



PRELIMINARY DECISION
Jemena 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 Jemena'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

Attachment 12 - Demand management incentive scheme

Attachment 13 - Classification of services

Attachment 14 - Control mechanism

Attachment 15 - Pass through events

Attachment 16 - Alternative control services

Attachment 17 - Negotiated services framework and criteria

Attachment 18 - f-factor scheme

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering technology
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 Jemena's forecast opex reasonably reflects the opex criteria.¹ We therefore do not accept the forecast opex Jemena included in its building block proposal.² Our alternative estimate of Jemena's opex for the 2016–20 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
Jemena's proposal	94.1	94.0	97.1	101.7	105.0	491.9
AER preliminary decision	75.8	76.1	77.0	78.3	79.5	386.7
Difference	-18.3	-18.0	-20.1	-23.4	-25.5	-105.2

Source: Jemena, *Regulatory proposal*, 30 April 2015, p.90; AER analysis.

Note: Excludes debt raising costs.

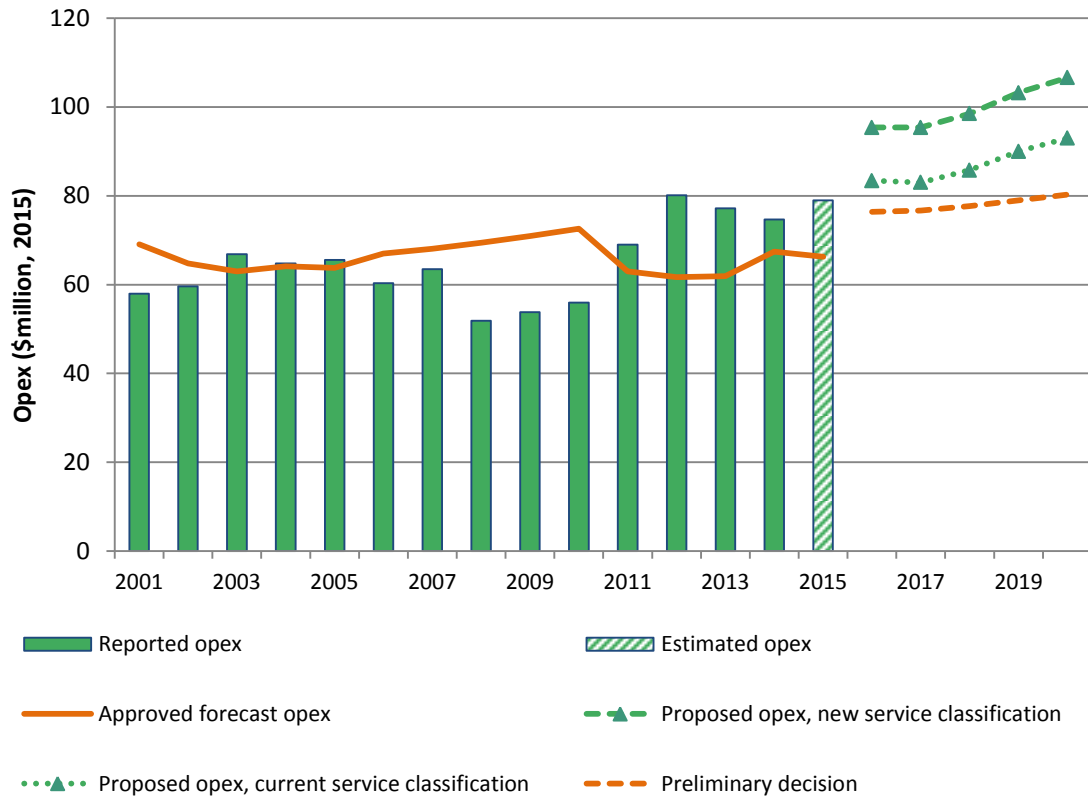
Figure 7.1 shows our preliminary decision compared to Jemena's proposal, its past allowances and past actual expenditure.

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 Jemena's past and proposed opex (\$ million, 2015)



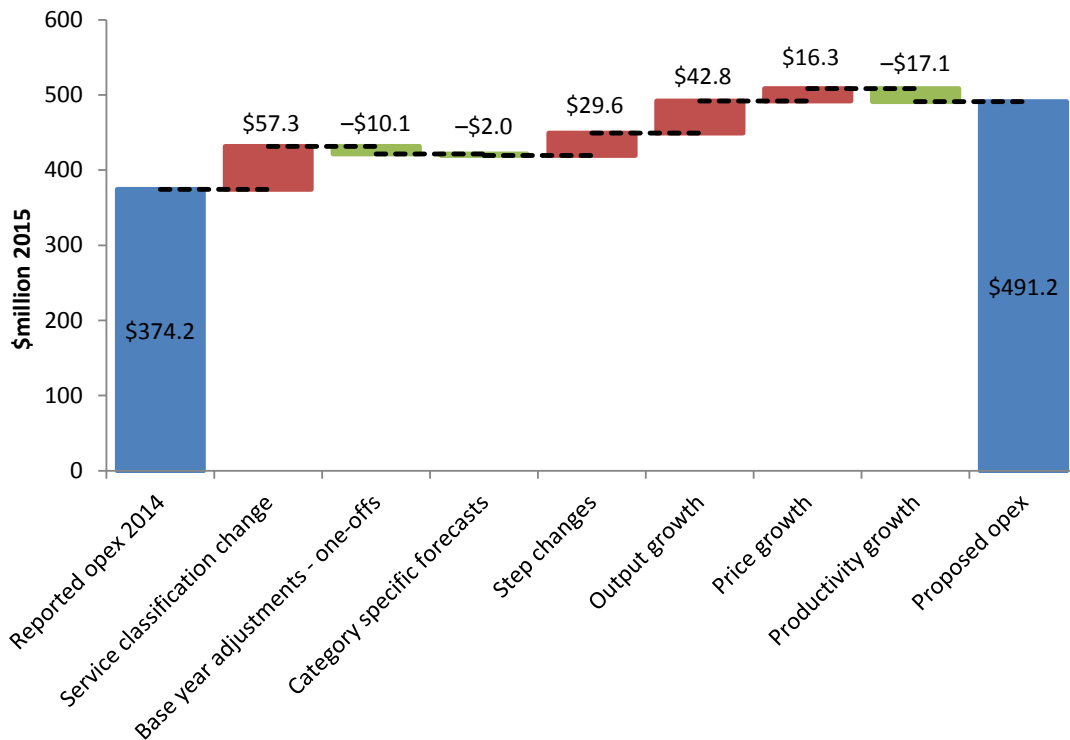
Source: Jemena, Regulatory accounts 2011 to 2014; Jemena, Economic benchmarking - Regulatory Information Notice response 2006 to 2013; AER analysis.

7.2 Jemena's proposal

Jemena proposed total forecast opex of \$491.9 million (\$2015) for the 2016–20 period (excluding debt raising costs, totalling \$7.1 million).⁴ In Figure 7.2 we separate Jemena's forecast opex into the different elements that make up its forecast.

⁴ Jemena subsequently proposed an additional \$29.9 million in step changes which increased total forecast opex to \$521.8 million (\$2015); Jemena, *Submission to Jemena Electricity Network 2016–20 regulatory proposal*, 13 July 2015.

Figure 7.2 Jemena’s opex forecast (\$ million, 2015)



Source: AER analysis. Excludes debt raising costs and DMIA.

We describe each of these elements below:

- Jemena 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 \$374.2 million (\$2015) over the 2016–20 regulatory control period.
- Jemena adjusted its base opex to add opex it proposed to reclassify as standard control services in the 2016–20 regulatory control period. This increased Jemena’s forecast by \$57.3 million (\$2015).
- Jemena also adjusted its base opex to remove opex for costs relating to non-recurrent events and circumstances that are not expected to endure in the 2016–20 regulatory control period. This reduced Jemena’s forecast by \$10.1 million (\$2015).
- Jemena included category specific forecasts for levies, guaranteed service level (GSL) payments, demand side management costs and self-insurance costs. This reduced its forecast by \$2.0 million (\$2015).
- Jemena 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 customer engagement program. This increased Jemena’s forecast by \$29.6 million (\$2015).

Subsequent to its proposal, Jemena identified a further \$29.9 million in step changes.⁵

- Jemena proposed output growth forecast using four different output growth models that adopted a variety of different output measures. Forecast increases in these measures increased Jemena's opex forecast by \$42.8 million (\$2015).
- Jemena accounted for forecast growth in prices related to labour price increases, contracted service price increases and materials price increases. These forecast price changes increased Jemena's opex forecast by \$16.3 million (\$2015).
- Jemena accounted for forecast growth in productivity, which reduced its opex forecast by \$17.1 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). We decide whether or not to accept the service provider's total forecast opex.

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.⁶ If we are satisfied, we accept the service provider's forecast.⁷ In the second task, we determine a substitute estimate of the required total forecast opex that we are satisfied reasonably reflects the opex criteria.⁸ 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:⁹

⁵ Jemena, *Submission to Jemena Electricity Network 2016–20 regulatory proposal*, 13 July 2015, p. 1.

⁶ NER, cl. 6.5.6(c) and 6.12.1(4).

⁷ NER, cl. 6.5.6(c) and 6.12.1(4)(i).

⁸ NER, cl. 6.5.6(d) and 6.12.1(4)(ii).

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

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:¹⁰

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]'.¹¹

The service provider's forecast is intended to cover the expenditure that will be needed to achieve the opex objectives. The opex objectives are:¹²

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.

¹⁰ NER, cl. 6.5.6(c).

¹¹ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113.

¹² NER, cl. 6.5.6(a).

Further, in undertaking these tasks we have regard to the opex factors.¹³ We attach different weight to different factors. This approach has been summarised by the AEMC as follows:¹⁴

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)

¹³ NER, cl. 6.5.6(c) and (d).

¹⁴ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

- 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.¹⁵

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).¹⁶ 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.¹⁷ 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.¹⁸

¹⁵ This is consistent with the approach we outlined in the explanatory statement to our Expenditure Assessment Guideline. See, for example, p. 131.

¹⁶ NEL, ss. 7A and 16(2).

¹⁷ NEL, s.7A(2).

¹⁸ That is, the trade-offs that may arise having considered the substitution possibilities between opex and capex, and the relative prices of operating and capital inputs: NER, cl. 6.5.6(e)(6) and 6.5.6(e)(7); NEL, ss. 7A(3), 7A(6) and 7A(7).

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.¹⁹ The Guideline sets out our intended approach to assessing opex in accordance with the NER.²⁰

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.²¹ For the most part, we have not departed from the approach set out in the Guideline in this final decision.²² In our Framework and Approach paper, we set out our intention to apply the Guideline approach in making this determination.²³ 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.²⁴ 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:²⁵

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,

¹⁹ AER, *Expenditure forecast assessment guideline - explanatory statement*, November 2013.

²⁰ NER, cl. 6.5.6.

²¹ NER, cl. 6.2.8(c).

²² We did not apply the DEA benchmarking technique. We outline the reasons why we did not apply this technique in Appendix A of our all NSW distribution determinations for the 2015–20 regulatory control period.

²³ AER, *Stage 2 Framework and approach - NSW electricity distribution network service providers*, January 2014, p. 50.

