



PRELIMINARY DECISION
Powercor distribution
determination
2016 to 2020

Attachment 7 – Operating
expenditure

October 2015

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Note

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

The preliminary decision includes the following documents:

Overview

Attachment 1 - Annual revenue requirement

Attachment 2 - Regulatory asset base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency benefit sharing scheme

Attachment 10 - Capital expenditure sharing scheme

Attachment 11 - Service target performance incentive scheme

Attachment 12 - Demand management incentive scheme

Attachment 13 - Classification of services

Attachment 14 - Control mechanism

Attachment 15 - Pass through events

Attachment 16 - Alternative control services

Attachment 17 - Negotiated services framework and criteria

Attachment 18 - f-factor scheme

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	advanced metering infrastructure
augex	augmentation expenditure
CAM	cost allocation method
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DAE	Deloitte Access Economics
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DNSP	distribution network service provider
DUoS	distribution use of system
EA	enterprise agreement
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
GSL	guaranteed service level
MRP	market risk premium
MPFP	multilateral partial factor productivity

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

7 Operating expenditure

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

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

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

7.1 Preliminary decision

We are not satisfied that Powercor's forecast opex reasonably reflects the opex criteria.¹ We therefore do not accept the forecast opex Powercor included in its building block proposal.² Our alternative estimate of Powercor's opex for the 2016–20 period, which we consider reasonably reflects the opex criteria, is outlined in Table 7.1.³

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

	2016	2017	2018	2019	2020	Total
Powercor's proposal	243.0	250.9	262.6	271.4	280.3	1308.2
AER preliminary decision	221.4	225.2	230.9	236.0	241.6	1155.1
Difference	-21.6	-25.7	-31.7	-35.4	-38.7	-153.1

Source: Powercor, *Powercor 2016–20 PTRM regulatory proposal.xlsx*, April 2015; AER analysis.

Note: Excludes debt raising costs and DMIA.

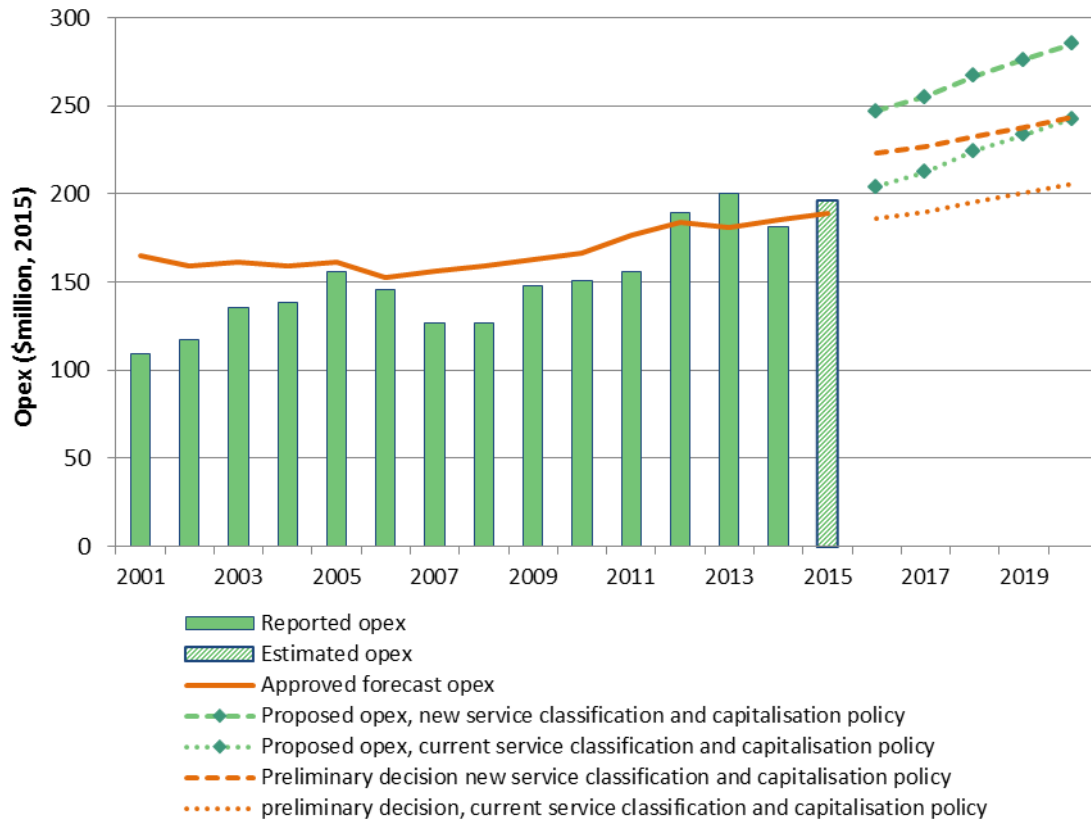
Figure 7.1 shows our preliminary decision compared to Powercor's proposal, its past allowances and past actual expenditure.

¹ NER, cl. 6.5.6(c).

² NER, cl. 6.5.6(d).

³ NER, cl. 6.12.1(4)(ii).

Figure 7.1 Our preliminary decision compared to Powercor’s past and proposed opex (\$ million, 2015)

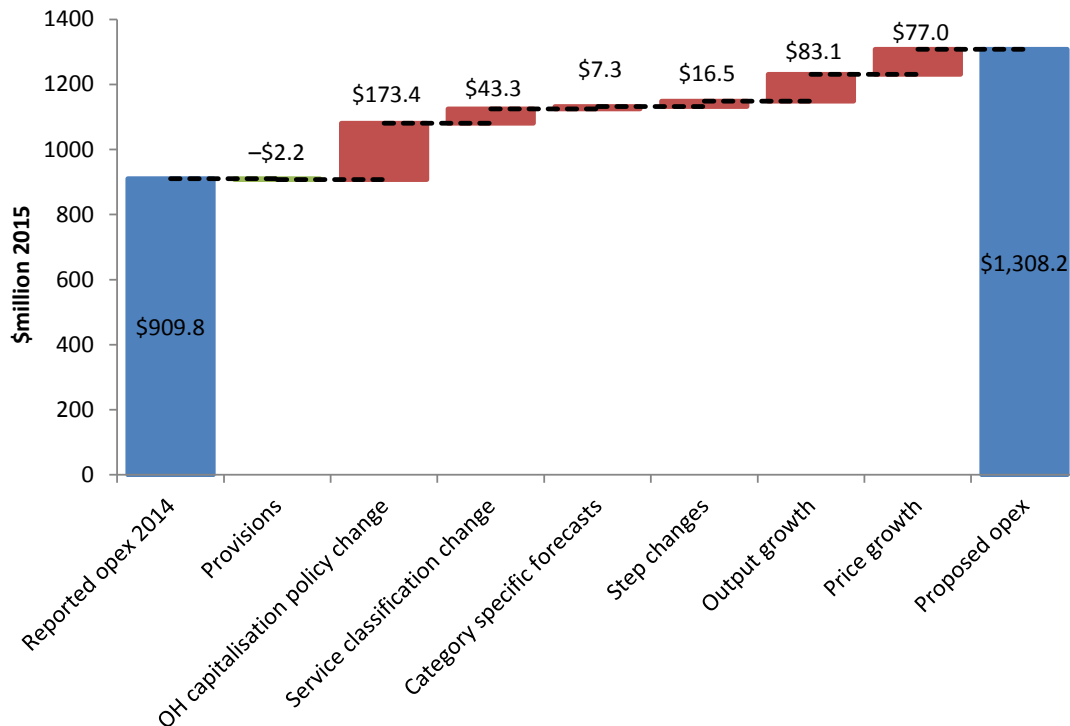


Source: Powercor, Regulatory accounts 2011 to 2014; Powercor, *Economic benchmarking - Regulatory Information Notice response 2006 to 2013*, AER analysis.

7.2 Powercor’s proposal

Powercor proposed total forecast opex of \$1308.2 million (\$2015) for the 2016–20 period (excluding debt raising costs, totalling \$22.5 million). In Figure 7.2 we separate Powercor’s forecast opex into the different elements that make up its forecast.

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



Source: AER analysis.

We describe each of these elements below:

- Powercor used the actual opex it incurred in 2014 as the base for forecasting its opex for the 2016–20 regulatory control period. Its reported expenditure for 2014 would lead to base opex of \$909.8 million (\$2015) over the 2016–20 regulatory control period.
- Powercor 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 Powercor’s forecast by \$2.2 million (\$2015).
- Powercor adjusted its base opex to reflect its revised overhead capitalisation policy. This increased Powercor’s forecast by \$173.4 million (\$2015).
- Powercor also adjusted its base opex to add opex that are classified as standard control services in the 2016–20 regulatory control period. This increased Powercor’s forecast by \$43.3 million (\$2015).
- Powercor included category specific forecasts for regulatory reset costs, guaranteed service level (GSL) payments, demand management incentive allowance (DMIA) costs and defined benefit superannuation scheme costs. This increased its forecast by \$7.3 million (\$2015).
- Powercor identified step changes in costs it forecast to incur during the forecast period, which were not incurred in 2014. These costs broadly related to changes in regulatory and legal obligations, operating costs arising from capital program

impacts, and delivering on customer expectations identified during its customer engagement program. This increased Powercor's forecast by \$16.5 million (\$2015).

- Powercor proposed output growth forecast using four different output growth models that adopted a variety of different output measures. Forecast increases in these measures increased Powercor's opex forecast by \$83.1 million (\$2015).
- Powercor accounted for forecast growth in prices related to labour price increases, contracted service price increases and materials price increases. These forecast price changes increased Powercor's opex forecast by \$77.0 million (\$2015).

7.3 AER's assessment approach

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

Our assessment approach, outlined below, is, for the most part, consistent with the Expenditure forecast assessment guideline (the Guideline).

There are two tasks that the NER require 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.⁴ If we are satisfied, we accept the service provider's forecast.⁵ In the second task, we determine a substitute estimate of the required total forecast opex that we are satisfied reasonably reflects the opex criteria.⁶ 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:⁷

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

The opex criteria that we must be satisfied a total forecast opex reasonably reflects are:⁸

⁴ NER, cl. 6.5.6(c) and 6.12.1(4).

⁵ NER, cl. 6.5.6(c) and 6.12.1(4)(i).

⁶ NER, cl. 6.5.6(d) and 6.12.1(4)(ii).

⁷ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. vii.

1. the efficient costs of achieving the operating expenditure objectives
2. the costs that a prudent operator would require to achieve the operating expenditure objectives
3. a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The AEMC noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.⁹

The service provider's forecast is intended to cover the expenditure that will be needed to achieve the opex objectives. The opex objectives are:¹⁰

1. meeting or managing the expected demand for standard control services over the regulatory control period
2. complying with all applicable regulatory obligations or requirements associated with providing standard control services
3. where there is no regulatory obligation or requirement, maintaining the quality, reliability and security of supply of standard control services and maintaining the reliability and security of the distribution system
4. maintaining the safety of the distribution system through the supply of standard control services.

Whether we are satisfied that the service provider's total forecast reasonably reflects the opex criteria is a matter for judgment. This involves us exercising discretion. However, in making this decision we treat each opex criterion objectively and as complementary. When assessing a proposed forecast, we recognise that efficient costs are not simply the lowest sustainable costs. They are the costs that an objectively prudent service provider would require to achieve the opex objectives based on realistic expectations of demand forecasts and cost inputs. It is important to keep in mind that the costs a service provider might have actually incurred or will incur due to particular arrangements or agreements that it has committed to may not be the same as those costs that an objectively prudent service provider requires to achieve the opex objectives.

Further, in undertaking these tasks we have regard to the opex factors.¹¹ We attach different weight to different factors. This approach has been summarised by the AEMC as follows:¹²

⁸ NER, cl. 6.5.6(c).

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

¹⁰ NER, cl. 6.5.6(a).

¹¹ NER, cl. 6.5.6(e).

¹² AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

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

The opex factors that we have regard to are:¹³

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period
- the actual and expected operating expenditure of the distribution network service provider during any preceding regulatory control periods
- the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the distribution network service provider in the course of its engagement with electricity consumers
- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure
- whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the distribution network service provider under clauses 6.5.8 or 6.6.2 to 6.6.4
- the extent the operating expenditure forecast is referable to arrangements with a person other than the distribution network service provider that, in our opinion, do not reflect arm's length terms
- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)
- the extent to which the distribution network service provider has considered and made provision for efficient and prudent non-network alternatives
- any relevant final project assessment conclusions report published under 5.17.4(o),(p) or (s)
- any other factor we consider relevant and which we have notified the distribution network service provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.

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

¹³ NER, cl. 6.5.6(e).

- our benchmarking data sets including, but not necessarily limited to:
 - (a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN
 - (b) any relevant data from international sources
 - (c) data sets that support econometric modelling and other assessment techniques consistent with the approach set out in the Guideline as updated from time to time.
- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.¹⁴

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

As we noted above, the two tasks that the NER require 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

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

¹⁵ NEL, ss. 7A and 16(2).

¹⁶ NEL, s. 7A(2).

¹⁷ That is, the trade-offs that may arise having considered the substitution possibilities between opex and capex, and the relative prices of operating and capital inputs: NER, cl. 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.

While the Guideline provides for regulatory transparency and predictability, it is not binding. We may depart from the approach set out in the Guideline but we must give reasons for doing so.²⁰ For the most part, we have not departed from the approach set out in the Guideline in this final decision.²¹ In our Framework and Approach paper, we set out our intention to apply the Guideline approach in making this determination.²² There are several parts of our assessment:

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

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

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

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

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

²⁰ NER, cl. 6.2.8(c).

²¹ We did not apply the DEA benchmarking technique. We outline the reasons why we did not apply this technique in Appendix A of our all NSW distribution determinations for the 2014–19 period.

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

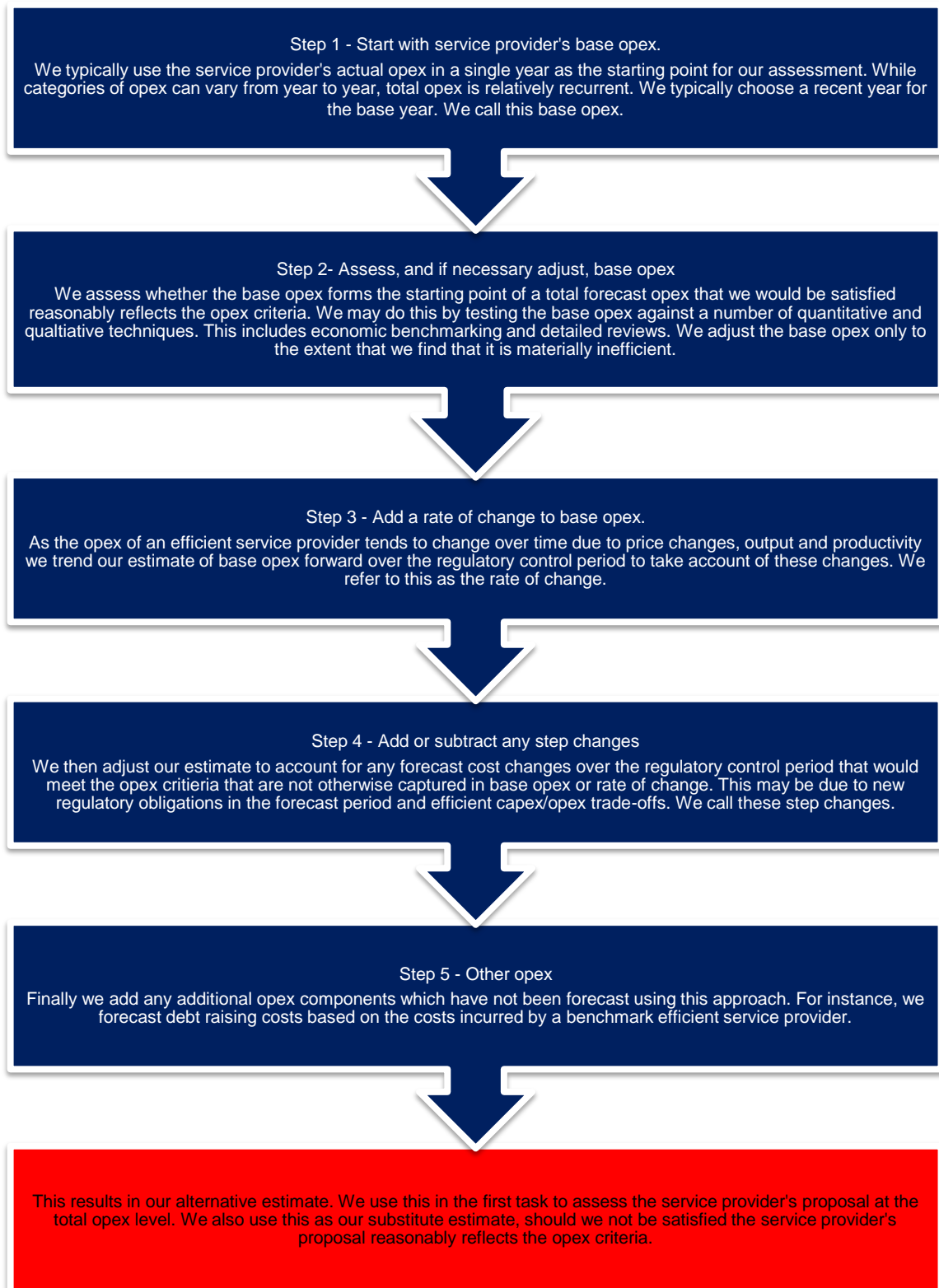
²³ AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

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

Building an alternative estimate of total forecast opex

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

Figure 7.3 How we build our alternative estimate



Underlying our approach are two general assumptions:

1. the efficiency criterion and the prudence criterion in the NER are complementary

2. actual operating expenditure was sufficient to achieve the opex objectives in the past.

