

FINAL DECISION Jemena distribution determination 2016 to 2020

Attachment 7 – Operating expenditure

May 2016



and an address

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Note

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

The final decision includes the following documents:

Overview

- Attachment 1 Annual revenue requirement
- Attachment 2 Regulatory asset base

Attachment 3 - Rate of return

- Attachment 4 Value of imputation credits
- Attachment 5 Regulatory depreciation
- Attachment 6 Capital expenditure
- Attachment 7 Operating expenditure
- Attachment 8 Corporate income tax
- Attachment 9 Efficiency benefit sharing scheme
- Attachment 10 Capital expenditure sharing scheme
- Attachment 11 Service target performance incentive scheme
- Attachment 12 Demand management incentive scheme
- Attachment 13 Classification of services
- Attachment 14 Control mechanisms
- 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
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
augex	augmentation expenditure
CAM	cost allocation method
capex	capital expenditure
ССР	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MFP	multifactor productivity
MPFP	multilateral partial factor productivity
MRP	market risk premium
MTFP	multilateral total factor productivity
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider

Shortened form	Extended form
opex	operating expenditure
PFP	partial factor productivity
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
VBRC	Victorian Bushfire Royal Commission
WACC	weighted average cost of capital

7 Operating expenditure

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

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

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

7.1 Final decision

We are not satisfied that 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 We compare our substitute estimate of Jemena's opex for the 2016–20 regulatory control period with its initial regulatory proposal, our preliminary decision and Jemena's revised regulatory proposal in Table 7.1.³

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

	2016	2017	2018	2019	2020	Total
Jemena's initial 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
Jemena's revised proposal	93.2	91.2	92.6	94.9	95.6	467.4
AER final decision	89.8	88.0	89.0	90.8	91.2	448.8

Source: AER analysis.

Note: Excludes debt raising costs.

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

¹ NER, cl. 6.5.6(c).

² NER, cl. 6.5.6(d).

³ NER, cl. 6.12.1(4)(ii).



Figure 7.1 AER final decision compared to Jemena's past and proposed opex (\$ million, 2015)

Source: AER analysis. Note: Includes debt raising costs.

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

7.2 Jemena's revised proposal

In its revised proposal, Jemena proposed a forecast opex of \$467.4 million (\$2015) for the 2016–20 regulatory control period.⁴ This is a 5.0 per cent decrease from the \$491.9 million (\$2015) it initially proposed.

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

⁴ Jemena, Opex forecast model.xlsx, January 2016, excludes debt raising costs.



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

Source: Jemena, Revised regulatory proposal, opex model, January 2016; AER analysis.

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. This results in a base opex of \$368.7 million (\$2015) over the 2016–20 regulatory control period. This is \$2.7 million (\$2015) lower than our preliminary decision due to an updated estimate of inflation in 2015.
- Jemena's 2014 regulatory accounts include one-off accounting adjustments relating to provision changes. It adjusted base opex to remove the movement in provisions in 2014. The effect of this is to set the net forecast expenditure in this cost category to zero. This reduced Jemena's forecast by \$0.1 million (\$2015). This is consistent with our preliminary decision.
- To forecast the increase in opex between 2014 and 2015 Jemena added the difference between its opex allowances for 2014 and 2015. This is consistent with the approach set out in the *Expenditure Forecast Assessment Guideline* (the Guideline). This reduced Jemena's forecast by \$5.6 million (\$2015). This is consistent with our preliminary decision.

- Jemena also adjusted its base opex to add opex that is classified as standard control services in the 2016–20 regulatory control period. This increased Jemena's forecast by \$46.0 million (\$2015). This is \$43.3 million (\$2015) higher than our preliminary decision. This reflects different approaches to the allocation of AMI costs. In our preliminary decision we allocated these costs to alternative control services metering.
- Jemena proposed output growth using our approach to forecasting output growth. However, Jemena forecast higher customer numbers growth than it did in its initial proposal. Output growth increased Jemena's opex forecast by \$23.6 million. This is \$14.9 million (\$2015) higher than our preliminary decision.
- Jemena adopted the forecast of price growth in our preliminary decision in its revised regulatory proposal. Price growth increased Jemena's opex forecast by \$6.7 million. This is \$0.6 million (\$2015) higher than our preliminary decision because it was applied to a higher base opex.
- Jemena identified step changes in costs it forecast to incur during the forecast period, which were not incurred in 2014. This increased Jemena's forecast by \$26.8 million (\$2015). This is \$23.6 million (\$2015) higher than the step changes in our preliminary decision.
- Jemena included a category specific forecast for guaranteed service level (GSL) payments. This increased its forecast by \$1.2 million (\$2015). This is \$0.9 million (\$2015) higher than the GSL payments we forecast in our preliminary decision. The increase in GSL payments reflects new Electricity Distribution Code (EDC) requirements.

7.3 Assessment approach

This section sets out our general approach to assessment.⁵ 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 Guideline.

There are two tasks that the NER requires us to undertake in assessing total forecast opex. In the first task, we form a view about whether we are satisfied a service provider's proposed total opex forecast reasonably reflects the opex criteria.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

⁵ The discussion in this section, to the extent it differs from that set out in the preliminary decision, clarifies the assessment approach that we applied in both the preliminary decision and this final decision.

⁶ NER, cll. 6.5.6(c), 6.12.1(4).

⁷ NER, cll. 6.5.6(c), 6.12.1(4)(i).

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

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.

⁸ NER, cll. 6.5.6(d), 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.

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).

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 service provider requires to achieve the opex objectives.

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

¹³ NER, cll. 6.5.6(c), (d).

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

- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)
- the extent to which the distribution network service provider has considered and made provision for efficient and prudent non-network alternatives
- any relevant final project assessment conclusions report published under 5.17.4(o),(p) or (s)
- any other factor we consider relevant and which we have notified the distribution network service provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.

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

As we noted above, the two tasks that the NER requires us to undertake involve us exercising our discretion. In exercising discretion, the National Electricity Law (NEL) requires us to take into account the revenue and pricing principles (RPPs).¹⁵ In the overview we discussed how we generally have taken into account the RPPs in making this final decision. Our assessment approach to forecast opex ensures that the amount of forecast opex that we are satisfied reasonably reflects the opex criteria is an amount that provides the service provider with a reasonable opportunity to recover at least its efficient costs.¹⁶ By us taking into account the relevant capex/opex trade-offs, our assessment approach also ensures that the service provider faces the appropriate incentives to promote efficient investment in, and provision and use of, the network and minimises the costs and risks associated with the potential for under and over investment and utilisation of the network.¹⁷

Expenditure Forecast Assessment Guideline

After conducting an extensive consultation process with service providers, users, consumers and other interested stakeholders, we issued the Expenditure Forecast Assessment Guideline in November 2013 together with an explanatory statement.¹⁸ The Guideline sets out our intended approach to assessing opex in accordance with the NER.¹⁹

While the Guideline provides for regulatory transparency and predictability, it is not binding. We may depart from the approach set out in the Guideline but we must give

¹⁵ NEL, ss. 7A, 16(2).

¹⁶ NEL, s. 7A(2).

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

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

¹⁹ NER, cl. 6.5.6.

reasons for doing so.²⁰ For the most part, we have not departed from the approach set out in the Guideline in this final decision.²¹ In our framework and approach paper, we set out our intention to apply the Guideline approach in making this determination.²² There are several parts of our assessment:

- We develop an alternative estimate to assess a service provider's proposal at the total opex level.²³ We recognise that a service provider may be able to adequately explain any differences between its forecast and our estimate. We take into account any such explanations on a case by case basis using our judgment, analysis and stakeholder submissions.
- 2. We assess whether the service provider's forecasting method, assumptions, inputs and models are reasonable, and assess the service provider's explanation of how its method results in a prudent and efficient forecast.
- 3. We assess the service provider's proposed base opex, step changes and rate of change if the service provider has adopted this methodology to forecast its opex.

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

If we are not satisfied with the service provider's proposal, we approach our second task by using our alternative estimate as our substitute estimate. The AEMC expressly endorsed this approach in its decision on the major rule changes that were introduced in November 2012. The AEMC stated:²⁴

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

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

²⁰ NER, cl. 6.2.8(c).

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

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

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

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

Building an alternative estimate of total forecast opex

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

Figure 7.3 How we build our alternative estimate



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



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

Underlying our approach are two general assumptions:

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

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

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

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

Step 1—Base year choice

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

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

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

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

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

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

Step 2—Assessing base opex

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

As we set out in the Guideline, to assess the service provider's actual expenditure, we use a number of different qualitative and quantitative techniques.²⁶ This includes benchmarking and detailed reviews.

Benchmarking is particularly important in comparing the relative efficiency of different service providers. The AEMC highlighted the importance of benchmarking in its changes to the NER in November 2012:²⁷

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

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. In our preliminary decision we used

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

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

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

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

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

Step 3—Rate of change

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

- price growth
- output growth
- productivity growth.

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

Step 4—Step changes

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

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

In our final step, we assess the need to make any further adjustments to our opex forecast. For instance, our approach is to forecast debt raising costs based on a

²⁸ We discuss the benchmarking models in detail in appendix A.

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

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

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

7.3.1 Interrelationships

In assessing Jemena's total forecast opex we took into account other components of its regulatory proposal, including:

- the operation of the EBSS in the 2010–15 regulatory control period, which provided 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 step change for demand management
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- changes to the classification of services from standard control services to alternative control services
- concerns of electricity consumers identified in the course of its engagement with consumers.

7.4 Reasons for final decision

Generally we agree with Jemena on the approach to forecasting total opex. However, due to some differences with forecasts of the inputs used we are not satisfied Jemena's proposed total forecast opex of \$467.4 million (\$2015) reasonably reflects the opex criteria. We must not, therefore, accept Jemena's proposed total forecast opex.³⁰ As discussed above, we have used our alternative estimate of \$448.8 million (\$2015) as our substitute estimate.³¹

Figure 7.4 illustrates how we constructed our forecast. The starting point on the left is what Jemena's opex for each year of the 2016–20 regulatory control period would be if it was set equal to its reported opex in 2014.

³⁰ NER, cl. 6.5.6(d).

³¹ NER, cll. 6.5.6(d), 6.12.1(4)(ii).

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



Source: AER analysis.

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

Table 7.2 Pro	posed vs final	decision to	otal forecast	opex (\$	million,	2015)
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	2016	2017	2018	2019	2020	Total
Jemena's revised proposal	93.2	91.2	92.6	94.9	95.6	467.4
AER final decision	89.8	88.0	89.0	90.8	91.2	448.8
Difference	-3.4	-3.2	-3.6	-4.1	-4.4	-18.6

Source: AER analysis.

Note: Excludes debt raising costs.

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

7.4.1 Base opex

Starting point for base opex

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

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

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

We received some submissions that raised queries about the recent decline in productivity of the Victorian services providers and what it may mean for using actual opex in 2014 as the base opex.³²

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

We outline our assessment of base opex in appendix A.

Adjustment for Advanced Metering Infrastructure (AMI) costs

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

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

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

³² VECUA, Submission to the AER Preliminary 2016-20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 4, pp. 60-62; Consumer Challenge Panel Sub Panel 3, Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period, 25 February 2016, p. 11–12.

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

By applying these principles we have made an adjustment to Jemena's base opex of \$8.4 million (\$2015). As discussed in Attachment 16 the revised approach leads to a commensurate reduction in metering opex from our preliminary decision.

Table 7.3 illustrates how we have constructed base opex.

	Our final decision
Reported 2014 opex	74.2
Remove movement in provisions	-0.0
Remove DMIA expenditure	-0.1
GSL payments	-0.1
Remove scrapping of assets	-0.4
AMI cost reallocation	8.4
Other service classification changes	0.5
Adjusted 2014 opex	82.6
2015 increment	-1.1
Estimated 2015 opex	81.5

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

Source: AER analysis.

7.4.2 Rate of change

The efficient level of expenditure required by a service provider in the 2016–20 regulatory control period may differ from that required in the final year of the 2011–15 regulatory control period. Once we have determined the opex required in the final year of the 2011–15 regulatory control period, we apply a forecast annual rate of change to forecast opex for the 2016–20 regulatory control period. This accounts for the forecast change in opex due to price, output and productivity growth.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than Jemena's over the forecast period. Table 7.1 below compares Jemena's and our overall rate of change in percentage terms for the 2016–20 regulatory control period.

	2016	2017	2018	2019	2020
Jemena	2.32	2.24	2.54	2.59	2.55
AER	1.77	1.74	1.99	2.05	2.16
Difference	-0.55	-0.50	-0.55	-0.54	-0.39

Table 7.1 Forecast annual rate of change in opex (per cent)

Source: AER analysis.

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

- Jemena used the forecast price change we determined in our preliminary decision in its revised regulatory proposal. However, it did not update its forecast of labour price growth to account for changes in economic conditions since we published our preliminary decision. Our preliminary decision used an average of the WPI growth rates forecast by Deloitte Access Economics (DAE) prepared in June 2015 and BIS Shrapnel prepared in November 2014. Our updated forecast uses an average of forecasts from DAE prepared in February 2016 and CIE prepared in November 2015. Consequently, our forecast of price growth is on average 0.22 percentage points lower than Jemena's forecast.
- Jemena forecast higher output growth due to a higher forecast growth in customer numbers. Jemena forecast future customer numbers using a projection of population growth in local government areas. We used historical growth in customer numbers to forecast future growth. Also, Jemena did not ratchet its maximum demand forecast. We have also updated our output weights to match those in our latest benchmarking report. Consequently, we have forecast output growth 0.28 percentage points lower, on average, than Jemena did.

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

7.4.3 Step changes

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

- service testing and inspection program
- enclosed substation inspection and rectification
- vegetation management
- demand management opex/capex trade-off
- new tariff implementation

- new RIN reporting requirements
- power of choice
- adoption of chapter 5A.

In total these step changes contribute \$17.1 million (\$2015) or 3.8 per cent to our total opex forecast for Jemena for the 2016–20 regulatory control period. We consider these step changes represent the efficient and prudent costs of meeting new regulatory obligations or represent an efficient capex/opex trade-off. We were not satisfied there were reasons to change our opex forecast for other step changes.

Table 7.4 summarises our final position on each of Jemena's proposed step changes.

Table 7.4Step changes (\$ million, 2015)

Proposal	Initial proposal	Preliminary decision	Revised proposal	Final decision
Service inspection and testing program	6.2	0	6.2	5.8
Overhead switch inspection	2.2	0	0	0
Enclosed substation inspection and rectification	0.8	0	0.6	0.2
Electricity distribution price review	8.0	Included in base year		
Vegetation management	15.9	0	6.9	2.3
ESV code of practice changes	0.9	0	0	0
Vulnerable customer initiative	1.0	0	1.0	0
Customer engagement	0.9	Included in base year		
New technology trial: pole-top fire detection	1.4	0	1.4	0
Demand management opex/capex trade- off	0.7	0.7	0.7	0.7
Cic	cic	0	cic	0
New tariff implementation	2.5	2.5	2.5	0.5
RIN reporting	19.7	0	5.9	5.9
Increased GSL obligations			0.9	Included as a category specific forecast
Power of choice			0.9	0.9
Adoption of chapter 5A			0.7	0.7
Total	60.3	3.2	27.7 ^a	17.1

Source: AER analysis.

Note: a) Excludes cic step change.

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

7.4.4 Other costs not included in the base year

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

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

7.4.5 Assessment of opex factors

In deciding whether we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.³³

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

Table 7.5 AER consideration of opex factors

Opex factor	Consideration
	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider.
The 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.	The second element, that is, the benchmark operating expenditure that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period.
	We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of Jemena's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.
The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Jemena's actual past opex with that of

³³ NER, cl. 6.5.6(e).

	other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network	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. ³⁴
electricity consumers.	We have considered the concerns of electricity consumers as identified by Jemena– particularly in considering Jemena's proposed step changes.
	We have considered capex/opex trade-offs in considering Jemena's proposed step changes. For instance we have provided a step change for demand management on the basis that it is an efficient capex/opex trade-off. We considered the relative expense of capex and opex solutions in considering this step change.
The relative prices of capital and operating inputs	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 in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.
	As noted above we considered capex/opex trade-offs in considering a step change for Jemena's demand management. We considered the substitution possibilities in considering this step change.
The substitution possibilities between operating and	Some of our assessment techniques examine opex in isolation—either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability.
capital expenditure.	In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs.
	We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs.
Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the	The incentive scheme that applied to Jemena's opex in the 2010–15 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach.
or 6.6.2 to 6.6.4.	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.