²⁴ AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

²⁵ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

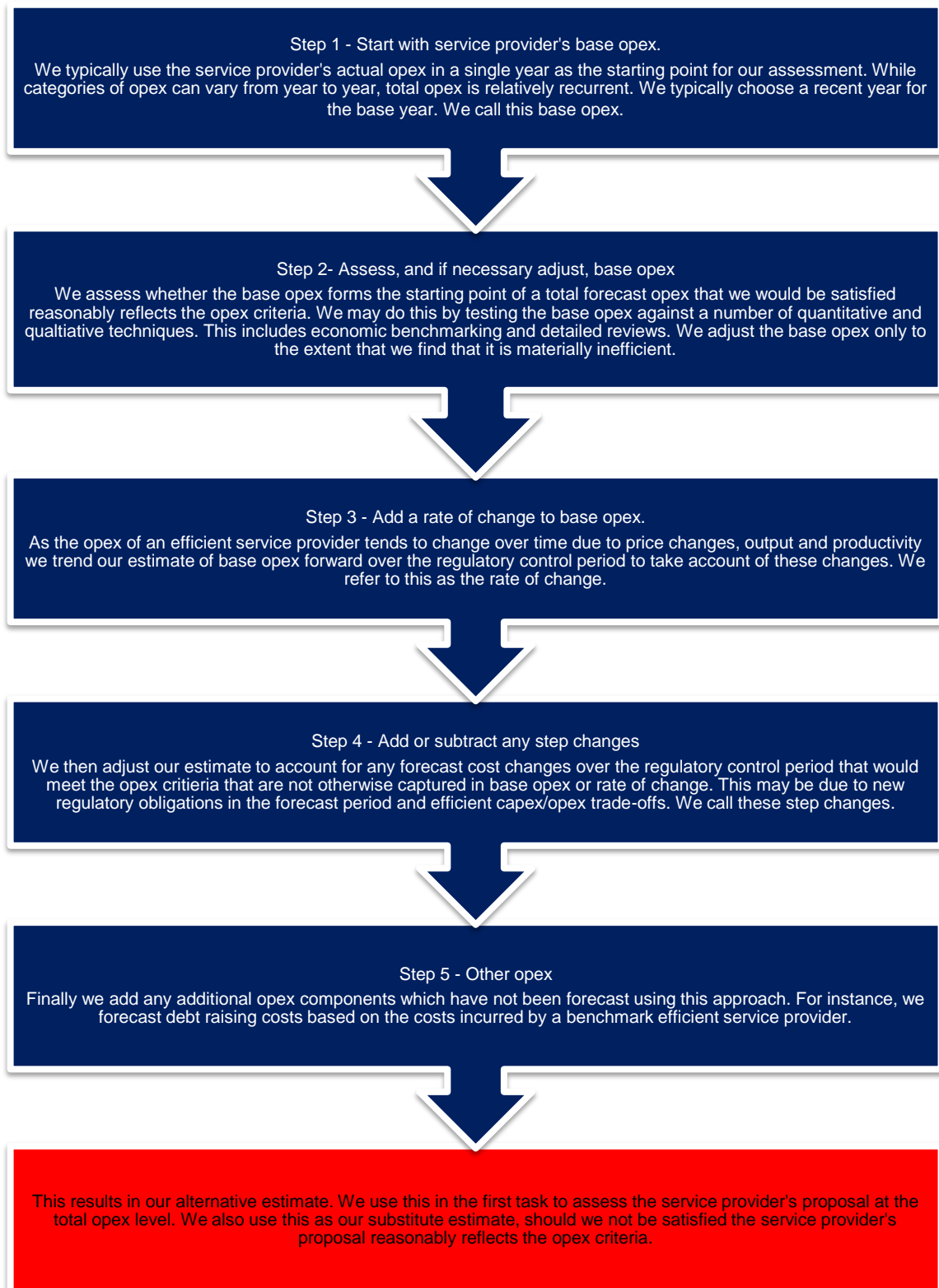
benchmarking the NSP against others will provide an indication of both whether the proposal is reasonable and what a substitute should be. Both the consideration of "reasonable" and the determination of the substitute must be in respect of the total for capex and opex.

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

Building an alternative estimate of total forecast opex

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

Figure 7.3 How we build our alternative estimate



Underlying our approach are two general assumptions:

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

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model that 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).²⁶

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:

²⁶ 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.²⁷ 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 2012:²⁸

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

²⁷ AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

²⁸ 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.²⁹

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.³⁰

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

²⁹ The benchmarking models are discussed in detail in appendix A.

³⁰ 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.

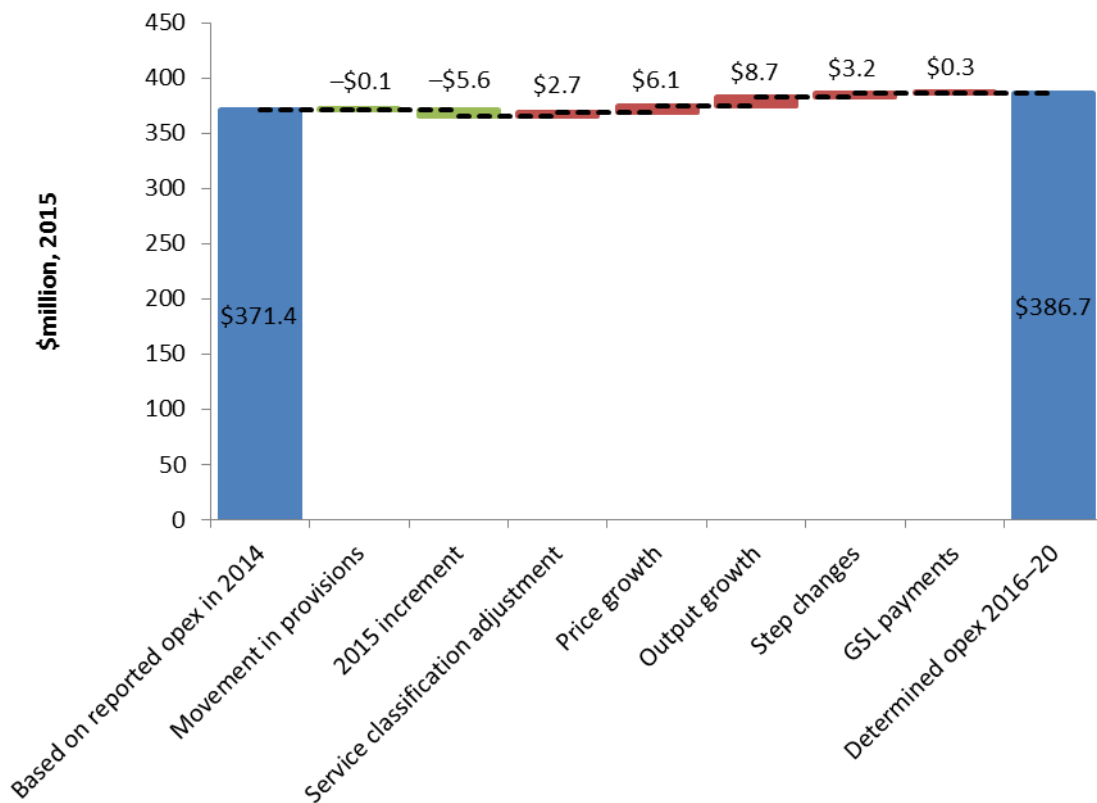
After applying these five steps, we arrive at our alternative estimate.

7.4 Reasons for preliminary decision

We are not satisfied that Jemena's proposed total forecast opex of \$491.9 million (\$2015) reasonably reflects the opex criteria.³¹ As we discussed above, we have therefore used our alternative estimate as our substitute estimate.³²

Figure 7.4 illustrates how we constructed our forecast. The starting point on the left is what Jemena’s opex would have been for the 2016–20 regulatory control period if it was set based on Jemena’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 Jemena’s proposed total opex and our preliminary decision estimate.

³¹ NER, cl. 6.5.6(d).

³² NER, cl. 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
Jemena's proposal	94.1	94.0	97.1	101.7	105.0	491.9
AER preliminary decision	75.8	76.1	77.0	78.3	79.5	386.7
Difference	-18.3	-18.0	-20.1	-23.4	-25.5	-105.2

Source: AER analysis.

Note: Excludes debt raising costs.

Jemena subsequently proposed an additional \$29.9 million in step changes which increased its proposed total opex forecast to \$521.8 million. This increases the difference between Jemena's proposed total opex and our preliminary decision estimate to -\$135.6 million.

We outline the key elements of our alternative opex forecast and areas of difference between our estimate of opex and Jemena's estimate below.

7.4.1 Forecasting method assessment

As noted above, our estimate of total opex is unlikely to exactly match Jemena'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 Jemena's forecast method and found only minor differences between its method and our own. We found these minor differences did not explain why Jemena's forecast opex is higher than our own estimate.

7.4.2 Base opex

We have forecast a base opex amount of \$73.7 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	74.8
Remove movement in provisions	-0.0
Remove DMIA expenditure	-0.1
GSL payments	-0.1
Remove scrapping of assets	-0.4
Service classification adjustment	0.5
Adjusted 2014 opex	74.8
2015 increment	-1.1
Estimated 2015 opex	73.7

Source: AER analysis.

Consistent with Jemena’s proposal we have relied on Jemena’s reported opex in 2014 to forecast opex. Benchmarking indicates Jemena 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 Jemena's over the forecast period. Table 7.4 below compares Jemena'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
Jemena	2.30	2.63	2.64	2.53	2.48
AER	0.98	1.30	1.55	1.67	1.58
Difference	-1.32	-1.33	-1.09	-0.86	-0.90

Source: AER analysis.

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

- To forecast labour price growth, Jemena used the forecast change in the utilities WPI as forecast by BIS Shrapnel. Jemena's forecast is higher than ours, which we base on forecasts from Deloitte Access Economics and BIS Shrapnel.
- Jemena proposed different output growth drivers to ours. We forecast a lower output growth, using the same output growth measures and weightings as used in Economic Insights' economic benchmarking report.³³ We used the circuit length forecasts from Jemena's reset RIN and ratcheted maximum demand forecasts from AEMO. We used our own forecast of customer numbers.

The differences in each forecast rate of change component are:

- our forecast of price growth is on average 0.32 percentage points lower than Jemena's forecast
- our forecast of output growth is on average 1.68 percentage points lower than Jemena's forecast
- our forecast of productivity growth is on average 0.89 percentage points lower than Jemena's forecast.

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

³³ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 40–41.

7.4.4 Step changes

We have included two step changes in our total opex forecast:

- We are satisfied Jemena requires an increase in opex to implement new tariffs required by changed regulatory obligations.
- We are satisfied the additional opex associated with Jemena's demand management programs is an efficient capex/opex trade-off.

We are not satisfied that adding step changes for the other cost drivers identified by Jemena would lead to a forecast of opex that reasonably reflects the opex criteria.

We generally consider base opex already reflects the cost of meeting existing regulatory obligations and maintaining the reliability, safety and quality of supply of standard control services. We acknowledge that some types of projects and programs of expenditure a service provider undertakes will differ between years and between regulatory control periods. However, we do not consider variation in the expenditure on projects and programs is a reason to increase the revenue it can recover from electricity network consumers. For this reason we did not include step changes for:

- service inspection and testing program
- overhead switch inspections
- regulatory proposal
- customer engagement
- insurance premiums.

We may approve step changes for new regulatory obligations and capex/opex trade-offs if we consider they are not already accounted for in the base year. Jemena proposed five step changes associated with regulatory changes. We do not consider there is evidence Jemena's operating costs will materially increase as a result of regulatory changes associated with:

- enclosed substation inspection and rectification
- ESV code of practice changes.

We acknowledge that changed regulatory obligations may give rise to a justifiable step change for:

- vegetation management
- RIN reporting costs.

However, on the basis of the information and evidence Jemena has provided so far, we do not have sufficient material to form a view as to the quantum of an efficient opex step change. These two step changes account for over half of the total value of step changes Jemena proposed.

A summary of Jemena's proposed step changes and our position are outlined in Table 7.5.

Table 7.5 Step changes (\$ million, 2015)

	Jemena's proposal	AER position
Service inspection and testing program	6.2	–
Overhead switch inspection	2.2	–
Enclosed substation inspection and rectification	0.8	–
Regulatory proposal	8.0 ^a	–
Vegetation management	15.9 ^b	–
ESV code of practice changes	0.9	–
Vulnerable customer assistance	1.0	–
Customer engagement	0.9	–
Pole-top fire detection (new technology trial)	1.4	–
Demand management opex/capex trade-off	0.7	0.7
Insurance premiums	0.2	–
New tariff implementation	2.5	2.5
RIN reporting	19.7 ^c	–
Total	60.3	3.2

Source: AER analysis; Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 1. Jemena, *Submission to Jemena Electricity Network 2016-20 regulatory proposal*, 13 July 2015, p. 1.

Note: a: While Jemena proposed a step change of \$8.0 million (\$2015) for its regulatory proposal, it also proposed a negative base year adjustment. Considered together they reduced its total opex forecast.

b: Jemena proposed a vegetation management step change of \$5.63 million in its regulatory proposal. It increased the proposed vegetation management step change to \$15.89 million in a subsequent submission.

c: Jemena proposed a new step change of \$19.65 million for RIN reporting in the same submission.

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

7.4.5 Other costs not included in the base year

Guaranteed service level payments

We have forecast guaranteed service level (GSL) payments as the average of GSL payments made by Jemena 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 3.