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

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

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

Step 1 – Base year choice

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

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

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

- 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.

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

- Rather than use all of the opex that a service provider incurs in the base year, service providers also often forecast specific categories of opex using different methods. We must also assess these methods in deciding what the starting point should be. If we agree that these categories of opex should be assessed differently, we will also remove them from the base year.

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

Step 2 - Assessing base opex

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

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

Benchmarking is particularly important in comparing the relative efficiency of different service providers. The AEMC highlighted the importance of benchmarking in its changes to the NER in November 2012.²⁷

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

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. For this decision we have used multilateral total factor productivity, partial factor productivity measures and several opex cost function models.²⁸

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.

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

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

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

Step 3 - Rate of change

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

- price growth
- output growth
- productivity growth.

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

Step 4 - Step changes

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

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

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

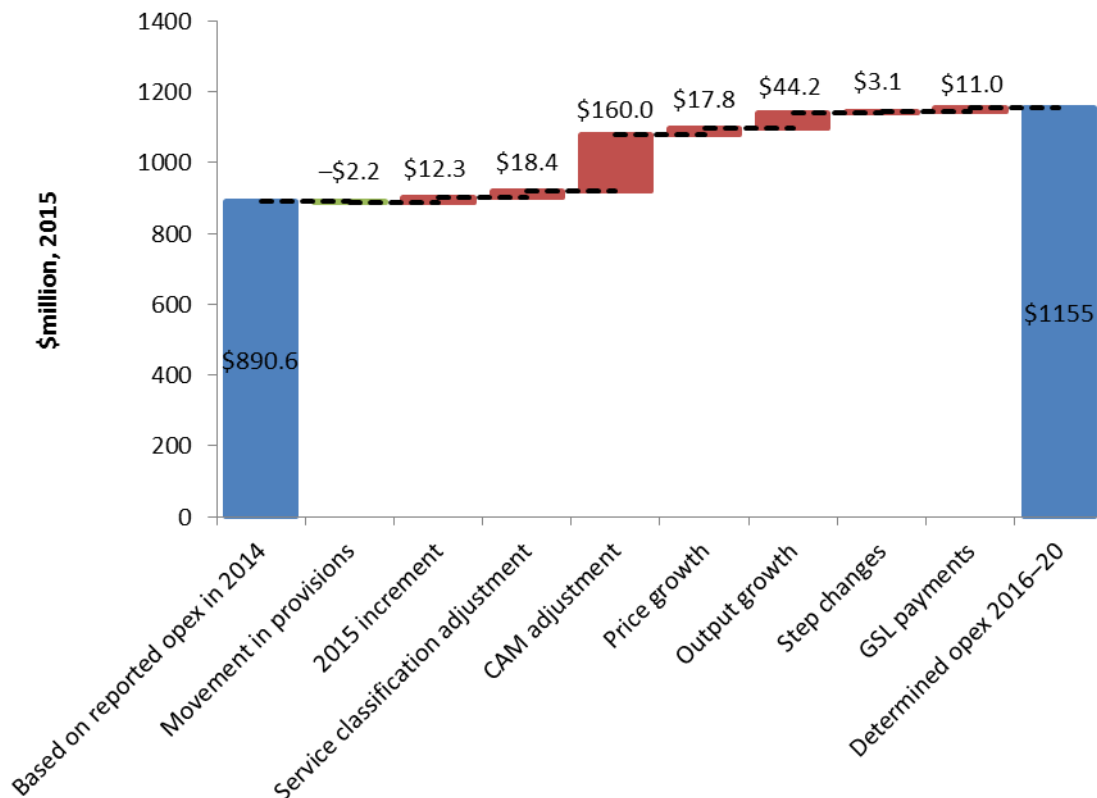
²⁹ AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

7.4 Reasons for preliminary decision

We are not satisfied that Powercor’s proposed total forecast opex of \$1308.2 million (\$2015) reasonably reflects the opex criteria.³⁰ As we discussed above, we have therefore used our alternative estimate as our substitute estimate.³¹

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

Figure 7.4 AER preliminary decision opex forecast



Source: AER analysis.

Table 7.2 summarises the quantum of the difference between Powercor’s proposed total opex and our preliminary decision estimate.

³⁰ NER, cl. 6.5.6(d).

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

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

	2016	2017	2018	2019	2020	Total
Powercor's proposal	243.0	250.9	262.6	271.4	280.3	1308.2
AER preliminary decision	221.4	225.2	230.9	236.0	241.6	1155.1
Difference	-21.6	-25.7	-31.7	-35.4	-38.7	-153.1

Source: AER analysis.

Note: Excludes debt raising costs.

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

7.4.1 Forecasting method assessment

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

7.4.2 Base opex

We have forecast a base opex amount of \$215.8 million (\$2015). Our forecast of base opex is outlined in Table 7.3.

Table 7.3 AER forecast of base opex

Reported 2014 opex	181.5
Remove debt raising costs	-0.2
Remove movement in provisions	-0.4
Remove DMIA expenditure	-0.2
Remove GSL payments	-2.2
Remove scrapping of assets	-0.7
Capitalisation policy change	32.0
Service classification adjustment	3.7
Adjusted 2014 opex	213.3
2015 increment	2.5
Estimated 2015 opex	215.8

Source: AER analysis.

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

We have also included an adjustment for corporate overheads in our opex forecast. Powercor proposed to expense all corporate overheads from 2016. We have agreed with this approach but have used a different methodology to Powercor to determine the adjustment. In making this adjustment, Powercor proposed to roll into its opex all corporate overheads which it capitalised in 2014. However, its capitalised corporate overheads in 2014 appear relatively high compared to earlier years in the current regulatory control period. We are not satisfied based on the evidence we have considered that Powercor's actual capitalised overheads in 2014 are reflective of its recurrent expenditure. Therefore instead of using its methodology we have used an average of capitalised corporate overheads from 2012 to 2014. This ensures the overheads we include in Powercor's opex forecast are not overly influenced by factors in any one year.

We also have not included an adjustment for Advanced Metering Infrastructure (AMI) expenditure. During the 2011–15 regulatory control period, incremental costs associated with implementing and operating smart meters were regulated under the Advanced Metering Infrastructure Order in Council (AMI OIC). This included costs associated with new or upgraded IT systems.

With the expiry of the AMI OIC, opex associated with AMI is now to be regulated under the NER. All distributors proposed to allocate this expenditure between standard control services and alternative control services. The proportions allocated between

each type of service differed for each service provider. We consider any cost allocation issues relating to metering costs would be best dealt with in a new Distribution Ring Fencing Guideline, which, at this stage will be developed by December 2016.

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

7.4.3 Rate of change

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

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

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

	2016	2017	2018	2019	2020
Powercor	3.36	3.86	3.41	3.59	3.10
AER	1.56	1.77	2.07	2.27	2.39
Difference	-1.80	-2.10	-1.35	-1.32	-0.71

Source: AER analysis.

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

- To forecast labour price growth, Powercor used wage increases in its existing enterprise agreement for 2016 and 2017, then used Frontier Economics' recommended extrapolation of long term enterprise agreements from a comparator group of service providers. Powercor's forecast is higher than ours, which we base on forecasts from Deloitte Access Economics and BIS Shrapnel.
- Powercor proposed different output growth drivers to ours. Powercor used four econometric models to quantify the relationship between growth in opex and the growth in key cost drivers that affect the size of its network. We forecast a lower output growth, using the same output growth measures and weightings as used in

Economic Insights' economic benchmarking report.³² We used customer numbers and circuit length forecasts from Powercor's reset RIN and ratcheted maximum demand forecasts from AEMO.

The differences in each forecast rate of change component are:

- our forecast of price growth is on average 0.93 percentage points lower than Powercor's forecast
- our forecast of output growth is on average 0.51 percentage points lower than Powercor's forecast

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

7.4.4 Step changes

We have included one step change in our opex forecast. We are satisfied that additional opex associated with Powercor's customer relationship management system arises due to new regulatory requirements.

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

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

Table 7.5 Step changes (\$ million, 2015)

	Powercor proposal	AER position
Step changes		
Customer charter	0.5	–
Superannuation - accumulation members	4.6	–
Monitoring IT security	2.0	–
Mobile devices	4.1	–
Customer Information System and Customer Relationship Management	5.2	3.1
Sub-total	16.5	3.1
Other adjustments to opex forecast		
Superannuation - defined benefit members	11.7	-
Regulatory reset costs	-2.0	–

³² Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 40–41.

Sub-total	9.6	0.0
Total	26.1	3.1

Source: Powercor, *Regulatory proposal*, April 2015, pp. 175, 187; AER analysis.

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

7.4.5 Other costs not included in the base year

Guaranteed service level payments

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

Debt raising costs

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

7.4.6 Interrelationships

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

- the operation of the EBSS in the 2011–15 regulatory control period, which provided Powercor 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 Powercor's proposed base year adjustment for the change to its overhead capitalisation policy
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block

- changes to the classification of services from standard control services to alternative control services
- concerns of electricity consumers identified in the course of its engagement with consumers.

7.4.7 Assessment of opex factors

In deciding whether we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.³³ Table 7.6 summarises how we have taken the opex factors into account in making our preliminary decision.

Table 7.6 AER consideration of opex factors

Opex factor	Consideration
<p>The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.</p>	<p>There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider.</p> <p>The second element, that is, the benchmark operating expenditure that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period.</p> <p>We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of Powercor's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.</p>
<p>The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.</p>	<p>Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Powercor's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.</p>
<p>The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network</p>	<p>We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their</p>

³³ NER, cl. 6.5.6(e).

Opex factor	Consideration
Service Provider in the course of its engagement with electricity consumers.	regulatory proposals, such that they factor in the needs of consumers. ³⁴
The relative prices of capital and operating inputs	<p>We have considered capex/opex trade-offs in considering Powercor's proposed step changes. For instance we considered whether a step change for increased mobile radio costs is an efficient capex/opex trade-off. We considered the relative expense of capex and opex solutions in considering this step change.</p> <p>We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.</p>
The substitution possibilities between operating and capital expenditure.	<p>As noted above we considered capex/opex trade-offs in considering step change for Powercor's mobile radio costs. We considered the substitution possibilities in considering this step change.</p> <p>Some of our assessment techniques examine opex in isolation – either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability.</p> <p>In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs.</p> <p>We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs.</p> <p>Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.</p>
Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	<p>The incentive scheme that applied to Powercor's opex in the 2011–15 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach.</p> <p>We have applied our estimate of base opex consistently in applying the EBSS and forecasting Powercor's opex for the 2016–20 regulatory control period.</p>
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	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

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

Opex factor	Consideration
	arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our preliminary decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be significant in reaching our preliminary decision.

Source: AER analysis.

A Base opex

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

A.1 Position

We have used a base opex amount of \$215.8 million in our alternative opex amount. The base opex amount we have used in our preliminary decision forecast is outlined below in Table A.1.

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

	Our preliminary decision
Reported 2014 opex	181.5
Remove debt raising costs	-0.2
Remove movement in provisions	-0.4
Remove DMIA expenditure	-0.2
Remove GSL payments	-2.2
Remove scrapping of assets	-0.7
Capitalisation policy change	32.0
Service classification adjustment	3.7
Adjusted 2014 opex	213.3
2015 increment	2.5
Estimated 2015 opex	215.8

Source: AER opex model.

A.2 Proposal

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

- remove debt raising costs, movements in provisions, DMIA expenditure and GSL payments in 2014
- add forecast opex on corporate overheads to give effect to a capitalisation policy change
- add opex for service classification changes.

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

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

	Powercor's proposal
Reported 2014 opex	182.0
Remove debt raising costs	-0.2
Remove movement in provisions	-0.4
Remove DMIA expenditure	-0.2
Remove GSL payments	-2.2
Capitalisation policy change	34.7
Service classification adjustment	8.7
Adjusted 2014 opex	222.2

Source: Powercor, *Regulatory proposal*, April 2015, p. 175; Powercor, *PAL PUBLIC MOD 1.36*, April 2015.

A.3 Assessment approach

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

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

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

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

- Benchmarking results
- Adjustments to base opex

A.4 Benchmarking results

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

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

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

- multilateral total factor productivity (MTFP) which is an index that measures the ratio of inputs used for output delivered
- opex multilateral partial factor productivity (MPFP) which is an index-based technique that measures the ratio of output quantity index to opex input quantity index³⁵
- econometric modelling techniques:
 - Cobb Douglas stochastic frontier analysis (SFA)—this estimates the efficient level of opex required for a service provider by constructing an efficient frontier and compares this to the actual opex used by the service provider
 - Cobb Douglas least squares estimation—is similar to the above in modelling opex cost function but uses least squares estimation method to estimate an industry-average technology, and includes dummy variables for Australian distributors to capture firm-specific efficiency
 - Translog least squares estimation—this is similar to the Cobb Douglas least squares estimation technique but assumes more flexible functional form regarding the relationship between opex and outputs.

Each benchmarking technique compares the relative efficiency of service providers to its peers. These techniques differ in terms of estimation method, model specification and the inclusion of operating environment factors (factors that may differentiate service providers). Despite this, Economic Insights found:³⁶

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

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

³⁵ At the time of developing the Expenditure forecast assessment guideline, we had not received data from service providers so we considered data envelopment analysis (DEA) may be another technique we could apply. However, we have been able to apply stochastic frontier analysis. This is a superior technique to DEA. Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, p. 7.

³⁶ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 46–47.

We note the benchmarking we have presented in this preliminary decision only includes the data we have used in our latest distribution benchmarking report.³⁷ This used the actual opex incurred by the Victorian service providers from 2006 to 2013.

While the benchmarking does not include actual opex in 2014, the year each of the Victorian service providers proposed as the base, we would not expect this would lead to material differences in the benchmarking results or our conclusions on the relative efficiency of each provider. On some of our benchmarking techniques (e.g. econometric models), we only assess average efficiency over a sample period of eight years. This means an additional year of data will not materially affect our conclusions about the relative efficiency of the service providers over the sample period. In any case, we note that Powercor's actual opex in 2013 was \$199 million (\$2015) while in 2014 it had fallen to \$182 million (\$2015). Therefore, as we have found Powercor is to be relatively efficient based on its opex incurred in 2013, it is reasonable to assume that its opex in 2014 is also relatively efficient.

