stated:[24]

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

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

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

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

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

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

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.

Figure 7.3 How we build our alternative estimate

Underlying our approach are two general assumptions:

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

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model that has been employed by a number of Australian regulators over the last fifteen years. We refer to it as a 'revealed cost method' in the Guideline (and we have sometimes referred to it as the base-step-trend method in our past regulatory decisions).[25]

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

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

Step 1 – Base year choice

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

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

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

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

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

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

Step 2 - Assessing base opex

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

As we set out in the Guideline, to assess the service provider's actual expenditure, we use a number of different qualitative and quantitative techniques.[26] 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:[27]

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

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. For this decision we have used multilateral

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

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

total factor productivity, partial factor productivity measures and several opex cost function models.[28]

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

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

Step 3 - Rate of change

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

- price growth
- output growth
- productivity growth.

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

Step 4 - Step changes

Next we consider if any other opex is required to achieve the opex objectives in the forecast period. We refer to these as ‘step changes’. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs. As the Guideline explains, we will typically include a step change only if efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.[29]

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

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28 The benchmarking models are discussed in detail in appendix A.

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

benchmarking approach rather than a service provider's actual costs. This is to be consistent with the forecast of the cost of debt in the rate of return building block.

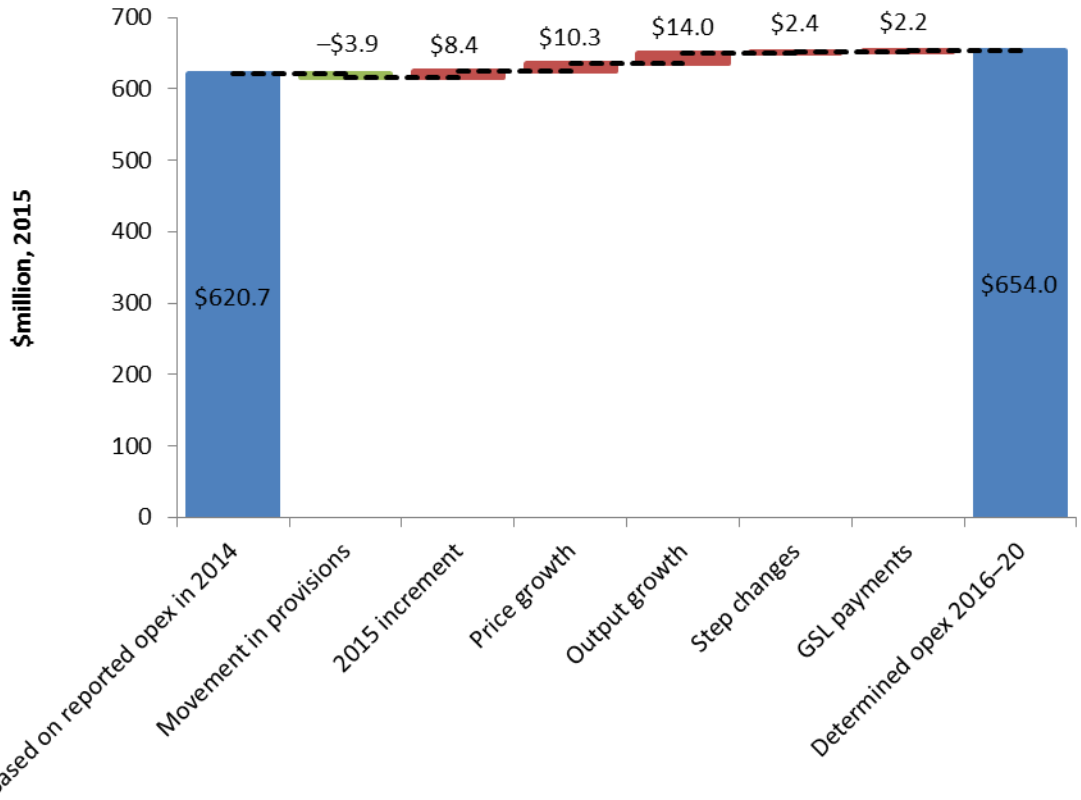
After applying these five steps, we arrive at our alternative estimate.

7.4 Reasons for preliminary decision

We are not satisfied that United Energy's proposed total forecast opex of $780.2 million ($2015) reasonably reflects the opex criteria.[30] As we discussed above, we have therefore used our alternative estimate as our substitute estimate.[31]

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.

Figure 7.4 AER preliminary decision opex forecast



Source: AER analysis.

Table 7.2 summarises the quantum of the difference between United Energy's proposed total opex and our preliminary decision estimate.

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30 NER, cl. 6.5.6(d).

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

Table 7.2 Proposed vs preliminary decision total forecast opex ($ million, 2015)

	2016	2017	2018	2019	2020	Total
United Energy's 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
Difference	–25.6	–26.4	–25.2	–26.0	–22.9	–126.1

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 Forecasting method assessment

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

7.4.2 Base opex

We have forecast a base opex amount of $125.0 million ($2015). Our forecast of base opex is outlined in Table 7.3.

Table 7.3 AER forecast of base opex

	Our preliminary decision
Reported 2014 opex	126.0
Remove movement in provisions	–0.8
Remove DMIA expenditure	–0.7
Remove GSL payments	–1.2
Adjusted 2014 opex	**123.4**
2015 increment	1.7
Estimated 2015 opex	**125.0**

Source: AER analysis.

Consistent with United Energy's proposal we have relied on United Energy's reported opex in 2014 to forecast opex. Benchmarking indicates United Energy is operating relatively efficiently when compared to other service providers in the NEM so we consider this is a reasonable starting point for determining our opex forecast.

We have not included an adjustment for Advanced Metering Infrastructure (AMI) expenditure. 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. All distributors proposed to allocate this expenditure between standard control services and alternative control services. The proportions allocated between each type of service differed for each service provider. We consider any cost allocation issues relating to metering costs would be best dealt with in a new Distribution Ring Fencing Guideline, which, at this stage will be developed by December 2016.

In the interim, before this Guideline is developed, our preferred approach is to allocate all costs formerly regulated under the AMI OIC to alternative control services. As this is similar to the historical approach where AMI costs are recovered separately to most distribution network costs, this approach will help in promoting transparency around trends in AMI and standard control expenditure.

7.4.3 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.

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	1.41	1.85	2.63	2.53	2.27
AER	0.99	1.19	1.57	1.59	1.49
Difference	**–0.42**	**–0.66**	**–1.05**	**–0.94**	**–0.77**

Source: AER analysis.

The following factors drive the difference between our forecast rate of change and United Energy's:

- To forecast labour price growth, United Energy used forecast growth in the WPI for the utilities industry as forecast by BIS Shrapnel. United Energy's forecast is higher than ours, which we based on forecasts from Deloitte Access Economics and BIS Shrapnel.
- United Energy adopted our approach to forecasting output growth. We used customer numbers and circuit length forecasts from United Energy's reset RIN and ratcheted maximum demand forecasts from AEMO.

The differences in each forecast rate of change component are:

- our forecast of annual price growth is on average 0.32 percentage points lower than United Energy's
- our forecast of annual output growth is on average 0.44 percentage points lower than United Energy's

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

7.4.4 Step changes

We have included one step change in our opex forecast. We are satisfied that additional opex associated with United Energy's pole top inspection program arises due an efficient capex/opex trade-off.

We also consider the amendments to Electric Line Clearance (ELC) Regulations 2015, published 28 June 2015, may result in a change in costs. Some amendments may result in an increase in costs and other amendments may result in a decrease in costs. Given the uncertainty around the net impact of these changes we have not included any changes in costs for this step change at this time.

We are not satisfied there are reasons to change our opex forecast for other reasons.

A summary of the costs we assess as step changes and our preliminary position is outlined in Table 7.5.

Table 7.5 Step changes ($ million, 2015)

	United Energy proposal	AER position
New regulatory obligations		
Power of Choice – Metering competition	3.5	–
Power of Choice – Customer access to data	1.7	–
Power of Choice – Embedded network	0.7	–
Power of Choice – Demand management IT Platform	1.6	–
Power of Choice – Network	3.5	–
Regulatory Information Notice reporting	1.6	–
Energy Safe Victoria safety obligations	1.0	–

Energy Safe Victoria rule changes	72.5[32]	0.0[a]
Customer response/initiated		
Effortless Customer Experience program	6.0	–
Stakeholder engagement	1.3	–
Council trees	3.0	–
Existing regulatory obligations – recurrent but non-annual		
Customer charter	0.7	–
Regulatory submission cost	-5.2[33]	–
Neutral testing	0.4	–
Network planning and analytics – IT Capital Program	4.1	–
Guideline 11 EWOV direction	4.5	–
Change in external environment		
IT security costs	4.0	–
Insurance premiums	2.3	–
Capex/opex trade-off		
Pole top inspection	2.4	2.4
Real price escalations	0.5	–[34]
Total	**112.4**[35]	**2.4**

Source: United Energy, *Operating expenditure overview*, 30 April 2015, p. 23 and AER analysis.

Note: a: Energy Safe Victoria rule changes are a new regulatory obligation that may give rise to a justifiable step change. However, on the basis of the information and evidence United Energy has provided so far, we do not have sufficient material to form a view as to the quantum of an efficient opex step change.

We discuss each of the step changes United Energy proposed in more detail in appendix C.

7.4.5 Other costs not included in the base year

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.

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 We apply price growth in our rate of change to base opex and step changes rather than applying a step change specific labour escalation.

35 United Energy proposed $53.8 million in its initial proposal. This total takes into account the updated Energy Safe Victoria rule change proposal and the net impact of regulatory submission costs.

Guaranteed service level payments

We have forecast guaranteed service level (GSL) payments as the average of GSL payments made by United Energy between 2010 and 2014. We note that the GSL revenue provided under this approach is almost identical to adopting a single year revealed cost approach and applying the EBSS. Further, the incentives provided by this forecasting approach are consistent with adopting a single year revealed cost approach and applying the EBSS. We have adopted the historical averaging approach to maintain consistency with how GSL payments have been forecast for previous regulatory control periods.

Debt raising costs

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

7.4.6 Interrelationships

In assessing United Energy's total forecast opex we take into account other components of its regulatory proposal, including:

- the operation of the EBSS in the 2011–15 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 pole top inspection program
- 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.

7.4.7 Assessment of opex factors

In deciding whether we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.[36] Table 7.6 summarises how we have taken the opex factors into account in making our preliminary decision.

Table 7.6 AER consideration of opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark operating expenditure that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period. We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of United Energy's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.
The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of 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.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[37]
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering United Energy's proposed step changes. For instance we considered whether a step change for pole top inspections is an efficient capex/opex trade-off. We

[36] NER, cl.6.5.6(e).

[37] AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

Opex factor	Consideration
	considered the relative expense of capex and opex solutions in considering this step change. We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above we considered capex/opex trade-offs in considering United Energy's proposed step changes. Some of our assessment techniques examine opex in isolation—either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs. Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.
Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to United Energy's opex in the 2011–15 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our estimate of base opex consistently in applying the EBSS and forecasting United Energy's opex for the 2016–20 regulatory control period.
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our preliminary decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be significant in reaching our preliminary decision.

Source: AER analysis.

A Base opex

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

A.1 Position

We have used a base opex amount of $125.0 million in our alternative opex amount. The base opex amount we have used in our preliminary decision forecast is outlined below in Table A.1.

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

	Our preliminary decision
Reported 2014 opex	126.0
Remove movement in provisions	–0.8
Remove DMIA expenditure	–0.7
Remove GSL payments	–1.2
Adjusted 2014 opex	**123.4**
2015 increment	1.7
Estimated 2015 opex	**125.0**

Source: AER opex model.