³⁴ AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

	opex en
The extent the operating expenditure forecast is referable	concern
to arrangements with a person other than the Distribution	arm's lei
Network Service Provider that, in the opinion of the AER,	party pro
do not reflect arm's length terms.	Likewise
	north (nr

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 the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives. 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.

This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our final decision.

We have not found this factor to be significant in reaching our final decision.

Source: AER analysis.

A Base opex

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

A.1 Final decision

We have used a base opex amount of \$81.5 million in our final decision opex amount. The comparison of the base opex amount in our preliminary decision, Jemena's revised proposal and our final decision is outlined below in Table A.1.

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

	Preliminary decision	Revised proposal	Our final decision
Reported 2014 opex	74.8	74.3	74.2
Remove movement in provisions	0.0	0.0	0.0
Remove DMIA expenditure	-0.1	-0.1	-0.1
GSL payments	-0.1	-0.1	-0.1
Remove scrapping of assets	-0.4	-0.4	-0.4
AMI cost reallocation		8.7	8.4
Other service classification changes	0.5	0.5	0.5
Adjusted 2014 opex	74.8	82.9	82.6
2015 increment	-1.1	-1.1	-1.1
Estimated 2015 opex	73.7	81.8	81.5

Source: AER, Jemena preliminary decision opex model, October 2015; Jemena, Attachment 08-03 JGN SCS Distribution - Opex Forecast Model, January 2016; AER, Jemena final decision opex model, May 2016.

A.2 Jemena's revised proposal and submissions

In Jemena's revised proposal it proposed a base opex amount of \$81.8 million (\$2015)

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

There were also some minor differences on the reported amount for 2014 opex and the 2015 increment. This reflected differences in inflation estimates.

We received several submissions in response to our preliminary decisions for the Victorian service providers which either disagreed with our conclusions on base opex

or requested further evidence to support our decision. In particular, VECUA considered there is extensive evidence of material inefficiencies in some Victorian distributors' opex. It considered this has been revealed by our benchmarking. As a result it considered using a revealed cost method to be flawed and a benchmarking approach should be used. It considered CitiPower to be the benchmark provider.³⁵

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

- the decline in the Victorian distributors' productivity over the previous regulatory control period
- increases in the Victorian distributors' opex over the previous regulatory control period
- the opex reductions that should be realised from the Victorian distributors' major capex programs over the previous regulatory period.³⁶

The CCP was concerned we have presumed 2014 opex is efficient and that we have relied on it to set forecast expenditure in light of the recent decline in productivity. It also urged we review this in detail. It was not convinced that increased bushfire mitigation expenditure and expansion of the network were driving the decline in productivity.³⁷

Further specific comments we received are addressed below.

A.3 Assessment approach

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

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

³⁵ VECUA, Submission to the AER Preliminary 2016-20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 60.

³⁶ VECUA, Submission to the AER Preliminary 2016---20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, pp. 4, 60–62.

³⁷ Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 25 February 2016, pp. 11–12.

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.

A.4 Reasons for final decision

Incentive regulation and the revealed cost forecasting approach

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

Network services are monopoly services with little scope in any given location for a competitor to duplicate the network efficiently.³⁸ Monopoly businesses do not have an incentive to set prices at an efficient level because there is no competitive discipline on their decisions. They do not need to consider how and whether or not rivals will respond to their prices. Monopolies' profits depend only on the behaviour of consumers, their cost functions, and their prices or the amount supplied.³⁹

Without regulation, the resulting market power would lead to high prices and probably insufficient investment. Accordingly, we must regulate the prices and other aspects of these services to ensure reliable and affordable electricity.⁴⁰

Information asymmetries make it difficult for us to accurately assess the efficiency of the network businesses' proposals. We need to make judgements about 'efficient' costs.⁴¹

Incentive regulation is used to partially overcome information asymmetries. We apply incentive-based regulation across all energy networks we regulate—consistent with the NER.⁴² This is a fundamental aspect of the regime. As stated by the AEMC:

Set out in Chapter 6 of the NER, the incentive regulation framework is designed to encourage distribution businesses to spend efficiently and to share the benefits of efficiency gains with consumers. Specifically, it is designed to encourage distribution businesses to make efficient decisions on when and what type of expenditure to incur in order to meet their network reliability, safety, security and quality requirements.⁴³

³⁸ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no.* 62, 2013, p. 65.

³⁹ ACCC, Submission to the Productivity Commission's inquiry into the economic regulation of airport services, March 2011, p. 8.

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

⁴¹ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no.* 62, 2013, p. 190.

⁴² Clause 6.2.6(a) of the NER states that for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C (Building Block Determinations for standard control services). Further, the RPPs state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.

⁴³ AEMC, Consultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, February 2015, p. 3.

Broadly speaking, incentive regulation is designed to align the commercial goals of the business to the goals of society or, in the case of energy regulation, the NEO.⁴⁴ It relies on the principle that the network businesses' objective is to maximise profits.⁴⁵ Businesses that are able to improve their efficiency are rewarded with higher profits.⁴⁶ Businesses that allow their efficiency to deteriorate earn lower-than-expected profits. The actual revenue allowance set by the regulator should not influence the basic incentive of network businesses to minimise costs and, thereby, maximise profits. The drive to maximise shareholder returns should, in theory, push the businesses to become more efficient and productive over time. This allows us to leave the minutiae of input and output decision-making to the businesses.⁴⁷

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

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

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

The main tool we have to assess whether incentive regulation is working is benchmarking. However, all the benchmarking we have undertaken, which was presented in our preliminary decision ⁴⁸ shows that, on the whole, the Victorian service providers are operating relatively efficiently when compared to their counterparts in

⁴⁴ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no.* 62, 2013, p. 188.

⁴⁵ Put simply, it is assumed that shareholders want the business to maximise profits because the greater the profits, the greater their income.

⁴⁶ As stated by the AER in its Expenditure Forecast Assessment Guideline explanatory statement, 'the ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's forecast) because network businesses can retain a portion of cost savings made during the regulatory control period.', p. 42.

⁴⁷ Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no.* 62, 2013, pp. 27–28.

⁴⁸ AER, *Preliminary decision, Attachment* 7, October 2015, pp. 31–40.

New South Wales and Queensland.⁴⁹ We do acknowledge the gap between the Victorian service providers and the NSW and Queensland service providers has narrowed in recent years on the MTFP and Opex MPFP benchmarks. However, as discussed in our annual benchmarking report⁵⁰, and below, changes in bushfire mitigation requirements including vegetation management are a significant driver of this outcome.

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

We also note that VECUA has inferred that because CitiPower is the best performer on one benchmarking model, the opex of all other Victorian service providers should be deemed to be inefficient.⁵¹ We do not agree with this finding. Because benchmarking models are subject to limitations regarding specification of outputs and inputs, data imperfections and other uncertainties, we consider it is preferable to interpret the findings of any benchmarking conservatively. We do not consider it is reasonable to conclude that because one service provider is ranked highest in one model then all other service providers must be inefficient.⁵²

Reasons for productivity decline/increase in opex in Victoria

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

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

⁴⁹ Our preliminary decision was based on benchmarking we had presented in our most recent distribution benchmarking report published in November 2014 (AER, 2014 Annual benchmarking report, November 2014). After releasing our preliminary decision in October 2015 we published an additional distribution benchmarking report in November 2015 (AER, 2015 Annual benchmarking report, November 2015). The 2015 version of the report still indicates that the Victorian service providers are operating relatively efficiently compared to their counterparts in New South Wales and Queensland.

⁵⁰ AER, 2015 Annual benchmarking report, November 2015, p. 8.

⁵¹ VECUA, Submission on the AER Preliminary 2016-20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 60.

⁵² We also note the model VECUA refers to measured average opex efficiency over an eight year period (2006 to 2013). For the purposes of setting base opex we are reaching a conclusion on efficient opex for 2014 As the costs facing the Victorian service providers are different in 2014 to the average costs they faced from 2006 to 2013, it is not possible to directly infer 2014 efficiency by assessing 2006 to 2013 efficiency.

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

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



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

Source: AER analysis

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



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

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

Source: AER analysis.


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

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

- Minimum clearance spaces surrounding aerial bundled cable or insulated cable now applied to small tree branches. Under the previous version of the regulations, the minimum clearance spaces did not apply to small tree branches under specified conditions.
- Minimum clearance spaces surrounding powerlines in hazardous bushfire risk areas now applied to tree branches above a powerline of 22kV. Under the previous version of the regulations the minimum clearance space did not apply under specified conditions.⁵³

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

Source: AER analysis.

⁵³ Victorian Competition and Efficiency Commission, Proposed Electrical Safety (Electric Line Clearance) Regulations 2010 Regulatory Impact Statement, pp. xviii-xix.

regulatory control period.⁵⁴ At the time, we forecast increases in opex of \$206 million (\$2015) from 2011 to 2015 due to these new regulations.⁵⁵

Vegetation management expenditure across the industry was also likely affected by heavy rainfall during the period. The year 2010 was the fifth wettest year on record in Victoria following one of the wettest springs on record,⁵⁶ and 2011 was the twelfth wettest year on record.⁵⁷ While we have not collected evidence on the effects of this pattern on vegetation growth in Victoria, we did observe that above average rainfall in South Australia in 2010 and 2011 led to significant increases in vegetation growth and vegetation management expenditure.⁵⁸

The moderate increase in maintenance expenditure across the industry in part also reflects other increases in regulatory obligations following the Black Saturday bushfires. For instance, one of the Victorian Bushfire Royal Commission's (VBRC) recommendations was to mandate maximum thirty seven month inspection cycles of single wire earth return lines (SWER) and 22KV feeders in high bushfire risk areas.⁵⁹ This came into force in the Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011⁶⁰ and is now mandated by the Electrical Safety (Bushfire Mitigation) Regulations 2013.⁶¹ This has contributed to the increase in pole inspection expenditure in Figure A.4.

 ⁵⁴ AER, Victorian electricity distribution network service providers distribution determination 2011–15, October 2010,
 p. 301; AER, Opex step changes - final decision model; AER analysis.

⁵⁵ Following an Australian Competition Tribunal decision, we reconsidered the amount we had forecast for Powercor and CitiPower. This led to a further increase in our forecast for Powercor and CitiPower of \$27 million (\$2015). See AER, Vegetation management forecast operating expenditure step change 2011-15.

⁵⁶ Bureau of Meteorology, <u>http://www.bom.gov.au/climate/current/annual/vic/archive/2010.summary.shtml</u>, 4 January 2011.

⁵⁷ Bureau of Meteorology, <u>http://www.bom.gov.au/climate/current/annual/vic/archive/2011.summary.shtml</u>, 3 January 2012.

⁵⁸ AER, SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation management.

⁵⁹ Victorian Bushfires Royal Commission, *Final Report - Summary*, July 2010, p. 29.

⁶⁰ Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011, Cl. 5A(j); Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011, cl. 5A(j).

⁶¹ Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011, cl. 6(i).





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

Since 2009, wage growth in the ABS' Electricity Gas Water and Wastewater (EGWWS) classification has been on average 3.7 per cent per annum in nominal terms. In real terms EGWWS wage growth has been on average 1.3 per cent. As indicated in Figure A.5, this has largely matched the rate of wage growth in the mining industry and has exceeded wage growth across the Australian economy. This, in part, is likely to reflect the impact of the mining boom on the EGWWS sector. The impact of the demand for mining labour has previously been recognised as a driver of utilities wages by Deloitte and BIS Shrapnel.⁶²

Source: AER analysis.

⁶² Access Economics, Forecast growth in labour costs: update of March 2010 report, September 2010, p. vii; BIS Shrapnel, Labour Cost Escalation Forecasts to 2016–17 - Australia and Queensland, January 2012, p. 21.





Source: ABS, 6345.0 Wage Price Index, December 2015.

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

Importantly, we do not expect these drivers to persist in the 2016–20 regulatory control period. For instance, the *Electrical Safety (Electric Line Clearance) Regulations 2015* led to relatively minimal changes to the Victorian service providers' regulatory requirements for vegetation management. As discussed in Appendix B, we also expect efficient wage growth in the utility sector to slow. This is in part attributable to the reduced competition for labour from the mining sector.⁶³

A.5 Allocation of AMI costs

Our final position on base opex incorporates an adjustment of \$8.4 million for Advanced Metering Infrastructure (AMI) costs. This is a change in position from our preliminary decision where we allocated all AMI costs to alternative control services (ACS) metering. Our revised approach is based on advice on cost allocation principles for IT and communications systems from Energy Market Consulting Associates

⁶³ Deloitte Access Economics, Forecast growth in labour costs in NEM regions of Australia, February 2016, p. 39.

(EMCa). These principles are aligned with the cost allocation principles in our Cost Allocation Guidelines and in the NER.

Preliminary decision approach and consideration of stakeholder views

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

With the expiry of the AMI OIC, opex associated with AMI is now to be regulated under the NER. Jemena initially proposed an adjustment to its SCS base opex of \$10.9 million (\$2015) for AMI opex previously regulated under the AMI OIC. Other opex associated with smart meters was allocated to ACS metering. Jemena's proposed base opex amount for ACS metering was \$10.1 million (\$2015). Jemena did not specify in its initial proposal how it had determined its allocation of AMI costs across SCS and ACS metering.

In our preliminary decision we did not allocate any AMI costs to SCS. Each of the Victorian service providers had adopted a different approach to allocating AMI costs in their initial proposals. Presently, metering services are not subject to competition but, following NER changes, competition is scheduled to begin from December 2017.⁶⁴ We considered that a different approach to allocating costs across each of the Victorian service providers would not help in promoting effective competition. We considered a consistent approach to be preferable which could be dealt with through our Distribution Ring Fencing Guideline in accordance with a national framework.⁶⁵ We are scheduled to publish a Distribution Ring Fencing Guideline by 1 December 2016.

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

Jemena's revised SCS opex base year adjustment for AMI was \$8.7 million (\$2015). Its revised base opex amount for ACS metering was \$11.5 million (\$2015). For IT costs previously regulated under the AMI OIC, Jemena allocated 44 per cent to metering ACS and 56 per cent to SCS. This allocation percentage was identical to Jemena's initial proposal. The allocation of IT costs was based on the estimated utilisation of each main system by Jemena staff. For all other AMI costs Jemena either allocated 100 per cent wholly to SCS or ACS metering based on the primary driver for each category.⁶⁶

 ⁶⁴ AEMC, National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2015,
 26 November 2015, p. i.

⁶⁵ AER, CitiPower preliminary decision, Attachment 7, October 2015, p. 44.

⁶⁶ Jemena, *Response to information request JEN AER #031* [email to AER], 5 February 2016.

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

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

- a number of the IT systems rolled out as part of the AMI metering service are needed even if the service providers did not provide a metering service e.g. for customer billing and providing data to the market, and should therefore be considered to contribute to the distribution network SCS⁶⁷
- as some of these costs should be allocated to SCS, in the event of metering competition, they would be at an unfair disadvantage if all AMI costs are allocated to ACS⁶⁸
- costs must be correctly allocated now in line with the regulatory framework.⁶⁹
 Several service providers considered costs should be allocated in accordance with their Cost Allocation Methods (CAM).⁷⁰
- different DNSPs adopted different approaches to the AMI roll out (e.g. purpose built IT systems compared to upgrades / lifecycle replacement of existing systems) and these differences limit the extent to which cost allocation between standard control services and alternative control services will or can be consistent across all DNSPs.⁷¹

The Victorian Government also disagreed with our preliminary decisions on this issue. It considered we must resolve this issue to the best of our ability now.⁷² It considered that if all AMI costs are allocated to ACS then metering charges will be higher than they should be. It considered that there is a risk that this may encourage inefficient entry from new competitors.⁷³ The CCP agreed with our preliminary decision to allocate all AMI costs to ACS metering pending development of the Distribution Ring Fencing Guideline.⁷⁴

⁶⁷ AusNet Services, *Revised regulatory proposal, Attachment 11-6*; CitiPower, *Revised regulatory proposal*, p. 151; Powercor, *Revised regulatory proposal*, January 2016, pp. 150–151.

⁶⁸ AusNet Services, *Revised regulatory proposal, Attachment 11-7*; CitiPower, *Revised regulatory proposal*, p. 151; Jemena, *Revised regulatory proposal, Attachment 9-1*, p. 23; Powercor, *Revised regulatory proposal*, p. 151; United Energy, *Revised regulatory proposal*, January 2016, p. 106.

⁶⁹ Jemena, Revised proposal, Attachment 9-1, p. 22; United Energy, Revised proposal, pp. 104–105.