A.4.1 MTFP and MPFP findings

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

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

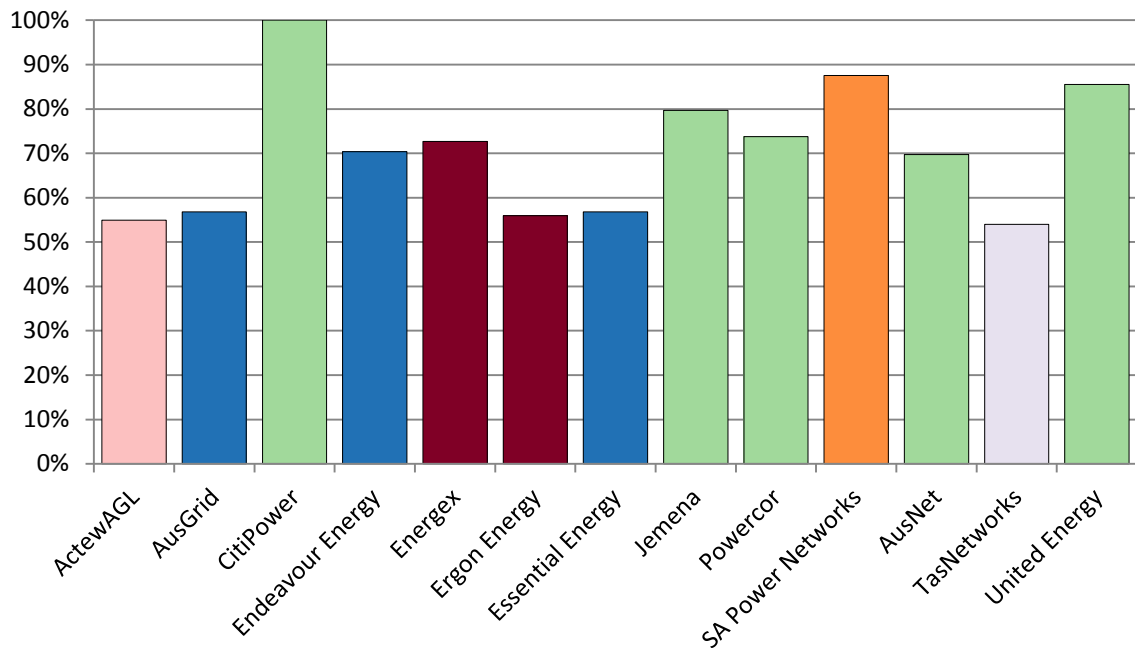
MTFP measures total output relative to an index of all inputs used. MPFP measures total output relative to one particular input (e.g. opex partial productivity is the ratio of total output quantity index to an index of opex quantity).

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

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

³⁷ AER, 2014 *Annual distribution benchmarking report*, November 2014.

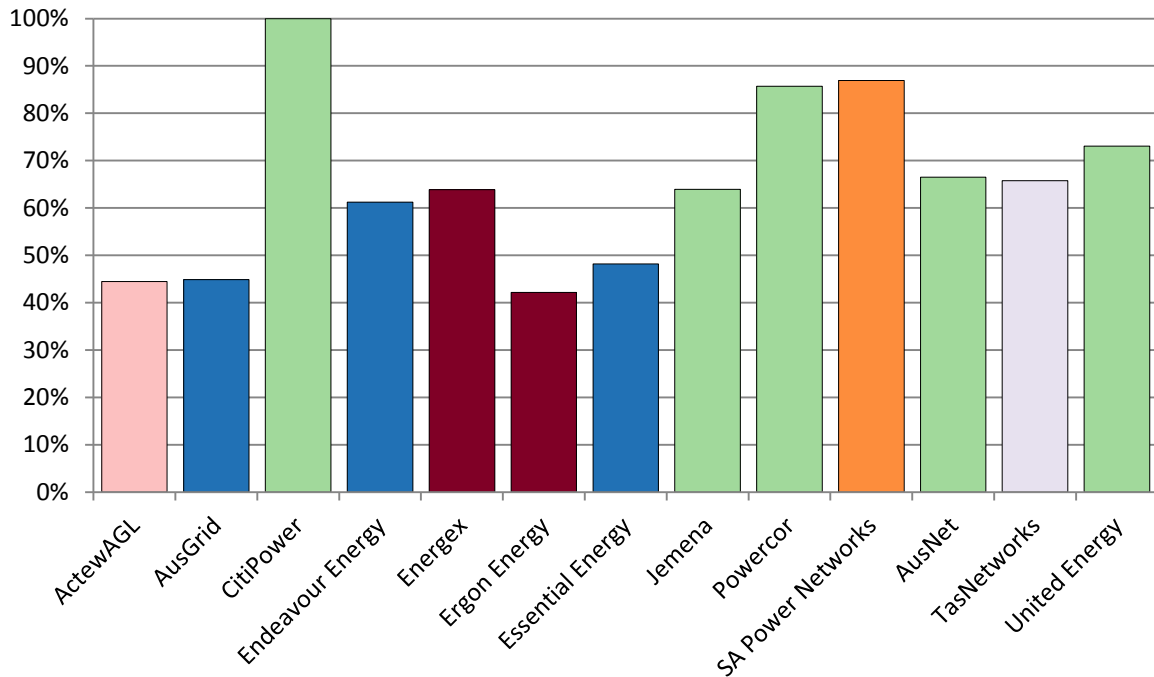
Figure A-1 MTFP Performance (average 2006–2013)



Source: AER analysis.

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

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



Source: AER analysis.

For further detail on MTFP and MPFP we direct readers to our previous publications.³⁸

We note that the ACT, NSW and Queensland service providers have made a number of submissions on our use of benchmarking in the NSW, ACT and Queensland distribution determinations. We have considered these submissions and have concluded that the benchmarking we have relied upon is appropriate. We have published these submissions along with our consideration of them on our website.³⁹

The Victorian service providers also submitted some benchmarking as part of their proposals. For instance, Jemena and United Energy submitted reports from Huegin.⁴⁰ In general, the analysis it undertook was consistent with analysis it undertook for the NSW and Queensland distribution service providers. AusNet Services also submitted

³⁸ These include: Economic Insights, 2014 and AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014, and our draft determinations for the NSW and ACT distribution network service providers; AER, *Better Regulation, Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013; ACCC/AER, *Benchmarking Opex and Capex in Energy Networks, Working Paper no.6*, May 2012.

³⁹ <http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements> .

⁴⁰ Huegin, *Jemena Electricity Networks (Vic) Ltd Productivity Study, Efficiency and growth for the 2015–20 regulatory period*, April, 2015.

Huegin, *Benchmarking United Energy's operating expenditure - an indication of benchmarking results using the AER's techniques*, April, 2015 .

some analysis which considered the operating environment factors they consider disadvantage them in benchmarking performance.⁴¹ We recognise that operating environment factors specific to each business will affect their benchmarking performance. Our view is that Powercor and the other Victorian service providers already appear relatively efficient when compared to the NSW and Queensland service providers. On this basis we did not consider it necessary to consider the detailed operating environment factors affecting the individual performance of each Victorian business for this preliminary decision.

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

Economic Insights has previously modelled the opex cost function of the service providers using three models.⁴² These models are Cobb Douglas SFA, Cobb Douglas least squares estimation (CD LSE) and Translog least squares estimation (TLG LSE). The TLG LSE and CD LSE models are econometric modelling of Translog and Cobb Douglas opex cost functions, respectively.⁴³ They are parametric techniques, which means that they model the underlying cost function of the service providers as specified.

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

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

The Victorian Energy Consumer and User Alliance (VECUA) considered on the basis of one of these models, Cobb Douglas SFA, that all Victorian service providers appear materially inefficient when compared to CitiPower.⁴⁴

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

⁴¹ AusNet Services, *Regulatory proposal*, April 2015, pp. 83–91.

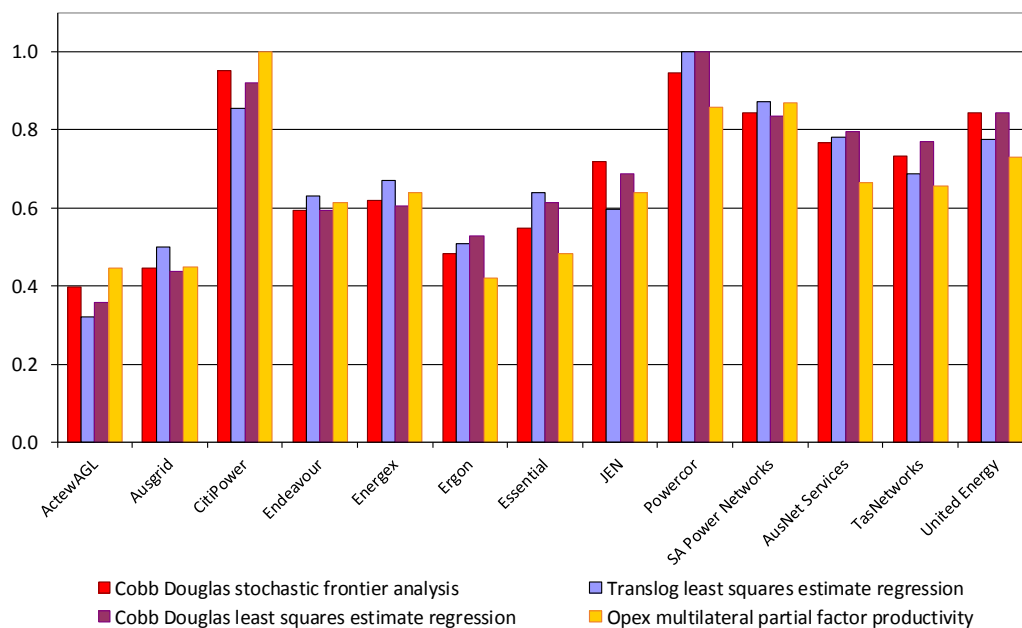
⁴² Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, p. iii.

⁴³ Economic Insights describes the opex cost functions in detail. Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 27–31.

⁴⁴ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 revenue proposals*, 13 July 2015, p. 34.

- The results below reflect raw efficiency scores. There are other operating environment factors affecting each businesses performance which are not captured in each of the benchmarking models.
- The scores below reflect average efficiency scores over the 2006 to 2013 period, so these cannot be used directly to infer the relative efficiency gap between providers in any one year.
- Powercor performs worse than CitiPower on the Cobb Douglas SFA model, but on other models it performs better than CitiPower. We do not consider it would be reasonable to conclude one service provider was relatively efficient when alternative benchmarking models indicate a different ranking.

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



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

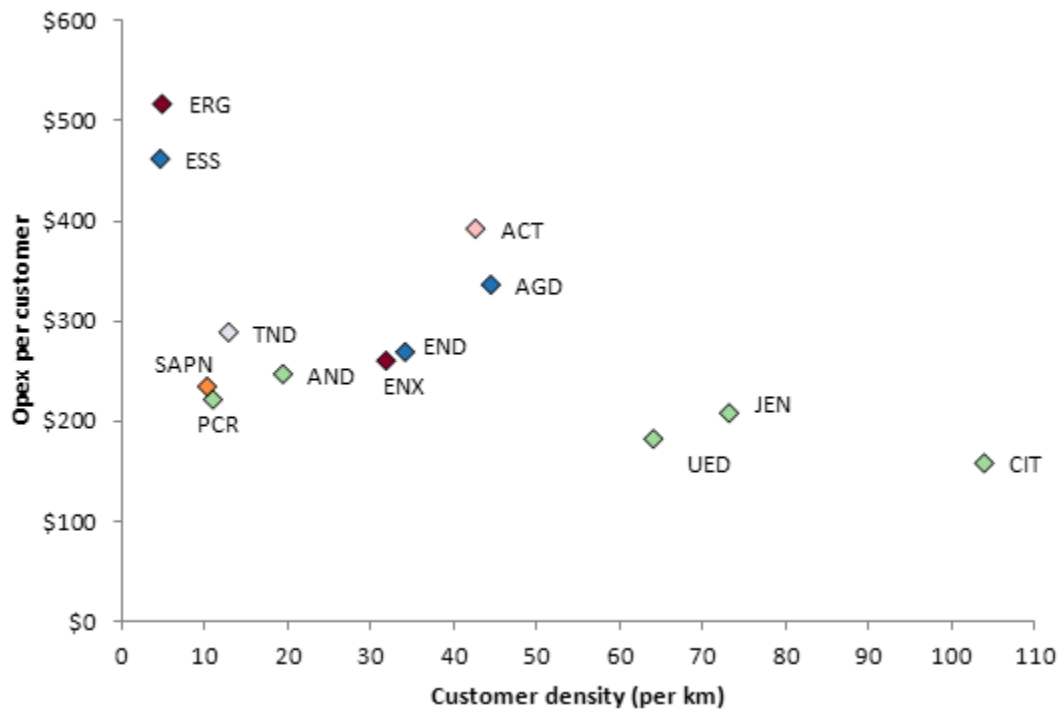
A.4.3 Partial performance indicators

In our annual benchmarking report we also present a number of partial performance indicators.⁴⁵ These indicators examine the service providers' use of assets, opex and total inputs in delivering its distribution services. Under these metrics, Powercor appears to be one of the more efficient networks. As such, we consider that this benchmarking supports the findings of the econometric benchmarking discussed above.

⁴⁵ AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014.

Although a number of PPIs are presented in this report we consider that the most relevant PPIs are opex per customer and total cost per customer. This is because customer numbers appears to be the most material driver of costs for service providers.⁴⁶ Figure A-4 and Figure A-5 present these PPIs. These figures show that Powercor (PCR) incurs relatively low opex and total cost per customer when compared to its peers.

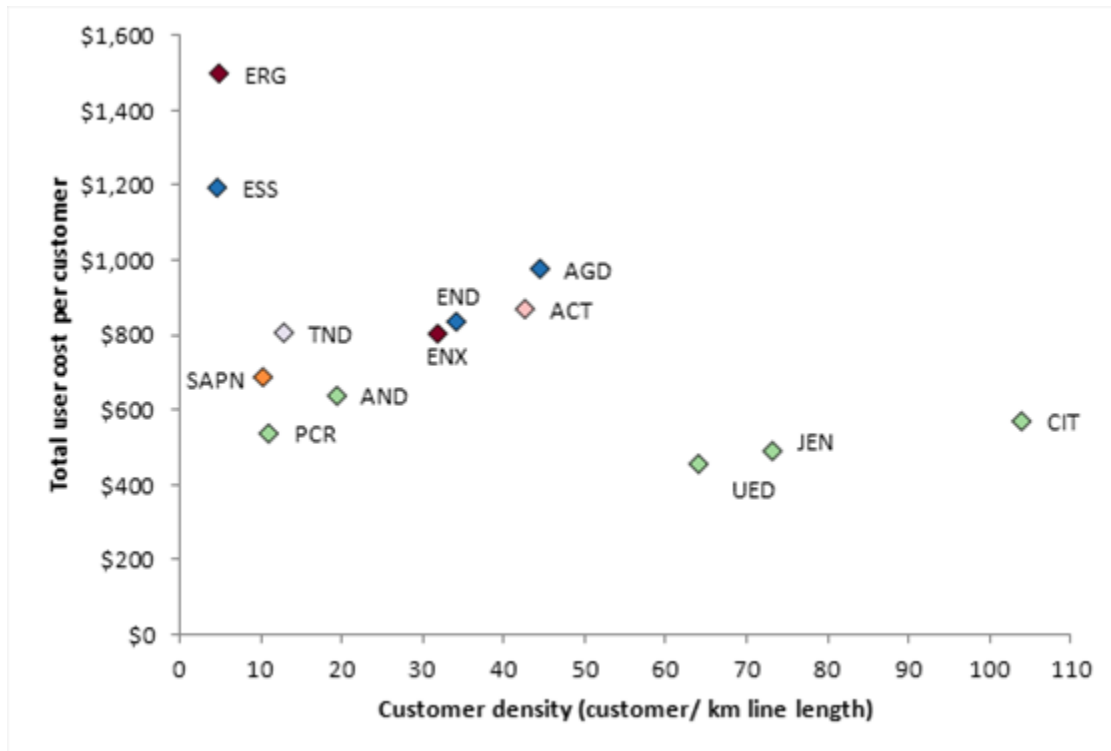
Figure A-4 PPI of operating expenditure per customer (2009 to 2013)



Source: AER analysis.