A.2 Proposal

United Energy proposed a base opex amount based on its actual opex in 2014. It made adjustments to this amount to:

- add costs associated with AMI which had been allocated to standard control services opex
- remove DMIA expenditure
- add efficient incremental costs associated with the 2015 regulatory year.[38]

Table A.2 illustrates United Energy's forecast of adjusted base opex.

[38] United Energy, *Regulatory proposal*, p. 90.

Table A.2 United Energy forecast of adjusted base opex ($2015)

	United Energy's proposal
Reported 2014 opex	124.8
Remove DMIA expenditure	–0.7
Remove GSL payments	–1.1
Service classification adjustment	18.9
Adjusted 2014 opex	**141.8**
2015 increment	0.8
Estimated 2015 opex	**142.6**

Source: United Energy, *Proposed opex forecast model,* 30 April 2015.

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. This includes economic benchmarking, partial performance indicators and category-based techniques. 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.

Our assessment of United Energy's base opex is set out below under the following headings:

- Benchmarking results
- Service classification changes
- Other adjustments.

A.4 Benchmarking results

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative performance. We have used economic benchmarking as a 'first pass' test to assess whether United Energy's opex shows signs of material inefficiency.

On this basis we do not consider there is evidence justifying a departure from a revealed cost approach for United Energy.

The benchmarking techniques, developed by our consultant Economic Insights, measure either the overall efficiency of service providers or how efficiently they use opex in particular. They are:

- multilateral total factor productivity (MTFP) which is an index that measures the ratio of inputs used for output delivered
- opex multilateral partial factor productivity (MPFP) which is an index-based technique that measures the ratio of output quantity index to opex input quantity index[39]
- econometric modelling techniques:
    - Cobb Douglas stochastic frontier analysis (SFA)—this estimates the efficient level of opex required for a service provider by constructing an efficient frontier and compares this to the actual opex used by the service provider
    - Cobb Douglas least squares estimation—is similar to the above in modelling opex cost function but uses least squares estimation method to estimate an industry-average technology, and includes dummy variables for Australian distributors to capture firm-specific efficiency
    - Translog least squares estimation—this is similar to the Cobb Douglas least squares estimation technique but assumes more flexible functional form regarding the relationship between opex and outputs.

Each benchmarking technique compares the relative efficiency of service providers to its peers. These techniques differ in terms of estimation method, model specification and the inclusion of operating environment factors (factors that may differentiate service providers). Despite this, Economic Insights found:[40]

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

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

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[39] At the time of developing the Expenditure forecast assessment guideline, we had not received data from service providers so we considered data envelopment analysis (DEA) may be another technique we could apply. However, we have been able to apply stochastic frontier analysis. This is a superior technique to DEA. Economic Insights, Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs, November 2014, p. 7.

[40] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 46–47.

We note the benchmarking we have presented in this preliminary decision only includes the data we have used in our latest distribution benchmarking report.[41] This used the actual opex incurred by the Victorian service providers from 2006 to 2013.

While the benchmarking does not include actual opex in 2014, the year each of the Victorian service providers proposed as the base, we would not expect this would lead to material differences in the benchmarking results or our conclusions on the relative efficiency of each provider. On some of our benchmarking techniques (e.g econometric models), we only assess average efficiency over a sample period of eight years. This means an additional year of data will not materially affect our conclusions about the relative efficiency of the service providers over the sample period. In any case, we note that United Energy's actual opex in 2013 was $123.5 million ($2015) while in 2014 it was $125.7 million ($2015). Therefore, as we have found United Energy to be relatively efficient based on its opex in 2013, it is reasonable to assume that its opex in 2014 is also relatively efficient.

A.4.1 MTFP and MPFP findings

Economic Insights' MTFP and MPFP modelling indicates that United Energy is relatively efficient overall and also in the use of its opex.

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

MTFP measures total output relative to an index of all inputs used. MPFP measures total output relative to one particular input (e.g. opex partial productivity is the ratio of total output quantity index to an index of opex quantity).

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

The MTFP results indicate that United Energy is amongst the most productive service providers in the NEM.

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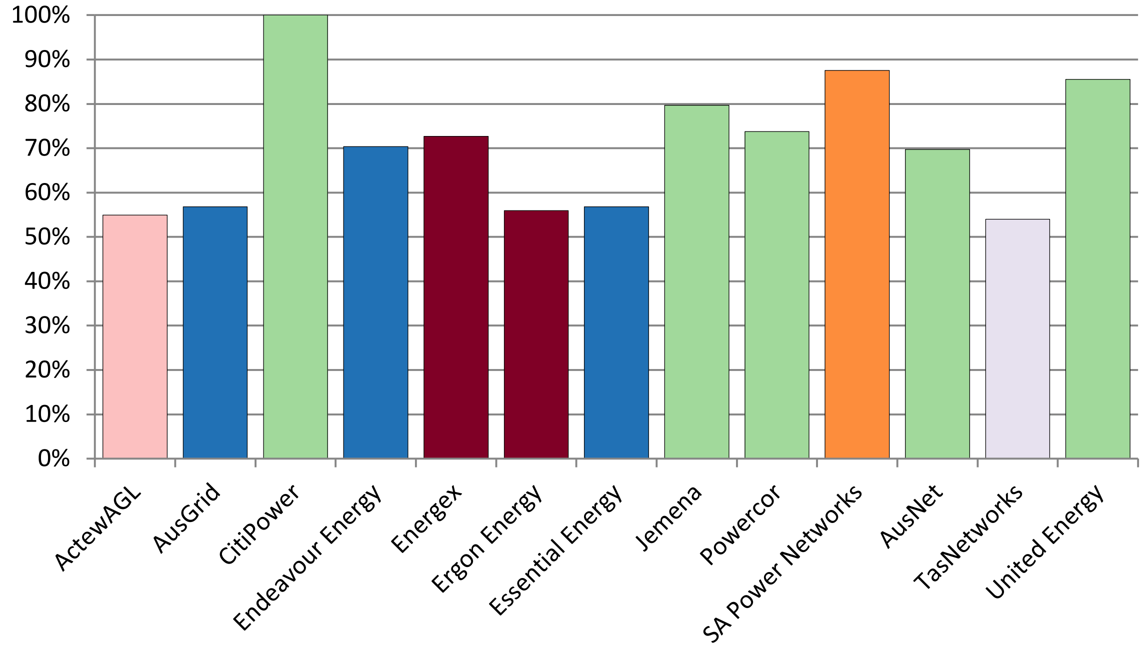
41 AER, *2014 Annual distribution benchmarking report,* November 2014.

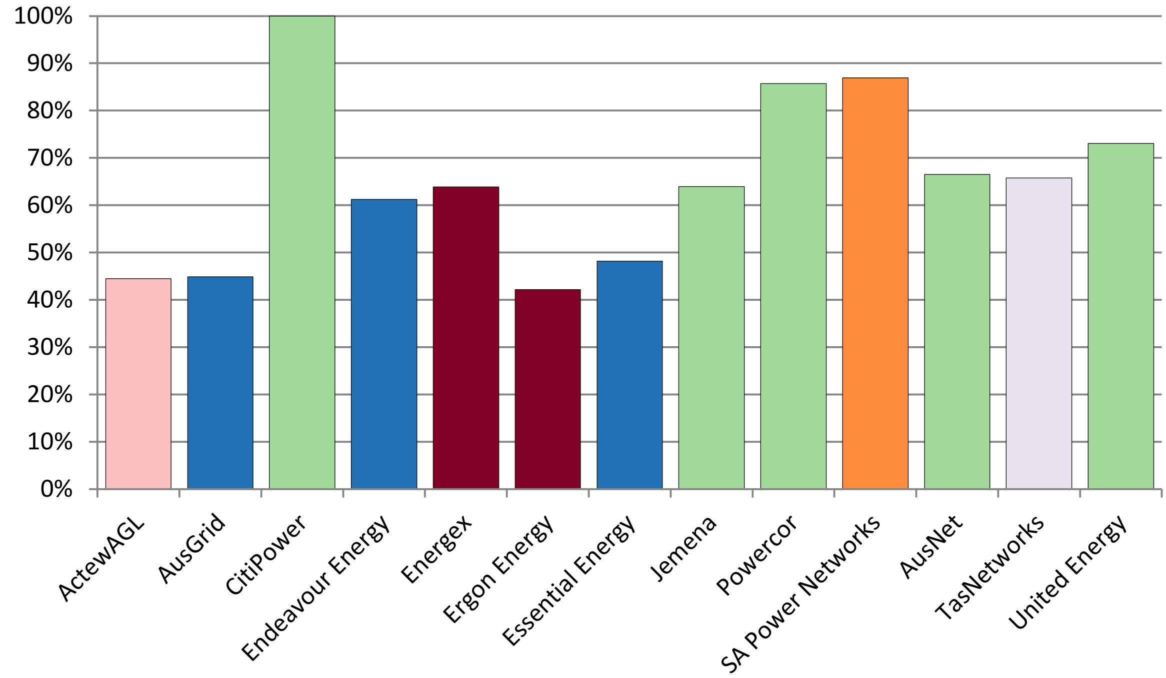
Figure A.1 MTFP Performance (average 2006–2013)



Source: AER analysis.

Figure A.2 presents the opex MPFP results. As would be expected, the performance of the service providers changes somewhat under this comparison technique, reflecting the different combination of opex and capital used by the service providers to deliver network services. Neither measure suggests United Energy is performing materially worse than its peers. Therefore there is no evidence of material inefficiency.

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



Source: AER analysis.

For further detail on MTFP and index number benchmarking approaches we direct readers to our previous publications.[42]

We note that the ACT, NSW and Queensland service providers have made a number of submissions on our use of benchmarking in the NSW, ACT and Queensland distribution determinations. We have considered these submissions and have concluded that the benchmarking we have relied upon is appropriate. We have published these submissions along with our consideration of them on our website.[43]

The Victorian service providers also submitted some benchmarking as part of their proposals. For instance, Jemena and United Energy submitted reports from Huegin.[44] In general, the analysis it undertook was consistent with analysis it undertook for the

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42 These include: Economic Insights, 2014 and AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014, and our draft determinations for the NSW and ACT distribution network service providers.
AER, *Better Regulation, Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013.
ACCC/AER, *Benchmarking Opex and Capex in Energy Networks, Working Paper no.6*, May 2012.

43 http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements.

44 Huegin, *Jemena Electricity Networks (Vic) Ltd Productivity Study, Efficiency and growth for the 2015–20 regulatory period*;
Huegin, *Benchmarking United Energy's operating expenditure - an indication of benchmarking results using the AER's techniques*.

NSW and Queensland distribution service providers. AusNet Services also submitted some analysis which considered the operating environment factors they consider disadvantage them in benchmarking performance.[45] We recognise that operating environment factors specific to each business will affect their benchmarking performance. Our view is that United Energy and the other Victorian service providers already appear relatively efficient when compared to the NSW and Queensland service providers. On this basis we did not consider it necessary to consider the detailed operating environment factors affecting the individual performance of each Victorian business for this preliminary decision.

A.4.2 Findings from econometric modelling of the opex cost function

Economic Insights has chosen to model the opex cost function of the service providers using three models.[46] These models are Cobb Douglas SFA, Cobb Douglas least squares estimation (CD LSE) and Translog least squares estimation (TLG LSE). The TLG LSE and CD LSE models are econometric modelling of Translog and Cobb Douglas opex cost functions, respectively.[47] They are parametric techniques, which mean that they model the underlying cost function of the service providers as specified.

Like the opex MPFP analysis, these models also indicate that United Energy performs well against its peers.

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

The Victorian Energy Consumer and User Alliance (VECUA) considered on the basis of one of these models, Cobb Douglas stochastic frontier analysis, that all Victorian service providers appear materially inefficient when compared to CitiPower.[48]

We do not consider it is appropriate to use the efficiency score of the frontier service provider to determine what is 'materially inefficient'. We consider it should be a point lower than the frontier to provide an appropriate margin for forecasting error, data error and modelling issues. We also note the following:

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[45] AusNet Services, *Regulatory proposal*, 30 April 2015, pp. 83–91.

