PRELIMINARY DECISION
Ergon Energy determination
2015−16 to 2019−20

Attachment 7 − Operating expenditure

April 2015

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

Note

This attachment forms part of the AER's preliminary decision on Ergon Energy's 2015–20 distribution determination. 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 – Connection policy

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure

Shortened form	Extended form
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 pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

7 Operating expenditure

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

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

- Appendix A—Base opex
- Appendix B—Rate of change
- Appendix C—Step changes
- Appendix D— Forecasting method assessment.

7.1 Preliminary decision

We are not satisfied that Ergon Energy's forecast opex reasonably reflects the opex criteria.[1] We therefore do not accept the forecast opex Ergon Energy included in its building block proposal.[2] Our forecast of Ergon Energy's total opex for the 2015–20 regulatory control period, which we consider reasonably reflects the opex criteria, is outlined in Table 7.1.[3]

Table 7.1 Our preliminary decision on total opex ($ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy's proposal	349.6	356.1	363.6	372.9	379.0	1821.1
AER preliminary decision	314.4	320.3	325.4	332.0	337.8	1629.9
Difference	–35.2	–35.8	–38.3	–40.9	–41.1	–191.3

Source: AER analysis.

Note: Excludes debt raising costs.

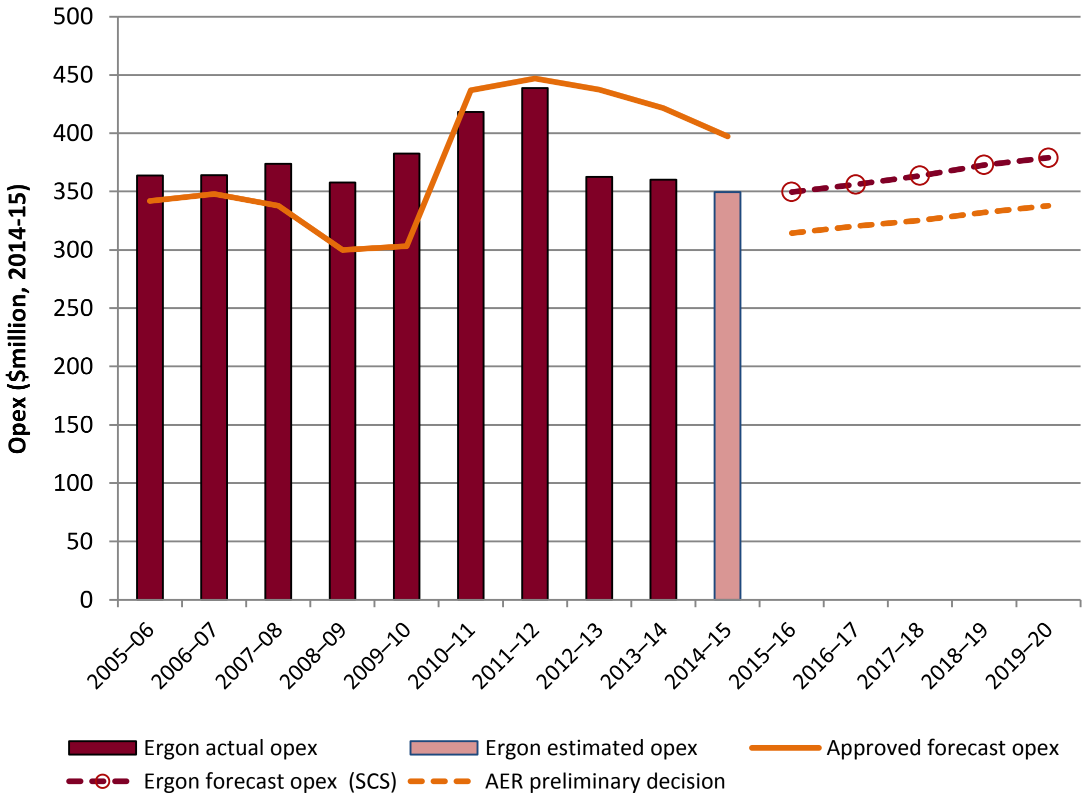
Figure 7.1 shows our preliminary decision compared to Ergon Energy's proposal, its past allowances and past actual expenditure.

1 NER, cl. 6.5.6(c).

2 NER, cl. 6.5.6(d).

3 NER, cl. 6.12.1(4)(ii).

Figure 7.1 Our preliminary decision compared to Ergon Energy's past and proposed opex ($ million, 2014−15)



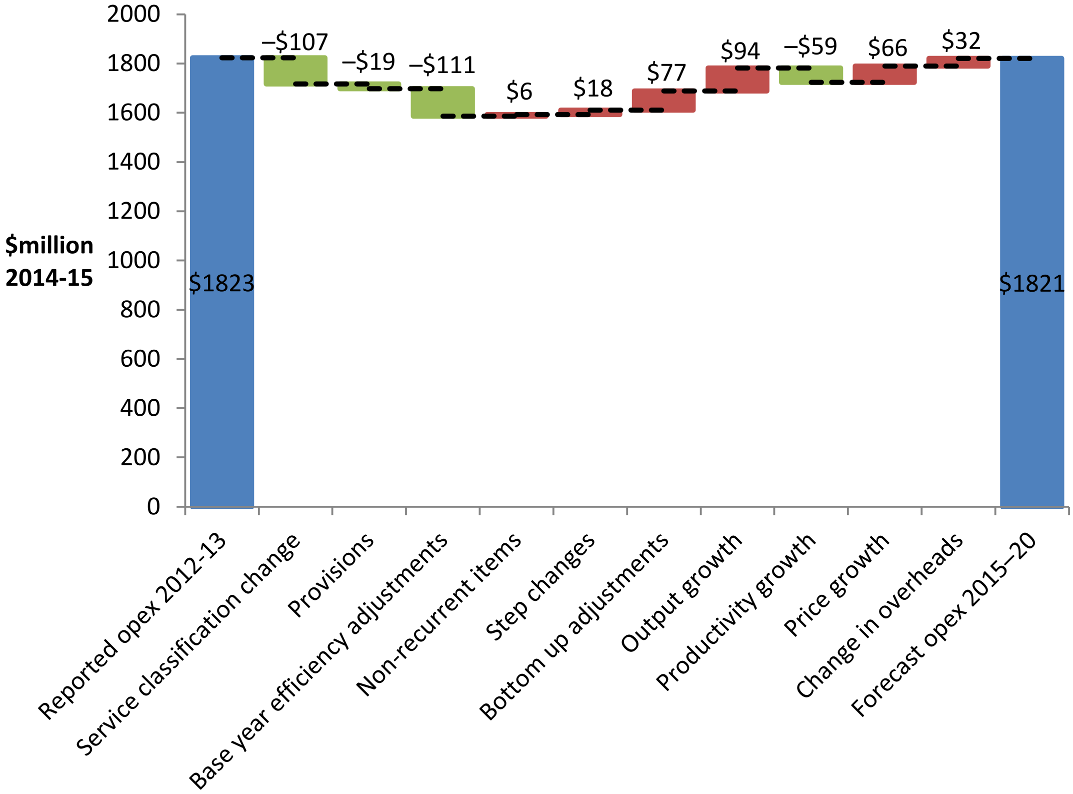
Note: The opex for the period 2005/06 to 2014/15 include some services that have been reclassified as ancillary reference services; the forecast opex for period 2015/16 to 2019/20 does not. The opex for the period 2005/06 to 2009/10 also includes debt raising costs; the opex and forecast opex for the period 2010/11 to 2019/20 do not.

Source: Ergon Energy, Regulatory accounts 2005/06 to 2009/10; Ergon Energy 2010/11–2014/15 PTRM, Annual Reporting RIN 2010/11–2013/14, *Regulatory proposal for the 2015–20 period* - Regulatory Information Notice; AER analysis.

7.2 Ergon Energy's proposal

Ergon Energy proposed total forecast opex of $1821 million ($2014–15) for the 2015–20 regulatory control period (excluding debt raising costs, totalling $61.2 million). In Figure 7.2 we separate Ergon Energy's forecast opex into the different elements that make up its forecast. These elements reflect Ergon Energy's forecasting method and do not always match the elements in the Guideline forecasting method.

Figure 7.2 Ergon Energy's opex forecast ($ million, 2014–15)



Source: AER analysis.

We describe each of these elements below:[4]

- Ergon Energy used the actual opex it incurred in 2012–13 as the base for forecasting its opex for the 2015–20 regulatory control period. It forecast this would lead to base opex of $1.8 billion ($2014–15) over the 2015–20 regulatory control period.
- Ergon Energy adjusted its base opex to remove opex on metering and connection services. These services have been reclassified as alternative control services so need to be removed from Ergon Energy's standard control services opex. This reduced Ergon Energy's forecast by $107 million ($2014–15).
- Ergon Energy accounted for movements in provisions in its base year. This decreased Ergon Energy's opex forecast by $19 million ($2014–15).
- Ergon Energy identified $111 million ($2014–15) in efficiency gains relative to its base year.

[4] Due to differences in the way we and Energex have classified certain changes, the steps in Figure 7.2 and Figure 7.3 will not directly reconcile. Although these differences in classification affect the presentation of the steps, they do not affect the outcomes of the forecasts.

- Ergon Energy included $6 million ($2014−15) for non-recurrent expenditures not included in its base year.
- Ergon Energy added $18 million ($2014–15) for step changes.[5]
- Ergon Energy included $77 million ($2014-15) for expenditure it forecast on a bottom up basis.
- Ergon Energy forecast output growth would increase its opex forecast by $94 million ($2014–15).
- Ergon Energy forecast productivity growth would decrease its opex forecast by $59 million ($2014–15).
- Ergon Energy forecast price growth would increase its opex forecast by $66 million ($2014–15).
- Ergon Energy forecast that overheads allocated to opex would increase by $32 million ($2014–15). This was due to both an increase in total overheads and increases in the proportion allocated to opex.

7.3 Assessment approach

Our assessment approach, outlined below, is, for the most part, consistent with the Guideline.[6] We decide whether or not to accept the service provider's total forecast opex. We accept the service provider's forecast if we are satisfied that it reasonably reflects the opex criteria.[7] If we are not satisfied, we replace it with a total forecast of opex that we are satisfied does reasonably reflect the opex criteria.[8]

It is important to note that we make our assessment about the total forecast opex and not about particular categories or projects in the opex forecast. The Australian Energy Market Commission (AEMC) has expressed our role in these terms:[9]

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

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

1. meeting or managing the expected demand for standard control services over the regulatory control period

---

5 This number does not include the proposed increase in ICT costs. In Ergon Energy's proposal this step change is included in the increase in capex and opex overheads.

6 We did not apply the DEA benchmarking technique. We outline the reasons why we did not apply this technique in section A.4 of our base opex appendix. We also have not applied the equation for estimating final year opex. We outline why we have not made this assumption in Appendix B.

7 NER, cl. 6.5.6(c).

8 NER, cl. 6.5.6(d).

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

10 NER, cl. 6.5.6(a).

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.

We assess the proposed total forecast opex against the opex criteria set out in the NER. The opex criteria provide that the total forecast must reasonably reflect:[11]

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]'.[12]

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.[13] We attach different weight to different factors when making our decision to best achieve the NEO. This approach has been summarised by the AEMC as follows:[14]

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

The opex factors we have regard to are:

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period
- the actual and expected operating expenditure of the distribution network service provider during any preceding regulatory control periods

[11] NER, cl. 6.5.6(c).

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

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

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

- 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.

For this determination, there are two additional operating expenditure factors that we will take into account under the last opex factor above:

- our benchmarking data sets including, but not necessarily limited to:

  (a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN

  (b) any relevant data from international sources

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

  as updated from time to time.
- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.[15]

---

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

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.

More broadly, we also note in exercising our discretion, we take into account the revenue and pricing principles which are set out in the National Electricity Law.[16]

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

The Expenditure Forecast Assessment Guideline

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

We may depart from the approach set out in the Guideline but if we do so we give reasons for doing so. In this determination for the most part we have not departed from the approach set out in the Guideline. [19] In our Framework and Approach paper for each service provider, we set out our intention to apply the Guideline approach in making this determination.

Our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves.[20] By doing this we form a view on whether we are satisfied that the service provider's proposed total forecast opex reasonably reflects the opex criteria. If we conclude the proposal does not reasonably reflect the opex criteria, we use our estimate as a substitute forecast. 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:[21]

> 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.

---

16 NEL, s. 16(2); s. 7A.

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

18 NER cl. 6.5.6.

19 We did not apply the DEA benchmarking technique. We outline the reasons why we did not apply this technique in section A.4 of our base opex appendix. We also have not applied the equation for final year opex. We outline why we have not made this assumption in Appendix B.

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

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

Our estimate is unlikely to exactly match the service provider's forecast because the service provider may not adopt the same forecasting method. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate.

If a service provider's total forecast opex is materially different to our estimate and we find no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not reasonably reflect the opex criteria. Conversely, if our estimate demonstrates that the service provider's forecast reasonably reflects the opex criteria, we will accept the forecast.[22] Whether or not we accept a service provider's forecast, we will provide the reasons for our decision.[23]

Building an alternative estimate of total forecast opex

Our approach to forming an alternative estimate of opex involves five key steps which we outline below in Figure 7.3.

22 NER, clause 6.5.6(c).

23 NER, clause 6.12.1(3)(ii).

Figure 7.3 Our assessment approach

Step 1 - Start with service provider's opex.

We typically use the service provider's actual opex in a single year as the starting point for our assessment. We call this the base year. While categories of opex can vary from year to year, total opex is relatively recurrent. We typically choose a recent year for our assessment.

Step 2- Assess base year opex

We assess whether opex the service provider incurred in the base year reasonably reflects the opex criteria. We have a number of techniques including economic benchmarking by which we can test the efficiency of opex in the base year.

If necessary we make an adjustment to the base year expenditure to ensure it reflects the opex critieria. We can utilise the same techniques available to assess the efficiency of base year opex to make an adjustment to base year opex.

Step 3 - Add a rate of change to base opex.

As the opex of an efficient service provider tends to change over time due to price changes, output and productivity we trend our estimate of base opex forward over the regulatory control period to take account of these changes. We refer to this as the rate of change.

Step 4 - Add or subtract any step changes

We then adjust base year expenditure to account for any forecast cost changes over the regulatory control period that would meet the opex critieria that are not otherwise captured in base opex or rate of change. This may be due to new regulatory obligations in the forecast period and efficient capex/opex trade-offs. We call these step changes.

Step 5 - Other opex

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

Having established our estimate of total forecast opex we can compare our alternative opex forecast with the service provider's total forecast opex.

If we are not satisfied there is an adequate explanation for the difference between our opex forecast and the service provider's opex forecast, we will use our opex forecast .

Underlying our approach are two general assumptions:

1. the efficiency criterion and the prudence criterion in the NER are complementary
2. actual expenditure was sufficient to achieve the expenditure 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).

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 constructing our forecast below.

Step 1—Starting point—base year expenditure

We prefer 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, we have 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, we penalise the service provider when it is relatively less efficient. This gives us 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 remove it from the base year in undertaking our assessment. For instance, for this preliminary decision we removed metering and ancillary network services which will be reclassified as alternative control services in the 2015–20 regulatory control period.

- Rather than use all opex 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 year 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 year expenditure

Regardless of the base year we choose, the service provider's actual expenditure may not reflect 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 test whether actual expenditure in that year should be used to forecast efficient opex in the next regulatory control period.

As we set out in the Guideline, to assess the efficiency of a service provider's actual expenditure, we use a number of different techniques.[24]

For instance, we may undertake a detailed review of a service provider's actual opex. For this preliminary decision, we have reviewed Ergon Energy’s labour and workforce practices, IT arrangement, and utilisation of regional depots.

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:[25]

> 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

---

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

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

Total Factor Productivity, Partial Factor Productivity and several opex cost function models to assess Ergon Energy's efficiency.[26]

We also have regard to trends in total opex and category specific data to construct category benchmarks. We have also used this information to inform our assessment of the efficiency of 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, our broader benchmark modelling.

If we determine that a service provider's base year expenditure does not reasonably reflect the opex criteria, we will not use it as our starting point for our estimate of total forecast opex. Rather, we will adjust it so it reflects an efficient, recurrent level of opex that does reflect the opex criteria. To arrive at an adjustment, we use the same techniques we used to assess the service provider's efficiency.

Step 3—Rate of change

Once we have chosen a starting point that reflects the opex criteria, we apply an annual escalator 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 year opex and the rate of change in opex of an efficient service provider do not already include the proposed costs.[27]

---

[26] The benchmarking models are discussed in detail in Appendix A, which details our assessment of base opex.

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

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

In our final step, we make any further adjustments we need for our opex forecast to achieve the opex objectives. 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 total opex forecast.

Comparing the service provider's proposal with our estimate

Having established our estimate of total forecast opex we can test the service provider's proposed total forecast opex. This includes comparing our alternative total with the service provider's total forecast opex. However, we also assess whether the service provider's forecasting method, assumptions, inputs and models are reasonable, and assess the service provider's explanation of how that method results in a prudent and efficient forecast.

The service provider may be able to adequately explain any differences between its forecast and our estimate. We can only determine this on a case by case basis using our judgment.

This approach is supported by the AEMC's decision when implementing the changes to the NER in November 2012. The Commission stated:[28]

> the AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

If we are not satisfied there is an adequate explanation for the difference between our opex forecast and the service provider's opex forecast, we will use our opex forecast in determining a service provider's total revenue requirement.

As outlined in the Guideline, if the prudent and efficient opex allowance to achieve the opex objectives is lower than a service provider's current opex, we would expect a prudent operator would take the necessary action to improve its efficiency and prudency. We would expect a service provider (including its shareholders) to bear the cost of any inefficiency or imprudent actions. To do otherwise, would mean electricity

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

network consumers would fund some costs of a service provider's inefficiency or imprudent actions.

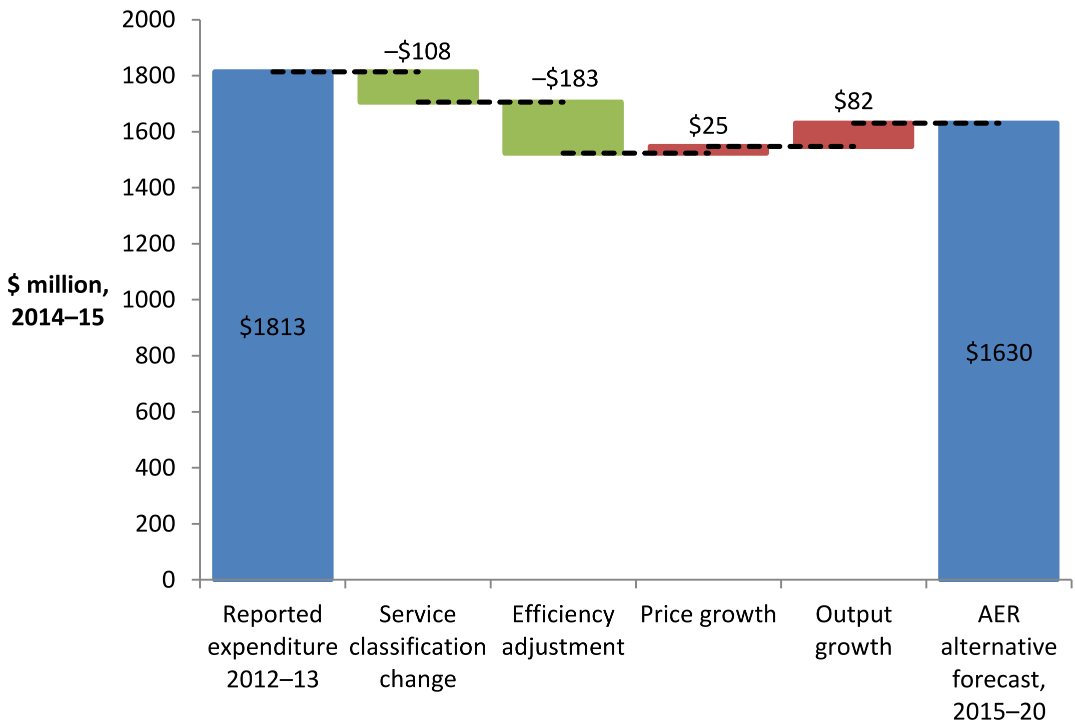
Accordingly, if our opex forecast is lower than a service provider's current opex we would generally not consider it open to us to provide a transition path to the efficient allowance. This approach is reflected in the NER, which provides that we must be satisfied that the opex forecast reasonably reflects the efficient costs of a prudent operator given reasonable expectations of the demand forecast and cost inputs to achieve the expenditure objectives.[29]

7.4 Reasons for preliminary decision

We are not satisfied Ergon Energy's total forecast opex reasonably reflects the opex criteria. We compared Ergon Energy's opex forecast to an opex forecast we constructed using the method outlined above. Ergon Energy's proposal is higher than ours and we are not satisfied that it reasonably reflects the opex criteria. For this reason, we have substituted Ergon Energy's total opex forecast with our total opex forecast.

Figure 7.4 illustrates how our forecast has been constructed. The starting point on the left is what Ergon Energy's opex would have been for the 2015–20 regulatory control period if it was set based on Ergon Energy's reported opex in 2012–13.

Figure 7.4 AER preliminary decision opex forecast



Source: AER analysis

[29] AER, *Expenditure forecast assessment guideline - Explanatory statement*, November 2013, p. 23.

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

Table 7.2 Proposed vs preliminary decision total forecast opex ($ million, 2014–15)

	2015−16	2016−17	2017−18	2018−19	2019−20	Total
Ergon Energy's proposal	349.6	356.1	363.6	372.9	379.0	1821.1
Our preliminary decision	314.4	320.3	325.4	332.0	337.8	1629.9
Difference	–35.2	–35.8	–38.3	–40.9	–41.1	–191.3

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

The key differences between our forecast of total opex and Ergon Energy's proposed total opex forecast stem from differences in base opex and step changes.

On the basis of our benchmarking results and detailed review of Ergon Energy's implementation of the Independent Review Panel's (IRP) findings, we are not satisfied that the expenditure in Ergon Energy's base year reasonably reflects the opex criteria. We have substituted our forecast of base opex as the starting point for estimating total opex that reasonably reflects the opex criteria.

We have not included any step changes in our forecast opex for Ergon Energy. We are not satisfied that adding step changes for the cost drivers identified by Ergon Energy would lead to a forecast of opex that reasonably reflects the opex criteria.[30]

The key elements of our opex forecast and areas of difference between our estimate of opex and Ergon Energy's estimate are outlined below.[31]

7.4.1 Forecasting method

As noted above, our estimate of total opex is unlikely to exactly match Ergon Energy's. Broadly, differences between the two forecasts can be explained by differences in the forecasting methods adopted and the inputs and assumptions used to apply the method. We have reviewed Ergon Energy's forecast method to identify if and where Ergon Energy's forecasting method departed from the method set out in the Expenditure forecast assessment guideline (the guideline forecasting method). Where Ergon Energy's forecasting method did depart from the guideline forecasting method we considered whether this departure explained the difference between Ergon Energy's forecast of total opex and our own. We also considered whether adopting

[30] In the case of the demand management step change we are not satisfied that the incremental costs represent an efficient opex capex trade-off.

[31] For each of these parts of opex, our analysis is supported by an appendix.

Ergon Energy's approach was required to produce an opex forecast that reasonably reflects the opex criteria, having regard to the opex factors.

In appendix D we set out our consideration of Ergon Energy's forecasting methodology in determining our alternative estimate opex for the 2015–20 regulatory control period. Having considered the differences between the guideline forecasting method and Ergon Energy's method, we are satisfied that the guideline forecasting method produces an opex forecast that reasonably reflects the opex criteria. We have not used category specific forecasting methods to separately forecast any of Ergon Energy's opex categories other than debt raising costs in our substitute total opex forecast. We formed our alternative estimate of total opex using the guideline forecasting method with all opex categories other than debt raising costs included in base opex.

7.4.2 Base opex

We first assessed Ergon Energy's proposed base year of 2012–13. We tested Ergon Energy's base opex in 2012–13 using overall benchmarking techniques. We then examined the drivers of the results of these benchmarking techniques by examining key components of opex. For Ergon Energy, we looked specifically at its labour costs and overheads.

The main techniques we used to test the efficiency of Ergon Energy's base opex are outlined in Table 7.3. Our findings from our detailed review support our overall benchmarking findings, which conclude that Ergon Energy's actual base opex is materially inefficient. Therefore, without an efficiency adjustment, we consider a forecast base opex based on Ergon Energy's actual historical opex would not reasonably reflect the opex criteria.

Table 7.3 Assessment of Ergon Energy's opex

Technique	Description of technique	Findings
Economic benchmarking	Economic benchmarking measures the efficiency of a service provider in the use of its inputs to produce outputs. The economic benchmarking techniques we used to test Ergon Energy's efficiency included Multilateral Total Factor Productivity, Multilateral Partial Factor Productivity and opex cost function modelling. We compared Ergon Energy's efficiency to other service providers in the NEM.	Despite differences in the techniques we used, all benchmarking techniques show Ergon Energy does not perform as efficiently as other service providers in the NEM. We consider that differences in Ergon Energy 's operating environment not captured in the benchmarking models do not adequately explain the different benchmarking results between Ergon Energy and other service providers.
Review of reasons for benchmarking performance	We engaged Deloitte to review the reasons for the service providers' benchmarking performance, including the extent they had implemented the	Deloitte found that while Energex and Ergon Energy have both achieved significant efficiency gains since the IRP's review (particularly reflected in FTE reductions), much of these benefits were realised

Technique	Description of technique	Findings

	recommendations of the recent review by the Independent Review Panel (IRP).[32]	after the 2012–13 base year. Deloitte also observed that the service providers have identified they can further reduce their costs. Further, the service providers have not yet addressed a number of IRP recommendations. Deloitte conclude that Ergon Energy's and Energex's opex prior to and in 2012–13 was higher than necessary to achieve efficient operations.[33]
		
		Deloitte's key findings include[34]:
		
		• both service providers (but Ergon Energy in particular) have high total labour costs compared to more efficient peers, which is a result of having too many employees rather than the cost per employee
		
		• certain EBA provisions, while not necessarily unique to Energex and Ergon Energy, limit their ability to quickly adjust their workforces flexibly and utilise them productively. This is amplified by the large proportion of employees engaged under EBAs. Examples include:
		  ○ no forced redundancies
		  ○ contractors are unable to perform certain tasks, such as switching (unique to QLD)
		  ○ certain tasks cannot be performed by a single person (unique to Ergon Energy)
		  ○ minimum apprentice numbers
		  ○ restrictions on outsourcing.
		
		• Energex and Ergon Energy have not implemented the IRP's recommendation that they market test the ICT services that SPARQ (a joint venture owned by the two distributors) provides, resulting in significant inefficiencies
		
		• Ergon Energy has not yet implemented a LSA model for its regional depots, despite the IRP's recommendation (based on Powercor's success with this model) to do so. Deloitte considers Ergon Energy could realise efficiencies if it implemented an LSA model.

Source: AER analysis.

[32] The QLD Government set up the IRP to investigate inefficiencies with the QLD service providers. In May 2013, the IRP found that through a series of reforms, Energex and Ergon could together achieve an estimated $1.4 billion reduction in operational costs over the 2015-20 regulatory control period. The IRP made 45 recommendations, including 18 which focused on overhead expenses and operational efficiencies. Independent Review Panel on Network Costs, Electricity Network Costs Review, 2013.

[33] Deloitte, *Queensland distribution network service providers—opex performance analysis*, April 2015, pp. iv–xix.

[34] Deloitte, *Queensland distribution network service providers—opex performance analysis*, April 2015, pp. iv–xix.

Arriving at an alternative estimate of base opex

We are unable to use Ergon Energy's historical opex to prepare our alternative forecast of opex because basing our forecast on Ergon Energy's historical opex would not result in a forecast opex that would reasonably reflect the opex criteria.

We therefore need to determine a starting point that would lead to a forecast opex that would reasonably reflect the opex criteria.

We have used the results from our preferred benchmarking model (Cobb Douglas SFA) to adjust to Ergon Energy’s base opex to determine a starting point for our forecast of overall opex that would reasonably reflect the criteria.[35] Our preferred benchmarking model measures the opex efficiency of all service providers in the NEM over the 2006 to 2013 period relative to a frontier service provider. The outputs in the model are customer numbers, line length and ratcheted maximum demand.

In doing this, we have not adjusted Ergon Energy’s base opex relative to the efficiency of the frontier service provider. This is consistent with the preference in the Guideline to rely on revealed costs and only adjust base opex where it is materially inefficient.

Instead, we have used a benchmark comparison point that is the lowest of the efficiency scores in the top quartile of possible scores. This is equivalent to the efficiency score for the business at the bottom of the upper third (top 33 per cent) of companies in the benchmark sample (represented by AusNet Services). We have done this because:

- this recognises that more than a third of the service providers in the NEM, operating in varied environments, are able to perform at or above our benchmark comparison point. We are confident that a firm that performs below this level is therefore spending in a manner that does not reasonably reflect the opex criteria. An adjustment back to this appropriately conservative point is sufficient to remove material inefficiency while still incorporating an appropriately wide margin for potential modelling and data errors for the purposes of forecasting
- given it is our first application of benchmarking, it is appropriate to adopt a cautious approach
- we consider this approach achieves the NEO and RPP because it is sufficiently conservative to avoid the risks associated with undercompensating the service provider but also promotes efficiency incentives.

Our estimate of base opex is $304.6 million (real 2014–15). Table 7.4 illustrates the steps we have undertaken to derive our estimate. Table 7.4 shows that we start with -average opex in the 2006 to 2013 period. This is because the benchmarking models compare average efficiency over the sample period.

[35] Stochastic frontier analysis (SFA) can directly estimate efficiency scores and has superior statistical properties. Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, November 2014, p. v.

A key reason we use average period efficiency scores is because it reduces the impact of year–specific fluctuations not under the control of the service provider (such as weather conditions). Average efficiency results also provide us with an estimate of underlying recurrent expenditure not influenced by year on year changes, which we require for the Guideline approach to estimating total forecast opex.[36]

Our detailed assessment of base opex is outlined in appendix A to this attachment.

Table 7.4 Arriving at our alternative estimate of base opex

	Description	Output	Calculation
Step 1 – Start with Ergon Energy's average opex over the 2006 to 2013 period	Ergon Energy's network services opex was, on average, $340.4 million ($2013) over the 2006 to 2013 period.	$340.4 million ($2013)	
Step 2 —Calculate the raw efficiency scores using our preferred economic benchmarking model	Our preferred economic benchmarking model is Economic Insights' Cobb Douglas SFA model. We use it to determine all service providers' raw efficiency scores. Based on Ergon Energy's customer numbers, line length, and ratcheted maximum demand over the 2006 to 2013 period, Ergon Energy's raw efficiency score is 48.2 per cent.	48.2 per cent[37]	
Step 3—Choose the comparison point	For the purposes of determining our alternative estimate of base opex, we did not base our estimate on the efficient opex estimated by the model. The comparison point we used was the lowest performing service provider in the top quartile, AusNet Services. According to this model AusNet Services' opex is 76.8 per cent efficient based on its performance over the 2006 to 2013 period. Therefore to determine our substitute base we have assumed a prudent and efficient Ergon Energy would be operating at an equivalent level of efficiency to AusNet Services.	76.8 per cent[38]	
Step 3— Adjust Ergon Energy's raw efficiency score for operating environment factors	The economic benchmarking model does not capture all operating environment factors likely to affect opex incurred by a prudent and efficient Ergon Energy. We have estimated the effect of these factors and made a further adjustment to our estimate where required. We have determined a 24.4 per cent reduction to Ergon Energy's comparison point	61.7 per cent	= 0.768 / (1 - 0.244)

36 Economic Insights, Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs, April 2015, section 4.1.

37 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 37.

38 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 37.

	Description	Output	Calculation
	based on our assessment of these factors. Material operating environment factors we considered were not accounted for in the model include Ergon Energy's the division of responsibility for vegetation management and extreme weather.		
Step 4—Calculate the percentage reduction in opex	We then calculate the opex reduction by comparing Ergon Energy's efficiency score with the adjusted comparison point score.	22.0 per cent	= 1 – (0.482 / 0.617)
Step 5—Calculate the midpoint efficient opex	We estimate efficient opex at the midpoint of the 2006 to 2013 period by applying the percentage reduction in opex to Ergon Energy's average opex over the period. This represents our estimate of efficient opex at the midpoint of the 2006 to 2013 period.	265.6 million ($2013)	= (1 – 0.220) × 340.4 million
Step 6— Trend midpoint efficient opex forward to 2012–13	Our forecasting approach is to use a 2012–13 base year. We have trended the midpoint efficient opex forward to a 2012–13 base year based on Economic Insights' opex partial factor productivity growth model. It estimates the growth in efficient opex based on growth in customer numbers, line length, ratcheted maximum demand and share of undergrounding. It estimated the growth in efficient opex based on Ergon Energy's growth in these inputs in this period to be 7.85 per cent.	286.5 million ($2013)	= 265.6 × (1+ 0.0785)
Step 7—Adjust our estimate of 2012–13 base year opex for CPI	The output in step 6 is in real 2013 dollars. We need to convert it to real 2014–15 dollars for the purposes of forming our substitute estimate of base opex. This reflects two and a half years of inflation. This is our estimate of base opex.	304.6 million ($2014 –15)	= 286.5 × (1 + 0.063)

Source: AER analysis

7.4.3 Rate of change

The efficient level of expenditure required by the services providers in the 2015–20 regulatory control period may differ from that required in the 2012–13 base year. Once we have determined our forecast of base opex we apply a forecast annual rate of change to forecast opex for the 2015–20 regulatory control period.

Our forecast of the overall rate of change used to derive our forecast of opex is higher than Ergon Energy's over the forecast period. Table 7.5 below compares Ergon Energy's and our overall rate of change in percentage terms for the 2015–20 regulatory control period.

Table 7.5 Forecast rate of change in opex (per cent)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Ergon Energy			1.43	1.52	1.54	1.51	1.58
AER	1.33	0.50	1.35	1.86	1.59	2.05	1.76
Difference			-0.08	0.34	0.05	0.53	0.18

Source: AER analysis.

The differences between our forecast rate of change and Ergon Energy's are driven by the following two reasons:

1. Ergon Energy's forecast of price growth is higher than ours due to its approach to labour price growth. Ergon Energy's labour forecast is higher than our labour forecast. Also Ergon Energy assigns a greater weight to internal labour than we do. Ergon Energy forecast labour using the average weekly ordinary time earnings (AWOTE) which we consider is not a reasonable methodology to forecast labour. We have applied an average of Energex's utilities sector forecast and our consultant's Deloitte Access Economics' forecast. We consider the average of these two forecasts represents the best forecast of the Queensland utilities sector available.
2. Ergon Energy's forecast productivity growth includes general efficiency improvements in its productivity growth. We have forecast productivity growth of zero. Our forecast is based on the short to medium term productivity outlook for a benchmark distribution service provider.

The differences in each forecast rate of change component are:

- our forecast of price growth is on average 0.82 percentage points lower than Ergon Energy's
- there is no material difference between output growth
- our forecast of productivity growth is 0.97 percentage points lower than Ergon Energy's.

We have outlined our detailed assessment of the forecast rate of change in appendix 0.

7.4.4 Step changes

We have not included any step changes in our forecast opex for Ergon Energy. We are not satisfied that adding step changes for the cost drivers identified by Ergon Energy would lead to a forecast of opex that reasonably reflects the opex criteria.

As well as the opex changes proposed by Ergon Energy to its opex forecast that it described as 'step changes', Energex proposed other changes to its opex forecast that we consider should be assessed as step changes. We outline all the cost changes we have assessed as step changes in Table 7.6.

Table 7.6 Summary of AER assessment of step changes ($ million, 2014—15)

Proposed step change	Ergon Energy proposal	AER position	Reason for decision
Non-network ICT	53.7	–	IT system costs are a business as usual cost that a prudent service provider acting efficiently to deliver standard control distribution services would incur. They are therefore included in our estimate of base opex.
Non-network alternatives (demand management)	18.4	–	Ergon Energy has not satisfied us that the incremental costs of these initiatives are efficient.
Parametric insurance	60.3	–	Given the cost of the insurance, the expected payout and the size of Ergon Energy's asset base, we consider Ergon Energy has not provided us with sufficient evidence to convince us that it is more efficient for it to purchase parametric insurance than to continue to self insure. Given the nature of the proposed insurance product, we are also concerned that consumers may pay to transfer cyclone and storm risk to a third party but may still bear costs associated with the cyclones.
Remediation of contaminated land	6.3	–	Base opex already provides sufficient funding for Ergon Energy acting as a prudent service provider to meet all its existing regulatory obligations.
Regulatory reset costs	6.3	–	While regulatory reset costs are one cost category that may increase relative to the base year, there are likely to be other costs that will decline. We are not convinced that our total opex forecast would need to change just because this one category of cost is expected to increase relative to the base year.
Overheads reallocated to opex	26.3	–	Overheads are a business as usual cost that a prudent service provider acting efficiently to deliver standard control distribution services would incur. They are therefore included in our estimate of base opex.

Source: AER analysis; Ergon Energy, *Regulatory proposal: Attachment 06.01.04*.

We have outlined our detailed assessment of step changes in Appendix C.

7.4.5 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 Ergon Energy's total forecast opex we took into account other components of its regulatory proposal, including:

- 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 the RAB and opex, for example, in considering Ergon Energy's proposed demand management step change.
- The approach to the assessing rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block.
- Changes to the classification of services from standard control services to alternative control services.
- Consistency with the application of incentive schemes - in particular our preliminary decision not to subject any expenditure to the EBSS during the 2015–20 regulatory control period.
- Concerns of electricity consumers identified in the course of its engagement with consumers.

7.4.7 Assessment of opex factors

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.[39] Table 7.7 summarises how we have taken the opex factors into account in making our preliminary decision.

Table 7.7 AER consideration of opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark operating expenditure that would be incurred by an efficient service provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period. We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking, opex cost function modelling, PPIs, category analysis and a detailed review of Ergon Energy's labour and workforce practices. We have used our judgment

39 NER, clause 6.5.6(e).

Opex factor	Consideration
	based on the results from all of these techniques to holistically form a view on the efficiency of Ergon Energy's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.
The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Ergon Energy's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.40 We have considered the concerns of electricity consumers as identified by Ergon Energy – particularly those expressed in the engagement program overview provided as an attachment to its regulatory proposal. For example, a clear theme present in this document is that customers consider that electricity has become less affordable.41
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering Ergon Energy's step change for demand management. We considered the relative expense of capex and opex solutions in considering this step change. We also have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above we considered capex/opex trade-offs in considering Ergon Energy's step change for demand management expenditure. We considered the substitution possibilities in considering this step change. Some of our assessment techniques examine opex in isolation – either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs. Further, we considered the different capitalisation practices of service providers and how this may affect opex performance

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

41 Ergon Energy, *Regulatory Proposal:* Attachment to Regulatory Proposal, 0A.01.04, 31 October 2014 p. 2.

Opex factor	Consideration
	under benchmarking.
Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to Ergon Energy's opex in the 2010–15 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. In this instance, we have forecast efficient opex based on benchmark efficient service provider. We have considered this in deciding how the EBSS should apply to Ergon Energy in the 2015–20 regulatory control period.
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our preliminary decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have considered Ergon Energy's provision for non-network alternatives in our assessment of Ergon Energy's proposed step change for demand management.

Source: AER analysis.

The NER require that we notify the service provider in writing of any other factor we identify as relevant to our assessment, prior to the service provider submitting its revised regulatory proposal.[42] Table 7.8 identifies these factors.

[42] NER, clause 6.5.6(e)(12).

Table 7.8 Other factors we have had regard to

Opex factor	Consideration
Our benchmarking data sets, including, but not necessarily limited to: • data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN • any relevant data from international sources • 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.	This information may potentially fall within opex factor (4). However, for absolute clarity, we are using data we gather from NEM service providers, and data from service providers in other countries to provide insight into the benchmark operating expenditure that would be incurred by an efficient and prudent distribution network service provider over the relevant regulatory period.
Economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.	This information may potentially fall within opex factor (4). For clarity, and consistent with our approach to assessment set out in the Guideline, we are have regard to a range of assessment techniques to provide insight into the benchmark operating expenditure that an efficient and prudent service provider would incur over the relevant regulatory control period.

7.5 The impact of our decision

In response to our issues paper (and again in response to our draft decisions for the NSW and ACT service providers), Ergon Energy submitted that our approach will increase the safety, reliability and security risk of its network because it will need to immediately restructure, reduce staff and stop certain expenditure programs.[43]

Ergon Energy also submits that if we were to implement the opex reductions in the same manner as the NSW/ACT draft decisions, the NEL and NER require that we provide a realistic forecast of its actual costs while incentivising efficiency reductions over time in a realistic manner. This includes a transition to mitigate the consequences of requiring service providers to immediately review, and substantially reduce, expenditure.[44]

This section clarifies our approach in light of these submissions.

7.5.1 Safety and reliability

Ergon Energy has submitted that the reductions we are making to revenue based on our assessments of opex and capex will lead to safety and reliability risks. In making this submission, Ergon Energy is assuming that it would continue to run its business

---

43 Ergon Energy, *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 issues paper*, 30 January 2015, pp. 10-19; Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*; 13 February 2015, pp. 23−34.

44 Ergon Energy, *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 issues paper*, 30 January 2015, pp. 10-19; Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*; 13 February 2015, pp. 23−34.

the way it is currently, but with less funds. Therefore, Ergon Energy submits, it would need to scale back activities and reduce staff.[45]

We recognise that service providers must meet their safety and reliability obligations. However, we must consider how much consumers should pay for a service provider to do so. The NER require that we determine a total forecast opex that includes the *efficient* costs that a *prudent operator* would require to achieve the opex objectives (which include safety and reliability obligations).

As we explain below, benchmarking enables us to determine the efficient costs that a prudent operator would require to achieve the opex objectives because we are comparing Ergon Energy to all other service providers in the NEM. As we explain in section A.6, all the NEM service providers are operating safe and reliable networks. Further, many are doing so for less cost than Ergon Energy.

To the extent that differences between service providers may exist, we 'normalise' for these differences when we assess operating environment factors. Based on this assessment, we reduce the performance gap between Ergon Energy and the benchmark comparison point.

Importantly, service providers have the flexibility (and indeed the responsibility) to reallocate funds and resources during the regulatory period in response to changing circumstances, events and risks. Service providers are not constrained to current plans and processes or by the assumptions and forecasts in either their proposals or the determinations we make. This may require a departure from a business as usual approach.

We recognise that Ergon Energy may continue to incur costs above efficient levels due to, for example, its EBA or other practices it has in place that prevents it from easily reducing costs. However, Ergon Energy's shareholder, not consumers, must bear these costs.

We are not satisfied that Ergon Energy has provided sufficient evidence to support its claims such that we would change our approach to safety and reliability from the approach set out in our NSW/ACT draft decisions. We consider that our approach, including our use of benchmarking, appropriately accounts for safety and reliability obligations because:

- service providers at and above our benchmark comparison point are meeting their safety and reliability obligations at lower cost
- our decisions set the revenue service providers can recover from consumers, but do not direct or constrain the quantum or allocation of a service provider's spending

---

[45] Ergon Energy, *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 issues paper*, 30 January 2015, pp. 10-19; Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*; 13 February 2015, pp. 23−34.

- the enforcement of safety regulations is not determined by the quantum of regulatory revenue.

The effect of using benchmarking on safety and reliability

As we explain above, we use several assessment techniques—including benchmarking—to assess the efficiency of revealed opex and determine whether we need to adjust them before building up our alternative estimate.

In section A.4, we explain that we do not apply any benchmarking techniques 'deterministically' or 'mechanically'. As foreshadowed in the Guideline, improved data and the development of benchmarking has improved our ability, over simply using revealed costs, to determine a total opex forecast that reasonably reflects the opex criteria. In section A.8 we explain how we use benchmarking to set a 'comparison point', to which we compare the service provider's opex efficiency.