7.4.6 Interrelationships

In assessing Jemena'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 Jemena 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 Jemena's proposed demand management program
- the approach to the assessing rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- changes to the classification of services from standard control services to alternative control services
- concerns of electricity consumers identified in the course of its engagement with consumers.

7.4.7 Assessment of opex factors

In deciding whether we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.³⁴ 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

³⁴ NER, cl. 6.5.6(e).

Opex factor	Consideration
	<p>annual snapshot of the relative efficiency of each service provider.</p> <p>The second element, that is, the benchmark operating expenditure that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period.</p> <p>We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of Jemena's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.</p>
<p>The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.</p>	<p>Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Jemena's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.</p>
<p>The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.</p>	<p>We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.³⁵</p>
<p>The relative prices of capital and operating inputs</p>	<p>We have considered capex/opex trade-offs in considering Jemena's proposed step changes.</p> <p>We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.</p>
<p>The substitution possibilities between operating and capital expenditure.</p>	<p>As noted above we considered capex/opex trade-offs in considering Jemena's proposed step changes. For instance we have considered whether a step change for demand management costs is an efficient capex/opex trade-off. We considered the relative expense of capex and opex solutions in considering this step change.</p> <p>Some of our assessment techniques examine opex in isolation—either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we</p>

³⁵ AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

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

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 Jemena's base opex.

A.1 Position

We have used a base opex amount of \$73.7 million (\$2015) 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	74.8
Remove movement in provisions	-0.0
Remove DMIA expenditure	-0.1
GSL payments	-0.1
Remove scrapping of assets	-0.4
Service classification adjustment	0.5
Adjusted 2014 opex	74.8
2015 increment	-1.1
Estimated 2015 opex	73.7

Source: AER opex model.

A.2 Proposal

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

- remove the demand management innovation allowance (DMIA) expenditure, GSL payments and non-recurrent costs
- add costs associated with proposed service classification changes.

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

Table A.2 Jemena forecast of adjusted base opex (\$2015)

	Jemena's proposal
Reported 2014 opex	73.2
Remove DMIA expenditure	-0.1

	Jemena's proposal
Remove GSL payments	-0.1
Remove non-recurrent costs	-2.0
Service classification adjustment	11.5
Adjusted 2014 opex	82.5

Source: Jemena, *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 Jemena's base opex is set out below under the following headings:

- Benchmarking results
- Service classification changes
- Base year adjustments and category specific forecasts.

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 Jemena'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 Jemena.

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 index³⁶
- 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:³⁷

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.

We note the benchmarking we have presented in this preliminary decision only includes the data we have used in our latest distribution benchmarking report.³⁸ 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

³⁶ 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.

³⁷ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 46–47.

³⁸ AER, *2014 annual distribution benchmarking report*, November 2014.

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 Jemena's actual opex in 2013 was \$77.2 million (\$2015) while in 2014 it had fallen to \$74.8 million (\$2015). Therefore, as we have found Jemena's opex to be relatively efficient based on its 2013 opex, 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 Jemena is relatively efficient overall and also in the use of its opex.

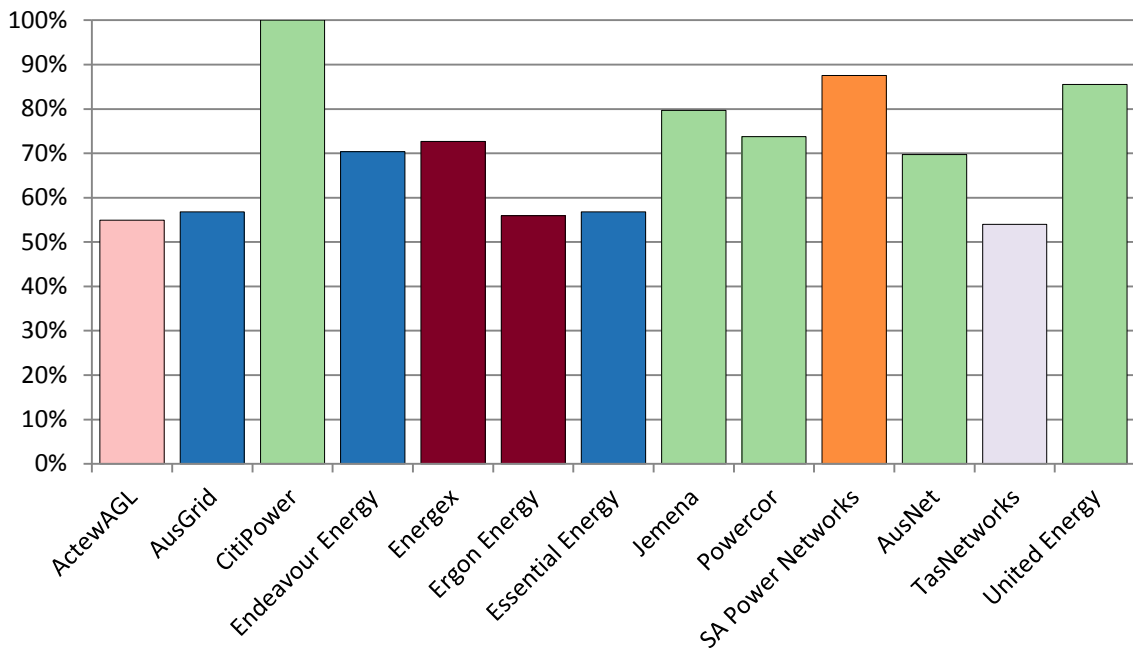
MTFP allows for the comparison of productivity levels between service providers and across time. Productivity is a measure of the quantity of output produced from the use of a given quantity of inputs. When there is scope to improve productivity, this implies there is productive inefficiency.

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 Jemena performs relatively well compared to other service providers in the NEM.

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



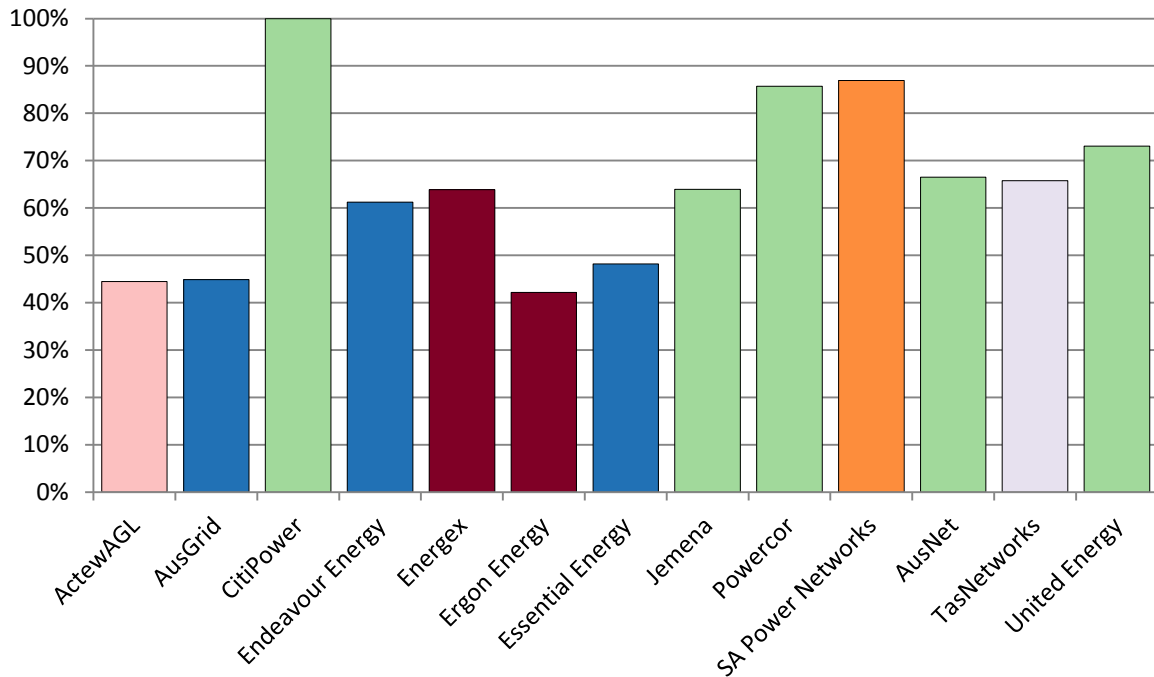
Source: AER analysis.

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. Jemena performs worse on this measure than on MTFP. However, while the results are different for Jemena, we do not consider this provides any indication of material inefficiency. Some distributors might choose a different mix of opex and assets that might be overall efficient. By reaching a conclusion on the efficiency of one input (i.e opex) on the basis of opex benchmarking without regard to how the service provider uses its assets would also be inconsistent with the NER as it would not provide for efficient capex/opex trade-offs.

For further detail on MTFP and index number benchmarking approaches we direct readers to our previous publications.³⁹

³⁹ These include: Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 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.

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



Source: AER analysis.

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.⁴⁰

The Victorian service providers also submitted some benchmarking as part of their proposals. For instance, Jemena and United Energy submitted reports from Huegin.⁴¹ In general, the analysis it undertook was consistent with analysis it undertook for the 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.⁴² We recognise that operating environment factors specific to each business will affect their benchmarking performance. Our view is that Jemena 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

⁴⁰ <http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements>.

⁴¹ 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*.

⁴² AusNet Services, *Regulatory proposal*, 30 April 2015, pp. 83–91.

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.⁴³ 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.⁴⁴ They are parametric techniques, which mean that they model the underlying cost function of the service providers as specified.

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.⁴⁵

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:

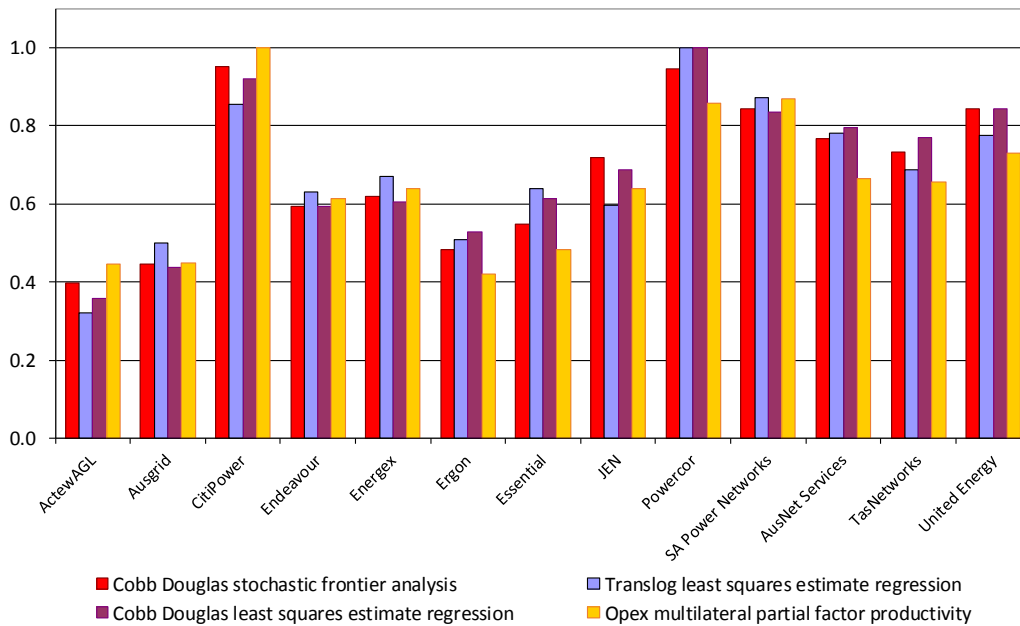
- The results below reflect raw efficiency scores. There are other operating environment factors affecting each businesses performance which are not captured in each of the benchmarking models.
- The scores below reflect average efficiency scores over the 2006 to 2013 period so cannot be used directly to infer the relative efficiency gap between providers in any one year.
- As outlined above, Jemena is an average performer on opex benchmarking but performs relatively well on total expenditure benchmarking (i.e MTFP). We do not consider it would be reasonable to conclude Jemena was relatively inefficient when alternative benchmarking models we have produced indicate a different ranking.

⁴³ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, p. iii.

⁴⁴ 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.

⁴⁵ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 revenue proposals*, 13 July 2015, p. 34.

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



Source: Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014.