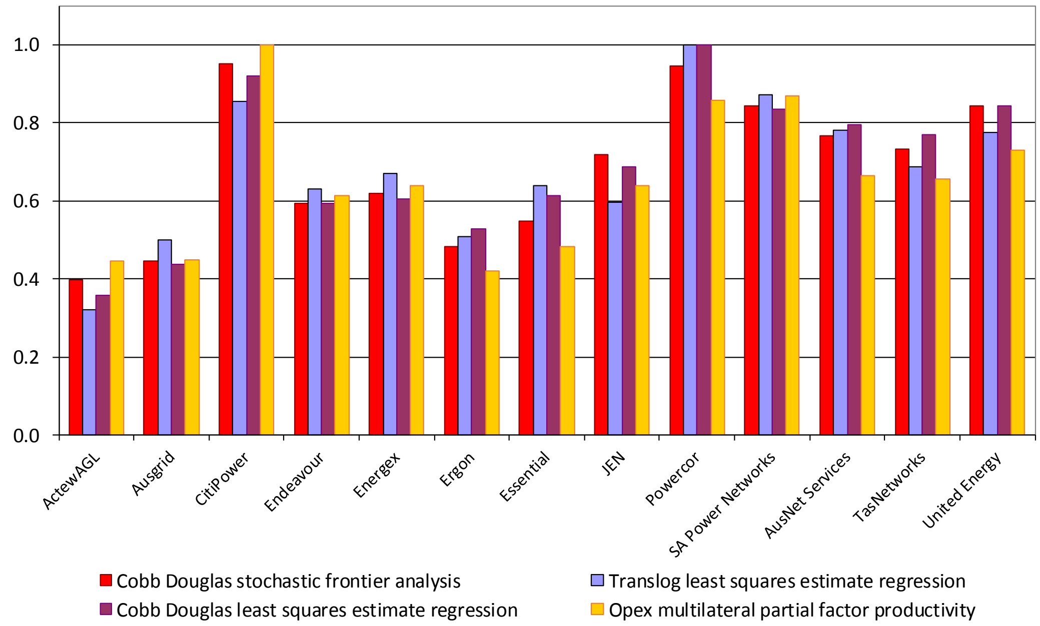
[46] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, p. iii.

[47] Economic Insights describes the opex cost functions in detail. Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 27–31.

[48] Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 revenue proposals*, 13 July 2015, p. 34.

- The results below reflect raw efficiency scores. There are other operating environment factors affecting each businesses performance which are not captured in each of the benchmarking models.
- The scores below reflect average efficiency scores over the 2006 to 2013 period so cannot be used directly to infer the relative efficiency gap between providers in any one year.

Figure A.3 Econometric modelling and opex MPFP results, 2006-2013



Source: Economic Insights, 2014.

A.4.3 Partial performance indicators

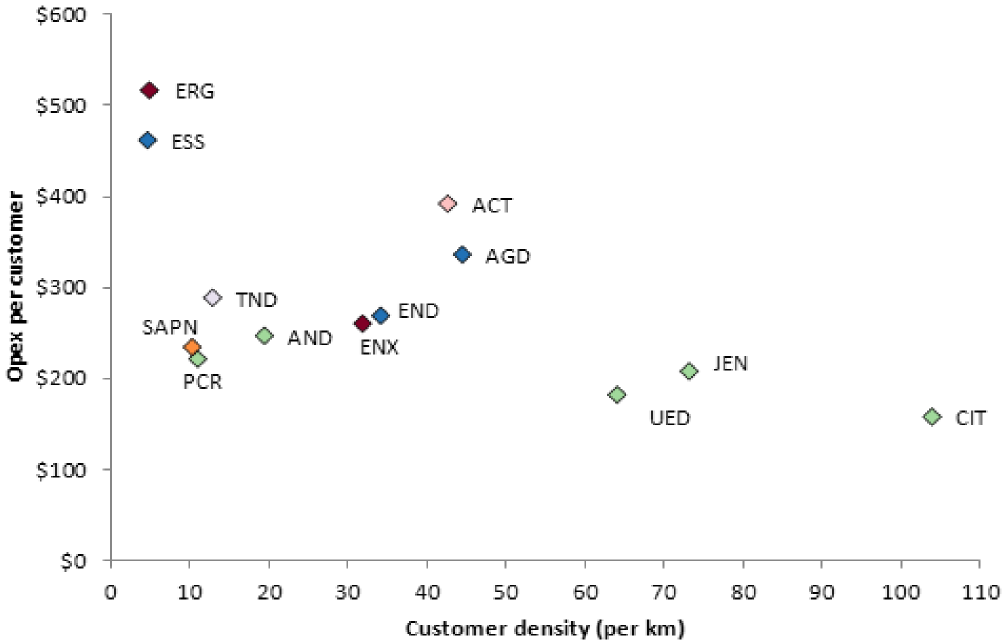
In our annual benchmarking report we also present a number of partial performance indicators.[49] These indicators examine the service providers' use of assets, opex and total inputs in delivering its distribution services. Under these metrics, United Energy appears to be one of the more efficient networks. As such, we consider that this benchmarking supports the findings of the econometric benchmarking discussed above.

Although a number of PPIs are presented in this report we consider that the most relevant PPIs are opex per customer and total cost per customer. This is because customer numbers appears to be the most material driver of costs for service

[49] AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014.

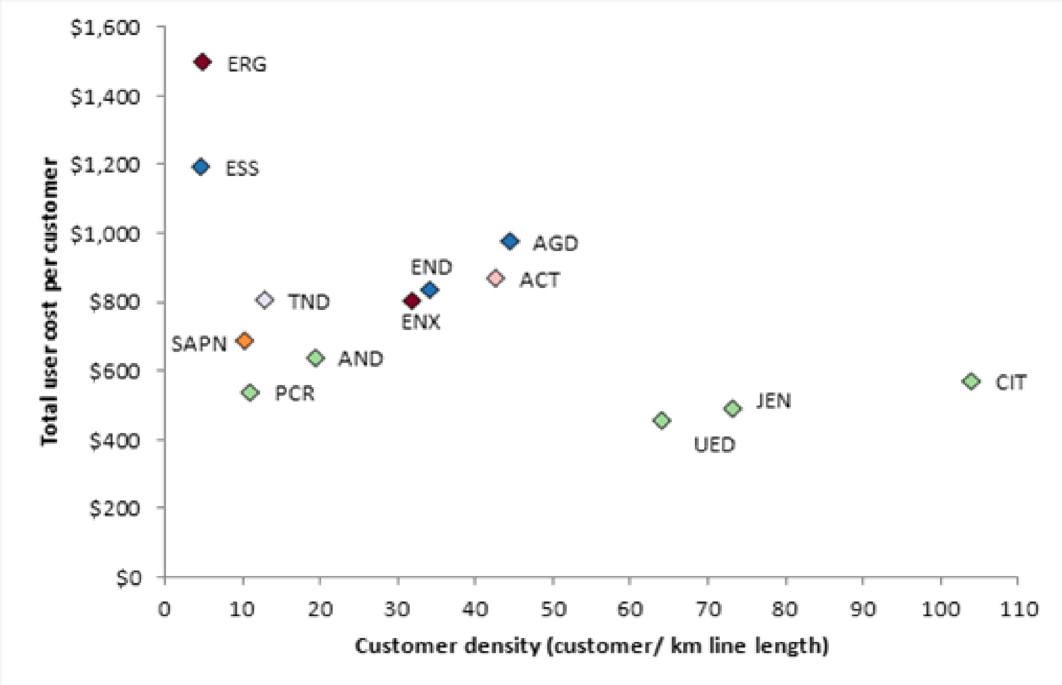
providers.[50] Figure A.4 and Figure A.5 present these PPIs. These figures show that United Energy (UED) incurs relatively low opex and total cost per customer when compared to its peers.

Figure A.4 PPI of operating expenditure per customer (2009 to 2013)



[50] The number of customer connections has the highest coefficient in Economic Insights econometric models and its SFA Cobb Douglas Model. Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 33–35.

Figure A.5 PPI of total cost per customer (2009 to 2013)



A.4.4 Trend in opex

Benchmarking across the 2006–13 period indicates that United Energy performs relatively well against its peers. However, as our preference is to use a single year of expenditure, we must also consider whether it is appropriate to use the end point.

In real terms, United Energy's opex in 2014 is 13 per cent higher than the average over the benchmarking period (Figure A.6). This increase in opex has contributed to a decline in opex MPFP in 2012 and 2013. This is illustrated in Figure A.7. This trend in productivity was noted by the Consumer Challenge Panel and the VECUA in their submissions.[51]

[51] Consumer Challenge Panel sub panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 5 August 2015, pp. 11-12; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 revenue proposals*, 13 July 2015, p. 35.

Figure A.6 United Energy’s opex compared to approved forecast

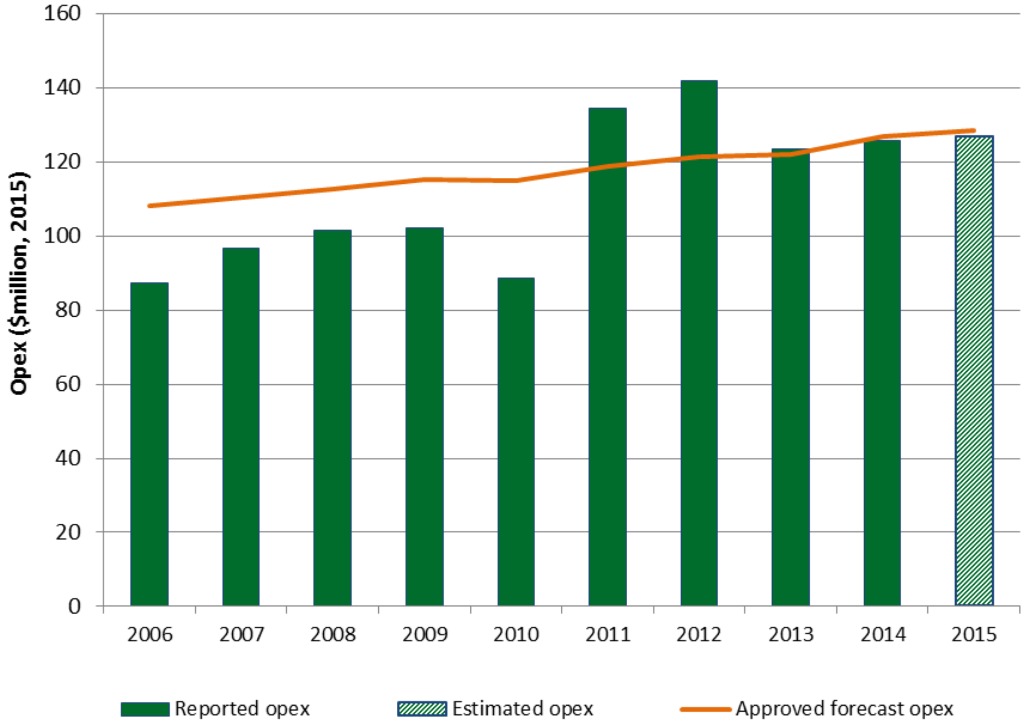
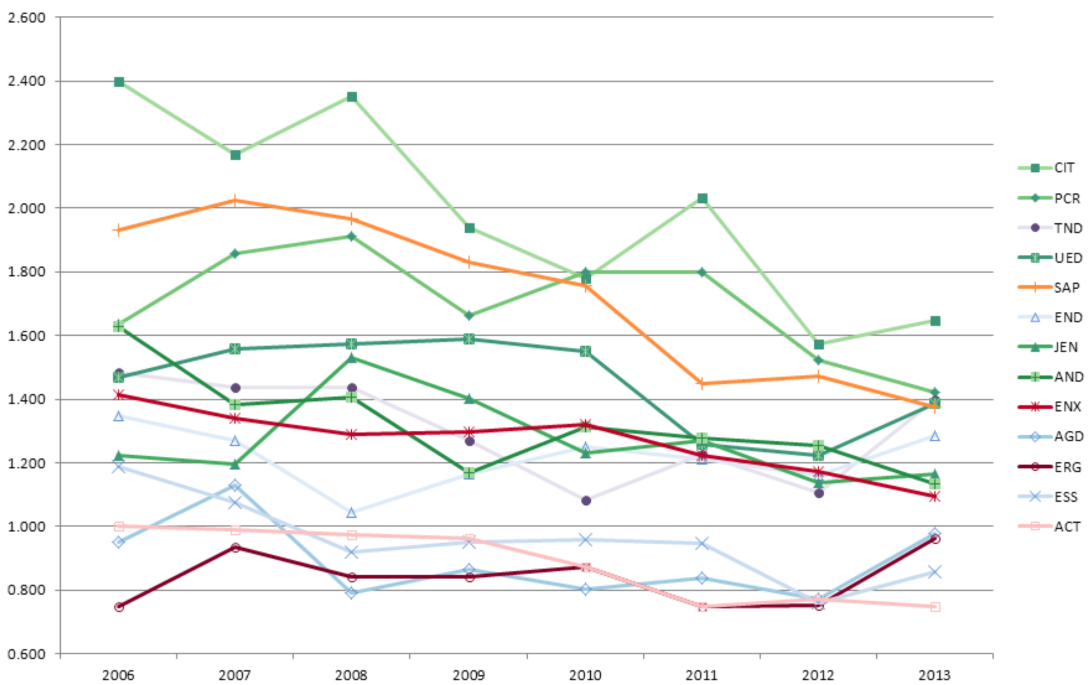