⁷⁰ AusNet Services, *Revised regulatory proposal, Attachment 11-7*; CitiPower, *Revised regulatory proposal*, pp. 152– 153; Powercor, *Revised regulatory proposal*, January 2016, pp. 152–153.

⁷¹ CitiPower, *Revised proposal*, p. 152; Jemena, *Revised regulatory proposal*, *Attachment* 9-1, p. 24; Powercor, *Revised regulatory proposal*, p. 152; United Energy, *Revised regulatory proposal*, January 2016, p. 105.

⁷² Victorian Government, Submission on preliminary decisions, p. 10.

⁷³ Victorian Government, *Submission on preliminary decisions*, p. 10.

⁷⁴ CCP, Report on AER preliminary decision, p. 23.

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

While there would be some benefit in waiting to consider this issue through the Distribution Ring Fencing Guideline process, given advanced meters have already been rolled out in Victoria, the cost allocation issues the Victorian service providers currently face are different to those that may potentially be faced by other service providers in other states. Therefore, on balance, it is appropriate to consider the allocation of AMI costs between SCS and ACS, notwithstanding we have not yet completed the Distribution Ring Fencing Guideline. We therefore have developed a revised position on how such costs should be allocated for the 2016–20 regulatory control period.⁷⁵

EMCa advice on cost allocation

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

EMCa carried out a desktop review of the AMI information submitted by the Victorian service providers as part of their regulatory submissions. It also reviewed relevant AMI regulatory decision and guidance documents. It compared the allocation approach for AMI-related IT and communications expenditure and collated evidence on the key drivers and rationale provided by each business to justify the allocation approaches taken.⁷⁶

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

- 1. the cost allocation principles in the NER⁷⁷
- 2. our Cost Allocation Guideline⁷⁸
- 3. approved Cost Allocation Methods for each service provider.⁷⁹

⁷⁵ We note that our decision to allocate these costs in this way for the 2016–2020 regulatory control period does not prevent us from re-considering this issue through the Ring Fencing Guideline process.

⁷⁶ EMCa, Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure, 6 April 2016, p. 2.

⁷⁷ NER, s. 6.15.2.

⁷⁸ AER, *Electricity distribution network service providers - Cost allocation guideline*, June 2008.

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

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

While noting the AER's Decisions approving the CAMs, given the high-level nature of the documents it is not possible to assess from the CAMs alone, whether the DNSPs have adopted a cost allocation approach for metering-related IT and communications that is consistent with NER's CAG. Moreover the variety of methods used by the DNSPs in allocating costs between SCS and metering ACS directly demonstrates the latitude in interpretation that has been applied in the CAMs.⁸⁰

EMCa considers it is more instructive to allocate such costs by direct reference to the NER's Cost Allocation Principles (CAP) and our Cost Allocation Guidelines (CAG). By basing the allocation of AMI costs on consistent principles with reference to the main reason the system was put in place (i.e. driver), EMCa considers this would provide a more reasonable platform for metering competition.⁸¹

In line with our CAG and the NER's CAP, EMCa considers that costs should be directly attributed (to distribution network SCS or metering ACS) only where the relevant systems are solely used to provide that service or where use for the other services can be considered immaterial as defined by Australian accounting standards. Where costs are shared and material, EMCa recommends the costs be allocated on a causal basis.⁸²

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

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

⁷⁹ AusNet Services, Cost Allocation Method, November 2014; CitiPower, Cost Allocation Method, April 2014; Jemena, Cost Allocation Method, July 2014; Powercor, Cost Allocation Method, April 2014; United Energy Cost Allocation Method, October 2014.

⁸⁰ EMCa, Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure, 6 April 2016, p. 22.

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

Table A.2	Proposed allocation	of AMI IT and	communications	costs
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Allocation between ACS/SCS	
Allocated solely to ACS metering	Communications infrastructure opex including Network Management Systems (NMS), Metering Management Systems (MMS), Network Operations and Control Centre (NOCC) Metering data management systems
	Field force mobility systems
	Network billing systems
Allocated solely to SCS	Customer Information Systems
	Outage management systems
	B2B systems for managing AMI- related transactions with other market participants
	GIS
	Asset management systems
Shared between ACS and SCS	Performance and reporting regulatory systems
	Middleware / integration bus technology
	Data analysis systems
	New / upgraded IT infrastructure to support the additional AMI functionality

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

Several service providers considered that a common allocation method would be challenging to apply given they implemented AMI at different stages of their IT lifecycles. However, EMCa did not afford this much weight given it had recommended the service providers apply a causal allocation method. This gives consideration to the reason the cost was incurred and recognises the different stage of the service providers' IT lifecycles. EMCa considered the service providers' arguments would only be relevant if it were advocating the same fixed allocation percentage be used across all service providers.⁸³

⁸³ EMCa, Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure, 6 April 2016, p. iii.

Application of cost allocation principles to Jemena's AMI costs

We invited Jemena to comment on EMCa's draft framework for allocating AMI costs to which it responded on 24 March. We also requested that Jemena allocate its costs in accordance with EMCa's framework.⁸⁴

Jemena limited its comments to the issue of the cost apportionment of the MDMS system. It notes the MDMS has multiple functions that would still be required by the DNSP even in the absence of the AMI OIC and metrology obligations currently imposed on JEN. Given this, and the lack of time it considers it has to properly consider an appropriate cost allocation, Jemena proposed costs associated with this system be allocated on a 50:50 basis.⁸⁵

As requested, Jemena also provided an alternative cost allocation model based on its understanding of EMCa's recommended methodology. In doing so, Jemena reviewed each line item of IT cost, and assigned an allocator to each item to determine whether the cost should be SCS or ACS metering.⁸⁶ As a result Jemena's allocation of IT costs between ACS metering and SCS changed from 44:56 (revised proposal) to 30:70 (EMCa allocation). However, in its written response Jemena noted that EMCa's allocation framework did not reflect Jemena's preferred cost allocation methodology.⁸⁷

Allocation of MDMS

To identify whether a system should be solely related to the provision of metering services, EMCa considered the main reason the system was implemented (i.e. driver). As a MDMS captures, processes, stores and makes available metering data it considers MDMS should be solely allocated to metering. EMCa does not consider the fact that the metering data is also used within the distribution business should mean the parts of the cost of the system should be allocated to SCS. EMCa notes future metering service providers in the NEM would all require an MDMS in providing a metering service which indicates that an MDMS is central to provide a metering service. It therefore maintained its advice to allocate all these costs to ACS.⁸⁸

Based on EMCa's advice, we are satisfied that the driver of implementing a MDMS is to provide a metering service. Therefore we agree that these costs should be solely allocated to alternative control services. As competitors for metering will all require an MDMS that cannot be recovered through network tariffs, this allocation approach will help to ensure that future competitors for metering are not unfairly disadvantaged.

⁸⁶ JEN - AMI IT Cost Allocation - IR049 - 2016.03.24.xlsx.

⁸⁴ Jemena, AER information request – Jemena - #049 – Advanced Metering Infrastructure costs [email to AER], 24 March 2014.

 ⁸⁵ Jemena, AER information request – Jemena - #049 – Advanced Metering Infrastructure costs. Pdf [email to AER], 24 March 2014, p. 3.

⁸⁷ Jemena, Response to AER information request – Jemena - #049 – Advanced Metering Infrastructure costs. Pdf [email to AER], 24 March 2014, p. 3.

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

We also consider EMCa's advice is consistent with our approach to service classification which classifies metering data services as an alternative control service.⁸⁹ These services are defined as the collection, processing, storage, delivery and management of metering data.

Methodology for allocating IT costs

We considered Jemena's cost allocation approach in response to EMCa's draft report. However, it was not clear how Jemena's revised approach aligned with EMCa's framework. Jemena's model included specific allocators for hundreds of different tasks and costs but Jemena provided limited supporting information to explain its approach. Jemena was also explicit in stating that it considered its revised proposal contained a more appropriate allocation approach, emphasising the limited time it had to reallocate its costs in accordance with EMCa's framework.⁹⁰

On balance, we were not satisfied we could place any significant weight on Jemena's revised allocation approach. In light of this we consider Jemena's revised proposal allocation method is the most appropriate basis for allocating IT costs in this final decision. However, we identified and made changes to the apportionment of FTEs in Jemena's revised proposal allocation approach where it was clearly inconsistent with EMCa's framework. For instance, in accordance with EMCa's framework, Jemena's MDMS (Itron) and its network management system (SSN) should be wholly allocated to alternative control services. Jemena's SAP/ISU system is mainly utilised for network billing as its customer information system, so this can be allocated 100% to SCS under EMCa's framework.

Applying such changes leads to small changes in the allocation of costs from Jemena's revised proposal. On the one hand, a revised allocation of MDMS and NMS increase the costs allocated to alternative control services metering. On the other hand, this is largely offset by a reduced allocation as a result of a revised allocation of SAP-ISU costs to SCS. The net result is that \$8.4 million (\$2015) rather than \$8.7 million (\$2015) is allocated to standard control services base opex.

Table A.3 illustrates how (in percentage terms) the allocation of IT and communications costs has changed between Jemena's initial proposal, revised proposal and our final decision.

⁸⁹ AER, Final framework and approach for the Victorian electricity distributors, 24 October 2014, p. 49.

⁹⁰ Jemena, Response to AER information request – Jemena - #049 – Advanced Metering Infrastructure costs. pdf [email to AER], 24 March 2014, p. 3.

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

Initial proposal		Revised proposal		Final decision		
SCS	ACS	SCS	ACS	SCS	ACS	
56	44	56	44	54	46	

Source: Jemena, Regulatory proposal, Attachment 8-4, 30 April 2015; Jemena, Revised Regulatory proposal, Attachment 9-1, January 2016; AER analysis.

A.6 Other adjustments to base opex

Inflation

The other change to our preliminary decision base opex estimate reflects an update of how we have inflated base opex from nominal dollars to real \$2015. For our preliminary decision we estimated the annual inflation rate to December 2015 would be 2.5 per cent, based on the RBA's forecast in its statement on monetary policy.⁹¹ For this final decision we have used the actual inflation rate of 1.7 per cent as reported by the ABS.⁹² This actual inflation rate was not available at the time of our preliminary decision.

⁹¹ Reserve Bank of Australia, Reserve Bank of Australia statement of monetary policy, August 2015, p. 67.

⁹² ABS catalogue 6401.0, December 2015.

B Rate of change

Once we have determined the efficient opex required in 2015 we apply a forecast annual rate of change to forecast opex for the 2016–20 regulatory control period. We do this to account for likely changes in demand and cost inputs for each year of the forecast period. As set out in the Expenditure Forecast Assessment Guideline (the Guideline), the rate of change accounts for forecast:⁹³

- 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 forecast opex.

B.1 Position

We are not satisfied Jemena's proposed rate of change for the 2016–20 regulatory control period reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.⁹⁴

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 because:

- our labour price growth measure reasonably reflects current and forecast economic conditions
- our output growth measure reasonably reflects the forecast increase in services that customers require.

We note that we and Jemena have applied a zero estimate of forecast productivity growth.

In the sections below we discuss the reasons why we consider our rate of change forecast is preferable to Jemena's forecast. We have applied the same rate of change methodology to derive our alternative estimate of opex as we used in our preliminary decision. We have updated our estimate of the rate of change in opex to reflect the most recent forecasts of labour price growth in the Victorian utilities industry from Deloitte Access Economics (DAE) and the Centre for International Economics (CIE). We used DAE and BIS Shrapnel in our preliminary decision but none of the DNSPs submitted an up to date forecast from BIS Shrapnel with their revised regulatory proposals. We have also updated our forecasts of customer numbers growth and

⁹³ AER. Better Regulation explanatory statement expenditure forecast assessment guideline, November 2013, p. 61.

⁹⁴ NER, cl. 6.5.6(c)(3).

ratcheted peak demand growth. The net impact of these changes results in an annual rate of change of 1.94 per cent, which is on average 0.52 per cent higher than our preliminary decision estimate.

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 regulatory control period.

The differences in the forecast rate of change components are:

- our forecast of annual price growth is on average 0.22 percentage points lower than Jemena's
- our forecast of annual output growth is on average 0.28 percentage points lower than Jemena's.

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

	2016	2017	2018	2019	2020	Average
Jemena	2.32	2.24	2.54	2.59	2.55	2.45
AER	1.77	1.74	1.99	2.05	2.16	1.94
Difference	-0.55	-0.50	-0.55	-0.54	-0.39	-0.51

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

Source: AER analysis.

B.2 Preliminary position

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

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

this would be applicable to the forecast period. This was also consistent with Economic Insights' recommendations.

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

B.3 Jemena's revised proposal and submissions

Jemena made several adjustments to its rate of change methodology from its initial proposal. In its revised proposal Jemena:⁹⁵

- adopted the forecast price growth in our preliminary decision
- adopted the output growth forecasting method in our preliminary decision
- revised its forecasts of customers numbers growth and peak demand growth
- adopted the forecast productivity growth in our preliminary decision.

These changes have resulted in a decrease in the average annual rate of change estimated by Jemena from 2.52 per cent in its initial proposal to 2.45 per cent in its revised proposal.

B.4 Reasons for position

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

B.4.1 Overall rate of change

We are not satisfied that Jemena's forecast of the rate of change will provide an opex forecast that reasonably reflects the opex criteria. We have adopted a rate of change lower than that proposed by Jemena to forecast our alternative estimate of opex. Jemena's higher forecast output growth is the primary driver of this difference. CitiPower also forecast higher price growth than we have.

Jemena forecast no growth in productivity for the 2016–20 regulatory control period. This is consistent with our forecast of productivity growth.

Table B.2 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.

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

⁹⁵ Jemena, *Revised regulatory proposal*, 6 January 2016, p. 46.

Table B.2 Jemena and AER rate of change (per cent real)⁹⁶

	2016	2017	2018	2019	2020	Average	
Jemena revised proposal							
Price growth	0.22	0.50	0.79	0.92	0.85	0.66	
Output growth	2.09	1.74	1.73	1.66	1.69	1.78	
Productivity growth	-	-	-	-	-	-	
Overall rate of change	2.32	2.24	2.54	2.59	2.55	2.45	
AER							
Price growth	0.25	0.23	0.49	0.59	0.63	0.44	
Output growth	1.51	1.51	1.50	1.45	1.52	1.50	
Productivity growth	_	_	_	_	_	-	
Overall rate of change	1.77	1.74	1.99	2.05	2.16	1.94	
Overall difference	-0.55	-0.50	-0.55	-0.54	-0.39	-0.51	

Source: AER analysis.

B.4.2 Forecast price growth

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

We forecast price growth based on the forecast growth in labour and non-labour prices. We used the forecast change in the wage price index (WPI) for the electricity, gas, water and waste services industry (the utilities industry) as the forecast change in the labour price.⁹⁷ Specifically, we have used the average of the utilities WPI growth forecasts from DAE and CIE. We assumed non-labour prices grow with CPI. We applied input price weights of 62 per cent for labour and 38 per cent for non-labour.

⁹⁶ The rate of change = $(1 + \text{price growth}) \times (1 + \text{output growth}) \times (1 + \text{productivity growth}) - 1$.

⁹⁷ We consider the utilities industry is an appropriate comparison point because the electricity industry makes up a majority of the ABS' utilities classification. We recognised that the utilities industry is a broad measure that includes other workers but captures all electricity workers. Deloitte Access Economics considered that electricity labour is large component of the utilities sector and therefore it would have a notable impact on the WPI series. It also considered that a difference between electricity labour and non-electricity labour does not mean electricity labour would necessarily have higher wage growth.

We are satisfied that this approach to forecasting labour price growth reasonably reflects a realistic expectation of the labour price growth faced by a prudent and efficient firm. This forward looking approach draws on available current market information from multiple sources, including from enterprise agreements, on the expected changes to the drivers of labour price. This is particularly important when labour drivers have changed significantly in recent times and wage price growth, for both the economy as a whole, and the utilities industry more specifically, is at the lowest level on record.⁹⁸

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

For our preliminary decision we used an average of the WPI growth rates forecast by DAE and BIS Shrapnel. DAE prepared its forecast in June 2015. BIS Shrapnel prepared its forecasts in November 2014.

We received updated forecasts from DAE in February 2016. However, none of the Victorian DNSPs provided updated WPI forecasts from BIS Shrapnel.

AusNet Services, CitiPower and Powercor all provided WPI growth forecasts from CIE with their revised regulatory proposals, as they did with their initial proposals. In our preliminary decision for AusNet Services we raised a number of concerns with CIE's WPI growth forecasts. Specifically, we stated that CIE WPI growth forecasts looked inconsistent with the prevailing labour market conditions in that they peaked in 2016 and remained above the historic average over the entire forecast period.⁹⁹ However CIE has addressed these concerns in its revised forecasts, which we discuss further below. We compare the Victorian utilities WPI forecasts from all three forecasters in Table B.3.