In doing this, we are appropriately determining an estimate of total forecast opex that is sufficient for a prudent and efficient service provider (facing the same exogenous circumstances as the service provider we are assessing) to meet its safety and reliability obligations, in light of realistic expectations of demand and cost inputs for such a service provider. This is because benchmarking enables us to compare the service provider we are assessing to the 'comparison' service providers that have efficiently achieved their legislated safety and reliability obligations over the benchmark period.

However, to the extent differences may exist, we consider whether they will have an impact on benchmarking performance as part of our assessment of operating environment factors. As we explain in section A.6, we take into account all factors which we reasonably consider are exogenous and non-duplicative. These factors can result in substantial adjustments, providing additional opex to reflect the particular exogenous circumstances of each service provider. Several of these factors are directly relevant to safety and reliability, such as an allowance for different OH&S regulations and licence conditions. We have adopted a conservative approach to non-material factors which are individually immaterial but may have a collective impact.

Otherwise, however, our examination in section A.6 of safety metrics for all service providers (including those who form part of our benchmark comparison point[46]) demonstrates that the comparator providers have managed to safely and reliably meet the requirements to provide standard control services in the relevant period Therefore, the service providers under assessment can maintain their current levels of safety and reliability but for a lower cost.

46 While the benchmark comparison point is AusNet Services in this decision, the comparison point for the operating environment factors is the customer weighted average of the service providers that score equal to or above the benchmark comparison point.

Further, reliability is also included in our MTFP and opex MPFP benchmarking, which we use to cross-check our preferred benchmarking technique. Given the consistency in results across our benchmarking techniques, we consider that the benchmark opex amounts will not undercompensate for reliability.

The AER does not direct or constrain service provider spending

Ergon Energy's submissions suggest that, in determining total forecast opex, we are requiring service providers to "immediately review, and substantially reduce, expenditure in areas such as workforce levels and inspection and maintenance" due to "immediate cuts".[47] Ergon Energy also submits that EBA obligations (and associated costs) are fixed, regardless of the view we take of an efficient level of expenditure.[48]

The assumption inherent in these statements is that we determine, dictate and limit what service providers can spend.

This assumption is incorrect. We do not determine, dictate or limit what service providers can spend. As the AEMC notes, we determine the revenue required by a prudent and efficient service provider in a workably competitive market. [49] We allow service providers to recover these costs from consumers. It is for a service provider to take this revenue and direct it as it sees fit, including by changing its behaviour to meet new or changing circumstances.[50]

Accordingly if a service provider, for whatever reason, wishes to spend above what we have determined to be prudent, efficient and realistic costs to achieve the opex objectives (for example because it has entered into a particular contract or it has decided to maintain activities at a level which require resourcing above an efficient cost level), it could do so. Alternatively, if the service provider considered its opex forecast should be spent differently to our alternative estimate or to its own proposal, including to achieve longer term efficiencies, it is entitled to do so.

To the extent that service provider incurs costs above efficient levels, the service provider—not consumers—must bear the costs.

In assessing the proposals put to us by service providers our task is to assess efficient costs that can be recovered by the service provider from its customers. We acknowledge and accept that a service provider may choose to spend in excess of the revenue that we have determined would be required of a prudent and efficient service

[47] Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2014, p. 23.

[48] Ergon, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2014, pp. 25-27.

[49] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p 182.

[50] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p 182−183.

provider (facing that service provider's exogenous circumstances). However, as noted by the AEMC in the 2012 Rule Determination:[51]

> If a service provider is run inefficiently then its shareholders, and not its customers, should bear the financial consequences of inefficient financing practices.

Jacobs' (in a report commissioned by the NSW service providers) notes:[52]

> There are many strategies open to the distributor management teams to attempt to prepare the organisations for the reduced opex expenditures... and Corporate responses such as workplace reforms, restructures, renegotiation of contracts etc. will take time to implement.

How a service provider will respond in light of funded opex being reduced is a matter of corporate governance and for shareholders. Our role is to determine the revenue allowance that should be funded by consumers, which we base on an assessment of efficient costs.

Safety regulation and enforcement is unaffected by regulatory allowances

Some service providers have suggested that we should have sought the advice of jurisdictional safety regulators in deciding on the appropriateness of our opex forecasts.[53]

We disagree with these submissions. Just as we do not constrain service providers' decisions about safety, safety regulators do not take account of regulatory allowances when regulating or taking enforcement action. These activities are, quite properly, carried out independently. For example in Queensland, the Office of Fair and Safe Work Queensland (which includes Workplace Health and Safety Queensland and the Electrical Safety Office) is the regulator enforcing the WHS Act as in force in that jurisdiction. The regulator is specifically appointed to (among other things) promote an understanding and acceptance of, and compliance with, the WHS Act.[54] We consider that neither the Office nor its regulator could properly take into account the quantum of regulatory forecasts in determining whether or not a service provider has carried out its WHS obligations.

As we explain above, we do not dictate how much a service provider can or will actually spend during the regulatory control period. Our assessment of the opex allowance required for a service provider to carry out its statutory obligations is based

---

51 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 73.

52 Ausgrid Attachment 1.01 - Jacobs - Reliability Impact Assessment, p. 12.

53 For example, Ausgrid, *Revised Regulatory Proposal*, pp. 31−33.

54 Work Health and Safety Act 2011 (QLD), Section 152.

on our benchmarking work and factors specific to the service provider. We determine an amount that the service provider acting prudently and incurring only efficient costs would require to provide a safe and reliable service and to meet its regulatory obligations, including its responsibilities in relation to the health and safety of its workers. It is the responsibility of the service provider to decide how it will spend its regulated allowance to meet these obligations.

To the extent that the regulated allowance is less than that which the service provider proposed, it will need to consider factors such as reprioritising its spending programs or re-appraising the need for the level of activity it is considering. If the service provider incurs costs above the opex forecast we determine, it must seek alternative sources of funding as it will not be able to recover these additional expenditures from its customers.

As set out above, health and safety obligations are not enforced by reference to regulatory revenue. Regardless of regulatory revenue, service providers are obligated to protect their workers and other persons involved in their operations.

7.5.2 Realistic outcomes

Ergon Energy submits that if it were to implement large opex reductions, the NEL and NER require that we provide a realistic forecast of their actual costs while incentivising efficiency reductions over time in a realistic manner. This includes a transition to mitigate the consequences of requiring service providers to immediately review, and substantially reduce, expenditure.[55]

Ergon Energy points to the third opex criterion—"a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives"[56]—as the driver of this apparent requirement.

We disagree with these submissions for two reasons. Firstly, our view is Ergon Energy's interpretation of the 'realistic' criterion is incorrect. In our view, this criterion is concerned with ensuring that there is a proper basis for estimating the demand and cost inputs that a prudent and efficient service provider would incur over the forecast period.[57] The demand forecast and cost inputs are for those of a prudent and efficient service provider operating Ergon Energy's network. They are not the cost inputs which result from previous inefficient decision making. Such an approach would undermine the incentive based aims of the regulatory scheme when read as a whole, because a service provider that bound itself by less than efficient decisions would be rewarded with a forecast that includes increased cost inputs.

---

55 Ergon Energy, *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 issues paper*, 30 January 2015, pp. 10-19; Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*; 13 February 2015, pp. 23−34.

56 NER, cl. 6.5.6(c)(3).

57 To this end, our approach is to apply a 'rate of change' to base opex that incorporates such factors including the demand for electricity, input prices and output growth.

We consider, therefore, that the opex criteria do not impose a requirement for the AER to be satisfied as to how the service provider in question will actually operate its business with the efficient total forecast opex. Such an interpretation runs counter to the notion of a prudent and efficient service provider—albeit facing the same exogenous circumstances as the service provider in question—implied by the opex criteria. Consumers should not be required to fund the consequences of long-term inefficient contracts. This notion was affirmed by the AEMC's removal of "individual circumstances" from the 'prudent' criterion. We are not persuaded by submissions to the effect that we must consider a service provider's actual cost inputs because the AEMC did not remove "individual circumstances" from the 'realistic' criterion.[58] The phrase "individual circumstances" does not form part of the criterion.

Second, Ergon Energy's views are based upon the incorrect assumption that it is the AER's role to dictate how it must run its business. We do not approve specific projects or dictate the legal obligations a service provider enters into. Our task is to determine an efficient level of *total* opex for a prudent service provider to meet the opex objectives over a five year regulatory control period. As the AEMC notes, this underpins the incentive properties of the regulatory regime:[59]

> The level, rather than the specific contents, of the approved expenditure allowances underpin the incentive properties of the regulatory regime in the NEM. That is, once a level of expenditure is set, it is locked in for a period of time, and it is up to the NSP to carry out its functions as it sees fit, subject to any service standards.

Therefore, as we stated above, we are providing Ergon Energy with a forecast that we are satisfied reasonably reflects the opex criteria. It is the responsibility of the service provider to decide how it will spend the revenue it recovers from consumers. If the service provider decides to spend more than it can recover from consumers it must seek alternative sources of funding to do so.

Transition path

Ergon Energy has submitted that the NEL and NER enable (and require) us to provide a transition to efficient expenditure in the event we make large reductions in opex.[60] Its opinion is the NER provide us with sufficient discretion to apply a transition or, in the alternative, the control mechanism provides a means of doing so. To not provide a transition would be unachievable and not 'realistic' because it would need to

---

58 Ergon Energy, *Submission on the Queensland Electricity Distribution Regulatory Proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015, pp. 10−14.

59 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 93.

60 Ergon Energy, *Submission on the Queensland Electricity Distribution Regulatory Proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015, pp. 10−14; Ergon Energy, *Submissions on the draft decisions: NSW and ACT distribution determinations 2014-15 to 2018-19*, 13 February 2015, pp. 23−27.

immediately review and substantially reduce its opex, jeopardising the safety of the network.[61]

Ergon submits that we should consider a transition path to ensure that forecast expenditure reasonably reflects both prudent and efficient costs.[62] It appears that Ergon therefore accepts that no transition is required where the revenue recovered from consumers is sufficient to meet the opex objectives.

We agree that a transition path is unnecessary when our allowance is sufficient to achieve the opex objectives. We have not been persuaded by any submissions that suggest it is more appropriate for the consumers, rather than service providers, to bear the cost of becoming more efficient. We have also received several submissions from stakeholders that argue the opposite. That is, the type of approach advocated by service providers would be inconsistent with the NEL and NER.[63]

If a transition is a "premium" above the efficient costs that a prudent operator would require, we cannot include that premium in our estimate of total forecast opex that we are satisfied reasonably reflects these opex criteria. Conversely, if a transition is included as part of an allowance that does reasonably reflect the opex criteria, no further premium is required or possible.

We also note that legal advice provided to ActewAGL (but relevant to Ergon Energy's submissions) contradicts Ergon Energy's view. That advice states that if we applied a transition path pursuant to clause 6.12.1(11) of the NER we would likely be in error:[64]

> Although we think that the establishment of a “glide path” is open to the AER, having regard to the analysis above, there is a tension in this conclusion, in that it proceeds on the assumption that the NEO requires ActewAGL to be allowed forecast opex at a level which exceeds that which the AER has legitimately allowed to ActewAGL pursuant to clause 6.12.1(4)(ii) of the NER. In our view, it is difficult to imagine a circumstance in which that consequence

---

[61] Ergon Energy, *Submission on the Queensland Electricity Distribution Regulatory Proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015, pp. 10−14.

[62] Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19,* 13 February 2015, p. 26.

[63] Origin Energy, *Submission to AER draft determination for NSW electricity service providers*, 13 February 2015, pp. 7-8; EnergyAustralia, *Submission to Australian Energy Regulator - Determination of allowable revenue for NSW electricity distribution networks*, 13 February 2015, p. 6; CCP, *Response to AER Draft Determination Re: ActewAGL Regulatory Proposal, 2014−19*; p. 10, 35-36; CCP, *Submission on NSW DNSPs regulatory proposals 2014−19*,15 August 2014, p. 3; CCP, *Submission to AER– Responding to NSW draft determinations and revised proposals from electricity distribution networks*, February 2015, p. 55; EUAA, *Submission to Energex Revenue Proposal (2015/16 to 2019/20)*, 30 January 2015, pp, 22−29; EUAA, *Submission to Ergon Energy (Ergon) Revenue Proposal (2015/16 to 2019/20)*, 30 January 2015, pp, 22−29; QCOSS, *Understanding the long term interests of electricity consumers – Submission to the AER’s Queensland electricity distribution determination 2015−2020*, pp. 57-−9; Far North Queensland Regional Organisation of Councils, *AER Issues Paper - Queensland Electricity Distribution Regulatory Proposals 2015-16 to 2019-20*, 30 January 2015, pp. 3−4; Australian PV Institute, *APVI Submission to the AER on the Issues Paper on Ergon’s and Energex’s Network−s Regulatory Proposals*, December 2014, pp. 5−6.

[64] Young and McClelland, *ActewAGL Distribution - AER draft decision on operating expenditure for 2015 to 2019 regulatory control period - memorandum of advice*, 13 February 2015, paras 95−105.

> might arise, without the AER's decision under clause 6.12.1(4)(ii) involving errors of the kind specified in section 71C of the NEL.

This legal advice suggests, in the alternative, that clause 6.12.1(4)(ii) allows the AER to use its discretion to take endogenous circumstances (such as the actual business structure vis-á-vis the prudent service provider's structure) into account because it would be inconsistent with the NEO for us to "presume, from the outset, that [our] discretion is circumscribed so that [we] must *only* consider the efficient costs than an objectively prudent distributor might incur. In particular, [it is asserted that we have] an obligation to consider the manner in which [a service provider] has structured its business in reliance on previous determinations made by [us], and its ability to transition to much lower levels of opex immediately.[65]

We have carefully considered this view and we are not convinced it is a sound interpretation of the NEO and the NER. It assumes that:

- service providers should expect that opex allowances for future regulatory periods will be of the same order as opex allowances for previous regulatory periods; and
- service providers are entitled to structure their business on that assumption.
- Neither of these assumptions is correct. We determine the opex forecast (which forms part of the revenue which a service provider may recover from consumers) on the basis of the best information available to us at the time. If new benchmarking data shows that efficient costs are lower than previously thought, this information will be reflected in our determination.

The legal advice submitted by ActewAGL also assumes that we are requiring service providers to immediately change their circumstances. As set out above, this is not the case.

We consider that requiring service providers to bear their own transition costs is in both the short and long term interests of consumers. It will encourage service providers to make decisions that are prudent, reasonable and efficient in the long term. It will ensure consumers are not required to pay for inefficient expenditure or the consequences of inefficient expenditure. We consider that such incentives and consumer protections are likely to contribute substantially to the NEO.

This does not constrain service providers from taking time to transition to efficient levels or spend their opex allowances on transition costs. As we explained in our draft decision, we do not prevent service providers from carrying out inefficient spending—including because of previous agreements, practices or arrangements. A service provider may have bound itself, contractually, to inefficient practices. However, the funds for inefficient spending should not be provided from an allowance which is assessed at the level of prudent and efficient spending. Accordingly, a service provider would need to fund any desired or required transition spending by:

[65] Young and McClelland, *ActewAGL Distribution - AER draft decision on operating expenditure for 2015 to 2019 regulatory control period - memorandum of advice*, 13 February 2015, paras 68−94.

- achieving greater efficiencies elsewhere in its practices; or
- paying lower dividends to shareholders.

These are the choices a competitive business must make, where efficiencies are revealed by a market.[66] These are the choices a regulated business, funded by consumers, should also make, where efficiencies are revealed by robust analysis. We consider that if this results in a disparity in profits between more and less efficient service providers, it indicates our approach is creating appropriate incentives and a better approximation of a workably competitive market.

66 Second reading speech, National Electricity (South Australia) (National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, p. 6.

A Base year opex

In this appendix, we present our detailed analysis of the QLD service providers' base year opex. Base year opex is the starting point for our approach to developing an estimate of the total forecast opex we consider meets the requirements of the NER.[67] We use this approach to assess each of the service providers' total forecast opex proposals. If we are not satisfied the service providers' opex proposals reasonably reflect the opex criteria, our estimates form the basis of any adjustments we will make.[68] This approach is set out in the Guideline and is in accordance with principles that have been endorsed by the AEMC.[69]

To ensure our estimates of total forecast opex reasonably reflect the opex criteria, we must be satisfied the starting point is an appropriate reflection of the ongoing efficient costs a prudent operator would require in the forecast period. If we use the service provider's revealed expenditure that includes, for example, inherent inefficiencies as the basis for a forecast, the forecast will also contain these inefficiencies. Therefore, if we find that the base year expenditure is inefficient or in some other way unrepresentative of the expenditure needed to achieve the opex objectives in the forecast period, we adjust it.

The structure of this appendix is:

- Section A.1 sets out a summary of our findings and base year adjustments
- Section A.2 provides an exposition of ex ante incentive regulation and the role of benchmarking
- Section A.3 outlines our approach to assessing base opex
- Section A.4 presents the results of our benchmarking
- Section A.5 presents the results of our category analysis and qualitative review
- Section A.6 contains our assessment of operating environment factors
- Section A.7 explains our conclusions on base opex and whether we propose to make any adjustments to base year opex for the purposes of our constructing an alternative total opex forecast.
- Section A.8 outlines our assessment of the base year adjustments proposed by Ergon Energy.

---

67 As we explain in the opex attachment, this is the efficient total forecast opex we consider a prudent service provider would require to achieve the opex objectives in the forthcoming period.

68 NER, cl. 6.5.6(c) and (d) and 6.12.1(4).

69 AER, *Expenditure forecast assessment guideline*, November 2013, p 7; AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

A.1 Summary

In this section we provide a summary of our findings and our view of the base year opex that we are satisfied represents a starting point for total forecast opex that reasonably reflects the opex criteria. We have carefully considered all material before us, including our own analysis, the service providers' regulatory proposals and submissions in forming our view on base year opex for each service provider.

A.1.1 Preliminary determination adjustments

Table A.1 contains our preliminary determination estimates of base year opex.

Table A.1 Preliminary decision estimates of efficient base year opex ($million 2013–14)

	Energex	Ergon
Revealed base opex (adjusted)[a]	411.3	341.1
AER base opex	**347.7**	**304.6**
Difference	63.6	36.5
Percentage opex reduction	**15.5%**	**10.7%**

Note: (a) This number is the revealed 2012–13 opex, so it differs from the starting number in Table 7.4, which is average opex over 2006–13. We have adjusted the service providers' revealed opex for debt raising costs, new CAM (if applicable) and new service classifications.

Source: AER analysis.

We are not satisfied that the service providers' revealed expenditure in 2012–13 are appropriate starting points for determining our estimates of total forecast opex. We take this view based on quantitative and qualitative analysis using several assessment techniques, which include:

- review of the service providers' regulatory proposals
- four economic benchmarking techniques—three econometric and one index-based—including consideration of operating environment factors
- partial performance indicators
- category analysis
- targeted detailed review of certain types of expenditure.

We are satisfied that material inefficiency exists in the service providers' revealed expenditure. Therefore, and in accordance with the process we outlined in the Guideline, we have reduced the service providers' revealed expenditure to estimate base year opex amounts that we are satisfied reasonably reflect the opex criteria and would therefore represent an appropriate starting point for developing our total opex forecast.

A.1.2 Why the service providers' revealed opex is not an appropriate starting point for estimating total forecast opex

Our analysis shows that it would not be appropriate to rely on the service providers' revealed opex as starting points for estimating total forecast opex that reasonably reflects the opex criteria. Our benchmarking demonstrates that the service providers' revealed opex is inefficient. Other quantitative techniques as well as qualitative review by Deloitte Access Economics (Deloitte) support the benchmarking findings.

Our review

As set out in the Guideline, our preference is to rely on revealed expenditure as the basis for determining our estimate of total forecast opex that reasonably reflects the opex criteria. However, we cannot simply assume that revealed expenditure for 2012−13 is reflective of the opex criteria for the 2015−20 regulatory control period. We use benchmarking to test the service providers' revealed expenditure against that of their peers.[70] We then use category analysis and detailed review of significant cost categories to see if they are consistent with our benchmarking findings. This approach is set out in the Guideline and in section A.3 (which details our assessment approach for base opex).

Benchmarking

We have assessed the service providers' revealed expenditure using economic benchmarking and partial performance indicators (PPIs).

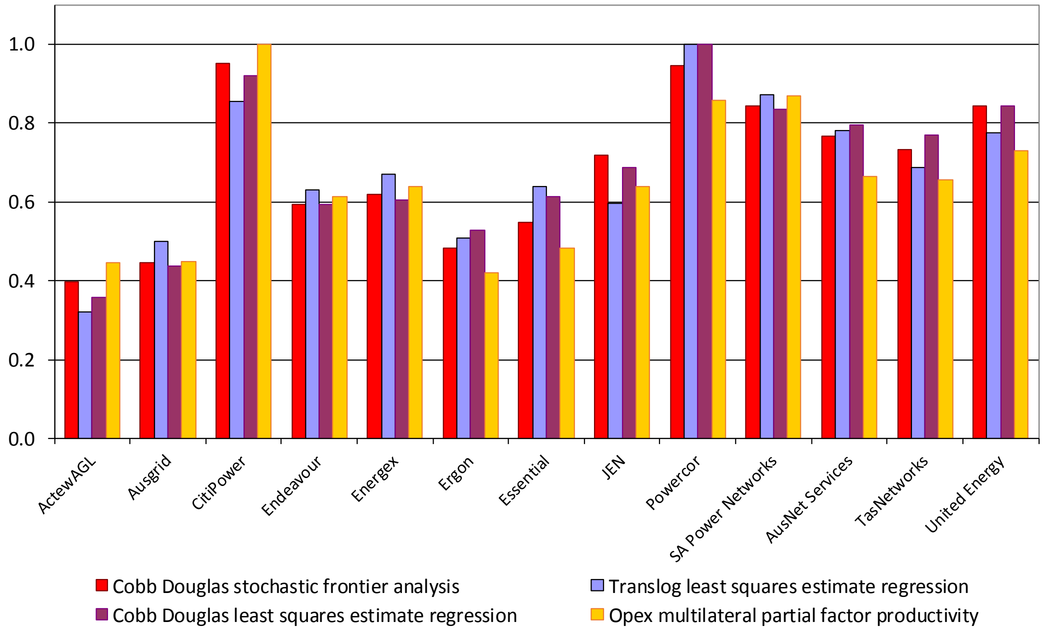
Economic benchmarking

We rely on the economic benchmarking techniques developed by Economic Insights for assessing the relative efficiency of service providers compared to their peers. Economic Insights developed four benchmarking techniques that specifically compare opex performance, using data submitted by all service providers, over the period 2006 to 2013.

Figure A.1 presents the results of each of Economic Insights' opex models (stochastic frontier analysis (SFA), econometric regressions and opex MPFP) for each service provider in the NEM.

[70] AER, *Expenditure Forecast Assessment Guideline*, November 2013, pp. 7–8.

Figure A.1 Econometric modelling and opex MPFP results (average efficiency scores for 2006 to 2013)



Source: Economic Insights, 2014.

Each model differs in terms of estimation method or model specification and accounts for key operating environment factors (such as differences in customer density and degree of network undergrounding that may differentiate service providers) to differing degrees. Accordingly, the results will never be identical. However, Figure A.1 demonstrates that the results of the four models are consistent. All models show that the efficiency of the Queensland service providers' revealed expenditure does not compare favourably with that of many of their peers. Energex has a higher efficiency score than Ergon Energy on all measures.

Our preferred model is SFA (in red on the chart above) because it can directly estimate efficiency scores and has superior statistical properties.[71] The best performing business under this model is CitiPower, with a score of 0.95. We refer to CitiPower as the 'frontier' firm throughout this appendix.

Section A.4 discusses economic benchmarking in more detail. Our benchmarking techniques and benchmarking results were the subject of many submissions. In considering the various points raised in submissions, we have been able to further test the robustness of our approach. The submissions we received on benchmarking and the manner in which we have taken those submissions into account in our decisions are also discussed in section A.4. Economic Insights' final decision report provides

---

71 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. v.

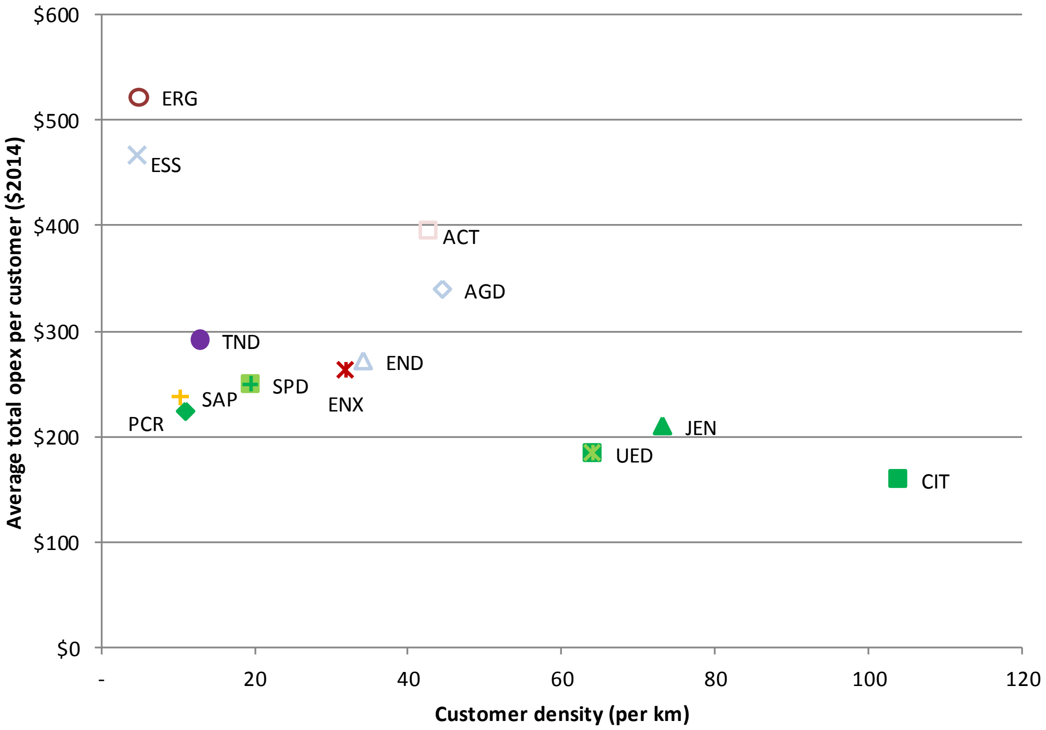
further detail, including analysis of the positions and alternative models advanced by the service providers' consultants.[72]

Partial performance indicators

PPIs are a simplistic form of benchmarking. They measure the ratio of total output and one input factor. They are often used as they are easy to calculate and understand. However when used in isolation their results should be interpreted with caution because they are not as robust as our economic benchmarking techniques that relate inputs to multiple outputs using a cost function.

When examined in conjunction with other indicators they can provide supporting evidence of efficiency. We consider the PPI results do provide further evidence to support the results of our economic benchmarking techniques. Figure A.2, a key metric, compares average annual opex per customer for each service provider.

Figure A.2 Average annual opex per customer for 2009 to 2013 against customer density ($2013-14)



Source: Economic benchmarking RIN data.

Note: ACT = ActewAGL, AGD = Ausgrid, CIT = CItiPower, END = Endeavour, ENX = Energex, ERG = Ergon, ESS = Essential, JEN = Jemena, PCR = Powercor, SAP = SA Power Networks, SPD = AusNet, TND = TasNetworks, UED = United Energy.

72 Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015.

Figure A.2 demonstrates a clear demarcation between Ergon Energy and all other distributers except Essential Energy. Energex incurs a lower average opex per customer, similar to that incurred by AusNet Services and Endeavour Energy. This is consistent with the economic benchmarking results which indicate that Energex performs better than Ergon Energy.

'Per customer' PPIs tend to be less favourable towards rural service providers who typically operate more assets per customer. We must bear this in mind when we consider the results in Figure A.2. In particular, Ergon Energy has a low density network so it will appear to perform worse on PPIs than it does on the economic benchmarking models – particularly compared to frontier performers CitiPower and Powercor.

PPIs do not explicitly account for operating environment differences and examine only one output. However, bearing these limitations in mind, our PPI metrics (opex per customer and total user cost per customer) support the economic benchmarking results. We consider these PPIs remain useful tools of comparison if their limitations are understood. Further, our first annual benchmarking report contains additional PPIs that examine different outputs. These PPIs similarly show the NSW service providers generally perform poorly compared to their peers.[73] PPIs were the subject of some submissions from stakeholders. We consider PPIs in further detail in section A.4.

Incorporating differences between service providers

While Economic Insights' benchmarking models account for key differences between service providers—customer density, network line length and degree of network undergrounding, for example—they do not account for all differences. This is because accounting for too many differences in the model can lead to unstable results. The available data on operating environment differences is also a limiting factor.

Accordingly, we have conducted a detailed examination of the operating environment factors (OEFs) proposed by the Queensland service providers. On the basis of this analysis, we consider it is necessary to increase the efficiency scores for Energex and Ergon Energy by 17 per cent and 24 per cent, respectively, to appropriately account for exogenous differences particular to their networks. The most significant exogenous difference between the best performing service providers and Energex and Ergon Energy is the proportion of subtransmission network over 66kV. We considered these differences would adversely impact on the NSW service providers' efficiency scores and should not be interpreted as inefficiency.

Our assessment of operating environment factors is set out in detail in section A.5.

Figure A.3 shows the efficiency scores for the Queensland distributors compared to the frontier service provider (CitiPower):

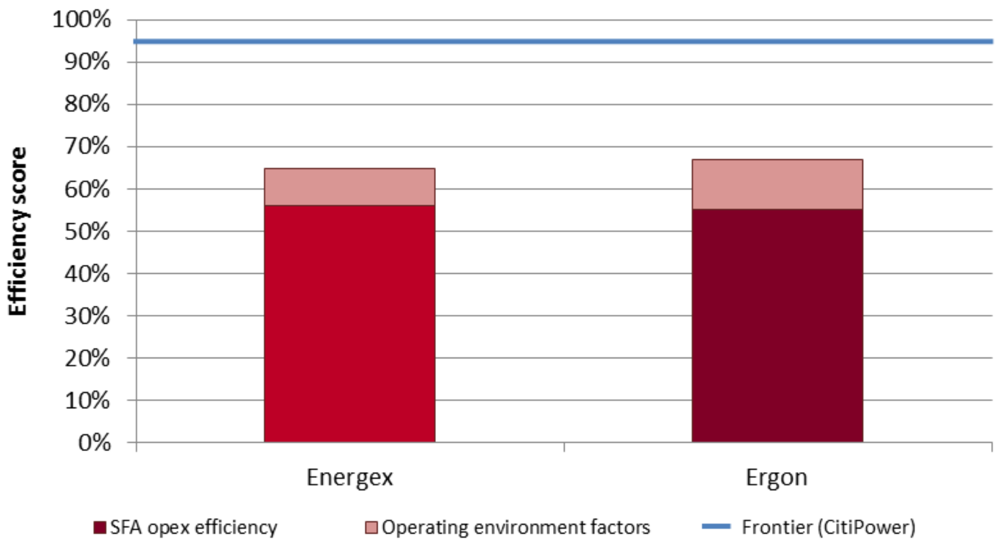
---

[73] AER, Electricity distribution network service providers–annual benchmarking report, November 2014, Appendix A.

- using the Cobb Douglas SFA model (Economic Insights' recommended model for quantifying an adjustment to revealed opex) and
- incorporating the allowance for exogenous differences in operating environments.

Our operating environment factor adjustments are percentage adjustments relative to the frontier. Therefore, the operating environment factor adjustments in Figure A.3 will not reflect the absolute percentages reported above. That is, the light red proportion represents 17 per cent (Energex) and 24 per cent (Ergon Energy) of the frontier efficiency score rather than an addition of 17 or 24 percentage points on top of the SFA opex efficiency score.

Figure A.3 Comparison of raw SFA efficiency scores to the frontier, adjusted for operating environment factors



Source: AER analysis.

Note: The raw SFA efficiency scores displayed are 'rolled forward' from a period-average basis (for 2006-2013) to the 2012–13 base year. We explain this in section A.8 in our discussion of the adjustment process.

Figure A.3 demonstrates that, even allowing for exogenous operating environment factors, Energex and Ergon Energy have efficiency scores well below the frontier efficiency score of 95 per cent using our SFA benchmark model.

We used additional assessment techniques to see if they supported the benchmarking results and to help us understand what might be driving differences in benchmark performance.

Category analysis and qualitative assessment

We used more granular assessment techniques in two stages as a means of understanding what drives the benchmarking results. In the first stage, we examined the service providers' regulatory proposals and conducted category analysis of key opex categories.

Energex's and Ergon Energy have prepared their proposals in light of recent government-initiated efficiency reviews. The Queensland Government reviews were:

- the 2011 Electricity Network Capital Program Review (the ENCAP Review),[74] which resulted in revised security and reliability standards
- the 2012 Independent Review Panel (IRP) investigation[75] into areas of inefficiencies in the Queensland service providers. The task of the IRP was to develop options to:
    - improve the efficiency of capital and operating expenditure
    - deliver savings in corporate and overhead costs including ICT[76] costs.

In May 2013, the IRP found that through a series of reforms, Energex and Ergon could together achieve an estimated $1.4 billion reduction in operational costs over the 2015−20 regulatory control period. The IRP made 45 recommendations, including 18 which focused on overhead expenses and operational efficiencies.[77]

Energex's and Ergon Energy's regulatory proposals include a series of efficiency adjustments to base opex and in the forecast period as a result of these reviews, including FTE reductions.[78] This suggests labour costs could be one of the drivers of their benchmarking performance.

Further, category analysis showed the Queensland distributors had 'high' or 'very high' costs on labour and overheads metrics compared to most of their peers.

Due to the overlap between the IRP review and our category analysis results (and because labour costs account for approximately 75 per cent of opex for Ergon Energy and 95 per cent for Energex)[79] for the second stage, we engaged Deloitte to review the reasons for the service providers' benchmarking performance, including the extent they

---

[74] Queensland Government, *Electricity network capital program review 2011: Detailed report of the independent panel*, October 2011.

[75] Commissioned by the Interdepartmental Committee on Electricity Sector Reform (IDC), initiated by the Queensland Government.

[76] Information and communications technology

[77] Independent Review Panel on Network Costs, Electricity Network Costs Review, 2013. The IRP's recommendations were for the most part accepted by the Queensland Government. However, some of the reforms also related to structural change, including a recommendation that Energex, Ergon and Powerlink either be structurally combined into a single entity, or transferred under the umbrella of a holding company similar to Networks NSW. The QLD Government accepted these reforms in principle only. They are beyond the scope of our review. See Queensland Government response to the Interdepartmental Committee on Electricity Sector Reform 2013.

[78] For example, Energex, *Energex regulatory proposal appendix 8: Application of base–step–trend (BST) model*, October 2014, pp. 18, 33–55, 65; Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal), pp. 13–16.

[79] Energex, Response to information request AER Energex 002, received 19 December 2014; Ergon Energy, Response to information request AER Ergon 021, received 31 January 2015.

had implemented the recommendations of the recent review by the Independent Review Panel (IRP).

Deloitte's detailed review findings

Deloitte found that while Energex and Ergon Energy have both achieved significant efficiency gains since the IRP's review (particularly reflected in FTE reductions), much of these benefits were realised after the 2012–13 base year. Deloitte also observed that the service providers have identified they can further reduce their costs. Further, the service providers have not yet addressed a number of IRP recommendations. Deloitte conclude that Ergon Energy's and Energex's opex prior to and in 2012–13 was higher than necessary to achieve efficient operations.[80]

Deloitte's key findings include:[81]

- both service providers (but Ergon Energy in particular) have high total labour costs compared to more efficient peers, which is a result of having too many employees rather than the cost per employee
- Ergon Energy's EBA prohibits certain activities (such as switching) from being conducted by a single person; in other states these activities can be performed by a single person
- certain EBA provisions, while not necessarily unique to Energex and Ergon Energy, limit their ability to quickly adjust their workforces flexibly and utilise them productively. This is amplified by the large proportion of employees engaged under EBAs. Examples include:
    - no forced redundancies
    - contractors are unable to perform certain tasks, such as switching (unique to QLD)
    - minimum apprentice numbers
    - restrictions on outsourcing
- both service providers (but Energex in particular) incurred significant overtime in expenditure in the base year
- Energex and Ergon Energy have not implemented the IRP's recommendation that they market test the ICT services that SPARQ (a joint venture owned by the two service providers) provides, resulting in inefficiency in base opex for both service providers
- Ergon Energy has not yet implemented a LSA model for its regional depots, despite the IRP's recommendation (based on Powercor's success with this model) to do so.

80 Deloitte, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. v–xx.

81 Deloitte, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. v–xx.

Deloitte considers Ergon Energy could realise efficiencies if it implemented an LSA model.

We explain Deloitte's findings in further detail in section A.5.3.

Adjustments to revealed opex

We consider the evidence shows that there is a gap between the revealed costs in the base year and the benchmark opex that an efficient provider would incur. In these circumstances we may need to make an adjustment to the revealed base opex. Making an adjustment involves consideration of the appropriate technique, the appropriate benchmark comparison point and the appropriate manner in which to make the adjustment. Our approach of using benchmarking as a basis for making adjustments to opex is consistent with Ofgem's approach.[82]

The best technique for the adjustment

We have adopted Economic Insights' recommendation to rely on the Cobb Douglas SFA model as the preferred technique upon which we base an adjustment to revealed opex. This technique directly estimates efficiency scores and has superior statistical properties.[83]

The benchmark comparison point

For the reasons we outline in detail in section A.7, we have decided that, on balance, the appropriate benchmark comparison point is the efficiency score for the business at the upper third (top 33 per cent) of companies in the benchmark sample (represented by AusNet Services). This reduces the benchmark comparison point from 0.95 (the frontier) to 0.77. We have done this because:

- this recognises that more than a third of the service providers in the NEM, operating in varied environments, are able to perform at or above our benchmark comparison point. We are confident that a firm that performs below this level is therefore spending in a manner that does not reasonably reflect the opex criteria. An adjustment back to this appropriately conservative point is sufficient to remove the material over-expenditure in the revealed costs while still incorporating an appropriately wide margin for potential modelling and data errors for the purposes of forecasting
- it is consistent with the preference in the Guideline to rely on revealed costs and only adjust base opex where it is materially inefficient

---

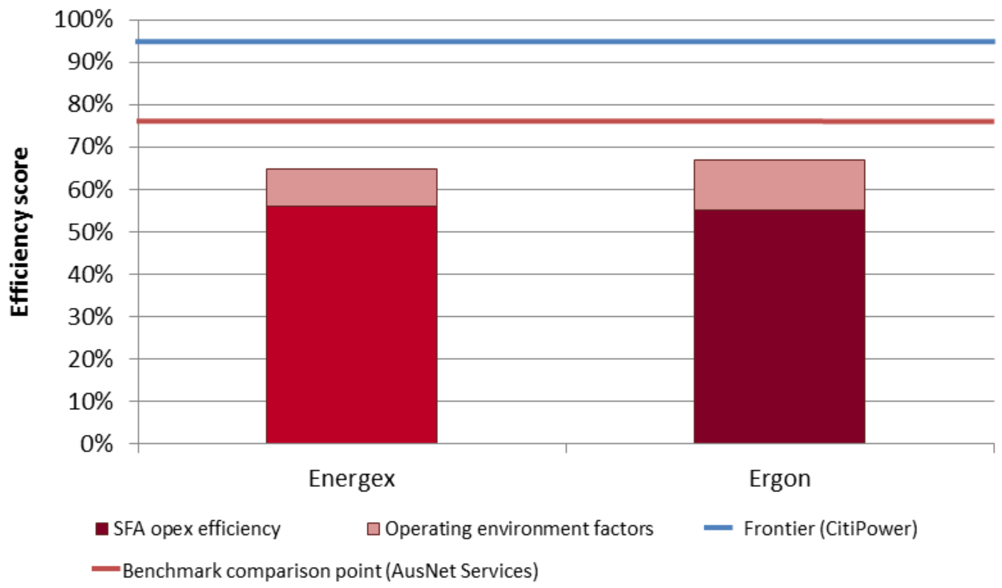
82 Noting that Ofgem now assesses total expenditure rather than capex and opex separately. See, for example, Ofgem, RIIO-ED1–Final determinations for the slow-track electricity distribution companies-Overview, 28 November 2014, Chapter 4.

83 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. v.

- given it is our first application of benchmarking, it is appropriate to adopt a cautious approach, allowing a margin for potential data and modelling issues and other uncertainties
- we consider this approach achieves the NEO and RPP because it is sufficiently conservative to avoid the risks associated with undercompensating the service provider but also promotes efficiency incentives.

Figure A.4 shows the efficiency scores using our SFA model for the Queensland distributors compared to our benchmark comparison point, represented by the red line (AusNet Services). The blue line represents the frontier (CitiPower).

Figure A.4 Comparison of SFA efficiency scores to the benchmark comparison point, adjusted for operating environment factors



Source: AER analysis.

Note: (1) The raw SFA efficiency scores displayed are 'rolled forward' from a period-average basis (for 2006-2013) to the 2012–13 base year. We explain this in section A.8 in our discussion of the adjustment process.

(2) As explained above, our operating environment factor adjustments are percentage adjustments relative to the frontier. Therefore, the operating environment factor adjustments in Figure A.4 (in light red) will not reflect the absolute percentages (17% for Energex, 24% for Ergon Energy).

Figure A.4 demonstrates the difference between the frontier firm and our benchmark comparison point. Despite this lower target, a gap remains between Energex's and Ergon Energy's efficiency scores, adjusted for operating environment factors and the benchmark comparison point. This is explained in more detail in section A.7.

The adjustment process

The adjustment process involves using the SFA model (our most robust benchmarking technique) to estimate average efficiency over the 2006–13 period. We then adjust the SFA results to take into account the reduced benchmark comparison point and operating environment factor allowances that we discussed above. Because we compare average efficiency, we must 'roll forward' the average efficient opex to the 2012–13 base year, because that is the relevant starting point for estimating total forecast opex that reasonably reflects the opex criteria. We do this by applying the measured rate of change, which accounts for the difference between output, price and productivity in the 2012–13 base year and at the period average (2006 to 2013).[84]

A key reason we use average period efficiency scores is because they reduce the impact of year–specific fluctuations not under the control of the service provider (such as weather conditions). Given the sample period is only eight years, Economic Insights considers the average is sufficiently recent to avoid potential loss of current relevance.[85]

Average efficiency results also provide us with an estimate of underlying recurrent expenditure not influenced by year on year changes, which we require for the Guideline approach to estimating total forecast opex.

We discuss our adjustment in detail in section A.8.

A.1.3 Summary responses to Ergon Energy's submissions

Ergon Energy provided submissions to the issues paper to the Queensland electricity distribution regulatory proposals and to the draft decision for the NSW distribution determinations, commenting on our approach to assessing opex.[86] While Ergon Energy acknowledged the role of benchmarking in our assessment of expenditure, it considers:

- our approach "uses benchmarking, to the near exclusion of every other relevant consideration"
- our benchmarking is "not fit for the purpose to which it has been put" so we should not rely on it to adjust forecasts of base opex
- our approach does not adequately consider service providers' individual circumstances.

Throughout this appendix, we respond to the submissions put forward by Ergon Energy and other stakeholders in the course of explaining our approach and findings. This section provides an overview of our response to the above three key submissions.

---

84 This differs slightly from the rate of change we apply in Appendix B. While the approach is the same, to trend base opex forward over the forecast period, we apply forecast growth. When rolling forward average efficient opex, we apply measured growth because we can observe what has actually changed between the period average and the base year.

85 Economic Insights, 2015, pp. 43–44.

86 Ergon Energy, *Submission on the Queensland Electricity Distribution Regulatory Proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015; Ergon Energy, *Submissions on the draft decisions: NSW and ACT distribution determinations 2014–15 to 2018–19*, 13 February 2015. Energex provided a submission to the Issues paper for the Queensland electricity determination, however it did not raise any concerns on base opex.