Figure A.7 MPFP of distributors over the benchmarking period



However, as highlighted above, the increase in opex in 2012 and 2013 has not significantly affected United Energy's relative ranking on this benchmarking measure.

We also note a key driver of United Energy's increase in opex is its change in business model. Up until 30 July 2011, United Energy's business model was mostly centred on a single outsourced contract with one outsourced provider. However, according to United Energy, JAM was making a loss in providing services under the agreement.[52] The contract price as reflected in United Energy's reported opex would have therefore underestimated the actual costs incurred in providing the services. Upon the end of this arrangement, United Energy restructured to a new model involving multiple outsourced providers and greater insourcing. In restructuring, it reported significant transition costs in the 2011 and 2012 years.[53]

Another key driver of United Energy's increased opex in this time is because of changed regulatory requirements rather than a decline in United Energy's efficiency. As outlined below in Table A.3, United Energy's opex on vegetation management rose from $4.8 million ($2015) in 2009 to $14.9 million ($2015) in 2013. The key reason for this is the introduction of the Electricity Safety (Electric Line Clearance) Regulations 2010. Under the previous version of these regulations, the Electricity Safety (Electric Line Clearance) Regulations 2005, the Victorian service providers were able to ask for exemptions from the regulations, where they could demonstrate to Energy Safe Victoria that appropriate risk mitigation was in place. Under the 2010 version of the regulations, following the Black Saturday bushfires, many of these exemptions were removed. This led to an increase in United Energy's vegetation management expenditure.

Table A.3 United Energy vegetation management expenditure

	2009	2010	2011	2012	2013
Vegetation management expenditure ($2015)	4.8	5.7	10.9	16.4	14.9
% of total opex	5	5	8	12	12

Source: Category Analysis RINs 2009-2014; AER analysis.

A.5 Service classification changes

We have not included additional opex associated with reallocated metering expenditure in our opex forecast.

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

52 AER, *Victorian distribution determination final decision*, 2011–15, p. 274.

53 United Energy, 2011 annual RIN response, Worksheet 12a; 2011 annual RIN response, Worksheet 12a.

With the expiry of the AMI OIC, opex associated with AMI is now to be regulated under the NER. United Energy proposed an adjustment to its base opex of $19.0 million for opex previously regulated under the AMI OIC.

Each of the Victorian service providers have taken a different approach to how these costs should be allocated across standard control and alternative control (metering) services. Where any costs regulated under AMI OIC are shared between standard control distribution services and metering services, United Energy have proposed allocating the whole proportion to standard control services.[54]

The approach taken by the other Victorian service providers is outlined below:

- CitiPower and Powercor have each used a granular approach, which, where possible, quantifies the proportion of each IT system previously regulated under AMI OIC that is used for standard control services. For many IT systems, they deem the proportion used for metering to be relatively immaterial so they have allocated the whole proportion of the IT system cost to standard control services.[55]
- Jemena, similar to CitiPower and Powercor has also taken a relatively granular approach to determining the amount of costs to be allocated between standard control services and metering services. However, it has allocated all shared costs previously regulated under the AMI OIC between standard control and alternative control services, not only IT.[56]
- AusNet Services has taken a similar approach to United Energy. Where any costs are shared between different services, it has allocated the whole proportion to standard control services.[57]

As outlined in Table A.4, the proportion of metering opex allocated to standard control services differs substantially across the Victorian service providers.

Table A.4 Proportion of metering opex allocated to standard control services

AusNet	CONFIDENTIAL
CitiPower	32 per cent
Jemena	61 per cent
Powercor	27 per cent
United Energy	79 per cent

Source: AER analysis.

[54] United Energy, *Revenue Capped Metering Services - Supporting Paper*, 30 April 2015.
[55] CitiPower, *Regulatory proposal, Appendix F - Base year adjustments*, p. 12.
[56] Jemena, *Regulatory proposal*, opex model.
[57] AusNet Services, *Regulatory proposal*, p. 204;

We consider a consistent approach across Victorian service providers is preferable. While metering services are not currently subject to competition, given policy developments in this area, in the near future it is likely they will be.[58] The cost allocation approaches by incumbent providers have the potential to affect competition from new entrants and competition between Victorian distributors.

Based on the current guidance from the AEMC, we will be required to develop and publish a Distribution Ring Fencing Guideline by 1 December 2016.[59] We consider any cost allocation issues relating to metering costs would be best dealt with in the development of this Guideline in accordance with a nationally consistent approach.

In the interim, before this Guideline is developed, our preferred approach is to allocate all costs formerly regulated under the AMI OIC to alternative control services. As this is similar to the historical approach where AMI costs are recovered separately to most distribution network costs, this approach will help in promoting transparency around trends in AMI and standard control expenditure.

We note that the allocation of costs between standard control services and metering services makes no difference to the assessment of the efficiency of these costs. As both metering services and standard control services are regulated under a revenue cap then this approach also makes no difference to the ability of the current service providers to recover their efficient costs.

We received a submission from the Victorian Department of Economic Development, Jobs, Transport and Resources which agreed that some of these costs may be standard control services but considered there was a risk that consumers would be paying for these costs twice.[60] As we have not allocated any AMI costs to standard control services opex, there is no risk of consumers paying for these costs twice.

A.6 Estimate of final year expenditure

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

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

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

where:

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

[58] AEMC, *Draft Rule Determination - National Electricity Amendment (Expanding Competition in Metering and Related Services) 2015*, 26 March 2015.

[59] AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

[60] Victorian Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 6.

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

F_b is the determined opex allowance for the base year

A_b is the amount of actual opex in the base year

$non\text{-}recurrent\ efficiency\ gain_b$ is the non-recurrent efficiency gain in the base year.

The estimate of final year opex should be consistent in both our opex forecast and the EBSS in order to share United Energy's efficiency gains made in 2015 with its network users as intended by the EBSS. Version one of the EBSS for distribution businesses does not allow estimated final year expenditure to be adjusted for non-recurrent efficiency gains (version two, which will apply in the 2016–20 regulatory control period does). We are required to have regard to whether the opex forecast is consistent with the EBSS when deciding whether we are satisfied that the proposed opex forecast reasonably reflects the opex criteria.[61] To ensure consistency with estimated final year expenditure in the EBSS, we have not adjusted our estimate of final year expenditure for any non-recurrent efficiency gains.

We applied this equation to derive an estimated opex of $125.0 million ($2015) for 2015. We then applied our forecast rate of changes, and added step changes, to derive our alternative estimate of opex for the 2016–20 regulatory control period.

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

B Rate of change

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

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

As set out in our *Expenditure forecast assessment guideline* (the Guideline), we have developed an opex forecast incorporating the rate of change to account for:[62]

- 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

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. We consider that applying our methodology to derive an alternative estimate of opex will result in a forecast that reasonably reflects the efficient and prudent costs faced by United Energy given a realistic expectation of demand forecasts and cost inputs.

The differences in the forecast rate of change components are:

- our forecast of annual price growth is on average 0.32 percentage points lower than United Energy's
- our forecast of annual output growth is on average 0.44 percentage points lower than United Energy's.

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

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

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

	2016	2017	2018	2019	2020
United Energy	1.41	1.85	2.63	2.53	2.27
AER	0.99	1.19	1.57	1.59	1.49
Difference	**–0.42**	**–0.66**	**–1.05**	**–0.94**	**–0.77**

Source: AER analysis.

B.2 United Energy proposal

Table B.2 shows United Energy's proposed cumulative change in opex for each rate of change component reported in its reset RIN. The method United Energy used to forecast the rate of change method was broadly consistent with our own.

Table B.2 United Energy proposed opex by rate of change drivers ($'000, 2015)

	2016	2017	2018	2019	2020
Price growth	794.1	1149.1	1598.4	1859.5	1592.8
Output growth	1195.4	1458.7	2109.7	1706.8	1609.3
Productivity growth	–	–	–	–	–

Source: United Energy reset RIN table 2.16.1.

We discuss how United Energy forecast each of the rate of change components below.

Forecast price growth

United Energy stated that it expected the costs of two inputs—labour and materials—will increase by more than the consumer price index (CPI) in the 2016–20 regulatory period. It assumed the costs of other inputs will increase in line with the CPI.

However, it only adjusted its opex forecast for real price growth in labour. Materials comprise only a small component of its opex and it did not expect real price growth will significantly impact forecast opex. It engaged BIS Shrapnel to forecast labour price growth.

Table B.3 United Energy's proposed real price growth (per cent)

	2016	2017	2018	2019	2020
Labour	0.9	1.3	1.8	2.1	1.8
Non-labour	–	–	–	–	–

Source: United Energy, *Regulatory proposal*, p. 91.

United Energy adopted a weighting of 62 per cent for labour and 38 per cent non-labour price growth. United Energy noted that this is consistent with our November 2014 draft decision for determining the rate of price growth for the NSW and ACT distributors' opex.

Forecast output growth

United Energy stated that it applied the output growth measures and respective weightings that we used in our November 2014 draft decisions for the NSW and ACT distributors, being:

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

The forecast growth rate for each output measure, and the overall output growth rate are in Table B.4.

Table B.4 United Energy's proposed output growth (per cent)

	2016	2017	2018	2019	2020
Customer numbers	1.06	0.95	1.02	0.93	0.89
Circuit length	0.82	–0.35	0.82	0.62	0.70
Ratcheted maximum demand	0.20	1.96	3.29	2.38	2.15
Output growth	**0.85**	**1.03**	**1.50**	**1.21**	**1.14**

Source: United Energy, *Proposed opex model*, 30 April 2015.

Forecast productivity growth

United Energy forecast zero productivity growth in its rate of change. United Energy stated that this is consistent with our November 2014 draft decision for the NSW and ACT distributors' opex.

B.3 Assessment approach

As discussed above, we assess the annual change in expenditure in the context of our assessment of United Energy's proposed total forecast opex.

The rate of change itself is a build-up of various components to provide an overall number that represents our forecast of annual change in overall required opex during the 2016–20 regulatory control period. We consider the rate of change approach captures all drivers of changes in efficient base opex except for material differences between historic and forecast step changes. The rate of change approach we have adopted takes into account inputs and outputs, and how well the service provider utilises these inputs and outputs.