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

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

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

⁹⁸ ABS, Catalogue 6345.0, Table 9b.

⁹⁹ AER, *Preliminary decision: AusNet Services, Attachment 7*, October 2015, p 56.

The forecast Victorian utilities WPI growth rates from BIS Shrapnel are higher on average than the historic average rate at the national level of 1.2 per cent per annum. By contrast, the forecast utilities WPI growth rates from both DAE and CIE are lower, on average, than the historic average rate. We noted in our preliminary decision that WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, were at their lowest level on record.¹⁰⁰ WPI growth rates, both at the Australian all industry more specifically, have since fallen further.¹⁰¹

We note that CIE's revised forecasts are significantly lower than its initial forecasts from December 2014. Its revised average annual WPI growth forecasts are 0.8 per cent lower. CIE stated that the primary driver of this reduction was a downgrade to its forecast GDP growth and an upgrade to its forecast labour supply growth.¹⁰² Consequently it is clear that CIE considered changes in economic conditions between December 2014, when it released its initial forecasts, and November 2015, when it released its revised forecasts, have had a significant impact on wage growth expectations. BIS Shrapnel's December 2014 forecasts do not account for these changed conditions. Consequently we consider BIS Shrapnel's outdated forecasts should not be included in our average. Instead we have used CIE's forecasts because they reflect up to date economic information.

B.4.3 Forecast output growth

We are not satisfied Jemena's proposed average annual output growth of 1.8 per cent for the 2016–20 regulatory control period reflects the increase in output an efficient service provider requires to meet its opex objectives. We forecast average annual output growth of 1.5 per cent for the 2016–20 regulatory control period.

Our approach to forecasting output growth

We have maintained our preliminary decision methodology to forecast output growth.¹⁰³ We updated our output weights to match those in our latest benchmarking report. The output growth factors we used and their respective weights are:

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

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

¹⁰⁰ AER, *Preliminary decision, Jemena determination 2016–20, Attachment 7*, October 2015, p. 57.

¹⁰¹ ABS, *6345.0 Wage price index*, Table 9b.

¹⁰² CIE, Labour price forecasts, 23 November 2015, p. 25.

¹⁰³ AER, *Preliminary decision, Jemena determination 2016–20*, Attachment 7, October 2015, pp. 53–54.

We have used the forecast circuit length adopted by Jemena in its revised regulatory proposal opex model, which was consistent with our preliminary decision and Jemena's initial regulatory proposal. This produces an average annual growth rate of 2.02 per cent for circuit length.

Consequently the difference between the output growth forecast in Jemena's revised proposal and our preliminary decision is due to different forecasts for the growth in customer numbers and ratcheted peak demand. We discuss these below.

Forecast growth in customer numbers

We are not satisfied Jemena's proposed average annual customer numbers growth of 1.90 per cent for the 2016–20 regulatory control period reasonably reflects the increase in output a prudent and efficient service provider would require to achieve the opex objectives. We forecast average annual customer numbers growth of 1.54 per cent for the 2016–20 regulatory control period.

Jemena updated its customer numbers forecast using updated population forecasts.¹⁰⁴ This increased its forecast annual average customer numbers growth rate from 1.2 per cent to 1.9 per cent. ACIL Allen forecast Jemena's customer numbers.¹⁰⁵ 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:¹⁰⁶

- 1. Forecasting the population of each LGA using the LGA specific forecasts.
- 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. Applying a weighting to the number of households within each LGA based on the estimated proportion within JEN's distribution area and aggregating the results across all LGAs.
- 4. Calculating the yearly growth in households within Jemena's region using the number of households in step 3.
- 5. Applying the forecast annual growth in households in step 4 and applying it to the number of residential customers in Jemena's 2014 annual RIN.

In our preliminary decision we raised concerns with this forecasting approach. We noted that residential customer numbers, as reported by Jemena in its economic benchmarking RIN, grew on average by 0.8 per cent per year between 2007 and 2014. Over the same period the estimated residential population in the LGAs Jemena serves grew on average by 2.0 per cent. Consequently we concluded that at least one of the assumptions made by ACIL Allen did not hold during this period. For this reason we

¹⁰⁴ Jemena, *Revised regulatory proposal*, Attachment 7-7, 6 January 2016, p. v.

¹⁰⁵ Jemena, *Revised regulatory proposal*, Attachment 7-7, 6 January 2016, p. 2.

¹⁰⁶ Jemena, *Revised regulatory proposal*, Attachment 7-7, 6 January 2016, p. 2.

were not satisfied that Jemena's forecast of customer number growth reflected a realistic expectation of the customers Jemena will need to serve.¹⁰⁷

We then looked at the forecast of total population growth in the LGAs that Jemena serves.¹⁰⁸ The Victorian Government forecast the total population in the LGAs 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 were satisfied that the historic average growth in residential customer numbers of 0.8 per cent per year would reasonably reflects the increase in customer numbers Jemena will need to serve.¹⁰⁹

Jemena considered our preliminary decision method for forecasting residential customer numbers was inappropriate because it considered:

- our forecast method incorrectly represented the customer numbers growth rate for Jemena's network
- evidence does not support rejecting its method and assumptions for forecasting residential customer numbers.

We discuss both of these issues below.

Which source of historic customer numbers data should we use?

For our preliminary decision we based our forecast on the number of residential customer numbers reported by Jemena in its economic benchmarking RIN. However, we consider the residential customer numbers reported by Jemena in its economic benchmarking RIN understate the growth in Jemena's residential customer numbers, due to the definitions used in the RIN.¹¹⁰ Consequently, for this final decision, we have used the residential customer numbers reported by Jemena in its annual RINs, which we are satisfied better reflect the growth in customer numbers.

We note that customers are defined differently in the economic benchmarking RIN than they are in the annual RIN.¹¹¹ Jemena also noted that in undertaking the AMI rollout, it identified services that had long standing disconnections. It removed a number of these services rather than replacing the legacy meter with an AMI meter.¹¹² We are satisfied that for these reasons that the customer numbers reported by Jemena in its economic benchmarking RIN understate the growth in its residential customer

¹⁰⁷ AER, *Preliminary decision, Jemena determination 2016–20, Attachment 7*, October 2015, p. 56.

¹⁰⁸ We note that, contrary to Jemena's assertions in its revised regulatory proposal, we did use the 2015 population forecasts.

¹⁰⁹ AER, *Preliminary decision, Jemena determination 2016–20, Attachment 7*, October 2016, p. 56.

¹¹⁰ We note that total customer numbers growth in the economic benchmarking RIN is similar to the growth in total customer numbers reported in Jemena's annual RINs.

¹¹¹ One important different between the customer numbers reported in the economic benchmarking RIN is that they include de-energised meters. Jemena allocated its de-energised meters to the different customer categories by using the same proportions as for active meters.

¹¹² Jemena, *Revised regulatory proposal, Attachment* 7-7, 6 January 2016, p. 7.

numbers. Consequently we have instead used the residential customer numbers reported by Jemena in its annual RINs.

Does evidence support the method and assumptions Jemena used to forecast residential customer numbers?

Consistent with our preliminary decision, we are not satisfied that evidence supports the method and assumptions Jemena used to forecast residential customer numbers. Particularly, we are not satisfied that Jemena has demonstrated that its estimates of household number growth reflect actual household number growth. We have instead used the historic average residential customer number growth between 1996 and 2014, as reported by Jemena in its annual RINs, to forecast residential customer number growth. Residential customer numbers growth has been relatively stable historically and there is no evidence to suggest this will change in the forecast period.

We compared Jemena's forecast of customer number growth to its estimates of historic household number growth and historic actual customer numbers growth (Figure B.1). It is clear that the assumed one to one relationship between customer number growth and estimated household numbers growth does not hold historically. We also found that forecast customer number growth is higher for every year of the 2016–20 regulatory control period than actual customer numbers growth in every year since 2002.



Figure B.1 Annual growth in estimated households and residential customers (per cent)

Source: AER analysis; ACIL Allen, Forecast customer numbers model.

Consequently we sought further information from Jemena. We asked it if it could identify a reason why its actual annual customer numbers growth did not align with annual household numbers growth as estimated by ACIL Allen.¹¹³ Jemena provided a response from ACIL Allen.¹¹⁴ ACIL Allen stated that the historical household numbers series, which it estimated, were not robust estimates. It stated that estimating the number of households in Jemena's region was challenging because the Victorian Government published its population forecasts on a local government area (LGA) basis.¹¹⁵ This makes forecasting challenging because other DNSPs also operate in eight of the nine LGAs in which Jemena operates. ACIL Allen consequently stated that the problem with its historical estimated households series is that it relied on a single static estimate of the proportion of the population for each LGA that is supplied by Jemena. However, it considered that that proportion will have changed due to the differences in growth rates and due to where the growth has occurred within each LGA.¹¹⁶

Given this, ACIL Allen considered that the reason that its estimated annual household growth differed from actual customer number growth for the period from 1997 until 2010 was because its estimates of household numbers were not robust. However, it considered the problem was not as clear in recent years.¹¹⁷

We agree with ACIL Allen that the most likely cause of the divergence between estimated household number growth and customer number growth was the allocation of population growth within each LGA to the different DNSPs that operate in those LGAs. However, we consider that this issue is equally relevant for the forecast period as it was for estimating historic household numbers growth.

Figure B.1 shows that from 1997 until 2006, actual annual customer number growth was higher than estimated household number growth. Actual annual customer number growth averaged 1.8 per cent while estimated household number growth average 0.9 per cent. However, from 2007 estimated household number growth has been higher in every year except 2011. Since 2007, actual annual customer number growth averaged 1.4 per cent while estimated household number growth averaged 1.9 per cent. This suggests that prior to 2007 ACIL Allen assumed too little of the population growth within the nine LGAs was within Jemena's network. However, since 2007 ACIL Allen has assumed too much of the population growth within the nine LGAs was within Jemena's network. However, since 2007 ACIL Allen has assumed too much of the population growth within the nine LGAs was within Jemena's network. Although the difference between estimated household number growth and actual customer number growth has been smaller since 2007, we consider the difference is still material.

This is why we asked Jemena if it could disaggregate its actual customer numbers by LGA. We asked it to provide customer numbers for each LGA within its distribution

¹¹³ AER, *Information request 034* [email to Jemena], 3 February 2016.

¹¹⁴ Jemena, Response to information request 034 [email to AER], 10 February 2016, p. 3.

¹¹⁵ ACIL Allen, Letter to Jemena, 10 February 2016 , p. 3.

¹¹⁶ ACIL Allen, Letter to Jemena, 10 February 2016 , p. 3.

¹¹⁷ ACIL Allen, Letter to Jemena, 10 February 2016 , p. 3.

area if it could do so. Jemena did not state that it could not derive this information. It stated that it did not maintain customer numbers by LGA in the ordinary course of business and was therefore unable to provide the information requested.¹¹⁸ Without this information, and a better understanding of where within the nine LGAs the population growth is occurring, we consider it is not possible to use the LGA population forecasts to produce a forecast of Jemena's residential customer numbers growth.

Since 1997 residential customer numbers growth has been relatively stable around 1.6 per cent each year; more stable than ACIL Allen's estimates of household growth. Consequently we tested whether historic average customer numbers growth, or estimated household number growth, was more reflective of actual customer numbers growth. We found the mean absolute difference between the historic average customer numbers growth and actual customer numbers growth (0.35 per cent) was less than half the mean absolute difference for estimated household growth (0.73 per cent). This shows that ACIL Allen's estimates of household numbers growth have been a poor predictor of actual customer number growth and that actual customer numbers growth has been relatively stable.

Given we do not know how much of the forecast population growth in the nine LGAs will occur in Jemena's distribution area the population forecasts are of limited value. However they do not suggest that population growth in Jemena's distribution area will be materially different to what it has been historically.

Given these considerations, we consider the historic average residential customer numbers growth of 1.59 per cent each year will reasonably reflect Jemena's actual residential customer numbers growth in the forecast period.

The impact of embedded networks

In our preliminary decision we suggested that one possible reason why estimated household growth did not match actual customer numbers growth was because some apartment blocks, with multiple households, are embedded networks that Jemena would treat as a single customer.¹¹⁹

Jemena stated that it reviewed its customer connections from 2010 to 2015. It found that, on average, only 4 embedded network connections occurred per year in its distribution area. Those networks had on average 58 apartments per site, meaning 232 customers per year connected to its network as part of an embedded network. This is less than two per cent of new connections. ¹²⁰ Given this, we are satisfied that embedded networks are not a key driver of the divergence between Jemena's estimated household growth and its actual residential customer numbers growth.

¹¹⁸ Jemena, *Response to information request 034* [email to AER], 10 February 2016.

¹¹⁹ AER, Preliminary decision, Jemena determination 2016–20, Attachment 7, October 2015, p. 55.

¹²⁰ Jemena, *Revised regulatory proposal, Attachment* 7-7, 6 January 2016, p. 6.

Consistency with customer growth forecasts for other networks

Jemena noted that we used ACIL Allen's customer numbers forecasts in our 2013–17 access arrangement decision for AusNet Services' gas distribution network. Jemena noted that AusNet Services gas distribution network overlaps Jemena's network area and that ACIL Allen used the same method for those forecasts as it did for Jemena's.¹²¹

AusNet Services' gas distribution area does overlap Jemena's distribution area, but it is also significantly larger. It covers an area that includes towns as far apart as Portland, Horsham and Bendigo. Consequently AusNet Services' distribution area covers significantly more LGAs and it would be the sole distributor operating in many of these LGAs. As a result, the problem of allocating forecast population growth between multiple network service providers operating in the same LGA was not significant in our access arrangement decision for AusNet Services. However, even if this problem had existed for AusNet Services' gas distribution network, we should not ignore it for Jemena simply because we did not consider it in that decision.

Forecast growth in peak demand

We are not satisfied Jemena's proposed average annual ratcheted peak demand growth of 1.28 per cent for the 2016–20 regulatory control period reasonably reflects the increase in output a prudent and efficient service provider would require to achieve the opex objectives. We forecast average annual ratcheted peak demand growth of 1.06 per cent for the 2016–20 regulatory control period.

For the reasons discussed in attachment 6, appendix C, we are satisfied that Jemena's forecasts of maximum demand reasonably reflect a realistic expectation of the demand forecast required to achieve the opex objectives. However, Jemena did not ratchet its maximum demand forecasts.

We ratcheted the maximum demand we use as an output measure in our output specification. Ratcheted maximum demand is the highest value of maximum demand observed up to the year in question. It recognises capacity Jemena used to satisfy demand and gives it credit for this capacity in subsequent years, even if annual maximum demand is lower in subsequent years.

Jemena's weather corrected peak demand hit a local peak of 968.7 MW in 2013.¹²² It did not forecast peak demand to surpass this level again until 2016. Consequently we set ratchet peak demand to this level for 2014 and 2015.

¹²¹ Jemena, *Revised regulatory proposal*, *Attachment* 7-7, 6 January 2016, p. 6.

¹²² Consistent with our preliminary decision and Jemena's revised regulatory proposal we used non-coincident summated weather adjusted system annual maximum demand with a 50 per cent probability of exceedance measure at the transmission connection point in MW. Jemena did not provide weather corrected peak demand values in its annual benchmarking RIN for 2006 to 2013. Consequently we used the weather corrected historic peak demand values published by AEMO instead.

B.4.4 Forecast productivity growth

We have applied a zero per cent productivity growth forecast in our estimate of the overall rate of change. This reflects our expectations of the forecast productivity for a prudent and 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.¹²³ This is also consistent with our preliminary decision.

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

The Guideline states that we will incorporate forecast productivity in the rate of change we apply to base opex when assessing opex. Forecast productivity growth will be the best estimate of the shift in the productivity frontier.¹²⁴

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

To reach our best estimate of forecast productivity we considered Economic Insights' economic benchmarking, 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 discuss these further in our preliminary decision.¹²⁵

VECUA, however, stated that our decision to apply zero productivity growth 'is illogical and is not supported by the evidence'. It stated that we need to forecast positive productivity growth for the Victorian distributors to bring their productivity back into line with their previous productivity levels and into line with the levels the electricity transmission, gas distribution and other asset intensive industry sectors achieve.¹²⁶

VECUA asserted that a key reason for the distributors' productivity declines during the previous regulatory period was our provision of excessive opex allowances. It considered these been a strong driver of the networks' inefficient labour practices. It stated that such factors must not be used to justify poor productivity outcomes in future years.¹²⁷ VECUA, however, provided no evidence to support these assertions. Productivity declines, however, have not been unique to Australian electricity distribution networks. We have seen similar declines in productivity in Ontario and New

¹²⁵ AER, Preliminary decision, Jemena determination 2016–20, Attachment 7, October 2015, pp. 68–73.