A.4.3 Partial performance indicators

In our annual benchmarking report we also present a number of partial performance indicators.⁴⁶ These indicators examine the service providers' use of assets, opex and total inputs in delivering its distribution services. Under these metrics, Jemena appears to be one of the more efficient networks. As such, we consider that this benchmarking supports the general conclusion of no evidence of material inefficiency.

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 providers.⁴⁷ Figure A.4 and Figure A.5 present these PPIs. These figures show that Jemena (JEN) incurs relatively low opex and total cost per customer when compared to its peers.

⁴⁶ AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014.

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

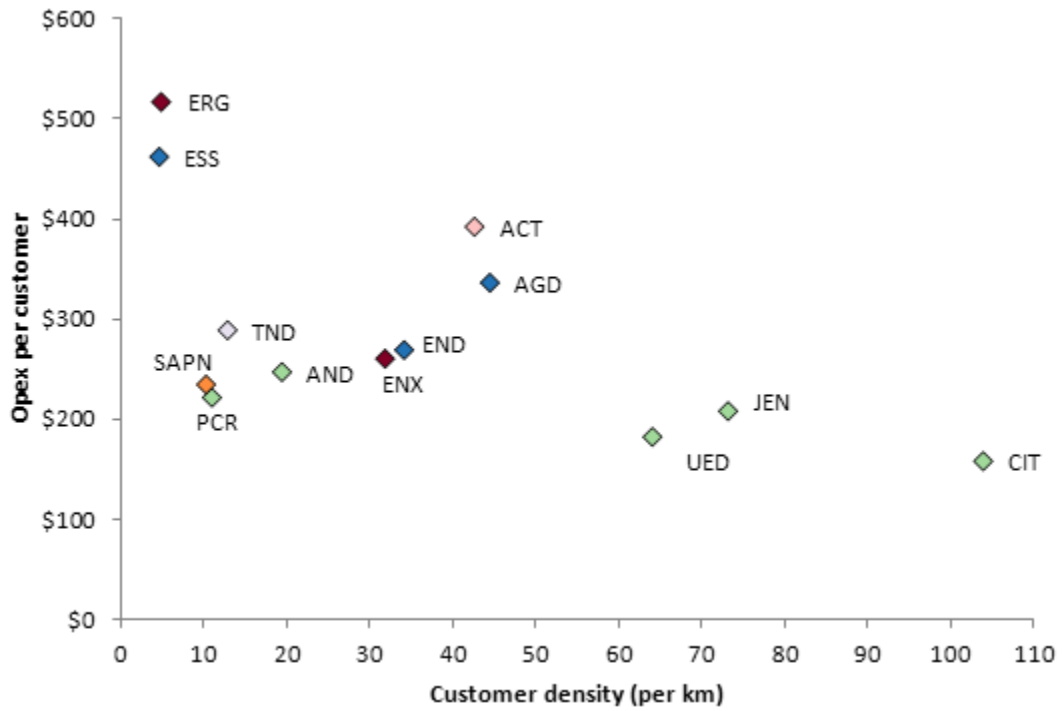
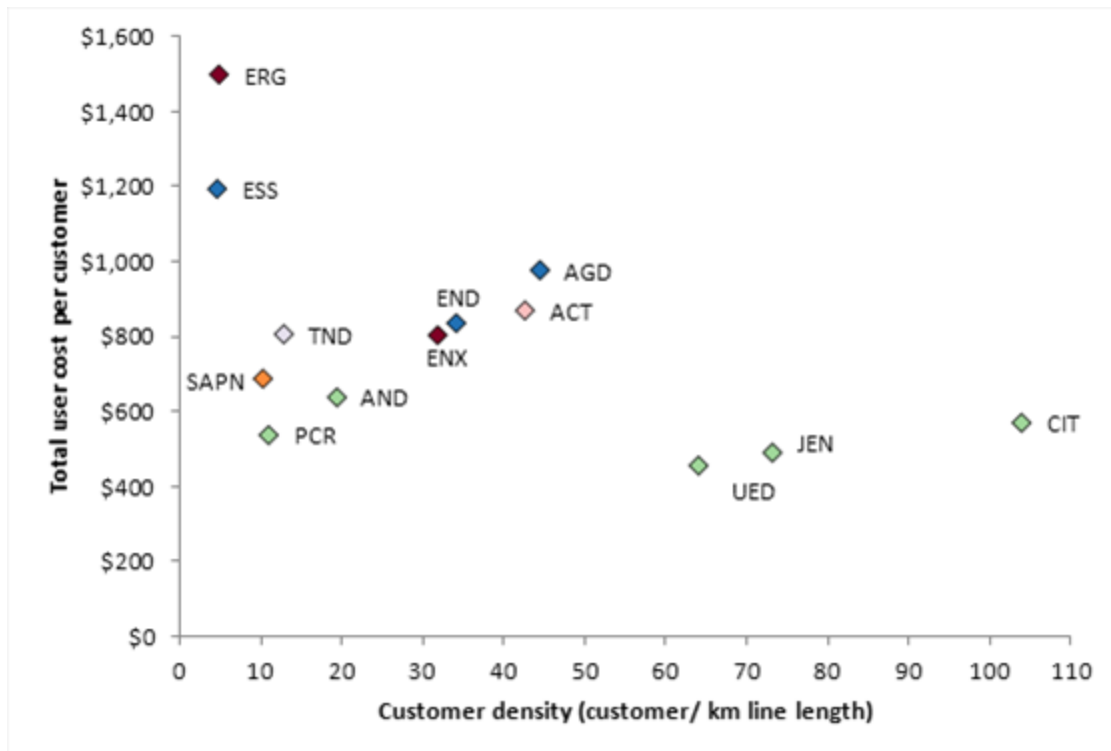


Figure A.5 PPI of total cost per customer (2009 to 2013)



A.5 Service classification changes

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

With the expiry of the AMI OIC, opex associated with AMI is now to be regulated under the NER. Jemena proposed an adjustment to its base opex of \$11.0 million (\$2015) for opex previously regulated under the AMI OIC.⁴⁸ Jemena did not specify in its proposal how it determined the proportion of costs that should be allocated to standard control services opex. However, from its opex model it is apparent Jemena determined a different allocation percentage for standard control services and alternative control services for each individual category of opex.

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

- CitiPower and Powercor have quantified the proportion of each IT system previously regulated under AMI OIC that is used for standard control services. For many IT systems, they each deem the proportion used for metering to be relatively immaterial so they allocate the whole proportion of the IT system cost to standard control services.⁴⁹
- Where any costs regulated under AMI OIC are shared between standard control distribution services and metering services, AusNet Services and United Energy have proposed to allocate the whole proportion to standard control services.⁵⁰

As outlined in Table A.3, the proportion of metering opex allocated to standard control services differs substantially across the Victorian service providers.

Table A.3 Proportion of metering opex allocated to standard control services

AusNet	CONFIDENTIAL
CitiPower	32 per cent

⁴⁸ Jemena, *Attachment 08.03 - JEN Forecast Opex Model, Input/SCS Adjustments worksheet*, April 2015

⁴⁹ Powercor, *Regulatory proposal, Appendix F - Base year adjustments*, 30 April 2015, p. 12.

⁵⁰ AusNet, *Regulatory proposal*, 30 April 2015, p. 204; United Energy, *Revenue Capped Metering Services - Supporting Paper*, 30 April 2015.

Jemena	61 per cent
Powercor	27 per cent
United Energy	79 per cent

Source: AER Analysis.

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.⁵¹ 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 2016.⁵² 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.⁵³ As we have not allocated any AMI costs to standard control services opex, there is no risk of consumers paying for these costs twice.

Jemena also proposed a service classification change for supply abolishment. We have agreed to this approach, consistent with the direction we provided in the Framework and Approach paper.⁵⁴

⁵¹ AEMC, *Draft Rule Determination - National Electricity Amendment (Expanding Competition in Metering and Related Services) 2015*, 26 March 2015.

⁵² AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

⁵³ Victorian Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 6.

⁵⁴ AER, *Final Framework and approach for the Victorian Electricity Distributors*, 24 October 2014, p. 43.

A.6 Other adjustments

We have agreed to Jemena's proposed adjustments to its base year opex for losses on the scrapping of assets. Losses on the scrapping of assets are accounting records of the shortfalls between the proceeds from selling assets and their accounting written down values. Jemena stated that consistent with accounting standards, and subject to audit, these losses are reported as opex in its statutory accounts.⁵⁵ As these costs are only costs for accounting purposes and do not involve an actual outlay of funds, we do not consider we should be forecasting these for regulatory purposes. To do so would mean Jemena's consumers would be compensating it whenever it reports a loss on the sale of an asset in the base year.

We have also agreed to the adjustment Jemena made to its base opex for DMIA and GSL payments.

We have not included Jemena's other proposed adjustments in our forecast. We make our assessment about total forecast opex and not about particular categories or projects. We use a top down forecasting method to derive our forecast of total opex. Jemena proposed several other small adjustments to its base opex to remove non-recurrent opex. At the same time Jemena forecast increases in other non-recurrent opex as step changes. In general, we consider the total forecast opex Jemena incurred in 2014 is a reasonable indicator for its total opex requirements in the 2016–20 period. We have not attempted to identify the non-recurrent opex Jemena incurred in the base year nor the non-recurrent opex Jemena may incur in each year of the 2016–20 period. We do not consider such a granular approach is likely to lead to a better forecast of total opex.

A.7 Estimate of final year expenditure

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

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

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

where:

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

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

⁵⁵ Jemena, *Response to IR#011*, 14 July 2015, p. 2.

A_b is the amount of actual opex in the base year

non-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 Jemena'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.⁵⁶ 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 \$73.7 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 period.

⁵⁶ 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:⁵⁷

- 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 Jemena's over the forecast period. Table B.1 shows Jemena's and our overall rate of change in percentage terms for the 2016–20 period. We consider that applying our methodology to derive an alternative estimate of opex will result in a forecast that reasonably reflects the efficient and prudent costs faced by Jemena 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 Jemena's
- our forecast of annual output growth is on average 1.68 percentage points lower than Jemena's
- our forecast productivity growth is on average 0.89 percentage points lower than Jemena's.

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

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

	2016	2017	2018	2019	2020
Jemena	2.30	2.63	2.64	2.53	2.48

⁵⁷ AER. *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

AER	0.98	1.30	1.55	1.67	1.58
Difference	-1.32	-1.33	-1.09	-0.86	-0.90

Source: AER analysis.

B.2 Jemena proposal

Table B.2 shows Jemena's proposed cumulative change in opex for each rate of change component reported in its reset RIN. Jemena's rate of change methodology is different to ours because it adopted a different approach to forecasting price growth.

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

	2016	2017	2018	2019	2020
Price growth	780.2	1509.4	2332.9	3085.5	3870.9
Output growth	3542.8	5450.9	7281.0	9127.0	10947.3
Productivity growth	-1269.1	-1919.2	-2521.6	-3109.6	-3671.2

Source: Jemena reset RIN table 2.16.1.

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

Forecast price growth

Jemena proposed price growth for the following expenditure categories:

- labour
- external labour
- materials
- other.

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

Table B.3 Jemena forecast price growth consultants and proposed methodology

Price growth	Consultant	Method
Labour	BIS Shrapnel	The forecast change in the WPI for the EGWWS sector.
External labour	BIS Shrapnel	The forecast change in the WPI for the construction sector.
Materials	BIS Shrapnel	A simple average of raw commodity prices

Other	Not applicable	Assumed to grow with the CPI.
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Source: Jemena, *Regulatory proposal*, p. 86.

Table B.4 Jemena's proposed real price growth (per cent)

	2015	2016	2017	2018	2019	2020
Labour	0.48	0.88	1.35	1.76	2.11	1.81
External labour	0.78	1.19	1.63	1.49	1.61	1.92
Materials	2.37	2.71	3.82	1.42	-6.11	-2.41
Other	-	-	-	-	-	-

Source: Jemena, *Regulatory proposal, Attachment 08.03, Proposed opex forecast model*.

Forecast output growth

Jemena forecast output growth based on the forecast growth in customer numbers and physical system capacity. It estimated physical system capacity as the product of distribution transformer capacity and network line length. It weighted the forecast growth in customer numbers and physical system capacity by the cost elasticities for those variables estimated by Huegin.⁵⁸ Its forecast of output growth is in Table B.5.