⁴⁶ The number of customer connections has the highest coefficient in Economic Insights econometric models and its SFA Cobb Douglas Model. Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, pp. 33–35.

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



Source: AER analysis.

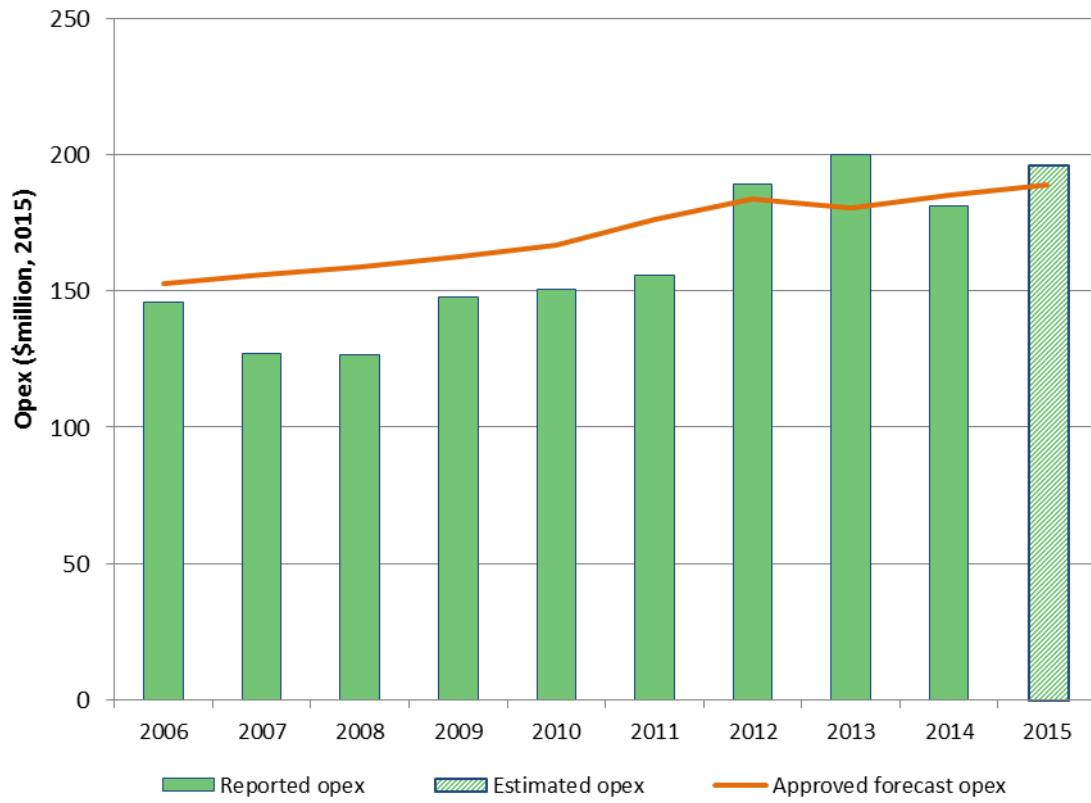
A.4.4 Trend in opex

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

In real terms, Powercor's opex in 2014 is 14 per cent higher than the average over the benchmarking period (Figure A-6). This increase in opex has contributed to a decline in opex MPFP in 2012 and 2013. This is illustrated in Figure A-7 (Powercor is ranked second in 2013). This trend in productivity was noted by the Consumer Challenge Panel and the VECUA in their submissions.⁴⁷

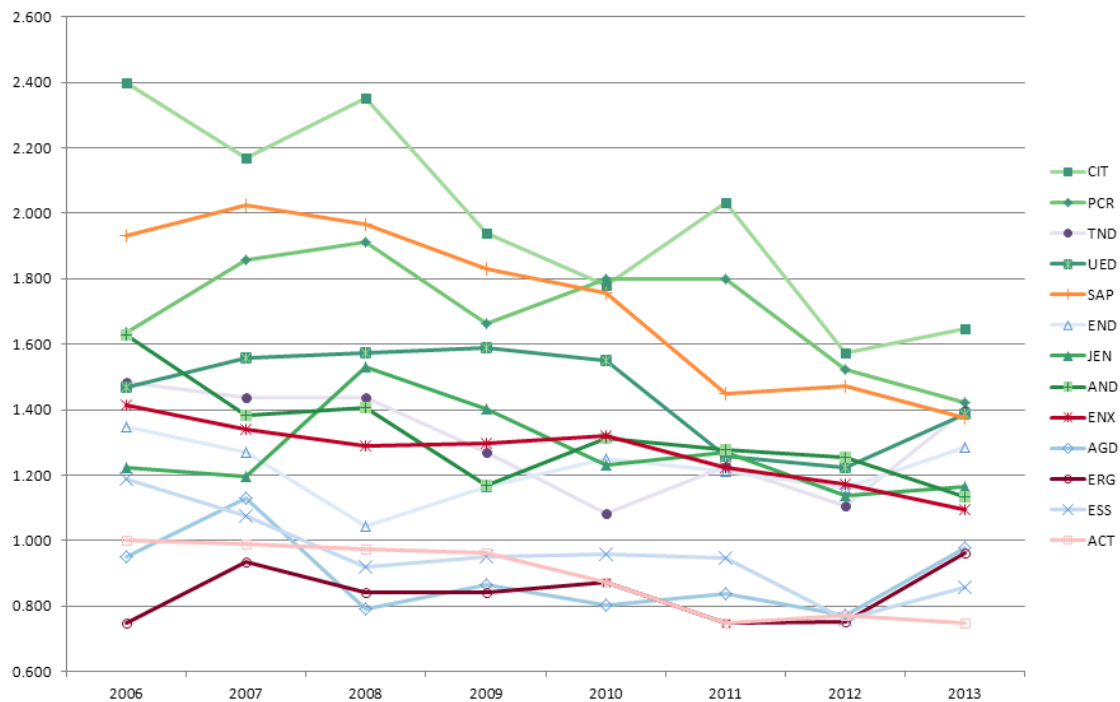
⁴⁷ Consumer Challenge Panel sub panel 3, *Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 5 August 2015, pp. 11-12; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 revenue proposals*, 13 July 2015, p. 35.

Figure A-6 Powercor's opex compared to approved forecast



Source: Powercor, *Economic benchmarking - Regulatory Information Notice response 2006 to 2013*, April 2015; AER analysis.

Figure A-7 MPFP of distributors over the benchmarking period



Source: Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, November 2014, p. 20.

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

We also note that the key driver of Powercor's increased opex in this time is changed regulatory requirements rather than a decline in Powercor's efficiency.

As outlined below in Table A.3, Powercor's opex on vegetation management rose from \$16.5 million (\$2015) in 2009 to \$47.9 million (\$2015) in 2013. The key reason for this is the introduction of the Electricity Safety (Electric Line Clearance) Regulations 2010. Under the previous version of these regulations, the Electricity Safety (Electric Line Clearance) Regulations 2005, the Victorian service providers were able to ask for exemptions from the regulations where they could demonstrate to Energy Safe Victoria that appropriate risk mitigation was in place. Under the 2010 version of the regulations, following the Black Saturday bushfires, many of these exemptions were removed. This led to an increase in Powercor's vegetation management expenditure.

Table A.3 Powercor vegetation management expenditure

	2009	2010	2011	2012	2013
Vegetation management expenditure (\$2015)	16.5	11.4	29.6	44.1	47.9
% of total opex	11	8	19	24	24

Source: Powercor *Economic Benchmarking RINs 2009-2014*; AER analysis.

A.5 Adjustments to base opex

A.5.1 Change in capitalisation policy—corporate overheads

We have included an adjustment of \$32.0 million (\$2015) to Powercor's base opex for changes in corporate overhead capitalisation policy. Our adjustment reflects an average of Powercor's capitalised corporate overheads between 2012 and 2014. We did not approve Powercor's proposed adjustment in entirety which only reflected Powercor's capitalised corporate overhead expenditure in 2014. We were not satisfied its capitalised corporate overheads in 2014 was reflective of recurrent expenditure.

We previously approved a revised CAM for CitiPower and Powercor.⁴⁸ The proposed amendment would change the way CitiPower and Powercor capitalise their corporate overheads. CitiPower and Powercor currently partly expense and partly capitalise their corporate overhead expenses. After the revised CAM takes effect from 1 January 2016, CitiPower and Powercor would fully expense these costs.

Powercor proposed an increase of \$34.7 million (\$2015) to its base opex for its change in capitalisation policy. No corporate overheads were proposed as capex.

Powercor proposed to adjust its opex for its capitalisation policy by adding total capitalised corporate overheads from 2014 to its actual opex in 2014. In its regulatory proposal, Powercor did not provide any reasons which supported the methodology it had used. In response to an information request, Powercor provided the following reason why it had used its actual capitalised corporate overhead expenditure in 2014:

The reason for using 2014 is based on the AER's revealed cost approach, which determines that the penultimate year (which is the latest audited year) is the most reflective year of ongoing costs in the next regulatory control period.⁴⁹

Consistent with our decision to approve Powercor's revised CAM, we have approved an increase in opex for Powercor's change in capitalisation policy. As a result of this change, corporate overheads are only included in forecast opex and not forecast

⁴⁸ AER, *CitiPower and Powercor, Revised cost allocation methods*, 17 October 2014.

⁴⁹ Powercor, *Information request Vic EDPR - Powercor - IR007*, 3 July 2015, p. 2.

capex. We note that both SA Power Networks and United Energy already expense all corporate overheads so this accounting approach is not unusual.

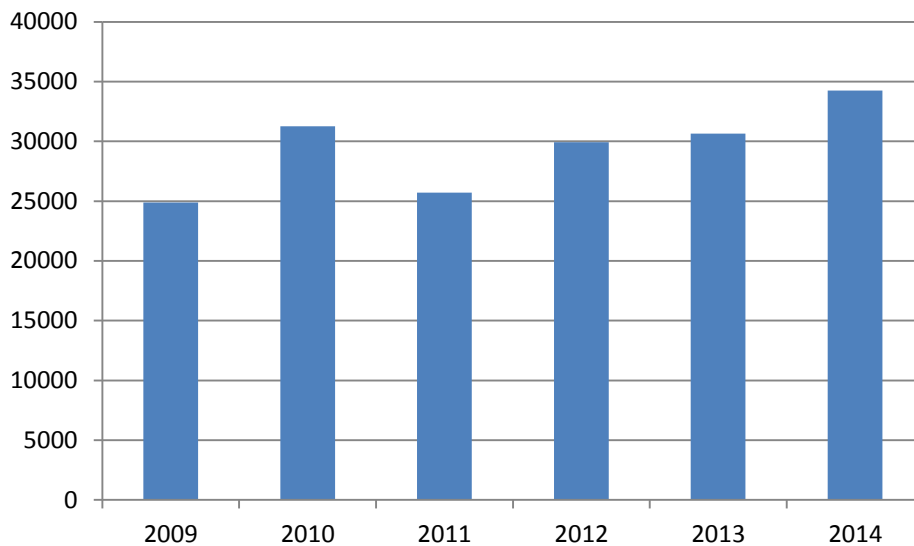
However, we do not consider there was sufficient evidence to support the methodology Powercor used in adjusting its base year opex.

We often use the most recent audited year as the base year in forecasting future expenditure. However, we do not simply assume the most recent audited year is reflective of prudent and efficient ongoing opex. For instance, expenditure in a single year is often affected by non-recurrent factors. If these costs are higher than average in the most recent audited year, forecast opex would be higher than required to meet the opex objectives.

We are also more confident in using a single year of recent expenditure to forecast future expenditure when a service provider faces strong incentives to reduce its expenditure in that year. For instance, Powercor is subject to the EBSS. This ensures the incentives facing it to reduce opex are continuous (i.e. the same) throughout the regulatory control period and there is no incentive to increase expenditure in the year used to forecast expenditure going forward.

As outlined in Figure A-8, Powercor’s capitalised corporate overhead expenditure was materially higher in 2014.

Figure A-8 Powercor – capitalised corporate overhead expenditure (\$2015)



Source: Powercor, Category analysis RINs 2009-2014; AER analysis.

When we asked Powercor to explain and quantify the drivers of the increase in 2014, it provided the following response:⁵⁰

The main factors which drove an increase in corporate overheads from 2013 to 2014 were IT costs and regulation costs.

IT costs were driven by the following:

- increase in ipads and iphones;
- increase in data costs (more ipads, more data required to run them);
- increase in telecommunication costs (more iphones, more plans required to run them);
- move in cloud based software purchases; and
- general increase in volume and amount for support and maintenance costs for software and hardware.

Regulation costs were driven by increased RIN internal compliance costs and increase in RIN audit fees.

Powercor did not quantify the factors that affected its capitalised corporate overheads.

Based on the information in its proposal and its response to our request for further information, we do not have sufficient confidence that the capitalised corporate overhead expenditure Powercor incurred in 2014 would be reflective of Powercor's recurrent expenditure in these categories. For instance, IT expenditure is the largest component of Powercor's capitalised corporate overhead expenditure (39 per cent in 2014). As outlined in Powercor's response, its IT costs in 2014 were affected by increases in ipads and iphones. We are not convinced that the step up in capex Powercor incurred in 2014 on ipads and iphones is reflective of its recurrent expenditure.

We also note that while Powercor identified regulation costs was one of the main factors driving the increase in its capitalised corporate overhead costs between 2013 and 2014, this does not appear to be consistent with the data it reported in its Category Analysis RINs. It shows that the increase in regulatory costs in 2014 only contributed to 9 per cent of the increase.⁵¹

We also do not consider that Powercor faced strong incentives to incur efficient capex towards the end of the 2011-15 regulatory control period. No incentive mechanism was applied to Powercor's capex. Without such a mechanism, its incentive to incur efficient capex declined over the 2011-15 period. This means, all else being equal, it was incentivised to delay its capital expenditure towards the end of the period. This is another reason why we do not consider it is appropriate to rely solely on its capitalised corporate overhead expenditure in 2014.

⁵⁰ Powercor, *Information request: Vic EDPR - Powercor - IR007*, 3 July 2015, p. 1.

⁵¹ Powercor, *CA RIN 2009-2014*; AER analysis

We have instead used an average of Powercor's capitalised corporate overhead expenditure between 2012 and 2014 in adjusting its base. This ensures our revised forecast of its base opex is not overly influenced by the factors affecting Powercor's capitalised corporate overheads in any one year, or by the weaker incentives it faced in 2014.

A.5.2 Service classification change—IT metering expenditure

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

During the 2011–15 regulatory control period, incremental costs associated with implementing and operating meters were regulated under the Advanced Metering Infrastructure Order in Council (AMI OIC). These 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. Powercor proposed an adjustment to its base opex of \$4.9 million for IT metering expenditure previously regulated under the AMI OIC.

Each of the Victorian service providers have taken a different approach to how these costs should be allocated across standard control and alternative control (metering) services. CitiPower and Powercor have each used a granular approach, which, where possible, quantifies the proportion of each IT system previously regulated under AMI OIC they have used for standard control services. For many IT systems, Powercor deems the proportion used for metering to be relatively immaterial so allocates the whole proportion of the IT system cost to standard control services.⁵²

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

- Jemena, similar to CitiPower and Powercor has also taken a relatively granular approach to determining the amount of costs to be allocated between standard control services and metering services. However, it has allocated all shared costs previously regulated under the AMI OIC between standard control and alternative control services, not only IT.⁵³
- Where any costs regulated under AMI OIC are shared between standard control distribution services and metering services, AusNet Services and United Energy have proposed to allocate the whole proportion to standard control services.⁵⁴

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

⁵² Powercor, *Regulatory proposal, Appendix F - Base year adjustments*, April 2015, p. 12.