Reasonable weight placed on benchmarking

Ergon Energy submits that our approach relies exclusively on benchmarking to both reject forecast opex and as the basis for substituted opex. In so doing, Ergon Energy submits, we are effectively disregarding our revealed cost approach and 2010–15 determination.[87]

We do not agree. As outlined in the Guideline, and in this preliminary decision, we have relied on several assessment techniques, both quantitative and qualitative to assess the service providers' proposed forecast opex. In doing so, we have used the same techniques as the basis for determining substitute opex. We have used our discretion to give benchmarking prominent, but appropriate weight based on its robustness and utility.

We have assessed the service providers' proposals using the techniques outlined in the Guideline. We have engaged with the details of the service providers' proposals to the extent they are relevant to our assessment of base opex. They were the starting point for our assessment. Ultimately, however, we must form a view on the amount of a service provider's forecast, not the specific contents of the proposal.[88]

Further, since our 2010–15 determination, we have developed new techniques that give us better insight into assessing expenditure and have new information that we are able to take into account. All stakeholders should expect us to use new techniques and information when they become available.[89] This new information demonstrates that the service providers' revealed costs are inefficient. However, we have not moved away from revealed costs—we use them when it is appropriate to do so. Rather, we have used new techniques to ensure that we are better able to make a decision that reasonably reflects the opex criteria for the future. Our approach represents a refinement of our longstanding approach to assessing opex.

We discuss these issues in detail in section A.3.

Benchmarking is robust, reliable and reasonable

Ergon Energy submitted (and used numerous consultants to support its view) that our benchmarking is fundamentally flawed due to, for example:[90]

- failure to account for differences between service providers

---

87 Ergon Energy, *Submissions on the draft decisions: NSW and ACT distribution determinations 2014–15 to 2018–19*, 13 February 2015, pp. 9–10.

88 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 93.

89 We have indicated in previous decisions and in defending those decisions our preference to use up to date information where possible. The Tribunal has endorsed this approach and indicated a similar preference: see for example Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11 at [61] to [62].

90 Ergon Energy*, Submissions on the draft decisions: NSW and ACT distribution determinations 2014–15 to 2018–19*, 13 February 2015, pp. 9–22.

- sensitivity to data changes
- variance in results
- not having regard to forecast changes in costs
- data comparability and reliability.

Our view is that Economic Insights' benchmarking is robust and reliable. The model specification and estimation methods are superior to the alternatives proposed by service providers and their consultants. In addition, the Australian data we are using are robust because we have gathered, tested and validated it over three years of consultation with service providers and other interested stakeholders. The international data Economic Insights has used (to improve the precision of the models) has been used by the electricity regulators in the respective jurisdictions in recent regulatory decisions.[91]

Economic Insights responds to the service providers' submissions in detail in its final decision report.[92] We also discuss this further in section A.4.

Individual circumstances are considered

Ergon Energy submits that by relying on benchmarking as part of our assessment approach, we have failed to comply with the NER requirements to have regard to their individual circumstances. In particular, Ergon Energy refers to the need for us to consider its specific cost inputs.[93]

Benchmarking is a tool we use to assess regulatory proposals. We also use it in setting a substitute forecast if we are not satisfied that a service provider's proposed forecast reasonably reflects the opex criteria. We have considered the service providers' proposals in significant detail in conducting our assessments. We have conducted detailed reviews and analysed the service providers' forecasting approaches. We also have had regard to the service providers' individual circumstances through our review of operating environment factors (see section A.6) to the extent required by the NER and in accordance with the intent of the AEMC.

We disagree with Ergon Energy's view that the NER require us to consider their endogenous circumstances. The AEMC is clear that while exogenous circumstances

91 Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, section 3.2.

92 Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, section 3.10.

93 Ergon Energy, *Submission on the Queensland Electricity Distribution Regulatory Proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015, pp. 10–14; Ergon Energy, *Submissions on the draft decisions: NSW and ACT distribution determinations 2014–15 to 2018–19*, 13 February 2015, pp. 23–27.

are relevant and should be accounted for, endogenous circumstances should not be considered.[94]

We discuss these issues in detail in section A.3.

A.2 Ex ante incentive regulation and the role of benchmarking

This section explains ex ante regulation, and how our approach to benchmarking fits appropriately within the legal and regulatory framework.

A.2.1 Ex ante incentive regulation

Network services are 'natural' monopolies with little scope in any given location for a competitor to duplicate the network efficiently.[95] Monopoly businesses do not have an incentive to set prices at an efficient level because there is no competitive discipline on their decisions. They do not need to consider how and whether or not rivals will respond to their prices. Monopolies' profits depend only on the behaviour of consumers, their cost functions, and their prices or the amount supplied.[96]

Without regulation, the resulting market power would lead to high prices and probably insufficient investment. Accordingly, we must regulate the prices and other aspects of these services to ensure reliable and affordable electricity.[97]

Information asymmetries make it difficult for the AER to accurately assess the efficiency of the service providers' proposals. We need to make judgements about 'efficient' costs.[98]

Incentive regulation is used to partially overcome information asymmetries. We apply incentive-based regulation across all energy networks we regulate—consistent with the NER.[99] This is a fundamental aspect of the regime. As stated by the AEMC:

> Set out in Chapter 6 of the NER, the incentive regulation framework is designed to encourage distribution businesses to spend efficiently and to share the benefits of efficiency gains with consumers. Specifically, it is designed to encourage distribution businesses to make efficient decisions on when and

---

94 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113. See also pp. viii, 25, 98, 107–108.

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

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

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

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

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

> what type of expenditure to incur in order to meet their network reliability, safety, security and quality requirements.[100]

Broadly speaking, incentive regulation is designed to align the commercial goals of the business to the goals of society or, in the case of energy regulation, the NEO.[101] It relies on the principle that the network businesses' objective is to maximise profits.[102] Businesses that are able to improve their efficiency are rewarded with higher profits.[103] Businesses that allow their efficiency to deteriorate earn lower-than-expected profits. The actual revenue allowance set by the regulator should not influence the basic incentive of network businesses to minimise costs and, thereby, maximise profits.

To elaborate, the regime requires us to forecast and lock-in opex at the start of each five-year regulatory period that an efficient and prudent business would require.[104] The business is then given financial rewards when it improves its efficiency and spends less than the forecast during the regulatory period—while maintaining or improving its service standards. If the business spends less than the forecast it will still earn revenue to cover the total forecast amount. Hence it can 'keep the difference' between the forecast and its actual expenditure until the end of the regulatory control period. Conversely, if its spending exceeds the forecast, it must carry the difference itself until the end of the period.

Over time, incentive regulation should in theory allow the regulator to use the information revealed by businesses to develop better forecasts of efficient expenditure—consistent with the opex criteria. This will reduce the scope for the businesses to earn excessive rents and allow the regulator to apply stronger incentives for further cost reduction.[105]

However, using a network business' past information to set future targets can reduce the incentives of the business to lower costs since the business knows that any cut in its expenditure will decrease its revenue allowance in the future. Although the current regulatory approach allows the business to retain the benefit of any reductions in expenditure for a period of time, setting the appropriate level of incentive is difficult as it involves judgments about businesses' reactions to the incentive regime.[106] Moreover,

---

[100] AEMC, C*onsultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015,* February 2015, p. 3.

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

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

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

[104] This takes into account the realistic expectations of demand forecasts and cost inputs, to meet and manage the demand for network businesses' services, comply with their regulatory obligations and maintain the safety of the system.

[105] Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 192.

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

the achievement of best-practice can be costly from the standpoint of managerial effort.[107]

Therefore, the incentives created by the regime can be somewhat mixed.[108] But, as a first principle, energy regulation in Australia is intended to be incentive-based where possible.[109] This can be contrasted with a pure cost of service model.

A.2.2 Contrast with a cost of service regime

Cost of service regulation, as its name implies, compensates businesses for the costs incurred to provide services. If a business reduces its costs, the benefits of cost efficiency accrue to consumers in the form of lower prices, not to the business as profits. On the other hand if costs increase then so do prices.

Cost of service regulation creates an environment that provides greater assurance to businesses that investments in sunk assets will be recovered. However, a pure cost of service approach provides low-powered incentives for cost reductions because actual costs are fully passed through to consumers. Joskow states:

> Since the regulator compensates the firm for all of its costs, there is no “rent” left to the firm as excess profits. This solves the adverse selection problem. However, this kind of cost of service recovery mechanism does not provide any incentives for the management to exert optimal (any) effort. If the firm’s profitability is not sensitive to managerial effort, the managers will exert the minimum effort that they can get away with. While there are no “excess profits” left on the table since revenues are equal to the actual costs the firm incurs, consumers are now paying higher prices than they would have to pay if the firm were better managed and some rent were left with the firm and its managers.[110]

Such low-powered incentives created by a pure cost of service model are typically not observed in competitive markets. This is an important distinction between incentive and cost of service regulation.

---

107 ACCC & Public Utility Research Centre University of Florida, Infrastructure regulation and market reform: Principles and practice, May 1998, p. 39.

108 Joskow finds incentive-based regulation applies elements of cost of service regulation in practice: ‘This basic price-cap regulatory mechanism used to regulate electricity, gas and water distribution and transmission companies in the UK, is often contrasted with characterizations of cost-of-service or “cost plus” regulation that developed in the U.S. during the 20th century. However, I believe that there is less difference than may first meet the eye. The UK’s implementation of a price cap based regulatory framework is best characterized as a combination of cost-of-service regulation, the application of a high powered incentive scheme for operating costs for a fixed period of time, followed by a cost-contingent price ratchet to establish a new starting value for prices. (Joskow, Incentive regulation in theory and practice: electricity distribution and transmission networks, 2005, pp. 70–71.)

109 AER, *Overview of the Better Regulation reform package*, April 2014, p. 4.

110 Joskow, Incentive regulation in theory and practice: electricity distribution and transmission networks, 2005, pp. 10–11.

In our view, the NEO and the supporting incentive-based regime seek to emulate workably competitive market outcomes. Incentive regulation is designed to impose the pressures of competition on natural monopolies. The AEMC states:

> The role of incentives in regulation can be traced to the fundamental objective of regulation. That is, to reproduce, to the extent possible, the production and pricing outcomes that would occur in a workably competitive market in circumstances where the development of a competitive market is not economically feasible.[111]

Competition generally places downward pressure on prices and can act as an impetus for cost reductions and quality improvements. In a competitive market, businesses have a continuous incentive to respond to consumer needs at the lowest cost to increase demand for their services and, thereby, maximise shareholder returns.[112] Businesses that are less efficient are unable to pass their full costs onto consumers and ultimately pay lower returns to their shareholders.

Consistent with competitive market outcomes, the AEMC considers shareholders, by seeking a commercial return on investment, create incentives within the business to encourage efficient outcomes.[113] Moreover, the AEMC finds that shareholders should ultimately bear the risk of business inefficiencies:

> … the return on debt estimate should reflect the efficient financing costs of a benchmark efficient service provider. It should try to create an incentive for service providers to adopt efficient financing practices and minimise the risk of creating distortions in the service provider's investment decisions. If a service provider is run inefficiently then its shareholders, and not its customers, should bear the financial consequences of inefficient financing practices.[114]

Although the AEMC is referring to return on debt in the above quote, the same principle applies to opex. Risk should generally be borne by the party that is best able to manage it. Consumers of network energy services are not in a position to influence the network businesses strategy to manage opex, such as staffing decisions. And they do not have the choice of changing energy suppliers. Shifting the risk of business inefficiencies away from the managers and shareholders of the networks would create negative incentives:

> It is also in present and future consumers' interests that the regulatory framework does not provide excess returns, reward inefficiency or effectively 'bail out' a network company that has encountered financial difficulty as a result of its own actions (or inaction); for example because of an inappropriate financial structure or poor management. To do so would weaken or even

111 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 no. 18*, November 2006, p. 93.

112 ACCC, *Submission to the Productivity Commission's inquiry into the economic regulation of airport services*, March 2011, pp. 8–9.

113 AEMC, *Rule Determination: Economic Regulation of Network Service Providers*, November 2012, p. 34.

114 AEMC, *Rule Determination: Economic Regulation of Network Service Providers*, November 2012, p. 73.

> remove the disciplines that capital markets place on all companies, reducing or removing the effectiveness of the incentives we place on network companies under the regulatory regime to the detriment of consumers. The primary responsibility for the financial integrity of a network company lies firmly with that company's management and owners.[115]

A.2.3 How benchmarking helps manage incomplete information about efficient costs

Incentive regulation relies on effective assessment tools to overcome information asymmetries. The 'revealed cost approach' and benchmarking are our two main tools.

As outlined in the Guideline, the AER typically uses the 'base-step-trend' forecasting approach to assess most opex categories. That is, we:

- assess whether base opex reasonably reflects the opex criteria
- assess the prudency and efficiency of forecast cost increases or decreases associated with new regulatory obligations and capex/opex trade-offs (step changes)
- apply trend analysis to forecast future expenditure levels.[116]

The revealed cost approach is a way to determine an efficient base. It relies on the principle that the primary objective of a business is to maximise its profits. The regulatory framework allows network businesses to keep the benefit of any cost reductions for a period of time (as discussed above). The AER may apply various incentive schemes, such as the EBSS in conjunction with the STPIS, to provide the business with a continuous incentive to improve its efficiency in supplying electricity services—while maintaining or improving service standards.

The drive to maximise shareholder returns should in theory push the businesses to become more efficient and productive over time. Actual past expenditure should therefore be a good indicator of the efficient expenditure the business requires in the future.

So, where incentive regulation is effective, the revealed cost approach can at least partially overcome information asymmetries that exist between the business and relevant stakeholders about the efficient opex base. We prefer to use revealed (past actual) costs as the starting point for assessing and determining efficient forecasts.[117] It allows us to leave the minutiae of input and output decision-making to the businesses.[118]

---

115 Ofgem, *Regulating Energy Networks for the Future: RPI–X@20: Emerging Thinking – Embedding financeability in a new regulatory framework, Parallel consultation paper*, 20 January 2010, p. 4.

116 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, 2013, pp. 22–24.

117 AER, *Expenditure Forecast Assessment Guideline explanatory statement*, 2013, p. 42.

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

However, we cannot automatically assume the network businesses will respond to the efficiency incentives.[119] The businesses' objectives may not align with the incentives of the regime.[120] We undertake an assessment of whether the base year opex reasonably reflects the opex criteria to determine if it is appropriate for us to rely on a business' revealed costs to forecast future expenditure needs.

In recent years, we have expanded our regulatory toolkit to make greater use of benchmarking, which is a way of determining how well a network business is performing against its peers and over time, and provides valuable information on what is 'best practice' (see Box 1). Benchmarking:

- improves the effectiveness of the regulatory process by enhancing the information available to us
- gives us an alternative source of comparative information about the costs of operating a business in the national electricity market to test the businesses' proposals
- allows us to gain some insight into whether or not there are material inefficiencies in a business' base opex and, therefore, represent a good basis for forecasting future opex.

We use benchmarking to investigate whether an adjustment to base opex is required—that is, we look for evidence of 'material inefficiencies' in a network business' base opex. If the business is materially inefficient compared to its peers, the revealed cost approach may not be appropriate.[121] Reliance on historic costs in these circumstances could yield an outcome inconsistent with the opex criteria and, more broadly, the NEO and RPPs which give effect to incentive regulation.

[119] The NER require us to be satisfied that a business' total opex forecast reasonably reflects the expenditure criteria (NER, cl. 6.5(c)). Further, we must consider the actual and expected expenditure of the service provider during preceding regulatory control periods, and whether expenditure is consistent with our incentive schemes (NER, cl. 6.5.6(e)(5) and (8)).

[120] ACCC & Public Utility Research Centre University of Florida, *Infrastructure regulation and market reform: Principles and practice*, May 1998, p. 39.

[121] AER, *Expenditure Forecast Assessment Guideline explanatory statement*, 2013, p. 93.

Box 1: AER benchmarking techniques

Benchmarking is just one way of assessing whether a business' expenditure proposal is efficient.[122] We use multiple benchmarking techniques to inform our assessment of efficient opex. This includes 'economic benchmarking', partial performance indicators and category-based techniques. In addition, we undertake detailed reviews to investigate the drivers of, or potential explanations for, high expenditure indicators.

Specifically, our consultant, Economic Insights used a stochastic frontier analysis (SFA) model to estimate efficient base year opex and calculate the trend in opex going forward. Economic Insights used two other econometric models as well as multilateral total factor productivity (MTFP) and multilateral partial factor productivity (MPFP) indexes to cross-check the findings of the SFA model. Further, Economic Insights used international data to improve the robustness and precision of the models, but not to benchmark Australian networks against those operating overseas.

Stochastic frontier analysis

SFA is an extended econometric method that can be used in cost benchmarking analysis. SFA enables the estimation of a cost frontier, from which actual costs incurred by businesses can be compared. SFA is similar to other econometric cost models in that it specifies a cost function that relates costs to outputs, input prices, and environmental factors.

However, it differs from traditional econometric approaches in two main ways. First, SFA focuses on estimating the cost frontier representing the minimum costs ('best practice') rather than estimating the cost function representing the 'average' business. Second, SFA aims to separate the presence of random statistical noise from the estimation of inefficiency. SFA also has the advantage that it allows for economies and diseconomies of scale and can include environmental factors.

A.2.4 Benchmarking is part of the regulatory framework

The NER has always required us to have regard to benchmark opex that would be incurred by an efficient network business (cl. 6.5.6(e)(4)). The AEMC's November 2012 network regulation rule changes promote the AER's use of benchmarking for assessing and determining opex forecasts. The new rules stipulate that the AER will undertake and publish regular benchmarking reports, and that we must have regard to these reports in assessing whether networks' proposed opex forecasts reasonably reflect the opex criteria. Further, the AEMC removed potential constraints in the NER on the way the AER may use benchmarking.[123]

Benchmarking promotes the revenue and pricing principles (RPPs), which we are required to take into account when making our decisions. The principles include that a service provider should be provided with: (1) a reasonable opportunity to recover at

[122] Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 27.

[123] AEMC, *Rule Determination: Economic Regulation of Network Service Providers*, November 2012.

least its efficient costs; and (2) effective incentives to promote economic efficiency in the provision of its direct control services.

First, benchmarking allows us to more accurately assess whether networks' proposed opex forecasts are efficient. It gives us an additional source of evidence about the networks' performance. Indeed, the AEMC considered that benchmarking is a critical exercise in assessing the efficient costs of a network business and approving its opex forecast.[124]

Our use of benchmarking may mean we forecast a business' future opex requirements at a lower level compared to its historical costs to reflect the opex criteria. A prudent operator would not discount the possibility that we could better detect inefficient costs over time. Each network knows that their revenue allowance may be reduced if it is shown that other networks are operating more efficiently.

The revenue allowance determined by the AER does not set a business' actual operating budget. We predict the operating expenditure required for each network business acting as a prudent operator, incurring efficient costs. The business should attempt to outperform it. The business is expected to organise itself efficiently to make the most efficient use of its resources.[125] Management should attempt to minimise costs in an effort to maximise shareholder value.

That is, a prudent operator is expected to respond to the incentives of the regime—consistent with the NEO and competitive market outcomes.[126] The incentive regime is designed to provide the impetus for the business to deliver safe, reliable and secure services to its customers.

Second, energy regulation in Australia is intended to be incentive-based where possible. Benchmarking strengthens incentives for network businesses to minimise costs—it creates effective incentives to promote: efficient investment, the efficient provision of services and the efficient use of the distribution system, consistent with the NEO.

Benchmarking creates a form of competitive pressure on the networks, whereby information about the relative performance of a business can be an important incentive for improvement.[127] Benchmarking is widely used by private sector firms to identify opportunities for operational efficiencies and other improvements.

---

[124] AEMC, *Rule Determination: Economic Regulation of Network Service Providers*, November 2012, p. 112.

[125] Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, pp. 170–171.

[126] In a competitive market environment, various forces keep managers from deviating from profit-maximising objectives behaviour. If a competitive business is run inefficiently and unprofitably, it could be driven out of business or taken over by rivals/new entrants that do maximise profits. Managers who lose their jobs in these circumstances can find it difficult to obtain new jobs. Incentives such as stock ownership and other performance bonuses also motivate managers to maximise profits.

[127] AER, *Expenditure Forecast Assessment Guideline explanatory statement*, 2013, p. 42.

A.2.5 Benchmarking is a common regulatory tool

The use of benchmarking in economic regulation of energy networks is well-established. The AER/ACCC undertook two studies in 2012 on how benchmarking is applied around the world. These studies cover the key methods, relevant literature and regulatory practices, as well as the major technical and implementation issues in benchmarking energy networks.[128][129] The studies carefully list the advantages and disadvantages of each benchmarking method in the context of energy network regulation. We also commissioned a thorough analysis of benchmarking approaches in some European countries.[130]

The Productivity Commission found utility regulators around the world use static (and dynamic) benchmarking to encourage regulated businesses to achieve the long-run efficiency outcomes of decentralised, workably competitive, markets.[131] Benchmarking has been used by:

- Australian regulators, including state based electricity regulators and the AER
- international regulators such as OFGEM (United Kingdom), CER (Ireland), NZCC (New Zealand), and OEB (Ontario Canada)
- various academics in the Australian, European, American and other contexts.[132]

Unlike some industries, electricity network distribution businesses are good candidates for benchmarking opex. All network businesses use a similar set of assets, such as poles, wires, transformers and cables, to provide network services to customers. Indeed, Bain & Company states '… in some ways, utilities are one of the most straightforward industries to benchmark because they perform essentially the same tasks wherever they are.'[133]

This commonality means that economic benchmarking of costs can be used to measure the economic efficiency of a network business by comparing its performance not only to other businesses, but also to its own past performance.[134] Historically, electricity distribution has exhibited low technology change in comparison to, for example, communications where the pace of technology change is more dynamic.[135]

However, it is important to recognise that network businesses do not operate under exactly the same operating environment conditions. Further, distribution businesses

---

[128] ACCC/AER, *Benchmarking Opex and Capex in Energy Networks, ACCC/AER Working Paper no. 6*, May 2012.

[129] ACCC/AER, *Regulatory Practices in Other Countries: Benchmarking Opex and Capex in Energy Networks*, May 2012.

[130] Schweinsberg, Stronzik, and Wissner, *Cost Benchmarking in Energy Regulation in European Countries*, Wik Consult, December 2011.

[131] Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 148.

[132] Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62*, 2013, p. 148.

[133] Bain & Company, Sustained cost reduction for utilities, 2013, p. 2.

[134] AER, *Expenditure Forecast Assessment Guideline explanatory statement*, 2013, p. 132.

[135] Coelli, Estache, Perelman, Trujillo, *A Primer on Efficiency Measurement for Utilities and Transport Regulators*, 2003, p. 11.

can vary in the scope of electricity distribution services they provide. Benchmarking needs to properly account for these differences so that when comparisons are made across networks, we are comparing ‘like-with-like’ to the greatest extent possible.[136] As stated by the AEMC:

> ... when undertaking a benchmarking exercise, circumstances exogenous to a NSP should generally be taken into account, and endogenous circumstances should generally not be considered. In respect of each NSP, the AER must exercise its judgement as to the circumstances which should or should not be included.
>
> …
>
> If there are some exogenous factors that the AER has difficulty taking adequate account of when undertaking benchmarking, then the use to which it puts the results and the weight it attaches the results can reflect the confidence it has in the robustness of its analysis.

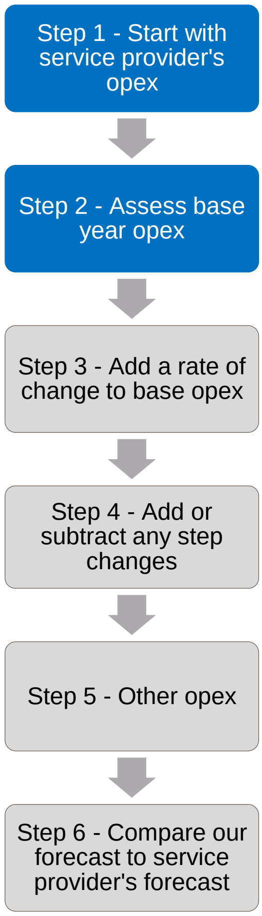
Our benchmarking models account for key differences in operating environment factors (section A.6). This is followed by our review of a large set of operating environment factors to determine whether it is necessary to provide further allowance for operating environment differences.

We undertook an extensive research and consultation process to develop the benchmarking used in the annual benchmarking report and in the determinations. This has been in conjunction with Economic Insights, which is an internationally recognised expert consultant on benchmarking. As discussed in section A.3, we released a significant benchmarking study in 2012 and consulted heavily on both the Guideline (including through an issues paper, draft guideline and workshops) and regulatory information notices. We have further developed our benchmarking models through this determination process.

136 AER, *Expenditure Forecast Assessment Guideline explanatory statement*, 2013, p. 132.

A.3 Assessment approach

In section 7.3, we presented a diagram explaining the five steps in our approach to assessing a service provider's total forecast opex.



This section explains our approach to assessing base opex, which covers Step 1 and Step 2 of this overall approach.

Assessing base opex is a crucial part of our overall assessment approach because it is the foundation upon which we build our own estimate of total forecast opex that we consider reasonably reflects the opex criteria. We use our estimate to:

- determine whether to either accept or not accept a service provider's total forecast opex proposal by reference to the opex criteria;[137] and
- in the event we must reject a service provider's proposal[138] (that is, if it does not reasonably reflect the opex criteria) replace that proposed forecast.

The starting point for developing our estimate is the service provider's revealed costs (in this case, opex for the 2012–13 financial year). This is base opex, represented by Step 1, above. Base opex has been audited, and is used by the service providers as an agreed starting point.[139]

As foreshadowed in the Guideline[140], we use the following techniques to assess whether the base opex is suitable as a starting point for determining an estimate of total forecast opex that reasonably reflects the opex criteria (represented by Step 2, above):

- economic benchmarking—more complex techniques that use applies economic theory to measure the efficiency of a service provider's use of inputs to produce a number of different outputs, having regard to operating environment factors
- partial performance indicators—simplistic techniques that relate total opex and total user cost to one cost driver, such as line length or customer density (known as aggregated category benchmarks in the Guideline)

137 NER, cl. 6.5.6(c), considered in more detail below.
138 NER, cl.6.5.6(d), considered in more detail below.
139 Energex, *Regulatory Proposal*, p. 130; Ergon Energy, *Regulatory Proposal*, 75–76.
140 AER, *Expenditure forecast assessment guideline,* November 2013, p. 22

- category analysis—that compares, across service providers, the cost of delivering a particular category of opex (such as maintenance, vegetation management, etc.) to identify areas for detailed review
- detailed review—targeted, qualitative, examination of particular categories of expenditure, such as labour costs and vegetation management, conducted with the assistance of industry experts.

Benchmarking is particularly important in Step 2 of our approach because it enables us to compare the relative efficiency of the total opex of different service providers.[141] The NER give us discretion as to how we use benchmarking in our assessment.[142]

As part of our application of economic benchmarking, we consider differences in service providers' operating environments that could account for some differences in the relative efficiency scores. Based on this review we make appropriate adjustments to efficiency scores.

We have a preferred benchmarking model, which is Cobb Douglas stochastic frontier analysis (SFA).[143] This model creates an efficiency score for all service providers in the NEM. In the event we make an adjustment to base opex, we use this model as the starting point.

If a service provider performs well on our economic benchmarking techniques, we consider it is unnecessary for us to review base opex in further detail. No adjustment is required because we consider the service provider's base opex is not materially inefficient and, therefore, an appropriate starting point for our estimate of total forecast opex that reasonably reflects the opex criteria. Conversely, if our economic benchmarking techniques indicate that a service provider's opex is not efficient, we then review base opex in further detail and consider whether it is necessary to adjust base opex.

Theoretically, all service providers who rank below the service provider with the highest efficiency score on our preferred technique could be considered inefficient. If we decided to apply benchmarking deterministically, we could simply determine the degree of a service provider's inefficiency against the efficiency score of the most efficient service provider and adjust their opex accordingly.

However, we are not applying benchmarking deterministically. As we demonstrate in the diagram below, we have regard to a number of sources of evidence in forming a view on base opex efficiency, consistent with the approach we outlined in the Guideline. If it is clear that base opex is inefficient, we depart from revealed costs. When we do so, we rely on the most robust benchmarking model as the basis for adjustment.

---

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

142 AEMC, *Final Rule Determination*, 29 November 2012, pp. 112–113.

143 Economic Insights, 2014, p. iv.

In doing so, however, we rely on the concept of material inefficiency introduced in the Guideline. Because our preference (as stated in the Guideline) is to rely on the revealed cost approach to determine the starting point for our estimate of total forecast opex, we depart from revealed costs only when we consider base opex is *materially* inefficient.[144] The concept of material efficiency recognises that efficiency is a relative term, and one which properly does not adjust a service provider's revealed costs for immaterial inefficiency.

Therefore, in deciding what is materially inefficient, we consider it is appropriate to provide a margin for the effect of potential modelling and data limitations. To give effect to this consideration, we do not compare service providers to the frontier business. We consider the appropriate "benchmark comparison point" is the lowest of the efficiency scores for service providers in the top quartile of possible scores on our preferred SFA model. This is equivalent to the efficiency score for the business at the bottom of the upper third (top 33 per cent) of companies in the benchmark sample (represented by AusNet Services).[145] Our approach of using benchmarking as a basis for making adjustments to opex is consistent with Ofgem's approach.[146]

This means that we will not adjust the base year opex of a service provider unless its efficiency score (taking into account operating environment factors) is below the service provider with the lowest of the efficiency scores in the top quartile of possible scores. We have done this because:

- given it is our first application of benchmarking, it is appropriate to adopt a cautious approach, allowing a margin for potential modelling and data issues and other uncertainties

Step 2
Assess base year opex

Step 2a
Using several sources of evidence, form a view about the efficiency of base opex:
- Economic benchmarking techniques, adjusted for operating environment factors
- Detailed reviews
- Partial performance indicators
- Category analysis

Step 2b
Determine the appropriate adjustment using the most robust benchmarking technique (SFA) and a benchmark comparison point that reflects 'materially inefficient' rather than the efficient frontier

144 AER, *Expenditure forecast assessment guideline*, November 2013, p. 32–33.

145 This approach is a departure from our draft decision approach to determining the benchmark comparison point. We discuss this further in section A.7.

146 Noting that Ofgem now assesses total expenditure rather than capex and opex separately. See, for example, Ofgem, *RIIO-ED1–Final determinations for the slow-track electricity distribution companies-Overview*, 28 November 2014, Chapter 4.

- we consider this approach is consistent with the NEO and RPP because it is sufficiently conservative to avoid the risks associated with undercompensating the service provider but also promotes efficiency incentives.

This has the effect of significantly reducing the target against which we compare and (if necessary) adjust service providers' base opex. Our detailed consideration of adjustments to base opex is set out in section A.8.

A.3.1 Our approach to benchmarking since May 2012

We released a working paper on benchmarking in May 2012, and commenced work on the Guideline in December 2012, following the November 2012 Rule change. We finalised the Guideline in November 2013. We subsequently engaged in an extensive process of information gathering that culminated in our first Annual Benchmarking Report in November 2014. Service providers and any other interested parties have had access to the benchmarking RIN data since we published it on our website in May 2014. For the past three years, we have consulted widely with service providers and other stakeholders on our approach and its legal and economic underpinnings. Stakeholders also participated in the rule change process. Table A.2 below sets out this consultation process.

Table A.2 Full process of the development of benchmarking data set

Milestone	Date
ACCC/AER working paper on benchmarking in electricity networks released. This report provides a comprehensive list of data that had been used in previous energy benchmarking studies.	May-12
AER releases issues paper on expenditure forecast assessment guideline. Issues paper includes: • detailed description of benchmarking techniques • data on the inputs and outputs for benchmarking electricity networks • potential applications of benchmarking techniques	Dec-12
AER workshop – general guideline consultation - Initiation roundtable	Feb-13
Economic benchmarking workshop on outputs	Mar-13
Economic benchmarking workshop on inputs	Mar-13
Economic benchmarking workshop on measurement of outputs and environmental factors	Apr-13
Economic benchmarking techniques workshop on network input measurement	May-13
Preliminary RIN templates circulated for comment	Jun-15
Revised preliminary RIN templates circulated for comment	Jul-13
Draft Economic benchmarking RINs released	Sep-13
Draft expenditure forecast guideline released	Aug-13
Workshop RIN auditing requirements & economic benchmarking data requirements	Oct-13
Final expenditure forecast assessment guideline released	Nov-13
Final RINs for economic benchmarking released	Nov-13

Milestone	Date
AER answers questions regarding how the economic benchmarking RIN templates are to be completed.	Nov 14
Unaudited RIN responses received AER initiates comprehensive review of RIN data. Review includes: • Comparing RIN information with information previously reported by service providers to ensure consistency such as regulatory proposals, previous RIN responses and service provider annual reports • reviewing time series data to identify any anomalous data points • Reviewing basis of preparation to ensure that data has been prepared in accordance with EBT RIN instructions and definitions • Comparing data across service providers to identify potential anomalies.	Mar-14
Final audited RIN responses received	Apr-14
Benchmarking data released for public consultation	May-14
Draft benchmarking report and data circulated to NSPs and other stakeholders	Aug-14

We have, therefore, consulted widely with stakeholders regarding our approach to assessing expenditure forecasts. These consultations have included discussions on how we should use benchmarking in our analysis. During this process, some service providers raised concerns similar to those filed in their responses to the NSW/ACT draft decisions. These include submissions that:

- our approach is inconsistent with the NEL and NER
- we have placed excessive weight on benchmarking in our approach[147]
- we must give primacy to service provider's regulatory proposals in assessing or determining an opex forecast
- we are required to (and have not) had regard to the service providers' individual circumstances
- our benchmarking approach is flawed
- our approach ignores the constraints and obligations the service providers face so the result is unrealistic.

Some service providers have also raised additional issues subsequent to the consultation process, the RINs, our annual benchmarking report and the NSW/ACT draft decisions.[148] This includes material prepared as early as 2012 which was,

147 For example. Huegin Consulting, *Submission on the AER Expenditure Guidelines: A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 10 and p. 13.

148 For example, in the explanatory statement to our expenditure forecast assessment guideline, we ask no less than 24 questions on economic benchmarking. In their submission on the explanatory statement the NSW service providers did not address any of these questions despite having multiple reports that were relevant. AER, *Better Regulation, Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues paper*, December 2012, pp 88–91.

unfortunately, not provided to us by service providers until after we had published the NSW/ACT draft decisions.[149] Issues raised in this material include:

- the sensitivity of data envelopment analysis to input and output specifications and sample size
- there is additional benchmarking data and variables that should be considered by us in making our assessments.

We acknowledge that many aspects of our decision making relate to forward looking, technical and difficult matters, on which reasonable minds can differ. However, it is important to distinguish different decisions which we potentially could have made in exercising our discretion from a substantive reason why our decision is or would be unreasonable or incorrect. As the Tribunal has noted:[150]

> It is axiomatic that there will be no one correct or best figure derived from a forecast that in terms of cl 6.5.6(c) 'reasonably reflects' the opex criteria – the very nature of forecasting means that there can be no one absolute or perfect figure. Different forecasting methods are more likely than not to produce different results. Simply because there is a range of forecasts and a distributor's forecast falls within the range does not mean it must be accepted when, as here, the AER has sound reason for rejecting the forecast.

We have had careful regard to the new submissions and concerns raised by service providers. We encourage all stakeholders to actively, transparently and cooperatively participate in our consultation processes as that assists all stakeholders in delivering the best outcomes in accordance with the legislative framework.

A.3.2 How our approach is consistent with NER requirements

We consider that our assessment approach is consistent with the requirements of the NER. That is, we consider that our approach to assessing and, if required, substituting a service provider's proposal is consistent with:

- the opex criteria[151]
- the opex objectives
- the opex factors
- the revenue and pricing principles.

Fundamentally, we consider that our decision is likely to contribute to the achievement of the NEO by incentivising and funding efficient, prudent and realistic expenditures. We take this view because our approach:

---

149 For example: Evans & Peck, Review of factors contributing to variations in operating and capital costs structures of Australia distributors, Final Report, November 2012; Huegin Consulting , Distribution benchmarking study, 2012

150 Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11 at [69]

151 The opex criteria broadly reflect the NEO as noted by the AEMC, Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, p. 113.

- ensures that the opex forecast reasonably reflects the efficient costs a prudent service provider requires to safely and reliably provide electricity services; and
- encourages service providers to efficiently invest and operate electricity services, by ensuring that service providers (and not consumers) bear the cost of expenditure in excess of prudent and efficient.[152]

Incentives can only be effective if the service providers, rather than consumers, bear the burden of funding spending that does not reasonably reflect the opex criteria.

Opex criteria

The opex criteria in clause 6.5.6(c) of the NER require the AER to assess a service provider's proposal to decide whether it reasonably reflects:

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

We consider that the opex criteria work together as a single overall requirement.[153] Prudency and efficiency are complementary.[154] The Australian Competition Tribunal refers to them as a unified concept, and has described them as a single "prudent and efficient requirement".[155]

In turn, "prudent and efficient" costs can only be sensibly given meaning by reference to the demand forecast for the services the service provider provides and the realistic cost inputs that a prudent and efficient provider would require to achieve its opex objectives. When we refer to prudent and efficient costs, we mean costs that a prudent and efficient provider would require, having regard to realistic expectations of cost inputs and the demand forecast to achieve its objectives.

Importantly, the demand forecast and cost inputs are for those of a prudent and efficient service provider operating that network. They are not the cost inputs which

---

153 The Tribunal has applied the term in this fashion in at least the following matters: Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by United Energy Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA) Transmission Pty Ltd [2012] ACompT 6

154 AEMC, *Draft rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, p 76.

155 Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 at 199; Application by EnergyAustralia and Others [2009] ACompT 8 at 141, citing reports prepared by service providers and the NER from 2008.

result from previous inefficient decision making. This does not mean that we do not take account of circumstances or factors which are beyond the control of a service provider when making our assessment.

It is inherent in the opex criteria, each criterion being concerned with the costs of achieving the opex objectives that we must have regard to an objective prudent and efficient service provider. However, in doing so, we must also have regard to the differing exogenous circumstances of the service provider we are assessing when making our decisions. This includes costs that arise due to the individual circumstances affecting the manner in which the service provider operates, but over which it does not have control. Such circumstances include geographic factors, customer factors, network factors and jurisdictional factors.[156]

However, the costs that reasonably reflect the opex criteria do not include costs that result from prior inefficient or imprudent spending. These costs may relate to the quality of management or financial decisions. Such factors are within a service provider's control and are inconsistent with costs that a prudent and efficient service provider would incur. This remains the case where a service provider has used revenue recovered by consumers in previous regulatory periods, consistent with our previous decisions, to make such decisions. This view is consistent with the incentive based aims of the regulatory scheme when read as a whole.

It is also consistent with the rationale provided by the AEMC for removing the phrase "individual circumstances" from the opex criteria.[157] Accordingly, we disagree with an interpretation of the opex criteria that a forecast which reflects a "realistic expectation of cost inputs" must take account of past discretionary decisions made by a service provider that bind the service provider, but do not reflect the efficient costs that an objectively prudent operator would incur. This is the case even if, as discussed below, those costs are contractually fixed.

Our approach also satisfies the requirement in the opex criteria that we determine a *total* forecast opex.[158] We are not required to assess individual projects or components of a forecast because such an approach would de-incentivise efficient and prudent discretionary spending and would effectively result in a cost of service regime.[159]

The total forecast opex is forward looking and directed towards the requirements of an objectively efficient and prudent operator in the future, which will then be funded by consumers through the building block revenue model established under the NER.

---

[156] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113. See also pp. viii, 25, 98, 107–108.

[157] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp 107, 113.

[158] NER, cl. 6.5.6(a).

[159] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 No.9* at 93.

We must estimate a total forecast which we are satisfied *reasonably reflects* the opex criteria. We use this estimate as a comparator for the service provider's proposal and as a substitute if required. As the AEMC and the Tribunal have identified, the NER gives us broad discretion in how we perform this task.[160]

In this context, we take the view that the opex criteria should be understood as applying an objective test—albeit a test that applies to a particular network and must therefore incorporate certain individual circumstances of that network. The intention behind the regulatory regime is to determine an objective forecast for the operating costs of the network that should be funded by consumers. If a service provider can better this forecast in its actual spending it is rewarded with the cost savings. If it overspends the forecast it bears the costs.

We therefore consider that an appropriate application of the opex criteria involves us making an assessment about what objectively would be:

- the efficient costs of achieving the opex objectives, rather than the actual costs a service provider has spent or intends to spend
- the costs that a prudent service provider for that network would require (rather than the actual costs the actual service provider in question intends or is contractually obliged to provide given all their circumstances and past decision making)
- a realistic expectation of the demand forecast (rather than the service provider's own demand forecast) and
- a realistic expectation of the cost inputs to achieve the objectives (not the actual cost inputs that the provider might incur, or have committed itself to spend money on, to achieve the opex objectives).

It follows, as the Tribunal has noted, there is unlikely ever to be one unique "correct" total forecast. Reasonable minds may differ as to the data and techniques.[161] The AEMC has also recognised this.[162] We expect and observe service providers and their consultants to disagree with aspects of our decision.

Opex objectives

Our assessment approach ascertains the total forecast opex for a prudent and efficient service provider, informed by a realistic expectation of the demand forecast and cost inputs, to achieve the opex objectives. One of these objectives is the applicable 'regulatory obligations or requirements' that the service provider must meet that are associated with the provision of standard control services.[163] Service providers are also

---

160 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp 165.

161 Application by Envestra Limited (No 2) [2012] ACompT 3 at [146] , approved of in Application by APA GasNet Australia (Operations) Pty Limited (No 2) [2013] ACompT 8 at [232].

162 AEMC*, Economic Regulation of Transmission Services, Rule Determination*, 16 November 2006 at 50, 52, 53.

163 NER cl. 6.5.6(1).

expected to comply with regulatory obligations under the RPP in the NEL.[164] The other opex objectives relate to safety, demand and, to the extent they are not regulatory obligations, reliability and security levels.

In acting to fulfil the opex objectives and having regard to the RPP, we therefore have close regard to the definition of 'regulatory obligation or requirement' in the NEL.[165] This definition is exhaustive. That is, only matters within the terms of the definition constitute 'regulatory obligations or requirements'.

To fall within the NEL definition, a regulatory obligation or requirement must be attributable to one of the following categories:

- distribution system safety duties
- distribution reliability standards
- distribution service standards
- obligations under the NEL, NER, NERL and NERR
- obligations under legislation in a participating jurisdiction levying tax, regulating the use of land or protecting the environment
- an Act or instrument of a participating jurisdiction that materially affects the provision of electricity network services.

A participating jurisdiction is defined as a jurisdiction which has, in force, a version of the NEL.[166]

Accordingly, it is clear that the definition of 'regulatory obligations or requirements' is limited in application.[167] We have assessed claims by service providers in a manner consistent with this definition and the NSW/ACT draft decisions. Because this definition in the NEL is limited to the matters set out above, we do not consider that the following constitute 'regulatory obligations or requirements' as defined in the NEL:[168]

- obligations at common law, tort and contract (such as common law duties of care in negligence)
- obligations to comply with legislation that is not from a participating jurisdiction
- obligations to comply with legislation that is from a participating jurisdiction, but which does not fall into the categories identified in the definition in the NEL.

164 NEL, s. 7A(2)(b).

165 NER chapter 10, definition of 'regulatory obligation or requirement' and NEL, s2D.

166 NEL s 5. This means that only jurisdictions which have passed a version of the NEL are participating jurisdictions.

167 See Second reading speech, National Electricity (South Australia) (NEL -Miscellaneous Amendments) Bill 1996, p. 6.

168 Although these obligations may be informed by other requirements that do meet the definition.

For example, all legal persons (including corporations such as service providers) are required to comply with the requirements of the Australian Consumer Law.[169] These requirements are imposed by participating jurisdictions as well as by the Commonwealth. However, they do not fall into the NEL definition outlined above.

We therefore disagree with submissions which assert that a variety of requirements are 'regulatory obligations or requirements' under the NEL. For example, 'laws of general application to corporations and individuals, such as the Competition and Consumer Act, Corporations Act, Privacy Act, intellectual property legislation or motor traffic legislation'[170] are not 'regulatory obligations or requirements'.