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

¹²⁴ AER, Better regulation explanatory statement expenditure forecast assessment guideline, November 2013, p. 65.

¹²⁶ VECUA, Submission on the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 5.

¹²⁷ VECUA, Submission on the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 67.

Zealand, which operate different regulatory frameworks. Further, we are unaware of any incentive for the Victorian DNSPs to increase their actual opex when it is not efficient to do so.

Although it stated that forecast productivity growth should be positive, VECUA did not suggest a basis on which to forecast positive productivity growth. VECUA did state that some of its participants operate in asset intensive industries that have delivered positive productivity growth during the 2006–13 period.¹²⁸ However it did not identify which industries it was referring to or why those industries would be an appropriate benchmark for electricity distribution. The CCP also considered forecast productivity should be positive. However, it did suggest we should consider the approach IPART uses to forecast productivity growth for the industries it regulates.¹²⁹ The approach the CCP referred to was the approach used by IPART to regulate rural and regional buses and local council rates. IPART forecast productivity based on the 15-year average of the ABS market sector value-added multifactor productivity (MFP) based on quality adjusted hours worked. They set forecast productivity growth to zero when the 15 year average is negative.¹³⁰ The 15 year average productivity growth for the EGWWS industry is –3.3 per cent. Consequently IPART's approach to forecasting productivity also results in a forecast growth of zero.

Consistent with previous submissions, the Victorian Department of Economic Development, Jobs, Transport and Resources (DEDJTR) stated that:¹³¹

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

We stated in our preliminary decision that DEDJTR had not identified or quantified the 'value added benefits' or the further benefits it expected to be realised over the 2016–20 regulatory control period. We stated that without this information we could not incorporate them into our opex forecast. We also note that DEDJTR had not provided us the independent assessment of the benefits of the AMI program that it had referred to.¹³²

DEDJTR stated in its submission on our preliminary decisions that Deloitte forecast the benefits associated with the rollout of smart meters in a public report it prepared in 2011 for the Department of Treasury and Finance.¹³³ The most significant benefits identified in this report relate to capex and metering expenditure. Deloitte also

¹²⁸ VECUA, Submission on the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 67.

¹²⁹ CCP, *Submission*, 25 February 2016, p. 30.

¹³⁰ IPART, *IPART cost indices—productivity factor*, Fact sheet, October 2014, pp. 1–2.

¹³¹ DEDJTR, *Submission*, 14 January 2016, p. 1.

¹³² AER, *Preliminary decision, Jemena determination 2016–20, Attachment 7*, October 2015, p. 72.

¹³³ Deloitte, *Advanced metering infrastructure cost benefit analysis*, 2 August 2011.

identified some 'other smaller benefits' that may be relevant to standard control services opex. Of these smaller benefits, the most material reductions in standard control services opex were from:¹³⁴

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

DEDJTR stated that a recent review it undertook indicates that the DNSPs are in the early stages of realising these benefits and therefore their revealed 2014 operating expenditure would not reflect them.¹³⁵ DEDJTR did not provide this review. It also did not identify how the savings are allocated across the DNSPs and the extent to which these savings are reflected in base opex.

Jemena stated in its revised regulatory proposal that the benefits of the Advanced Metering Infrastructure (AMI) rollout that it has realised to date have largely been realised through savings in alternative control services opex. It stated the same was true of standard control services opex and its standard control services opex forecast already reflected the productivity benefits of AMI.¹³⁶ It expected future benefits of the AMI rollout will relate to capex, rather than opex.¹³⁷

Jemena stated that, although the Deloitte report provides useful input into the benefits from AMI meters to Victorian electricity users at the time it was developed; we should not rely on it to adjust Jemena's revenue requirement for the 2016–20 regulatory control period because:¹³⁸

- it was released five years ago and does not reflect more recent legislative, regulatory and market developments including recent rule changes expanding competition in metering and related services, and changes to the value of customer reliability
- it does not provide sufficient detail to accurately apply adjustments to the individual Victorian DNSPs
- initiatives may require additional investment to realise the benefits and Jemena did not include specific allowances for the initiatives
- some of the benefits are already captured in base year opex

¹³⁴ DEDJTR, *Submission*, 14 January 2016, p. 3.

¹³⁵ DEDJTR, Submission, 14 January 2016, p. 3.

¹³⁶ Jemena, *Revised regulatory proposal*, 6 January 2016, p. 159.

¹³⁷ Jemena, *Revised regulatory proposal*, 6 January 2016, p. 159.

¹³⁸ Jemena, *Submission*, 4 January 2016, pp. 12–14.

• the Deloitte report identifies issues which could 'impact the legitimacy of its findings'.

Given this, Jemena considered it was not possible to rely on the Deloitte report to inform adjustments to the revenue required of the Victorian DNSPs.

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

C Step changes

In assessing a service provider's total opex 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 Final position

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

- service testing and inspection program
- enclosed substation inspection and rectification
- vegetation management
- demand management opex/capex trade-off
- new tariff implementation
- new RIN reporting requirements
- power of choice
- adoption of chapter 5A.

In total these step changes contribute \$17.1 million (\$2015) or 3.8 per cent to our total opex forecast for Jemena for the 2016–20 regulatory control period.

Table C.1 sets out our position on Jemena's proposed step changes.

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

Proposal	Initial proposal	Preliminary decision	Revised proposal	Final decision
Service inspection and testing program	6.2	0	6.2	5.8
Overhead switch inspection	2.2	0	0	0
Enclosed substation inspection and rectification	0.8	0	0.6	0.2
Electricity distribution price review	8.0	Included in base year		
Vegetation management	15.9	0	6.9	2.3
ESV code of practice changes	0.9	0	0	0
Vulnerable customer initiative	1.0	0	1.0	0
Customer engagement	0.9	Included in base year		
New technology trial: pole-top fire detection	1.4	0	1.4	0
Demand management opex/capex trade- off	0.7	0.7	0.7	0.7
Cic	cic	0	cic	0
New tariff implementation	2.5	2.5	2.5	0.5
RIN reporting	19.7	0	5.9	5.9
Increased GSL obligations			0.9	Included as a category specific forecast
Power of choice			0.9	0.9
Adoption of chapter 5A			0.7	0.7
Total	60.3	3.2	27.7 ^a	17.1

Source: Jemena, Regulatory proposal, Attachment 8-6, 30 April 2015; AER, Jemena preliminary decision opex model; Jemena, Revised regulatory proposal, Attachment 8-2, 6 January 2016; AER, Jemena Final decision opex model – final decision.

Note: a) Total excludes cic step change. Numbers may not add due to rounding.

C.2 Preliminary position

In its initial regulatory proposal Jemena proposed 13 step changes above its base opex equal to \$60.3 million (\$2015).¹³⁹

¹³⁹ In its initial proposal Jemena identified \$29.6 million (\$2015) in step changes. Subsequent to its proposal, Jemena identified a further \$29.9 million in step changes.

The step changes were for costs 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.

In our preliminary decision, we included two step changes in our opex forecast.¹⁴⁰ We included a step change in opex for two demand management programs which were efficient capex/opex trade-offs. We also included a step change for costs associated with introducing cost reflective tariffs which we considered were driven by a regulatory change.

C.3 Jemena's revised proposal and submissions

In its revised proposal, Jemena proposed 16 step changes totalling \$27.7 million (\$2015) or 5.9 per cent of its revised total opex forecast.¹⁴¹ It accepted our position on six of the 13 step changes assessed in our preliminary decision and it proposed three new step changes. The proposed step changes in Jemena's revised proposal are set out above in Table C.1.

We received general comments about our consideration of step changes from:

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

While VECUA has some residual concerns with the step changes we allowed in our preliminary decision, overall, it agreed with our assessments of the Victorian service providers' proposed step changes.¹⁴² The CCP considered we were correct to reject most of the step changes in the Victorian service providers' proposals. It considered there is a tendency for the service providers to present a range of small cost increases without considering the overall ups and downs from year to year. It considered this results in a cumulative bias in the DNSPs' proposals.

The Victorian Government submitted that in our preliminary decisions we did not accept step changes in operating expenditure that were not considered material. It stated it expects us to adopt the same approach in assessing the operating expenditure forecasts in the revised regulatory proposals.¹⁴³

¹⁴⁰ AER, Preliminary decision, Jemena determination 2016–20, Attachment 7 Opex, October 2015, p. 7-25.

¹⁴¹ Jemena, *Revised regulatory proposal*, 6 January 2016, pp. 50-51.

¹⁴² VECUA, Submission on the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs, 6 January 2016, p. 63.

¹⁴³ Victorian Government, *Submission on the revised regulatory proposals, Victorian EDPR 2016-20*, 12 February 2016, p. 4.

C.4 Assessment approach

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

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

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

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

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

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

By applying the rate of change to the base year opex, we also adjust our opex forecast to account for real price increases. A step change should not double count price increases already compensated through this adjustment. Applying a step change for costs that are forecast to increase faster than CPI is likely to yield a biased forecast if we do not also apply a negative step change for costs that are increasing by less than CPI. A good example is insurance premiums. A step change is not required if insurance premiums are forecast to increase faster than CPI because within total opex

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

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

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

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

Usually increases in costs are not required for discretionary changes in inputs. Efficient discretionary changes in inputs (not required to increase output) should normally have a net negative impact on expenditure. For example, a service provider may choose to invest capex and opex in a new IT solution. The service provider should not be provided with an increase in its total opex to finance the new IT since the outlay should be at least offset by a reduction in other costs if it is efficient. This means we will not allow step changes for any short-term cost to a service provider of implementing efficiency improvements. We expect the service provider to bear such costs and thereby make efficient trade-offs between bearing these costs and achieving future efficiencies.

One situation where a step change to total opex may be required is when a service provider chooses an operating solution to replace a capital one. For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute

capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.

C.5 Reasons for position

We have included eight step changes in our opex forecast. We explain the reasons for our position on each of Jemena's proposed step changes in more detail below.

C.5.1 Service inspection and testing program

We have included a service inspection and testing program step change of \$5.8 million (\$2015) in our final decision opex forecast.

In its initial proposal, Jemena proposed an opex step change for service testing of \$6.2 million.¹⁴⁴ The Victorian DNSPs are required to undertake service inspection and testing at least every ten years. Jemena included service testing as a step change because it did not undertake this activity in the base year.

In our preliminary decision, we did not include the step change in our total opex forecast because we considered service testing was an existing obligation.¹⁴⁵

In its revised proposal, Jemena explained that it last met the ten year requirement to inspect and test services during the installation of the AMI meters.¹⁴⁶ It stated the additional cost of testing services at the time of installation was negligible and was included in the capital cost of installing the meters. Therefore, it was not included in revealed standard control opex in the base year.

In our final decision we have revised our position on the service inspection and testing program step change.

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.¹⁴⁷ The service inspection and testing step change is similar to a capex/opex trade-off. This is because the costs of service inspection were recovered as capex in the 2011–15 regulatory control period, however they will be recovered as opex in the 2016–20 regulatory control period. Because this program is similar to a capex/opex trade-off, we have now included it as a step change in our total opex forecast.

In assessing the efficiency of these proposed costs, we reviewed Jemena's business case materials and sought further information from Jemena. Jemena based its forecast for this step change on the per unit service costs it incurred when it last undertook a full

¹⁴⁴ Jemena, Regulatory proposal, Attachment 8-6 Operating expenditure step changes, 30 April 2015, pp. 5-6.

¹⁴⁵ AER, *Preliminary decision, Jemena determination 2016-20, Attachment 7 Opex*, October 2015, p. 7-67.

¹⁴⁶ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, pp. 1–4.

 ¹⁴⁷ AER, Better regulation, Expenditure forecast assessment guideline for electricity distribution, November 2013, pp. 15, 35.

service inspection between 2002 and 2009.¹⁴⁸ It then added \$1.29 per inspection to increase the scope of works to include a photograph of defects. We consider the use of revealed unit costs is an appropriate forecasting method. However, we do not consider Jemena needs additional opex to photograph defects. Photography is not required by the regulatory obligation; rather Jemena included it in the scope of works because it is an efficient inspection technique.¹⁴⁹ Consistent with our expenditure forecast assessment guideline we consider efficiency measures should be self-funding.¹⁵⁰ We expect the service provider to bear such costs and thereby make efficient trade-offs between bearing these costs and achieving future efficiencies.

We have included a step change for the service inspection and testing program of \$5.8 million (\$2015) which is based on the revealed unit costs but does not include the incremental cost of taking a photo.

C.5.2 Enclosed substation inspection and rectification

We have included an enclosed substation inspection step change of \$0.2 million (\$2015) in our final decision opex forecast. We are satisfied this cost increase is driven by a changed regulatory obligation.

In its initial proposal, Jemena forecast an increase in opex of \$0.8 million (\$2015) for enclosed substation inspection and rectification.¹⁵¹ Jemena stated the step change was driven by a change in the electricity safety (bushfire mitigation) regulations.¹⁵²

The bulk of the costs associated with the electricity safety (bushfire mitigation) regulations result from inspection requirements. The *Electricity Safety (Bushfire Mitigation) Regulations 2013* require that Jemena inspect its supply network at least every three years in hazardous bushfire risk areas (HBRA) and at least every five years in other areas.¹⁵³ The previous regulations, the *Electricity Safety (Bushfire Mitigation) Regulations 2003 (amended 2010),* also required Jemena to inspect its atrisk supply network at least every three years. However, the 2003 regulations did not seem to include inspection requirements for the supply network in other areas.¹⁵⁴

¹⁴⁸ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 3.

Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 3.
 AER, Better regulation, Expenditure forecast assessment guideline for electricity distribution, November 2013,

p. 16.

¹⁵¹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 12–13.

¹⁵² On 20 June 2013 new Electricity Safety (Bushfire Mitigation) Regulations 2013 came into effect.

¹⁵³ *Electricity Safety (Bushfire Mitigation) Regulations 2013, section 7(1)(i)* states the business must provide a plan for inspection that ensures that—

⁽i) the parts of the major electricity company's supply network in hazardous bushfire risk areas are inspected at intervals not exceeding 37 months from the date of the previous inspection and

⁽ii) the parts of the major electricity company's supply network in other areas are inspected at specified intervals not exceeding 61 months from the date of the previous inspection.

¹⁵⁴ Electricity Safety (Bushfire Mitigation) Regulations 2003 Version incorporating amendments as at 21 October 2010 5A(j) states a plan for inspection that ensures that all of the major electricity company's at-risk supply networks are inspected at regular intervals of no longer than 37 months.

In our preliminary decision, we did not include a step change for this program.¹⁵⁵ We recognised there was a regulatory change; however, we considered that the regulatory burden on Jemena had not materially increased. We considered the *Electricity Safety (Bushfire Mitigation) Regulations 2013* largely mirrored the position that had been in place since 2010.

We also noted that almost two thirds of the cost of this step change was for rectification work on enclosed substations found to be defective. We considered rectification work is part of asset maintenance which is business as usual for a network service provider. Consumers would be paying double if we added rectification costs as a step change when asset maintenance is already accounted for in the base opex forecast.

In its revised proposal, Jemena reproposed a step change for its enclosed substation inspection and rectification program but reduced the proposed amount from \$0.8 million to \$0.6 million (\$2015).¹⁵⁶ Jemena reduced the amount of the step change because it undertook more rectification work in the 2014 base year than anticipated.¹⁵⁷ Of the proposed \$0.6 million, \$0.3 million was for the inspection program and \$0.3 million was for the rectification of defects.

In support of the proposed step change Jemena stated:¹⁵⁸

- the new obligation requires it to increase the scope of its routine inspection program
- the forecast opex step change is only for the consequential incremental rectification costs – not all rectification costs.

Jemena stated the updated regulations include a requirement to inspect all parts of the network, including enclosed substations whereas the previous regulations applied to poles and lines only. Jemena stated it had not previously included the inspection of enclosed substations in its inspection plan.¹⁵⁹

We have revised our position on the enclosed substation inspection and rectification step change since our preliminary decision. We consider Jemena will incur increased inspection costs as a result of the changed regulations but we are still not satisfied it will incur increased rectification costs.

Where the Electricity Safety Act 1998 defines the supply network as a network consisting of electric lines, substations, circuits and any other thing required for the purposes of the transmission, distribution or supply of electricity.