⁵³ Jemena, *Regulatory proposal, opex model*, April 2015

⁵⁴ AusNet, *Regulatory proposal*, April 2015, p. 204; United Energy, *Revenue Capped Metering Services - Supporting Paper*, 30 April 2015.

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

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

Source: AER analysis.

We consider a consistent approach across Victorian service providers is preferable. While metering services are not currently subject to competition, given policy developments in this area, in the near future it is likely they will be.⁵⁵ The cost allocation approaches by incumbent providers have the potential to affect competition from new entrants and competition between Victorian distributors.

Based on the current guidance from the AEMC, we will be required to develop and publish a Distribution Ring Fencing Guideline by 1 December 2016.⁵⁶ We consider any cost allocation issues relating to metering costs would be best dealt with in the development of this Guideline in accordance with a nationally consistent approach.

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

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

We received a submission from the Victorian Department of Economic Development, Jobs, Transport and Resources which agreed that some of these costs may be standard control services but considered there was a risk that consumers would be

⁵⁵ AEMC, *Draft Rule Determination - National Electricity Amendment (Expanding Competition in Metering and Related Services) 2015*, 26 March 2015.

⁵⁶ AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

paying for these costs twice.⁵⁷ As we have not allocated any AMI costs to standard control services opex, there is no risk of consumers paying for these costs twice.

A.5.3 Other service classification changes

We have included other increases in opex to reflect changes in service classification in our forecast.

Powercor proposed several other adjustments to give effect to service classification changes. It included an increase in opex of \$3.1 million to align its reporting of pole treatment costs with the definition we set out in the Category Analysis RIN and an increase in \$0.6 million to give effect to the reclassification of supply abolishment from alternative control services to standard control services. The amount included in Powercor's forecast is consistent with the amount incurred in 2014. We are satisfied that the corresponding amount has been removed from its capex and alternative control services forecasts.

A.5.4 Other adjustments

Powercor also made adjustments to its base opex to:

- remove opex incurred in 2014 on debt raising costs, the Demand Management Innovation Allowance and GSL payments, and
- adjust for movements in provisions.

We have agreed to these adjustments, consistent with our standard opex forecasting approach.

In addition in reaching our forecast of base opex we have removed \$0.7 million in reported opex for losses associated with the scrapping of assets. Losses on the scrapping of assets are accounting records of the shortfalls between the proceeds from selling assets and their accounting written down values. As a loss on the scrapping of an asset is an accounting adjustment to expenditure, rather than an actual outlay made by Powercor in providing network services, we do not consider this is something that should be recovered from Powercor's consumers. Consistent with this approach, we also propose to exclude this cost from the EBSS in the 2016 to 2020 period.

A.6 Estimate of final year expenditure

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

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

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

⁵⁷ Victorian Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 6.

where:

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

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

F_b is the determined opex allowance for the base year

A_b is the amount of actual opex in the base year

non-recurrent efficiency gain_b is the non-recurrent efficiency gain in the base year.

The estimate of final year opex should be consistent in both our opex forecast and the EBSS in order to share Powercor's efficiency gains made in 2015 with its network users as intended by the EBSS. Version one of the EBSS⁵⁸ for distribution businesses does not allow estimated final year expenditure to be adjusted for non-recurrent efficiency gains (version two,⁵⁹ which will apply in the 2016–20 regulatory control period does). We are required to have regard to whether the opex forecast is consistent with the EBSS when deciding whether we are satisfied that the proposed opex forecast reasonably reflects the opex criteria.⁶⁰ To ensure consistency with estimated final year expenditure in the EBSS, we have not adjusted our estimate of final year expenditure for any non-recurrent efficiency gains.

We applied this equation to derive an estimated opex of \$215.8 million (\$2015) for 2015. We then applied our forecast rate of changes, and added step changes, to derive our alternative estimate of opex for the 2016–20 period.

⁵⁸ AER, *Electricity distribution network service providers - Efficiency benefit sharing scheme*, June 2008.

⁵⁹ AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

⁶⁰ NER, cl. 6.5.6(e)(8).

B Rate of change

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

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

As set out in our *Expenditure forecast assessment guideline* (the Guideline), we have developed an opex forecast incorporating the rate of change to account for:⁶¹

- price growth
- output growth
- productivity growth.

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

B.1 Position

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than Powercor's over the forecast period. Table B.1 shows Powercor's and our overall rate of change in percentage terms for the 2016–20 period. We consider that applying our methodology to derive an alternative estimate of opex will result in a forecast that reasonably reflects the efficient and prudent costs faced by Powercor given a realistic expectation of demand forecasts and cost inputs.

The differences in the forecast rate of change components are:

- our forecast of annual price growth is on average 0.93 percentage points lower than Powercor's
- our forecast of annual output growth is on average 0.51 percentage points lower than Powercor's.

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

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

	2016	2017	2018	2019	2020
Powercor	3.36	3.86	3.41	3.59	3.10
AER	1.56	1.77	2.07	2.27	2.39

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

Difference	-1.80	-2.10	-1.35	-1.32	-0.71
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Source: AER analysis.

B.2 Powercor proposal

Table B.2 shows Powercor's proposed cumulative change in opex for each rate of change component reported in its reset RIN. Powercor's rate of change methodology is different to ours because it applied different output growth drivers and adopted a labour price measure based on benchmarked enterprise agreements (EAs).

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

	2016	2017	2018	2019	2020
Price growth	6528.0	10960.6	15256.9	19651.6	24312.9
Output growth	7977.7	12494.4	16575.9	21147.9	24646.3
Productivity growth	-	-	-	-	-

Source: Powercor, *Reset RIN table 2.16.1*, April 2015.

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

Forecast price growth

Powercor proposed price growth for the following categories:

- labour
- materials
- contracts.

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

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

Price growth	Consultant	Method
Labour	Frontier Economics	Powercor's existing EAs up until the expiry of those EAs. For the years following the expiry of the EAs, Frontier Economics recommended the extrapolation of long term Enterprise Agreements from a comparator group of distribution service providers.
Contracts	Centre for International Economics	Forecast change in the WPI for the construction sector.
Materials	Not applicable	Materials prices are assumed to grow with the CPI.

Source: Powercor, *Regulatory proposal*, April 2015, pp. 74, 81, 82.

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

	2015	2016	2017	2018	2019	2020
Labour	2.16	1.87	1.68	1.68	1.68	1.68
Contracts	1.22	0.96	2.15	1.73	1.72	1.74
Materials	–	–	–	–	–	–

Source: Powercor, *Regulatory proposal*, April 2015, pp. 73–74, 81.

Forecast output growth

Powercor used the average output growth from four econometric models to forecast output growth. Frontier Economics developed three of the models. Powercor stated the fourth model was the opex cost function model developed by Economic Insights that we used for our draft decisions for the NSW and ACT distributors. Table B.5 shows the forecast output growth from of each of the models.

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

	2015	2016	2017	2018	2019	2020
Model 1—Frontier Economics	0.88	1.59	2.89	1.40	1.39	0.96
Model 2—Frontier Economics	2.56	3.23	2.23	2.62	3.10	2.07
Model 3—Frontier Economics	1.23	1.40	1.17	1.26	1.38	1.13
Model 4—Economic Insights	1.78	1.93	1.76	1.84	1.96	1.73
Average	1.61	2.04	2.01	1.78	1.96	1.47

Source: Powercor, *Regulatory proposal*, April 2015, p.171.

Powercor derived its proposed output growth rates using the forecast growth rates for the output variables in Table B.6.

Table B.6 Powercor's proposed output variable growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Customer numbers	1.75	1.75	1.81	1.82	1.82	1.82
Zone substation transformer capacity	-0.07	1.42	4.07	0.93	0.93	0.00
Ratcheted maximum demand	2.56	3.23	2.23	2.62	3.10	2.07
Route line length	0.31	0.31	0.31	0.31	0.31	0.31
Circuit length	0.40	0.41	0.44	0.43	0.50	0.50

Source: Powercor, *Regulatory proposal*, April 2015, p. 180.

Forecast productivity growth

Powercor did not apply a productivity adjustment to its rate of change. It considered it is not appropriate to apply pre-emptive productivity adjustments to its opex forecasts. It also considered there is no evidence to justify making pre-emptive productivity adjustments to its opex forecasts.⁶²

B.3 Assessment approach

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

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

The rate of change formula for opex is:

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

where Δ denotes the proportional change in a variable.

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

⁶² Powercor, *Regulatory proposal*, 30 April 2015, p. 182.

view on the overall rate of change in deciding what to apply to derive our alternative opex forecast.

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

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

B.3.1 Price growth

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

To determine the appropriate forecast change in labour prices we assessed forecasts from Frontier Economics and Deloitte Access Economics. We discuss our consideration of the choice of labour price forecast below in section B.4.2.

B.3.2 Output growth

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

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

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

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

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

B.3.3 Productivity

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

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

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

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

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

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

B.4 Reasons for position

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

B.4.1 Overall rate of change

We have adopted a rate of change lower than that proposed by Powercor to forecast our alternative estimate of opex. Powercor's higher forecast price growth is the primary driver of this difference. Powercor also forecast higher output growth than us.

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

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

Powercor did not include a forecast change in productivity for the 2016–20 regulatory control period. This is consistent with our forecast of productivity growth.

Table B.7 shows Powercor's and our overall rate of change and each rate of change component for each regulatory year of the 2016–20 regulatory control period.

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

	2016	2017	2018	2019	2020
Powercor					
Price growth	1.30	1.82	1.61	1.60	1.61
Output growth	2.04	2.01	1.78	1.96	1.47
Productivity growth	–	–	–	–	–
Overall rate of change	3.36	3.86	3.41	3.59	3.10
AER					
Price growth	0.22	0.50	0.79	0.92	0.85
Output growth	1.33	1.26	1.26	1.34	1.53
Productivity growth	–	–	–	–	–
Overall rate of change	1.56	1.77	2.07	2.27	2.39
Difference	–1.80	–2.10	–1.35	–1.32	–0.71

Source: AER analysis.

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

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

B.4.2 Forecast price growth

We are not satisfied Powercor's proposed average annual price growth of 1.6 per cent for the 2016–20 regulatory control period reflects the increase in prices an efficient service provider requires to meet the opex objectives. We forecast an average annual price growth of 0.7 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.⁶⁵ We assumed non-labour prices grow with CPI.

In determining our forecast of price growth we have considered:

- whether hybrid approaches to forecast labour price growth produce unbiased forecasts
- how the labour price forecasting method reflects changes in labour market conditions
- which price measure best reflects the change in the price of contracted services
- what price weightings should be applied to each of the chosen price measures

We discuss our consideration of each of these below.

Hybrid forecasting methods

Powercor proposed using its existing EAs to forecast labour price growth until the expiry of those EAs. For the years following, it proposed using the historic average wage increases from a group of privately owned distribution service providers.⁶⁶ We consider this to be a 'hybrid forecasting method' because Powercor did not adopt the same forecasting method across the entire forecast period.

We have not adopted a hybrid forecasting approach that includes Powercor's enterprise agreement in our forecast of price growth. We base our alternative estimate on setting base opex and the rate of change for an efficient and prudent service provider to achieve the opex objectives rather than the distributor's actual costs.

Powercor forecast labour price growth equal to the wage increases in its enterprise agreements for the period up to the expiry of those agreements. It applied a five year historical average EA growth rate for all privately owned electricity networks, calculated by Frontier Economics, to forecast labour price growth for the period following the expiry of each of its enterprise agreements.⁶⁷

Wage increases in an individual enterprise agreement will often deviate from the industry average. One reason for this is because the wage increase in an individual agreement are affected by the market conditions at the time when the firm made the agreement. These conditions will be different than those that existed when other firms make their agreements. For example, when labour market conditions are softening the

⁶⁵ 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 a 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.

⁶⁶ Powercor, *Regulatory proposal*, 30 April 2015, p. 74.

⁶⁷ Powercor, *Regulatory proposal*, 30 April 2015, p. 74.

wage increases in an agreement made a year ago will likely be higher, all else equal, than an agreement made today. Thus, different firms may have negotiated different wage increases for the same year because they negotiated them at different points in time.

Consequently, using an individual enterprise agreement to forecast labour price growth at the start of the forecast period and an industry average for the remainder would likely not produce an opex forecast consistent with the opex criteria. For example, if a firm has higher wages than the industry average (because it negotiated its latest agreement prior to the labour market softening) then you would expect, all else equal, that the wage increases in its next enterprise agreement would be lower than the industry average. Applying a forecast of the industry average wage increases for the remainder of the period would not reflect a realistic expectation of the cost inputs required to achieve the opex objectives.

For the reasons discussed above, we do not consider it is appropriate to use more than one approach to forecast labour price growth over a single regulatory period. Therefore, we have used a consistent forecasting approach to forecast labour price growth over the entire forecast period.

We also have concerns that adopting the wage rate increases in an individual firm's enterprise agreement would reduce the incentive to negotiate efficient wages. Deloitte Access Economics (DAE) expressed similar concerns:⁶⁸

For the AER's purposes of setting a price for electricity distribution that is in the interest of electricity consumers over the long term, EBA outcomes are useful for understanding the short term constraints that a regulated firm is experiencing.

However, if regulators simply compensate a business for its commercial negotiations with employees, then they would be effectively undercut or even remove the incentive for businesses to move to the most productive workers over time, and to the long term efficient outcome for electricity consumers.

Similarly, the Victorian Energy Consumer and User Alliance (VECUA) stated that we 'must ensure that Australia's distribution networks are not allowed to continue with their previous approach of effectively treating inefficient EBA outcomes as a "pass through"'.⁶⁹

Labour market conditions

As noted above we used a forecast of WPI growth for the utilities sector to forecast labour price growth. We consider the average of the utilities WPI growth forecasts from

⁶⁸ Deloitte Access Economics, *A response to submissions on AER's preliminary decision for a Regulatory Proposal*, 11 September 2015, p. 13.

⁶⁹ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 43.

DAE and BIS Shrapnel represents a realistic expectation of the cost inputs required to achieve the opex objectives.

Where a consultant is used to forecast labour prices, we consider an averaging approach that takes into account the consultant's forecasting history, if available, to be the best methodology for forecasting labour price growth. We, and DAE, have previously undertaken analysis that found that DAE under-forecast utilities labour price growth at the national level. The analysis also found that BIS Shrapnel over-forecast price growth and by a greater margin.⁷⁰

We compared the Victorian utilities WPI forecast from DAE and BIS Shrapnel (Table B.8) and found them to be consistent with this analysis of past forecasts. Both sets of forecasts show a similar profile, with wage increase lower at the start of the forecast period and peaking in 2019. BIS Shrapnel's forecasts are consistently around 1.0 per cent higher than DAE's.

Table B.8 Forecast annual Victorian utilities WPI growth (per cent)

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

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

The profiles of the forecasts from both DAE and BIS Shrapnel are also consistent with the fact that WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, are currently at the lowest level on record.⁷¹ Given this, we consider it more likely that the average WPI growth rate over the forecast period will be lower than the historic average. The WPI for the utilities sector across Australia has grown by 1.2 per cent each year since the ABS started reporting it in September 1997.⁷² BIS Shrapnel forecast average annual growth in the WPI for Victoria to exceed this historic average over the forecast period. By comparison, DAE's forecast Victorian utilities WPI growth rates are lower, on average, than the historic average rate. Consequently we consider it likely that DAE's forecast will be the most accurate of both consultants' forecasts because they better reflect current labour market conditions. Again this is consistent with our previous analysis that found that DAE's forecast of utilities WPI growth were closer to actual WPI growth than BIS Shrapnel's. Given our previous analysis found an average of the forecast from DAE and BIS Shrapnel was closest to actual WPI growth we consider an average of BIS Shrapnel's and DAE's forecasts would produce the best forecast available of the growth in the Victorian utilities WPI.

⁷⁰ AER, *Powerlink Final decision*, April 2012, p. 54.

⁷¹ Australian Bureau of Statistics, Catalogue 6345.0, Table 9b.