It is unclear whether or not these submissions consider obligations to comply with laws of general application fall within the categories defined in the NEL. Regardless, for the reasons set out above, we do not consider that any of these obligations are a 'regulatory obligation or requirement' within the meaning of section 2D (and, by extension, section 5) of the NEL.

We also disagree with the service providers' submissions that compliance with the terms of their own EBAs[171] is a 'regulatory obligation or requirement'. For example, service providers have referred to redundancy costs 'required to be paid as a regulatory obligation'.[172]

First, of the six possible (and exhaustive) categories of obligations or requirements mentioned above, EBAs could conceivably only fall with an Act or instrument made or issued that 'materially affects a service provider's provision of electricity network services'. This is because the terms of an EBA could plausibly materially affect a service provider's provision of standard control services. However, that Act or instrument must be made by a 'participating jurisdiction'. Given a participating jurisdiction must have passed a version of the NEL, an EBA made under the Commonwealth's *Fair Work Act 2009* appears to be imposed by a law other than of a participating jurisdiction.[173] Further, the terms of an EBA itself are not contained in the *Fair Work Act 2009.*

Second, the consequences of breaching the *Fair Work Act 2009* are a separate and narrower subset of the potential consequences of a service provider breaching its EBA.

[169] Schedule 2 to the Competition and Consumer Act 2010 (Cth), various equivalents in state legislation identical terms.

[170] ActewAGL, *Revised proposal* at 2, 4.

[171] Pursuant to the *Fair Work Act 2009 (Cth)*.

[172] Implied by Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, pp. 32–34.

[173] The Commonwealth has not passed a version of the NEL so it is not a participating jurisdiction for the purposes of section 5 (and hence, section 2D) of the NEL. Commonwealth laws are 'regulatory obligations or requirements' if they fall within section 2D(1)(a). These relate to safety duties, reliability and service standards. However, commonwealth laws that fall within section 2D(1)(b), insofar as it refers to a 'participating jurisdiction', do not.

Third, we consider that the interpretation advocated by submissions is contrary to the requirement in clause 6.5.6(a) for a proposal to include the total forecast opex for a regulatory control period. It is important to note that when we determine total forecast opex, we do so within an overall incentive framework that requires the service provider to decide how to spend its allowed revenue requirement. As we mention above, a requirement that we consider the terms of EBAs when forming a view on total forecast opex would be more akin to a cost of service regime than an incentive regime.

Fourth, we note that while contractual or other obligations which do not fall within the definition are not regulatory obligations or requirements so defined, a service provider can still direct the revenue it recovers from customers (or from other sources) to comply with such obligations. The costs of compliance with obligations that are not within the definition of 'regulatory obligation or requirement' are treated like any other costs a service provider incurs.

Service providers have broad discretion about the contractual arrangements they enter into, and often have discretion about the manner in which they carry out their legal obligations. This discretion often includes whether to enter into particular legal obligations, such as employment contracts or arrangements with contractors.

We do not seek to interfere in the discretion a service provider has as to how and when to spend its total opex forecast to run its network. The service provider is free to decide how to manage its activities in light of the revenue recovered from consumers that we approve. Equally, the service provider bears the consequence of imprudent or inefficient decisions, including those relating to cost inputs or its response to demand forecasts. When a service provider enters into an agreement of any kind, it does so in the full knowledge that the forecast will apply for five years, without any guarantee that the same or a similar forecast will be approved for the following five year period.

As the AEMC notes, this underpins the incentive properties of the regulatory regime:[174]

> The level, rather than the specific contents, of the approved expenditure allowances underpin the incentive properties of the regulatory regime in the NEM. That is, once a level of expenditure is set, it is locked in for a period of time, and it is up to the NSP to carry out its functions as it sees fit, subject to any service standards.

Accordingly, where a service provider has entered into an EBA which requires it to incur expenditure that, objectively, would be viewed as inefficient or imprudent or involving cost inputs that an objectively prudent provider would not be realistically expected to incur, it is for the service provider to bear the costs of its decisions.

Once we determine the opex forecast we are satisfied reasonably reflects the opex criteria, it is for a service provider to manage its business as it sees fit. It is for the service provider to decide whether or not to fund particular projects, strategies or

---

174 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 93.

commitments to meet the demand for standard control services, comply with regulatory obligations and maintain safety and reliability. Our role is not to dictate how service providers spend money to comply with their broader obligations. We fund service providers so that if they are efficient and prudent, they will have sufficient opex to achieve the objectives.

Opex factors

We must take the opex factors into account in making our assessment of whether a service provider's proposed forecast reasonably reflects the opex criteria. In this way, they function similarly to the revenue and pricing principles. That is, they require us to have regard to matters, but give us discretion as to the weight we should apply to each.[175]

Our approach has regard to each of the opex factors set out below:

- 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

[175] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 101.

- 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.

However, for assessing base opex, we have exercised our discretion to emphasise the following factors specified in clause 6.5.6(e):

- the benchmark opex that would be incurred by an efficient service provider—we have had regard to the analysis and techniques used in our recent annual benchmarking report but we have also used other techniques in addition to those discussed in that document
- recent operating expenditure—we use the operating expenditure of the service provider in previous periods, particularly the most recent as a key input into our approach
- the relative prices of operating and capital inputs—we use input prices to trend base opex such that the total forecast opex allowances reasonably reflect a realistic expectation of demand forecast and cost inputs.

We will also have regard to the following opex factors which we consider relevant:[176]

- 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.

We identified our preference for using econometric techniques in our explanatory statement to the Guideline.[177]

The NER were specifically amended to allow us to take account of additional factors.[178] Service providers were on notice of our intention to use benchmarking from the 2012 rule change. We consider that these factors are particularly relevant to our approach

176 Consistent with our decisions for the NSW and ACT service providers.

177 AER, *Expenditure Forecast Assessment Guideline–Explanatory Statement*, November 2013, p. 131.

178 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 101.

to assessing the service provider's opex forecast and, if necessary, substituting our own opex forecast.

We have used our discretion to give weight to the opex factors which we consider are most relevant to our approach. The AEMC has recognised our discretion in this regard:[179]

> 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.

We have received submissions stating that we have placed unreasonable weight on benchmarking and "almost solely" relied on it as a deterministic or mechanistic tool.[180] They consider benchmarking is but one of the opex factors relevant to forming a view on whether total forecast opex proposals reasonably reflect the opex criteria. Additionally, they consider the NER seek we undertake a broader examination of a service provider's proposal.[181] Some submissions also state that the purpose of the benchmarking factor is:[182]

> ...for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data.

We disagree and consider we have had appropriate and reasonable regard to benchmarking, together with other techniques.

We agree that benchmarking is one of several opex factors that we are required to 'have regard to'. However, as we explain above, we have discretion as to how we have regard to each opex factor, including how much weight we attach to them. Indeed, the AEMC has stated that we may decide certain factors are not relevant.[183] We explained this in the explanatory statement to the Guideline.[184]

We consider it appropriate to give prominent, but not overwhelming weight to benchmarking base opex based on the robustness of the data and techniques and its utility in overcoming information asymmetry and in providing comparisons amongst firms in the NEM. Many stakeholders agree with this approach.[185] Our decision to use

---

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

180 Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*; pp. 10, 23; Ausgrid, *Revised Regulatory Proposal*, January 2015, pp. 15, 134–139.

181 Ausgrid, *Revised Regulatory Proposal*, January 2015, pp. 15, 134–139.

182 Ausgrid, *Revised Proposal*, January 2015, p. 126; Endeavour Energy, *Revised Regulatory Proposal*, January 2015, p. 100; Essential Energy, *Revised Regulatory Proposal*, January 2015, p. 107.

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

184 AER, *Expenditure Forecast Assessment Guideline–Explanatory Statement*, November 2013, p. 22.

185 For example, Origin Energy, *Submission to Queensland Electricity Distributors' Regulatory Proposals*, 30 January 2015, pp. 11–15; AGL, *Energex Regulatory Proposal: July 2015 to June 2020 - AGL submission to the Australian*

benchmarking techniques in our assessment of opex is consistent with the recommendations of the Productivity Commission,[186] the Australian Government's response to those recommendations[187] and the AEMC's intent:[188]

> The Commission considers that benchmarking is a critical exercise in assessing the efficiency of a NSP and approving its capital expenditure and operating expenditure allowances.

Neither the NER nor the AEMC's Final Rule Determination requires us to use benchmarking only as a means of identifying issues for further investigation, as some service providers have suggested.[189]

We also consider that our benchmarking approach is well supported by the available evidence. We have had regard to the criticisms of this approach, in their proper context of a proposed model followed by subsequent analysis and critique.

Some submissions consider that our reliance on benchmarking would amount to an error of law which ought to result in the invalidity of our decision should we maintain that approach in the final decision.[190]

We disagree with this view because the NER specifically require that we undertake benchmarking, not just arising from the benchmarking opex factor, but also from the opex criteria themselves. As we mention above, the criteria require that we examine efficient costs that an objectively prudent operator would require to achieve the opex objectives.[191] This invites a comparison of service providers. Additionally, the AEMC highlighted the importance of benchmarking in its changes to the NER in November 2012:[192]

> 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 efficiency over time, and relative to the efficiency of other service providers.

Energy Regulator, 30 January 2015, pp. 7–9; Consumer Challenge Panel, *CCP2 Panel Submission on Energex and Ergon Energy Capex and Opex Proposals*, 30 January 2015, pp. 16–26.

186 Productivity Commission, *Electricity network regulatory frameworks – inquiry report, Volume 1*, 9 April 2013, pp. 2–3, 187.

187 Australian Government, *The Australian Government response to the Productivity Commission inquiry report – Electricity Network Regulatory Frameworks*, June 2013, pp. i–ii, 3–9.

188 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. viii, 107, 113.

189 For example, Frontier Economics, *Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW*, January 2015, p.10.

190 e.g. ActewAGL, *Revised Regulatory Proposal*, 2.3.1, when read with section 2.2.4.

191 NER, cl. 6.5.6(c).

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

In previous regulatory periods, we have applied a revealed cost methodology to forecast opex. We have previously not been in a position to assess the efficiency of base opex when applying the revealed cost methodology because we did not have reliable benchmarking data and techniques to make that assessment.[193]

In this decision, we also use revealed costs. However, we now have reliable and robust data that allow us to assess relative efficiency and, where that assessment demonstrates that revealed costs are materially inefficient, to develop an alternative forecast. In this decision, we have been able to benchmark service providers' opex using various benchmark modelling techniques. We have also applied a range of other quantitative and qualitative techniques to test the validity and consistency of the results. We have:

- used category analysis, which allows us to examine specific key cost drivers between businesses
- conducted detailed reviews of certain historical and proposed opex, such as labour costs.

These approaches are set out in more detail in section A.5.

We have also decided to change the benchmark comparison point, which takes the lowest efficiency score of the service providers in the top quartile of possible efficiency scores rather than the frontier performer (CitiPower). Lowering the benchmark comparison point is an option suggested in response to our draft decision.[194]

We do not agree that adjusting base opex through benchmarking constitutes an unfair post hoc review or disregards our past decisions.[195] Submissions to this effect misunderstand the purpose of our forecasting approach. The purpose of adjusting revealed costs for benchmarking is not to take back funding allocated in a previous regulatory period. It is to properly assess whether the proposed forecast for the upcoming regulatory control period reasonably reflects the opex criteria. That adjustment is based on an assessment of actual historic costs we know have been sufficient to enable service providers to achieve the opex objectives.

Our economic benchmarking models suggest that there has been a longstanding efficiency gap between the NSW, ACT and Queensland service providers and those in other parts of the NEM.[196]

If our benchmarking indicated that the proposed base year opex was relatively efficient, those revealed costs would remain the starting point for assessing future expenditure. Where benchmarking reveals that base opex costs are not a good proxy

---

[193] See AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, p. 11.

[194] For example, PEG, *Statistical Benchmarking for NSW Power Distributors*, 19 January 2015, p 64

[195] For example, Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, pp. 9–10.

[196] See, for example, AER, *Draft Decision, Attachment 7*, section A.3; AER, *2014 Annual Benchmarking Report*, November 2014.

for future forecasts, we are able to take account of this information and adjust the base opex accordingly.

Some service providers suggested that our decision to adjust base opex means that we have not had regard to our previous decisions, or that a step change had occurred from revealed costs to benchmarking.[197]

We do not consider that taking account of further information, which we have collected in compliance with an express requirement in the NER, constitutes a lack of regard to our past decisions. Nor do we consider it a step change. It is not an unavoidable change in activity due to an external obligation.[198] As set out above, we do not require service providers to spend revenue they recover from consumers on any particular activity, nor do we limit or require their spending to this amount.

All stakeholders should expect us to use new techniques and information when they become available.[199] We have not moved away from revealed costs. Rather, we have used new techniques to ensure that we are better able to make a decision that reasonably reflects the opex criteria for the future. Our approach represents a refinement of our longstanding approach to assessing opex.

As set out above, our intention to use benchmarking has been the subject of an AEMC rule change and extensive consultation. The results of our benchmarking indicate that previous incentive signals and schemes used to motivate service providers were not sufficient.

Our approach gives due regard to the service providers' proposals and individual circumstances

Broadly, service providers have submitted that by relying on benchmarking as part of our assessment approach, we have:

- not started our assessment with their regulatory proposals or examined which aspects of their proposals involve inefficient expenditure in any level of detail[200]
- failed to comply with the NER requirements to have regard to their individual circumstances.[201]

---

197 ActewAGL, *Revised Regulatory Proposal*, p. 50; Ergon Energy, *Submission on Draft Decision*, p. 9.

198 See Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11 at [194](d)

199 We have indicated in previous decisions and in defending those decisions our preference to use up to date information where possible. The Tribunal has endorsed this approach and indicated a similar preference: see for example Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11 at [61] to [62].

200 Ausgrid, *Revised Regulatory Proposal*, pp. 27, 122, 134–136; Networks NSW, *NSW distributors' submission on the AER's draft determinations*, 13 February 2015, pp. 6–9.

201 Ausgrid, *Revised Regulatory Proposal*, pp. 10, 151–153.

The service providers' proposals

We consider that we have had due regard to the service providers' opex proposals. As outlined by the AEMC[202] and in our assessment approach, we start by looking at the service provider's proposal. Our assessment approach is built around a mechanism to assess the proposal to determine whether it reasonably reflects the opex criteria. Where we find the service provider's proposal does not reasonably reflect the opex criteria, we use that same mechanism to determine an alternative forecast.

As we discussed in the explanatory statement to the Guideline, information asymmetry and the inherent incentive to inflate expected expenditure needs means that we must test the service providers' proposals robustly.[203] Benchmarking is, in our view, an appropriate means of doing this and is consistent with the AEMC's intent:[204]

> Importantly, though, [the NSP's proposal] should be only one of a number of inputs. Other stakeholders may also be able to provide relevant information, as will any consultants engaged by the AER. In addition, the AER can conduct its own analysis, including using objective evidence drawn from history, and the performance and experience of comparable NSPs. The techniques the AER may use to conduct this analysis are not limited, and in particular are not confined to the approach taken by the NSP in its proposal.

Further, we have engaged closely with the assumptions and submissions in the proposal. For example, we have engaged in a detailed assessment of operating environment factors (see section A.6). We also explicitly examined the service providers' proposals and undertook a detailed review of reasons for their benchmarking performance (see section A.5). Finally, a key step in our overall opex assessment approach is to assess the service provider's proposed forecasting approaches (see appendix D).

Individual circumstances

Our base opex assessment approach gives extensive regard to the service providers' circumstances, as required by the NER and in accordance with the intent of the AEMC. The individual circumstances of a service provider can be exogenous (beyond their control) such as topography and climate, or endogenous (within their control) such as their approach to contracting. The AEMC expressed how it envisaged benchmarking would be applied as follows:[205]

> The final rule gives the AER discretion as to how and when it undertakes benchmarking in its decision-making. However, when undertaking a

[202] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 90, 95, 96, 111,   See also: AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, p. 7.

[203] AER, *Expenditure Forecast Assessment Guideline–Explanatory Statement*, November 2013, pp. 27–28.

[204] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 111–112.

[205] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113. See also pp. viii, 25, 98, 107–108.

> benchmarking exercise, circumstances exogenous to a NSP should generally be taken into account, and endogenous circumstances should generally not be considered. In respect of each NSP, the AER must exercise its judgement as to the circumstances which should or should not be included.

Individual circumstances are taken into account throughout our approach (including benchmarking):

- First, the benchmarking techniques which we use to compare service providers take into account many of their individual circumstances, most notably their key network characteristics[206] and their actual operating expenditure.
- Second, this process disaggregates those circumstances which we consider reflect inefficiency from those which are exogenous or uncontrollable factors.
- Third, we make appropriate adjustments to the benchmarking results based on findings from other techniques such as detailed review and analysis of operating environment factors. This is consistent with our discretion to make appropriate and transparent decisions on a case by case basis.[207]

We disagree with those service providers who submit that having regard to their circumstances preclude us from giving substantial weight to benchmarking. The clear intention of the AEMC was to remove restrictions on the AER's use of benchmarking:[208]

> The Commission considers that the removal of the "individual circumstances" phrase will clarify the ability of the AER to undertake benchmarking. It assists the AER to determine if a NSP's proposal reflects the prudent and efficient costs of meeting the objectives.

Our approach gives substantial weight to the individual circumstances of the service provider that are relevant to our task, whilst allowing us to use benchmarking as part of our approach.

A.3.3 Our approach is consistent with incentives

Some service providers have submitted that they developed their current business structure in good faith reliance on our prior determinations on what is efficient opex. They submit, therefore, that if they are required to align expenditure with a reduced level of opex determined by a new and substantially different method, then the reasonable costs incurred in the course of doing so must be considered to be efficient.[209]

---

[206] Depending on the technique, we account for line length, customer density, energy density, demand density, reliability, degree of undergrounding etc.

[207] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 10.

[208] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 107, 113.

[209] For example, ActewAGL, letter to Paula Conboy, 4 March 2015, p. 2.

In making this statement, these service providers appear to misunderstand the basis of our forecasting approach. We do not determine that past spending against a previous forecast is inefficient if it is below the forecast total opex we previously approved. Rather, we reward this lower actual expenditure through the EBSS.

However, that does not mean that a past level of expenditure is appropriate for making a forecast of costs against the opex criteria for a future regulatory control period. The NER is an incentive framework. The opex forecast we approve, together with the relevant schemes, provide bonuses for improving efficiency while maintaining or improving service standards, beyond the previous period's revealed costs. This regime encourages businesses to be as efficient as is prudent to beat the total opex forecast and continuously improve their efficiency. In that context, a network business should not be expecting to receive historical costs whenever a new forecast of total opex is assessed.

The AER makes decisions on the basis of the relevant evidence it has before it at the time. In 2010, on the basis of the evidence before us, and also having regard to the circumstances in which we made our decision, we determined what we considered to be an appropriate basis for forecasting total opex for the period 2010–15.

We have additional evidence now, through more detailed benchmarking. As we note above, our benchmarking results indicate that several service providers spend considerably more on a standardised basis than other businesses in the NEM to provide services in a manner that achieves the opex objectives. In assessing future forecasts we need to have regard to this new information.

One of benchmarking's positive attributes is that it increases the incentive to reduce opex. This is something that HoustonKemp acknowledges.[210] We consider that this increased incentive reflects a decision that is in the long term interests of consumers and reflects the opex objectives.

Despite this, HoustonKemp considers that our approach is inconsistent with the NEO.[211] We disagree. If benchmarking shows a service provider's revealed opex is materially inefficient, it is not possible to set an opex forecast based solely on revealed expenditure that is consistent with the opex criteria. Such an approach would ignore relevant considerations and techniques which we regard as robust and important. The AEMC agrees.[212] In such circumstances, therefore, benchmarking will deliver an alternative forecast that achieves the NEO to a greater degree than revealed expenditure.

---

210 HoustonKemp, *AER Determination for ActewAGL Distribution - Contribution to NEO and preferable NEO decision*, 13 February 2015, pp. 26–27.

211 HoustonKemp, *AER Determination for ActewAGL Distribution - Contribution to NEO and preferable NEO decision*, 13 February 2015, pp. 26–27.

212 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 107, 113.

A.3.4 The benchmarking we rely on in our approach is robust, reliable and reasonable

Service providers have submitted that our benchmarking is fundamentally flawed because:[213]

- our analysis is not robust
- we have made errors in the application of our models
- we should have regard to conceptual limitations of benchmarking, particularly given the heterogeneity of Australian service providers
- the RIN data used in the benchmarking contains problems
- there has been a lack of testing and peer review.

Economic Insights responds to these submissions in detail in its report, and we explain in section A.2 why benchmarking is appropriate in the context of our ex ante regulatory framework. We also outline why our benchmarking is robust, reliable and reasonable in section A.4. Further, we demonstrate the alternative approaches proposed by the service providers are not robust. For example, some of the alternative approaches proposed by the service providers:[214]

- misunderstand the rationale for using international data and, consequently, the manner in which Economic Insights has used it
- include outputs that reflect secondary cost drivers rather than functional outputs, which can reward inefficient practices
- exclude key functional outputs—CEPA, for example, presents a function with only one or two outputs, which is not adequate to accurately model service provider cost characteristics
- inappropriately incorporate some operating environment variables without considering their potential effect on the model—depending on the estimation method used, the 'capital intensiveness' (or equivalent) variable, for example, overstates the opex efficiency of the ACT, NSW and QLD service providers simply because they own assets with a capacity of more than 66kV
- suggest the inclusion of many unjustified operating environment variables, which can undermine the ability of a model to explain the relationship between inputs and outputs
- use estimation methods that are not robust because of the underlying assumptions they make about the nature of inefficiency.

---

213 For example, Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2013, pp. 9–22; Ausgrid, *Revised Regulatory Proposal,* pp. 129–153.

214 Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, section 3.

In this section, we set out some general principles regarding the nature of benchmarking.

This decision is the first time that we have had sufficient information to conduct rigorous benchmarking analysis. However, we have done so over a long consultation period, using data provided and cross-checked by the service providers themselves. We have used benchmarking analysis in a way that acknowledges benchmarking cannot produce a single "right" answer—but we also rely on benchmarking as an important technique for assessing base opex.

Frontier Economics agree that no single "right" answer exists. It acknowledges both the power of benchmarking and the impressive knowledge the AER's expert (Economic Insights) brings to the subject matter.[215] Huegin makes the same point.[216] Huegin also notes that "the approach that appears to be most common in regulatory jurisdictions around the world is to use a combination of results from different benchmarking techniques to arrive at relative levels of efficiency between businesses."[217]

Accordingly, the level of confidence we require to use benchmarking is that which assists us in being satisfied or dissatisfied that a proposal or comparative estimate reasonably reflects the opex criteria. We are confident that our approach provides us with the necessary comfort to use benchmarking in this way. We therefore disagree with the submission by Frontier Economics that we have placed undue reliance on our benchmarking approach.[218] We do not agree with suggestions by service providers that:[219]

- Australian data is unreliable
- international data is inapplicable, and
- our benchmarking results do not accord with sensibility checks.[220]

The Australian data was supplied by the service providers themselves, in accordance with our compulsory information gathering powers. We required Australian data provided by service providers to be audited and certified by statutory declaration by the

215 Frontier Economics: *Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW,* January 2015, p. vii.

216 Huegin, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL Technical response to the application of benchmarking by the AER*, 16 January 2015, pp. 7, 13.

217 Huegin, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL Technical response to the application of benchmarking by the AER*, 16 January 2015, p. 11.

218 Frontier Economics*: Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW*, January 2015.

219 Frontier Economics: *Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW*, January 2015, pp. vii, ix.

220 Endeavour, *Revised Regulatory Proposal*, p. 179; Ausgrid, *Revised Regulatory Proposal*, pp. 150–153; Essential, *Revised Regulatory Proposal*, p. 189.

CEOs of the service providers. We obtained international data from comparable jurisdictions where similar analysis had previously been conducted.[221]

As we explain in section A.4, we have conducted detailed review of the Australian data, and the international data has been used by the regulators in the respective jurisdictions for determinations. Therefore, we consider that the data we have used for benchmarking is robust for this purpose. Economic Insights also considers that the data is sufficiently robust for benchmarking .The approach taken by Economic Insights produced a functional data set which is both consistent across benchmarking techniques, is dataset insensitive and has undergone significant testing and cross-checking.[222]

It is true that as service provides continue to provide audited information, the dataset will improve still further. However, this does not mean that we are not sufficiently confident at this stage to use benchmarking to assess base operating expenditure. We reject the suggestion that the EI approach is unreliable. The results it has produced are consistent with our other analyses, such as our detailed review of base year opex and our cross checking of our benchmarking results.

We have also considered our modelling in light of the service providers' operating environment factors and the potential for data and modelling issues. We have reviewed the operating environment circumstances that service providers proposed, or which we independently considered, might explain differences in costs compared to other jurisdictions. We have also conducted analysis using other techniques to cross-check the benchmarking results. We disagree, therefore, that we have not conducted 'sensibility checks' of our benchmarking.

Indeed, we have ultimately made cautious adjustments to the SFA benchmarking results to ensure that any adjustments to base opex:

- exclude differences caused by factors other than inefficiency
- appropriately account for potential data and modelling issues that could adversely affect the service providers.

The expert reports prepared for the service providers indicate distinct areas where the authors disagree with Economic Insights' draft decision report. However, benchmarking is something that reasonable minds will invariably differ on. As identified above, Frontier Economics and Huegin acknowledge this. Economic Insights' view is that its models are more robust than those produced by the service providers' consultants.

Therefore, for the reasons set out in section A.4 and Economic Insights' final decision report, we do not consider that these criticisms do more than identify alternative possible answers to the benchmarking question. We are not persuaded that Economic

[221] Economic Insights, *Economic Benchmarking of NSW and ACT distributor Opex*, 17 November 2014 at 29.

[222] Economic Insights, *Economic Benchmarking of NSW and ACT distributor Opex*, 17 November 2014 at 32.

Insights' approach is materially affected by the issues raised by the service providers' consultants. We remain satisfied that, despite expected disagreement about outcomes, our use of benchmarking in our assessment approach is consistent with the NER and the NEL.

A.4 Our benchmarking is robust, reliable and reasonable

In this section we set out our analysis of the benchmarking techniques we have used to test whether base year opex of the Queensland service providers is efficient. In particular, we set out why our approach and results are robust, reliable and reasonable. In doing so, we explain why our approach is preferable to those proposed by the service providers and their consultants in response to our draft determinations for the NSW and ACT service providers.

In this section we set out our benchmarking metrics that examine the efficiency of opex as a whole.[223] Category analysis metrics are considered separately in in section A.5.

A.4.1 Preliminary determination

Our decision is to rely on the same benchmarking analysis that we applied in our draft determinations for the NSW and ACT service providers to test the efficiency of the Queensland service providers' revealed opex. In coming to this view, we have considered the submissions of the service providers, their consultants and legal advisors, consumer representatives and other stakeholders.

We consider our benchmarking—including the data we have used—is robust, reliable and reasonable. In reviewing the alternatives put forward by the service providers' consultants we have identified shortcomings. Issues identified with the consultant's models include:[224]

- only using the Australian data set which has inadequate variation to support robust model estimation
- including inappropriate operating environment factors (such as a 132kV line variable) leading to inefficiency gaps being understated
- applying models that make inappropriate assumptions about the nature of inefficiency and hence allocate persistent inefficiency to operating environment differences
- applying models that will misleadingly find service providers to be 'efficient by default'

We summarise the key concerns and provide our responses in Table A.3. Economic Insights provides detailed responses in its report.[225]

---

223 These include our partial performance indicators, opex MPFP, and Econometric models.

224 Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, p. 53. (Economic Insights, 2015).

225 Economic Insights, 2015.

Table A.3 Summary of service providers' key benchmarking submissions and our response

Service provider submission	Our response	Reference
'Conceptual limitations' with benchmarking exist including:[226] 1. the inability to differentiate between observed cost differences due to inefficiency or something else 2. the heterogeneity of Australian service providers make it impossible to normalise for differences, leading to bias in the models 3. previous doubts about data quality and the scope to apply benchmarking by the AEMC, the PC, the AER and Economic Insights.	Conceptual limitations do not exist: 1. we have extensively examined the extent to which the efficiency gap could be driven by other factors in our operating environment factor assessment, to identify and quantity the impact of factors that are relevant and not already accounted for in the model 2. Australian service providers are comparable in using opex and capital input in providing electricity distribution services to customers. To the extent that operating environments are different, we have considered this under our ex-post operating environment factor assessment 3. prior comments about data quality and limitations of benchmarking are outdated. Our review and Economic Insights' review of the database indicates that it is sufficiently robust for the application of benchmarking techniques.	We discuss these submissions in section A.4.3 under: 1. Model specification, estimation methods 2. Model specification, estimation methods 3. Data.
Errors exist in the application of benchmarking, including: 1. using an untested and non-peer reviewed model[227] 2. inconsistent results[228] 3. use of a false frontier[229] 4. poor variable selection[230] 5. use of a dummy variable[231] 6. insufficient data preparation[232] 7. post model adjustments[233]	We have used a robust, reliable and reasonable approach that is not in error: 1. Economic Insights' models are informed by economic theory, engineering knowledge and industry. The draft decision provided for the service providers to engage their own experts to review Economic Insights model, and we have considered these reports. 2. The approaches taken by the service providers' consultants to criticise the model results are not sound	We discuss these submissions in section A.4.3 under: 1. Model specification 2. Efficiency results 3. We discuss this in the adjustments section. 4. Model specification and data 5. Data

226 Ausgrid, *Revised Regulatory Proposal*, pp. 130–142; ActewAGL, *Revised Regulatory Proposal*, pp. 125–134, attachment C12.

227 Ausgrid, *Revised Regulatory Proposal*, p. 143; ActewAGL, *Revised Regulatory Proposal*, pp. 150–153.

228 Ausgrid, *Revised Regulatory Proposal*, p. 143; ActewAGL, *Revised Regulatory Proposal*, pp. 146–149, 175–181.

229 Ausgrid, *Revised Regulatory Proposal*, pp. 143–144.

230 Ausgrid, *Revised Regulatory Proposal*, pp. 144–147; Herbert Smith Freehills, *AER Draft Decision – Forecast Operating Expenditure (confidential),* 13 February 2015, pp. 8–9.

231 Ausgrid, *Revised Regulatory Proposal*, p. 147.

232 Ausgrid, *Revised Regulatory Proposal*, pp. 143–150 and Herbert Smith Freehills*, AER Draft Decision – Forecast Operating Expenditure (confidential)*, 13 February 2015, pp. 10–11; ActewAGL, *Revised Regulatory Proposal*, pp. 140–146.

233 Ausgrid, *Revised Regulatory Proposal*, p. 150; ActewAGL *Revised Regulatory Proposal*, pp. 153–166.

Service provider submission	Our response	Reference
8. no reasonableness check of results.[234]	3. We consider Economic Insights' approach is more reasonable than the alternatives proposed by the service providers. 4. The variables included in the models are appropriate and international data is required for accurately estimating parameter estimates 5. The service providers' consultants have misunderstood the purpose of the international data and the role of country dummy variables. 6. The data is robust and reliable and the concerns raised by the service providers are misplaced. 7. Economic Insights' two stage approach is appropriate and indeed much more reasonable than alternatives proposed by the service providers' consultants. 8. We have conducted several reasonableness checks of the results including PPIs, category analysis and detailed review.	6. Data 7. Model specification 8. Efficiency results.
Advice from Herbert Smith Freehills specifically comments on Economic Insights' use of international data. Key comments include:[235] • Economic Insights' model is heavily reliant on overseas data • overseas data is not comparable with Australian data • Economic Insights does not adequately account for differences between countries • Economic Insights' data contains errors.	The service providers, their consultants and Herbert Smith Freehills have misunderstood how Economic Insights has used international data. Economic Insights has used the international data only to more accurately estimate parameter estimates, not as comparators for the Australian service providers. Further, Economic Insights considers submissions on the international data quality are misguided given that international regulators have used it for benchmarking and have undertaken similar testing and validation to the AER.[236]	We address these matters as part of our discussion on data in section A.4.3.
Our PPIs do not support the economic benchmarking results because: • we have not acknowledged the inherent limitations.[237] • per-customer metrics are biased against rural service providers and	Our view remains that PPIs are complementary to economic benchmarking and are an appropriate means crosschecking validity.	We address this submission in our discussion on PPIs in section A.4.3.

234 Ausgrid, *Revised Regulatory Proposal*, p. 151;Herbert Smith Freehills, *AER Draft Decision – Forecast Operating Expenditure (confidential),* 13 February 2015, p. 9.

235 Herbert Smith Freehills, *AER Draft Decision – Forecast Operating Expenditure (confidential),* 13 February 2015, pp. 6–8.

236 Economic Insights, 2015, pp. 20, 26.

237 ActewAGL, *Revised Regulatory Proposal*, pp. 181–187.

Service provider submission	Our response	Reference
do not show relative efficiency.[238]		

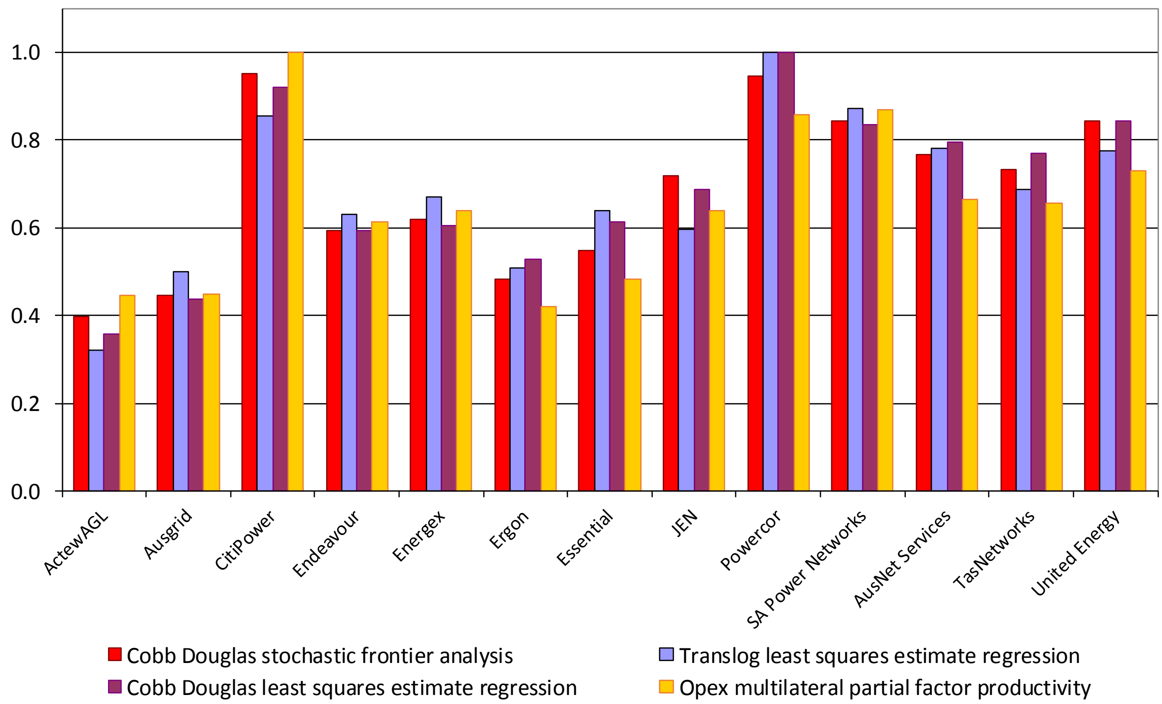
A.4.2 Benchmarking findings

We have applied six benchmarking techniques to assess the efficiency of the Queensland service provider's revealed expenditure. Four of these techniques (which were developed by Economic Insights) enable us to assess relative opex efficiency. On the basis of advice from Economic Insights, we relied on Economic Insights' Cobb Douglas SFA model as the preferred technique for this purpose. We have applied the same base year models for the Queensland service providers as we applied for the NSW and ACT service providers. This is because all of these service providers have proposed 2012–13 as their base year.

Figure A.5 presents the results of each of Economic Insights' four opex models (stochastic frontier analysis (SFA), econometric regressions and opex MPFP) for each service provider in the NEM. A score of 1 is the best score.

The red bars in Figure A.5 represent the SFA results. The best performing service provider under this model is CitiPower, with a score of 0.95. We refer to CitiPower as the 'frontier' firm.

Figure A.5 Econometric modelling and opex MPFP results (average efficiency scores for 2006 to 2013)



238 Essential Energy, *Revised proposal*, pp. 201–202.

Source: Economic Insights, 2014.

Each model may differ in terms of estimation method or model specification and accounts for operating environment circumstances (factors that may differentiate service providers) to differing degrees. Accordingly, the results will never be identical. However, Figure A.5 demonstrates that the results of the four models are consistent. All models show that the efficiency of the Queensland service providers revealed expenditure does not compare favourably with that of many of their peers.

The Cobb Douglas SFA model, being a statistical technique, directly estimates the efficient opex cost function. In doing so it takes into account economies of scale, density and the relationship between opex and the multiple outputs service providers face. Further the Cobb Douglas SFA model has a random error term that separates the effect of data noises or random errors from inefficiency.[239] It is, therefore, the most sophisticated of Economic Insights' economic benchmarking techniques.

We considered the two other econometric models (Cobb Douglas LSE and Translog LSE) provided useful cross checks for the Cobb Douglas SFA model. The Translog LSE model allows for a more flexible opex cost functional form incorporating second order coefficients. The LSE and SFA Cobb Douglas models both estimate efficiency using slightly different techniques. By running both methods we could observe whether the efficiency measurement technique made a material difference to relative efficiency performance.

Economic Insights found that all three econometric techniques produced consistent results:[240]

> The efficiency scores across the three econometric models are relatively close to each other for each distributor 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.

Additionally, we used opex MPFP and MTFP (index-based techniques) as a different means of checking the more sophisticated econometric models.

As an opex specific technique, opex MPFP provided a means of using a relatively less data intensive approach—capable of incorporating five outputs and four inputs and some operating environment factors—with an Australian-only service provider dataset.

Multilateral total factor productivity allows for the comparison of productivity levels between service providers and productivity 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.

---

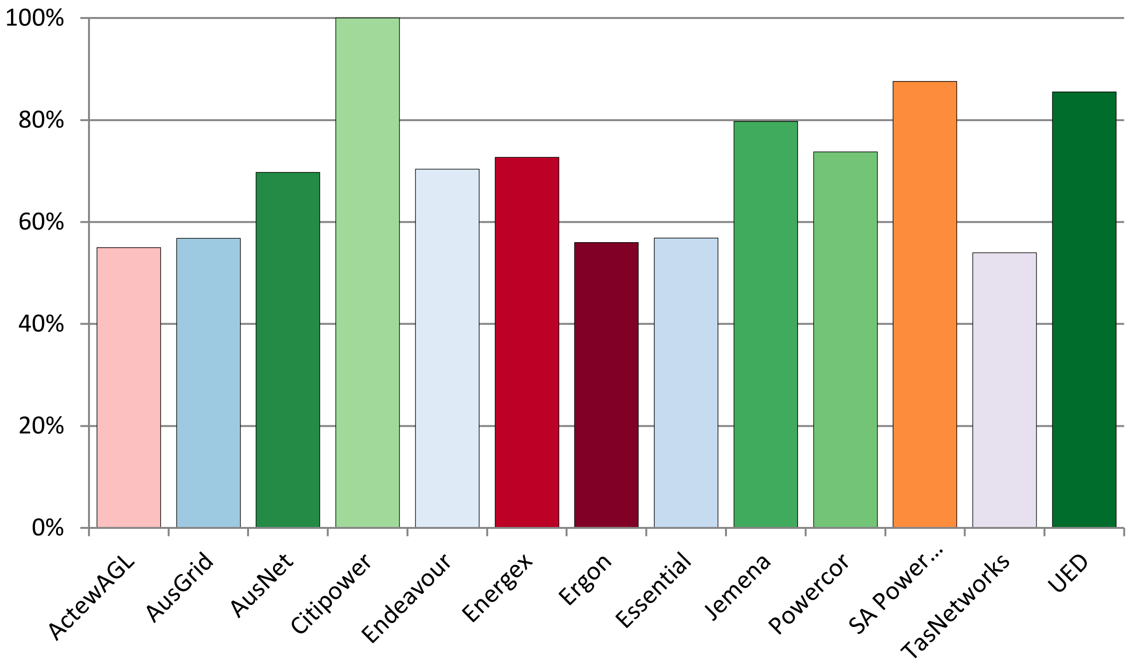
[239] Economic Insights, 2014, p. 7.

[240] Economic Insights, 2014, pp. 46–47.

MTFP played an important role as the overarching indicator of total productive efficiency and, consequently, as a check on the techniques that examine opex efficiency. This is necessary because a service provider could, for example, appear to be inefficient in the use of opex alone, but be efficient overall.

Economic Insights found the MTFP and opex MPFP results supported the econometric models.[241] The results of Economic Insights MTFP analysis are presented in Figure A.6 A number of other service providers perform better than the Queensland service providers under the MTFP analysis.

Figure A.6 MTFP performance (average 2006–2013)



Source: Economic Insights, 2014.

Finally, we used PPIs, which are simple, intuitive metrics to provide another perspective on the relative efficiency of service providers. The PPIs only focus on one aspect of a service provider's performance and do not specifically capture operating environment differences. However, bearing these limitations in mind, we considered they were consistent with the other, more sophisticated benchmarking results. The results of our PPI's are presented below.

241 Economic Insights, 2014, p. 46–47.

A.4.3 Submissions on NSW and ACT benchmarking

In response to our draft decisions for the NSW and ACT service providers, these service providers submitted a large amount of material expressing concerns with our approach to benchmarking and the results. This included reports from the following consultants:

- Frontier Economics[242]
- Huegin[243]
- Cambridge Economic Policy Associates (CEPA)[244]
- Pacific Economics Group Research (PEGR)[245]
- Advisian (formerly Evans and Peck)[246]
- Pricewaterhouse Coopers (PwC).[247]

In addition to submissions from other stakeholders, on 13 February 2015 we received from service providers further legal opinion and consultants' reports on benchmarking from:

- Herbert Smith Freehills (submitted by the NSW service providers)
- Young and McClelland (submitted by ActewAGL)
- Huegin (two reports, submitted by Ergon Energy)
- Synergies (two reports, submitted by Ergon Energy)
- Frontier Economics (submitted by Ergon Energy)
- Ernst & Young (EY) (submitted by Ergon Energy).

Economic Insights addresses this material in the report it has prepared for this final decision. In this section, we have grouped the key benchmarking issues raised by the service providers and their consultants into:

- model specification
- data
- estimation methods
- efficiency results.

---

242 Ausgrid, *Revised Regulatory Proposal*, *Attachment 1.05*.

243 Ausgrid, *Revised Regulatory Proposal, Attachment 1.06*; ActewAGL, *Revised Regulatory Proposal, Attachment C4.*

244 Ausgrid, *Revised Regulatory Proposal, Attachment 1.07*; ActewAGL, *Revised Regulatory Proposal, Attachment C3.*

245 Ausgrid, *Revised Regulatory Proposal, Attachment 1.08*.

246 Ausgrid, *Revised Regulatory Proposal, Attachment 1.09*; ActewAGL, *Revised Regulatory Proposal, Attachment C2.*

247 Ausgrid, *Revised Regulatory Proposal*, Attachment 1.10.

We discuss each topic below. Consistent with our approach in the draft decisions for the NSW and ACT service providers, we have adopted Economic Insights' approach and recommendations on the basis of its expertise in economic benchmarking, including the application of economic benchmarking in the regulatory context. Accordingly, to the extent we refer to 'our approach' or 'our model', this should be interpreted as the approach and models recommended by Economic Insights' and applied in its analysis. Economic Insights' final decision report contains detailed analysis and explanation of its approach and results in light of the information submitted by the service providers and their consultants.

Model specification

Model specification relates to the specification of the outputs, inputs and operating environment variables that Economic Insights has used in its benchmarking model.