Table B.5 Jemena's proposed output growth (per cent)

	2015	2016	2017	2018	2019	2020
System physical capacity	5.91	5.41	5.74	5.15	5.07	4.76
Customer numbers	0.83	1.38	1.23	1.24	1.24	1.25
Output growth	2.33	2.57	2.56	2.39	2.37	2.28

Source: Jemena, *Regulatory proposal, opex model*.

Forecast productivity growth

Jemena included forecast productivity growth in its rate of change. Its forecast productivity growth is its forecast of economies of scale, calculated from its forecast of output growth and the elasticities estimated by Huegin. Its forecast of productivity growth is in Table B.6.

⁵⁸ Jemena, *Regulatory proposal, Attachment 8-2*, 30 April 2015, p. 14.

Table B.6 Jemena's proposed productivity growth (per cent)

	2015	2016	2017	2018	2019	2020
Productivity growth	0.85	0.94	0.93	0.87	0.86	0.83

Source: Jemena, *Regulatory proposal*, opex model.

B.3 Assessment approach

As discussed above, we assess the annual change in expenditure in the context of our assessment of Jemena'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 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 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 Jemena'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 Jemena'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.⁵⁹

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.⁶⁰

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 Jemena's proposed 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 Jemena to forecast our alternative estimate of opex. Our forecast of each component of the rate of change is lower than Jemena's. Jemena's higher forecast output growth is the primary driver of this difference. Jemena also forecast higher price and productivity growth than us.

Table B.7 shows Jemena'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.7 Forecast overall rate of change (per cent)

	2016	2017	2018	2019	2020
Jemena					
Price growth	0.68	1.01	1.12	1.03	1.04
Output growth	2.57	2.56	2.39	2.37	2.28
Productivity growth	0.94	0.93	0.87	0.86	0.83

⁵⁹ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

⁶⁰ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 66.

Overall rate of change	2.30	2.63	2.64	2.53	2.48
AER					
Price growth	0.22	0.50	0.79	0.92	0.85
Output growth	0.75	0.80	0.75	0.75	0.73
Productivity growth	–	–	–	–	–
Overall rate of change	0.98	1.30	1.55	1.67	1.58
Difference	-1.32	-1.33	-1.09	-0.86	-0.90

Source: AER analysis.

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

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

B.4.2 Forecast price growth

We are not satisfied Jemena'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.

The difference between our forecast of opex price growth and Jemena's is due to:

- the price measures chosen to represent the prices of the opex inputs used
- the forecast growth of the chosen price measures.

We discuss our consideration of each of these below.

Choice of price measures

We forecast price growth based on the forecast growth in labour and non-labour prices. We use the forecast change in the wage price index (WPI) for the electricity, gas, water and waste services industry (the utilities industry) as the forecast change in the labour price.⁶¹ We assumed non-labour prices grow with CPI.

Jemena proposed price growth for:

- internal labour costs (utilities WPI)
- external labour costs (construction WPI)

⁶¹ We used the forecast change in the WPI for the utilities industry because this is the industry to which the ABS assigns electricity distribution.

- materials costs (a simple average of raw commodities prices)
- other costs (CPI).

There are two differences between Jemena's choice of price measures and our price measures:

1. Jemena treated contracted services as a labour cost whereas we treat them as a mix of labour and non-labour costs.
2. Jemena forecast the price growth of materials whereas we included materials costs in non-labour costs which we forecast to increase at the same rate as CPI.

We discuss our reasons for these two differences below.

Contracted services

Distributors use external contractors to deliver a variety of services such as vegetation management, asset inspections and traffic management. We treat contracted services differently to Jemena. We include the labour component of contracts that provide field services in our labour weighting. The non-labour component of those contracts, and contracts that provide non-field services, are included in the non-labour weighting.⁶² We forecast that the price of the components we include in labour will increase at the same rate as the utilities WPI. The component we include as non-labour we forecast will increase at the same rate as the CPI. Jemena assumed that the price of contracted services (which it called 'external labour') will change at the same rate as the price of construction labour.

Jemena provided no reasons in its regulatory proposal why it used the forecast growth in a wage price index to forecast the growth in the price of contracted services. To the extent that contracted services deliver field services, we would include the labour component of these services in our labour weighting. We apply the forecast change in the Victorian utilities WPI to these labour costs. The contracts that we include in the non-labour component are for non-field services. This includes services such as legal, accounting, IT and other administrative services.

The ABS publishes data on the movement in the price of goods and services. It publishes producer price indices for different industries as both input price indices and output price indices. That is, it publishes indices of the prices of inputs used by an industry and the prices of outputs produced by an industry. We looked at the output producer price indices that most closely reflect the non-field services that an efficient service provider would purchase (Table B.8). These are the same producer price

⁶² We define labour this way so we only include the productivity related to providing field services in the productivity component of the opex cost function. This is true for both our measurement of historic productivity growth and the forecast productivity growth in our opex forecast. We do this because when we measure historic productivity growth we are interested in the productivity growth achieved by the service providers rather than the productivity growth achieved by contractors providing services that are not unique to electricity distribution.

indices that we use for the price of non-labour inputs in our opex cost function modelling that we use to measure historic productivity growth.

Table B.8 Annual growth in the PPIs of selected ANZSIC classifications

Index	Annual growth
All industries, domestic, intermediate inputs	2.9
Data processing, web hosting and electronic information storage services	1.0
Other administrative services	2.7
Legal and accounting services	3.8
Market research and statistical services	4.0
Weighted average producer price index*	2.6
Consumer price index	2.8

* We calculated the weighted average using the same weights used by Economic Insights in its opex cost function modelling.

Note: We measured annual growth over the period September 2001 to September 2014.

Source: ABS catalogue 6427.0.

This analysis suggests that while the cost of some non-field services has increased by more than CPI others have increased by less than CPI. However, the price growth of services tends to grow at a similar rate to CPI. Having reviewed the historic change in various producer price indices we found no evidence that the price of the non-field services purchased from contractors by an efficient service provider vary materially from CPI.

Overall we are satisfied that the forecast growth in CPI reflects the increase in prices for non-field contracted services required by an efficient service provider to meet the opex objectives.

Materials

We have treated materials as a non-labour costs and consider that the price materials will move in line with the CPI. Jemena assumed that the price of materials will change at the rate of a simple average of forecast price growth of a sample of raw commodities.⁶³ The raw commodities included in the average were copper, aluminium, steel, oil, concrete and wood.⁶⁴

We are not satisfied that a simple average of the forecast price growth of the materials chosen by Jemena reflects the price growth of the materials prices affecting Jemena's opex because Jemena does not purchase raw commodities. Further, Jemena's

⁶³ Jemena, *Regulatory proposal*, 30 April 2015, p. 86.

⁶⁴ Jemena, *Regulatory proposal*, Attachment 8-2, 30 April 2015, p. 14.

materials price forecasting approach does not account for the forecast change in prices of other inputs that the manufacturers of the materials Jemena does purchase, or their productivity growth.

Further, CPI growth reflects the price growth of these raw commodities to the extent that they are inputs used to product the goods and services included in the CPI basket. The prices of the various goods and services in the CPI basket will all grow at different rates. The fact the price of one good or service varies at a different rate to the CPI is not a reason to forecast the price growth of that good or service separately. In fact, forecasting the price growth of a good or service that varies from the CPI, while assuming the price of all other goods and services will grow at the same rate as CPI will result in a biased forecast. This is because the prices of the remaining goods and services will grow by less (more) than the CPI if the other good (service) grows by more (less) than the CPI.

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

Jemena 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.9).

Table B.9 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, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 10; BIS Shrapnel, *Real labour and material cost escalation forecasts to 2020*, November 2014, p. ii.

⁶⁵ AER, *Powerlink Final decision*, p. 54, April 2012.

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 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 VECUA 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 Jemena's proposed average annual output growth of 2.4 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 consider our weighted average output measure using our economic benchmarking variables to be more reflective of the change in outputs Jemena must meet. This results in an average forecast output growth of 0.8 per cent per annum for the 2016–20 regulatory control period.

The difference between Jemena's output growth forecast and our own arises because:

- we are not satisfied that the output measures and forecasting method adopted by Jemena to forecast output growth reflect a realistic expectation of the output growth Jemena will experience
- we are not satisfied that Jemena 's forecasts of customer numbers and 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)

⁶⁶ ABS, Catalogue 6345.0, Table 9b.

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.

- 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.

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
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 customer numbers and peak demand

We used the forecast circuit length reported by Jemena in its reset RIN. This produces an average annual growth rate of 2.02 per cent for circuit length.

However, we have not used the forecast maximum demand or customer numbers reported by Jemena in its reset RIN. The Ethnic Community Council of Victoria, VECUA, and the Victorian Greenhouse Alliances all noted that the Victorian service providers' peak demand forecasts were higher than those forecast by AEMO.⁷¹ VECUA 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 Jemena's forecasts of maximum demand reflect a realistic expectation of the demand

⁶⁹ Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November, p. 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*, 13 July 2015, p. 14; Victorian Greenhouse Alliances, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 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.

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.

Both VECUA and the CCP noted that Jemena forecast that customer numbers would grow at a faster rate than the historic rate.⁷⁴

ACIL Allen forecast Jemena's customer numbers.⁷⁵ It forecast the growth in residential customer numbers based on the forecast growth in population, as forecast by the Victorian Department of Planning and Community Development using the following method:⁷⁶

1. Forecasting the population of each local government area (LGA) using the LGA specific growth rates.
2. Converting population to the number of households by dividing the population forecasts for each LGA by the average number of individuals per household in that LGA.
3. Aggregating the expected number of households that are within Jemena's distribution region using the proportion of area of each LGA within Jemena's region.
4. Calculating the yearly growth in households within Jemena's region using the number of households in step 3.

ACIL Allen stated that it applied these growth rates to Jemena's customer numbers from 2013 onwards to estimate the number of residential customers within Jemena's region.⁷⁷ Consequently it implicitly assumed that a one per cent increase in households will result in a one per cent increase in customers. ACIL Allen also stated that it assumed the average number of individuals per household for each LGA does not change during the forecast period.⁷⁸ Combining these two assumptions means that ACIL Allen assumed that a one per cent increase in the population will result in a one per cent increase in customers.

However, these assumptions may not necessarily hold. For example, some apartment blocks, with multiple households, are embedded networks that Jemena would treat as a single customer.

To test these assumptions we compared the historic growth in the population in Jemena's region against the historic growth in customer numbers.

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

⁷⁴ CCP, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, p. 32–34; Victorian Energy Consumer and User Alliance, Submission, p. 14.

⁷⁵ ACIL Allen, *Electricity consumption forecasts*, 16 December 2014.

⁷⁶ ACIL Allen, *Electricity consumption forecasts*, 16 December 2014, pp. 47–48.

⁷⁷ ACIL Allen, *Electricity consumption forecasts*, 16 December 2014, p. 48.

⁷⁸ ACIL Allen, *Electricity consumption forecasts*, 16 December 2014, p. 41.

We found that from 2007 to 2014 customer numbers grew by 0.8 per cent per year on average.⁷⁹ The estimated residential population in the local government areas Jemena serves grew by 2.0 per cent per on average over the same period. Consequently at least one of the assumptions made by ACIL Allen did not hold during this period. For this reason we are not satisfied that Jemena's forecast of customer number growth reflects a realistic expectation of the customers Jemena will need to serve.

We then looked at the Victorian Department of Planning and Community Development's forecast of population growth in the local government areas that Jemena's serves. It forecast the total population in the local government areas that Jemena serves will grow by 2.0 per cent per year on average between 2015 and 2020. This is the same growth rate as over the period 2007 to 2014. Consequently we are satisfied that the historic average growth in residential customer numbers of 0.8 per cent per year reasonably reflects the increase in customer numbers Jemena will need to serve. We have used the forecasts of non-residential and unmetered customer numbers reported in Jemena's reset RIN. This produces an average annual growth rate of 0.8 per cent for customer numbers.

Jemena's approach to forecasting output growth

Jemena adopted the following output growth measures and weightings:

- customer numbers (70.5 per cent)
- system physical capacity (29.5 per cent).

Jemena's weighting for customer numbers (70.5 per cent) is similar to our own (67.6 per cent). Consequently the key difference between Jemena's output growth forecast and our own is its use of system physical capacity rather than circuit length and ratcheted maximum demand.