⁷² Australian Bureau of Statistics, Catalogue 6345.0, Table 9b.

Powercor stated that its labour price forecasting method was simpler and more transparent.⁷³ In the explanatory statement accompanying the *Expenditure forecast assessment guideline* we set out a set of principles for the assessment of forecasting methods. We stated that a forecasting method should be:

- valid
- accurate and reliable
- robust
- transparent
- parsimonious
- fit for purpose

We agree that the labour price forecasting method adopted by Powercor is simpler (more parsimonious) and more transparent than the forecasting methods adopted by DAE and BIS Shrapnel. However, the consideration of these principles is a matter of balance. For example, parsimony (or simplicity) can come at the expense of validity, accuracy, robustness and fitness for purpose. Forecasting methods based on historic averages do not account for changes in labour market conditions that will prevail in the forecast period. We consider that, on balance, the forecast change in the utilities WPI better meets the principles set out in the Guideline.

We are not satisfied that Powercor's labour price growth forecasts reasonably reflect the increase in prices an efficient service provider requires to meet the opex objectives because the forecasting method it proposes does not account for:

- general labour market conditions we expect to prevail in the forecast period
- industry specific labour market conditions we expect to prevail in the forecast period
- the impact of that wage negotiations of the publicly owned electricity network service providers will have on negotiations in the forecast period.

As noted by the CCP, wage growth is at historic lows.⁷⁴ WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, are currently at the lowest level on record.⁷⁵ As noted above, both DAE and BIS Shrapnel forecast that wage growth will rebound before peaking in 2019. Powercor's labour price forecasting method has no means to account for this. Consequently we are not satisfied that Powercor's labour price growth forecasts reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives, particularly in the earlier years of the 2016–20 regulatory control period.

⁷³ Powercor, *Regulatory proposal*, 30 April 2015, pp. 79–80.

⁷⁴ CCP, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, p. 29.

⁷⁵ Australian Bureau of Statistics, Catalogue 6345.0, Table 9b.

Similarly, VECUA stated that the electricity network sector is in contraction and that 'industries in contraction do not face real labour price increasing drivers'.⁷⁶ Again, Powercor's labour price forecasting method has no means of accounting for forecast changes in industry specific labour market drivers as it relies on historic averages.

Frontier Economics stated that public sector employers can face different pressures and constraints to private sector employers, particularly during periods of fiscal strain. This can result in different labour cost outcomes, particularly over the short to medium term.⁷⁷ This is why it used only privately owned service providers' EAs to forecast labour price growth. While different labour cost outcomes may occur over the short to medium term these differences cannot persist indefinitely. Any wage differences between private and publicly owned electricity networks services providers will influence future wage negotiations. More workers employed by publicly owned electricity distributors will seek to move to privately owned electricity distributors, while fewer will seek to move the other way. This will impact the supply and demand for labour and the outcome of wage negotiations. Using an historic average does not account for any impact these wage differences will have on future wage negotiations.

Powercor stated that utilities WPI forecasts have not proven accurate or reliable. It stated consultants' utilities WPI forecasts have tended to be lower than the industry average enterprise agreement wage increases and there are large differences in forecasts between consultants.⁷⁸

However, Powercor based its conclusions on a comparison of utilities WPI forecasts against enterprise agreement wage increases for privately owned electricity network businesses. Powercor did not compare forecast WPI increases against actual WPI increases to substantiate its assertion that WPI forecasts have not been accurate. As discussed above, we have compared the forecast increases of the Australian utilities WPI from both DAE and BIS Shrapnel against actual WPI increases. DAE was the most accurate but under forecast. BIS Shrapnel was less accurate and over forecast. This is why we use an average of the two forecasts.

Powercor, however, compared forecast WPI increases against the actual enterprise agreement wage increases of the privately owned electricity networks. But Australian utilities WPI wage increases are comparable to the enterprise agreements for electricity network service providers when public sector enterprise agreements are included.

Powercor stated that using a historical industry average of enterprise agreement wage increases would also provide a strong incentive to seek to outperform the industry. It therefore argued that applying an industry average of enterprise agreement wage

⁷⁶ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 42.

⁷⁷ Frontier Economics, *Labour cost escalation forecasts using Enterprise Bargaining Agreements*, February 2015, pp. 14, 31–32.

⁷⁸ Powercor, *Regulatory proposal*, 30 April 2015, p. 80.

increases was consistent with the revenue and pricing principles in the NEL.⁷⁹ However, the same is true of using forecast wage increases that reflect forecast changes in market conditions. The forecast wage increase from DAE and BIS Shrapnel are equally unaffected by an individual firm's wage negotiations and the same incentives will prevail.

Opex price weightings

We weight the forecast price growth to account for the proportion of opex that is labour and non-labour. We adopted a 62 per cent weighting for labour and 38 per cent for non-labour. We forecast the labour component based on the utilities WPI and we base the non-labour component on the CPI. These weightings are consistent with the weightings used in Economic Insights' benchmarking analysis.

Powercor stated that it adopted the following opex price weightings based on its own historic expenditure:⁸⁰

- labour costs—44.6 per cent
- contracts—49.7 per cent
- materials—5.7 per cent.

However, what we have included as labour is different to what Powercor has included as labour. Our labour component includes both labour directly employed by a benchmark efficient service provider and labour employed by contractors to provide field services. We do not include labour employed by contractors that provide non-field services in the labour weighting. Non-field services include services such as legal, accounting, IT and other administrative services that are not unique to providing electricity distribution services.

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

Powercor stated that our draft decisions for the NSW and ACT distributors assumed that material costs contribute to 38 per cent of operating expenditure. It stated that it examined the category analysis RIN data reported by all distributors. It calculated that the weighted average contribution of materials costs to standard control services opex across the industry was five per cent in 2013.⁸¹

⁷⁹ Powercor, *Regulatory proposal*, 30 April 2015, p. 76.

⁸⁰ Powercor, *Regulatory proposal*, 30 April 2015, p. 82.

⁸¹ Powercor, *Regulatory proposal*, 30 April 2015, p. 82.

However, the 38 per cent weighting we used for those determinations was not for 'materials' but for non-labour expenses. This includes, among other expenses, materials as well as contract costs for non-field services. We also note that Powercor allocated certain expenditure to 'contracts' that we would allocate to non-labour. This includes licence fees and GSL payments. Powercor escalated these expenses by the forecast change in the construction WPI. We see no reason why licence fees and GSL payments would increase at the same rate as the construction WPI.

SA Power Networks and Ergon Energy stated that the price weightings we used for our November 2014 draft distribution determination for the NSW and ACT service providers were outdated.⁸² Consequently we have investigated whether we could update the benchmark weightings. To do so we considered opex data from a sample of the most efficient service providers according to our opex benchmarking analysis, specifically:

- AusNet Services
- CitiPower
- Jemena
- Powercor
- SA Power Networks
- United Energy

We assessed the proportion of the total opex of these service providers that was labour, contracts and other. That is, we divided the labour opex of the six service providers by their combined total opex for 2014.⁸³ We did the same for contracts and other. The resulting weights are in (Table B.9).

Table B.9 Opex price weightings (per cent)

	Labour	Contracts	Other
Powercor	44	50	6
Benchmark	43	40	17

Source: Powercor, *Regulatory proposal*, 30 April 2015, p. 82; AER analysis.

As noted by Economic Insights, it has become increasingly difficult to ascertain what the exact split between the labour component and the materials and services component of opex should be with the move to greater (and varying) use of contracting

⁸² SA Power Networks, *Revised regulatory proposal*, July 2015, p. 219; Ergon Energy, *Submission to the AER on its preliminary determination: Operating expenditure*, July 2015, pp. 10–11.

⁸³ We used 2013–14 for SA Power Networks, which operates on a financial year basis.

out of field services by distributors.⁸⁴ Similarly, we note that the data provided by the service providers does not differentiate between expenditure for contracts that provide field services and contracts that provide non-field services. Further, for those contracts that provide field services only the labour related expenses should be allocated to the labour weighting. Consequently, the 2014 data provided by the service providers only enables us to identify that the labour weighting should be somewhere between 43 per cent and 83 per cent. In the absence of more precise information we are satisfied that the 62 per cent weighting for labour remains appropriate. Economic Insights also stated that the existing 62 per cent share of labour in opex remains the best estimate of the labour required to perform a distributor's core functions.⁸⁵

We consider that we should not use a service provider's own base year opex price weightings to forecast price growth. Doing so would provide the service provider an incentive to use more than the efficient proportion of internal labour in the base year to increase its forecast price growth. Consequently we cannot assume an individual service provider's opex price weightings are efficient, even if our benchmarking analysis finds the services providers base opex to be efficient.

We reviewed Powercor's actual price weightings from 2009 to 2014. They varied from 38 per cent to 46 per cent with the biggest variation from one year to the next being 5 per cent. The average proportion of opex relating to directly employed labour was 42 per cent over the period. This suggests that service providers have some capacity to respond to an incentive to increase the proportion of opex that relates to directly employed labour. For example, a service provider could reduce its contracted services expenditure in the base year (for which it would receive an EBSS benefit) and increase its forecast rate of change at the same time.

Contracted services

We treat contracted services differently to Powercor. As discussed above, we include the labour component of contracts that provide field services in our labour weighting. The non-labour component of those contracts, and contracts that provide non-field services, are included in the non-labour weighting. We forecast that the price of the components we include in labour will increase at the same rate as the utilities WPI. The component we include as non-labour we forecast will increase at the same rate as the CPI.

Powercor assumed that the price of contracted services (which it called 'contracts') will change at the same rate as the price of construction labour. This different approach is a material driver of the difference between Powercor's price growth forecast and our own.

⁸⁴ Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 7 October 2015, p. 30.

⁸⁵ Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 7 October 2015, p. 30.

Powercor provided no reasons in its regulatory proposal why it used the forecast growth in a wage price index to forecast the growth in the price of contracted services other than to say its contracts are for labour based services. It stated that the construction sector most closely reflected the types of labour skills required to deliver the services it contracts but it did not state why.⁸⁶

Powercor noted that it uses contractors for services such as vegetation management, asset inspection, electrical construction, civil works and traffic management.⁸⁷ To the extent that these relate to opex, we would include the labour component of these services in our labour weighting since they are for field services. We apply the forecast change in the Victorian utilities WPI to these labour costs. The contracts that we include in the non-labour component are for non-field services. This includes services such as legal, accounting, IT and other administrative services.

The ABS publishes data on the movement in the price of goods and services. It publishes producer price indices for different industries as both input price indices and output price indices. That is, it publishes indices of the prices of inputs used by an industry and the prices of outputs produced by an industry. We reviewed the output producer price indices that most closely reflect the non-field services that an efficient service provider would purchase (Table B.10). These are the same producer price indices that we use for the price of non-labour inputs in our opex cost function modelling that we use to measure historic productivity growth.

Table B.10 Annual growth in the producer price indices of selected ANZSIC classifications

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

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

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

Source: ABS catalogue 6427.0.

⁸⁶ Powercor, *Regulatory proposal*, 30 April 2015, p. 81.

⁸⁷ Powercor, *Regulatory proposal*, 30 April 2015, p. 81.

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

We also note that Powercor did not provide any reasons as to why the construction sector most closely reflected the services it contracts. We note that the ABS does state that:⁸⁸

Units mainly engaged in the construction of water, gas, sewerage or stormwater drains or mains, electricity or other transmission lines or towers, pipelines, or any other civil engineering projects are included in Division E Construction.

However, here we are considering the price measure that best reflects the non-field services an efficient service provider contracts for and is in its opex, not capex. These include services such as legal, accounting, IT and other administrative services.. These are not included in the construction ANZSIC classification.

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

B.4.3 Forecast output growth

We are not satisfied Powercor's proposed average annual output growth of 1.9 per cent for the 2016–20 regulatory control period reflects the increase in output an efficient service provider requires to meet its opex objectives. We forecast an average annual output growth of 1.3 per cent for the 2016–20 regulatory control period. The difference between Powercor's output growth forecast and our own arises because:

- we are not satisfied that the output measures and forecasting method adopted by Powercor to forecast output growth reflect a realistic expectation of the output growth Powercor will experience
- we are not satisfied that Powercor's forecasts of maximum demand reflect a realistic expectation of the demand forecast required to achieve the opex objectives.

⁸⁸ <http://www.abs.gov.au/ausstats/abs@.nsf/Product+Lookup/73F4863F0CDC7D4CCA257B9500133B80?opendocument>.

Our approach to forecasting output growth

We have adopted the following output growth measures and weightings:

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

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

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

1. The output aligns with the NEL and NER objectives.
2. The output reflects services provided to customers.
3. Only significant outputs should be included.

Economic Insights discusses the process for selecting the output specification in its economic benchmarking assessment of opex for the NSW and ACT electricity distributors.⁸⁹

We note that, while VECUA had some issues with our approach to forecasting output growth, it considered that overall our approach is more reflective of the change in outputs required than the approaches proposed by the Victorian service providers.⁹⁰

Forecast growth in peak demand

We used the forecast customer numbers and circuit length reported by Powercor in its reset RIN. This produces an average annual growth rate of 1.79 per cent for customer numbers and 0.45 per cent for circuit length.

However, we have not used the forecast maximum demand numbers reported by Powercor in its reset RIN. The Ethnic Community Council of Victoria, VECUA, and the Victorian Greenhouse Alliances all noted that the Victorian service providers' peak demand forecasts were higher than those forecast by AEMO.⁹¹ VECUA also noted that the Victorian distributors' past peak demand forecasts 'were subsequently proven to be

⁸⁹ Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November, pp. 9, 10.

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

⁹¹ Ethnic Community Council of Victoria, *Submission to the Australian Energy Regulator Victoria Electricity Pricing Review*, 15 July 2015, p. 1; Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 14; Victorian Greenhouse Alliances, *Local Government Response to the Victorian Electricity Distribution Price Review 2016-20*, 15 July 2015, p. 32.

overblown'. It also stated it was concerned that AEMO has consistently overestimated its energy forecasts in recent years.⁹²

For the reasons discussed in attachment 6, appendix C., we are not satisfied that Powercor's forecasts of maximum demand reflects a realistic expectation of the demand forecast required to achieve the opex objectives. Instead we have used AEMO's 2014 transmission connection point maximum demand forecasts.⁹³ This produces an average annual growth rate of 0.40 per cent for ratcheted maximum demand.

Powercor's approach to forecasting output growth

Powercor used the average output growth from four econometric models to forecast output growth. Frontier Economics developed three of the models. Powercor stated the fourth model was the opex cost function model developed by Economic Insights that we used for our draft decisions for the NSW and ACT distributors.

Frontier Economics conducted econometric opex cost function modelling to forecast output growth.⁹⁴ The modelling used Australian data only and applied the random-effects estimation method to the panel data of 13 service providers over eight years. Frontier Economics chose three preferred models, each from a group of competing but similar model specifications. The three preferred models specify different combinations of explanatory variables, each comprising directly one or two output measures, and some operating environment variables.

Frontier Economics identified the small sample size as a reason why it was unable to include all the drivers of opex in a single model. It therefore suggested averaging three different models to incorporate more opex drivers.⁹⁵ We consider the best solution to the problem of insufficient data is to include more data. This is why we also included data from the Ontario and New Zealand service providers. As demonstrated by Economic Insights, the Australian distributor data show insufficient time-series variability to support robust model estimation.⁹⁶ By using only Australian data, Frontier Economics have essentially used only 13 cross-sectional observations for its econometric modelling—a sample size too small for robust parameter estimation.

Other reasons why we are not satisfied the Frontier Economics output growth model specifications will reflect the output growth Powercor will experience include:

⁹² Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 15.

⁹³ <http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting/Transmission-Connection-Point-Forecasting-Report-for-Victoria>

⁹⁴ Frontier Economics, *Operating expenditure scale escalation econometric model*, January 2015.

⁹⁵ Frontier Economics, *Operating expenditure scale escalation econometric model*, January 2015, p. 27

⁹⁶ Economic Insights, *Response to consultants' reports on economic benchmarking of electricity DNSPs*, 22 April 2015, pp. 20–22.