In this sub-section, we compare Economic Insights' model specification to the alternatives proposed by the service providers' consultants. First, we reiterate why Economic Insights' modelling approach is robust and reliable. Second, we restate why the inputs, outputs and operating environment factors Economic Insights has chosen are appropriate. Finally, we explain why the alternative models proposed are not robust or reliable.

Our approach is robust and reliable

Economic Insights' model specification has been developed using a logical, structured and consultative approach. We set out this approach below.

The first step we took in developing our benchmarking data base was to consult criteria for selecting input, output and operating environment factors. We set out our initial selection criteria in our issues paper we released for the Guideline.[248] Our final selection criteria are set out in the explanatory statement to the Guideline.[249]

We also developed a broad data set for benchmarking. In developing this data set we considered the model specifications applied in other service provider benchmarking studies.[250]

As part of the Better Regulation reform program we hosted open workshops which were chaperoned by Economic Insights. In these workshops we consulted on engineering, accounting and economic aspects of the model specification with service providers and other interested stakeholders. We published numerous papers on the inputs, outputs and operating environment circumstances of service providers and how these should be measured.

248 AER, *Issues paper, expenditure forecast assessment guideline*, December 2012, pp. 82–136.
249 AER, *Explanatory statement, expenditure forecast assessment guideline*, 2013, November 2013, pp. 145–146.
250 AER, *Issues paper, expenditure forecast assessment guideline*, December 2012, p. 77.

In light of the selection criteria and workshops Economic Insights developed a preliminary model specification which we stated we would test once we collected data.[251] Once we received data Economic Insights ran a number of different model specifications including the preliminary model specification.[252] Economic Insights identified a preferred MPFP model specification on the basis that this specification was not biased towards a particular type of service provider unlike the other model specifications they ran.[253] We circulated the results of the preferred model specification and other specifications that were run by Economic Insights in consultation on our draft annual benchmarking report. Economic Insights modified the MPFP model specification in light of comments received from stakeholders and produced a report based on these considerations which we had regard to in making our draft determination.[254]

We released the benchmarking model and underlying data for consultation with our draft determination. We have considered submissions on the model specification, including alternative models that have been developed, and consider that Economic Insights' model specification is the most appropriate. Their model specification has been developed through extensive consultation, drawing on industry knowledge and expertise, economic theory and their econometric experience. The reasons for not adopting alternative model specifications proposed in submissions below.

Outputs, Inputs and operating environment factors

Model specification comprises the input, outputs and operating environment variables relevant to the networks operated by the service providers. In this section we separately outline why their inputs, outputs and operating environment factors are appropriate. Economic Insights sets out its reasoning for its model specification in section 2 of its report.[255]

Outputs

The outputs that we applied in our Cobb Douglas SFA model are:

- Ratcheted maximum demand
- Customer numbers
- Circuit line length

Economic Insights considers that this output specification captures the key elements of service providers' functional outputs that are valued by customers. Also, the ratcheted maximum demand variable introduces an important demand side element to the

---

[251] AER, *Explanatory statement, expenditure forecast assessment guideline*, November 2013, pp. 141–142.
[252] Economic Insights, Memorandum - DNSP MTFP Results, 2014.
[253] Economic Insights, Memorandum - DNSP MTFP Results, 2014.
[254] AER, *Electricity distribution network service providers Annual benchmarking report*, November 2014, p. 47.
[255] Economic Insights, 2015, pp. 2–19.

measurement of system capacity outputs required.[256] PEGR applied these variables, as well as energy delivered, in its economic benchmarking analysis undertaken for the Ontario Energy Board.[257]

This specification has the advantage of incorporating all of a service provider's main outputs. A service provider needs to provide the capacity necessary to meet demand. This capacity output is better captured by the ratcheted maximum demand variable.[258] Fixed components of distribution output (such as providing access for each customer) are captured by the customer numbers output. The distance over which service providers have to distribute electricity, and the number of assets required to do so, is likely to be captured by the circuit line length variable.

Inputs

Our benchmarking model only includes one input, which is opex. This is appropriate as the purpose of the model is to consider the efficiency of the service providers in using opex to deliver their outputs.

Operating environment factors

Our opex modelling directly accounts for a number of operating environment factor differences. Economic Insights' model specification directly accounts for the main density factors such as customer density and demand density. This is because, as noted by Economic Insights, customer numbers, line length and ratcheted maximum demand are included as outputs.[259]

The model specification also accounts for the effect of underground lines by including an operating environment variable for the proportion of underground lines. Underground lines will require less maintenance and no vegetation management. Further, underground lines are less exposed to exogenous factors that may cause network interruptions.

To capture the effect of cross country operating environment differences Economic Insights also includes dummy variables for Ontario and New Zealand service providers.[260]

---

256 Economic Insights, 2015, p. 3.

257 Pacific Economics Group Research, *Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board, Report prepared for the Ontario Energy Board*, Madison, 2013.

258 An alternative measure to ratcheted maximum demand could be substation capacity. In consultation on the output specification there was some debate as to whether substation capacity or maximum demand should be used. It was noted that, substation capacity would capture the effect of investment in capacity in excess of requirements. We consider that the use of ratcheted peak demand reaches a balance between these two perspectives. Ratcheted maximum demand is the highest level of demand observed over the benchmarking period. As such, it is reflective of the capacity that was required to meet demand over the period.

259 Economic Insights, 2015, pp. 10–11.

260 Economic Insights, 2015, p. 14 (section 2.2.4).

We separately estimated the effect of operating environment factors that could not be directly incorporated into Economic Insights' Cobb Douglas SFA model. Our analysis of these adjustments is detailed in section A.6.

Some of service providers' consultants submit that we should have made adjustments to the data prior to undertaking the modelling for operating environment factors.[261] We consider that making ex-post adjustments for operating environment factors, as advised by Economic Insights, is an effective, reasoned and practical approach.

To adjust for operating environment factors prior to modelling we would need to adjust each data point in the sample for the presumed effect of each operating environment factor. This is impractical with the numerous operating environment factors we have considered. To do this would involve considerable judgement regarding the effect of operating environment factors to the 68 service providers in the sample.

Other consultants have argued that we need to directly incorporate more operating environment factors into the model.[262] We consider this approach is inappropriate as:

- only a limited number of variables can be included in economic benchmarking analysis[263]
- Economic Insights has captured a number of important operating environment factors directly in its model[264]
- The availability of data on operating environment factors is a constraint on the number of operating environment factors that can be directly incorporated into the model[265]

Given these points we consider that accounting for operating environment factors not directly incorporated in the modelling through post-model adjustments is a preferable approach. Economic Insights supports this conclusion.[266]

Proposed alternative approaches are not appropriate

We prefer our benchmarking model specification to alternatives proposed by the service providers. The model specification that Economic Insights has applied is an appropriate approach to measuring outputs and inputs for Australian distributors in the current context. This specification was developed the model through a rigorous consultation process, and has been informed by industry knowledge, economic theory and econometric expertise. As noted above, the model specification incorporates key service provider functional output variables valued by customers.

---

261 Frontier, *Taking account of heterogeneity between networks when conducting economic benchmarking analysis*, February 2015, p. xii. CEPA, *Expert Report, Benchmarking and setting efficiency targets*, 2015, pp. 17–18.

262 PEG, 2015, pp.52, 54. Huegin, 2015a, p.47.

263 Economic Insights, 2015, p. 12.

264 Economic Insights, 2015, p. 12.

265 Economic Insights, 2015, p. 18.

266 Economic Insights, 2015, p. 18.

A number of submissions have proposed alternative approaches to incorporating outputs, inputs and operating environment factors into our benchmarking modelling.

We consider the alternative specifications proposed by consultants in the sections below.

The inclusion of a variable for lines with a voltage of 132 kV and above

CEPA, PEG and Frontier all include a variable for lines above 66kV in their model. [267]

As noted by Economic Insights, in the benchmarking data set, only service providers in NSW, Queensland and the ACT have significant lengths of lines above this voltage.[268] There is therefore a risk that this variable may pick up other characteristics that are shared by distributors in these states relative to distributors in the other states. This appears to be the case.[269]

A useful comparison point is the costs that Ausgrid actually allocates to these assets in its regulatory accounts which we have used to develop our operating environment factor adjustment for these assets. Ausgrid reports its costs for 66kV and above assets separately (as they are predominantly classified as dual function assets). In its category analysis RIN Ausgrid allocated 7.5 per cent of its opex to 132 kV lines. However:

- CEPA's modelling implies that 31 per cent of Ausgrid's opex would be allocated to these assets
- PEG's model implies that 44 per cent of Ausgrid's opex would be allocated to these assets
- Frontier's model implies 34 per cent of Ausgrid's opex would be allocated to these assets [270]

Incorrect output specification

We consider that a number of the alternative models have an incomplete output specification. For instance, CEPA develops a benchmarking model with only one primary output.[271] We consider that it is necessary to incorporate several output variables to adequately represent the functional outputs of service providers, and Economic Insights agrees.[272]

---

267 CEPA, 2015a, p. 20. PEG, 2014, pp. 22–23.

268 Economic Insights, 2015, p. 48.
PEG uses a sample of Australian and US data to model the efficiency of the US service providers. This data set is different to that applied by Economic Insights which used service providers from New Zealand and Ontario. However as none of the US service providers have 132 kV line lengths this variable has a similar effect to including the 66kV plus variable in the Australian, Ontario and New Zealand benchmarking models.

269 Economic Insights, 2015, pp. 48–49.

270 Economic Insights, 2015, p. 50.

271 Economic Insights, 2015, pp. 7, 51.

272 Economic Insights, 2015, pp. 7, 51.

Huegin run a number of models using the outdated output specifications proposed by the AER and Economic Insights when consulting on the development of benchmarking models.[273] However, Huegin did not address the issues identified by Economic Insights when Economic Insights ran these specifications (like the multiplicative nature of the lines and transformer capacity variable).[274] These concerns were set out in the memorandum Economic Insights developed on its MTFP benchmarking.[275] We consider that these alternative output specifications have been superseded and Economic Insights agrees.[276]

Incorrect input specification

In a number of instances we have identified issues with the approach taken to incorporate inputs into alternative benchmarking models. We detail these below.

Synergies applies a DEA model with three inputs: opex, MVA of transformer capacity and the user cost of capital of distribution lines (the value used to weight capital inputs under Economic Insights' benchmarking model).[277] We consider that the addition of the user cost of capital of distribution lines means that the modelling cannot be used to draw conclusions in regards to opex efficiency.[278]

McKell's model only models a subset of opex, composed of maintenance, repair, inspection, vegetation management and similar 'upkeep' costs.[279] The upkeep costs exclude overhead costs.[280] These are a significant proportion of service provider costs. Because costs are excluded from McKell's model it does not measure the efficiency total opex (which also includes overhead costs and service provider operating costs). We prefer Economic Insights' benchmarking modelling because it estimates total opex.[281] We note that the Energy Supply Association of Australia also notes this limitation of McKell's analysis.[282]

PEG submits that it is necessary to levelise opex prices across service providers.[283] By 'levelising' prices, PEG means that we should not use a common opex price index. Instead, PEG submits that we should make allowance for possible different price levels across service providers.[284]

273 Huegin, 2015a, pp. 35–36.
274 Economic Insights, Memorandum – DNSP MTFP results, 2014.
275 Economic Insights, Memorandum – DNSP MTFP results, 2014.
276 Economic Insights, 2015, p. 51.
277 Synergies, 2015, p. 42.
278 Economic Insights, 2015, p. 51.
279 The McKell Institute, Nothing to gain, plenty to lose: why the government, households and businesses could end up paying a high price for electricity privatisation, 2014, p. 34.
280 ESAA, *Lies, damn lies and statistics - comparing networks*, 2015.
281 Economic Insights, 2015, p. 53.
282 ESAA, *Lies, damn lies and statistics - comparing networks*, 2015.
283 PEGR, 2015, pp. 52, 55.
284 Economic Insights, 2015, pp. 8–9.

Economic Insights explains that assuming a common annual opex price level and growth rate across service providers provides a more accurate and unbiased approach. This is because the mining boom in Australia has led to a high demand for field staff of the type employed by service providers right across Australia over the last several years. This has had the effect of greatly reducing any pre–existing labour price differences for field staff across the country. [285]

Economic Insights also observes that there is inadequate information to levelise Australian service provider opex prices and that PEG's attempts to introduce differences in opex price levels and price growth rates across distributors is likely to create errors.[286]

Data

In this sub-section we explain, in response to the service providers' criticisms, why our data is robust, reliable and used appropriately. First, we explain why we have used international data and our approach to incorporating it. In doing so, we address the approaches proposed by the service providers. Second, we emphasise the comparability of the data we have used. Third, we respond to the service providers' submissions on the quality of the data. Finally, we explain why our approach to conducting post-modelling adjustments is preferable to alternatives put forward by the service providers.

International data

We explained in our draft decisions for the NSW and ACT service providers that Economic Insights included international data in the econometric models. Specifically, Economic Insights used databases of service providers from New Zealand and Ontario.[287] Economic Insights also investigated including data from the US but decided against doing so. This was due to the US data not being of consistent quality, incorporating data from vertically integrated monopolies (which introduces cost allocation issues) and lacking consistent data on variables such as line length and maximum demand.[288]

In response to our draft decisions for the NSW and ACT service providers, the service providers and their consultants raised several concerns with Economic Insights' inclusion of international data including:

- the model is heavily reliant on overseas data
- overseas data is not comparable with Australian data
- Economic Insights does not adequately account for differences between countries

---

285 Economic Insights, 2015, pp. 8–9.
286 Economic Insights, 2015, pp. 8–9.
287 Economic Insights, 2015, p. 26.
288 Economic Insights, 2015, pp. 25–26.

- Economic Insights' data contains errors.

The first three issues appear to be based on a misunderstanding of how Economic Insights has used the international data. The concerns with data quality are also misplaced. Economic Insights discusses international data in detail in its report in section 3.1. We highlight the key responses below.

Rationale for including international data

As set out in the draft decision for the NSW and ACT service providers, the rationale for Economic Insights incorporating international data into its econometric modelling is not to undertake international benchmarking.[289] Rather, by including these extra data in the sample, Economic Insights can improve the precision of the results for the Australian service providers.

It is necessary to include international data because while the Australian database is robust and reliable for economic benchmarking, it is small. In particular, it shows little time-series variability—a common situation in utilities benchmarking.[290] Unlike index-based techniques such as MTFP and MPFP, econometric cost functions require a large number of observations to produce robust results.[291]

Consequently, as Economic Insights explained in its NSW/ACT draft decision report, econometric analysis using the Australian-only data set did not produce sufficiently stable results:[292]

> After a careful analysis of the economic benchmarking RIN data we concluded that there was insufficient variation in the data set to allow us to reliably estimate even a simple version of an opex cost function model…the time series pattern of the data is quite similar across the 13 distributors. Hence, in this case, there is little additional data variation supplied by moving from a cross–sectional data set of 13 observations to a panel data set of 104 observations. As a consequence we are essentially trying to use a data set with 13 observations to estimate a complex econometric model. The 'implicit' degrees of freedom are near zero or even negative in some cases, producing model estimates that are relatively unstable and unreliable.

The lack of time-series variation in the Australian dataset has also affected some models developed by the service providers' consultants. CEPA, for example, acknowledge that it was unable to accurately estimate SFA models robustly and consistently using the Australian only data.[293]

Therefore, to robustly estimate the relationship between opex and outputs using an econometric opex cost function, additional cross-sectional data—that is, more service providers—provides a means of increasing the number of observations. This is an

289 Economic Insights, 2015, p. 20.

290 Economic Insights, 2015, pp. 20–21.

291 Economic Insights, 2015, pp. 20–21.

292 Economic Insights (2014), pp. 28–29.

293 CEPA, 2015, p. 19.

approach PEG agrees with and has indeed undertaken.[294] Economic Insights concluded:[295]

> …to obtain robust and reliable results from an econometric opex cost function analysis we needed to look to add additional cross sectional observations which meant drawing on overseas data, provided largely comparable distributor data were available.

By including the NZ and Ontario data, Economic Insights produced econometric results with significantly more accurate parameter estimates. Accurate parameter estimates are essential because they enable more robust opex efficiency comparisons among the Australian distributors.[296] Further, they are important given the results are applied to our trending to forecast output changes and productivity changes. Parameter estimates must be accurate to account for the effect of forecast output change on opex. More precise parameter estimates allow more accurate accounting for output change in forecasts of future opex productivity.[297]

Importantly, the efficiency rankings produced by the SFA model with Australian-only data are consistent with the rankings produced by the three-country database. This demonstrates that rather than influencing the results, the international data simply (albeit significantly) increases our confidence in the results.[298]

The similarity in Australian service provider rankings using both approaches is evident from Figure A.7, which we discuss below in 'Efficiency results'. It is, therefore, misleading for the service providers to contend that the model is heavily reliant on overseas data.

Approach to incorporating international data

The approach Economic Insights has taken to incorporate international data is to:

- select purpose-built economic benchmarking databases used in recent regulatory decisions which have comparable and consistent data
- explicitly account for jurisdictional differences where possible.

As we explain above, the purpose of this approach is to strengthen the confidence in the results rather than compare Australian service providers to international service providers. For this reason, many of the concerns raised by the service providers' consultants are misplaced.

---

[294] PEG, 2014, pp. 53–57.

[295] Economic Insights (2014), pp. 28–29.

[296] Economic Insights (2014), p. 31.

[297] Economic Insights, 2015, p. 20.

[298] Economic Insights, 2015, p. 25.

Purpose-built databases

Economic Insights has only used databases with a long history of productivity measurement and which the regulators of the respective jurisdictions have recently used in their determinations. Further, Economic Insights ensured the databases contain similar variable coverage.[299]

The New Zealand database, for example, is similar in construction to the Australian database and includes consistent data from 1996 to 2013. The NZCC has used productivity studies for regulatory determinations since 2003 with the most recent (2014) using a similar output and input specification to that used by Economic Insights for this determination.[300]

Similarly, the Ontario database contains most of the same outputs as the Australian database and includes consistent data from 2002 to 2013. The OEB used this dataset in its most recent determination in 2013, following a study conducted by PEGR.[301]

Economic Insights was, therefore, satisfied that these two databases were appropriate candidates for inclusion. In contrast, upon examination of the US database prepared by PEG, Economic Insights was not satisfied that (among other things) it included enough of the key quantity variables that are fundamental to productivity measurement. Accordingly, Economic Insights did not use this database.[302]

Economic Insights observes that the NZCC and OEB undertook testing and validation of the international databases such that they were comfortable with relying on them for benchmarking in their regulatory determinations. The views of Huegin and Frontier Economics that the data contains errors or that Economic Insights has failed to apply due diligence to the data[303] are, therefore, not convincing.

Accounting for differences

Economic Insights was explicit in identifying differences between the New Zealand and Ontario databases and the Australian database. In particular, Economic Insights made adjustments for:[304]

- differences in the composition of the international databases by choosing a dataset that balanced the number of small service providers with the number of possible observations
- possible cross-country differences and inconsistencies in accounting definitions, price measures, regulatory and physical operating environments (such as the impact of harsher winter conditions in Ontario) by using country dummy variables.

---

[299] Economic Insights (2014), pp. 29–31.

[300] Economic Insights (2014), pp. 29–31.

[301] Economic Insights (2014), pp. 29–31.

[302] Economic Insights (2014), pp. 29–31.

[303] Frontier Economics, (NSW/ACT), 2015, p. vii. Huegin, (NSW), 2015, p.15.

[304] Economic Insights (2014), pp. 29–32.

Limitations in the Ontario database meant Economic Insights included one operating environment variable and no capital input variable. However, Economic Insights was satisfied that these omissions would unlikely significantly influence the results.[305] Subsequent testing of significance levels and monotonicity properties by Economic Insights revealed this to be the case in the three models used in our decision.[306]

Despite this approach, one of the key concerns raised by the service providers' consultants is that Economic Insights does not appropriately account for differences between countries. In particular, they do not agree that the dummy variables are adequate.[307]

CEPA agrees that the dummy variables control for level differences between databases but considers they do not account for cost relationship differences.[308] Similarly, Frontier Economics and PEG submit that each service provider's costs are influenced by factors not captured by the explanatory variables in Economic Insights' model.[309]

In response to this, Economic Insights considers for such differences to have a material impact on the model results, significant differences in the technology to distribute electricity would need to exist. Economic Insights notes the international service providers deliver the same services using poles, wires and transformers so it does not agree that such a fundamental difference exists.[310] Economic Insights is, therefore, confident that the dummy variables are robust and reasonable:[311]

> Because our objective was not to undertake international benchmarking as such but, rather, to improve the precision of parameter estimates to facilitate opex efficiency measurement across the Australian distributors only, there is no need for the coverage of opex in each jurisdiction to be identical nor for operating environment conditions to be identical…
>
> It is hence invalid to interpret the country dummy coefficients as differences in efficiency levels as FE has done or reflections of cost disadvantages as Synergies has done.

A detailed discussion of Economic Insights' approach to incorporating international data is in section 3 of the report attached to this decision.

305 Economic Insights (2014), p. 32.
306 Economic Insights was not satisfied, following this testing, that the SFA Translog model was robust or reliable enough to be useful.
307 PEG, p. 55; Frontier, pp. 40, 43; CEPA, p. 17.
308 CEPA, p. 17.
309 Frontier, p. 18; PEG, p. 55.
310 Economic Insights (2014), p. 14.
311 Economic Insights (2014), p. 17.

Inappropriate alternatives to Economic Insights' use of international data proposed by the service providers

Some of the service providers' consultants have proposed alternative approaches to using international data in the manner Economic Insights has. For example, PEG advocates using US data[312] and others, including Frontier Economics[313] and CEPA[314] suggest discarding the international data and relying only on Australian data.

As we explain above and Economic Insights addresses in its report, the US database is unusable because the lack of sufficient data fundamental to productivity measurement makes it inconsistent with the Australian database. The alternative of relying only on Australian data is also not feasible due to the lack of time-series variation that may lead to unstable results, which PEG and CEPA recognise.[315]

Frontier Economics' 'strong' recommendation that we completely discard Economic Insights' model is also not feasible given the NER requirements that we conduct benchmarking.[316] Further, for the reasons outlined in this report, we consider that Economic Insights' data and modelling is robust.

Comparability of data

Our view is that the data we have relied on for economic benchmarking is robust, reliable and comparable.

We collected consistent data from all service providers using the same reporting requirements, following extensive consultation with the service providers and other stakeholders. The RIN requirements allowed some reporting flexibility, including the ability to estimate data if actual data were not available. However, the requirements and definitions were clear. Further, we required the RIN responses to be independently audited and also certified by the service providers' CEOs. Therefore, we were satisfied the data is sufficiently comparable across service providers.

In addition, on the recommendation of Economic Insights, our NSW/ACT draft decision adjustments incorporated an allowance in favour of the service providers to allow for potential data and modelling issues:[317]

> [I]t is prudent to adopt a conservative approach to choosing an appropriate benchmark for efficiency comparisons. Adopting a conservative approach allows for general limitations of the models with respect to the specification of outputs and inputs, data imperfections and other uncertainties…

---

312 PEG, 2014, pp. 57–63.

313 Frontier, pp. xviii–xix, 100–102.

314 CEPA, pp. 16–22.

315 PEG, pp. 53–57; CEPA, p. 19.

316 Frontier, pp. vii–viii.

317 Economic Insights, 2014, pp. 47–48.

> Rather than adopt the frontier distributor as the benchmark for efficiency comparisons, we are of the view that it would be prudent to instead adopt a weighted average of the efficiency scores in the top quartile of the efficiency score range…This is equivalent to allowing an additional margin on the frontier distributor's input use of 10 per cent in calculating the benchmark for the NSW/ACT distributors (0.95/1.1 = 0.86) and is thus a relatively generous allowance.

The service providers raised a number of concerns about the robustness of the Australian data and the comparability of service providers. In particular, submissions considered that:

- Australian service providers are among the largest in the benchmarking sample, especially Essential Energy and Ergon Energy[318]
- many variables in the economic benchmarking RIN were not provided by service providers on a consistent basis[319]
- we have not taken into account certain differences between services providers, including related party arrangements.[320]

Relative size of service providers

With reference to the appropriateness of international service providers, several consultant reports consider that the Australian service providers are disadvantaged because they have some of the longest circuit lengths in the benchmarking sample. They consider Essential Energy and Ergon Energy are particularly disadvantaged because they have the longest circuit length and the lowest customer density of all service providers.[321] They also noted that Ausgrid and Energex have a high customer numbers and ratcheted maximum demand relative to the sample average.

We disagree that the size of the Australian service providers are not a comparative disadvantage to other providers in the sample.

Rural providers with very low customer density

Economic Insights considers that the long circuit length of Essential Energy and Ergon Energy does not underestimate their efficiency. Economic Insights states that if Essential Energy and Ergon Energy were genuine outliers, it would expect the flexible translog function to given them much higher efficiency scores than the less flexible Cobb Douglas function. The results, however, are very similar.[322]

---

[318] Frontier Economics, (NSW/ACT) 2015, pp. 25–31. Synergies, (Ergon) 2015, pp. 4–5; Huegin, (NSW), 2015, pp.58–59.

[319] PwC, pp. 24–32.

[320] PwC, pp. 33–37.

[321] Frontier Economics, (NSW/ACT) 2015, pp. 25–31. Synergies, (Ergon) 2015, pp. 4–5; Huegin, (NSW), 2015, pp.58–59.

[322] Economic Insights, 2015, p. 30.

Economic Insights acknowledges that it would be desirable to have more 'large' rural providers in the sample, but considers these two service providers are unusual with no service providers in comparable countries with accessible data having the same extent of lines.[323] Economic Insights did not consider there was justification to adjust Essential Energy's and Ergon Energy's efficiency scores on the basis of their very low customer density.

While comforted by Economic Insights' reasoning, we also engaged EMCa to consider whether—from an engineering perspective—the relationship between opex and customer density changes at the very low densities of Essential Energy and Ergon Energy. EMCa found it is feasible to compare sparse rural distributors (like Essential Energy and Ergon Energy) with other rural distributors included in the benchmarking data set.[324] As such, the findings for our benchmarking model are applicable to the sparse rural service providers.

In any event, the service providers used to derive the benchmark frontier (that we compared Essential Energy to in the draft decision) contains three rural providers—Powercor, SA Power Networks and AusNet Services. Further, we have changed the benchmark comparison point to AusNet services, who is at the bottom of the top quartile of observed scores, which means we have given more weight to (among other things) the characteristics of these rural providers. In our view, this significantly mitigates any perceived disadvantage Essential Energy and Ergon Energy face due to their low customer density.

Customer numbers and demand

While Ausgrid and Energex may have high customer numbers and ratcheted maximum demand relative to the sample average, we do not consider they are comparatively disadvantaged. Economic Insights advises that there are sufficient comparably sized service providers to conclude that Ausgrid and Energex are not significantly distant from other observations such that they would be considered outliers.[325]

The consistent results of the benchmarking models, including consistency with the MPFP model (which does not include the international data) provides comfort that Ausgrid and Energex are sufficiently comparable to other service providers in the sample.

Consistency of variables

Some submissions considered that service providers may not have provided several variables in the economic benchmarking RIN on a consistent basis.[326] We do not consider these concerns are valid, or are sufficiently significant for us to not to conduct benchmarking. Economic Insights, as an economic benchmarking expert, is well

[323] Economic Insights (2015), p. 30 (section 3.3).

[324] EMCA, 2015, p. 1.

[325] Economic Insights, 2015, p. 30.

[326] PwC, pp. 24–32.

qualified to form an opinion on the appropriateness of data for economic benchmarking. As we explained in our NSW/ACT draft decision, Economic Insights considered the Australian database to be robust and suitable for economic benchmarking:[327]

> Given the extensive process that has been gone through in forming the AER's economic benchmarking RIN database to ensure maximum consistency and comparability both across distributors and over time, the database is fit for the purpose of undertaking economic benchmarking to assess distributor opex efficiency levels and to estimate models that can be used to forecast future opex partial productivity growth rates.

The econometric models require only six aggregate variables from the service providers to function effectively (network services opex, energy delivered, customer numbers, ratcheted maximum demand, circuit length and proportion of underground cables). Many submissions on data comparability do not actually relate to these variables. Accordingly, we consider concerns raised about the following matters are not relevant to our findings:

- RAB values[328] – these are not included in the opex modelling
- differences in opex category reporting, including treatment of metering costs – Economic Insights' model's use total network services opex, which excludes metering
- revenue data – our benchmarking models do not rely on revenue
- route line length – we have not used route line length in the opex models[329]
- inconsistency in energy density and customer density calculations – these measures are not central to our analysis but, in any case, we rely on our own calculations, which are on a consistent basis
- system and operating model changes – the aggregate nature of the required variables and our precise definitions for these variables mitigate the impact of such changes
- weather adjusted maximum demand – we do not use this data

---

327 Economic Insights, 2014, p. 3.

328 RAB data is relevant to our MTFP model and opex MPFP model. We use RAB data to weight the volume of inputs and outputs. However, because MTFP is an index-based benchmarking method, the outcomes of the MTFP model will be less sensitive to the weighting of inputs than they will be to the amounts of the inputs themselves. Therefore, any purported comparability concerns with RAB data will have only a very minimal impact on the MTFP results. Economic Insights, 2015.

329 We have used route line length normalise the results of our PPIs. However, we consider that discrepancies in the measurement of route line length will not affect the conclusions of this analysis. The large differences in customer density in these models are not likely to be impacted by slight inaccuracies in the estimates of route line length. In addition, as part of our testing and validation process, we identified and adjusted for the issue with UED's route line length identified by PwC. We circulated this data set to all service providers with our draft economic benchmarking report and published this data set on our website with our draft determination.

To the extent that PwC and EY submit that circuit length the data is not appropriate for use in benchmarking because some service providers have estimated it, we consider:[330]

- As we explain below, neither PwC nor EY demonstrate that the data is not suitable.
- we consider that the estimates are reasonable because the service providers are the best placed to estimate their own asset characteristics and their CEOs have certified they are the best estimates the service provider can provide
- where estimated circuit length may vary from actual circuit length, we would be concerned if service providers were able only to estimate a value—of core assets they manage—that deviated from reality to the point where it would result in a material difference to their benchmarking performance.

Differences between service providers

Some submissions raise comparability matters that are relevant to our opex modelling.[331] However, we have taken these into account in our draft and final decisions:

- differences in capitalisation policies and cost allocation methods – we considered these as part of our operating environment factor assessment and made an adjustment if we considered one was warranted[332]
- differences in vegetation management clearance requirements between states – we considered this as part of our operating environment factor assessment and made an adjustment if we considered one was warranted[333]
- differences in network age, service quality and reliability standards – we considered these as part of our operating environment factor assessment and made an adjustment if we considered one was warranted[334]
- related party arrangements – considered as part of our examination of opex factors. We considered ownership arrangements are not a key concern for total opex assessment because benchmarking enables us to compare the relative efficiency of each service provider's opex regardless of the arrangements they have in place (which are the service provider's choice)[335]
- provision reporting – service providers must develop their provision accounts in accordance with consistent Australian accounting standards so they must meet the same requirements even if they may be named differently. Further, opex reported on a cash basis and accrual basis to be approximately equal on average. [336] Hence

---

330 PWC, 2015, p. 31. EY, Briefing Paper: RIN Data Review Ergon Energy, 13 February 2015, pp. 6–7.

331 PwC, pp. 33–37.

332 AER, Draft decision – attachment 7, section A.5.

333 AER, Draft decision – attachment 7, section A.5.

334 AER, Draft decision – attachment 7, section A.5.

335 AER, Draft decision – attachment 7, p. 7–24.

336 Economic Insights, 2015, p. 56.

the use of eight years of panel data to derive an average efficiency score for the period will reduce the effect that provisions could have on the benchmarking results.

In our NSW/ACT draft decision, we did not explicitly consider differences in the allocation of responsibility for vegetation management across states or differences in fuel mix. In this final decision, however, we consider them as part of our operating environment factor assessment in section A.6.

Data quality

The service providers and their consultants submitted they had some concerns regarding the quality of benchmarking data we have used.[337] We disagree with submissions and maintain that our dataset is of good quality. As we mentioned above, Economic Insights considers our dataset is robust:

> While no dataset will likely ever be perfect, the AER's economic benchmarking RIN data provides the most consistent and thoroughly examined distributor dataset yet assembled in Australia… the AER's economic benchmarking RIN data are also considerably more detailed, comprehensive and consistent than regulatory data in comparable countries, including the United States. The Australian output and input data used in this study are thus considered to be quite robust and to compare more than favourably with overseas datasets used in previous studies.

PEG also submits that our dataset is "generally of good quality".[338] The CCP also praised the data, noting that it was supplied by the service providers.[339] Further, Jemena Gas Networks, and AusNet Services (Gas) have recently asked us to rely on their gas data after submitting benchmarking models prepared by Economic Insights.[340] The data they have relied on has not been subject to the same rigorous testing and validation process that the economic benchmarking RIN data has been subject to.

In this sub-section we briefly reiterate our data collection and validation process before addressing previous comments regarding data quality and explaining why alternatives proposed by the service providers are unreasonable.

---

337 Essential Energy, *Revised revenue proposal*, 2015, p. 189; Endeavour Energy, *Revised regulatory proposal*, 2015, p. 169; Ausgrid, *Revised regulatory proposal*, 2015, p. 130; ActewAGL, *Revised regulatory proposal*, 2015, p. 83; CEPA Expert Report, *Benchmarking and setting efficiency targets,* p. 32

338 PEGR, 2014, p. 30.

339 CCP, *Responding to NSW draft determinations and revised proposals from electricity distribution networks*, 2015, p. 50.

340 Economic Insights*, The Productivity Performance of Jemena Gas Networks' NSW Gas Distribution System Jemena Gas Networks (NSW) – Access Arrangement Information – Appendix 6.7*, August 2009
Economic Insights, *2013–2017 Gas Access Arrangement Review – Access Arrangement Information Appendix 6B,* 2012.

Data collection and validation process

The development of our benchmarking dataset has come about as the result of a public consultation process that began May 2012. We presented the full process we went through to collect, test and validate the data in our approach section. This process included several open workshops to discuss data requirements and four explicit opportunities for service providers to comment on the data prior to submitting unaudited RIN responses.[341]

Following this process, and before requiring audited RIN responses, we initiated a comprehensive testing and validation process involving:

- comparing RIN information with information previously reported by service providers (such as regulatory proposals, previous RIN responses and distributor annual reports) to ensure consistency
- reviewing time series data to identify any anomalous data points
- reviewing bases of preparation to ensure the service providers prepared the data in accordance with the RIN instructions and definitions
- comparing data across service providers to identify potential anomalies.

Where we identified anomalies or inconsistencies we drew these to the attention of the service providers. Ultimately, to ensure that the data was reliable we required independent audit of the service providers' RIN responses prior to final submission and the service providers' CEOs to sign a statutory declaration attesting to the robustness of the data.

We then published the audited RIN data on our website and called for submissions on the data.[342] In response, only Citipower and Powercor raised specific issues regarding data quality, which we addressed.[343] We subsequently undertook further review of audited RIN responses and discussed any further data issues directly with the relevant service providers.

When we consulted on our draft benchmarking reports in August 2014, we again circulated our benchmarking data set. In this process, Energex raised the only significant data-related issue, relating to the inclusion of feed-in tariffs. To account for this submission we excluded the value of feed in tariffs from opex.[344]

---

[341] We circulated, for comment,(1) preliminary EB RIN templates (2) revised preliminary RIN templates (3) draft RIN templates (4) draft expenditure forecast assessment guidelines.

[342] We did not only publish the data, but we also published the basis of preparation of each of the service providers of the data. The basis of preparation describes how the service providers completed the templates.

[343] Citipower and Powercor, Publication of The Economic Benchmarking RIN, June 2014. Citipower and Powercor commented on differences in the calculation of MVA capacity of lines across the service providers. They recommended that "The AER sensitivity test the impact on the benchmarking results by applying standard capacity values across different DNSPs". In response to this comment we undertook sensitivity tests of the data. Submissions are on our website at: www.aer.gov.au/node/25078.

[344] Energex's submission is on our website at: www.aer.gov.au/node/25078.

In the course of our testing and validation process, we found that some responses for certain variables (particularly for several operating environment variables) were not robust. Accordingly, we decided not to use these variables.

We are not professing that our benchmarking dataset is perfect. However, Economic Insights considers no dataset is ever likely to be perfect (Frontier Economics agrees[345]), and ours is suitable for benchmarking.[346] We are satisfied that we have undertaken a very comprehensive and inclusive process to develop a database that is sufficiently robust and reliable for benchmarking purposes.

Further, the data that we have used in our benchmarking models is aggregate data that the service providers themselves require for their own purposes. This data includes historic opex, reliability, demand, customers and the number and size or capacity of key assets. The customer numbers we use, for example, are the number of National Metering Identifiers that the service providers must submit to AEMO for settlement purposes.

Without reliable information on the quantity, location, nature and condition of their networks and assets, service providers would be unable to effectively (or safely) operate and maintain their networks. We also note that the data produced in the economic benchmarking RINs is derived from the same systems the service providers use to prepare their regulatory proposals, which they use to justify increases in revenue.

[345] Frontier, p. 101.

[346] Economic Insights, 2014, p. 3.

Previous comments on data quality

The service providers point to past comments the AER/ACCC, AEMC, PC and Economic Insights have made about benchmarking data as a reason why they consider our current benchmarking data is not robust.[347] The submissions highlight:[348]

- the AER's 2008 opinion that it did not have robust, consistent and reliable long term data suitable for TFP
- Economic Insights' 2009 view that the regulatory data available at the time were not fit for the purpose of a robust TFP analysis of the standard required to base regulatory pricing and revenue determinations on
- the AEMC's decision in 2011 not to adopt TFP for price and revenue determinations
- the PC's conclusion in April 2013 that there was little immediate scope for benchmarking to play a decisive role in determinations due to its incipiency.

Some service providers raised similar concerns during the development of our economic benchmarking RIN, in September 2013, also referring to the AEMC's TFP review. In that process, we explained that the AEMC's comments about data availability and quality related to data in the public domain or used in previous regulatory decisions.[349]

The same applies here. All of the above statements relate to data existing in the public domain or used in determinations at the time (that is, prior to April 2013). We collected the data we are using in this determination at the end of April in 2014.

Given the aforementioned positive comments about our *current* benchmarking data, we are not convinced that the service providers' submissions have merit.

Alternative approaches proposed by service providers

On behalf of the service providers, Frontier Economics considers we should spend more time collecting 'more consistent and reliable data across distributors' and work collaboratively with the service providers. In doing so, Frontier Economics observes that Ofgem has undertaken a decade or more of development work in respect of its data collection.[350] CEPA also comments that if we had consistent data across the Australian service providers we may not need to rely on international data.[351]

---

347 ActewAGL, *Revised Regulatory Proposal*, pp. 125–134, attachment C12; Ausgrid, *Revised Regulatory Proposal*, pp. 130–142.

348 ActewAGL, *Revised Regulatory Proposal*, pp. 125–134, attachment C12; Ausgrid, *Revised Regulatory Proposal*, pp. 130–142.

349 AER, *Draft RIN for economic benchmarking–explanatory statement*, September 2013, pp. 16–17.

350 Frontier, pp. 102–103.

351 C3 - CEPA Expert Report*, Benchmarking and setting efficiency targets,* p. 54–55.

Notwithstanding our view that our data is of good quality now, this alternative is not feasible. Econometric benchmarking analysis with Australian service providers can only be conducted with the international data. This is due to the cross-sectional variation issue we discuss above. As PEG observes, the number of companies in the Australian sample will always be limited, even as additional years of data accumulate.[352]

As for Frontier Economics' observations of Ofgem, we note the following. According to CEPA, in its 1999 price review for distribution services Ofgem benchmarked operating expenditure. It did so with only one year of opex data that required a number of significant adjustments. Using this data Ofgem developed a simple benchmarking model with only one dependent variable and determined the UK service providers could reduce their opex by 16 per cent (on average). The service providers subsequently were able to reduce their opex by 20 per cent (on average).[353]

We do not consider that Ofgem's approach was perfect. It does, however, indicate that Ofgem has in previously implemented opex benchmarking using a less sophisticated and less rigorously tested database than our own to determine expenditure requirements.

Adjustments to data

CEPA submits that our approach of adjusting for identified operating environment factors not explicitly included in the econometric models is 'not in line with the approach used by Ofgem'. CEPA's view is that a better approach is to adjust for operating environment differences prior to conducting the modelling.[354]

Economic Insights disagrees that the post-modelling adjustment approach is inappropriate. Economic Insights considers that given the purpose of the study, adjustment for operating environment factors can be done either:[355]

- as part of the modelling, if sufficient information is available for all included service providers across all jurisdictions, or
- after the modelling if data for particular variables are not universally and consistently available across countries, but are available for Australian distributors.

Economic Insights has adopted the latter approach because—given we are comparing Australian service provider performance to the most efficient Australian providers—the requisite information is not available for all service providers across all jurisdictions.

Economic Insights also notes that degrees of freedom considerations limit the number of operating environment variables that can usefully be included directly in economic

---

352 PEG, p. 65.

353 CEPA, *Background to work on assessing efficiency for the 2005 distribution price control review, 2003*, pp.43–44, 54.

354 CEPA, 2015b, p.18

355 Economic Insights, 2015, p. 18.

benchmarking models. This means that making the use of subsequent adjustment is the only way of allowing a fuller treatment of operating environment factors. Therefore, while Economic Insights' approach may be different to that adopted by Ofgem, it is a valid approach and one that makes optimal use of the information available.[356] By adopting the two step approach our analysis includes allowance for the impact of many more operating environment factors than have earlier economic benchmarking studies and the alternative models advanced by the distributors' consultants.[357]

We consider specific operating environment factors in detail in section A.6.

Estimation methods

In this sub-section we compare and contrast our estimation methods with the alternatives proposed by the service providers' consultants. First, we explain what we have done and why. Second, we explain why we have not used data envelopment analysis (DEA) and why the DEA analysis used by the service providers' consultants is inappropriate. Third, we demonstrate why the service providers' estimation methods are not robust or reliable.

Our estimation methods

We have applied the best available model for estimating efficient opex. Economic Insights explains that our Cobb Douglas SFA model is statistically superior to other benchmarking methods for the following reasons:[358]

- it specifies the relationship between opex and outputs and some operating environment factors in an opex cost function (unlike DEA and MPFP)
- it directly estimates an efficient frontier (unlike econometric models and MPFP)
- it contains a random error term that separates the effect of data noises or random errors from inefficiency (unlike econometric models, DEA and MPFP)
- the results of the Cobb Douglas SFA model can be verified with statistical testing (unlike DEA and MPFP).

In addition, Economic Insights undertook tests of the Cobb Douglas SFA model and have found that:[359]

- all the parameters are of the expected sign
- the parameter estimates all have plausible values
- estimated coefficients are statistically significant which indicates that they have been estimated to a high degree of precision

356 Economic Insights, 2015, p. 18.
357 Economic Insights, 2015, pp. 18–19.
358 Economic Insights, 2014, pp. 7–8.
359 Economic Insights, 2014, pp. 31–34.

- the confidence intervals for the efficiency scores are relatively narrow.

We have further confidence that the Cobb Douglas SFA model is appropriate because Economic Insights has also been able to corroborate the SFA model by producing consistent results using:

- other sophisticated econometric opex models using the same set of explanatory variables (Cobb Douglas LSE and translog LSE) that are more appropriate than the alternatives proposed by the service providers
- the opex MPFP model, which applies a different model specification and does not rely on international data.

In addition, the results of our partial performance indicators and detailed review are consistent with the economic benchmarking results.

Data envelopment analysis

Some submissions suggested we should use DEA because we foreshadowed we would use it in our expenditure forecast assessment guideline. However, we have chosen not to apply DEA because it is an inferior modelling technique to a SFA model.