Jemena has calculated system physical capacity as the product of distribution transformer capacity and network line length. We consider that taking the product of these two output measures does not produce a reasonable measure of output growth. To illustrate, assume there are two identical distribution networks. Combining the two identical networks would create a network twice the size of the individual networks. However, Jemena's proposed system physical capacity of the combined networks would be four times that of one of the individual networks because distribution transformer capacity and network line length have both doubled. Jemena have forecast distribution transformer capacity to increase by 3.21 per cent per year and network line length to increase by 2.06 per cent. This results in forecast system physical capacity increasing by 5.34 per cent per year, more than the two individual measures (Table B.10).

⁷⁹ We did not use the data for 2006 provided by Jemena because there appears to be a transfer of non-residential customers not on demand tariffs to residential customers in 2007. The rise in residential customers in 2007 was significantly higher than other years. At the same time the number non-residential customers not on demand tariffs fell.

Table B.10 Forecast system physical capacity

	2015	2016	2017	2018	2019	2020	Average
Line length	2.13	2.02	2.47	1.99	1.98	1.76	2.06
Distribution transformer capacity	3.70	3.33	3.19	3.10	3.02	2.94	3.21
System physical capacity	5.91	5.41	5.74	5.15	5.07	4.76	5.34

Source: Jemena, *Regulatory proposal, Opex model*, 30 April 2015.

Consequently we consider Jemena's proposed system physical capacity measure overstates output growth.

Economic Insights considers ratcheted maximum demand to be a better measure of the output a service provider must provide rather the level of assets such as distribution transformers and installed substation capacity.⁸⁰ This is because the assets to provide capacity may be in excess to customer's requirements. Meanwhile ratcheted maximum demand takes into account network capacity actually used even if maximum demand may be lower in subsequent years. Consequently we consider circuit length and ratcheted maximum demand better reflects the outputs Jemena will be required to deliver. Similarly, VECUA considered that ratcheted maximum demand 'is a more appropriate measure of the distributors' output than installed capacity factors'.⁸¹

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.⁸²

Jemena included a positive forecast productivity growth in its rate of change. It included forecast economies of scale, but not technical change, in its productivity growth forecast. It forecast economies of scale from its forecast of the output measures it used to forecast output growth and the elasticities estimated by Huegin.

The Guideline states that we will incorporate forecast productivity growth 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.⁸³

⁸⁰ Economics Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 7 October 2015, pp. 29–30.

⁸¹ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 45.

⁸² Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November, pp. 9, 10.

⁸³ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

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, Jemena' 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 Jemena for the following reasons:

- We are not satisfied that the output measures adopted by Jemena reflect the increase in output an efficient service provider requires to meet its opex objectives. Consequently its forecast of economies of scale will not reflect the economies of scale an efficient service provider will be able to achieve.
- 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.

Jemena's forecast of economies of scale

We discuss above why we are not satisfied that the output measures adopted by Jemena reflects the increase in output an efficient service provider requires to meet its opex objectives. For the same reasons Jemena's proposed system physical capacity measure overstates output growth, Jemena's forecast of economies of scale will also overstate the economies of scale an efficient service provider will be able to achieve.

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 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.⁸⁴

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

⁸⁴ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 41.

growth.⁸⁵ 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 2009.⁸⁶ However, total input quantity increased by 2.8 per cent per annum from 2010 to 2013.⁸⁷ 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.⁸⁸ 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.⁸⁹

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.

⁸⁵ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 20, 40.

⁸⁶ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 44–45.

⁸⁷ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 45.

⁸⁸ 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.

⁸⁹ 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.

VECUA considered that the distributors' productivity declined during the previous regulatory control period because we provided excessive opex allowances. It considered this should not be used to justify poor productivity outcomes in future years.⁹⁰ 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.⁹¹

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

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

As noted by VECUA, both the electricity transmission and gas distribution industries experienced positive opex productivity growth during the 2006–13 period.⁹² For electricity transmission network service providers average annual industry productivity was 0.85 per cent and for gas distribution Jemena Gas Networks proposed an average annual opex productivity of 0.95 per cent of which 0.83 per cent was attributed to the shift in the frontier.⁹³

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.

⁹⁰ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, pp. 45–46.

⁹¹ This includes productivity forecasts from Endeavour Energy, Essential Energy, ActewAGL, Ausgrid, Ergon Energy, Energex and SA Power Networks.

⁹² 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.

⁹³ AER, *JGN gas distribution determination – draft decision*, Attachment 7, Appendix A, November 2014.

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.⁹⁴

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.⁹⁵ 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.⁹⁶

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.⁹⁷ 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.

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

⁹⁴ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, pp. 45–46.

⁹⁵ DEDJTR, *Submission to Victorian electricity distribution pricing review*, 13 July 2015, p. 8.

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

⁹⁷ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

that DEDJTR did not provide us the independent assessment of the benefit 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.⁹⁸ 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.

⁹⁸ 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 Jemena for the 2016–20 regulatory control period.

C.1 Position

We have included two step changes in our total opex forecast:

- We are satisfied Jemena requires an increase in opex to implement new tariffs required by changed regulatory obligations.
- We are satisfied the additional opex associated with Jemena's demand management program is an efficient capex/opex trade-off.

We are not satisfied that adding step changes for the other cost drivers identified by Jemena would lead to a forecast of opex that reasonably reflects the opex criteria. A summary of Jemena's proposed step changes and our position are outlined in Table C.1.

Table C.1 Summary of draft position on step changes (\$ million, 2015)

	Jemena's proposal	AER position
Service inspection and testing program	6.2	–
Overhead switch inspection	2.2	–
Enclosed substation inspection and rectification	0.8	–
Regulatory proposal	8.0 ^a	–
Vegetation management	15.9 ^b	– ^d
ESV code of practice changes	0.9	–
Vulnerable customer assistance	1.0	–
Customer engagement	0.9	–
Pole-top fire detection (new technology trial)	1.4	–
Demand management opex/capex trade-off	0.7	0.7

	Jemena's proposal	AER position
Insurance (cic)	0.2	–
New tariff implementation	2.5	2.5
RIN reporting	19.7 ^c	– ^d
Total	60.3	3.2

Source: AER analysis; Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 1. Jemena, *Submission to Jemena Electricity Network 2016-20 regulatory proposal*, 13 July 2015, p. 1.

Note: a: While Jemena proposed a step change of \$8.0 million (\$2015) for its regulatory proposal, it also proposed a negative base year adjustment. Considered together they reduced its total opex forecast.

b: Jemena proposed a vegetation management step change of \$5.6 million in its regulatory proposal. It increased the proposed step change to \$15.9 million in a submission on 13 July 2015.

c: Jemena proposed a new step change of \$19.7 million for RIN reporting in a submission on 13 July 2015.

d: Vegetation management and RIN compliance are new regulatory obligations that may give rise to a justifiable step change. However, on the basis of the information and evidence Jemena has provided so far, we do not have sufficient material to form a view as to the quantum of an efficient opex step change.

C.2 Jemena's proposal

Jemena initially proposed twelve step changes totalling \$30.3 million. It referred to them as change factors. It proposed the step changes to meet new regulatory obligations, respond to changes in its operating environment and to respond to customers' preferences.⁹⁹ At the time Jemena filed its proposal, it stated it intended to propose an additional step change for RIN reporting but had not yet finalised the cost. It estimated the RIN reporting step change would be around \$2 million.¹⁰⁰

Jemena subsequently made a submission as part of the public submission process. In that submission it proposed a RIN reporting step change of \$19.7 million and increased the vegetation management step change from \$5.6 million to \$15.9 million.¹⁰¹ As a result the total value of proposed step changes doubled to \$60.3 million, or 11 per cent of total proposed opex.

C.3 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.¹⁰² Our

⁹⁹ Jemena, *Regulatory proposal*, 30 April 2015, p. 89.

¹⁰⁰ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 3.

¹⁰¹ Jemena, *Submission to Jemena Electricity Network 2016-20 regulatory proposal*, 13 July 2015, p. 1.

¹⁰² NER, cl. 6.5.6(c).

assessment approach specified in the *Expenditure forecast assessment guideline* (Guideline)¹⁰³ 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 in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.

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

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output then step changes that relate to forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of new office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year, which includes office maintenance) to account for forecast network growth.¹⁰⁴

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

¹⁰³ AER, *Expenditure assessment forecast guideline*, November 2013, pp. 11, 24.

¹⁰⁴ AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, p. 73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp. 164-165.

CPI. 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:¹⁰⁵

- whether there is a change in circumstances that affects the level of expenditure a prudent service provider requires to meet the opex objectives efficiently
- what options were considered to respond to the change in circumstances
- whether the option selected was the most efficient option—that is, whether the service provider took appropriate steps to minimise its expected cost of compliance
- the efficient costs associated with the step change and whether the proposal appropriately quantified all costs savings and benefits
- when this change event occurs and when it is efficient to incur expenditure, including whether it can be completed over the regulatory control 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.¹⁰⁶ 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.

¹⁰⁵ AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

¹⁰⁶ AER, *Expenditure assessment forecast guideline*, November 2013, p. 24.

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.¹⁰⁷ 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.¹⁰⁸ We agree with these submissions as our step 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 as it considered step changes have become a catchall for any actual or perceived risk of cost increases.¹⁰⁹ 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.4 Reasons for position

We have only included two of the thirteen step changes Jemena proposed in our alternative opex forecast. We consider each of the step changes Jemena proposed in detail below.

C.4.1 Service inspection and testing program

Jemena forecast an increase in opex of \$6.2 million (\$2015) for a service inspection and testing program. Our preliminary position is that Jemena does not require an increase in opex for this program.

Jemena stated it must undertake inspection and testing of service lines every 10 years in accordance with its regulatory obligations and for safety.¹¹⁰ It stated it did not undertake this activity in the base year. Therefore if we trend forward the base year level of expenditure on this program (zero) we will not provide sufficient funds for Jemena to undertake this program in the 2016–20 regulatory control period.

¹⁰⁷ AER, *Expenditure assessment forecast guideline*, November 2013, p. 24; AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, pp. 51–52.

¹⁰⁸ ERAA, *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.

¹⁰⁹ Consumer Challenge Panel, sub panel 3, *Response to proposals from Victorian electricity distribution network service providers - overview - 10 August 2015*, p. 5.

¹¹⁰ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 5–6.

Jemena's proposed program to inspect service lines is not a response to a new regulatory obligation but to existing regulatory obligations. We consider base opex already reflects the cost of meeting existing regulatory obligations and maintaining the reliability, safety and quality of supply of standard control services. We acknowledge that some types of projects and programs of expenditure a service provider undertakes will differ between years and between regulatory control periods. However, we do not consider variation in the expenditure on projects and programs is a reason to increase the revenue it can recover from electricity network consumers.

We make our assessment about the total forecast opex and not about particular categories or projects in the opex forecast. Within total opex we would expect to see some variation in the composition of expenditure from year to year. That is, expenditure for some categories will be higher than usual in a given year while other categories will be lower than usual. However, these variations tend to offset each other so that total opex is relatively stable.

Using a category specific forecasting method for some opex categories may produce better forecasts of expenditure for those categories but it may not produce a better forecast of total opex. If we apply a revealed expenditure forecasting method at the category level, forecast opex for those categories where expenditure is high in the base year will be higher than the efficient level of expenditure. Conversely, forecast opex will be lower than the efficient level for those categories where expenditure is low or even zero in the base year. Unless we identify every category of expenditure that is higher or lower than the efficient level, applying a base-step-trend forecasting approach to total revealed costs produces a better total opex forecast.

C.4.2 Overhead switch inspection program

Jemena forecast an increase in opex of \$2.2 million (\$2015) for an overhead switch inspection program. Our preliminary decision is that Jemena does not require an increase in opex for this program.

Jemena proposed a new inspection program to identify defects with aging overhead switches.¹¹¹ Jemena stated it has around 1000 air break switches in service which are increasingly reaching end of life. Therefore, it expects an increasing number of these assets will fail. It stated that to date, it runs the assets to failure and then replaces them. Rather than maintaining this approach, Jemena is proposing to undertake a cyclical five year inspection program to identify defects with overhead switches so that it can develop a more informed repair or capital replacement program. Jemena stated the drivers of this step change are:

- the deteriorating age profile of air break switches on the network
- an efficient capex/opex trade-off

¹¹¹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, Service inspection and testing program step change pp. 5–6, Overhead switch inspection step change, pp. 7–11.

- its commitment to maintain reliability of the network, in accordance with customers' stated preferences
- not repairing or replacing damaged switches will compromise network reliability and will increase safety risks.