- Specifying supply-side output or asset-based variables as output gives service providers credit for network capacity or assets that they have provided rather than what customers value. Similarly, VECUA considered that ratcheted maximum demand 'is a more appropriate measure of the distributors' output than installed capacity factors'.⁹⁷
- The most comprehensive model is model three that uses a composite scale variable, which combines three outputs (route length, customer numbers and ratcheted maximum demand) using fixed weights of 0.5, 0.25 and 0.25 respectively. However, the weights are not necessarily representative of relative output-cost shares for the Australian service providers under consideration. In addition, the route length variable would underestimate the output of urban service providers because it underestimates the line length dimension of the provision of system capacity.
- Frontier Economics eliminates some models because they have a larger standard deviation of the random-effects component of the error term. This is not a valid basis for selecting models because this component captures unobservable firm-specific differences, including inefficiencies. There is no reason to choose a model because it has a lower level of variation in the estimated inefficiency-related differences.
- Frontier Economics' estimation method may suffer from omitted variable bias. The random-effects estimation method used assumes that a firm's unobserved heterogeneity is uncorrelated with its observed characteristics as explicitly modelled. Violation of the independence assumptions may result in an omitted variable bias such that correlated variables may capture part of the impact of unobservables.

B.4.4 Forecast productivity growth

We have applied a zero per cent productivity growth forecast in our estimate of the overall rate of change. We base this on our expectations of the forecast productivity for an efficient service provider in the short to medium term. This is consistent with Economic Insights' recommendation to apply zero forecast productivity growth for other distribution network service providers such as Ergon Energy.⁹⁸

Powercor 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.⁹⁹

⁹⁷ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 45.

⁹⁸ Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 7 October 2015, p. 29.

⁹⁹ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

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

To reach our best estimate of forecast productivity we have considered Economic Insights' economic benchmarking, Powercor's proposal, our expectations of the distribution industry in the short to medium term, and observed productivity outcomes from electricity transmission and gas distribution industries.

We have applied a zero productivity forecast for Powercor for the following reasons:

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

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

Forecast outlook and historical productivity

As noted above, forecast productivity growth is our best estimate of the shift in the frontier for an efficient service provider. Typically we consider the best forecast of this shift would be based on recent data. However, this requires a business as usual situation where the historical data is representative of what is likely to occur in the forecast period.¹⁰⁰

Analysis from Economic Insights using MTFP and opex cost function models showed that from 2006 to 2013, the distribution industry experienced negative productivity growth.¹⁰¹ This means that the distribution industry inputs specified under the models increased at a greater rate than the measured outputs.

According to Economic Insights' modelling, the average annual output growth from 2010 to 2013 for the distribution industry was 0.6 per cent. During this period, the output measures of customer numbers and circuit length grew by 1.2 per cent and 0.5 per cent respectively. Maximum demand decreased by 4.1 per cent from its peak in 2009.¹⁰² However, total input quantity increased by 2.8 per cent per annum from 2010

¹⁰⁰ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 41.

¹⁰¹ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 20, 40.

¹⁰² Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 44–45.

to 2013.¹⁰³ This has been driven by substantial increases in both opex and capital inputs.

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

We note that in Victoria for the 2011–2015 period, the increase in regulatory obligations related to bushfires was forecast to be 9.0 per cent of total opex.¹⁰⁴ We consider the increase in bushfire safety requirements to be a one off step increase in the cost of compliance. We also approved a \$35.5 million (\$2009–10) step change for SA Power Network's vegetation clearance pass through as a result of changing weather conditions.¹⁰⁵

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

VECUA considered that the distributors' productivity declined during the previous regulatory period because we provided excessive opex allowances. It considered this should not be used to justify poor productivity outcomes in future years.¹⁰⁶ We agree that the productivity performance we have seen in the 2006–13 period should not be used as the basis for forecasting productivity in the 2016–20 period, for the reasons above. In part this is due to step changes resulting from new regulatory obligations that were introduced in this period.

¹⁰³ Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 45.

¹⁰⁴ AER, *Final decision: CitiPower Ltd and Powercor Australia Ltd vegetation management forecast operating expenditure step change*, August 2012, p. 2; AER, *CitiPower Pty Distribution determination 2011-15*, September 2012, p. 17; AER, *Powercor Australia Ltd Distribution determination 2011-15*, October 2012, p. 26; AER, *Final decision: Powercor cost pass through application of 13 December 2011 for costs arising from the Victorian Bushfire Royal Commission*, May 2011, p. 96; AER, *Final decision - appendices: Victorian electricity distribution network service providers - Distribution determination 2011-2015*, October 2011, pp. 301–304; AER, *Final Decision: SP AusNet cost pass through application of 31 July 2012 for costs arising from the Victorian Bushfire Royal Commission*, 19 October 2012, p. 3; AER, *SPI Electricity Pty Ltd Distribution determination 2011-2015*, August 2013, p. 20; AER, *Jemena Electricity Network (Victoria) Ltd: Distribution determination 2011-2015*, September 2012, p. 22; AER, *United Energy Distribution: Distribution determination 2011-2015*, September 2012, p. 19.

¹⁰⁵ AER, *SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation growth rates*, July 2013, p. 6.

¹⁰⁶ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, pp. 45–46.

Other industries and proposed productivity

In estimating forecast productivity for the distribution industry we have also had regard to the electricity transmission and gas distribution industry.

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

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

As noted by VECUA, both the electricity transmission and gas distribution industries experienced positive opex productivity growth during the 2006–13 period.¹⁰⁷ For electricity transmission network service providers average annual industry productivity growth was 0.85 per cent and for gas distribution Jemena Gas Networks proposed average annual opex productivity growth of 0.95 per cent of which 0.83 per cent was attributed to the shift in the frontier.¹⁰⁸

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

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

¹⁰⁷ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, p. 46.

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

¹⁰⁸ AER, *JGN gas distribution determination – draft decision, Attachment 7, Appendix A*, November 2014.

line with the levels being achieved by the electricity transmission sector and other asset intensive industry sectors.¹⁰⁹

Similarly, DEDJTR expected that firms operating in a competitive environment should achieve some productivity improvements. It stated the EBSS should reward service providers for productivity improvements that are greater than those expected in a business as usual environment. They should not be rewarded for achieving a business as usual level of productivity growth.¹¹⁰ We agree that service providers should not be rewarded for achieving a business as usual level of productivity growth. Consistent with the Guideline, we have forecast productivity growth as the best estimate of the shift in the productivity frontier.¹¹¹

DEDJTR also expected an additional level of productivity growth associated with the rollout of smart meters so that the service providers' customers realise the benefits for their investment in the smart meter rollout.¹¹² DEDJTR stated that:

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

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

The CCP stated that we should review the purpose and application of the productivity growth forecast in the rate of change. It stated we should consider the impact of the forecast productivity growth with the benchmarking analysis and the EBSS incentives.¹¹³ We consider that the incentive to minimise opex is primarily set at the margin. We designed the EBSS to work with the ex-ante opex and our opex forecasting approach to provide a continuous incentive at the margin. We designed the incentive to balance the incentive to reduce capex and maintain the level of service.

¹⁰⁹ Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016-20 Revenue Proposals*, 13 July 2015, pp. 45–46.

¹¹⁰ Department of Economic Development, Jobs, Transport and Resources, *Submission to Victorian electricity distribution pricing review – 2016 to 2020*, 13 July 2015, p. 8.

¹¹¹ AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

¹¹² AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

¹¹³ CCP, *Response to proposals from Victorian electricity distribution network service providers*, 5 August 2015, pp. 40–41.

The incentive at the margin is unaffected by the forecast productivity growth, to the extent it is not based on the individual distributors' own historic productivity growth. The CCP seem to suggest that overly generous opex allowances reduce this incentive. We agree that overly generous opex allowances may reduce the incentive to reduce opex. We do not see this as a productivity growth forecast issue but a total opex forecasting issue. We think it equally applies to all components of our opex forecasting approach.

C Step changes

In assessing the service provider's opex forecast (or developing our alternative forecast where we do not accept the service provider's), we recognise that there may be changed circumstances in the forecast period that may impact on the expenditure requirements of a service provider. We consider those changed circumstances as potential 'step changes'.

We typically allow step changes for changes to ongoing costs 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 Powercor for the 2016–20 regulatory control period.

C.1 Position

We have included one step change in our opex forecast. We are satisfied that additional opex associated with Powercor's customer relationship management system arises due to new regulatory requirements.

A summary of Powercor's proposed step changes, including the base year adjustments and bottom up forecasts we assessed as step changes, and our preliminary position is outlined in Table C.1.

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

	Powercor proposal	AER position
Step changes		
Customer charter	0.5	–
Superannuation - accumulation members	4.6	–
Monitoring IT security	2.0	–
Mobile devices	4.1	–
Customer Information System and Customer Relationship Management	5.2	3.1
Sub-total	16.5	3.1
Other adjustments to opex forecast		
Superannuation - defined benefit members	11.7	–
Regulatory reset costs	–2.0	–

	Powercor proposal	AER position
Sub-total	9.6	0.0
Total	26.1	3.1

Source: Powercor, *Regulatory proposal*, April 2015; AER analysis.

C.2 Powercor's proposal

Powercor proposed five step changes to its base level of standard control services opex. Powercor stated the step changes reflect new or increased activities or new or increased costs.

Powercor considered its approach to forecasting step changes was largely consistent with that proposed by us in the Guideline and our draft decision for the NSW and ACT electricity distribution businesses. In these documents we outlined that step changes should generally relate to a new obligation or some change in a service provider's operating environment beyond its control.

Powercor states it also included step changes where:

- base year expenditure is not sufficient to maintain the quality, reliability and security of supply of standard control services, or the safety, reliability and security of the distribution system
- the additional opex will result in cost savings to consumers, but are of limited benefit to its business.

In addition, Powercor also forecast several categories of opex using a category specific forecasting approach (defined benefits superannuation, regulatory reset costs, GSL payments). The effect of this approach was a forecast incremental increase in opex in two categories (defined benefits superannuation, GSL payments) and a decrease in one category (reset costs).

C.3 Assessment approach

Our assessment of proposed step changes must be understood in the context of our overall method of assessing total required opex using the "base step trend" approach. When assessing a service provider's proposed step changes, we consider whether they are needed for the total opex forecast to reasonably reflect the opex criteria.¹¹⁴ Our assessment approach specified in the *Expenditure forecast assessment guideline* (Guideline)¹¹⁵ and is more fully described at pages 11 to 20 of this attachment.

¹¹⁴ NER, cl. 6.5.6(c).

¹¹⁵ AER, *Expenditure assessment forecast guideline*, November 2013, pp. 11, 24.

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

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

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

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output then step changes that relate to forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of new office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year which includes office maintenance) to account for forecast network growth.¹¹⁶

By applying the rate of change to the base year opex, we also adjust our opex forecast to account for real price increases. A step change should not double count price increases already compensated through this adjustment. Applying a step change for costs that are forecast to increase faster than CPI is likely to yield a biased forecast if we do not also apply a negative step change for costs that are increasing by less than CPI. A good example is insurance premiums. A step change is not required if insurance premiums are forecast to increase faster than CPI because within total opex there will be other items opex where the price may be forecast to increase by less than CPI. If we add a step change to account for higher insurance premiums we might provide a more accurate forecast for the insurance category in isolation; however, our forecast for opex as a whole will be too high.

¹¹⁶ AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, p.73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp, 164-165.

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:¹¹⁷

- 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.¹¹⁸ 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.¹¹⁹ For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex

¹¹⁷ AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

¹¹⁸ AER, *Expenditure assessment forecast guideline*, November 2013, p. 24.

¹¹⁹ AER, *Expenditure assessment forecast guideline*, November 2013, p. 24; AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, pp. 51–52.

trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.

In their submissions, the Energy Retailers Association of Australia (ERAA) and Origin Energy both support the AER assessing proposed step changes in opex consistently across distributors and jurisdictions.¹²⁰ We agree with these submissions as our step change assessment approach is relevant for all network service providers. Origin considers that the approach the AER has taken to date ensures only efficient costs are included in the forecast allowances and removes the potential for double counting.

In its submission, the Consumer Challenge Panel stated “the AER needs to undertake further examination of the step change mechanism as it has become a catchall for any actual or perceived risk of cost increases”.¹²¹ We agree that step changes should not be included for all cost increases. We have examined each of the step changes according to our assessment approach and have included only those step changes that are needed for the total opex forecast to reasonably reflect the opex criteria.

C.4 Reasons for preliminary decision

C.4.1 Customer charter/reset costs

We have not included an increase in opex for Powercor’s customer charter in our alternative opex forecast.

Clause 9.1.2(b) of the Electricity Distribution Code requires Powercor to provide a customer charter to each customer at least once every five years.¹²² The charter must summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:

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

Powercor last provided a customer charter to all its customers in 2011. It proposed an increase in opex of \$0.5 million to provide its customer charter to its customers in 2016.¹²³

¹²⁰ ERAA, *Submission to the Victorian electricity distribution pricing review 2016-2020*, 13 July 2015, p. 1;

Origin Energy, *Submission to Victorian Electricity Distributors Regulatory Proposals*, 13 July 2015, pp. 4–5.

¹²¹ Consumer Challenge Panel, sub panel 3, *Response to proposals from Victorian electricity distribution network service providers - overview - 10 August 2015*, p. 5.

¹²² Essential Services Commission of Victoria, *Electricity Distribution Code*, May 2012, p. 25.

¹²³ Powercor, *Regulatory proposal*, April 2015, p. 187

In choosing a single year as a base year we assume that it is a representative year. While we consider opex is largely recurrent, we accept that there are activities that were not undertaken in the base year but may be required in other years. However, there are similarly activities that were undertaken in the base year that will not be required in subsequent years. It is for this reason we take a holistic top down approach. Otherwise we would have to analyse all opex activities individually.

The base year Powercor proposed and we chose was 2014. We consider the total amount of opex Powercor incurred in 2014 provides a good indicator of its forecast opex requirements for the 2016–20 regulatory control period. We are not confident that identifying one relatively minor non-recurrent increase in opex in the forward period requires a step change in total opex. For instance there are likely to have been several other costs incurred in the base year that were non-recurrent, or slightly higher than average.

To be consistent with this general forecasting approach, we have also not used a category specific forecast for reset costs. Powercor proposed a decrease in opex of \$2.0 million based on the difference between its actual reset costs in 2014 and its forecast costs for the 2016–20 regulatory control period. We have not made this adjustment in our forecast.

C.4.2 Superannuation

We have not included an increase in opex for superannuation in our alternative opex forecast.

Powercor forecast increases in opex for superannuation costs for defined benefits and accumulation members.

- A defined benefit superannuation scheme is where the employer pays an employee a set amount on retirement, typically based on the employees' earnings history. The benefit, or the formula used to determine the benefit, is defined in advance. The employer, therefore, bears any investment risk. Powercor's defined benefit scheme is now closed to new members. It has received advice from Mercer about forecast defined benefits costs over the 2016–20 period. It has forecast an increase in costs equivalent to a step change of \$11.6.¹²⁴
- In contrast, in an accumulation superannuation scheme, the employer makes a set contribution to an employee's superannuation fund. Powercor has sought a step change associated with the additional superannuation cost of employees that replace staff who retire, or are made redundant. These 'replacement' employees must be members of an accumulation scheme. Powercor has estimated the step

¹²⁴ Powercor, *Appendix F – Base year adjustments*, April 2015 pp. 5–6; Powercor, *Regulatory proposal*, April 2015, p. 175.

change for superannuation contributions associated with these staff to be \$3.5 million.¹²⁵

- Powercor also states that the Superannuation Guarantee (Administration) Act 1992 required, from 1 July 2014, that it increase our employee superannuation contributions by an increment of 25 basis points. As a result of this change, Powercor forecasts an increase in opex of \$1.1 million.¹²⁶

Powercor has proposed a category specific forecasting approach for superannuation. However, we are not satisfied there is sufficient evidence to forecast superannuation costs differently to other opex Powercor incurs.