As Economic Insights observes, DEA may identify certain service providers as efficient by default.[360] This is because DEA estimates the efficient frontier based upon the observed input and output combinations of service providers. This problem is compounded with the inclusion of additional output variables.[361] This is a particular concern when DEA is applied to a small sample of service providers (such as the Australian only data set).[362]

In addition, DEA models do not produce confidence intervals for efficiency estimates and DEA requires a large number of observations to be implemented satisfactorily. [363] Economic Insights considers that SFA is a preferable form of econometric model because it separates out the inefficiency component from the random noise component of the error term.[364]

In our expenditure forecast assessment guideline we indicated that we would use DEA. However, we also specified that we would take a holistic approach to developing benchmarking models based upon the availability of data. Once we received benchmarking data we discovered that we were able to develop a statistically superior SFA model. As such, we have decided to depart from the approach we set out in the Guideline.

---

360 Economic Insights, 2015, p. 41.
361 Economic Insights, 2015, p. 41.
362 Economic Insights, 2015, p. 41.
363 Economic Insights, 2015, p. 41.
364 Economic Insights, 2015, p. 41.

The service providers' estimation methods are not sufficiently robust or reliable

A number of consultancy reports submitted have presented alternative benchmarking models to cross-check opex cost modelling by Economic Insights.[365] Depending on the model specification, these estimation methods differ in how they estimate inefficiencies, unobserved firm heterogeneity effect, and random errors. The modelling differences include:

- treatment of unobserved firm heterogeneity and its separation from inefficiency
- the distributional form applied to modelled inefficiency
- The inclusion or exclusion of a random error term and the characteristics of this random error term.

The results of these models differ to that of Economic Insights. In our view, this is because the alternative models presented by the service providers' consultants are not robust. We outline our views on the alternative models below.

Use of DEA

A number of the service providers' consultants have chosen to develop DEA models. We have noted the limitations of DEA models above.

For instance, Huegin, Synergies and Frontier apply DEA models using a variety of inputs and outputs.[366] Frontier Economics finds more service providers to be efficient when additional output variables are added to the model or variable returns-to-scale technology is imposed. This illustrates the 'efficient by default' problem when using DEA. Economic Insights notes that Increasing the number of outputs from three to four increases the number of distributors with scores above 0.95 from two to seven, while also introducing variable returns to scale further increases the number with scores above 0.95 to 10 – simply because the sample is not large enough to support sensible efficiency analysis using this method.[367]

True fixed-effects (FE) model and true random-effects (RE) models

Frontier Economics developed FE and RE models. These models assume inefficiency varies randomly over time.[368] Consequently they attribute inefficiency that does not vary over time to latent heterogeneity.[369] This is an incorrect assumption where inefficiency persists over time as in such a circumstance these models will systematically underestimate inefficiency. Economic Insights notes that these models find very large mean efficiency scores which it considers would appear to be

---

365 Huegin, 2015(a,b), Frontier, 2015(a,b), Synergies, 2015b.

366 Huegin, 2015a, Synergies.

367 Economic Insights, 2015, p. 41.

368 Economic Insights, 2015, p. 33.

369 Economic Insights, 2015, p. 34.

unreasonably high given what is known about the relative performance of firms in this sample from other sources.[370] Economic insights also notes that, to its knowledge, these models have not been applied by any regulator in any country due to the inherent problems with the underlying assumptions in the models.[371]

Latent class modelling and k-means clustering

Huegin, in their report for the NSW and ACT distributors, use latent class SFA models to identify heterogeneity in the dataset.[372] In this methodology, clustering methods are used to identify subsets of the sample data so that separate efficiency frontiers can be estimated for each subset. Huegin's modelling is flawed, however, because:

- Huegin did not include country dummy variables in its modelling to capture cross country differences.[373]
- Huegin did not report parameter estimates for the model. When parameter estimates were later provided on request, some of the estimated coefficients had the incorrect signs[374]
- Latent class modelling will understate inefficiency because dividing any data set into subsets the mean efficiency score will almost invariably increase as the sample size decreases. [375]

In their subsequent report for Ergon Energy Huegin apply a different statistical technique, k–means clustering. This is used to look for clusters (classes) in Economic Insight's data set.[376] This approach has the following problems:[377]

- the Huegin clustering exercise involves a simple comparison of means, which is a linear analysis. The Economic Insights (2014) models are non–linear economic cost function models (Cobb–Douglas and translog) which are used to capture the classic diminishing marginal returns nature of economic cost structures.
- Huegin exclude the country–level dummy variables from the analysis, which introduces misspecification.
- The clustering methods identify clusters of service providers that are similar to each other in terms of closeness of their means. They do not provide evidence that the service providers in these clusters are significantly different from each other nor that they belong to separate cost functions.

---

[370] Economic Insights, 2015, p. 34.
[371] Economic Insights, 2015, p. 34.
[372] Huegin, (NSW/ACT), 2015, p. 56.
[373] Economic Insights, 2015, p. 38.
[374] Economic Insights, 2015, p. 39.
[375] Economic Insights, 2015, p. 39.
[376] Huegin, (Ergon), 2015.
[377] Economic Insights, 2015, p. 39

Efficiency results

In this sub-section we address the robustness and reliability of our approach, in light of the results of the service providers' alternative models. The service providers, their consultants and the McKell Institute submit that our benchmarking results are sensitive to the modelling approach and model specification adopted. They present alternatives to demonstrate this. They consider the extent of the variation in outcomes indicates the poor explanatory power of our benchmarking as a proxy for the real operating costs of the service providers.[378]

We agree that different modelling techniques and model specifications will produce different results. However, as we demonstrated above, Economic Insights' modelling is robust whereas the alternatives developed by the consultants of the service providers are not. Economic Insights has considered the alternative models proposed by the service providers' consultants in detail and has identified significant deficiencies.[379]

Our results are robust and reliable

Our view is that the results of Economic Insights' modelling are robust and reliable because the model specification, data and estimation methods are superior to everything proposed by the service providers and their consultants. The CCP agree that the model is robust and reliable:[380]

> Our assessment is that the work is thorough, and that care has been taken in choosing appropriate models, testing them and defining their limitations including the standard errors of their estimates. We find the consistency of its partial slope coefficients (across models) and the narrowness of its standard errors reassuring. The explanatory factors that the model has chosen are consistent with those we have seen in other modelling exercises…and the ordinary least squares and least square dummy variable approaches are well accepted.

Model specification

As we outline above, Economic Insights' model specification, in combination with a subsequent adjustment for operating environment factors, is appropriate because:

- it is informed by economic theory, engineering knowledge and industry expertise
- the inputs to the model reflect the key functions of service providers and the outputs reflect what is valued by customers

---

378 ActewAGL, *Revised regulatory proposal*, 2015. p.151 p. 175. Essential, *Revised regulatory proposal*, 2015, p. 182. Ausgrid, *Revised regulatory proposal*, 2015, p. 143. Huegin, (NSW/ACT), 2015, pp. 11–19. ActewAGL, *Revised regulatory proposal*, 2015, p.131–132, p. 149; CEPA, 2015, pp. 23–32; PEG, 2015, pp. 55–56; Huegin, 2015, pp. 35–36; Synergies, 2015 ; Frontier Economics, 2015 ; McKell Institute, 2015.

379 Economic Insights, 2015, p. 53.

380 CCP, p. 51.

- the ex post operating environment factor adjustment involves a thorough assessment of potential differences between the service provider in question and the frontier service providers.

In contrast, the alternative model specifications presented by the service providers' consultants seem to have little regard for the ultimate purpose of the benchmarking exercise. This is to, as accurately as possible, determine the efficiency of opex by examining the relationship between inputs and outputs. The service providers' alternative models either:

- Include a variable to capture the cost of lines above 66 kV that picks up other effects and leads to efficiency gaps being understated [381]
- do not cover key functional outputs—CEPA, for example, presents a function with only one or two outputs, which is not adequate to accurately model service provider cost characteristics[382]
- inappropriately measure inputs, such as Synergies use of input variables other than opex and PEGR's levelisation of opex prices.[383]

Data

As explained above, the data we have used is robust because:

- we developed the Australian dataset in consultation with the service providers and then conducted extensive testing and validation to ensure the variables relevant to the benchmarking models were reliable and fit for purpose
- the international datasets we use to improve the precision of the Australian efficiency results:
    - are used for economic benchmarking purposes by the regulators in the respective jurisdictions (OEB and NZCC)
    - contain sufficiently comparable service provider information for the purpose of enhancing the precision of the modelling results
    - have been in place in the mid–1990s and have been used in economic benchmarking since the early 2000s.

Conversely, the service providers seek to:

- either rely only on the Australian data, which does not produce stable results due to the lack of cross-sectional variation or
- include US data in the sample, which Economic Insights has demonstrated is not fit for purpose.

381 Economic Insights (2015), pp. v–vi.

382 Economic Insights (2015), pp. 51.

383 Economic Insights (2015), p. 51.

Estimation methods

Our use of Economic Insights modelling is appropriate as Economic Insights has applied the best available model for estimating efficient opex. They have chosen appropriate estimation methods that produce robust and reliable results for benchmarking opex. Economic Insights' Cobb Douglas SFA model is statistically superior to other benchmarking methods because it can (among other things) estimate the efficient frontier. Further the Cobb Douglas SFA model has a random error term that separates the effect of data noises or random errors from inefficiency.[384] .

Economic Insights has also been able to corroborate the SFA model by producing consistent results using:

- other sophisticated econometric opex models using the same set of explanatory variables (Cobb Douglas LSE and translog LSE) that are more robust than the alternatives proposed by the service providers
- the opex MPFP model, which applies a different model specification and does not rely on international data.

In addition, the results of our partial performance indicators and detailed review are consistent with the economic benchmarking results.

On the other hand, the service providers and their consultants have presented alternative estimation methods that Economic Insights has demonstrated are not robust because of the assumptions that underlie the modelling or the limited data set used.

Modelling results

We highlight in our discussion on international data, the importance of understanding how and why Economic Insights has used international data. Economic Insights is not using the international data to compare the absolute levels of opex between Australian service providers and their overseas peers. Rather, the purpose is to improve the precision of parameter estimates to facilitate opex efficiency measurement across the Australian distributors only.[385]

Ultimately, this means it is possible to compare efficiency scores within each jurisdiction but not across jurisdictions. The service providers' consultants have misunderstood this distinction, so the following observations and criticisms are not valid or compatible with Economic Insights' modelling approach:[386]

- reference to an Ontario firm as being the ‘frontier' or 'best performing' firm’[387]

---

[384] Economic Insights, 2014, p. 7.
[385] Economic Insights (2015), pp. 25–27 (section 3.2.1).
[386] Economic Insights (2015), pp. 25–27 (section 3.2.1).
[387] FE (2015a, p.12); Huegin (2015a, p. 26).

- comparisons of raw efficiency scores across countries[388]
- attempting to interpret country dummy variables as reflecting the extent to which an Australian service provider would need to have lower opex than a New Zealand or Ontario service providers to be 'fully efficient'[389]
- the need for reporting or operating environment 'standardisation' across countries[390]
- the need to include additional country dummy variables to allow for differences in exogenous variable coefficients across countries.[391]

Further, Economic Insights also demonstrates that the Ontario or New Zealand data are not 'driving the results' of the Cobb Douglas SFA model as is submitted by a number of the service providers consultants.[392]

Economic Insights is also clear that it is difficult to produce stable and reliable results with the Australian data on its own:[393]

> [It] is important to recognise that the characteristics of the Australian RIN data make any econometric model estimated using only the RIN data insufficiently robust to support regulatory decisions.

However, we can demonstrate that the robust Australian efficiency results that utilise the international data are very similar to the efficiency results using the Australian data alone. Figure A.7 compares the two and proves that the international data is not driving the results of the model.

388 FE (2015a, p.17); Synergies (2015b, p. 36)

389 FE (2015a, p.16); Synergies (2015b, p. 37)

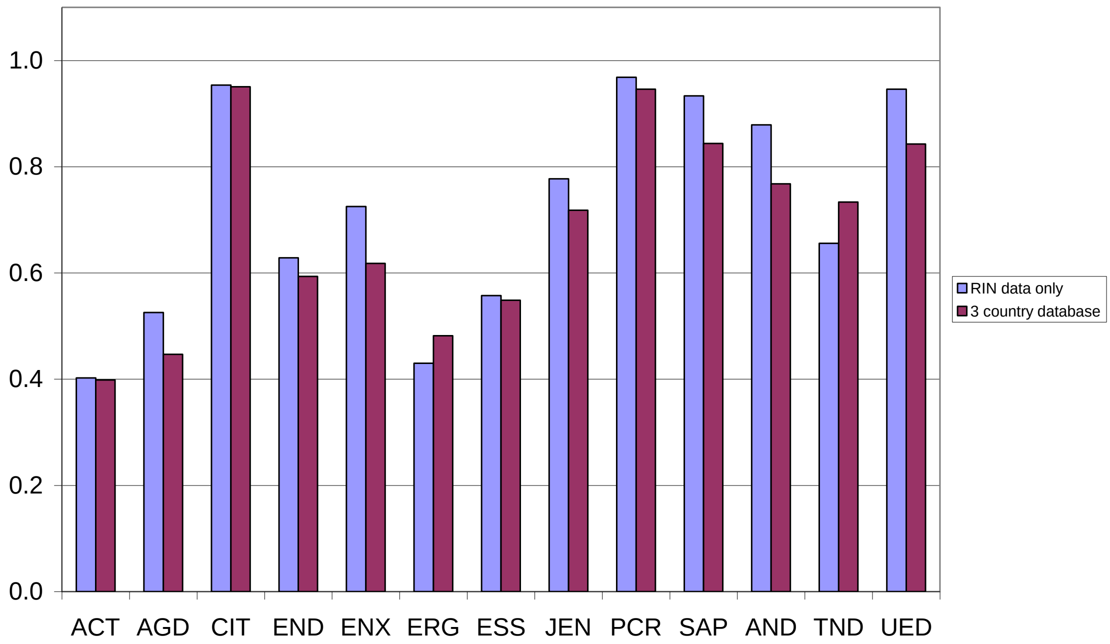
390 PEG (2015, p. 53), Synergies (2015b, pp.33–34) and FE (2015a, p. x); CEPA (2015b, pp.16–18)

391 FE (2015a, pp.24–25)

392 Economic Insights, 2015, pp. 23–25

393 PEG, 2015, pp. 65–66; Frontier Economics, (NSW/ACT), 2015, p. xi. CEPA, (NSW) 2015, pp.16–18. Huegin, Ergon 2015, pp.13,15.Economic Insights (2015), p. 21.

Figure A.7 Modelling results – all data and Australian only data



Source: Economic Insights, 2015

Different results to Ontario

A number of the consultants' reports submit that the efficiency results for the Ontario service providers differ markedly between those derived from (but not presented) in Economic Insights' 2014 report and those presented by PEG in 2013 and subsequently used by the Ontario Energy Board.[394]

Economic Insights notes that it is not surprising that the two sets of efficiency score rankings differ because Economic Insights' relate to *opex* efficiency while PEG's relate to *total* cost efficiency. The reason different efficiency measures were used in the two studies reflects the fundamentally different regulatory regimes – Australia uses building blocks regulation with its separate examinations of opex and capex whereas Ontario uses productivity–based regulation which focuses on total costs.[395]

Results from alternative modelling are not robust

Economic Insights has considered the alternative models presented by the service providers' consultants in detail and has serious flaws. These are as follows:[396]

394 For example, Huegin (2015a,c) and FE (2015a)

395 Economic Insights 2015, p. 45–46 (section 3.9).

396 Economic Insights, 2015, p. 53.

1. The Australian data has inadequate variation to support robust model estimation where it is the only data source used and where tests for parameter differences across countries are made
2. Use of a 132kV line variable inadvertently picks up other effects and leads to efficiency gaps being understated
3. Latent heterogeneity models incorrectly allocate persistent inefficiency effects to operating environment differences
4. Inadequate observation numbers lead to some models misleadingly finding service providers to be 'efficient by default'
5. Some output and input specifications are inadequate and/or not relevant
6. Other overseas data sources unduly limit the range of variables and number of comparators that can be included

The issues identified with each of the service provider's consultant's models are set out in Table A.4.

Table A.4 Problems identified with service providers' consultants' models

Consultancy report reviewed	Data	Benchmarking method	Model specification	Main issues identified
CEPA (2015a) and CEPA (2015b)	Australian only sample, 2006-2013, adjusted opex data	pooled OLS[397] / random-effects GLS[398] Cobb-Douglas / Translog function	DV[399]: real opex Output: circuit length, customer density (length or km2) OEF: selective variables from: undergrounding, RAB additions, 132kV share of circuit, share of SWER Other: Year	1 Use of Australian only data 2 Use of 132 kV variable 5 inadequate input/output specification Inappropriate adjustments to opex[400]
CEPA (2015a)	Full sample (Australia, NZ, Ontario) or jurisdiction-specific sample, 2006-2013	SFA Cobb-Douglas function	DV: real opex Output: customer number, circuit length, RMDemand OEF: undergrounding Other: Year	1 Use of Australian only data
FE (2015a)	Full sample, 2006-2013	True RE and True FE models[401]	DV: real opex	3 Use of latent heterogeneity model

397 Ordinary least squares

398 Generalised least squares

399 Denotes dependent variable, this aligns with the input specification that we discuss above.

400 Economic Insights, 2015, p. 52.

401 True random effects and true fixed effects

Consultancy report reviewed	Data	Benchmarking method	Model specification	Main issues identified
		Cobb-Douglas function	Output: customer number, circuit length, RMDemand OEF: undergrounding Other: Year	
FE (2015a)	Full sample or jurisdiction-specific sample, 2006-2013	SFA Cobb-Douglas function	DV: real opex Output: customer number, circuit length, RMDemand OEF: undergrounding Other Year	1 Use of Australian only data
FE (2015a)	Australian only sample, 2013 only	DEA CRS and VRS[402]	Input: real opex Output: Energy delivered, RMDemand, customer number, before adding circuit length;	4 finding distributors efficient by default
FE (2015b)	Full sample, 2006-2013	SFA Cobb-Douglas	DV: real opex Output: customer number, circuit length, RMDemand OEF: undergrounding, squared term for customer density, share of circuit above 66kV, country dummies Other: Year	2 Use of 132 kV variable 5 inadequate input/output specification
FE (2015b)	Australian only sample used for second stage regression, average of the period data	Second-stage OLS analysis	DV: raw efficiency scores from EI model and FE's modified model respectively OEF: selected variables, including share of circuit above 66kV, customer density (linear vs spatial), weather variables (e.g., wind gust speed, rainfall, temperature, humidity)	2 Use of 132 kV variable Single stage SFA is preferred, where appropriate.[403]
Huegin (2015a)	Full sample, 2006-2013	SFA Cobb-Douglas function	DV: real opex Output: customer number, circuit length, RMDemand Undergrounding or Year variable is modelled for explaining the efficiency term	5 inadequate input/output specification
Huegin (2015a)	Australian only sample, 2006-	Opex PFP	Seven alternative model specification previously considered	5 inadequate input/output

[402] Constant returns to scale and variable returns to scale

[403] Economic Insights, 2015, p. 37

Consultancy report reviewed	Data	Benchmarking method	Model specification	Main issues identified
	2013		by EI and AER	specification
Huegin (2015b)	Full sample	latent class modelling	DV: real opex Output: customer number, circuit length OEF: undergrounding	3 Use of latent heterogeneity model
Huegin (2015b)	Australian only sample	K-means clustering	18 variables on four dimensions are used to group the 13 Australian distributors	3 Use of latent heterogeneity model
Huegin (2015c)	Full sample vs. Australian only sample vs. Large rural only sample	SFA	DV: opex Output: customer number, circuit length, RMDemand OEF: undergrounding	1 Use of Australian only data
McKell (2014)	Australian only sample	OLS	DV: Upkeep cost per customer IV: line length	1 Use of Australian only data 5 inadequate input/output specification
PEGR (2014)	Australian sample (2006-2013) vs. Australian and US sample (unbalanced, with an addition of 170 observations for 15 US utilities 1995 to 2013)	FGLS[404]	DV: real opex Output: customer number, distribution substation capacity, distribution structure kilometres – Translog function OEF: overhead line percentage, 132kv or above network (kilometre), average rainfall, Victoria Bushfire Risk dummy, US firm dummy (relevant only to transnational data) Other: Year	2 Use of 132 kV variable 6 unduly limited specification due to data availability Stata coding error identified[405]
Synergies (2015b)	Australian and NZ sample	DEA	Output: customer number, peak demand, circuit length Input: operating costs, MVA of transformer capacity, user cost of capital associated with distribution lines	4 finding distributors efficient by default 5 inadequate input/output specification
Synergies (2015b)	Full sample or data from each jurisdiction, 2006–2013	SFA and LSE Cobb–Douglas function	DV: real opex Output: customer numbers, circuit length, RMDemand OEF: undergrounding	1 Use of Australian only data

404 Feasible generalised least squares

405 Economic Insights, 2015, p. 52.

Consultancy report reviewed	Data	Benchmarking method	Model specification	Main issues identified
			Other: Year	

Source: CEPA (2015a), Benchmarking and Setting Efficiency Targets for the Australian DNSPs: An Expert Report for ActewAGL Distribution, 19 January.

CEPA (2015b), Ausgrid – Attachment 1.07 – David Newbery Expert Report, January.

Frontier Economics (2015a), Review of the AER's Econometric Benchmarking Models and Their Application in the Draft Determinations for Networks NSW: A Report prepared for Networks NSW, January.

Frontier Economics (2015b), Taking Account of Heterogeneity Between Networks When Conducting Economic Benchmarking Analysis: A Report prepared for Ergon Energy, February.

Huegin (2015a), Huegin's Response to Draft Determination on behalf of NNSW and ActewAGL, Technical Response to the Application of Benchmarking by the AER, 16 January.

Huegin (2015b), Heterogeneity in Electricity Distribution Networks: Testing for the Presence of Latent Classes, 12 February.

Huegin (2015c), Benchmarking Ergon Energy's Operating Expenditure: A Study of the Relevance of the NSW Draft Decision Outcome on Ergon Energy's Benchmarking Results, 10 February.

McKell Institute (2014), Nothing to Gain, Plenty to Lose: Why the Government, Households and Businesses Could End Up Paying A High Price for Electricity Privatisation, December.

Pacific Economics Group Research (2014), Database for Distribution Network Services in the US and Australia, Final Report, 21 August.

Synergies Economic Consulting (2015), Concerns over the AER's Use of Benchmarking as It Might Apply in Its Forthcoming Draft Decision on Ergon, January.

Partial performance indicators

PPIs are complementary to economic benchmarking. We can compare the results from each method to crosscheck their validity. High costs on a single PPI do not necessarily indicate an inefficient level of base opex because each PPI examines only one driver of costs. However, if a service provider has high costs on several PPIs, it is likely that service provider's base level of opex is inefficient. In this respect, it is useful to compare PPI results with the economic benchmarking results.

For the purpose of PPI comparisons, we have chosen two 'per customer' metrics and used them to compare Energex and Ergon Energy to Powercor. This provides an indication of the magnitude of their costs – using an alternative benchmarking technique – relative to one of the top performers for economic benchmarking.

We have presented the metrics against customer density, which is the number of customers per km of route line length. We have done this because less dense (that is, rural) service providers have more assets per customer so they appear to have high higher costs on 'per customer' metrics than urban service providers. Presenting metrics against customer density provides a visualisation of the service providers' relative densities and makes it easier to distinguish between urban providers, rural providers and those in between. This then enables more meaningful comparisons.

Powercor's customer density makes it a better point of comparison to Energex and Ergon Energy than CitiPower (the other top performer) because CitiPower is significantly denser than all other service providers. Powercor, on the other hand, is closer in customer density to Ergon Energy and has a lower customer density than Energex. This means, in theory that Powercor should appear to be at a cost disadvantage relative Energex (due to Energex's higher customer density).

Importantly, this is a limitation of PPIs only; it does not apply to our economic benchmarking techniques because they explicitly take customer density into account.

Operating environment considerations

PPIs do not explicitly account for operating environment factors, so we must bear this in mind when interpreting the results. However, we have taken measures to minimise the effects of operating environment factors on PPIs. To account for scale, we have normalised our PPIs by customer numbers. Customer numbers is an easily understandable output measure that reflects the relative scale of service providers. Economic benchmarking also suggests customer numbers is the most significant driver of costs.

Total customer cost

Total customer cost for network services is a partial performance measure of the costs incurred by service providers that they pass on to customers. It includes opex, return on capital,[406] and depreciation costs.[407] This indicator only includes costs incurred in providing the core 'poles and wires' component of distribution services. We have excluded costs associated with other services such as connections, metering and public lighting. This is to prevent classification of services from influencing results on this indicator. As a total cost measure, it also takes into account differences in allocation between capex and opex.

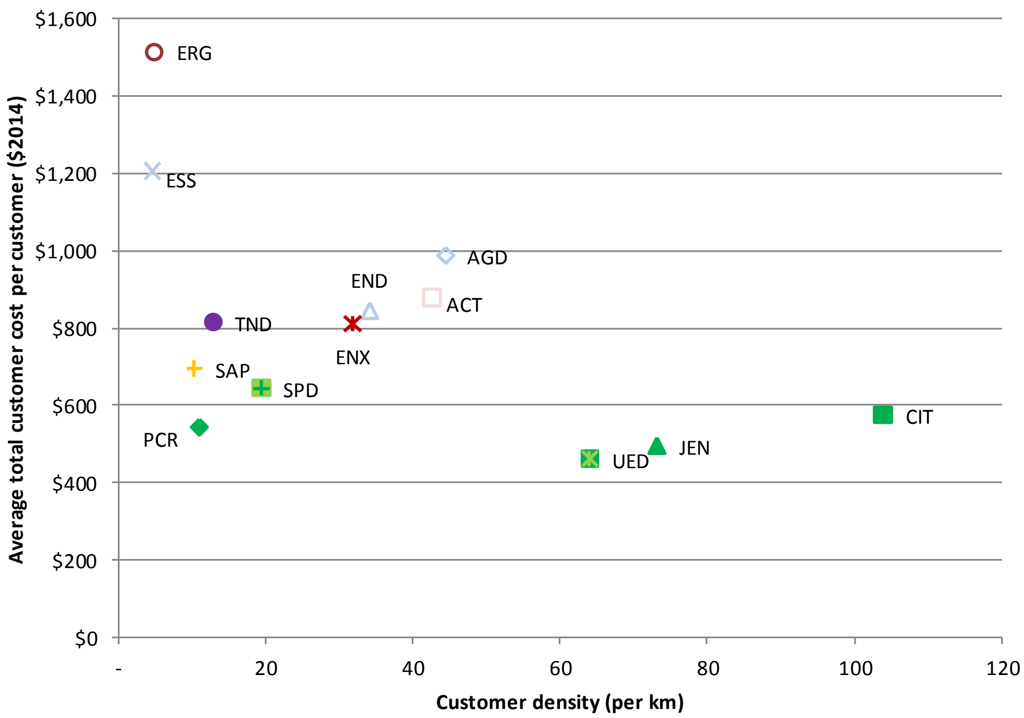
Total customer cost for network services is a good measure of asset costs and operating costs. We chose to use return on capital and depreciation costs to represent asset costs instead of capex because together, they are a better indication of asset

[406] We have applied a real vanilla weighted average cost of capital of 6.09. In calculating this average return on capital, we applied the parameters in the AER's rate of return guideline where possible, used a market risk premium of 6.5 per cent based our most recent transmission determination, a risk free rate based on the yield 10 year CGS 365 day averaging period, and a debt risk premium based on an extrapolation of the Bloomberg BBB fair yield curve.

[407] We have measured depreciation costs using straight line depreciation. Straight line depreciation entails a constant rate of depreciation over the expected life of an asset. Under this measure asset age should not affect the rate of depreciation unless fully depreciated assets are still utilised. However, asset age will influence the return on investment. The return on investment is calculated as a percentage of the total value of the RAB. This means that as an asset base gets older the return that distributors earn on it will decrease with time.

costs than capex. Capex, which only reflects new assets in a given year, has the potential to overstate or understate asset costs.

Figure A.8 Average annual total customer cost for 2009 to 2013 against customer density ($2013–14)



Source: Economic Benchmarking RIN data and AER analysis.

Figure A.8 shows that Energex and Ergon Energy have higher costs than Powercor. Energex appears to perform better than Ergon Energy, due to it appearing lower. Energex shows a similar cost per customer to TasNetworks and Endeavour Energy.

Because Ergon Energy has a lower customer density than Powercor, in theory, Ergon Energy should be at a cost disadvantage on this 'per customer' PPI. This is because it has more assets per customer and, therefore, more costs. The economic benchmarking results appear to support this notion because Ergon Energy appears to perform worse in Figure A.8 relative to Powercor than it does on the economic benchmarking results in section A.4.

However, the economic benchmarking results nevertheless indicate that Ergon Energy's costs are higher than Powercor's. The economic benchmarking techniques explicitly account for customer density. Therefore, differences in customer density can only account for part of the cost difference between Ergon Energy and Powercor.

On total customer cost per customer, Energex and Ergon Energy appear to have high costs relative to Powercor. These results are consistent with our economic benchmarking, which does account for factors such as scale and customer density. As a result, these operating environment factors only explain a part of the cost differential between Energex, Ergon Energy and Powercor. Table A.5 below compares Energex and Ergon Energy's total customer cost per customer to Powercor's.

Table A.5 Comparison of Energex and Ergon Energy's average total customer costs per customer to Powercor's for 2009 to 2013 ($2013)

Service Provider	Cost	Difference in total customer cost per customer to Powercor	Implied efficiency score[408]
Energex	$804	$266	67%
Ergon Energy	$1,499	$962	36%

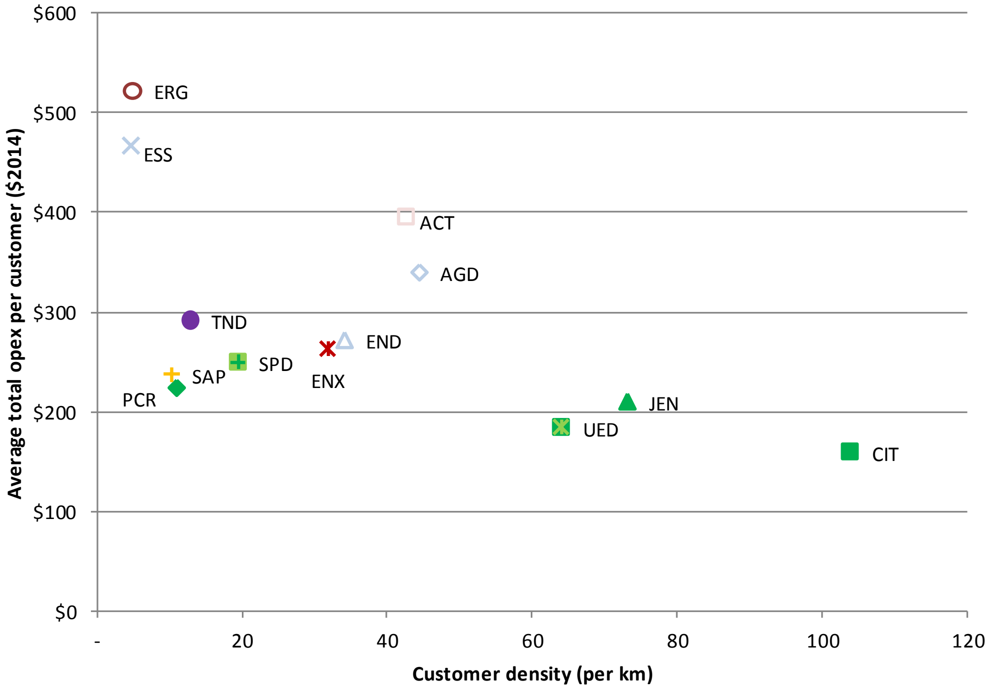
Source: Economic Benchmarking RIN and AER Analysis.

Total opex

This metric measures the opex cost per customer of providing core 'network services'. As with the total customer cost metric, we have excluded the costs associated with other services such as connections, metering and public lighting to prevent classification of services from influencing results. This measure does not include a capital component because it measures opex only. However, we can compare the results to Figure A.8 to ensure capitalisation approaches are not materially influencing the results.

408 We calculated the efficiency scores as Powercor's cost per customer divided by that of the relevant QLD service provider.

Figure A.9 Average annual opex for 2009 to 2013 against customer density ($2013-14)



Source: Economic benchmarking RIN data

Consistent with total user cost per customer, Energex and Ergon Energy appear to have high costs relative to Powercor. Figure A.9 also demonstrates that Energex's opex cost per customer is not as high as Ergon Energy's costs. This is consistent with the economic benchmarking results.

Consistent with Figure A.8, Ergon Energy appears to perform comparatively worse on Figure A.9 than it does on the economic benchmarking. However, as we mention above, economic benchmarking shows differences in customer density can only account for part of the cost difference between Ergon Energy and Powercor.

When we consider the impact of capitalisation, comparison between Figure A.9 and Figure A.8 shows the positions of Energex and Ergon Energy are largely unchanged. This indicates that their relatively high opex is not offset by lower capital costs. Table A.6 compares Energex and Ergon Energy's opex per customer to Powercor.

Table A.6 Comparison of Energex and Ergon Energy's average opex per customer to Powercor's for 2009 to 2013 ($2013)

Service Provider	Opex	Difference in opex per customer to Powercor	Implied efficiency score[409]
Energex	$261	$39	85%
Ergon Energy	$517	$295	43%

Source: Economic Benchmarking RIN, AER analysis.

409 We calculated the efficiency scores as Powercor's cost per customer divided by that of the relevant QLD service provider.

A.5 Category analysis and qualitative review

The aim of this section is to investigate the gap in performance that we identified in our economic benchmarking analysis between Energex, Ergon Energy and the frontier service providers. This is a two stage process where we first examine the service providers' proposals and use category analysis to identify potential drivers of the gap in performance, and then conduct targeted detailed reviews based on our first stage findings.

We have:

- examined the service providers' explanations of opex drivers in their regulatory proposals and supporting material (stage 1)
- conducted category analysis benchmarking for major categories of opex (stage 1)
- engaged Deloitte Access Economics (Deloitte) to review the reasons for the service providers' benchmarking performance, including the extent they had implemented the recommendations of the recent review by the Independent Review Panel (IRP) (stage 2).

This analysis can corroborate our economic benchmarking analysis, which looks at the efficiency of opex overall. It can do so by identifying factors that are contributing to the service providers' overall efficiency performance, and identifying whether base opex contains inefficiencies.

Importantly, the NER require us to form a view on total forecast opex.[410] In doing so, we are not required to assess individual projects or components of a forecast. It is, therefore, appropriate for us to rely on top down techniques such as economic benchmarking to assess whether a service provider's opex proposal reasonably reflects the opex criteria. However, while we could have relied solely on our economic benchmarking techniques to form a view about the efficiency of opex, we have supplemented that analysis with category analysis and detailed review. This is consistent with the Guideline, which explains that we would apply a number of different techniques to form a view about the efficiency of base opex.[411]

Category analysis and detailed review can assist in identifying whether base opex contains inefficiencies when they examine large portions of opex.

Therefore, we have used category analysis metrics to identify categories of expenditure that are high relative to other service providers. However, we consider it is appropriate to use the IRP review as the basis for our detailed review, because it examined significant components of expenditure such as overhead and other labour-

---

410 NER, cl. 6.5.6(c).

411 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 12–15.

related matters, and the review overlaps with the results of the category analysis metrics. While we have not reviewed every category of expenditure, by reviewing Energex's and Ergon Energy's labour costs (which comprise approximately 75 per cent of Ergon Energy's and 95 per cent for Energex's opex in 2012–13[412]) in detail, we are examining a significant proportion of their opex.

We are not using category analysis and detailed review to either examine all of opex or produce highly disaggregated findings. The NER do not require us to conduct, and indeed, the regulatory regime discourages us from conducting, a complete 'line by line' bottom up review of a service provider's operations. Category analysis and detailed review are not designed to reconcile with our overall benchmarks, they are designed to identify and explain the drivers of efficiency performance.

As set out in section A.2, in the context of information asymmetry between the regulator and the service provider, it is neither feasible nor desirable for the regulator to make findings at a granular level about the manner in which a service provider should operate. It is for the service provider's management to decide how best to operate its network with the opex that we determine reasonably reflects the opex criteria. We have primarily formed a view about efficiency drawing on the results of overall outcomes (economic benchmarking), which is corroborated by the detailed review.

A.5.1 Findings from the service providers' proposals

We examined Energex's and Ergon Energy's regulatory proposals which both state that they are in the process of transitioning to more efficient opex levels over time. This implies that both service providers are capable of meeting the opex criteria while spending less opex than they currently do. This supports the view that Energex's and Ergon Energy's proposed base year (2012–13) opex is not appropriate for forecasting opex over the 2015–20 regulatory control period in accordance with the NER.

As we explain in section A.3, we develop our own estimate of total forecast opex to compare with a service provider's proposal. While we might find that the base opex is not efficient, it may be that a service provider has proposed forecast opex lower than current levels, leading to us approving its overall opex forecast.

This section presents some evidence from the service providers' regulatory proposals (and subsequent submissions) to support the findings that their revealed opex is not an appropriate starting point for developing a forecast to compare with the service providers' forecast opex.

Background

The Queensland Government engaged an expert panel in 2011 to review the operations of Energex and Ergon Energy in what was termed the Electricity Network

[412] Energex, Response to information request AER Energex 002, received 19 December 2014; Ergon Energy, Response to information request AER Ergon 021, received 31 January 2015.

Capital Program Review (the ENCAP Review).[413] The ENCAP Review resulted in revised security and reliability standards, which gave rise to a significant reduction in the program of work for the current and forthcoming regulatory control period.[414]

In May 2012, the Queensland Government initiated the Interdepartmental Committee on Electricity Sector Reform (IDC) to undertake a broad assessment of the electricity industry. The IDC appointed a network-specific Independent Review Panel (IRP) to provide recommendations regarding the optimal structure and efficiency of distribution businesses. The IRP provided recommendations to the IDC in May 2013.[415] The Queensland Government accepted 44 of the 45 recommendations the IRP made to the IDC.[416]

In response to the IRP and the ENCAP Review, both Energex and Ergon undertook a series of efficiency programs aimed at addressing recommendations and criticisms presented in the ENCAP Review, and addressing issues that were investigated as part of the IRP report.[417]

Energex

Energex's regulatory proposal states that it identified additional efficiencies it can achieve in the forthcoming regulatory period. As a result, Energex has proposed a series of adjustments to its base year opex, recognising that it is not an appropriate starting point for forecasting opex. Changes to Energex's base year opex include the removal of:[418]

- emergency response and corrective repair expenditure above the historical average
- costs resulting from cancelled projects
- redundancy costs.

Further, Energex has identified additional efficiencies it can achieve in the forthcoming regulatory period, of $67.2 million ($2014–15), these include:[419]

- lower vegetation management costs after changing its operating model with suppliers, allowing the suppliers to more efficiently manage the utilisation of their resources.

---

413 Queensland Government, *Electricity network capital program review 2011: Detailed report of the independent panel*, October 2011.

414 Energex, *Regulatory proposal*, October 2014, p. 34.

415 Interdepartmental committee on electricity sector reform, *Report to government*, May 2013.

416 Energex, *Regulatory proposal*, October 2014, p. 24.

417 Energex, *Regulatory proposal*, October 2014, pp. 23–24; Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal), pp. 10–11.

418 Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, pp. 33–55.

419 Energex, *Regulatory proposal*, October 2014, p. 132; Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, p. 18.

- the ongoing development and implementation of a fully integrated Distribution Management System (DMS) will deliver further efficiencies in control centre activities through automated and semi-automated features and tools.
- the continuation of its Business Efficiency Program (BEP) to deliver significant efficiencies in its overhead expenditure categories. Energex adopted the IRP recommendations regarding its target level of FTE reductions, and is currently targeting a reduction in FTEs from 3,433 in 2012–13 to 2,990 FTEs in 2014–15.[420]
- Energex's efficiency adjustments for vegetation management and its DMS have been proposed as negative step changes, which we consider in appendix C.

We consider the extent of Energex's forecast efficiency gains may indicate that its revealed base opex is not an appropriate starting point for forecasting opex over the 2015–20 period.

Ergon Energy

We reviewed Ergon Energy's regulatory proposal which states that it identified additional efficiencies it can achieve in the forthcoming regulatory period. Ergon Energy commenced an initial wave of cost reduction measures in September 2011 (prior to the initiation of the IRP review), concluding in June 2013.[421] In its supporting documentation titled 'Our Journey to the Best Possible Price,' Ergon Energy outlines further efficiencies to be realised over the 2015–20 regulatory control period.[422]

For example, Ergon Energy identifies further efficiency gains to be realised as lower overhead costs, with an estimated reduction in costs of 15 percent or $260 million ($2014–15) over the forecast regulatory period.[423] While it is unclear exactly what proportion of this reduction applies to opex overheads, it provides evidence that overhead cost allocated to opex in the 2012–13 base year were too high. In addition, Ergon Energy has outlined a number of initiatives it is undertaking to realise efficiency gains. Ergon Energy:[424]

- has proposed changes in its enterprise agreement aimed at seeking a simplified and flexible agreement

[420] Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, pp. 62–66.

[421] Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal), p. 11.

[422] Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal).

[423] The 15 percent overhead cost reduction excludes reductions to fleet, ICT and IT asset charges. Ergon Energy also propose a further 1 percent annual productivity improvement in its overhead forecast, consistent with industry practice. Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal), pp. 13, 16.

[424] Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal), pp. 13–15.

- will continue to implement its DMS, which automates many of the manual processes in operating the network
- will implement its Field Force Automation project, which is expected to improve operational performance and service levels by standardising dispatch and automating field operations
- has a project (ROAMES Sustainable Integration Design) underway, which will integrate the ROAMES products and data into its processes to improve decision-making and operational effectiveness.

We consider the extent of Ergon Energy's forecast efficiency gains may indicate that its revealed base opex is not an appropriate starting point for forecasting opex over the 2015–20 regulatory control period.

Extent of efficiency gains

We find that although Energex and Ergon Energy have proposed efficiency gains in the forecast period, they are also increasing the proportion of their total overheads that are allocated to opex, rather than capex. They also reclassify some historical standard control opex as alternative control. These changes, taken together, may to some extent offset the opex efficiencies they are forecasting.

In total Energex and Ergon Energy forecast that they will deliver cost savings of $327.2 million ($2014–15) over the 2015–20 regulatory control period. However, as noted above, it is unclear exactly what proportion of Ergon Energy's proposed reduction in overheads applies to standard control services opex.[425] Therefore, Ergon Energy's actual reduction to standard control services opex may be overstated.

We recognise both Energex and Ergon Energy have realised some efficiency gains in the current regulatory period, but their identification of gains after the base year indicate their proposed 2012–13 base year opex does not represent efficient opex. We also received a number of submissions from stakeholders who considered that Energex's and Ergon Energy's base opex does not reflect that of a prudent and efficient service provider.[426] Deloitte considers the extent of base year efficiency, which we discuss below in section A.5.3.

---

[425] Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, pp. 33–55; Ergon Energy, *Supporting Documentation - Our Journey to the Best Possible Price* (Attachment 0A.01.02 to Ergon Energy's Regulatory Proposal), p. 13.