The rate of change formula for opex is:

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

Where Δ denotes the proportional change in a variable.

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

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

Since our rate of change approach is a holistic approach we cannot make adjustments to one component without considering the interactions with other rate of change components. For example, if we were to the adjust output to take into account economies of scale, we must ensure that economies of scale have not already been accounted for in our productivity growth forecast. Otherwise, this will double count the effect of economies of scale.

B.3.1 Price growth

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

To determine the appropriate forecast change in labour prices we assessed forecasts from BIS Shrapnel and Deloitte Access Economics. These forecasts are based on these consultants' views of general macroeconomics trends for the utilities industry and the overall Australian economy. We discuss our consideration of the choice of labour price forecast below in section B.4.2.

B.3.2 Output growth

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

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

To measure output growth, we select a set of output measures and apply a weighting to forecast growth in these measures.

We have assessed each of United Energy's output growth drivers and compared its forecast output growth with ours at the overall level.

We discuss in greater detail how we have estimated output growth in section B.4.3.

B.3.3 Productivity

We forecast our change in productivity measure based on our expectations of the productivity an efficient service provider in the distribution industry can achieve. We consider the historic change in productivity from Economic Insights' economic benchmarking analysis and whether this reflects a reasonable expectation of the benchmark productivity that can be achieved for the forecast period.

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

In the explanatory statement to the Guideline we noted that we would apply a rate of change to our estimate of final year opex (taking into account an efficiency adjustment, if required), to account for the shift in the productivity frontier over the forecast period.[63]

Since forecast opex must reflect the efficient costs of a prudent firm, it must reflect the productivity improvements it is reasonable to expect a prudent service provider can achieve. All else equal, a price taker in a competitive market will maintain constant profits if it matches the industry average productivity improvements reflected in the market price. If it is able to make further productivity improvements, it will be able to increase its profits until the rest of the industry catches up, and this is reflected in the market price. Similarly, if a service provider is able to improve productivity beyond that forecast, it is able to retain those efficiency gains for a period.[64]

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

64 AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 66.

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

We discuss how we have estimated productivity growth in more detail in section B.4.4.

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 rate of change using information provided in its reset RIN and opex model.

B.4.1 Overall rate of change

We have adopted a rate of change lower than that proposed by United Energy to forecast our alternative estimate of opex. United Energy forecast higher price growth and output growth than we did. United Energy did not include a forecast change in productivity growth for the 2016–20 regulatory control period. This is consistent with our forecast of productivity growth.

Table B.5 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.

Table B.5 Forecast overall rate of change (per cent)

	2016	2017	2018	2019	2020
United Energy					
Price growth	0.56	0.81	1.12	1.30	1.12
Output growth	0.85	1.03	1.50	1.21	1.14
Productivity growth	–	–	–	–	–
Overall rate of change	**1.41**	**1.85**	**2.63**	**2.53**	**2.27**
AER					
Price growth	0.22	0.50	0.79	0.92	0.85
Output growth	0.76	0.69	0.77	0.66	0.64
Productivity growth	–	–	–	–	–
Overall rate of change	**0.99**	**1.19**	**1.57**	**1.59**	**1.49**
Difference	**–0.42**	**–0.66**	**–1.05**	**–0.94**	**–0.77**

Source: AER analysis.

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

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

B.4.2 Forecast price growth

We are not satisfied United Energy's proposed average annual price growth of 1.0 per cent for the 2016–20 regulatory control period reflects the increase in prices an efficient service provider requires to meet the opex objectives. We forecast average annual price growth of 0.7 per cent for the 2016–20 regulatory control period.

United Energy adopted the same price measures to forecast price growth as we did. The difference between our forecast of opex price growth and United Energy's is due to the forecast growth of the chosen price measures, which we discuss below.

Forecast growth of individual measures

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

Where a consultant is used to forecast labour prices, we consider an averaging approach that takes into account the consultant's forecasting history, if available, to be the best methodology for forecasting labour price growth. We, and DAE, have previously undertaken analysis that found that DAE under-forecast utilities labour price growth at the national level. The analysis also found that BIS Shrapnel over-forecast price growth and by a greater margin.[65]

United Energy engaged BIS Shrapnel to develop forecasts of growth in the WPI for the utilities industry. BIS Shrapnel forecast average annual growth to exceed the long-term average. We compared the labour price growth forecasts from BIS Shrapnel against the forecasts from DAE and the historic average price growth rate (Table B.6).

Table B.6 Forecast annual WPI growth, Victoria, EGWWS (per cent)

	2016	2017	2018	2019	2020	Average
DAE	–0.2	0.3	0.8	0.9	0.9	0.5
BIS Shrapnel	0.9	1.3	1.8	2.1	1.8	1.6

Source: DAE; BIS Shrapnel; ABS.

The forecast 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 DAE are lower, on average, than the historic average rate. WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, are currently at the lowest level on record.[66]

65 AER, *Powerlink transmission determination 2012–17, Final decision*, p. 54, April 2012.

66 ABS, Catalogue 6345.0, Table 9b.

Given this, we consider it more likely that the average WPI growth rate over the forecast period will be lower than the historic average. The CCP also noted that wage growth is at historic lows.[67] Related to this, the Victorian Energy Consumer and User Alliance stated that the electricity network sector is in contraction and that 'industries in contraction do not face real labour price increasing drivers'.[68]

Consequently we consider it likely that DAE's forecasts will be the most accurate of both consultants' forecasts because they better reflect current labour market conditions. Again this is consistent with our previous analysis that found that DAE's forecast of utilities WPI growth were closer to actual WPI growth than BIS Shrapnel's. Given our previous analysis found an average of the forecast from DAE and BIS Shrapnel was closest to actual WPI growth we consider an average of BIS Shrapnel's and DAE's forecasts would produce the best forecast available of the growth in the Victorian utilities WPI.

B.4.3 Forecast output growth

We are not satisfied United Energy's proposed average annual output growth of 1.1 per cent for the 2016–20 regulatory control period reflects the increase in output an efficient service provider requires to meet its opex objectives. We forecast an average annual output growth of 0.7 per cent for the 2016–20 regulatory control period.

United Energy adopted our approach to forecasting output growth. The difference between its output growth forecast and our own arises because we are not satisfied that United Energy's forecasts of maximum demand reflect a realistic expectation of the demand forecast required to achieve the opex objectives

Our approach to forecasting output growth

We have adopted the following output growth measures and weightings:

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

These output measures are consistent with the output variables used by Economic Insights to measure productivity in its opex cost function analysis. This approach is consistent with the Guideline. United Energy also adopted these output measures.

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

1. The output aligns with the NEL and NER objectives.

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67 CCP, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, p. 29.

68 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 42.

2. The output reflects services provided to customers.
3. Only significant outputs should be included.

Economic Insights discusses the process for selecting the output specification in its economic benchmarking assessment of opex for the NSW and ACT electricity distributors.[69]

We note that, while VECUA had some issues with our approach to forecasting output growth, it considered that overall our approach is more reflective of the change in outputs required than the approaches proposed by the Victorian service providers.[70]

Forecast growth in peak demand

We used the forecast customer numbers and circuit length reported by United Energy in its reset RIN. This produces an average annual growth rate of 0.97 per cent for customer numbers and 0.46 per cent for circuit length.

However, we have not used the forecast maximum demand numbers reported by United Energy in its reset RIN. The Ethnic Community Council of Victoria, the Victorian Energy Consumer and User Alliance, and the Victorian Greenhouse Alliances all noted that the Victorian service providers' peak demand forecasts were higher than those forecast by AEMO.[71] The Victorian Energy Consumer and User Alliance also noted that the Victorian distributors' past peak demand forecasts 'were subsequently proven to be overblown'. It also stated it was concerned that AEMO has consistently overestimated its energy forecasts in recent years.[72]

For the reasons discussed in attachment 6, appendix C, we are not satisfied that United Energy's forecasts of maximum demand reflect a realistic expectation of the demand forecast required to achieve the opex objectives. Instead we have used AEMO's 2014 transmission connection point maximum demand forecasts.[73] AEMO forecasts no growth in maximum demand

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69 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, pp. 9, 10.

70 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 45.

71 Ethnic Community Council of Victoria, *Submission to the Australian Energy Regulator Victoria Electricity Pricing Review*, 15 July 2015, p. 1; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 14; Victorian Greenhouse Alliances, *Local Government Response to the Victorian Electricity Distribution Price Review 2016-20*, 15 July 2015, p. 32.

72 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 15.

73 http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting/Transmission-Connection-Point-Forecasting-Report-for-Victoria.

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. We base this on our expectations of the forecast productivity for an efficient service provider in the short to medium term. This is consistent with Economic Insights' recommendation to apply zero forecast productivity growth for other distribution network service providers such as Ergon Energy. [74]

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.[75]

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

To reach our best estimate of forecast productivity we have 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 have applied a zero productivity forecast for United Energy for the following reasons:

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

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

Forecast outlook and historical productivity

As noted above, forecast productivity is our best estimate of the shift in the frontier for an efficient service provider. Typically we consider the best forecast of this shift would

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

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

be based on recent data. However, this requires a business as usual situation where the historical data is representative of what is likely to occur in the forecast period.[76]

Analysis from Economic Insights using MTFP and opex cost function models showed that from 2006 to 2013, the distribution industry experienced negative productivity growth.[77] This means that the distribution industry inputs specified under the models increased at a greater rate than the measured outputs.

According to Economic Insights' modelling, the average annual output growth from 2010 to 2013 for the distribution industry was 0.6 per cent. During this period, the output measures of customer numbers and circuit length grew by 1.2 per cent and 0.5 per cent respectively. Maximum demand decreased by 4.1 per cent from its peak in 2009.[78] However, total input quantity increased by 2.8 per cent per annum from 2010 to 2013.[79] This has been driven by substantial increases in both opex and capital inputs.

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

We note that in Victoria for the 2011–2015 period, the increase in regulatory obligations related to bushfires was forecast to be 9.0 per cent of total opex.[80] We consider the increase in bushfire safety requirements to be a one off step increase in the cost of compliance. We also approved a $35.5 million ($2009–10) step change for SA Power Network's vegetation clearance pass through as a result of changing weather conditions.[81]

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76 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 41.

77 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 20, 40.

78 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 44–45.

79 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 45.

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

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

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

The VECUA considered that the distributors' productivity declined during the previous regulatory period because we provided excessive opex allowances. It considered this should not be used to justify poor productivity outcomes in future years.[82] We agree that the productivity performance we have seen in the 2006–13 period should not be used as the basis for forecasting productivity in the 2016–20 period, for the reasons above. In part this is due to step changes resulting from new regulatory obligations that were introduced in this period.

Other industries and proposed productivity

In estimating forecast productivity for the distribution industry we have also had regard to the electricity transmission and gas distribution industry and distribution network service provider's productivity forecasts.[83]

Measured declines in productivity in the electricity distribution sector are unlikely to reflect longer term trends. Economic Insights notes:[84]

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

As noted by VECUA, both the electricity transmission and gas distribution industries experienced positive opex productivity growth during the 2006–13 period.[85] For electricity transmission network service providers average annual industry productivity growth was 0.85 per cent and for gas distribution Jemena Gas Networks proposed an average annual opex productivity growth of 0.95 per cent of which 0.83 per cent was attributed to the shift in the frontier.[86]

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[82] Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, pp. 45–46.

[83] This includes productivity forecasts from Endeavour Energy, Essential Energy, ActewAGL, Ausgrid, Ergon Energy, Energex and SA Power Networks.

[84] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 56.

[85] Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 46.
AER, *TransGrid transmission determination – draft decision*, Attachment 7, Appendix A, November 2014; AER, *JGN gas distribution determination – draft decision*, Attachment 7, Appendix A, November 2014.