- ¹⁵⁵ AER, Preliminary decision, Jemena determination 2016-20, Attachment 7 Opex, October 2015, p. 7-70.
- ¹⁵⁶ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 10.
- ¹⁵⁷ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 10.
- ¹⁵⁸ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, pp. 6–10.
- ¹⁵⁹ We disagree with Jemena that the previous regulations only applied to poles and lines. The Electricity Safety (Bushfire Mitigation) Regulations 2003 required Jemena to inspect all of its at-risk supply network at least every three years.
Inspection costs

We agree the *Electricity Safety (Bushfire Mitigation) Regulations 2013* place an increased regulatory burden on Jemena. We consider Jemena will incur increased costs to inspect its supply network in low bushfire risk areas, including enclosed substations, at least every six years, which the previous regulations did not require. However, we disagree with Jemena that the scope of its HBRA inspection program has increased under the 2013 regulations. *The Electricity Safety (Bushfire Mitigation) Regulations 2003 (amended 2010)* required Jemena to inspect *all* of its at-risk supply network at least every three years. At that time, the *Electricity Safety Act 1998* defined 'at-risk supply network' as the parts of the supply network above the surface of land and in a hazardous bushfire risk area.¹⁶⁰ Accordingly, it appears that Jemena has been subject to a regulatory requirement to inspect substations in HBRA in the previous regulatory period.

In our preliminary decision we were concerned that we did not know how often Jemena inspected its enclosed substations prior to the new regulatory requirement. Jemena stated in its revised proposal that it undertook a one-off inspection program of enclosed substations during 2012 and 2013 but before that its usual approach was to reactively undertake rectification work.

We consider that to comply with the new requirement in the 2013 regulations, Jemena will need to inspect its enclosed substations in low bushfire risk areas once in the 2016–20 regulatory control period. While it may need to inspect some of its enclosed substations in HBRA more often than that, this does not appear to be a new requirement given the relevant definition of 'at-risk supply network' included all assets in HBRA. However, the majority of Jemena's enclosed substations are in low bushfire risk areas.

We consider Jemena's use of revealed unit rates multiplied by the number of inspections is a valid forecasting approach. Jemena reported it will have 2067 enclosed substations at the start of the 2016–20 regulatory control period.¹⁶¹ It also reported that the revealed inspection rate is \$120 per unit. Using this data, we estimate it will cost Jemena \$0.25 million (\$2015) to inspect all of its enclosed substations once in the 2016–20 regulatory control period.¹⁶²

We note our forecast inspection costs are lower than Jemena's because it proposed a higher number of inspections in the regulatory control period. One reason for this is because it proposed a four yearly inspection cycle rather than a five yearly inspection cycle for enclosed substations in low bushfire risk areas. It stated it could achieve

¹⁶⁰ Section 98AA of the relevant version of the Electricity Safety Act (version no. 057, incorporating amendments as at 21 October 2010), definition of "at-risk supply area".

¹⁶¹ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, Table 3-1, p. 8.

¹⁶² 2067 * \$120 = \$248,040. We have not included new substations since 2015 as these will not need to be inspected until the following regulatory control period.

efficiencies by aligning the enclosed substation inspection program with the existing four yearly pole and line inspection program. We do not consider consumers should pay extra for Jemena to realise this efficiency.

Rectification costs

We were concerned in our preliminary decision that Jemena included a step change in opex for rectification work. We considered rectification work was business as usual for a network service provider and therefore would already be included in the base year forecast.

We do not consider Jemena provided sufficient evidence in its revised proposal for us to change our position on rectification costs.

The *Electricity Safety (Bushfire Mitigation) Regulations 2013* address how regularly Jemena is required to inspect its supply network. It does not address the amount of rectification work Jemena is required to undertake. While the intention of the ESV would be that Jemena rectifies any defects it identifies, rectifying defects is not a new requirement and should not drive an increase in opex. Rectifying defects is business as usual for a network service provider and such costs should be already included in the base year opex forecast. While Jemena proposed removing rectification costs from the base year to avoid double counting costs already included in the base year, this is not our preferred approach. Our preferred approach is to leave rectification costs in the base year and to forecast total opex based on revealed costs in that year. This approach is consistent with the Guideline.¹⁶³

Even if the regulations specifically required Jemena to undertake rectification work, on the basis of the information before us, we are not satisfied Jemena's submission that it requires a step change is valid. Jemena stated its rectification costs would increase as a result of regular inspections because previously it incurred rectifications costs only when an issue was reported from the public or its crews.¹⁶⁴ However, we consider Jemena has not adequately justified its position. According to its revised proposal, in 2013 and 2014 Jemena undertook a substantial rectification program where it rectified 70 per cent of its enclosed substations. All else equal, we consider this recent rectification work would reduce the rectification work Jemena would need to undertake in the forecast period. Further, in the event Jemena does need to undertake additional rectification work in the forecast period, the associated costs should be offset by cost savings in other areas of opex, such as reactive maintenance. On balance, therefore, (and consistent with our preliminary decision) we are not satisfied that a step change for rectification costs would result in a total opex forecast that reasonably reflects the opex criteria.

 ¹⁶³ AER, *Better regulation, Expenditure forecast assessment guideline for electricity distribution*, November 2013, p.
32.

¹⁶⁴ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 8.

In summary we have included a step change of \$0.2 million (\$2015) for the changed regulatory obligation to inspect enclosed substations at least every five years in low bushfire risk areas. We have not included a step change for increased rectification costs.

C.5.3 Electricity distribution price review

Consistent with our preliminary decision, we have not included a step change in our final decision opex forecast for the costs of preparing Jemena's proposal for its electricity distribution price review. Rather we have included these costs in our base year forecast.

In its initial proposal, Jemena proposed removing the costs of preparing its regulatory proposal from the base year and adding them as a category specific forecast, or step change of \$8 million (\$2015).¹⁶⁵ It did this because it considered these costs were overrepresented in the base year.

In our preliminary decision, we did not include a category specific forecast for this program. Instead we did not remove these costs from the base year opex.¹⁶⁶

In its revised proposal, Jemena did not agree with our preliminary decision not to include a category specific forecast for the costs of preparing its regulatory proposal.¹⁶⁷ However, it accepted our preliminary position to leave these costs in the base year and not include a step change because it did not significantly change the outcome. Jemena stated it does not agree with our overall forecasting approach to forecast total opex and not to provide for category specific forecasts for certain costs. Jemena stated category specific forecasts for certain categories of opex will promote the national electricity objective (NEO) where:

- the costs are not in the base year opex
- a penalty under the EBSS would result.¹⁶⁸

When we assess opex, we do not assess whether the costs for a particular category are sufficiently reflected in base year opex or not. This is because we make our assessment about the total forecast opex and not about particular categories in the opex forecast.

In relying on a base year to forecast a service provider's future opex, we are not forecasting that the cost of each of the projects and programs a service provider undertook in the base year would be representative of the cost of each of the projects and programs it will undertake in the forward regulatory control period. Nor are we forecasting that opex on each category of opex will be similar to the base year. We are

¹⁶⁵ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 14–15.

¹⁶⁶ AER, *Preliminary decision, Jemena determination 2016-20, Attachment* 7 Opex, October 2015, p. 7-71.

¹⁶⁷ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 11.

¹⁶⁸ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 11.

forecasting the *total* amount of opex we consider that a prudent service provider would need to meet the opex criteria. While expenditure on projects and categories of opex vary from year to year, a service provider can often adjust its opex to meet changing priorities.

We agree using a category specific forecasting method for some opex categories may produce better forecasts of expenditure for those categories in isolation but it may not produce a better forecast of total opex. 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 than including category specific forecasts.

We also disagree with Jemena's statement that category specific forecasts for certain categories of opex are necessary where a penalty under the EBSS would result otherwise. We assume Jemena is saying that if the amount reflected in the base year for a particular category is too low, the base year forecast for that category will be too low and the EBSS may penalise it for spending more than the forecast. This is incorrect. The EBSS does not provide rewards and penalties at a category level. Rather the EBSS compares total opex with the total opex forecast.

C.5.4 Vegetation management

We have included a step change of \$2.3 million (\$2015) for increased costs to comply with *Electrical Safety (Electric Line Clearance) Regulations 2015* (ELC 2015). We are satisfied that the proposed costs are driven by a new regulatory obligation. The step change includes the costs to comply with new amenity tree standards and advice provided to local councils.

Jemena initially proposed a step change of \$5.6 million (\$2015) for additional costs it expected to incur to comply with changes to ELC 2015.¹⁶⁹ It based its initial proposal on expected draft changes to the ELC regulations. Following the release of the final version of ELC 2015, Jemena revised its proposal to \$15.8 million (\$2015).¹⁷⁰

In our preliminary decision, we considered the change in costs to comply with ELC 2015 was uncertain and we did not include a step change for costs to comply with ELC 2015. We based this on advice from Energy Safe Victoria (ESV) which indicated that the costs proposed by Jemena did not reflect the final regulations and ESV intended to issue guidance notes to all Victorian DNSPs.¹⁷¹

In its revised proposal, Jemena revised its forecast step change to \$6.9 million (\$2015).¹⁷²

¹⁶⁹ Jemena, Regulatory proposal, Attachment 8-6 Operating expenditure step changes, 30 April 2015, pp. 16–19.

¹⁷⁰ Jemena, *Submission to the Victorian EDPR*, July 2015.

¹⁷¹ AER, Preliminary decision, Jemena determination 2016-20, Attachment 7 Opex, October 2015, p. 7-72.

¹⁷² Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 14.

Jemena identified the following key changes to the ELC regulations that would result in an increase in costs to comply with its vegetation management obligations:

- amenity tree standard required to comply with Australian Standard 4373
- enhanced notification and consultation provisions
- obligations to provide assistance to Councils.¹⁷³

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

Amenity tree standards

Jemena considered it would require changes to its current tree management practices to comply with AS 4373. Jemena identified the following cost drivers:

- it previously engaged Certificate 2 qualified arborists for inspections but is now required to utilise Certificate 3 inspectors
- it must engage Certificate 2 qualified arborists for the cutting of trees
- removal of the ability to use mechanical cutters such as 'jarrafs'.¹⁷⁴

The total forecast cost proposed by Jemena to comply with these requirements is \$1.2 million (\$2015).

We have assessed the changes to ELC 2015 regarding amenity tree standards and we consider Jemena's proposed changes are consistent with AS 4373 and will require a change from its current vegetation management practices to comply with ELC 2015. We have also assessed Jemena's cost build up and we agree that the changes in the obligations relating to amenity tree cutting practices will require Jemena to incur additional costs to engage more qualified labour and changes in cutting equipment to comply with ELC 2015. We consider the proposed costs are prudent and efficient.

Notification requirements

We do not consider the changes to notification requirements in ELC 2015 are materially different from Jemena's current notification requirements.

Jemena considered ELC 2015 introduced additional notification and consultation obligations. Jemena identified the following new requirements:

- notices to owners/occupiers of contiguous land
- bespoke notices to owners/occupiers of private land
- notices to councils

¹⁷³ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, pp. 14–15.

¹⁷⁴ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, p. 17.

• publication of notices in a generally circulating newspaper.

Jemena proposed \$4.6 million (\$2015) to comply with ELC 2015 notification and consultation requirements. Jemena considered the increase in costs is driven both by the increase in the number of notices it must send out and additional information it must put in each notice.

Quantity of notices sent to customers

Based on legal advice from Susan Brennan SC, Jemena considered that it would be required to send a three-fold increase in the number of notices because there would be a 'notable change' between ELC 2010 requirements and ELC 2015 requirements.¹⁷⁵ Jemena considered the ELC 2015 changes require it to give written notice not only to owners and occupiers of the land on which the tree is located, but also to owners and occupiers of contiguous properties where the use of the property may be affected, which would include all nearby landowners rather than immediately adjacent owners.

The definition of "affected person" in ELC 2010 is:176

affected person, in relation to the cutting or removal of a tree on land, means an owner or occupier (including a person who is responsible for the management of public land) of adjacent land where the cutting or removal will affect the use of that adjacent land

The relevant provision in ELC 2015 states:¹⁷⁷

(3) A written notice under subclause (2) must be given to-

(c) If the tree is on land that is contiguous to private property and the use of that property may be affected during the cutting or removal—an owner or occupier of that property

Ms Brennan's advice suggests the ELC 2010 requirements were broader than the ELC 2015 requirements because:¹⁷⁸

- the 2010 requirements were arguably limited to the owner and occupier of private property on which the tree was related and did not extend to adjoining property
- the 2010 requirements did not expressly require notification to "contiguous" landowners (which is not defined in ELC 2015)
- a broad definition of "contiguous" is warranted, which is not limited to landowners on directly abutting land, because 'the intention of the provision is fuller disclosure and more open and transparent communication between responsible persons, the

¹⁷⁵ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 20.

¹⁷⁶ Electricity Safety (Electric Line Clearance) Regulations 2010, clause 1(1).

¹⁷⁷ Electricity Safety (Electric Line Clearance) Regulations 2015, clause 15(3)(c).

¹⁷⁸ Jemena, Attachment 8–6 Susan Brennan SC - Advice on vegetation management matters, 6 January 2016, pp. 12–14.

community in general and those occupying or managing the land on which trees are located $^{\scriptscriptstyle (179)}$

 the 'clear intent' of ELC 2015 is to ensure owners and occupiers of properties affected by work are duly notified of works which will affect them and, by ELC 2015 focussing on "use" of the land, Jemena obligation would extend to people whose use of land may be impacted by the emission of noise or dust and is not limited to directly abutting land.

We disagree with Jemena's submission for the following reasons.

First, the 2010 definition does not suggest an affected person was limited to private land, or that it did not extend to adjoining property. It explicitly includes references to public land and to adjacent land.

Second, we agree that the 2010 requirements do not refer to "contiguous" landowners and the lack of definition in ELC 2015 creates uncertainty as to its interpretation. Jemena's legal advice identified two dictionary definitions of 'contiguous' to be:

- touching, in contact
- in close proximity without actually touching, near.¹⁸⁰

Ms Brennan's advice considered the second, broader definition was the appropriate interpretation because of statements in the regulatory impact statement (RIS) (referred to above). We have examined the RIS and agree the intention of the 2015 provision is to enhance communication between responsible persons and land users.¹⁸¹

However, our interpretation of the reason for amendments to notification provisions was not to extend notification requirements to more properties or parties than ELC 2010. Rather, the RIS suggests a lack of clarity was the driver. For example, the RIS identifies the following issues with ELC 2010 notification requirements:¹⁸²

- the perceived level of variability in notification practices across different responsible persons
- a lack of consistent understanding among different stakeholders of the term "affected persons"
- a lack of guidance as to how to consult an affected person.

¹⁷⁹ Ms Brennan refers to page 44 of the Regulatory Impact Statement for the ELC 2015.

¹⁸⁰ Jemena, Attachment 8–6 Susan Brennan SC - Advice on vegetation management matters, 6 January 2016, 6 January 2016, p. 13.

¹⁸¹ Jemena, Attachment 8–6 Susan Brennan SC - Advice on vegetation management matters, 6 January 2016, pp. 12–14.

¹⁸² Jaguar Consulting, Regulatory impact statement Electricity Safety (Electric Line Clearance) Regulation 2015, September 2014, p. 30.

The RIS goes on to state that the changes between ELC 2010 and ELC 2015 are to enhance communication by 'specify[ing] in greater detail the notification and consultation requirements applying to responsible persons'.¹⁸³

In our view, therefore, a broad interpretation of "contiguous" is unwarranted. Rather, the first of the two definitions identified by Ms Brennan (that is, the narrower definition) would be more appropriate because:

- it is consistent with the term "adjacent" used in the ELC 2010 definition and the apparent lack of an intention in the RIS to increase the number parties that a responsible person must notify
- accords with written advice provided by ESV that it would consider use of contiguous land may be affected if vegetation cutting or removal causes limitations in accessing the property or requires vegetation workers require to have access to the property.¹⁸⁴

Third, while we agree that an intention of ELC 2015 is to ensure owners of affected properties are duly notified of works that will affect them, we disagree that ELC 2015 warrants a wider obligation to notify than ELC 2010. Ms Brennan's advice relies on "use" of land as the reason for extending notification requirements to non-adjacent landowners affected by noise and dust. However, as can be seen from the extract above, the 2010 definition of "affected person" also includes "use" of land. On this basis, even if notification requirements did extend to non-adjacent landowners (which, for the above reasons, we disagree) there is no apparent change in the requirements between 2010 and 2015.

Finally, no other Victorian DNSPs (who are subject to the same requirements) proposed an increase in costs for changes in notification requirements between ELC 2010 and ELC 2015.