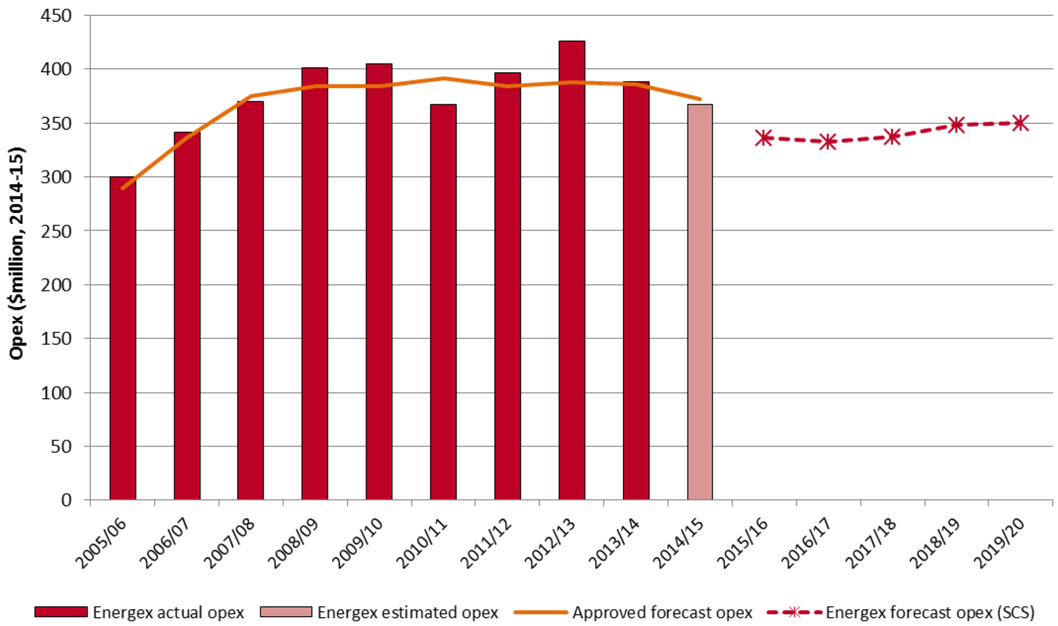
[426] See for example: AGL, *Energex Regulatory Proposal: July 2015 to June 2020 - AGL submission to the Australian Energy Regulator*, 30 January 2015, pp. 7–9; Cally Wilson, *Energex: A Sustainable Future?*, pp. 2–3; Origin Energy, *Submission to Queensland Electricity Distributors' Regulatory Proposals*, 30 January 2015, pp. 11–15; EUAA, *Submission to Energex Revenue Proposal (2015/16 to 2019/20)*, 30 January 2015, pp, 22–29; EUAA, *Submission to Ergon Energy (Ergon) Revenue Proposal (2015/16 to 2019/20)*, 30 January 2015, pp, 22–29; Alliance of Electricity Consumers, *Submission on Ergon Energy's Regulatory Proposal 2015–2020*, 30 January 2015, pp. 19–23.

We are also aware that both Energex and Ergon Energy have forecast a significant increase in opex overheads over the 2015–20 regulatory control period. This is driven by an increase in the opex share of total expenditure due to a reduction in forecast capex. We estimate the share of overheads Energex allocated to opex increases from 38 per cent in 2012–13 (after the proposed base year adjustments) to 45 per cent in 2019–20. This is driving a $139 million increase in opex over the 2015–20 regulatory control period. We estimate the change in overhead allocation has increased Ergon Energy's opex forecast by $32 million. This reallocation of overheads reduces the impact of any proposed efficiency gains to forecast opex.

In addition, Energex and Ergon Energy reallocated certain expenditures from standard control services to alternative control services to comply with our reclassification of metering services.[427] When we consider the impact of the reclassification, it becomes apparent that proposed total forecast opex levels are close to (in the case of Energex) or higher than (in the case of Ergon Energy) actual expenditure at the end of the 2010–15 period (see Figure A.10 and Figure A.11). This demonstrates that not all proposed reductions in opex are necessarily due to efficiency gains.

In accordance with the NER we have made our preliminary decision on the *total* forecast opex required by Energex and Ergon Energy.[428] We discuss the service providers' forecasting method in appendix D.

Figure A.10 Energex's past and forecast total opex, including reclassified services ($million, 2014−15)



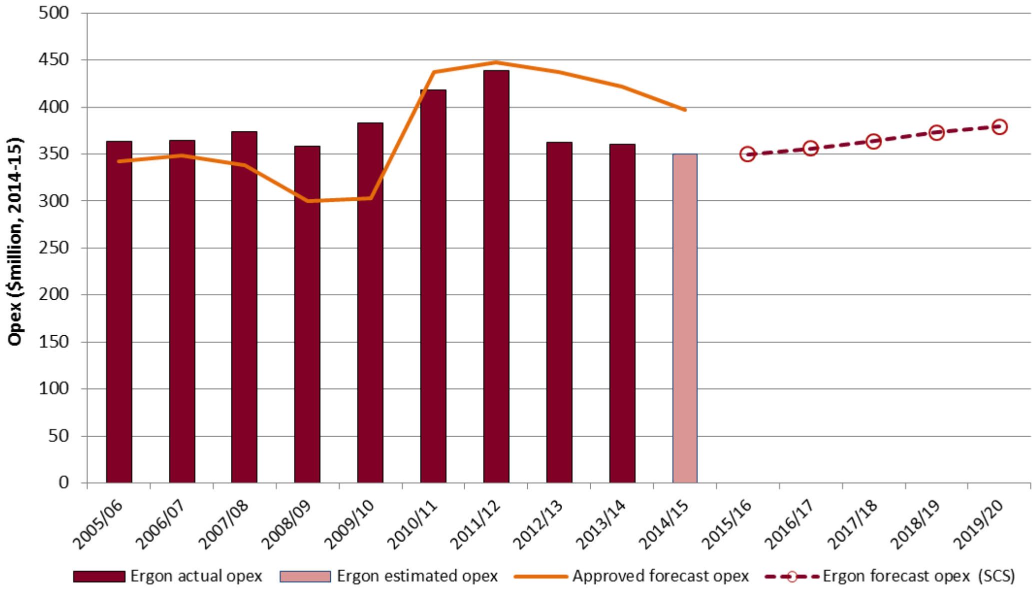
[427] Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, pp. 47–48; Ergon Energy, *Regulatory proposal 2015–20*, October 2014, p. 22.

[428] NER, cl. 6.12.1(4).

Note: The opex for the period 2005/06 to 2014/15 include some services that have been reclassified as ancillary reference services; the forecast opex for period 2015/16 to 2019/20 does not. The opex for the period 2005/06 to 2009/10 also includes debt raising costs; the opex and forecast opex for the period 2010/11 to 2019/20 do not.

Source: Energex, Regulatory accounts 2005/06 to 2009/10; Energex 2010/11–2014/15 PTRM, Annual Reporting RIN 2010/11–2013/14, *Regulatory proposal for the 2015–20 period* - Regulatory Information Notice; AER analysis.

Figure A.11 Ergon Energy's past and forecast total opex, including reclassified services ($million, 2014−15)



Note: The opex for the period 2005/06 to 2014/15 include some services that have been reclassified as ancillary reference services; the forecast opex for period 2015/16 to 2019/20 does not. The opex for the period 2005/06 to 2009/10 also includes debt raising costs; the opex and forecast opex for the period 2010/11 to 2019/20 do not.

Source: Ergon Energy, Regulatory accounts 2005/06 to 2009/10; Ergon Energy 2010/11–2014/15 PTRM, Annual Reporting RIN 2010/11–2013/14, *Regulatory proposal for the 2015–20 period* - Regulatory Information Notice; AER analysis.

A.5.2 Category analysis

As we outline above, we use category analysis metrics to identify if certain categories of Energex and Ergon Energy's opex are possible sources of inefficiency. The metrics suggest there may be inefficiencies in labour and overheads requiring further review.

Category analysis metrics are PPIs that focus on particular categories of opex in isolation. They provide a level of detail below the total cost and total opex PPIs we presented in section A.4. Category analysis is useful as an informative tool for identifying areas of high cost and potential inefficiency for further review. We use this detailed review to corroborate our economic benchmarking results.

Table A.7 shows a summary of the category analysis results. A service provider is 'high' when it appears above most of its peers and 'comparable' where the gap is less distinct. 'Very high' indicates a substantial gap to other service providers.

Table A.7 Summary of category analysis metrics – Energex and Ergon Energy's relative costs (average over 2008–09 to 2012–13)

	Energex	Ergon Energy
Labour	High	Very High
Total overheads	Very High	Very High
Total corporate overheads	Very High	Very High
Total network overheads	Comparable	Comparable
Maintenance	Comparable	High
Emergency response	Comparable	Comparable
Vegetation management	Very High	Comparable

Source: AER analysis.

Table A.7 suggests key areas of concern include labour and overheads. Given these categories overlap with areas that the IRP focussed on in its review, we decided to look at the extent to which Ergon Energy and Energex had implemented the findings of the IRP as the focus of our detailed review in section A.5.3.

Our analysis for each metric is below.

Labour

Our labour metric indicates that Energex's and Ergon Energy's labour expenditures are high relative to other service providers. This and the IRP led us to review their labour expenditure in further detail.

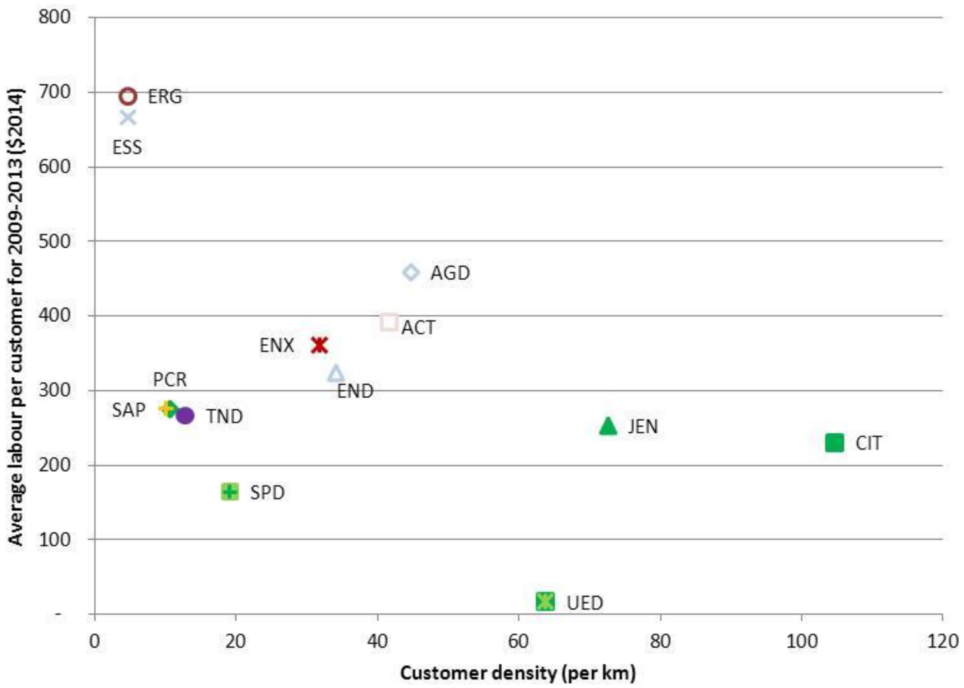
Figure A.12 measures labour costs per customer, normalised by customer density. Labour expenditure, in this context, only applies to costs incurred for internal labour. It excludes the labour costs of external contractors.[429] We have used labour expenditure rather than the number of staff because labour expenditure is a better indicator of the costs faced by service providers than staff numbers. Staff numbers may provide an indirect indicator, but due to differences in wages, firms with similar staff numbers may have different labour expenditures.

[429] Because this metric excludes contractor costs, contracting policies are likely to affect service providers' relative positions on this metric. This is likely why UED—who over the benchmarking period outsourced almost all of its opex – has such low labour costs per customer compared to everyone else.

Figure A.12 shows that Energex appears to have high labour costs per customer relative to AusNet, SA Power Networks, Powercor, Endeavour Energy and TasNetworks. While Energex also appears higher than JEN, UED and CitiPower, it is significantly less dense. Given 'per customer' metrics tend to favour higher density service providers, we must bear this in mind when comparing Energex to these businesses.

The results in Figure A.12 are consistent with the total customer cost PPI and (bearing Ergon Energy's customer density in mind) the economic benchmarking results. This indicates that lower costs in other areas do not offset relatively high labour costs for these businesses at the total level.

Figure A.12 Average annual labour expenditure per customer for 2009 to 2013 ($2013–14)



Source: Category analysis RIN data and economic benchmarking RIN data.

Ergon Energy appears to have the highest labour costs per customer of all service providers. This differs slightly to the economic benchmarking results, because Ergon Energy is not the worst performer on our economic benchmarking results. We consider that the observed high labour cost per customer could, in part, be due to the fact Ergon Energy is a particularly large network (by geographical size) with low customer density. However given the results of the economic benchmarking, we consider it is unlikely that the large gap between Ergon Energy and the other rural service providers can solely be due to customer density. We consider the impact of Ergon Energy's size on its opex in section A.4.3.

Total overheads

Our total overheads metric indicates that Energex's and Ergon Energy's total overheads are high relative to other service providers. This result and the findings of the IRP and led us to review their IT expenditure in further detail.

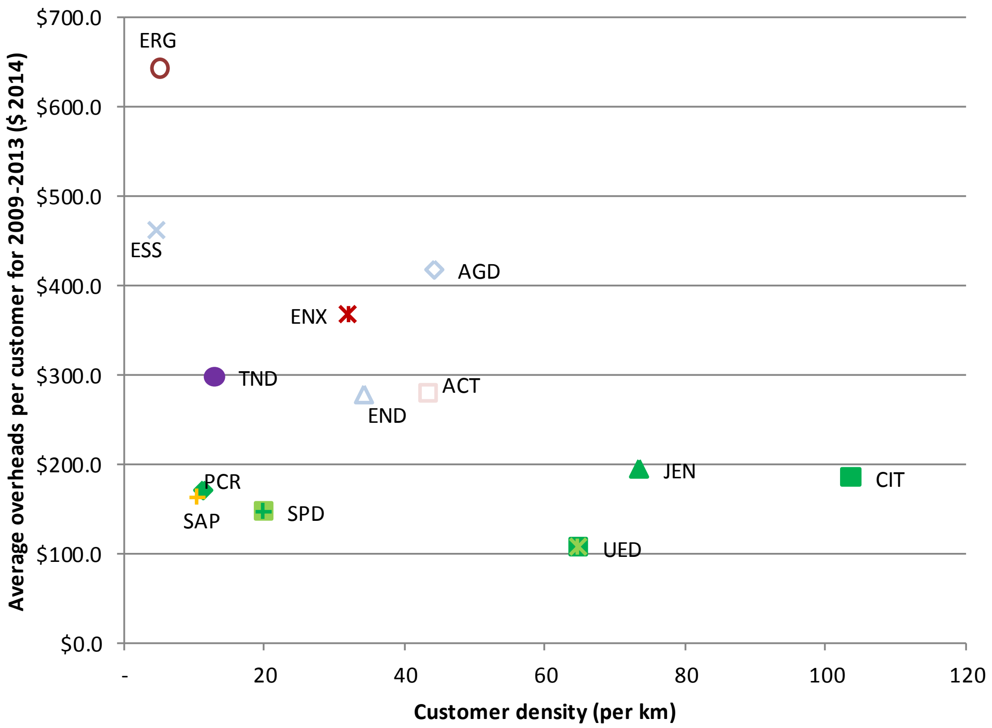
Total overheads are the sum of corporate and network overheads for both capex and opex allocated to standard control services. We have used total overheads to ensure that differences in capitalisation policies do not affect the analysis. It also mitigates the impact of service provider choices in allocating their overheads to corporate or network services. We present average total overheads per customer in Figure A.13.[430]

Figure A.13 shows that Energex appears to have high overhead costs relative to most other service providers, with the exceptions of Ausgrid, Essential Energy and Ergon Energy. Ergon Energy appears to have the highest overhead costs of all service providers. However, we note that Energex has removed corporate restructuring costs ($51m) and Ergon Energy has applied a reduction to overheads, in recognition that their actual base year amounts are not the appropriate starting point for efficient and prudent forecast opex.[431] Therefore, the results here may be overstated compared to their adjusted base expenditures.

[430] We chose total overheads per customer because total overheads are likely to vary with changes in the amount of work done on the network. Customer numbers are a good proxy for this.

[431] Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, p. 10; Ergon Energy, *Ergon Energy regulatory proposal appendix 06.01.01: Forecast expenditure summary – operating costs*, October 2014, p. 15.

Figure A.13 Average overheads per customer for 2009 to 2013 against customer density ($2013–14)



Source: Category analysis RIN data and economic benchmarking RIN data.

On this 'per customer' metric, Ergon Energy will appear higher than all service providers due to its low customer density. However, as noted above, differences in customer density can only account for part of the cost difference between Ergon Energy, and SA Power Networks and Powercor who are also rural (albeit slightly more dense). This result is consistent with the economic benchmarking results, which do account for customer density and show Ergon Energy has high costs relative to some of its peers.

Huegin prepared a number of non-network metrics for Energex and Ergon Energy that cover some of the sub categories of overhead, including fleet, property and IT expenditure.[432] While it is encouraging that Energex and Ergon Energy have engaged in category benchmarking, we have some concerns with Huegin's non-network metrics.[433]

432 Huegin Consulting Group, *The Energex expenditure forecast compared to industry benchmarks*, 14 October 2014, pp. 37–40; Huegin Consulting Group, *Ergon Energy benchmarks – category analysis*, 23 October 2014, pp. 14–17.

433 We consider it is not clear if the metrics presented are representative of all overhead expenditure. We also note that many of the metrics presented are costs per employee, per vehicle or per device and so on. They are, therefore, influenced by the number of staff, vehicles or devices. If a service provider has too many devices, for example, a metric that measures cost per device will show the service provider to perform favourably but ignores the underlying problem.

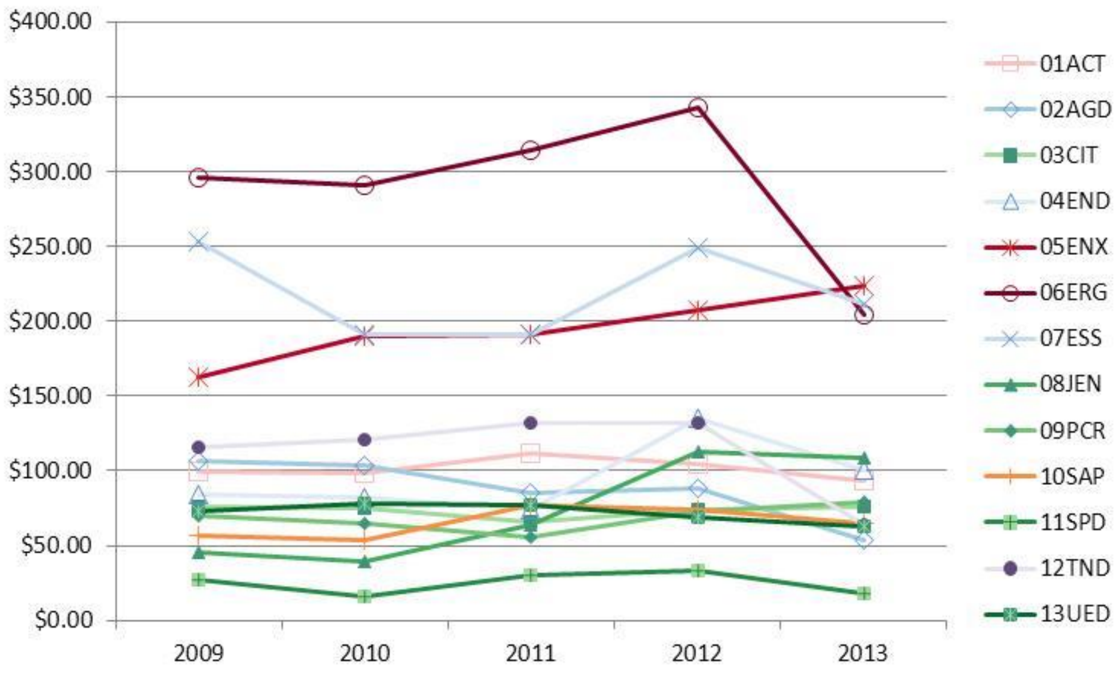
Corporate overheads

Our corporate overheads metric indicates that Energex's and Ergon Energy's corporate overheads are high relative to other service providers. This result (and the total overheads result, and the findings of the IRP led us to review their IT expenditure in further detail.

Corporate overheads, in this context, are all expensed and capitalised overhead costs allocated to standard control services that are not directly attributable to operating an electricity distribution system (that is, not network overheads). Among other things, these include costs incurred by legal, finance, and human resources functions. We have measured total corporate overheads rather than corporate opex overheads because opex overheads are affected by service providers' capitalisation policies.

Figure A.14 shows that Ergon Energy’s average annual expenditure on corporate overheads per customer is the highest of all service providers; however it has decreased significantly in 2012–13. Energex also exhibits very high corporate overhead expenditure per customer over the observed period. Energex and Ergon Energy perform particularly poorly on this metric relative to other service providers. We again note that Energex and Ergon Energy proposed reductions to their overhead expenditure in their respective base years, therefore corporate overhead should be lower than shown in this metric for 2012–13.

Figure A.14 Corporate overheads per customer 2009 to 2013 ($2013–14)



Source: Category analysis RIN data and economic benchmarking RIN data.

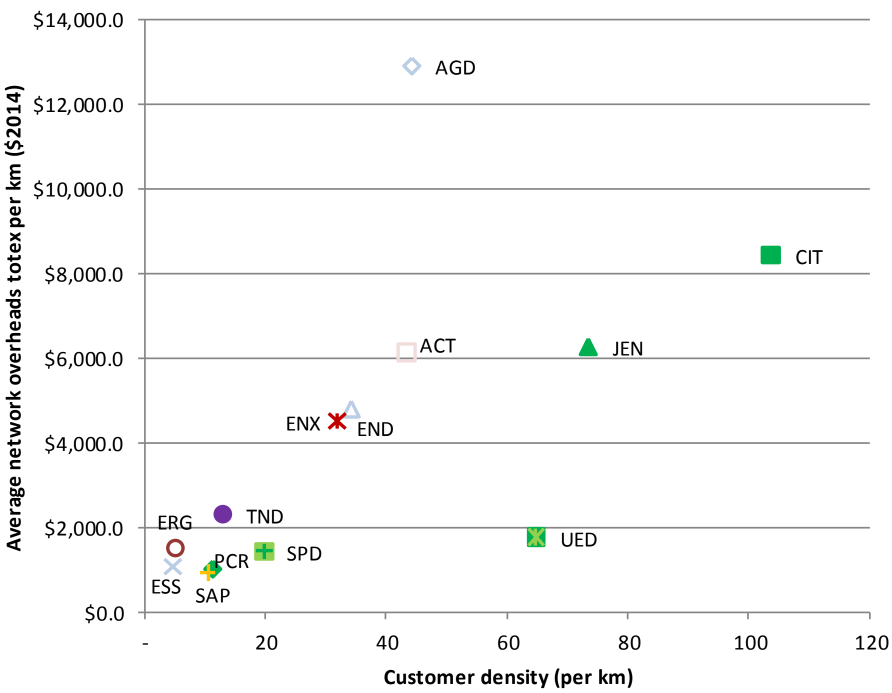
We have not presented this metric against customer density. Customer density should not greatly affect the level of corporate overheads a service provider incurs because corporate overheads should be largely fixed costs.

Network overheads

Our network overheads metric indicates that Energex's and Ergon Energy's network overheads are comparable to other service providers.

Network overheads are all expensed and capitalised overhead costs allocated to standard control services that are directly attributable to operating an electricity distribution system. Among other things, these include costs incurred by network planning and asset management functions. We present total network overheads per circuit km in figure A.15.[434]

Figure A.15 Average network overheads per circuit km for 2009 to 2013 against customer density ($2013–14)



Source: Category analysis RIN data and economic benchmarking RIN data

Energex and Ergon Energy appear to have network overhead costs that are comparable to service providers with similar densities. However, given Ergon Energy's

[434] We chose to normalise network overheads costs by circuit kilometre because asset volumes are more likely to drive network overhead costs than customer numbers. We have used circuit length as a proxy for assets. Circuit length is a more easily understandable and intuitive measure than capacity measures such as transformer capacity or circuit capacity.

much lower density, we would expect to see it on a lower position than all other service providers with the exception of Essential Energy, which has a similarly low customer density.

When making comparisons on 'per kilometre' metrics against customer density, we need to bear in mind that service providers with low customer densities should appear more favourably than those with high customer densities. Lower density service providers are typically larger networks with many kilometres of line to serve sparsely located customers. While this generally means they tend to have high 'per customer' costs, they also have low 'per kilometre' costs.

Maintenance

Our maintenance metric indicates that Energex's maintenance opex is comparable, and Ergon Energy's maintenance opex is high relative to other service providers. This and the findings of the IRP led us to review Ergon Energy's resourcing of regional depots.

Maintenance expenditure relates to the direct operating costs incurred in maintaining poles, cables, substations, and SCADA, but excludes vegetation management costs and costs incurred in responding to emergencies. We present average maintenance costs per circuit kilometre in figure A.16.[435]

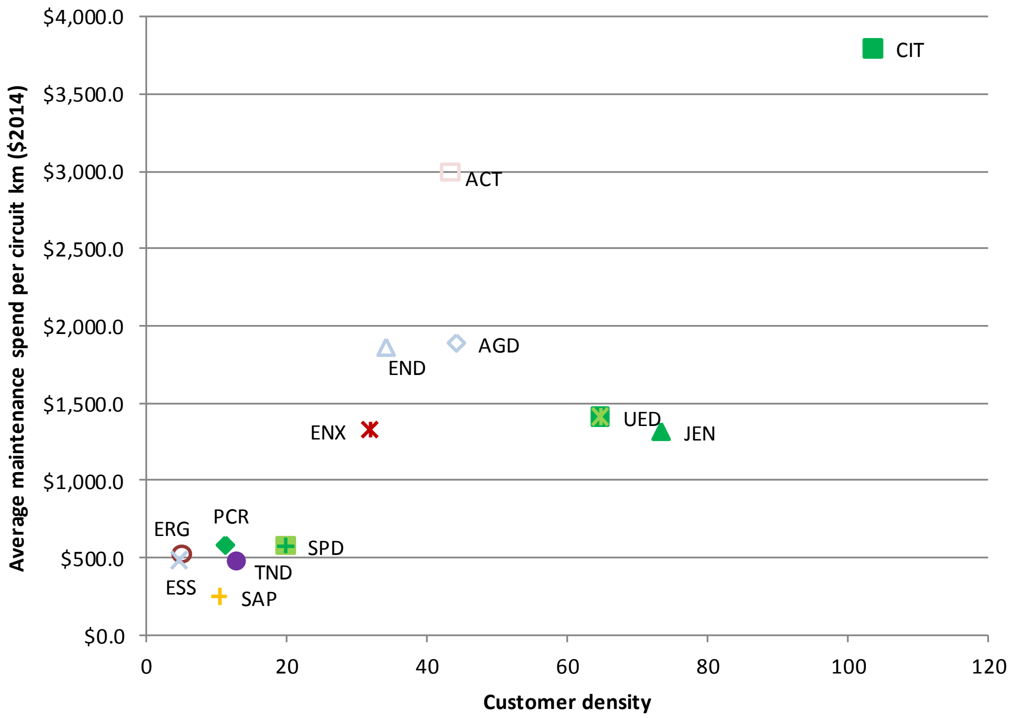
Figure A.16 shows that Energex appears to perform favourably compared to Endeavour Energy, which has a similar customer density. However, its performance is similar to JEN and UED, which have significantly higher customer densities. We would expect Energex to perform more favourably than JEN and UED on this metric.

Ergon Energy appears to have costs that are comparable to the other rural service providers. However, Ergon Energy, as one of the least dense service providers, should, in theory, have lower costs per kilometre than more dense service providers such as TasNetworks and SA Power Networks.

---

[435] We chose maintenance per circuit kilometre because assets are more likely to drive maintenance costs than customer numbers. We used circuit length because it is a more easily understandable and intuitive measure of assets than transformer capacity or circuit capacity.

Figure A.16 Average maintenance per circuit km for 2009 to 2013 against customer density ($2013–14)



Source: Category analysis RIN data and economic benchmarking RIN data.

Emergency response

Our emergency response metric indicates that Energex's and Ergon Energy's emergency response opex are comparable to other service providers.

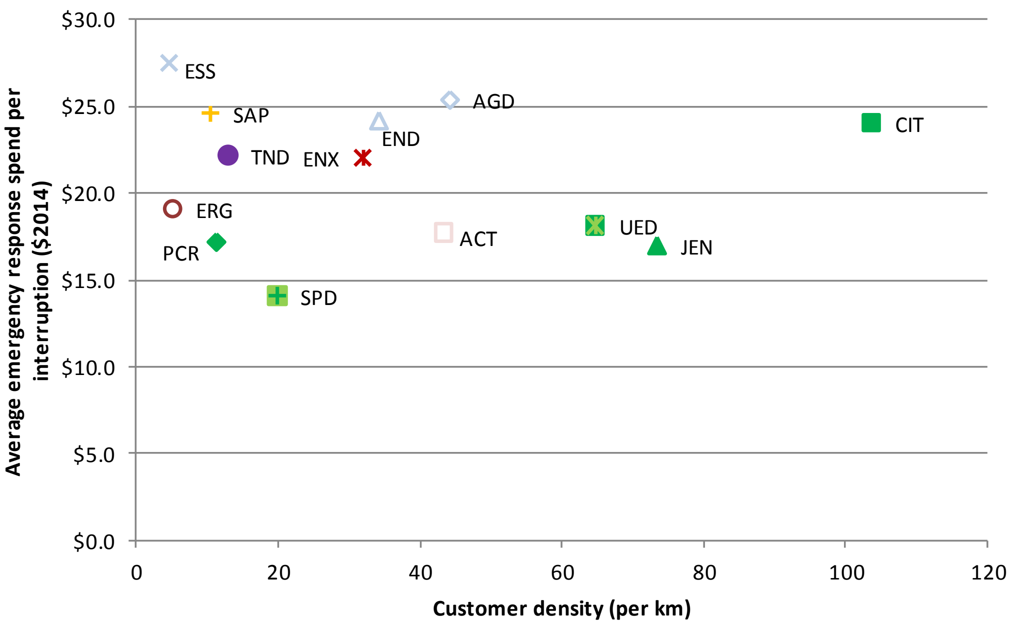
Emergency response expenditure is the direct operating cost incurred in responding to network emergencies, excluding costs associated with major event days. We excluded major event day emergency response costs and interruptions because response to major events does not reflect standard and comparable emergency response work. We present emergency response expenditure per interruption in figure A.17.[436]

Figure A.17 shows the range of service providers' emergency response expenditure per interruption is relatively narrow. Ergon Energy appears to have emergency

[436] We chose emergency response per interruption because the number of supply interruptions is more likely to drive emergency response costs than customer numbers. We used supply interruptions rather than interruption duration because the number of interruptions is more likely to drive emergency response costs than the duration of interruptions. Where there is an interruption, there must be expenditure to correct it. The duration of an interruption should not impose emergency response costs on the service provider. There may be other costs imposed on the service provider such as lost revenue or Guaranteed Service Level payments, but these are not emergency response costs.

response expenditure per interruption similar to a number of Victorian service providers including Powercor, UED and JEN. Energex performs favourably compared to the NSW service providers. Both Energex and Ergon Energy are reasonable performers on this metric.

Figure A.17 Average emergency response expenditure per interruption for 2009 to 2013 against customer density ($2013–14)



Source: Category analysis RIN data and economic benchmarking RIN data.

It is possible to make comparisons between service providers of different densities on this metric because customer density should not affect the average emergency response spend per interruption. Although customer density does not appear to affect costs, we have measured emergency response costs against customer density because the average spends against customer density are easier to read than the time trend of expenditures.

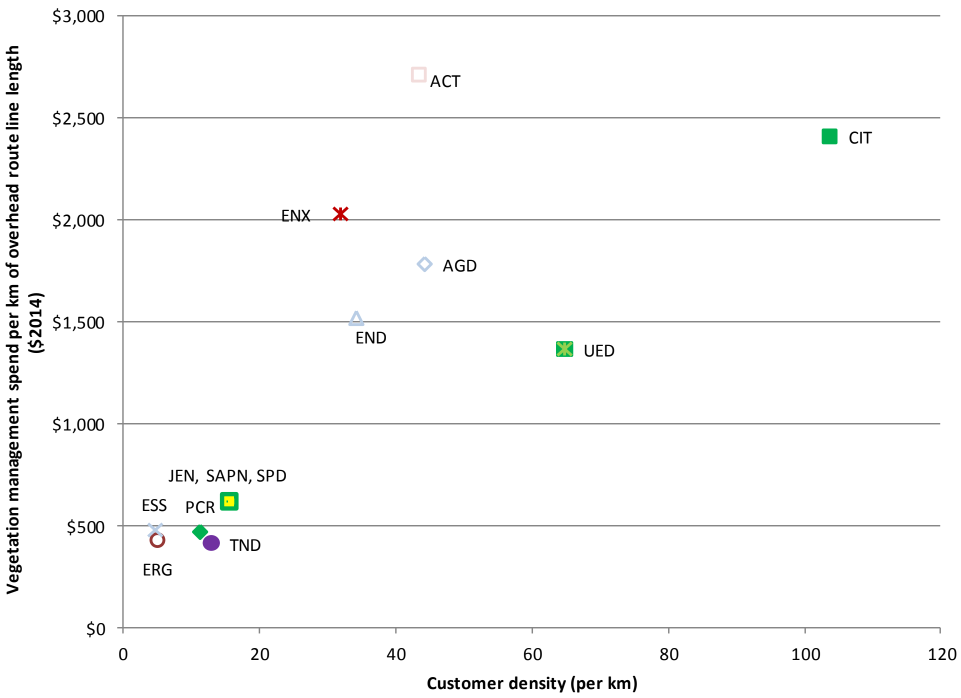
Vegetation management

Our vegetation management metrics indicate that Energex's vegetation management opex is high, and Ergon Energy's is comparable relative to other service providers.

Vegetation management expenditure includes tree trimming, hazard tree clearance, ground clearance, vegetation corridor clearance, inspection, audit, vegetation contractor liaison, and tree replacement costs. We present average vegetation management cost per kilometre of overhead route line length. However, as we use overhead route line length rather than maintenance span length (our preferred metric), we treat the results of figure A.18 with caution.[437]

Figure A.18 shows that Energex appears to have high costs relative to many other service providers including Ausgrid, Endeavour Energy and UED. Ergon Energy appears to perform well on this metric; however as a 'per kilometre' metric, this comparison will favour rural businesses. Given this, Ergon Energy, as one of the least dense service providers, should have lower costs per kilometre than more dense service providers such as TasNetworks.

Figure A.18 Average vegetation management costs per kilometre of overhead line length for 2009 to 2013 against customer density ($2014)



Source: Category analysis RIN and Economic benchmarking RIN

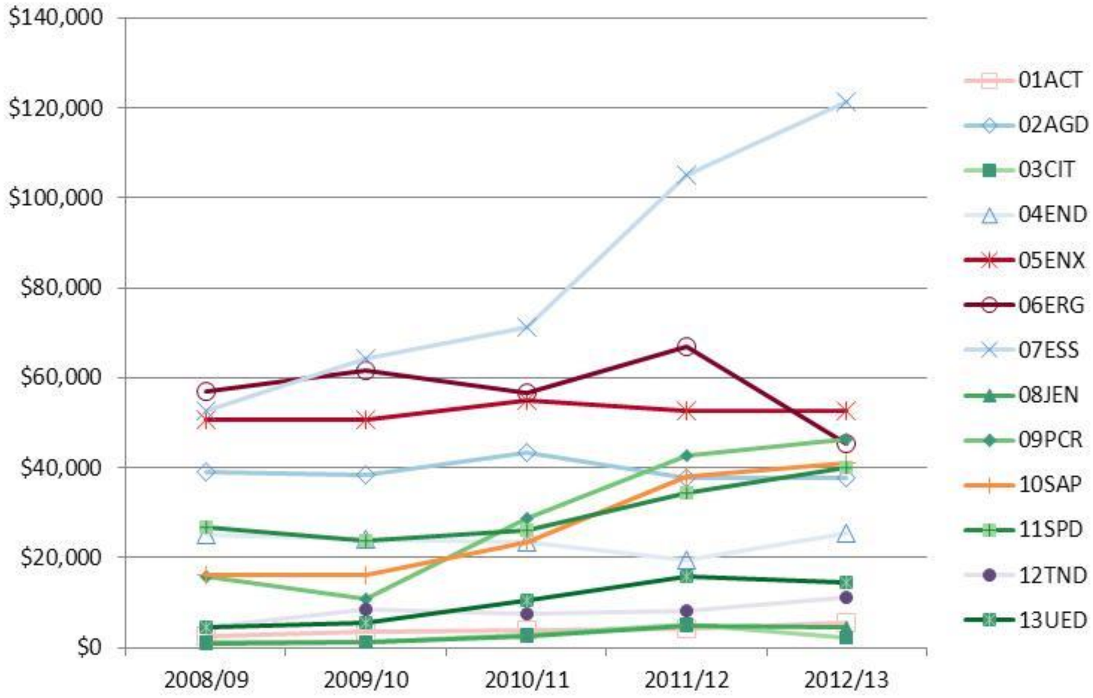
Figure A.19 shows the trend in total vegetation management costs. Figure A.19 is not normalised by an output so service providers are not directly comparable. We note that, Ergon Energy, which has a similarly sized rural network to Essential Energy, has had relatively stable vegetation management expenditure over the period but has significantly reduced its expenditure in the base year. Energex's vegetation management costs again appear high relative to other large networks such as Ausgrid;

---

437 Ideally, we would use maintenance span length. Maintenance span length measures the length of service providers' lines that have undergone vegetation management in the preceding twelve months. However, service providers' estimation assumptions seem to influence the data on maintenance spans. For some service providers maintenance spans were only a small part of overhead route line length, while for others they made up the vast majority of overhead route line length.

however, Energex has proposed a negative step change for vegetation management costs in the forecast period.[438] We discuss this step change in appendix C.

Figure A.19 Total vegetation management costs 2009 to 2013 ($'000, 2014)



Source: Category analysis RIN data

A.5.3 Detailed review

Our analysis in the above sections is consistent with the results from our economic benchmarking techniques. Category analysis metrics show that Energex and Ergon Energy's labour and overhead costs. The inefficiency in overheads is recognised by Ergon Energy in its regulatory proposal.[439] As a result, and due to overlap with the IRP findings, we conducted a detailed review of these topics.

As we explain above Energex's and Ergon Energy's regulatory proposals and supporting information provide evidence that both service providers have expended too much on labour and overheads. This, and our category analysis results, suggest further review is warranted. Several submissions on the AER's issues paper support this view.[440] In addition, the IRP report suggests further efficiencies are yet to be realised.

438 Energex, *Energex regulatory proposal appendix 8: Application of base-step-trend (BST) model*, October 2014, pp. 18–19.

439 Ergon Energy, *Regulatory proposal*, October 2014, p. 71.

440 See, for example, Energy Users Association of Australia, Submission to Ergon Energy revenue proposal 2015/16 to 2019/20, January 2015, pp. 22–26, 28; SPA Consulting Engineers (QLD), Submission to the Australian Energy

In order to better understand the expenditure drivers, we engaged Deloitte to assist us with our detailed review. Our scope of work for Deloitte primarily focussed on three questions:[441]

- What are the key factors driving the gap in opex performance (demonstrated by the benchmarking results) for Energex and Ergon Energy in comparison to their peers in 2012–13 and 2013–14?
- To what extent have Energex and Ergon Energy fully implemented any of the recommendations from the independent review?
- Are there reasons for Energex's opex productivity deteriorating between 2011–12 and 2012–13 other than inefficiency?

The answers to these questions are important to help us understand the factors that are contributing to Energex's and Ergon Energy's overall efficiency performance, and identifying whether their 2012–13 base opex contains inefficiencies.

Deloitte conducted a comprehensive and independent review, which involved:

- reviewing documents provided by Energex and Ergon Energy in response to requests for further information;
- holding in-depth discussions with Energex and Ergon Energy via video conference; and
- reviewing past and current regulatory proposals, supporting information and legislative requirements.

Deloitte's findings are:[442]

- key factors driving the efficiency gap include:
    - labour costs
    - workforce scheduling
    - workforce flexibility
    - overtime
    - SPARQ costs
    - regional depots (for Ergon Energy)
    - outsourcing

Regulatory Queensland determination for the period 2015–2020, January 2015, p. 4; Origin Energy, Submission to Queensland electricity distributors' regulatory proposals, January 2015, pp. 12–15; Consumer Challenge Panel (CCP2), Submission on Energex and Ergon 2015–20 capex and opex proposals, January 2015, p. 20.

441 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. v.

442 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. viii–xv.

- while Energex and Ergon have progressed implementing some IRP recommendations, they have not yet implemented all of them
- while significant efficiency gains have been achieved since the IRP's recommendations were finalised much of these benefits were realised after the 2012−13 base year. Energex and Ergon Energy have also both forecast further efficiency gains. The result is the base year opex for both service providers would not have been efficient.
- much of the fall in Energex's productivity appears to be explained by significant increases in ICT capex and one-off costs.

We consider Deloitte's findings support our conclusion that the base year opex proposed by both Energex and Ergon Energy contains inefficiencies and is inappropriate for forecasting opex in accordance with the NER.

Key factors driving the efficiency gap

Labour inefficiencies

Deloitte found evidence of inefficiency in Energex's and Ergon Energy's labour costs and practices. This is consistent with a number of submissions raising concerns about Energex's and Ergon Energy's labour expenses.[443] Deloitte found that both service providers (but Ergon Energy in particular) have high total labour costs compared to more efficient peers. Deloitte found this is a result of having too many employees rather than the cost per employee.[444]

The inference is therefore that Ergon's and Energex's workforces are less productive than their peers. There are a number of possible reasons for this, including workforce culture, management and operational decisions. Another factor is the restrictions included in Enterprise Bargaining Agreements (EBAs), as well as the relatively high percentage of employees subject to those EBAs.

Deloitte noted that more than 75 per cent of Energex and Ergon employees are employed under EBAs, which is significantly more than the Victorian distributors. This

---

[443] AGL, *Energex Regulatory Proposal: July 2015 to June 2020 - AGL submission to the Australian Energy Regulator*, 30 January 2015, p. 7; Cally Wilson, *Energex: A Sustainable Future?*, p. 2; CCIQ, *Submission on Energex's regulatory proposal 2015–20*, 30 January 2015, pp. 12–13; CCIQ, *Submission on Ergon Energy's regulatory proposal 2015–20*, 30 January 2015, p. 15; SPA Consulting Engineers (QLD), *Submission to the Australian Energy Regulator - Queensland Distribution Determination for the period 2015 – 2020*, 30 January 2015, pp. 4–5; Australians in Retirement, *A Submission to the Australian Energy Regulator From the Cairns and District Branch of Australians in Retirement*, 28 January 2015, p. 3; Cummings Economics, *Submission to Australian Energy Regulator on behalf of a Network of Electricity Users in Far North Queensland*, 30 January 2015, p. 30.

[444] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. viii–ix.

amplifies the effect of the EBA inflexibilities described below, relative to the Victorian distributorss.[445]

Workforce scheduling

The IRP found that 'the lack of a single, well-structured system for scheduling depot activities is contributing to under-utilisation of labour within the distributors.' The IRP recommended that Energex and Ergon implement an effective scheduling tool to improve efficiency and productivity of the workforce. It also made recommendations to improve the flexibility of the workforce and enhance workforce planning.[446]

Deloitte found that Energex and Ergon Energy have taken steps to improve their workforce scheduling processes and systems. However, for both service providers, the changes that have occurred to date were made after the 2012–13 base year.

Deloitte also observed some EBA limitations that would impact on efficient scheduling. Ergon Energy's Single Person Operation Guidelines and Queensland industry procedures require switching activities to be undertaken by a switching operator and switching assistant. In other states these tasks can be carried out by a single person. Ergon's EBA requires 'mutual agreement' with unions for the introduction of new tasks to the Single Person Operation Guidelines. Deloitte considers these limitations adversely affect idle time and overall labour productivity.[447]

Workforce flexibility

Deloitte considered that certain EBA provisions, while not necessarily unique to Energex and Ergon Energy, limit their ability to quickly adjust their workforces and utilise them productively. These include restrictions on:[448]

- involuntary redundancy—such restrictions impede management's ability to reduce the operational workforce
- when contractors may be used for core work—they must consult with unions before certain work can be outsourced. Consultation requirements are common among service provider EBAs, suggesting that the existence of these requirements alone does not drive the differences in outsourcing and workforce flexibility outcomes, rather how the requirements operate in practice
- the wages and conditions able to be offered to contractors— external contractors be employed under conditions that are equivalent to their own workforce. Such requirements are not unique to the Queensland service providers but the impact of

---

445 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. ix.