[86] AER, *JGN gas distribution determination – draft decision*, Attachment 7, Appendix A, November 2014.

Cyclical factors and regulatory obligations for the distribution sector may be the reason for the lower measured productivity in the distribution industry compared to the transmission and gas distribution industries. Over the medium to long term, however, we expect the distribution network service providers to have underlying productivity growth rates comparable to the electricity transmission and gas distribution industries. This is because the specific factors that have resulted in declining productivity for the distribution industry are unlikely to apply over the medium to long term and the distribution industry should be broadly similar to other energy networks. In the absence of information suggesting when this return to positive productivity growth will occur we are satisfied that the best forecast of productivity growth is zero.

VECUA noted some of its participants operate within asset intensive industry sectors that have delivered positive opex productivity growth during the 2006–13 period. It did not accept that there is any justification for the electricity distribution sector to have lower productivity expectations than those sectors. It therefore expected us to determine positive productivity growth rates for the Victorian distributors, aimed at bringing their productivity back into line with their previous productivity levels, and into line with the levels being achieved by the electricity transmission sector and other asset intensive industry sectors. [87]

Similarly, DEDJTR expected that firms operating in a competitive environment should achieve some productivity improvements. It stated the EBSS should reward service providers for productivity improvements that are greater than those expected in a business as usual environment. They should not be rewarded for achieving a business as usual level of productivity growth.[88] We agree that service providers should not be rewarded for achieving a business as usual level of productivity growth. Consistent with the Guideline, we have forecast productivity growth as the best estimate of the shift in the productivity frontier.[89]

DEDJTR also expected an additional level of productivity growth associated with the rollout of smart meters so that the service providers' customers realise the benefits for their investment in the smart meter rollout.[90] DEDJTR stated that:

> The Victorian Government has recently undertaken an independent assessment of the benefits of the AMI program realised to date and likely to be realised over the longer term. This work shows that the benefits associated with the installation of the smart meters have now largely been realised and that the value added benefits, which are now a focus of the program, are starting to be realised. Further benefits are expected to be realised over the next regulatory control period, subject to actions being taken and some risks.

87 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2105, pp. 45–46.

88 DEDJTR, *Submission to Victorian electricity distribution pricing review*, 13 July 2015, p. 8.

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

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

To the extent that the AMI rollout is mostly complete and the associated benefits have now largely been realised those benefits will be reflected in the service providers' base year expenditure. DEDJTR did not identify or quantify the 'value added benefits' or the further benefits it expects to be realised over the 2016–20 regulatory control period. Without this information we cannot incorporate them into our opex forecast. We note that DEDJTR did not provide us the independent assessment of the benefits of the AMI program that it referred to.

The CCP stated that we should review the purpose and application of the productivity growth forecast in the rate of change. It stated we should consider the impact of the forecast productivity growth with the benchmarking analysis and the EBSS incentives.[91] We consider that the incentive to minimise opex is primarily set at the margin. We designed the EBSS to work with the ex-ante opex and our opex forecasting approach to provide a continuous incentive at the margin. We designed the incentive to balance the incentive to reduce capex and maintain the level of service. The incentive at the margin is unaffected by the forecast productivity growth, to the extent it is not based on the individual NSPs own historic productivity growth. The CCP seem to suggest that overly generous opex allowances reduce this incentive. We agree that overly generous opex allowances may reduce the incentive to reduce opex. We do not see this as a productivity growth forecast issue but a total opex forecasting issue. We think it equally applies to all components of our opex forecasting approach.

91 CCP, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, pp. 40–41.

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.5 Position

We have included one step change in our opex forecast. We are satisfied the additional opex associated with United Energy's aerial inspection of pole top structures program is an efficient capex/opex trade-off.

We also consider the amendments to Electric Line Clearance (ELC) Regulations 2015, published 28 June 2015, may result in a change in costs. Some amendments may result in an increase in costs and other amendments may result in a decrease in costs. Given the uncertainty around the net impact of these changes we have not included any changes in costs for this step change at this time.

We did not consider other step changes United Energy proposed should affect our opex forecast.

A summary of United Energy's proposed step changes and our position is outlined in Table C.1.

Table C.1 Preliminary position on step changes ($ million, 2015)

	United Energy proposal	AER position
New regulatory obligations		
Power of Choice – Metering competition	3.5	–
Power of Choice – Customer access to data	1.7	–
Power of Choice – Embedded network	0.7	–
Power of Choice – Demand management IT Platform	1.6	–
Power of Choice – Network	3.5	–
Regulatory Information Notice reporting	1.6	–

	United Energy proposal	AER position
Energy Safe Victoria safety obligations	1.0	–
Energy Safe Victoria rule changes	72.5[92]	0.0 [a]
Customer response/initiated		
Effortless Customer Experience program	6.0	–
Stakeholder engagement	1.3	–
Council trees	3.0	–
Existing regulatory obligations – recurrent but non-annual		
Customer charter	0.7	–
Regulatory submission cost	-5.2[93]	–
Neutral testing	0.4	–
Network planning and analytics – IT Capital Program	4.1	–
Guideline 11 EWOV direction	4.5	–
Change in external environment		
IT security costs	4.0	–
Insurance premiums	2.3	–
Capex/opex trade-off		
Pole top inspection	2.4	2.4
Real price escalations	0.5	–[94]
Total	**112.4**[95]	**2.4**

Source: United Energy, *Operating expenditure overview*, 30 April 2015, p. 23 and AER analysis.

Note: a: Energy Safe Victoria rule changes are a new regulatory obligation that may give rise to a justifiable step change. However, on the basis of the information and evidence United Energy has provided so far, we do not have sufficient material to form a view as to the quantum of an efficient opex step change.

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92 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.

93 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.

94 We apply price growth in our rate of change to base opex and step changes rather than applying a step change specific labour escalation.

95 United Energy proposed $53.8 million in its initial proposal. This total takes into account the updated Energy Safe Victoria rule change proposal and the net impact of regulatory submission costs.

C.6 United Energy's proposal

United Energy identified step changes for costs it will incur during the 2016–20 regulatory control period. United Energy grouped its step changes into the following categories:

- New regulatory obligations – for new on-going, externally-imposed regulatory obligations that require United Energy to increase its opex
- Customer response/initiated – for step changes that respond to specific customer requests or needs that are not reflected in its base year
- Existing regulatory obligations that are recurrent but non-annual – step changes from existing obligations that, because they are recurrent but non-annual in nature, are not reflected in United Energy's base year
- Change in external environment – for step changes that respond to exogenous changes that are not reflected in its base year
- Capex/opex trade-off[96] – for step changes that relate to movements between capex and opex. [97]

C.7 Assessment approach

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.[98] Our assessment approach specified in the *Expenditure forecast assessment guideline* (Guideline)[99] and is more fully described at pages 9 to 18 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

96 United Energy, *Operating expenditure overview*, 30 April 2015, p. 22.

97 United Energy, *Operating expenditure overview*, 30 April 2015, p. 22.

98 NER, cll. 6.5.6(c).

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

in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.

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

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output then step changes that relate to forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of additional office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year which includes office maintenance) to account for forecast network growth.[100]

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

Further, to assess whether step changes are captured in other elements of our opex forecast, we will assess the reasons for, and the efficient level of, the incremental costs (relative to that funded by base opex and the rate of change) that the service provider has proposed. In particular, we have regard to:[101]

- 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

[100] AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, p. 73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp, 164-165.

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

- whether the option selected was the most efficient option—that is, whether the service provider took appropriate steps to minimise its expected cost of compliance
- the efficient costs associated with the step change and whether the proposal appropriately quantified all costs savings and benefits
- when this change event occurs and when it is efficient to incur expenditure, including whether it can be completed over the regulatory period
- whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.

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

Usually increases in costs are not required for discretionary changes in inputs.[102] 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.[103] 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.

In their submissions, the Energy Retailers Association of Australia (ERAA) and Origin Energy both support the AER assessing proposed step changes in opex consistently across distributors and jurisdictions.[104] We agree with these submissions as our step

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

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

[104] ERRA, *Submission to the Victorian electricity distribution pricing review 2016–2020*, 13 July 2015, p. 1; Origin Energy, *Submission to Victorian Electricity Distributors Regulatory Proposals*, 13 July 2015, pp. 4, 5.

change assessment approach is relevant for all network service providers. Origin considers that the approach the AER has taken to date ensures only efficient costs are included in the forecast allowances and removes the potential for double counting.

In its submission, the Consumer Challenge Panel considered we need to undertake further examination of the step change mechanism. It stated that it has become a catchall for any actual or perceived risk of cost increases and against the principle of a high level assessment when networks are proposing up to nineteen separate step changes.[105] We agree that step changes should not be included for all cost increases. We have examined each of the step changes according to our assessment approach and have included only those step changes that are needed for the total opex forecast to reasonably reflect the opex criteria.

C.8 Reasons for position

We have only included one of the nineteen step changes United Energy proposed in our alternative opex forecast.

Many of the changes United Energy proposed relate to discretionary business decisions about how to deliver services to its customers. 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. United Energy should accommodate discretionary spending within its existing opex rather than fund these projects through an increase in total opex.

Some proposed step changes United Energy linked to obligations which are yet to be imposed on United Energy. Where there is uncertainty about the nature and scope of what the regulatory obligation will be, we do not consider it is robust to incorporate a step change in our forecast. We note that where a change in United Energy's regulatory obligations does materially affect its opex in the future, it may qualify as a pass through event.

C.8.1 New regulatory obligation step changes

This section discusses the eight step changes that United Energy has classified as related to new on-going, externally-imposed regulatory obligations.[106]

Power of Choice

We have not included United Energy's proposed step changes related to the Power of Choice reforms in our total opex forecast.

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[105] Consumer Challenge Panel, sub panel 3, *Response to proposals from Victorian electricity distribution network service providers - overview - 10 August 2015*, p. 5.

[106] United Energy, *Operating expenditure overview*, 30 April 2015, p. 22.

United Energy included a range of step changes relating to Power of Choice reforms that have not been finalised. This includes:

- metering competition
- customer access to data
- embedded network
- demand management IT capital program.

Given the uncertainty at this time around what the Power of Choice reforms will require United Energy to implement, we have not included these proposals as step changes in our opex forecast. Should the AEMC make the final Power of Choice rule changes and United Energy takes the final rules into account in its revised proposal, we will assess the revised costs accordingly. If the reforms are not finalised prior to our final decision in April next year, then United Energy has the option of applying for a pass through amount under the regulatory change event or service standard event. We note Jemena, CitiPower, Powercor and AusNet proposed a nominated pass through event for Power of Choice related costs due to the uncertainty surrounding the changes to their roles and responsibilities.[107]

Our decision to not include United Energy's Power of Choice step changes is consistent with our capex assessment. We did not include the capex associated with power of choice because there is uncertainty around the costs. United Energy itself noted that detailed requirements are not available at this stage in each of its project justification documents.[108]

Power of choice – Network (Chapter 5 and Chapter 5A Rule change – Embedded Generation Connection, including solar)

We have not included a $3.5 million step change for changes to Chapter 5 and 5A of the NER. We consider the most of increase in costs can be recovered through enquiry fees. We would not expect that any other change in costs would be material.

We note United Energy referred to this as a Power of Choice related step change. The driver of this step change is the rule changes made to Chapter 5 and Chapter 5A of the NER made by the AEMC. These are not a part of the Power of Choice reforms.[109] For this reason we have assessed this step change separately to the other proposed Power of Choice step changes.

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[107] AusNet Services, *Electricity Distribution Price Review 2016–20*, 30 April 2015, p. 59. CitiPower, *CitiPower regulatory proposal 2016–20*, p. 261 and Powercor, *Powercor regulatory proposal 2016–20*, p. 269. Jemena, *2016–20 Electricity distribution price review regulatory proposal attachment 5–4*, 30 April 2015, p. 15.