As discussed in our assessment approach, an important consideration is whether the proposed step change is driven by an external obligation (such as new legislation or regulations) or an internal management decision (such as the decision to implement a new asset management strategy). 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. Jemena's proposal to implement condition-based monitoring of overhead switches is not a response to a new regulatory obligation; rather it is an internal business decision. Maintaining safety and reliability is a business as usual responsibility for a network service provider. We would expect our total opex forecast would already be sufficient for Jemena to maintain the reliability and safety of its network.

We may however include a step change if an increase in opex is an efficient capex/opex trade-off. Jemena did not provide information to satisfy us that this proposed step change represents an efficient capex/opex trade-off. Jemena stated that a large scale inspection program (opex) would inform a future targeted repair/replacement program in preference to a mass planned replacement program (capex).¹¹² However Jemena did not provide a cost benefit analysis to show that the program had a positive net present value (the amount by which the capex savings exceed the increased opex).

Nor do we consider that Jemena has demonstrated that a mass planned replacement program would be more efficient than maintaining the status quo which is a run to failure strategy. As Jemena itself stated "run to failure is a replacement strategy typically employed on these low cost/high volume and consumable assets, in which the consequence of failure is low...and network response to outages or replacement activity can be promptly addressed at relatively low cost".¹¹³

C.4.3 Enclosed substation inspection and rectification

Jemena forecast an increase in opex of \$0.8 million (\$2015) for enclosed substation inspection and rectification.¹¹⁴ Jemena stated this step change is driven by a change in regulatory obligations. The Electricity Safety (Bushfire Mitigation) Regulations 2013¹¹⁵

¹¹² Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 7.

¹¹³ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 10.

¹¹⁴ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 12–13.

¹¹⁵ S.7 of the Electricity Safety (Bushfire Mitigation) regulations 2013 commenced on 20 June 2013.

require that enclosed substations are inspected at least every three years in hazardous bushfire risk areas (HBRA) and every five years in low bushfire risk areas (LBRA).

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

Jemena stated to meet this obligation it will need to inspect 550 sites per annum. To forecast the cost of the step change Jemena assumed:

- an inspection cost of \$120 per site (based on a comparable inspection program)
- a defect rate of 50 per cent requiring some form of rectification work at a cost of \$440.

Even though this step change is related to a regulatory change we do not consider an increase in opex is needed. This is because the Electricity Safety (Bushfire Mitigation) Regulations 2013 largely mirror the position that has been in place since 2010.¹¹⁶

The regulatory impact statement on the 2013 electricity safety regulations stated:

The current regulatory context must be acknowledged. The proposed regulations largely mirror the position that has been in place since 2010. Moreover, the community has had a strong expectation that the recommendations of the VBRC will be implemented in practice. This implementation has been met and, indeed, slightly exceeded, insofar as the 37 month inspection regime has been applied universally to at risk assets.¹¹⁷

Because the new regulatory obligation does not impose a heavier burden on Jemena than what was previously in place, we consider the base level of opex provides sufficient funding for Jemena to meet those regulatory obligations. We note that no other distribution network service provider has proposed a step change to comply with the Electricity Safety (Bushfire mitigation) Regulation 2013.

We also note that almost two thirds of the cost of this step change is for rectification work on the substations once they have been inspected and found to be defective. Rectification work is a part of asset maintenance. We consider asset maintenance is business as usual for a network service provider and that base opex already reflects the cost of an efficient and prudent level of asset maintenance. Jemena did not outline in its proposal how frequently it was inspecting and rectifying substations in hazardous bushfire risk areas prior to 2013. Consumers may be paying double if we add rectification costs as part of a step change when asset maintenance is already accounted for in the base opex forecast.

¹¹⁶ Jemena intends to undertake the inspection of enclosed substations in LBRA at intervals shorter than that prescribed by the regulations (48 months instead of 61 months). It stated this was to ensure any missed substations do not fall outside the required period. However, this is Jemena's decision; it is not required by the regulation.

¹¹⁷ ESV, *Regulatory Impact Statement - Electricity Safety (Bushfire Mitigation) Regulations 2013*, February 2013, p. 7. Prepared by Jaguar Consulting.

In its submission, the VECUA stated the Victorian distribution businesses need to demonstrate that there has been a material change in a regulatory or legal obligation since the base year, and that the new obligation requires increased costs in comparison with the base year costs.¹¹⁸ It stated that for most step changes, the businesses failed to do this. We agree that Jemena has not demonstrated that there has been a material change in its legal obligations for enclosed substation inspection and rectification since the base year.

C.4.4 Regulatory proposal

Jemena proposed a step change of \$8.0 million (\$2015) for the cost of preparing its regulatory proposal for its five yearly price review. However, it also proposed a negative base year adjustment. Considered together, the step change and base year adjustment decreased Jemena's total opex forecast. Jemena stated the costs for preparing its regulatory proposal were higher in the base year than in other years. For that reason, it removed those costs from the base year and forecast these costs separately as a step change.¹¹⁹

We have not included a category specific forecast for this program. Rather, we have left these costs in the base year.

As noted in our assessment of the service inspection and testing program above, we make our assessment about the total forecast opex and not about particular categories or projects. Because total opex is more stable than opex at the category level, there is a risk that using a hybrid of revealed costs and category-specific forecasting approaches may, overall, lead to a biased forecast. To be consistent with this forecasting approach and our assessment of the service inspection and testing step change above, our position is not to forecast these costs separately. As such we have not included Jemena's proposed base year adjustment or the step change in our forecast.

C.4.5 Vegetation management

Our preliminary decision is not to include a step change for costs to comply with amendments to the Electrical Safety (Electric Line Clearance) Regulations 2015 (ELC). We consider the change in costs at this stage is uncertain. We expect Jemena's revised proposal for this step change to take into account both cost increases and cost decreases to comply with the new requirements.

Jemena proposed a \$5.5 million (\$2015) step change to comply with amendments to ELC 2015. Jemena based its forecast on anticipated changes that had not yet come into effect at the time of the initial proposal.¹²⁰

¹¹⁸ VECUA, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 37.

¹¹⁹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 14–15.

¹²⁰ Jemena Electricity Network, *Submission to Jemena Electricity Network Ltd 2016–20 regulatory proposal*, 13 July 2015, p. 13.

On 28 June 2015 the new amendments commenced in Victoria. We sent an information request to all Victorian distributors requesting updated information on costs to comply with ELC 2015.¹²¹ In response to our information request Jemena revised its step change to \$15.8 million (\$2015).¹²²

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

- amenity tree management standard AS 4373 (\$2.25 million)
- notification and consultation requirements (\$12.0 million)
- assistance which must be provided to councils (\$1.55 million).

We subsequently consulted with the ESV and it advised us that it intends to provide guidance to all Victorian distributors to ensure that they understand the manner in which the ESV will administer its rules.¹²³

The ESV also stated:

ESV does not accept that the new regulations will have cost impacts in the order of those claimed by the distribution businesses. The distribution businesses' interpretation does not reflect either the final regulations gazetted or the intent that ESV will clarify through more detailed guidance notes.¹²⁴

Based on the feedback from the ESV we do not consider Jemena's revised cost of \$15.8 million reflects the change in compliance cost for ELC 2015 because it is not consistent with the manner in which the ESV will administer ELC 2015.

The ESV also noted that it made amendments to reintroduce exceptions for structural branches in relation to both insulated and uninsulated electric lines which returns the flexibility of ELC 2005 where practicable.¹²⁵ 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 is achieved despite the reduced clearance dimension.¹²⁶ The ESV noted 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.¹²⁷

In our determination for the 2011–15 regulatory control period, we provided Jemena with a \$3.4 million (\$2010) step change for a regulatory change which removed the

¹²¹ AER, Jemena information request 9, 1 July 2015.

¹²² Jemena Electricity Network, *Submission to Jemena Electricity Network Ltd 2016–20 regulatory proposal*, 13 July 2015, p. 1.

¹²³ Energy Safe Victoria, ESV audit intent, 28 July 2015, p. 2.

¹²⁴ Energy Safe Victoria, ESV Audit intent, 28 July 2015, p. 2.

¹²⁵ Energy Safe Victoria, Response to AER email on electricity distribution proposals – ESV audit intent, 28 July 2015, p. 4.

¹²⁶ Jaguar Consulting, Regulatory Impact Statement Electricity Safety (Electric Line Clearance) Regulations 2015, September 2014, p. 41.

¹²⁷ Energy Safe Victoria, Response to AER email on electricity distribution proposals – ESV audit intent, 28 July 2015, p. 4.

structural branches exceptions. Since the ESV has now reversed this change (which removed the structural branches exceptions), we would expect a similar decrease in costs to the increase allowed in the 2011–15 period. The Consumer Challenge Panel (CCP) also noted that the 2010 amendments to vegetation management are being reviewed and consider these changes may have a significant impact on opex over the 2016–20 period.¹²⁸

We recognise 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.

There is some uncertainty around the decrease in costs due to the reintroduction of exceptions in 2015 and the increase in costs due to enhanced notification requirements and compliance with pruning of amenity trees. 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 Jemena'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.

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.4.6 Energy Safe Victoria code of practice changes

Jemena forecast an increase in opex of \$0.9 million (\$2015) for changes to the Energy Safe Victoria (ESV) code of practice.

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

Jemena stated the driver of this step is an expected change in regulatory obligations.¹²⁹ Jemena must comply with the Code of Practice for Electrical Safety (Blue Book).¹³⁰ It stated the Blue Book is regularly reviewed by ESV and it expects it will be reviewed again during the 2016–20 regulatory control period. It expects this would result in changes to its regulatory obligations regarding the management of electricity safety systems. As a result it stated it would have to review all of its 100 work procedures, manuals and work instructions.

We do not consider an increase in opex is needed for this program of opex. Generally we do not consider updating the Code of Practice for Electrical Safety is a new regulatory obligation. We consider the costs of Jemena complying with updated

¹²⁸ 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.

¹²⁹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 19–20.

¹³⁰ ESV, *Code of practice on electrical safety for work on or near high voltage electrical apparatus*, 2012.

industry standards, such as the Code of Practice for Electrical Safety, is a business as usual expense. We account for the cost of meeting business as usual expenses through our estimate of base opex. Furthermore, we note the cost implication of the update is uncertain. Jemena expects the blue book will be reviewed and expects this will result in changes to its regulatory obligations. We do not have enough information to include a step change on that basis.

C.4.7 Vulnerable customer assistance

Jemena forecast an increase in opex of \$1.0 million (\$2015) to provide assistance to vulnerable customers.¹³¹

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

Jemena proposed four initiatives to assist vulnerable customers:

- An in-home display trial for 500 customers to improve their understanding of their energy usage.
- A no interest loan scheme: Jemena would provide some funding to a community organisation which provides no or low-interest loans to vulnerable people so they buy new, more energy efficient appliances.
- Improved communications for culturally and linguistically diverse customers via pilot low-literacy communications material which covers energy safety issues.
- Community partnerships with local welfare agencies to develop energy literacy material to help vulnerable community groups better understand energy efficiency and costs.

In its submission, the Victorian Department of Economic Development, Jobs, Transport and Resources (DEDJTR) stated that the Essential Services Commission (ESC) is currently undertaking an inquiry into best practice financial hardship programs of energy retailers. The ESC expects to release its final report in late 2015.¹³² The DEDJTR submitted that if the inquiry reveals there is a role for the distribution network service providers in providing assistance to vulnerable customers, the AER should consider the level of expenditure required at that time, rather than seek to pre-empt the outcomes of the inquiry.¹³³

On the advice of DEDJTR, we have not included these costs in our forecast.

¹³¹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 21–23.

¹³² Essential Services Commission 2015, *Inquiry into the financial hardship arrangements of energy retailers: Our approach*, March 2015.

¹³³ Victorian Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review 2016–20*, 13 July 2015, p. 8.

C.4.8 Customer engagement

Jemena forecast an increase in opex of \$0.9 million (\$2015) for customer engagement. Jemena stated it incurred costs for customer engagement in the base year; however, these were included in the cost of preparing this revenue proposal which Jemena removed from the base year. Therefore, Jemena stated it required a step change for future customer engagement.¹³⁴

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

Changes to the NER in late 2012 require service providers to describe how they have engaged with consumers, and how they have sought to address any relevant concerns identified as a result of that engagement. Jemena was required to present this information in an overview report with its regulatory proposal.

We have not removed customer engagement costs or revenue proposal costs from the base year so we consider Jemena's customer engagement can be funded through the base level of opex.