It follows that Jemena appears to have adopted an overly conservative interpretation of the change in notification requirements. In our view, a prudent and efficient business would not adopt Jemena's interpretation so we cannot be satisfied that the additional expenditure proposed by Jemena reasonably reflects the opex criteria.

Information included in notices to customers

Jemena considered that each notice required additional work to comply with ELC 2015 such as including a diagram of specific tree details, including a dispute resolution procedure and researching whether a tree is of cultural, environmental, historical, ecological or aesthetic significance. Jemena identified the following cost drivers for the additional information it was required to put in its notices:

¹⁸³ Jaguar Consulting, Regulatory impact statement Electricity Safety (Electric Line Clearance) Regulation 2015, September 2014, p. 44.

¹⁸⁴ Energy Safe Victoria, Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance information, November 27, p. 5.

- Include a photo of the tree to be cut because it disagreed with the ESV's advice that a generic depiction of a tree was sufficient in its notices.¹⁸⁵
- Engage additional staff to conduct research and planning to identify trees of cultural, environmental, ecological, historical or aesthetic significance.
- Develop a dispute resolution procedure and to train employees on the procedure and administer the process.

Jemena also identified similar requirements for the notices it would provide to local councils.

We do not consider there would be a material increase in the work required to provide notices to individual customers and local councils for the following reasons:

- It is clear from ESV's guidance that a representation of the tree to be cut is acceptable and it is not necessary to use a photograph.¹⁸⁶ We also do not consider the requirement to provide a diagram is onerous. The primary driver of Jemena's proposed costs is the increase in the volume of notices rather than the increase in complexity of the notices. We note the other Victorian DNSPs (who are subject to the same requirements) did not propose an increase in costs to provide a diagrammatic representation of the tree to be cut in its notices to customers.
- The requirement to identify trees of cultural or environmental impact was already a requirement in ELC 2010.¹⁸⁷ We do not consider the additional requirement of identifying trees as listed in a planning scheme to be of ecological, historical or aesthetic significance to be onerous. This is because ELC 2010 already required the 'responsible person' to keep track of these trees in its vegetation management plan.¹⁸⁸ Further, many councils provide a register of significant vegetation online or is available through direct contract with council officers.¹⁸⁹
- ELC 2010 already requires a responsible person to establish procedures for the independent resolution of disputes relating to electric line clearance.¹⁹⁰ The new requirement in ELC 2015 is to include information on how to access a dispute procedure.
- The requirement to provide notices to councils is mentioned explicitly in ELC 2015, however ELC 2010 already required Jemena to provide a notice to all affected persons. The definition of affected person in ELC 2010 (provided above) included a person who is responsible for the management of public land. We consider this definition includes the local councils.

Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 22.
ESV 27 November, p. 3.

¹⁸⁷ Electricity Safety (Electric Line Clearance) Regulations 2010, Section 1 Clause 5(c).

Electricity Safety (Electric Line Clearance) Regulations 2010, Section 9 Clause 3(g).
For example, Maribyrnong council heritage overlay is available at

http://planningschemes.dpcd.vic.gov.au/schemes/maribyrnong/ordinance/43_01s_mari.pdf.

¹⁹⁰ Electrical Safety (Electric Line Clearance) Regulations 2010, Clause 9.

We also note that ESV has explicitly stated that it "would have no issue with a direct notice to the properties close to the trees instead of a notice in a newspaper, as an equivalent safety outcome."¹⁹¹ Based on this we do not consider Jemena requires additional opex to publish notices in a newspaper because it would already be providing notices directly for affected customers.

Assistance provided to councils

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

- safe limits of approach to electric lines for cutting or removing a tree
- methods for cutting or removing a tree.¹⁹²

Jemena proposed costs of \$1.15 million (\$2015) to provide this advice to its local councils.

In its guidance to Victorian DNSPs, ESV stated:

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

We note prior to ELC 2015, Jemena did not provide support to its local councils on safety issues.¹⁹³ Although ESV considers providing support to local councils is good industry practice, this is a new obligation in ELC 2015. We consider Jemena's forecast to provide information on safe cutting methods and sag and sway information is efficient and prudent.

Offsetting costs

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

¹⁹¹ Energy Safe Victoria, *Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance information*, November 27, p. 4.

¹⁹² Jemena, *Revised regulatory proposal, Attachment 8-2*, 6 January 2016, p. 24. On 2 February 2016, Jemena removed the confidentiality claim for this information.

¹⁹³ Jemena, *Revised regulatory proposal, Attachment 8-2*, 6 January 2016, p. 24. On 2 February 2016, Jemena removed the confidentiality claim for this information.

In its submission to our preliminary decision, the Victorian Government identified increases in vegetation management expenditure under ELC 2010 (in 2013) compared ELC 2005 (in 2009) for AusNet Services, Powercor and United Energy. It considered that the AER should assess both negative and positive step changes associated with the introduction of ELC 2015.¹⁹⁴

Jemena in its revised proposal, considered there would be no offsetting costs as a result of ELC 2015 for the following reasons:

- ESV did not expect the change in regulations to translate into cost savings for JEN, however ESV did not provide its reasons for this position.
- Its arborist reports noted that it was compliant with ELC 2010 in 2014.
- Based on arborist advice, Jemena considered the reintroduction of exceptions for maintenance of structural branches will not result in any cost savings for JEN.

Based on the information provided by Jemena and the ESV's advice, we are satisfied that there are unlikely to be cost savings as a result of the reintroduction of structural branches exceptions in ELC 2015.

Since Jemena's base year was already compliant with the ELC 2010 structural branches requirements, we are satisfied that its base year opex reflects vegetation management costs related to structural branches in the 2016–20 regulatory control period.

C.5.5 Vulnerable customer initiative

Consistent with our preliminary decision, we have not included a step change in our final decision opex forecast for a vulnerable customer initiative step change.

In its initial proposal, Jemena forecast an increase in opex of \$1.0 million (\$2015) to provide assistance to vulnerable customers.¹⁹⁵ Jemena proposed four initiatives to assist vulnerable customers:

- 1. an in-home display trial for 500 customers to improve their understanding of their energy usage
- 2. 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
- 3. improved communications for culturally and linguistically diverse customers via pilot low-literacy communications material which covers energy safety issues

¹⁹⁴ Victorian Government, Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016–20, January 2016, p. 7.

¹⁹⁵ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 21–23.

4. community partnerships with local welfare agencies to develop energy literacy material to help vulnerable community groups better understand energy efficiency and costs.

In our preliminary decision, we did not consider an increase in opex was needed for this program.¹⁹⁶ In its submission, the Victorian Department of Economic Development, Jobs, Transport and Resources (DEDJTR) stated that the Essential Services Commission (ESC) was undertaking an inquiry into best practice financial hardship programs of energy retailers.¹⁹⁷ 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.¹⁹⁸Given these factors, we did not include these costs in our forecast.

In its revised proposal, Jemena reproposed a \$1.0 million vulnerable customer assistance step change.¹⁹⁹ It stated:

- The ESC's hardship review is retailer focused and in no way duplicates, nor effects, the initiatives Jemena was proposing.
- We had not considered the support Jemena received from its customers on its initial proposal, for example, CUAC.²⁰⁰
- Jemena's Customer Council supported the customer support package.
- Jemena's proposed initiatives were targeted and reflected its advantages as a distributor in providing effective support for vulnerable customers in its network area.

In assessing this step change we re-examined Jemena's proposed vulnerable customer initiatives. We do not consider Jemena provided sufficient new information for us to change our preliminary position.

The ESC released its energy hardship inquiry draft report in September 2015.²⁰¹ It did not identify a role for distribution network service providers in providing assistance to vulnerable customers in the new framework. Jemena stated the review is retailer focused and does not affect the initiatives it is proposing.

¹⁹⁶ AER, Preliminary decision, Jemena determination 2016-20, Attachment 7, October 2015, p. 7-74.

¹⁹⁷ Essential Services Commission 2015, *Inquiry into the financial hardship arrangements of energy retailers: Our approach*, March 2015.

¹⁹⁸ Victorian Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review 2016 – 20*, 13 July 2015, p. 8.

¹⁹⁹ Jemena, Revised regulatory proposal, Attachment 8-2, 6 January 2016, pp. 34–35.

²⁰⁰ CUAC, Submission to the Victorian electricity distribution pricing review, 2016 -20, 13 July 2015.

²⁰¹ Essential Services Commission 2015, *Supporting Customers, Avoiding Labels. Energy Hardship Inquiry draft report,* September 2015.

We agree the inquiry into financial hardship programs is retailer focused. However, we consider the focus on retailers indicates that policy makers consider retailers are best placed to address customer hardship.

The current role of retailers in mitigating hardship originated from recommendations made in the 2005 Victorian Government Committee of Inquiry into the Financial Hardship of Energy Consumers. The inquiry identified three stakeholders as having responsibility for mitigating hardship:

- government
- retailers
- community based groups.²⁰²

Its report stated that submissions made to the inquiry almost universally supported the current framework for assisting energy customers in hardship, and the allocation of responsibilities among government, retailers and community groups in their various efforts.²⁰³ A key recommendation of the inquiry was that energy retailers develop and implement best practice hardship policies. Subsequently, the Energy Act 2006 required licensed energy retailers to prepare financial hardship policies. The legislation also empowered the ESC to develop guidelines to assist retailers and to approve their financial hardship policies.²⁰⁴

Policy makers' allocation of this responsibility to retailers makes sense given the direct relationship retailers have with customers compared to the limited relationship distribution businesses have. Retailers have information concerning customer energy consumption, payment records and the range of tariff products available. They also have direct experience in administering hardship programs and energy concessions for vulnerable customers that are provided by the state government.²⁰⁵

As policy makers have not clearly identified a role for distributors in providing support for vulnerable customers, we are not in a position to conclude that a step change in this instance would be required to achieve the opex objectives.

The NER also requires us to have regard to the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers identified during customer engagement.²⁰⁶ Jemena noted in its revised proposal that the Consumer Utilities Advocacy Centre (CUAC) strongly supported its

²⁰² Committee of inquiry into the financial hardship of energy consumers, Main report, September 2005. <u>http://www.energyandresources.vic.gov.au/energy/gas/your-bill/concessions-and-hardship/hardship/hardship-inquiry-main-report?SQ_DESIGN_NAME=mobile&SQ_ACTION=set_design_name.</u>

²⁰³ Committee of inquiry into the financial hardship of energy consumers, Main report, September 2005, Recommendation 5.

²⁰⁴ Essential Services Commission, Victoria 2006, Energy retailers' financial hardship policies: Framework Paper, December 2006, p. III.

²⁰⁵ The Department of Health & Human Services (DHHS) offers a variety of concessions and benefits to eligible cardholders to assist low-income Victorians with energy bills.

²⁰⁶ NER, cl. 6.5.6(e)(5A).

proposed assistance to vulnerable customers.²⁰⁷ CUAC has particular regard to low income, disadvantaged, and rural consumers. We acknowledge its active role on Jemena's Electricity Customer Council and in the choice of programs to assist vulnerable customers. We have had regard to CUAC's submission but note that it represents one community group.

While we received no other submissions on this particular step change we did receive a submission from the Victorian Energy Consumer and User Alliance (VECUA), who considered that our total opex forecasts for the Victorian distributors were well above the efficient levels. Further, it supported our approach to decline the majority of step changes proposed by the Victorian network service providers.

On balance, in the long term interest of all consumers, we consider we should not include an increase in opex for these projects. However, we consider it is open to Jemena to re-prioritise its total opex allowance to accommodate expenditure on this project.²⁰⁸ Alternatively, Jemena has the option of re-directing funds from categories of opex expected to decline during the 2016–20 period.

C.5.6 New technology trial: pole-top fire detection

Consistent with our preliminary decision, we have not included a step change in our final decision opex forecast to trial new technology for pole-top fire detection.

In its initial proposal, Jemena forecast an increase in opex of \$1.4 million (\$2015) to trial new technology for pole-top fire detection.²⁰⁹ Jemena proposed to lease multiple pole top early fault detection (EFD) systems to test the system on a number of feeders.

In our preliminary decision, we did not include a step change for this program.²¹⁰ We did not consider the program was a response to a new regulatory obligation and should be funded by reallocating the existing opex budget.

In its revised proposal, Jemena reproposed a step change of \$1.4 million for a pole-top fire early detection program.²¹¹ It stated the trial will:

- enable it to make better decisions about possible future implementation
- if successful, could reduce opex associated with responding to pole top fire faults and reduce the capital cost of replacing damaged assets
- Jemena stated there is no incentive for it to undertake the trial as the benefits will not be realised until subsequent periods. It considered our preliminary decision shows a bias against initiatives that facilitate dynamic efficiency.²¹²

²⁰⁷ VECUA, Submission to the Victorian electricity distribution pricing review, 2016–20, July 2015, p. 3.

²⁰⁸ We have not conducted a detailed analysis of the costs associated with this step change.

²⁰⁹ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, p. 28.

AER, Preliminary decision, Jemena determination 2016–20, Attachment 7, October 2015, pp. 7-75 to 7-76.

²¹¹ Jemena, Revised regulatory proposal, Attachment 8-2, 6 January 2016, pp. 37–40.

²¹² Jemena, *Revised regulatory proposal, Attachment 8-2*, 6 January 2016, p. 37.

In assessing this project we examined the business case submitted by Jemena. However, we are not satisfied that the material provided by Jemena justifies a change to our position.

We recognise that trialling technology may be prudent and consistent with good industry practice. However, as there are no new regulatory obligations or other exogenous circumstances underpinning Jemena's proposal to trial pole-top fire detection, we maintain our draft decision position that this project is discretionary.

Typically, we do not allow step changes for any short–term cost to a service provider of investigating new technologies or processes. We expect the service provider to bear such costs and thereby make efficient trade–offs between these costs and future efficiencies.

Generally, 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 including bushfire mitigation. In our view Jemena's base opex already includes the cost of maintaining the quality, safety, reliability and security of supply of its network. As discussed in our assessment of the vulnerable customers step change above, Jemena has the option of allocating the funds required for this project from its total opex allowance .

We do not agree that our preliminary decision shows a bias against initiatives that facilitate dynamic efficiency. We apply various incentive schemes such as the EBSS and capital expenditure sharing scheme (CESS) to provide network service providers with a continuous incentive to improve their efficiency in supplying electricity services. In addition, the Victorian Government applies an 'f-factor scheme'. This scheme provides incentives for distribution network service providers to reduce the risk of fire starts and to reduce the risk of loss or damage caused by fire starts.²¹³

Jemena stated the benefit of undertaking the program is to gain further information to inform better decisions about future implementation.²¹⁴ We expect Jemena to weigh the cost of the trial with the value of the information it will gain. We do not consider it needs a step change in opex for this.

C.5.7 Demand management opex/capex trade-off

Consistent with our preliminary decision, we have included a step change of \$0.7 million (\$2015) in our final decision opex forecast for a demand management opex/capex trade-off.

In its initial proposal, Jemena proposed two demand response opex programs to mitigate two network constraints which it stated it would otherwise need to be addressed through a capex response. The areas were:

²¹³ AER, *Victoria F-factor scheme determination 2012–15*, December 2011.

²¹⁴ Jemena, *Revised regulatory proposal, Attachment 8-2*, 6 January 2016, p. 37.

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

Jemena stated the demand response programs would enable it to defer related network augmentation works to the 2021–25 regulatory control period.²¹⁵

In our preliminary decision, after reviewing the cost benefit analysis Jemena provided, we agreed the size of the deferred capex savings outweighed the respective costs for each of the demand response programs.²¹⁶ We received no submissions on our preliminary position so we maintain our position in the final decision.

C.5.8 C-i-c

This step change is discussed in a confidential appendix because the information is commercial in confidence.

C.5.9 New tariff implementation

In our preliminary decision, we included a step change of \$2.5 million for Jemena to implement new cost reflective tariffs. However, in our final decision, we have revised the amount of the step change from \$2.5 million to \$0.5 million.

In November 2014, the Australian Energy Market Commission (AEMC) made a new rule to require network businesses to set prices that reflect the efficient cost of providing network services to individual consumers.²¹⁷ Prices based on these new rules were to apply in Victoria from 1 January 2017.

In its initial proposal, Jemena proposed a step change of \$2.5 million for costs to notify its customers of the new pricing structures, respond to customer enquiries and to migrate customers to the new tariff.²¹⁸ We considered these itemised costs were reasonable and we included them as a step change in our total opex forecast in our preliminary decision.

In December 2015, the Victorian Government announced that customers must opt-in to, rather than opt-out of, cost reflective network tariffs.