[108] For example United Energy, *Project justification – Power of Choice – Metering Competition (PJ19)*, 12 March 2015, p. 10.

[109] AEMC, *Rule determination National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014.

In April 2014 the AEMC made a rule change to Chapter 5 that addressed the difficulties in embedded generator proponents trying to connect. The AEMC considered that compliance with these new requirements would come at some cost for distributors.[110] The AEMC made a separate rule change to Chapter 5A in November 2014 and noted that embedded generator proponents may elect to use Chapter 5 instead of Chapter 5A if they wish to do so.[111] Changes to Chapter 5 commenced on 1 October 2014 and Chapter 5A commenced on 1 March 2015.

Amendments to Chapters 5 and 5A

The amendments to Chapter 5 are:

- distributors are now required to publish an 'information pack' setting out information to guide embedded generator proponents on matters such as the process requirements and potential costs
- distributors are now required to publish a register of generating plants that have been successfully connected to the network in the preceding five years to allow embedded generator proponents to better understand the types of equipment that have been able to connect to a distribution network
- the introduction of a two-stage connection enquiry process consisting of a preliminary enquiry stage followed by a detailed enquiry stage which set out explicit time frames and information requirements.[112] Previously there was a one-stage enquiry process which was less prescriptive
- the introduction of clear, relevant information requirements and timeframes for both parties at each stage of the connection process
- clarifying that the existing dispute resolution process set out in the NER is applicable to technical issues as well as other matters arising during a connection process.[113]

The change to Chapter 5A aligns the information requirements with Chapter 5 in regard to the information that is to be published by the distributors.[114] The final rule change also prescribes additional information requirements that distributors are to provide on their website on possible connection charges and fees, general technical

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110 AEMC, *Rule determination National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014, p. i.

111 AEMC, *Rule determination National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014, p. iii.

112 Previously there was a one-stage enquiry process which was less prescriptive. AEMC, *Rule determination National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014, pp. 58–59, pp. 72–73.

113 AEMC, *Rule determination National Electricity Amendment (Connecting Embedded Generators) Rule 2014*, 17 April 2014, p. 6.

114 AEMC, *Rule determination National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014*, 13 November 2014, p. 79

information and a register of generating plants which is similar to provisions in Chapter 5.[115]

Assessment of incremental efficient costs of Chapter 5 and 5A amendments

Consistent with the AEMC, we expect the distributors to incur an increase in costs to comply with the increased information requirements. However, United Energy's forecast is driven by increases in enquiries which can be recovered through an enquiry fee as opposed to a cost imposed across all customers. The Chapter 5 embedded generator connection process specifically permits distributors to charge a fee to the embedded generator proponent to recover the reasonable costs incurred to respond to a detailed enquiry.[116]

We note the requirement to publish an information pack relating to the enquiries process may not be recoverable through an enquiry fee. However, we consider this one off requirement to publish the information is not a material increase in United Energy's existing regulatory requirements to comply with Chapter 5 and 5A. This information pack would be drawn from existing information available to United Energy.

United Energy's claims about a significant additional cost associated with the changes to Chapter 5A also do not appear to be consistent with the AEMC's observations about the additional regulatory burden. The AEMC did not make significant changes to Chapter 5A. It stated that:

> The negotiation connection process in Chapter 5A provides a flexible and potentially shorter process that may be relevant for some embedded generator proponents. For this reason, it should remain in place.[117]

We have also considered the costs proposed by United Energy for this step change and we also have issues with United Energy's forecasting methodology.

To forecast the annual cost of the step change United Energy calculated the forecast increase in costs required in 2020. This is based on the forecast number of connections in 2020 multiplied by the numbers of hours for each enquiry. It estimated the increase in costs to be $0.7 million.

United Energy's forecast demand in 2020 for Chapter 5A enquiries is 150 per cent higher than 2015 demand. We do not consider it is reasonable for United Energy to forecast its 2016–20 costs using 2020 demand figures. This approach overstates the number of connections in each year prior to 2020.

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115 AEMC, *Rule determination National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014*, 13 November 2014, p. iii.

116 AEMC, *Rule determination National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014*, 13 November 2014, p. 82.

117 AEMC, *Rule determination National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014*, 13 November 2014, p. iii.

Regulatory Information Notice reporting

We have not included a step change of $1.6 million ($2015) for RIN reporting in United Energy's total opex forecast.

United Energy is required to report information to the AER through annual, economic benchmarking and category analysis RINs. As of 2016, we require RIN reporting to be based on actual rather than estimated data. United Energy stated the step change is to make changes to its IT systems and business processes and for new and modified work practices needed to meet our requirements for actual data.[118] The increase in opex was linked to additional ICT capex of $24.3 million ($2015).

As outlined in appendix B to the capex attachment 6, we have not included the proposed capex in our forecast. We consider the main driver for the project is United Energy's need to improve asset management data in line with industry practice, rather than comply with the RIN reporting obligation. In our capex assessment, we state United Energy did not make the necessary system upgrades to achieve this when the same systems were replaced in the 2011–2015 regulatory control period. As the proposed step change in opex depends on the forecast increase in capex, we have also not included the step change in our opex forecast.

Energy Safe Victoria safety obligations

We have not included a step change for "Energy Safe Victoria's (ESV) safety obligations". We do not consider there has been any change to the ESV's audit requirements.

United Energy proposed this step change to comply with what it considers to be more rigorous approach to audits the ESV introduced in late 2014. The proposed cost of this step change is $1 million ($2015).[119]

United Energy based its forecast costs on the opinion of former ESV staff now employed by United Energy.[120]

To assess the expenditure we requested United Energy's correspondence with ESV regarding the ESV's intention to apply a more rigorous audit program. In response, United Energy provided details of all of the ESV's audit programs.[121]

We found no information to indicate that the ESV's intends to adopt a more rigorous audit program. We confirmed this with the ESV which stated that:

> ESV confirms that it has no plans to introduce a more onerous audit program in a matter that would have any substantial impact on MECs. ESV further

[118] United Energy, *Operating expenditure overview*, 30 April 2015, p. 29.
[119] United Energy, *Operating expenditure overview*, 30 April 2015, pp. 30–31.
[120] United Energy, *Operating expenditure overview*, 30 April 2015, p. 31.
[121] United Energy, *Response to information request IR#009*, 15 July 2015.

> suggests that any change to audit practice would have no substantive effect on any of the MECs. The businesses are already legally obliged to comply with the regulation.[122]

Based on the information provided by the ESV, we do not consider there has been a change in regulatory obligations for the ESV's audit program.

Energy Safe Victoria rule changes

At this preliminary decision stage, we have not included a step change for Energy Safe Victoria (ESV) rule changes in our total opex forecast. We consider the change in costs at this stage is uncertain. We expect United Energy's revised proposal for this step change to take into account both cost increases and cost decreases to comply with the new requirements.

United Energy initially proposed an $8.7 million ($2015) step change to comply with the Electrical Safety (Electric Line Clearance) Regulations 2015 (ELC).

This forecast was based on United Energy's expectation that there would be minimal changes to ELC 2010. United Energy reserved the right to increase its step change if the ESV's final ELC 2015 was significantly different to ELC 2010.[123]

On 28 June 2015, the new amendments commenced in Victoria. We subsequently sent an information request to all Victorian distributors requesting updated information on costs to comply with ELC 2015.[124] In response to our information request United Energy revised its step change to $72.5 million ($2015).[125]

The two drivers of the proposed increase in costs related to:

- compliance with AS4373 "Pruning of amenity trees" ($37.5 million)
- notification and consultation requirements ($35 million).

United Energy stated that it was concerned that the benefits of the new practices did not justify the increase in costs and encouraged us to consult with the ESV.[126]

We have consulted with the ESV in regards to United Energy's interpretation of ELC 2015. The ESV considers that United Energy's $72.5 million cost estimate does not reflect the undertaking made by ESV during consultation that the regulations would be administered in a way that would achieve a practical outcome. The ESV expressed its intention to issue guidance notes on how it will administer ELC 2015.[127] The ESV also

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[122] Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, p. 1.
[123] United Energy, *Operating expenditure overview*, 30 April 2015, p. 31.
[124] AER, *United Energy information request IR#00 9*, 1 July 2015.
[125] United Energy, *Response to information request IR#009*, 21 July 2015, p. 1.
[126] United Energy, *Response to information request IR#009*, 21 July 2015, p. 2.
[127] Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, pp. 1–2.

noted that United Energy's $72.5 million increase in costs to comply were substantially higher than United Energy's original estimates of $300,000 for enhanced notification and $500,000 for meeting amenity standard AS 4373.[128] Based on the feedback from the ESV we do not consider United Energy's revised cost of $72.5 million reflects a reasonable estimate of the change in compliance cost for ELC 2015.

The ESV also noted that it also made amendments to reintroduce exceptions for structural tree branches in relation to both insulated and uninsulated electric lines which returns the flexibility of ELC 2005 where practicable. [129] This exception allows for reduced clearance distances to be adopted on the condition that appropriate risk mitigation activities are carried out to ensure that an equivalent safety outcome was achieved despite the reduced clearance dimension.[130] The ESV considered that the removal of these exceptions in ELC 2010 increased costs over time and expects that the reintroduction of these exceptions in ELC 2015 should decrease pruning costs over time.[131]

In our determination for the 2011–15 regulatory control period United Energy was provided with a $9.1 million ($2010) step change for the removal of the structural tree branches exceptions. Since the ESV has now reversed this change, this is a symmetrical decrease in regulatory obligations from the 2010 changes so we would expect a similar decrease in costs to the increase allowed for in the 2011–15 regulatory control period. The Consumer Challenge Panel (CCP) also noted that the 2010 amendments to vegetation management are being reviewed and consider these change may have a significant impact on opex over the 2016–20 regulatory control period.[132]

We have recognised that there are potentially both cost increases and cost decreases associated with the ELC 2015 amendments but the net impact of the changes are unclear at this stage. For this reason we have not included any change in costs for this step change in our preliminary decision opex forecast. Following further guidance from the ESV we expect United Energy's revised proposal to reflect the manner in which the ESV will administer its rules. The revised proposal should also clearly discuss any cost savings from the reinstatement of insulated cable exceptions as well as cost increases for new pruning and notification requirements.

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128 Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, pp. 1–2.

129 Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, p. 4.

130 Jaguar Consulting, *Regulatory Impact Statement Electricity Safety (Electric Line Clearance) Regulations 2015*, September 2014, p. 41.

131 Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, p. 4.

132 Consumer Challenge Panel, *Consumer challenge panel sub panel 3 response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 5 August 2015, p. 23.

Our final decision on this step change will take all these factors into account in coming up with the overall change in costs to comply with ELC 2015.

C.8.2 Customer response or customer initiated

This section discusses the three step changes that United Energy has classified as responding to customer requests or needs that are not reflected in its base year opex.

Effortless customer experience program

We have not included a step change in our opex forecast for United Energy's effortless customer experience program (ECE).

United Energy proposed an increase of $6 million ($2015) for this step change.[133] United Energy noted that the ECE is a company-wide transformation program that focuses on delivering an effortless experience to its customers during all customer transactions. United Energy proposed to deliver systems, update business processes, improve customer data management and roll-out customer service training. [134]

United Energy identified three drivers for this step change:

1. External: New regulatory requirements to:
    (a) manage contractual arrangements with customers and record their provision of explicit informed consent to contractual arrangements
    (b) capture and report on customer transactions to meet RIN reporting requirements.
2. Internal: Effortless customer experience program to improve consumer and stakeholder engagement.
3. Internal: Service improvements and operational efficiencies to counter escalating costs associated with the increasing volume of customer interactions.[135]

We consider this step change is a discretionary activity. Improving its customer services is a matter for United Energy to consider when weighing up all the priorities it faces. As outlined above these are not matters for which we typically increase a service provider's funding. Discretionary expenditure should be managed within a service provider's existing budget rather than be funded through an increase in prices. This was a similar point made by the VECUA in its submission.[136]

We also have a number of additional issues with this proposal.