As outlined above, we do not typically forecast opex at the category level. We generally consider it best to use consistent forecasting methods for all categories of opex. This is because hybrid forecasting methods (that is, combining revealed cost and category specific methods) can produce biased opex forecasts inconsistent with the opex criteria.

For instance, there is an incentive for a service provider to use a category specific forecasting method to forecast those categories where base year opex was low, but not for those categories of opex where base opex was high. There is a risk that while the forecast cost of the specific category could be more accurate, the total opex forecast may be less accurate. We note these views are similar to those expressed by Frontier Economics in previous advice to us,¹²⁷ and advice it provided to TransGrid.¹²⁸

Powercor agrees that using a category specific forecasting approach may not be appropriate if variations are relatively small. However, it considers it is appropriate to adopt a category specific approach for defined benefits because it considers it will lead to a more accurate reflection of its recurrent base year expenditure. Powercor also does not consider its forecasting approach to be biased. It notes that it has removed higher regulatory reset costs from its base opex.¹²⁹

This does not adequately address our concerns about forecasting bias. If we accepted a different forecasting methodology because a service provider identified some categories that it removed, then a service provider would be incentivised to remove categories of opex where the effect is relatively immaterial. It still may adopt biased forecasting approaches.

Putting these concerns aside, we also do not consider there is sufficient evidence that a category specific forecasting approach for superannuation will in fact lead to a more accurate estimate of total opex.

¹²⁵ Powercor, *Regulatory proposal*, April 2015, p. 188.

¹²⁶ Powercor, *Regulatory proposal*, April 2015, p. 188.

¹²⁷ Frontier Economics, *Opex forecasting and EBSS advice for the SP AusNet final decision – A report prepared for the Australian Energy Regulator*, January 2014.

¹²⁸ Frontier Economics, *Opex forecasting method – A report prepared for TransGrid*, December 2014

¹²⁹ Powercor, *Regulatory proposal*, April 2015, p. 185

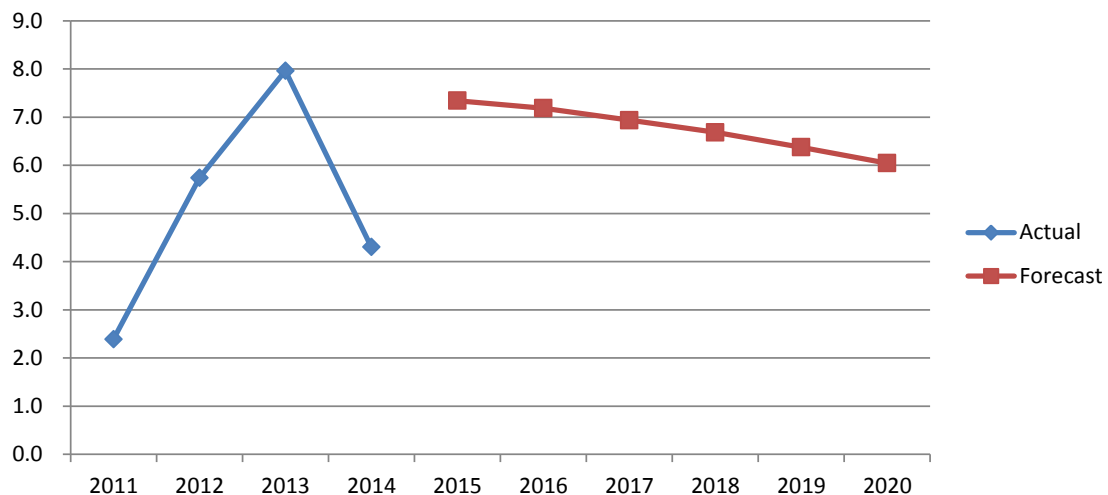
Powercor’s justification for forecasting these costs differently is that it considers them to be uncontrollable.

Our defined benefit superannuation scheme costs reflect the net position of the scheme’s defined benefit obligations relative to its defined benefit assets. These costs, therefore, are driven by a range of factors that are largely beyond our control. This includes the state of the global and domestic economies, interest rates, and market returns more generally. For this reason, our defined benefit costs are excluded from our Efficiency Benefit Sharing Scheme (EBSS) calculations.

Given the above, our actual defined benefit superannuation scheme costs are removed from our base year operating expenditure, and replaced by a forecast of costs for the 2016–2020 regulatory control period. This approach provides a more accurate reflection of our recurrent base year expenditure.¹³⁰

While we agree defined benefits costs are, to some degree, uncontrollable, we do not consider this is a sufficient reason to adopt a category specific forecasting approach. The economic factors which Powercor refers to (global economic conditions, interest rates, market returns), while relatively uncontrollable, are also subject to some uncertainty. Given such uncertainty, it is not clear how accurate Powercor’s forecasting approach is. It did not justify assumptions used in estimating its defined benefits costs, or how sensitive those assumptions are to fluctuations in different variables. As outlined in Figure C-1, Powercor’s reported defined benefits costs have varied considerably in recent years. This creates some doubt as to the robustness of its defined benefits forecast.

Figure C-1 Powercor defined benefits superannuation (\$2015)



Source: Powercor, *PAL Public MOD 1.30, 1.36*, April 2015.

¹³⁰ Powercor, Appendix F – Base year adjustments, date?, p. 5.

We also have not included a step change relating to the change in contributions required under legislation. Powercor already pays its workers 1 per cent more than the statutory minimum.¹³¹

C.4.3 Monitoring IT security

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

Powercor have proposed an increase in opex of \$2.0 million for IT security monitoring.¹³² Powercor only undertakes active monitoring of security threats during business hours. It considers that as technology has matured, the risk and its exposure to this risk have increased. It proposes 24 hour active monitoring by an external service provider.

Powercor notes that this is not a new regulatory obligation but notes that this does not mean it is not prudent and efficient. It states that IT security expenditure is not self-financing and typically driven by avoiding potential for future costs as opposed to productivity or efficiency gains.¹³³

The IT security monitoring Powercor undertakes is a discretionary business decision. As with many types of expenditure, Powercor has flexibility as to what monitoring it undertakes and how much it spends on this area of opex.

Monitoring IT security may be one such area where a service provider wants to devote increased resources. However, at 0.2 per cent of its annual opex, this is a relatively small increase in the cost of one component of Powercor's expenditure. Powercor has not demonstrated to us why this program could not be funded through other reductions in discretionary expenditure. We would typically consider a service provider should be able to fund relatively small increases in discretionary opex without forecasting an increase in total opex.

C.4.4 Mobile devices

We have not included a step change in our opex forecast for mobile devices.

Powercor's existing approach for accounting for these devices is a mixture of capital and operating expenditure. It states that it capitalises costs of mobile devices (phones and tablets) and protective accessories, as well as the labour component associated with formatting and setting up these devices. The corresponding data and repair requirements are expensed. It considers that moving to an operating expenditure only

¹³¹ Powercor, *Powercor Australia Ltd/CitiPower Pty and CEPU Enterprise Agreement 2013 – 2016*, ccl. 22.11; Powercor, *Powercor (ASU; APESMA; NUW) Enterprise Agreement 2013*, ccl. 22.11.

¹³² Powercor, *Regulatory proposal*, April 2015, p. 187.

¹³³ Powercor, *Regulatory proposal*, April 2015, p. 185.

model is a more efficient alternative.¹³⁴ It estimates this will cost an additional \$4.1 million in opex.

We do not consider there is sufficient evidence to demonstrate that this is an efficient trade-off.

In support of its proposal, Powercor provided a benefit cost analysis.¹³⁵ For a benefit-cost to demonstrate that an initiative is efficient, a service provider must demonstrate it is preferable to other viable alternatives. The other option Powercor considered in its benefit cost analysis was its existing practice which is a mixture of capex and opex. However, in estimating the cost of this option, Powercor assumed that it would incur the capex associated with replacing all of its phones and tablets every two years. Powercor states that the two year asset replacement cycle reflects the length of the maximum available warranty period from the manufacturer.¹³⁶

We do not consider it would be prudent to replace all smart devices every two years. The end of a warranty on a mobile device does not mean it would be efficient to replace that device. If a business owns its own phones and tablets, it can replace them when the devices fail. The useful life of many phones and tablets will extend beyond the warranty.

This assumption overstates the NPV of the capex that would likely to be required in the next regulatory control period if Powercor maintained its current approach to purchasing and leasing mobile devices. As we do not have confidence in the counterfactual estimate, we are not convinced its proposed change in its approach is efficient.

We also note that there are interactions between this proposed step change and Powercor's proposed capitalisation of corporate overheads. Even if we considered Powercor's approach to be an efficient trade-off, we consider its forecasting approach would overcompensate it for the prudent and efficient cost of leasing new mobile devices.

As outlined in the base opex appendix, Powercor is proposing to expense all of its corporate overheads in the next regulatory control period. Its methodology is to roll all the capitalised corporate overheads it incurred in 2014 into its base opex. In 2014 its capitalised corporate overheads included the cost of purchasing new mobile devices.¹³⁷ As Powercor also proposes a step change in opex for the cost of leasing mobile devices, its forecast opex effectively includes the cost associated with purchasing new mobile devices in 2014 (as a base year adjustment) plus the forecast cost of leasing new mobile devices (as a step change). We do not consider this approach is consistent with the opex criteria.

¹³⁴ Powercor, *Appendix G step changes*, April 2015, p. 14.

¹³⁵ Powercor, *PAL PUBLIC MOD 1.35*, April 2015.

¹³⁶ Powercor, *Re: Vic EDPR – PC - #IR011 – 8 July 2015*, 22 July 2015, p. 2.

¹³⁷ Powercor, *RE: Vic EDPR – Powercor – IR007 – 3 July 2015*, p. 1.

C.4.5 Customer relationship management

We have included a proposed step change in our opex forecast opex for Powercor's customer relationship management and customer information system of \$3.1 million.

CitiPower and Powercor propose to replace their existing billing and customer relationship management system in the 2016–20 period. Powercor states that its existing system was developed over fifteen years ago and the software is no longer supported by the vendor.¹³⁸ The software currently records usage data against a National Metering Identifier but has limited additional functionality. For instance, it does not record customer name and addresses.¹³⁹

We have considered the drivers for this proposed increase in opex, and are satisfied that the additional costs that will be incurred are as a result of new or changed regulatory obligations. As outlined in Attachment 6, we have also approved capex as a result of this upgrade.

On 6 November 2014 the AEMC made a rule change which will make it easier for customers to access their data. While the specifics of the format for the provision of data will be determined by the Australian Energy Market Operator in its data provision procedures, the determination sets out that, at a minimum, the data should include the customer, nature and extent of energy usage for daily time periods including:

- usage or load profile over a specified period; and
- a diagrammatic representation of the above information.¹⁴⁰

Powercor considers that these obligations will be more costly to meet with its existing system which doesn't automatically have access to such data.¹⁴¹

On 27 November 2014 the AEMC also made a rule change requiring tariffs to be set based on the long run marginal costs of providing the service. Powercor has identified several advanced tariffs it may not be able to implement due to the limited functionality of its existing billing system. For instance, it could not offer customers peak time rebates with its current billing system as its current system cannot record information such as customer name, address and contact information.¹⁴²

These reforms aim to help consumers to make more informed choices about how they use energy. We are satisfied that the additional expenditure Powercor proposed helps give effect to the intent of various rule changes. For instance, if Powercor is

¹³⁸ Powercor, *Appendix G step changes*, April 2015, p. 15.

¹³⁹ Powercor, *Appendix G step changes*, April 2015, p. 15.

¹⁴⁰ NER, r. 7.16

¹⁴¹ Deloitte Access Economics, *CitiPower and Powercor, Investing in a new billing system – Final report*, 16 December 2014, p. 5.

¹⁴² Deloitte, *CitiPower and Powercor - Investing in a new billing and customer relationship management system*, 16 December 2014, p. 11.

constrained in what tariffing options it can offer its customers, it could reduce the value to consumers of the network pricing reforms.

However, we have reduced the estimate of the cost of the step change. The model which estimated the costs of Powercor's step change only included additional software and hardware costs Powercor expects to incur as a result of its new system. It did not factor in the reduction in support costs that relate to the maintenance of its existing system. CitiPower and Powercor currently have a support arrangement with a third party provider. CitiPower and Powercor can cancel this support agreement at any time which Deloitte, in its advice to CitiPower and Powercor, assumed will occur once the new billing system is operational.¹⁴³ Deloitte estimated this will reduce CitiPower and Powercor's costs by approximately \$1 million per annum. Applying a pro-rata adjustment based on Powercor's customer numbers relative to CitiPower's, we have estimated this reduces Powercor's step change from \$5.1 million to \$3.1 million.

C.4.6 Changes to Electrical Safety (Electric Line Clearance) Regulations

We also note that Powercor's vegetation management obligations in the 2016–20 forecast period are different to the 2011–15 period. At this stage we have not forecast a change in opex for changes in these obligations. However we request that Powercor provide further information in its revised proposal about what change in opex it expects as a result of these changes.

On 28 June 2015 amendments to the Electrical Safety (Electric Line Clearance) Regulations 2015 (ELC 2015) commenced in Victoria. We subsequently sent an information request to all Victorian distributors requesting updated information on costs to comply with ELC 2015.¹⁴⁴ We considered the following amendments to ELC 2015 could impact on the service provider's costs:

- Compliance with AS4373 "Pruning of amenity trees"
- Enhanced notification and consultation requirements

In response to our information request Powercor noted compliance with ELC 2015 was likely to increase its vegetation management expenditure for the 2016–20 regulatory control period. However, Powercor was not intending to propose a step change on the basis that its current practices largely comply with its interpretation of the ELC 2015. Powercor also noted that since its interpretations may not accord with those of ESV, Powercor may revise its position.¹⁴⁵

¹⁴³ Deloitte, *CitiPower and Powercor - Investing in a new billing and customer relationship management system*, 16 December 2014, p. 16.

¹⁴⁴ AER, *Powercor information request 9*, 1 July 2015.

¹⁴⁵ Powercor, *Response to information request 9*, 14 July 2015.

We subsequently consulted with ESV and it advised us that it intends to provide guidance to all Victorian distributors to ensure that they understand the manner in which ESV will administer its rules.¹⁴⁶

ESV also noted that it also made amendments to reintroduce exceptions for structural branches in relation to both insulated and uninsulated electric lines which returns the flexibility of ELC 2005 where practicable.¹⁴⁷ This exception allows for reduced clearance distances to be adopted on the condition that appropriate risk mitigation activities are carried out to ensure that an equivalent safety outcome was achieved despite the reduced clearance dimension.¹⁴⁸ ESV noted that the removal of these exceptions in ELC 2010 increased costs over time and expects that the reintroduction of these exceptions in ELC 2015 should decrease pruning costs over time.¹⁴⁹

In our determination for the 2011–15 regulatory control period, Powercor was provided with a step change in opex for the removal of the structural branches exceptions. Since ESV has now reversed this change, this is a symmetrical decrease in regulatory obligations from the 2010 changes so we would expect a similar decrease in costs to the increase allowed for in the 2011–15 period. The Consumer Challenge Panel (CCP) also noted that the 2010 amendments to vegetation management are being reviewed and consider these changes may have a significant impact on opex over the 2016–20 period.¹⁵⁰

We have recognised that there are potentially both cost increases and cost decreases associated with the ELC 2015 amendments but the net impact of the changes are unclear at this stage. Following further guidance from ESV, we expect Powercor to be in a better position to assess the incremental effect of the regulatory changes. We expect it to address this in its revised proposal. We will take all these factors into account in reaching our final decision.

¹⁴⁶ Energy Safe Victoria, *ESV audit intent*, 28 July 2015, p. 2.

¹⁴⁷ Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, p. 4.

¹⁴⁸ Jaguar Consulting, *Regulatory Impact Statement Electricity Safety (Electric Line Clearance) Regulations 2015*, September 2014, p. 41.

¹⁴⁹ Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, p. 4.

¹⁵⁰ Consumer Challenge Panel, *Consumer challenge panel sub panel 3 response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 5 August 2015, p. 23.