In its submission, we note the VECUA stated that the distributors' base year opex allowance provides them with sufficient funds to fulfil the expectations of the AER's consumer engagement guideline.¹³⁵ We agree with this view.

C.4.9 Pole-top fire detection trial

Jemena forecast an increase in opex of \$1.4 million (\$2015) to trial new technology for pole-top fire detection. Our preliminary decision is that Jemena does not require an increase in opex for this program.

Jemena forecast an increase in opex to trial new technology for pole-top fire detection.¹³⁶ Pole top fires start as low partial discharges and detection of early partial discharges can help in reducing the risk of pole top fire starts. Jemena is proposing to lease a pole-top early fire detection (EFD) system in 2016 and to test the system on a number of feeders. This will include relocating the systems annually. Jemena stated it is necessary to test the technology before it makes a decision to roll it out permanently. Jemena proposed the early fire detection system trial because if successful, the long-term benefits would be reduced risk of pole fire incidents and a possible reduction in pole top fire mitigation expenditure.

Jemena's proposed program to trial pole-top fire detection technology is not a response to a new safety obligation. As outlined above, we recognise that a service provider will alter its expenditure over time on specific programs and projects. We consider base opex already reflects the cost of maintaining the reliability, safety and

¹³⁴ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 24–27.

¹³⁵ VECUA, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 38.

¹³⁶ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 28.

quality of supply of standard control services. Trialling pole-top fire detection technology may be an area where Jemena needs to devote additional resources in the 2016–20 regulatory control period. However, we do not determine opex at the program level. It is a prudent service provider's responsibility to reallocate its opex budget to meet these changing priorities.

We also note this trial if successful may result in other benefits for Jemena. For instance:

- Jemena may be able to reduce its capex on pole top expenditure. If so, it will keep the return on the RAB within the regulatory control period based on what we forecast would be an efficient capex spend. It will also receive Capital Expenditure Sharing Scheme (CESS) payments.
- Jemena may be able to reduce the frequency and duration of unplanned outages. If so will receive Service Target Performance Incentive Scheme (STPIS) payments.

We expect a service provider to weigh up the expected benefits it would receive from an efficiency initiative against the expected cost of the initiative and decide itself whether that initiative is worth funding. In our view, there is no compelling reason why Jemena should receive additional funding from its customers to pursue efficiencies. Our approach to implementing the CESS is outlined in Attachment 11 and the STPIS is outlined in Attachment 10.¹³⁷

C.4.10 Demand management capex/opex trade-off

Jemena forecast an increase in opex of \$0.7 million (\$2015) for two demand management capex/opex trade-offs.¹³⁸

We are satisfied the additional opex associated with Jemena's demand management program is an efficient capex/opex trade-off.

The step change is for two demand response opex programs to mitigate two network constraints which Jemena stated would otherwise need to be addressed through a capex response. The areas are:

- Footscray East (FE)
- North Heidelberg and Watsonia (NH-WT).

Jemena stated by transferring a portion of the risk of supply interruption and corresponding cost of expected unserved energy to participants of its demand response programs, it would be able to defer related network augmentation works to the 2021–25 regulatory control period. It estimated it would defer \$9 million of capex for FE and \$11 million for NH-WT.

¹³⁷ Also see AER, *Capital Expenditure Sharing Scheme for Electricity Network Service Providers- Explanatory Statement*, November 2013.

¹³⁸ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 29–30.

Using a discount rate of 7 per cent and annual straight-line depreciation rate of 2 per cent (over 50 years), Jemena estimated the deferred capex as:

- For FE: \$9 million x (0.07 + 0.02) = \$0.81 million (\$2014)
- For NH-WT: 11 million x (0.07 + 0.02) = \$0.99 million (\$2014).

Jemena estimated the costs of the demand response programs based on preliminary discussions with demand response aggregators. The cost of each targeted demand response project reflects the length of the program, the number of customers enrolled and the technical characteristics of the expected demand response. Jemena estimates the combined cost of the two programs is \$0.71 million (\$ 2015).

Even adjusting the estimated capex savings to reflect a discount rate of 5.5 per cent instead of 7 per cent, we consider the size of the deferred capex savings outweighs the respective costs for each of the demand response programs.¹³⁹ Therefore we consider it is efficient to increase opex to finance both of these demand response projects. We have included this step change in our opex forecast.

C.4.11 Insurance

Jemena proposed a step change of \$170,000 (\$2015) for insurance premiums not included in base year expenditure.¹⁴⁰

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

We note that we accepted this insurance step change for Jemena Gas Networks but on reflection we consider it is a cost that should already be accounted for by the base opex forecast. Even though we consider the insurance reflects a prudent and efficient risk management practice, risk management is part of business as usual for a network service provider. Because a new insurance product becomes available it does not mean consumers should have to pay a higher level of total opex. Given the immaterial amount we consider Jemena can fund this insurance from its total opex allowance.

C.4.12 New tariff implementation

We have included a step change of \$2.5 million for costs relating to the AEMC network pricing arrangements rule change in our opex forecast. We consider the new pricing framework created by the rule change involves a new set of obligations for Jemena relative to the current pricing rules.

¹³⁹ If we accept Jemena's estimated cost of the capex solutions but replace its assumed discount rate of 7 per cent with a discount rate of 5.5 per cent to be consistent with our WACC preliminary decision, we calculate the capex savings to be:

- For FE: \$9 million x (0.055+ 0.02) = \$0.675 million (\$2014)
- For NH-WT: 11 million x (0.055+ 0.02) = \$0.825 million (\$2014).

¹⁴⁰ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 31–34. [commercial in confidence].

Jemena forecast an increase in opex of \$2.5 million (\$2015) to comply with an AEMC rule made on 27 November 2014.¹⁴¹ The intent of the rule change is to drive cost reflective network pricing and to improve the transparency of distributors' pricing information.

We are satisfied Jemena requires an increase in opex to implement new tariffs required by changed regulatory obligations.

The network pricing rule change requires Jemena to set prices that reflect the efficient cost of providing network services to individual consumers.¹⁴² Jemena is required to develop a tariff structure statement (TSS) and to consult with consumers on its development. The Victorian distributors are required to submit their proposed TSS to the AER by 25 September 2015.¹⁴³ Prices based on the new set of pricing principles will apply in Victoria from 1 January 2017.

We consider the cost Jemena proposed for this step change is reasonable. Jemena provided a detailed costing of the step change. Most of the cost of the step change will be to transition customers to the new tariff structure. The costs will include two mass mail-outs to inform them of the new network tariff structure as well as managing increased call volumes, enquiries and disputes.¹⁴⁴

C.4.13 Regulatory information notice reporting

Jemena forecast an increase in opex of \$19.7 million (\$2015) for increased RIN reporting costs.¹⁴⁵ Jemena is required to report information to the AER through annual, economic benchmarking and category analysis RINs. The step change is to put in place procedures, systems and training to provide 'actual' RIN data rather than estimated data.¹⁴⁶

Our preliminary position is not to include a step change of \$19.7 million in our total opex forecast. This is for two reasons:

- We consider the total cost of the step change is not reasonable compared to Jemena's total opex.
- We consider the costs of some of the components of the step changes are not reasonable.

Jemena stated that until 2015 if it was unable to provide actual data in response to the RINs, it was allowed to estimate the data. However from 2015 onwards it must provide actual data. Jemena stated its current systems and processes are not able to report

¹⁴¹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 35–38.

¹⁴² <http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements>.

¹⁴³ AEMC, *Network pricing rule change, final determination*, 27 November 2014, pp. 107–108.

¹⁴⁴ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 36–38.

¹⁴⁵ Jemena, *Submission to its Regulatory proposal*, 13 July 2015, pp. 3–6.

¹⁴⁶ Jemena stated it would comply with the RINs but exclude providing actual data for areas where it is unlikely that providing actual data would meet a net benefit test.

actual RIN data. It stated the cost of the step change includes initial one-off costs and annual ongoing costs for both the benchmarking RINs and the category analysis RINs. These costs are summarised in Table C.2.

Table C.2 Proposed costs to provide actual data for the benchmarking RIN and the category analysis RIN (\$ million, 2015)

	One-off costs	Annual costs	Total
	2016	2017–20	2016–20
Benchmarking RINs	1.3	0.7	4.3
Category analysis RINs	8.9	1.6	15.3
Total	10.2	2.4	19.7

Source: Jemena, *Submission to its Regulatory proposal*, 13 July 2015, pp. 6–9. Numbers do not add due to rounding.

We assessed the costs of the step change at both an aggregate level and at a component level.

We consider the total cost of the step change is not reasonable. The total proposed cost of the step change for the 2016–20 regulatory control period is almost \$20 million or \$4 million per year. To put this in context, Jemena's total opex in the base year was only \$70 million (\$2015). We note that base year opex already includes the cost of providing RIN information to date. We do not consider Jemena has put forward persuasive evidence as to why the total cost to report 'actual' RIN data rather than estimated data would increase by such magnitude.

We also have concerns about Jemena's proposed costs at the component level:

- We are concerned Jemena has been overly conservative in its interpretation of the term 'actual' information. The definition of actual information requires information whose presentation is materially dependent on actual records.¹⁴⁷ This means actual physical information, for example, allows for the possibility that Jemena has undertaken some sampling to derive that information as against having recorded every instance. We consider Jemena would have already been using a sampling method to comply with previous RIN responses. Therefore to some extent, it has already been providing information where the presentation is materially dependent on actual records. For example, where the RIN requests the number of trees per span, it is not our intention that every tree in an easement must be counted. Rather, a total number of trees can be derived from a reasonable sample. Jemena contracts out tree maintenance to a third party. In tendering for the contract those

¹⁴⁷ AER, *Economic benchmarking RIN for distribution network service providers*, Instructions and definitions, November 2013.

third parties must have an idea of the volume of work or number of trees they will be required to maintain.

- The definition of 'actual' data leaves a lot of room for interpretation. Jemena stated its experts considered some of the data Jemena previously considered estimates would meet the actual information definition.¹⁴⁸ We consider there may be even more data that Jemena previously considered estimates that would meet the actual information definition.
- We are looking for Jemena to use registers used in the ordinary course of business to derive actual information. We defined actual information as information materially dependent on information recorded in the distributor's historical account records or other records used in the normal course of business, for example asset registers, outage analysis systems and tenders.
- We are concerned about the cost Jemena is proposing to report actual information on the assets it owns (RAB information) in the benchmarking RIN. We consider these amounts are too high when Jemena is already required to provide its opening RAB, disposals depreciation and additions every year. We also question why Jemena expects it will cost \$69,000 to provide actual information about its assets in 2016 and then an additional \$48,000 to provide the same information each year after that.
- We are concerned at the increased level of auditing costs Jemena is proposing (\$0.5 million). RIN data is already subject to audit. The requirement to provide actual information rather than estimates does not imply there is more information to be audited or that we require additional auditing. We are concerned that the proposed audit costs for the benchmarking RIN are \$18,300 in 2016 but double to \$33,800 each year after that. Similarly for the category analysis RIN.
- We are concerned Jemena may not have factored in the efficiencies it might realise when collecting data that is similar across both RINs. For example it might be able to obtain both sets of responses at the same time and using the same process. For example, Jemena stated the expected cost of providing the operating environment information in the benchmarking RIN is \$3 million and the expected cost of providing the vegetation management information in the category analysis RIN is a further \$1 million. We consider that both RINs are requesting similar information.
- We are concerned about the proposed cost of \$6.2 million for monitoring in the category analysis RINs. Jemena is proposing monitoring costs for repex, augex, connections, maintenance and public lighting without explaining what this is for. Monitoring comprises over 75 per cent of the on-going costs of complying with the category analysis RINs.
- Jemena proposed \$0.5 million for training under the project management cost of complying with the category analysis RIN. They have not explained the need for

¹⁴⁸ Jemena, *Submission to its Regulatory proposal*, 13 July 2015, p. 5.

project management training in addition to the \$0.9 million training costs forecast for the other categories.

We acknowledge that RIN compliance is a new regulatory obligation that may give rise to a justifiable step change. However, on the basis of the information and evidence Jemena 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 invite Jemena to reconsider the requested step change and the information and evidence provided in support in its regulatory proposal relating to the revocation and substitution of this distribution determination. If Jemena puts a better case to us in its revised proposal we may include a step change for RIN compliance in our final decision opex forecast.