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133 United Energy, *Operating expenditure overview*, 30 April 2015, p. 33.
134 United Energy, *Operating expenditure overview*, 30 April 2015, p. 33.
135 United Energy, *Operating expenditure overview*, 30 April 2015, p. 34.
136 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian distribution networks' 2016–20 revenue proposals*, 13 July 2015, p. 38, p. 49.

- United Energy did not identify the nature of the new regulatory requirements in its step change justification nor the cost of complying with these regulatory obligations. We note the only regulatory requirements United Energy referred to in its regulatory proposal is the cost benefit analysis for the capex related to the ECE. United Energy noted that it related to the cost of complying with Power of Choice regulatory requirements and data requirements to support RIN reporting.[137] It is not clear if there is any double counting of costs with these proposals. As outlined above, we have not included a step change in our opex forecast for RIN reporting requirements.
- It is also not clear how this step change will improve customer service. The benefits of the ECE identified by United Energy are broad and do not provide detail on how it addresses specific customer needs.
- United Energy noted that the ECE is based on feedback provided by customers through United Energy's stakeholder engagement but did not provide any detail of how it formed this view. We note that VECUA considered that the distributors need to provide clear evidence of all of their claims regarding consumer preferences.[138]
- Several of the benefits attached to the ECE program appear to benefit United Energy - for example, process efficiencies through reduced customer call and administrative costs to reduce the number of complaints. These operational efficiencies improvements do not appear to have been factored into the total forecast costs of the ECE.

Stakeholder engagement

We have not included a step change in opex for consumer engagement costs as part of our alternative opex forecast. We consider a prudent service provider would already be undertaking the level of consumer engagement commensurate with the rule requirements and so would not need an increase in its forecast total opex.

United Energy 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
- a second role focused on engaging stakeholders about future capital projects.[139]

Changes to the NER in late 2012 required service providers to describe how they have engaged with consumers, and how they have sought to address any relevant concerns

137 United Energy, Project justification – customer relationship management (PJ03), 10 March 2015, pp. 5, 9.

138 Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian distribution networks' 2016–20 revenue proposals*, 13 July 2015, p. 52.

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

identified as a result of that engagement. United Energy was required to present this information in an overview report with its regulatory proposal.[140] We do not consider this requirement is onerous.

Notwithstanding the rule change, we would expect a prudent service provider would already have programs in place to engage with consumers. For instance, we expect that a distribution network service provider would already be engaging closely with relevant consumers as part of its reset process to help understand their preferences around prices, reliability and service standards. We consider base opex should already provide sufficient funding for United Energy to undertake customer interaction, complaint handling and the like, as well as interaction with consumer groups.

VECUA also considers that the distributors' base year opex allowance provides them with sufficient funds to fulfil the expectations of the AER's consumer engagement guideline.[141]

Council trees

We have not included a step change in opex forecast for council trees.

United Energy proposed a $3 million ($2015) step change for a non-recurrent three year program to assist local councils in clearing their existing backlog of tree cutting.[142]

United Energy proposed this step change because of a specific need identified by local councils. United Energy also noted that it would only undertake this work if the step change was approved and local councils ask United Energy to undertake specific work.[143]

In any case we do not consider it is in the long term interests of consumers to pay for United Energy to assist local council to clear their backlog of tree cutting. We consider if local councils want to draw on United Energy's expertise in managing vegetation management then the local councils that require the service should pay for it. The council trees to be cut are not United Energy's responsibility. The costs associated with providing assistance to councils would be an unregulated service.

C.8.3 Existing regulatory obligations

United Energy proposed five step changes which it has classified as existing regulatory obligations that are recurrent but non-annual and are not reflect in its base year opex.

Our reasons for position and assessment for each step change is discussed below.

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

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

142 United Energy, *Operating expenditure overview*, 30 April 2015, p. 36.

143 United Energy, *Operating expenditure overview*, 30 April 2015, p. 36.

Customer charter, regulatory submission costs and neutral testing

We have not included an increase in opex for United Energy's customer charter in our alternative opex forecast.

Clause 9.1.2(b) of the Electricity Distribution Code requires United Energy to provide a customer charter to each customer at least once every five years.[144] The charter must summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:

- the identity of the distributor
- the distributor's guaranteed service levels
- other aspects of the customer's relationship under the Electricity Distribution Code and other applicable laws and codes.

United Energy last provided a customer charter to all its customers in 2012. It proposed an increase in opex of $0.7 million to provide its customer charter in 2017.[145]

This is a forecast non-recurrent increase in opex rather than new or changed regulatory obligation. We do not typically include non-recurrent increases in opex in our opex forecast. While categories of opex vary over time, total opex is relatively recurrent. We forecast future opex based on the total actual opex incurred by a service provider in single year. The year United Energy proposed and we chose was 2014. We consider the total amount of opex United Energy incurred in 2014 provides a good basis for forecasting its opex in the 2016–20 regulatory control period. We do not consider that identifying one relatively minor non-recurrent increase in opex in the forward period is a good reason to depart from using a base year approach and allow a step change to base level of opex. For instance there are likely to have been several other costs incurred in the base year that were non-recurrent, or slightly higher than average.

To be consistent with this general forecasting approach, we have also not used category specific forecasts in other areas.

For the same reasons, we have not included a step change for regulatory submission costs (-$5.2 million) [146] and neutral testing ($0.4 million). United Energy noted that under Electricity Safety (Network Assets) Regulations 1999 it was required to inspect earthing systems every 10 years. We have instead left these categories of opex in the base.

We also consider there should be productivity benefits to United Energy's new approach of conducting integrity testing by using an intelligent software solution to

144 Essential Services Commission of Victoria, *Electricity Distribution Code*, May 2012, p. 25.

145 United Energy, *Operating expenditure overview*, 30 April 2015, p. 37.

146 United Energy proposed a step increase of $2.3 million but removed $1.5 million from its base opex for a net impact of -$5.2 million.

detect neutral integrity issues. Therefore no step change is required. United Energy noted that this approach will avoid the need for routine site visits.[147]

Network planning and analytics – IT capital program

We have not included an increase in opex for United Energy's network planning and analytics – ICT capital program step change.

United Energy proposed an increase in opex of $4.1 million ($2015) for this step change. United Energy noted that the driver of this step change is opex associated with network planning and analytics capex. This will enable United Energy 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.[148]

The driver of this step change is not a change in regulatory obligation but rather enabling United Energy to maintain its current services and avoid increased opex. We consider base opex is sufficient for United Energy to maintain the quality, reliability and security of the supply of standard control services. We would expect this should be a business as usual expense for a prudent and efficient service provider.

Guideline 11 EWOV direction

We have not included an increase in opex for United Energy's Guideline 11 Energy and Water Ombudsman (EWOV) direction. We do not consider the clarification provided by EWOV in regards to how United Energy should comply with Guideline 11 results in a change to United Energy's regulatory obligations.

United Energy proposed $4.5 million to comply with ESCV's Electricity Industry Guideline No. 11 voltage variation compensation. In previous years United Energy interpreted that payments associated with acts outside of its control (e.g. weather, animal, bird) were not eligible. Recent position statements from EWOV have clarified that United Energy is required to make compensation payments for all voltage variations, regardless of the cause of the variation.[149]

We do not consider it is reasonable to include a relatively minor increase in opex to meet an existing regulatory obligation. Providing a step change for when a distributor is not meeting existing regulatory obligations may provide an incentive for distributors to not comply with regulatory obligations and seek a step change in its next regulatory determination. This incentive is not consistent with the revenue and pricing principles where the service provider should be provided with effective incentives to promote economic efficiency.[150]

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147 United Energy, *Operating expenditure overview*, 30 April 2015, p. 39.

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

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

150 NEL, s. 7A.

We also consider United Energy has overstated the costs associated with compliance. United Energy's forecast is based on the total number of complaints multiplied by the average cost of claims United Energy less EWOV complaint costs. This assumes that United Energy does not actually make any payments to its customers affected by voltage variations. We do not consider this to be the case because the EWOV direction only relates to claims over $1,000. We would expect that United Energy would already be paying compensation for claims below $1,000.

C.8.4 Change in external environment

This section discusses the two step changes United Energy has classified as responding to exogenous changes that are not reflected in its base year opex.

IT security costs

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

United Energy proposed $4 million ($2015) for IT security costs. This step change is for opex linked to its 'Security program' ICT capital project to manage and maintain the operational risks related to information security.[151]

The level and form of IT security monitoring United Energy undertakes is a discretionary business decision. However, as with many types of expenditure, United Energy has flexibility as to how much it spends in this area.

We agree from time to time a service provider may wish to increase its opex on particular programs of expenditure where there are increased risks. Monitoring IT security may be one such area where a service provider wants to devote increased resources.

However, United Energy has not demonstrated to us why this program could not be funded through other reductions in discretionary expenditure. We would typically consider a service provider should be able to fund increases in discretionary opex without forecasting an increase in total opex.

Insurance premiums

We have not included a step change in our opex forecast for increased insurance premiums.

United Energy proposed an insurance step change of $2.3 million ($2015) for increased insurance premiums.[152] It stated insurance costs had increased for:

- public liability and professional indemnity insurance

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151 United Energy, *Operating expenditure overview*, 30 April 2015, p. 41.

152 United Energy, *Operating expenditure overview*, 30 April 2015, p. 43. Costs for employment liability insurance, motor vehicle insurance, crime insurance and travel insurance are shared with Multinet Gas. United Energy stated that only 70 per cent of the forecast premiums for these policies are allocated to United Energy.

- property insurance
- directors and officers liability insurance
- employment liability insurance
- motor vehicle insurance
- crime insurance
- travel insurance.

Marsh provided a category specific forecast of insurance premiums for 2016–20. Marsh calculated the increase in insurance costs as the difference between the estimated insurance costs relative to the insurance costs in 2014.

Marsh stated that as market capacity and reinsurance capital are at record high levels, it anticipates that capacity and capital will at some point decrease. As such they anticipate progressive premium increases for most policies over the five year regulatory control period.[153]

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

We forecast opex by applying an annual 'rate of change' to our estimate of base opex for each year of the forecast regulatory control period. As discussed in our assessment approach, by applying the rate of change to our estimate of base 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 step change is not required if insurance premiums are forecast to increase faster than CPI because within total opex there will be other categories whose price is forecast to increase by less than CPI. If we add a step change to account for higher insurance premiums we might provide a more accurate forecast for the insurance category in isolation; however, our forecast for total opex as a whole will be too high.

C.8.5 Capex/opex trade-off

Pole top structures

We have included a $2.4 million ($2015) step change in our opex forecast for pole top structures. We consider this reflects an efficient capex/opex trade off.

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153 Marsh, Estimation of insurance premiums 2016–20 for United Energy [public version], p. 8.

United Energy proposed additional opex required for implementation of aerial camera inspection of pole top assets during regulatory cycle pole inspection activities.[154] United Energy noted that the six month trial of aerial camera inspection in 2014 assisted in reducing its capex in 2015. The forecast costs are based on the difference between the ongoing program and the six month trial in 2014.[155]

United Energy considers this program is a driver of its forecast pole top structure capex being lower than its average capex during the 2011–2015 period.

We have accepted United Energy's forecast capex for pole top structures. The forecast capex of $97 million is 4 per cent lower than the current period level of $101 million. More information on our capex assessment is discussed in appendix 6.

Since we have accepted United Energy's reduction in capex we have included the increase in opex for aerial inspections as an efficient capex/opex trade-off.

[154] United Energy, *Operating expenditure overview*, 30 April 2015, p. 44.

[155] United Energy, *Operating expenditure overview*, 30 April 2015, p. 45.