In its revised proposal, Jemena updated its cost build up for the step change to account for the Victorian Government's policy statement. The revised costs were marginally less than the initial proposal and Jemena reproposed a step change of \$2.5 million.

Jemena proposed costs for:

²¹⁵ Jemena, Regulatory proposal, Attachment 8-6 Operating expenditure step changes, 30 April 2015, pp. 29–30.

AER, Preliminary decision, Jemena determination 2016-20, Attachment 7, October 2015, p. 7-77.

²¹⁷ AEMC, Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 27 November 2014.

²¹⁸ Jemena, *Regulatory proposal, Attachment 8-6 Operating expenditure step changes*, 30 April 2015, pp. 35–38.

- additional staff to migrate customers to the new tariff structure
- an expected increase in call volumes, written enquiries, billing enquiries and disputes
- mass mail-outs to notify customers of the new tariffs and to promote the take-up of cost reflective tariffs (in light of the change to the opt-in approach).

In reassessing these costs, we realised that some of the costs were for activities that were not specifically required by the new rule. We need to be satisfied that our estimate of total forecast opex reasonably reflects the opex criteria. An estimate that includes costs not required to comply with regulatory obligations (or the other opex objectives) would not reasonably reflect the opex criteria.

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

However, the AEMC rule change does not oblige Jemena to conduct mail-outs to notify customers of the new tariffs. Rather, the onus will be on the retailers to offer the new tariff structures as part of their product offerings. Similarly, customers will direct most of their inquiries to the retailers. The AEMC agrees that the role of retailers in providing information to facilitate understanding of pricing signals is critical. In its rule determination the AEMC stated:

Most consumers will gain an understanding of pricing signals through the retail tariffs they are charged. This is because for most consumers, their primary relationship will be with their retailer. As such, the role of retailers in providing information to facilitate understanding of pricing signals is critical.²¹⁹

Similarly, the rule change does not require Jemena to promote the take-up of cost reflective tariffs. While we agree promoting cost reflective tariffs will help achieve the policy's objectives, we consider retailers are better placed to undertake this task than distributors. Distributors are not best placed to promote the take-up of cost reflective tariffs for the following reasons:

- The cost reflective tariff will not necessarily be reflected in retail electricity offers. Consequently, it is uncertain whether or not the distributor's cost reflective tariffs will have the impact on the retail offers that the distributor claims.
- The way in which consumers will see the networks tariffs will depend on how energy retailers choose to represent the new tariffs in their bills.

²¹⁹ AEMC, Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 27 November 2014, p. 67.

• Distribution charges only make up around 37 per cent of the bill for one of Jemena's typical residential customers.²²⁰

We informed Jemena of our changed position from our preliminary decision and invited it to comment.

In its response, Jemena stated we need to consider the case for successful distribution tariff reform. ²²¹ We support the case for successful distribution tariff reform. This is outlined in our submission to the AEMC's draft decision and draft rules.²²² However, as outlined above, we consider retailers, rather than distributors are best placed to promote the take-up of such tariffs.

Jemena also stated because it is required to comply with the network pricing principles, the rule change compels it to take steps to encourage customers to adopt the more cost-reflective tariffs where they are faced with a choice.²²³ Jemena also stated:

The customer impact pricing principles include that 'each tariff must be reasonably capable of being understood by retail customers'. This pricing principle directly relates to the elements the AER is considering excluding from its step change, particularly in relation to communicating with customers and having the means and ability to respond to their enquiries.²²⁴

The pricing principles specifically apply when a network business is determining the structure and level of its network prices.²²⁵ They require Jemena to develop tariff structures that are reasonably capable of being understood by its retail consumers.²²⁶ Being required to develop understandable tariff structures is not the same as being required to actively encourage customers to adopt cost reflective tariffs. Nor does it imply that Jemena is required to ensure customers understand the tariffs once developed. As discussed above, we consider that it is the role of retailers to provide information to facilitate understanding of pricing signals.

Consistent with the provisions of the new rule, in our final decision:

• we include costs for migrating customers to the new tariffs and for consultation with retailers (\$0.5 million)

²²⁰ AER, *Preliminary decision, Jemena 2016–20, Fact sheet.* October 2015.

²²¹ Jemena, *Response to information request IR#045 - New tariff implementation step change* [email to AER], 8 March 2016.

AER, Submission to AEMC Draft Decision Rule changes—Distribution network pricing arrangements, October 2014, p. 1.

Jemena, Response to information request IR#045 - New tariff implementation step change [email to AER], 8 March 2016, p. 5.

²²⁴ Jemena, *Response to information request IR#045 - New tariff implementation step change* [email to AER], 8 March 2016, p. 5.

AEMC, Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 27 November 2014, p. i.

²²⁶ NER, cl. 6.18.5(i).

 we do not include costs associated with customer education, customer enquiries or customer mail-outs (\$2 million).

In its submission on the revised proposals the Victorian Government stated we will need to assess whether the expenditure proposed by the network service providers for this step change is consistent with an opt-in rather than an opt-out approach.

While the impost on the network service providers could be less under an opt-in arrangement, it is difficult to predict the magnitude of this outcome. Jemena identified that the switch from opt-out to opt-in would not have a material impact on its forecast. Since we are proposing to provide a step change in opex only for costs related to transitioning customers to the new tariff structure, we do not consider the switch from opt-out to opt-in will materially affect Jemena's costs.

Our final decision is to include a step change of \$0.5 million for costs related to the AEMC network pricing arrangement rule change in our total opex forecast.²²⁷

C.5.10 RIN reporting

We have included a RIN reporting step change of \$5.9 million (\$2015) in our final decision opex forecast. We are satisfied the revised costs Jemena provided are the efficient costs of complying with the new RIN reporting requirements.

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

While the other DNSPs proposed mostly capex solutions, Jemena initially proposed a \$19.7 million opex step change.²²⁸ The step change was to set up procedures, systems and training to provide actual RIN data.

In our preliminary decision, we acknowledged RIN compliance is a new regulatory obligation that may give rise to a justifiable step change. However, we did not include a step change for Jemena's proposed RIN reporting costs because we considered:²²⁹

- the total proposed cost of the step change was not reasonable compared to Jemena's total opex
- the proposed costs of some of the components of the step changes were not reasonable.

In its revised proposal, Jemena proposed an alternate RIN solution involving a mix of both capex and opex. It proposed a materially reduced step change of \$5.9 million

²²⁷ \$389,341 includes Business analyst, Business SME backfill, and reporting framework.

²²⁸ Jemena, *Submission to its Regulatory proposal,* 13 July 2015, pp. 3–6.

AER, Preliminary decision, Jemena determination 2016–20, Attachment 7, October 2015, pp. 7-78 to 7-79.

(down from \$19.7 million) with additional \$2.1 million capex.²³⁰ Jemena's total revised RIN compliance costs of \$8.0 million (\$2015) is a reduction of \$11.7 million or 59 per cent from its initial proposal.

In examining this step change we assessed the process Jemena undertook to estimate the costs it would incur to comply with its RIN obligations. We consider the process it applied was sound. Jemena's process was to:

- identify what percentage of data would be currently defined as actual and estimated information.
- where information was identified as estimated, identify the activities required to produce actual information
- estimate the cost for each activity
- identify and compare options to achieve compliance.

Jemena engaged KPMG (its external auditors) to determine what percentage of information it reported in the 2014 RINs was actual information. KPMG stated 32 per cent of the financial data Jemena reported in the EB RINs and 10 per cent of the financial data it reported in the CA RINs was actual information.²³¹ We consider KPMG's estimates are reasonable given the definitions of actual data provided in the RINs.

Jemena engaged Parson Brinkerhoff (PB) to review what measures were required to transition from estimated to actual information.²³² The PB report formed the basis for Jemena's cost estimate. Jemena stated it needs to implement significant changes to its processes for data collection, management and reporting to provide actual information and the associated assurances of compliance.²³³ We agree Jemena would need to implement significant changes to its data collection processes. Jemena stated the detail provided by its consultants allowed it to be more specific in its cost calculations. This resulted in a sizeable decrease in its cost estimates.²³⁴

Jemena provided a detailed business case to support the changes to systems and information collection processes it considers it requires to comply with the RINs.²³⁵ It assessed four options. We consider it chose the least cost option that allows it to be compliant with RIN obligations.

Overall, we consider the proposed expenditure (capex and opex) reflects the efficient costs of a prudent service provider.

²³⁰ Jemena, Revised regulatory proposal, Attachment 8-2, 6 January 2016, pp. 49–67.

Jemena, Revised regulatory proposal, Attachment 8-10, KPMG, Letter outlining the definition of actual information,
17 December 2015, p. 3.

²³² Jemena, Revised regulatory proposal, Attachment 8-12, Parsons Brinckerhoff, Jemena Electricity Network Conversion of Regulatory Information Notice information to actual, October 2015.

²³³ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, p. 51.

²³⁴ Jemena, *Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes*, 6 January 2016, p. 56.

²³⁵ Jemena, *Revised regulatory proposal, Attachment 8-11, Business case for RIN actuals, 6* January 2016.

Jemena's forecast RIN compliance capex is discussed in attachment 6 of this final decision.

New step changes

In its revised proposal, Jemena proposed three new step changes that were not included in its initial proposal.

C.5.11 Increased guaranteed service level obligations

Jemena proposed a step change of \$0.9 million (\$2015) for the incremental costs of new GSL obligations in response to a rule change that was finalised after our preliminary decision.²³⁶ It proposed the step change in addition to a category specific forecast for GSL costs. Rather than assess the step change and the category specific forecast separately, we have assessed them together as one category specific forecast in section C.6.1 below.

C.5.12 Power of choice

We have included a \$0.9 million (\$2015) step change for Jemena's costs to comply with the Power of Choice program in our final decision opex forecast. We are satisfied this cost increase is driven by a changed regulatory obligation.

In its revised proposal, Jemena proposed a \$0.9 million (\$2015) new step change for the AEMC's final rule changes for the Power of Choice program.

Jemena noted that its Power of Choice program is principally capex in nature, however it included once-off opex costs for initial set up costs to comply with changes to its regulatory, technical and operational environment.

We have assessed Jemena's cost build up and we consider the opex costs proposed by Jemena are efficient, prudent and reflect the initial set up costs to comply with its Power of Choice obligations. We are satisfied that the proposed costs do not relate to Jemena's participation in a contestable metering market and other unregulated activities.

C.5.13 Adoption of chapter 5A

We have included a \$0.7 million (\$2015) step change to comply with the Victorian Government's adoption of Chapter 5A of the NER in our final decision opex forecast. We are satisfied this cost increase is driven by a changed regulatory obligation.

²³⁶ Essential Services Commission, Electricity Distribution Code Version 9, December 2015, pp. 19–20; ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision*, 23 December 2015.

In its revised proposal, Jemena proposed a new step change of \$0.7 million (\$2015) following the Victorian Government's decision to implement Chapter 5A of the NER in Victoria, to commence no later than 1 January 2017.²³⁷

To comply with its new obligations, Jemena must develop and publish its basic model standing offers for connection services in accordance with Chapter 5A of the NER. We are satisfied that the intention of the Victorian Government to adopt Chapter 5A of the rules to apply no later than 1 January 2017 will result in an increased regulatory obligation for Jemena.

We have assessed Jemena's cost-build up including its initial implementation costs and on-going costs associated with responding to enquiries. We consider the costs are efficient and prudent. These costs are also broadly comparable to United Energy, CitiPower and Powercor's proposed costs.²³⁸

C.6 Other costs not included in the base year

We prefer a 'base-step-trend' approach to assessing most opex categories. However, when appropriate, we may asses some opex categories using other forecasting techniques, such as an efficient benchmark amount. We also assess whether using alternative forecasting techniques in combination with a 'base-step-trend' approach produces a total opex forecast consistent with the opex criteria.

In our final decision opex forecast, we have included category specific forecasts for:

- GSL payments
- debt raising costs.

We forecast GSL costs using a five year historical averaging approach to maintain consistency with our forecasting method for previous regulatory control periods. The incentives provided by using a five year historical average are consistent with adopting a single year revealed cost approach and applying the EBSS. We forecast debt raising costs using the costs incurred by a benchmark firm.

C.6.1 Guaranteed service level payments

We have included a category specific forecast of \$0.6 million (\$2015) for GSL payments in our opex forecast for the 2016–20 regulatory control period.

The Electricity Distribution Code (EDC) requires Victorian electricity distributors to make payments to customers who receive a level of service that is worse than a specific threshold or level. The Essential Services Commission (ESC) updated the

²³⁷ Jemena, Revised regulatory proposal, Attachment 8-2 Operating expenditure step changes, 6 January 2016, p. 76.

²³⁸ United Energy, *Revised regulatory proposal, 6* January 2016, p. 204; CitiPower, *Revised proposal,* January 2016, p. 185. Powercor, *Revised regulatory proposal, 6* January 2016, p. 178.

EDC in December 2015, increasing the Victorian network service providers' GSL obligations.²³⁹

In its initial proposal, Jemena forecast GSL payments of \$0.4 million (\$2015). Jemena used a single base year to forecast GSL costs for the 2016–20 regulatory control period.²⁴⁰ Jemena did not account for the regulatory changes in its initial proposal because the new EDC rules were not finalised at the time.

In our preliminary decision, we included a category specific forecast of \$0.3 million (\$2015) for GSL payments in our opex forecast. We forecast GSL payments as the average of GSL payments made by Jemena between 2010 and 2014. We adopted the historical averaging approach to maintain consistency with our GSL payment forecasting methodology for previous regulatory control periods.²⁴¹

In its revised proposal, Jemena forecast GSL payments of \$1.2 million (\$2015). Its forecast included:

- a base level of GSL payments of \$0.3 million
- a step change of \$0.9 million to comply with the GSL rule change.

As noted above, we have assessed both components of Jemena's forecast GSL payments as a single category specific forecast.

The Victorian Government submitted that the basis for Jemena's revised proposal was the draft EDC rules published in November rather than the final EDC rules published in December.²⁴² On 24 February 2016, in response to our information request, Jemena amended its total GSL forecast from \$1.2 million to \$0.9 million (\$2015)²⁴³.

In its amended GSL forecast, Jemena:

- anticipated increases in the size and the frequency of GSL payments under the final EDC rules
- included spending for quality of supply monitoring and recording.

We discuss each component of Jemena's forecast step change in the sections below.

Electricity Distribution Code

In its amended forecast, Jemena proposed costs of \$0.6 million (\$2015) to comply with the final EDC rules. We have assessed the likely increase in the size and frequency of

²³⁹ Essential Services Commission, Electricity Distribution Code Version 9, December 2015, pp. 19–20; ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision*, 23 December 2015.

Jemena, Regulatory proposal, Attachment 8-6 Operating expenditure forecasting method and base year efficiency,
30 April 2015, p. 17.

AER, Preliminary decision Jemena – Opex model, October 2015.

²⁴² Victorian Government, Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016-20, 12 February 2016, p. 4.

²⁴³ Jemena, Response to AER information request – Jemena #039 [email to AER], 24 February 2016.

GSL payments due to the changes to the EDC and we consider Jemena's forecast is reasonable. This is because Jemena adopted an averaging approach rather than a single base year to forecast the expected increase in GSL payments as a result of the rule change.

Quality of supply monitoring

Jemena also included \$0.3 million (\$2015) in the proposed step change to establish better quality monitoring. However, Jemena is under no obligation to perform monitoring as part of the GSL framework. We do not consider Jemena is required to incur such costs under the EDC and therefore we have removed this increment from our forecast of the GSL step change.

Other submissions

The CCP noted the increased GSL payment forecast and suggested that the AER examine the forecast.²⁴⁴ The CCP suggested that GSL costs "could be recovered during the course of the regulatory period".²⁴⁵ We consider providing for GSL payments in our ex-ante opex forecast provides network service providers with an incentive to minimise those payments and to maintain service levels at an efficient level. Actual GSL costs may be either higher or lower than forecast as they depend on the frequency of unplanned outages. Recovering GSL costs ex-post, as the CCP suggests may remove the incentive for the distributor to maintain service levels.

C.6.2 Debt raising costs

Consistent with our preliminary decision, we have forecast debt raising costs using the costs incurred by a benchmark firm. Our assessment approach and the reasons for those forecasts are set out in the debt and equity raising costs appendix in the rate of return attachment.

²⁴⁴ Consumer Challenge Panel Sub Panel 3, *Submission to the AER*, 25 February 2016, p. 33.

²⁴⁵ Consumer Challenge Panel Sub Panel 3, *Submission to the AER, an overview*, 22 February 2016, p. 16.