446 Independent Review Panel on Network Costs, Electricity Network Costs Review, 2013, p. 60.

447 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. ix–x.

448 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. x–xi.

these requirements appears to be amplified in Queensland where a higher proportion of employees are covered by the EBAs.

- the ability for contractors to perform certain tasks such as switching—the Queensland service providers' EBAs state that they must 'restrict authorisation and access for external service providers' to certain tasks. These requirements increase the non-productive time of contractors, who must wait for an employee to attend a site at the beginning and conclusion of works, leading to inefficiency.
- minimum apprentice numbers—both Energex and Ergon Energy must employ a minimum number of apprentices, which restricts flexibility on changing the workforce size.

Deloitte found that it is likely these constraints, along with the high proportion of workforces employed on EBAs, have together delivered significantly less outsourcing of opex activities in recent years than the Victorian distributors. Deloitte considered that these constraints on workforce flexibility are likely to have delivered higher than efficient base year opex. Any changes to these requirements during the 2015−20 regulatory control period will likely improve the Queensland service providers' opex efficiency.[449]

Overtime

One of the IRP's findings was that it observed a large amount of Energex's and Ergon Energy's employees had very high gross to base (salary) ratios (GBR) of 1.5 and above. GBR measure the number of employees earning overtime compared to their base salary. An employee with a GBR of 1.5, for example, earns 50 per cent of its base salary in overtime (on top of his or her base salary).[450] The IRP considered this would likely to result in lower levels of productivity.[451]

Deloitte found that both Energex and Ergon Energy have taken steps to reduce overtime. However, Energex in particular incurred significant overtime in expenditure in the 2012–13 base year.

SPARQ (ICT) costs

The IRP made a number of observations and recommendations specifically targeted at Energex's and Ergon Energy's IT costs, which are incurred via charges paid to SPARQ. SPARQ is a joint venture company owned by Energex and Ergon Energy. SPARQ's fees are fully accounted for in Energex's and Ergon Energy's opex.[452]

---

[449] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. xi.

[450] Gross to Base (salary) Ratios, which is a measure of the number of employees earning compared to their base salary. An employee with a GBR of 1.5, for example, earns 50 per cent of its base salary in overtime.

[451] Independent Review Panel on Network Costs, Electricity Network Costs Review, 2013, p. 62.

[452] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. xii–xiii.

The most important IRP recommendations were associated with the need to place competitive pressure on SPARQ, through market testing the services it provides to Energex and Ergon, as well as the need to change the relationships between the service providers and SPARQ. The IRP recommended that Energex and Ergon Energy test alternative service delivery models for IT services by issuing market tenders for capital projects and relevant operational IT services.[453] Some submissions also raised concerns about Energex's and Ergon Energy's procurement of IT services through SPARQ.[454]

Deloitte found that some changes were implemented since the IRP's final report, including the development of an IT Panel which SPARQ manages. However, reforms to date do not fully reflect the IRP recommendations and, importantly, have not yet significantly improved competitive pressures on SPARQ.[455]

Deloitte also found that the Energex's and Ergon Energy's IT costs have increased significantly over the 2010–15 period, particularly in the base year, due to large increases in SPARQ's operational costs and asset management/service fees.[456]

Deloitte considered it is apparent that IT costs are a material source of inefficiency within Energex's and Ergon Energy's opex, and although some changes have been implemented following the IRP's final report, these are not reflected in the 2012–13 base year.

Regional depots and the Local Service Agent model

The IRP recommended that Ergon Energy move to a Local Service Agent (LSA) model to outsource work in regional areas, rather than running its own regional depots. Deloitte noted that Ergon Energy has not implemented the IRP's recommendation.[457]

Deloitte observed that, unlike Energex which has always existed as one entity, Ergon formed after the amalgamation of a number of smaller electricity distributors. This has resulted in Ergon facing a number of legacy issues including a high number of service depots.

Deloitte undertook research into the LSA model, which Powercor implemented following privatisation. Deloitte found it had significantly increased the operational

---

[453] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. xiii.

[454] Origin Energy, *Submission to Queensland Electricity Distributors' Regulatory Proposals*, 30 January 2015, pp. 14–15

[455] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. xiii.

[456] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. xiii.

[457] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. 58–59.

efficiency of Powercor's regional network areas. These efficiency outcomes are associated with:[458]

- reductions in the absolute number of depots and sites
- reductions in staff per depot, with more flexibility in rostering
- cultural change, driven by the small business incentives to reduce costs. Once the LSA model was established, significant efficiencies were identified and achieved in a range of existing processes, driven by a more cost-conscious approach and the need to reduce overtime.

Deloitte observed that while effort has been made to consolidate Ergon's legacy property assets and the depot network, there is likely to be scope for additional consolidation under a local service agent model. Therefore, Deloitte considered that applying an LSA model, combined with reform of the EBA restrictions around contractor switching, could deliver significant workforce cost efficiencies within Ergon Energy.[459]

Outsourcing

Deloitte observed that, with the exception of the constraints on contractor switching, which appears to be unique to Queensland service providers, all service provider EBAs nationally contain various limitations on the use of outsourcing (although the nature and extent of constraints vary). However, in practice, the level of outsourcing carried out by Energex and Ergon over the 2010−15 regulatory control period (between 30 and 40 per cent of labour opex) is materially lower compared to the Victorian distributors (between 50 and 90 per cent of opex, including related party outsourcing).

Overall, it appears that the Queensland service providers' EBA provisions, while not preventing outsourcing, may have imposed limits on their ability to engage contractors quickly and efficiently. It is likely that these constraints, along with the high proportion of their workforces employed on EBAs, have together delivered lower levels of outsourced opex over the period 2009-14.

Progress on IRP recommendations

Deloitte found that Energex has made significant progress in addressing the IRP recommendations. Of the 11 IRP recommendations relevant to Energex, it has fully implemented eight.

Ergon has also made progress in addressing the IRP recommendations. Of the 17 IRP recommendations relevant to Ergon, it has implemented nine, while progress on a

---

458 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, p. 61.

459 Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. 58–63.

further four recommendations is unclear. Another four recommendations have not yet been implemented.

Deloitte notes that significant efficiency gains have been achieved since the IRP's recommendations were finalised (particularly reflected in FTE reductions) as a result of Energex's Business Efficiency Program (BEP) and Ergon's Effectiveness and Efficiency Program (EEP) and implementation of the IRP's recommendations. However, much of these benefits were realised after the 2012−13 base year.

In addition to savings made in 2013−14, both businesses are expecting to make further efficiency gains in the 2015–20 regulatory control period, particularly through further reducing their staffing levels. As a result, Deloitte found that there are material opex savings not incorporated into base year opex and, therefore, base year opex for neither service provider is efficient.[460]

This supports our conclusion that the base year opex proposed by both Energex and Ergon Energy contains inefficiencies and is inappropriate for forecasting opex in accordance with the NER.

Energex's declining productivity

Although our benchmarking shows Energex as more productive than Ergon, its productivity declined significantly in 2012–13 and 2013–14 (the final two years of the benchmarking period).

Deloitte found that much of the fall in productivity in these years appears to be explained by significant increases in ICT capex (in SPARQ's Asset Management Fee, which is reflected in opex), redundancy costs associated with reducing its workforce and one-off opex associated with both addressing a manufacturing defect in its service lines and the aftermath of Tropical Cyclone Oswald.[461]

---

[460] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. xiv–xx.

[461] Deloitte Access Economics, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. xiv–xv.

A.6 The net impact of operating environment adjustments

When undertaking a benchmarking exercise, circumstances exogenous to a service provider should generally be taken into account. By taking into account exogenous circumstances, one can determine the extent to which cost differences are exogenous or due to inefficiency.[462] The purpose of our assessment of operating environment factors (OEFs) is to account for these exogenous circumstances.

In its Final Rule Determination on the Economic Regulation of Network Service Providers the AEMC stated:

> The final rule gives the AER discretion as to how and when it undertakes benchmarking in its decision-making. However, when undertaking a benchmarking exercise, circumstances exogenous to a NSP should generally be taken into account, and endogenous circumstances should generally not be considered. In respect of each NSP, the AER must exercise its judgement as to the circumstances which should or should not be included.[463]

The AEMC also noted that:

> The intention of a benchmarking assessment is not to normalise for every possible difference in networks. Rather, benchmarking provides a high level overview taking into account certain exogenous factors. It is then used as a comparative tool to inform assessments about the relative overall efficiency of proposed expenditure. [464]

In the course of the current ACT, NSW, Queensland and SA regulatory determinations, we have considered more than 60 OEFs that we, service providers and other stakeholders have referred to. We considered each factor using our three OEF criteria of exogeneity, materiality, and duplication. We do not provide an adjustment for non-exogenous or duplicative factors. For material, exogenous and non-duplicative factors, we make an adjustment to the level of that materiality. If such a factor is immaterial, we take a different approach that nonetheless recognises that such factors may have an impact on a service provider, albeit a small one.

We also consider that our approach to OEFs appropriately allows service providers to recoup at least efficient costs. In addition to adjusting for the material OEFs identified, we have provided an adjustment for the collective effect of immaterial OEFs that are exogenous and not accounted for elsewhere. Service providers receive positive 0.5 per cent adjustments for OEFs identified as immaterial that may disadvantage

---

462 Oakley Greenwood, *Review of NSW DBs Regulatory Submissions*, 5 August 2014, p. 16.

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

464 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, pp 107–108.

them or where there the direction of the advantage is uncertain. In future reviews, as we collect more information on OEFs, we are likely to adopt a stricter approach to the consideration of OEFs.

A.6.1 Preliminary decision

We have provided an input margin of 17.1 and 24.4 per cent to Energex and Ergon Energy to account for differences in operating environment factors (OEFs), not accounted for in Economic Insights' SFA model.[465] We have come to this conclusion after assessing over 60 different OEFs that we, service providers, and other stakeholders identified in the process of this review and in response to our draft benchmarking report.

To account for OEFs not captured in Economic Insights' SFA model, we have identified OEF adjustments. For each OEF identified, we considered if it is necessary to provide an OEF adjustment for it. We determined which factors require an adjustment using our three OEF adjustment criteria: exogeneity, materiality, and duplication. Where we were satisfied that an OEF adjustment is required we assessed the OEF to estimate its impact on service providers' opex.

During the course of our investigations we also identified additional OEFs that did not meet our OEF adjustment criteria because they would not individually create material differences in opex.

Although individually the effects of these OEFs on opex may not be material, their combined effect may be. To allow for the collective effect that these OEFs may have, we have provided an allowance of 5.0 and 6.1 per cent to Energex and Ergon Energy respectively. The method we used is discussed further in our approach section.

We identified several OEFs that require OEF adjustments. Table A.8 below summarises the adjustments.

Table A.8 Summary of material OEF adjustments[466]

Factor	Energex	Ergon	Reason against OEF criteria[467]
Bushfires	–0.5%	–2.6%	• The geographic characteristics and settlement patterns of a network area are beyond the control of service providers. • Regulatory obligations associated with bushfire risk can have a material impact on service providers' opex.

[465] The comparison firms are all service providers that score equal to or above the benchmark comparison point on Economic Insights' Cobb Douglas SFA benchmarking model, which is our preferred economic benchmarking method.

[466] Totals do not add due to rounding.

[467] Our OEF criteria, Exogeneity, materiality, and duplication, are explained in detail in our section on our approach to OEFs. Total do not sum due to rounding.

Factor	Energex	Ergon	Reason against OEF criteria[467]
			• Economic Insights' SFA model does not account for differences in bushfire risk.
Cyclones	0.0%	4.6%	• Cyclones are beyond service providers' control. • Information provided by Ergon Energy suggests that the effect of extreme weather events on opex can be material. • Economic Insights' SFA model does not include variables that account for the effect of cyclones
Extreme weather	2.7%	3.0%	• The weather is beyond service providers' control. • Information provided by Energex and data in the category analysis RINs suggests that the effect of extreme weather events on opex can be material. • Economic Insights' SFA model does not include variables that account for the effects of extreme weather
Licence conditions	0.0%	0.7%	• The 2005 Queensland network planning requirements were not determined by the Queensland service providers. • Category analysis and economic benchmarking RIN data suggest that the increased transformer capacity to meet the 2005 change in network planning requirements may lead to a material increase in maintenance expenditure. • Economic Insights' SFA model does not include a variable that accounts for licence conditions.
Network Access	0.0%	1.1%	• The amount of a service provider's network with non-standard vehicle access is determined by land use that is beyond service providers' control. • Information provided by Ergon Energy and in the Economic Benchmarking RIN data suggests that differences in network access can lead to material differences in opex. • There are no variables in Economic Insights' SFA model that account for differences in non-standard vehicle access.
OH&S regulations	0.5%	0.5%	• OH&S regulations are not set by service providers. • Data from the ABS and a PwC report commissioned by the Victorian Government suggest that differences in OH&S regulations may materially affect service provider's opex. • Economic Insights' SFA model does not include a variable that accounts for differences in OH&S legislation.
Taxes and levies	2.7%	1.7%	• Taxes and levies are not set by service providers. • The taxes and levies identified by the

Factor	Energex	Ergon	Reason against OEF criteria[467]
			Queensland service providers account for a material part of their standard control services opex. • Economic Insights' SFA model does not include a variable that accounts for differences in taxes and levies.
Termite exposure	0.2%	0.5%	• The prevalence of termites in a geographic area is beyond service providers' control. • Data on Powercor's termite management costs and data from the CSIRO on the range of termites suggest that the Essential Energy may have a material cost disadvantage due to termite exposure. • Economic Insights' SFA model does not include a variable that accounts for differences in termite exposure.
Subtransmission	3.2%	4.6%	• The boundary between distribution and transmission is not determined by service providers • Data from Ausgrid's regulatory accounts suggest that subtransmission assets are up to twice as costly to operate as distribution assets. • Economic Insights' SFA model does not include a variable that accounts for subtransmission assets.
Vegetation management	3.4%	4.1%	• The division of responsibility for vegetation management and other stakeholders is not determined by service providers • Information from Energy Safe Victoria, the Victorian service providers, the Queensland service providers, the category analysis RINs, and Economic Benchmarking RINs, suggests that differences in responsibilities for vegetation management could lead to material differences in opex. • Economic Insights' SFA model does not include a variable that accounts for differences in the division of responsibility for vegetation management.
Immaterial factors	5.0%	6.1%	There are various exogenous, individually immaterial factors not accounted for in Economic Insights' SFA model that may affect service providers' costs relative to the comparison firms. While individually these costs may not lead to material differences in opex, collectively they may.
Total	17.1%	24.4%	

Source: AER analysis.

We have considered OEFs raised by other service providers in their regulatory proposals and revised regulatory proposals. We have also considered submissions on those proposals where relevant. We have done this for consistency in our approach to

OEFs and to capture the effect of relevant OEFs on the Queensland service providers' opex.

We have considered all of the submissions made to us on OEFs, but not all service providers have had the same opportunities to provide information on the OEFs that affect their costs yet. We have sought information on some of the OEFs raised by the ACT, NSW and Queensland service providers from the Victorian service providers, but our review has focused on the OEFs in the context of the current decisions. The Victorian service providers have not yet had the same opportunity to present us their cost disadvantages. In future reviews we expect that the Victorian service providers and other stakeholders will provide further information on the effect of OEFs. These submissions may reveal cost advantages that the Queensland service providers have relative to the Victorian service providers. Cost advantages have the effect of decreasing the total adjustment made to a service provider's opex for OEFs. Therefore our current approach may favour the ACT, NSW, and Queensland service providers to the extent that not all of their cost advantages have been revealed.

In line with the AEMC,[468] we have separated the analysed factors into five groups which are considered separately below:

- customer factors
- endogenous factors
- geographic factors
- jurisdictional factors
- network factors.

[468] AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers)*, November 2012, p. 113.

A.6.2 Approach to operating environment factors

It is important to recognise that service providers do not operate under exactly the same operating environment factors (OEFs). OEFs may have a significant impact on measured efficiency through their impact on a service provider's opex. It is desirable to adjust for material OEF differences to ensure that when comparisons are made across service providers, we are comparing like with like to the greatest extent possible. By identifying the effect of OEFs on costs one can determine the extent to which cost differences are exogenous or due to inefficiency.[469]

Some key OEFs are directly accounted for in Economic Insights' SFA model. Where this has not been possible, we have considered the quantum of the impact of the OEF on the Queensland service providers' opex relative to the comparison firms. We have then adjusted the SFA efficiency scores based on our findings on the effects of OEFs.

We have accounted for OEFs using a two-step process. In the first step we have assessed whether an adjustment for an OEF would meet our OEF criteria: exogeneity, materiality, and duplication. In the second step, we assessed OEFs that met the exogeneity and duplication criteria to estimate the collective effect that they may have on service providers' opex. The purpose of the second step is to account for the effect of OEFs that do not meet the materiality criterion individually, but which do meet the criterion when considered collectively.

OEF assessment: Step one

Where an OEF meets all three of our OEF adjustment criteria we have provided an OEF adjustment. Our three OEF criteria are as follows:

1. **Exogeneity:** The first criterion is that an OEF should be outside the control of service providers' management. Where the effect of an OEF is within the control of service provider's management we would not generally provide an adjustment for the OEF.[470] Adjusting for that OEF may mask inefficient investment or expenditure.
2. **Materiality:** The second criterion is that an OEF should create material differences in service providers' opex. Where the effect of an OEF is not material, we would generally not provide an adjustment for the factor. We do note, however, that we have provided a collective adjustment for individually immaterial factors.[471] [472]

---

[469] Oakley Greenwood, *Review of NSW DBs Regulatory Submissions*, 5 August 2014, p. 16.

[470] AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers)*, November 2012, p. 113.

[471] We have treated any OEF that will increase a service provider's opex by 0.5 per cent or more, relative to other service providers, as material. We chose 0.5 per cent as the materiality threshold because this is the materiality threshold we used in the Economic Benchmarking RIN. The materiality threshold relates to differences between the previous cost allocation method (CAM) and the current CAM. If service providers' current CAMs lead to material differences in reported opex compared to their past CAM, they are required to backcast their costs using their current CAM. The comparable threshold for preparing financial statements, in AASB 1031: Materiality, is between 10 and 5 per cent.

3. **Duplication:** The third criterion is that the OEF should not have been accounted for elsewhere. Where the effect of an OEF is accounted for elsewhere, we have not provided an adjustment for that factor. To do so would be to double count the effect of the OEF.[473] [474]

Given the nature of OEFs, as circumstances that differ between service providers, we have had to rely on a wide array of different information sources. For each OEF we have considered the evidence before us in making our conclusions. In some cases this has meant calculating the effect of OEFs using different types of data or methods. The calculation of OEF's below explains how we have taken this into account.

OEF assessment: Step two

In the second stage of our OEF assessment we have considered if each individually immaterial OEF, that meets the exogeneity and duplication criteria, will provide a cost advantage or disadvantage to the relevant service provider.

Where an individually immaterial OEF is likely to provide a cost disadvantage we have provided a positive adjustment equal to our materiality threshold, 0.5 per cent, in our collective adjustment for immaterial factors. We have also done this where there is some doubt about if an individually immaterial OEF will provide a cost advantage or disadvantage. Alternatively, where an individually immaterial OEF is likely to provide a cost advantage we have provided an OEF adjustment of negative 0.5 per cent in our collective adjustment for individually immaterial OEFs.

There is one exception to this. Where we have been able to quantify the effect of a factor that is individually immaterial we have only adjusted for the amount quantified. We consider that this provides a transparent and reasonable approach to estimating the effect of factors that individually may not be material but collectively may be.

We consider that this is an appropriately conservative approach. We note that the AEMC has stated that the purpose of benchmarking is not to normalise for every possible difference between networks. However, after considering the impact of more than 60 proposed OEFs, in addition to adjusting for 10 material OEFs, we have provided an adjustment for the collective effect of 19 immaterial OEFs. We consider it is appropriate to take this additional step in our benchmarking analysis given this is the first time we have applied benchmarking and the information on OEFs available to us at this stage. We also note that we have provided positive adjustments where the

---

[472] We also note that irrelevant OEFs will also be captured by the materiality criterion. Where an OEF is not relevant, for example it does not affect the comparison firms or the service provider being benchmarked, it will not lead to a difference in opex.

[473] For example, Economic Insights' SFA model captures the effect of line length on opex by using circuit length as an output variable. In this context, an OEF adjustment for circuit length would double count the effect of route line length on opex. Another example is that we exclude metering services from our economic benchmarking data. In this case, an OEF adjustment would remove the metering services from services providers' benchmarked opex twice.

[474] We also note that the SFA model uses dummy variables that account for all systematic differences in operating environments between the Australian and overseas service providers.

direction of advantage for immaterial factors is unclear. This is to allow service providers to recoup at least efficient costs incurred as a result of those immaterial OEFs, consistent with the revenue and pricing principles in the NEL. In future, as our information set improves we may reconsider our approach to immaterial OEFs.

Table A.9 below provides a summary of the quantification of the effect of immaterial factors.

Table A.9 Summary of immaterial OEF adjustments[475]

Factor	Energex	Ergon
Asset lives	-0.5%	0.5%
Building regulations	0.5%	0.5%
Capitalisation practices	0.5%	-0.5%
Cultural heritage	0.5%	0.5%
Corrosive environments	0.5%	0.5%
Environmental regulations	0.5%	0.5%
Environmental variability	-0.5%	0.5%
Fire ants	0.1%	0.0%
Grounding conditions	0.5%	0.5%
Mining boom cost imposts	0.0%	0.5%
Planning regulations	0.5%	0.5%
Private Power poles	-0.5%	-0.5%
Proportion of 11kV and 22kV lines	0.5%	0.5%
Rainfall and humidity	0.5%	0.5%
Skills required by different service providers	0.5%	0.5%
Solar uptake	0.5%	0.5%
Traffic management	0.5%	0.5%
Transformer capacity owned by customers	-0.1%	-0.4%
Topography	0.5%	0.5%
Total	5.0%	6.1%

Source: AER analysis.

475 Totals do not add due to rounding.

OEF assessment: comparison point

To determine if an OEF provides a cost advantage, or disadvantage, to a service provider we first determine who the service provider is being compared to. For the purpose of estimating the effect of OEFs, the comparison point is the customer weighted average of the service providers that score equal to or above the benchmark comparison point. This compares the service providers being benchmarked to all service providers at or above the benchmark point. This ensures that the operating circumstances of all the comparison firms are taken into account when assessing a service provider's base year opex. This allows a better estimate of service providers' underlying efficiency than a comparison to the service provider at the benchmark comparison point. Using the single firm at the benchmark comparison point could lead to OEF adjustments that unfairly advantage or disadvantage service providers.

For example, there may be a situation where there is an OEF that affects the service provider at the benchmark comparison point and other service providers above the benchmark comparison point differently. Providing an OEF based on a comparison to the service provider at the benchmark comparison point would lead to an OEF adjustment that would not reflect the broad variety of operating environments that the comparison firms operate in. This is because there are other service providers above the benchmark comparison point that may be advantaged or disadvantaged by the OEF under consideration. For this reason, as a comparison point for OEF assessment, we use the customer weighted average of all service providers that are at or above the benchmark comparison point.

OEF assessment: calculation of OEFs

We have had to estimate the impact of OEFs using different data sources. In some circumstances we have had access to the information required to estimate the incremental efficient cost of an OEF. In others we have only had the historical costs of the service provider being benchmarked to estimate the effect.

Where the efficient incremental costs can be estimated, the relevant OEF adjustment can be made in isolation. This is because the OEF adjustment is the percentage increase on the efficient costs estimated by the SFA model. An example of this is shown in Table A.10 below. The example shows how an adjustment would be calculated, using information on efficient costs, in the case that a service provider required a 50 per cent OEF adjustment.

Table A.10 Worked example of impact of an OEF where efficiency of costs has been demonstrated

Cost component		$m 2013
Firm's costs including exogenous factor	A	$150
Efficient costs estimated by SFA model	B	$100
Cost incurred for OEF	C	$50
OEF adjustment	D=(B+C)/B-1	50%
Forecast of efficient costs including OEF	E=B*(1+D)	$150

Source: AER analysis

Where we only have information on the historical share of opex an OEF represents for the service provider being benchmarked,[476] the OEF adjustment must be calculated with reference to the impact of other OEF adjustments. This change is made to translate the impact of the OEF on the service provider's historical costs, to the OEF adjustment to the efficient base year costs forecast by the SFA model.

This is done for two reasons. Treating the historical cost as fully efficient runs the risk of overcompensating the service provider. This is because those costs may contain some inefficiency. Additionally, if the impact of OEFs on historical opex is not taken into account, the OEF may over or undercompensate the service provider; depending on the direction of the adjustment. This is because the starting point to estimate the percentage change in opex due to the OEF will be affected by OEFs.

The Queensland service providers are affected by five OEFs where information on the efficient costs is not available: cyclones, extreme weather, licence conditions, customer owned distribution transformers, and the division in responsibility for vegetation management. The calculation of the adjustment to these factors can be found in the OEF summary spreadsheet attached to this decision.

OEF assessment: Non-recurrent costs

We are not satisfied that an OEF adjustment should be made for non-recurrent costs. Providing an OEF for non-recurrent costs would treat those costs as if they were recurrent. Economic Insights' benchmarking results are used as the basis for our forecast of opex. If we adjust the benchmarking results with an OEF adjustment for non-recurrent costs, it has the effect of including those non-recurrent costs in our opex forecast.

Additionally, an OEF adjustment for a non-recurrent cost would not meet the duplication OEF criterion. Economic Insights' SFA model takes non-recurrent costs into account. The SFA efficiency scores are based on the average performance of service

[476] In the case that there is no evidence to suggest those costs are efficient.

providers over the period. Therefore the effects of transitory increases or decreases in relative opex efficiency are reduced. Also SFA modelling accounts for transitory variations in data using a compound stochastic variance term. This statistical technique accounts for random shocks in opex.[477]

In the following sections we consider the OEFs raised by service providers and other stakeholders.

A.6.3 Customer factors

Customer Density

We are not satisfied that it is necessary to provide an OEF adjustment for customer density. An adjustment for customer density does not satisfy the duplication OEF adjustment criterion. On the basis of second stage regression analysis of the opex MPFP results, we are not satisfied that output variables in Economic insights' SFA model do not sufficiently accounts for the effects of customer density.

Customer density is a useful proxy for identifying the distance between customers. As each service provider has an obligation to serve existing customers, we assume that this is therefore an exogenous factor. Customer density, in and of itself, does not drive costs. Factors correlated with customer density are the underlying cost drivers. These include:

- Asset exposure - A shorter line will have be less exposed to degradation from the elements and damage from third parties.
- Asset numbers - The need to service customers that are spaced further apart will require additional substations, length of lines or cables to provide the same level of service.
- Travel times - the time taken to travel between customers or assets increases as those assets or customer are spaced further apart.
- Traffic management - traffic management requirements typically increase proportionally to the volumes of traffic on, or adjacent, to the worksite.
- Asset complexity - The complexity of assets in a given location - for example; multiple circuits on a pole, or circuits in a substation.
- Proximity to third party assets - Increased urban density results in more third-party overhead and underground asset being in proximity to electrical assets. This proximity requires increased co-ordination, planning, design, and installation costs.
- Proportion of overhead and underground - Increased urban density can result in greater obligations or constraints on the service providers in relation to the

[477] Aigner, D.J., C.A.K. Lovell and P. Schmidt, *Formulation and estimation of stochastic frontier production function models, Journal of Econometrics 6*, 21–37, 1977, p. 25.

augmentation or construction of underground/overhead assets. Maintenance of underground assets is typically reduced compared with overhead.

- Topographical conditions - adverse topographical conditions such as swamps, mountainous terrain, amongst other things will typically result in less habitable areas and increased costs associated with access to these areas.

Each of the above factors will affect network opex differently. It is obvious that some will have more of an adverse effect on rural services, while others will have a more adverse effect on urban services. The following table summarises the effect of the factors on networks depending on their respective customer density.

Table 7.A.11 Customer density factor impacts

Factor	Opex benchmark benefit
Asset complexity	Rural networks
Asset exposure	Urban networks
Asset numbers	Urban networks
Proportion of overhead and underground	Urban networks
Proximity to third-party assets	Rural networks
Topographical conditions	Urban networks
Traffic management	Rural networks
Travel times	Urban networks

The cost relationships explored in the table are simplifications. In reality, some may not be linear. For example, travel times may initially decrease as customer density increases but then increase again. This is because traffic congestion is likely to affect CBD areas more than urban or rural areas. We have made these simplifications to help demonstrate the effect that customer density may have on costs.

The fact that it is a simplification aside, the table demonstrates that it is not evident what the overall impact of customer density is on service providers' opex. Given the complexity of the above factors, it is clear that it is important to consider the impacts of customer density in any benchmarks that are undertaken.

We have considered a number of measures for aggregating the impacts from the above factors. Historically, industry benchmarks have used a number of representative measures including:

- Customer density measured as customers per (circuit) km of line (cust/km)
- Energy density measured as energy delivered per (circuit) km of line (kWh/km)
- Demand density measured as demand per (circuit) km of line (MVA/km)
- Customer density measured as customers per square kilometre of service territory

The use of service territory as a density measure has proven problematic. This is due to the difficulty in accurately measuring service territory items such as lakes, national parks, and unpopulated areas. As networks do not incur costs for areas that are un-serviced, customers per square kilometre of service area is not a useful measure for opex or service comparisons.

We are not satisfied that linear density is insufficient to capture the effects of customer density. This is because opex will be driven by the length of line that must be maintained rather than the area that the service provider nominally covers. Using a measure of spatial density may cover nominally servicing areas in which a service provider has no assets or customers. An example of this, provided by Economic Insights, is the Northern Territory distributor: Power and Water Corporation. [478] Nominally, Power and Water Corporation's service area is all of the Northern Territory.[479] In reality, Power and Water Corporations electricity distribution network covers Darwin and Katherine (with a transmission line between the two) on its main network with smaller networks around the Territory serviced mostly by isolated, diesel generator–based systems.[480] Therefore measuring customer density using Power and Water Corporations nominal service area would provide a misleading picture of the customer density of Power and Water Corporation's network.

This also applies to the consideration of Ergon Energy, Essential Energy, and SA Power Networks. Although Ergon Energy is nominally responsible for electricity distribution across all of Queensland (except South East Queensland), there are large parts of western Queensland where it has no assets. Similarly, there are parts of western NSW and the great dividing ranges that are nominally part of Essential's service area, but to which Essential provides no services. There are also large parts of northern South Australia where SA Power Networks has no assets.

Customer requirements

We are not satisfied an OEF adjustment for customer requirements would meet the duplication OEF adjustment criterion. Special customer requirements are accounted for elsewhere. This is because our economic benchmarking data only capture information on network services.

All service providers have customers with high security of supply requirements. Examples of these include hospitals, state parliaments, military installations, banks, stock exchanges, and telecommunications facilities. Many manufacturing industries also have very high requirements for supply security due to the costs of lost production and equipment damage.

---

478 Economic Insights, April 2015, pp. 14–15.

479 Power and Water Corporation, About Power and Water, available at: www.powerwater.com.au/about_power_and_water [last accessed 9 March 2015].

480 Power and Water Corporation, Electricity Map, available at: www.powerwater.com.au/community_and_education/student_resources/maps/electricity_map [last accessed 9 March 2015].

We are not satisfied that an adjustment for customer requirements would be appropriate. This is because connection services are excluded from our economic benchmarking data. Connection services are not included in network services. Because connection services are excluded from network services, connection services cannot affect benchmarking that uses network services data. Connection services include the opex and capex incurred for new connections or the modification of connections. These services can include the addition of feeders to a customer's premises for increased redundancy or upstream augmentation. Therefore, the services required to provide additional security of supply to customers with special requirements are connection services. We acknowledge that the modifications required by special customers may lead to service providers incurring additional opex to service the new assets. However, the additional inputs are also reflected in outputs, such as line length and ratcheted peak demand, in Economic Insights' benchmarking models.

Mix of demand to non-demand customers

We are not satisfied that an OEF adjustment for differences in the ratio of demand to non-demand customers would meet the duplication OEF adjustment criterion. To the extent that the ratio of demand to non-demand customers does have an impact on costs, Economic Insights' SFA benchmarking model accounts for it.

Demand customers are customers that are billed predominantly on the basis of their peak capacity requirements. These in general are large commercial and industrial customers. Non-demand customers are customers that are billed predominantly on the energy throughput delivered to them.

An adjustment for the ratio of demand to non-demand customers is not necessary because to the extent that the ratio of demand to non-demand customers has an effect on costs, Economic Insights' SFA model accounts for that effect. The model takes into account peak demand and customer numbers, which should capture the effect of differences in the ratio of demand to non-demand customers. The data used also exclude metering and connection costs. Therefore, Economic Insights' SFA model account for the main factors through which demand customers may impose higher costs on service providers than non-demand customers.

Population growth

We are not satisfied that an OEF adjustment for population growth would meet the duplication OEF adjustment criterion. Economic Insights' SFA model accounts for population growth through customer numbers and peak demand.

Population growth (or decline) affect all service providers. Some service providers will experience higher growth than others and some areas of their networks will experience more growth than others.

We are not satisfied that it is necessary to provide an OEF adjustment for population growth. Economic Insights' SFA model accounts for population growth. Customer numbers and peak demand are output variables in Economic Insights' SFA model.

We are also satisfied that it is not necessary to provide an OEF adjustment for differences in population growth in greenfields and brownfields developments because connection costs are not included in our economic benchmarking data. Brownfields developments may have higher connection costs than greenfields developments. However Economic Insights' SFA model uses network services data. Network services exclude connection services. Because network services do not include connection services, connection services cannot affect benchmarking that uses network services data.

Load growth

We are not satisfied that an OEF adjustment to account for differences in load growth would meet the duplication OEF adjustment criterion. Economic Insights' SFA model accounts for load growth.

In support of Ausgrid's 2014 regulatory proposal Advisian (formerly known as Evans and Peck) raised load growth as a possible OEF that may impede like for like comparison between service providers.[481]

An adjustment for load growth is not necessary because to the extent that load growth has an effect on costs, Economic Insights' SFA model accounts for that effect. Economic Insights' SFA model accounts for changes in network capacity by including ratcheted peak demand as an output variable.

Load factor

We are not satisfied that an OEF adjustment for differences in load factor would meet the materiality or duplication OEF adjustment criteria. Load factor will not to lead to material differences in opex between services providers. The relevant cost driver is peak demand, which is accounted for in Economic Insights' SFA model.

Load factor is a network's average demand divided by its peak demand. Service providers design electricity networks to taking into account the expected peak demand for electricity services. While the actual energy usage on a network is important from a billing perspective, energy is not the driver for capital expenditure, and as a result, it is not the driver for opex either. The higher peak demand, the more assets will be required to accommodate those peaks.

We are not satisfied that an adjustment for load factor is necessary because load factor does not drive costs. The relevant cost driver is peak demand. As mentioned above service providers design electricity networks accounting for the expected peak demand. While the "peakiness" of the load may alter the timing of some demand driven projects, the magnitude of the peak will be the primary driver for this form of expenditure.

Further, we are also not satisfied that an adjustment for load factor is required because Economic Insights' SFA model accounts for differences in peak demand. Ratcheted peak demand is an output in Economic Insights' SFA model. As mentioned above it is peak demand that determines the capacity required by a network, not load factor.

---

481 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, pp. 28–29.

Network length

We are not satisfied that an OEF adjustment to account for differences in network length meets the duplication OEF adjustment criterion. Economic Insights' SFA model accounts for differences in network length.

Network length is the length of a service provider's network. It can be measured using route line length or circuit line length. Route line length is distance between service providers' poles. Circuit line length is the length of lines in service, where a double circuit line counts as twice the length. All else equal, the longer a service provider's network length is the more costs it will incur.

An adjustment for network length is not necessary because to the extent that network length has an effect on costs, Economic Insights' SFA model accounts for that effect. The SFA model account for changes in network line length. Circuit length is included as an output in all of these models.

Economies of scale

We are not satisfied that an OEF adjustment for economies of scale would meet the duplication OEF adjustment criterion. The benchmarking model that we are using as the basis of our forecast of base opex, the Cobb Douglas SFA opex cost function, accounts for economies of scale.

We are not satisfied that an adjustment for economies of scale is necessary because the Cobb Douglas functional form, which is used in Economic Insights' SFA model, accounts for economies of scale. This is because it permits the estimation of the cost elasticities of the output variables. That is, the estimated coefficients of the output variables.

A.6.4 Endogenous factors

Activity scheduling

We are not satisfied that an OEF adjustment for differences in activity scheduling would meet the exogeneity OEF adjustment criterion. How a service provider chooses to schedule its business processes is a management decision.

Activity scheduling is the scheduling of routine network inspection and maintenance activities.

Ergon Energy's consultant Huegin, submitted that activity scheduling will lead to cost differences across service providers.[482] Huegin stated that a high degree of maintenance costs for service providers are preventative activities such as inspections. The scheduling of inspections will determine the workload, and therefore costs of those preventative activities.

[482] Huegin, *Ergon Energy Expenditure Benchmarking*, 17 October 2014, p. 14.

How frequently a service provider chooses to inspect its assets is a management decision. We note that some environmental conditions may lead to more frequent asset inspections or maintenance. We have considered these environmental conditions as they have been raised by stakeholders. Examples of these include asset age and humidity.

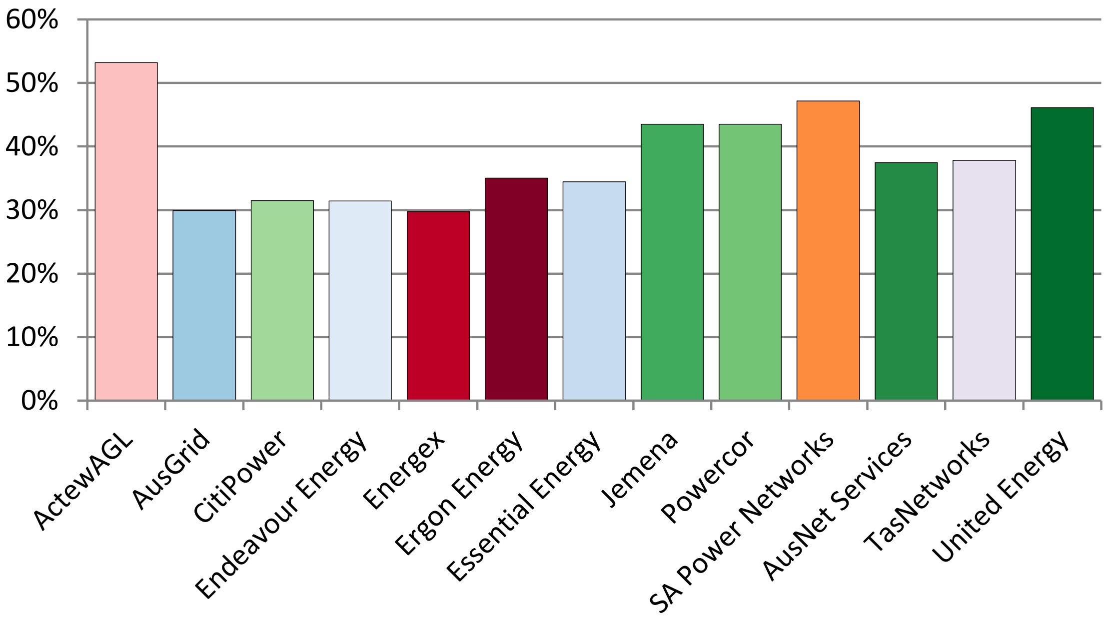
Capitalisation practices

We are not satisfied that an OEF adjustment for differences in capitalisation practices would not satisfy the materiality OEF adjustment criterion. Differences in capitalisation practices will not lead to material differences in opex between the Queensland service providers and the comparison firms.

For clarification, capitalisation practices include both service providers decision on the relative quantity of capital and operating costs and also the policies service providers use to classify costs as assets or expenses. Using different mixes of assets and expenses to provide will affect the operating expenditure a service provider incurs. Differences in the policies service providers use to classify costs as assets or expenses will affect the opex service providers record. Both of these have the potential to affect service providers' efficiency scores in Economic Insights SFA model. However, choices on capital inputs and accounting policies are management decisions so would not satisfy the exogeneity OEF criterion. Nonetheless, because these differences may lead to differences in costs unrelated to efficiency, we have treated this OEF as if it satisfies the exogeneity OEF criterion.

Figure A.20 below shows that opex made up between 30 to 45 per cent of totex for most NEM service providers during the benchmarking period, with the Queensland service providers expensing less of their totex than any other service provider.

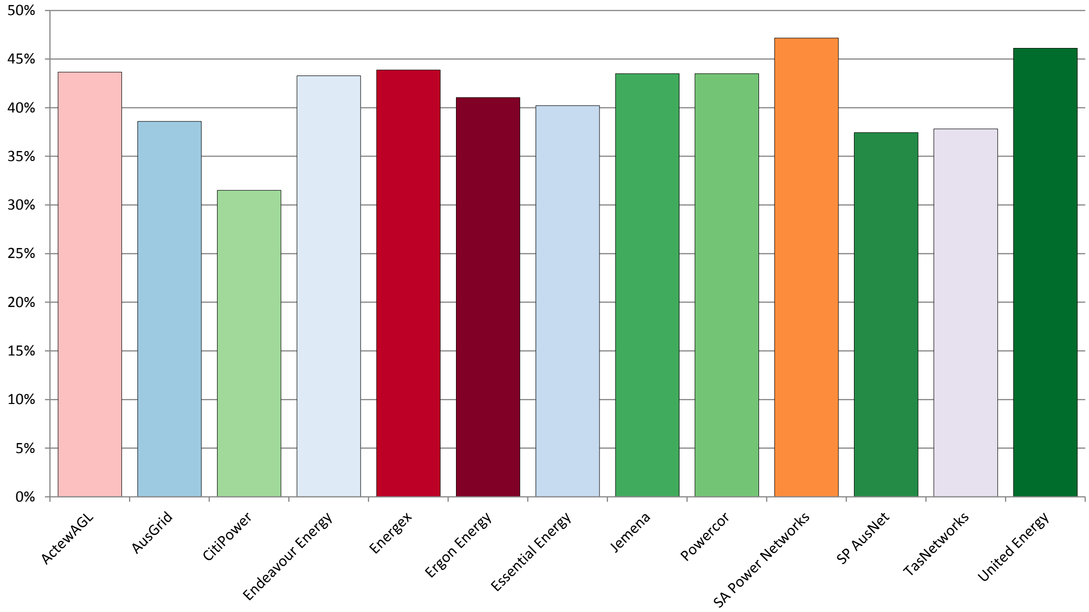
Figure A.20 Average opex as a percentage of totex, 2006 to 2013



Source: Economic benchmarking RIN

Figure A.21 below shows opex as a percentage of totex in the forecast period for the ACT, NSW, and Queensland service providers. Figure A.21 also shows opex as a percentage of totex for all other service providers during the benchmarking period. We note that the forecast of Energex's opex as a percentage of totex (43.9 per cent) is similar to the customer weighted average for the comparison firms (42.5 per cent). Opex as a percentage of totex for Ergon Energy (41.1 per cent) is slightly lower than the customer weighted average for the comparison firms.

Figure A.21 Forecast opex as a percentage of totex for ACT, NSW and Queensland service providers (2014-19 and 2015-20), and average actual opex as a percentage of totex for other service providers (2006 to 2013).



Source: Economic Benchmarking RIN responses 2006 to 2013; AER Analysis

Note: Opex as a percentage of totex is based on standard control services costs for the forecast expenditures. It is based on network services for the historical expenditures. This is because we do not forecasts capex for network services. We forecast capex for standard control services only.

Both Figure A.20 and Figure A.21show that in the benchmarking period and the forecast period the Queensland service providers have a similar opex to capex ratios as the customer weighted average of the comparison firms. Although in the benchmarking period there the Queensland service providers' opex to capex ratios were lower, in the forecast period they are estimated to be very similar. As a result we consider that differences in capitalisation practices are not likely to lead to material differences in opex between the Queensland service providers and the comparison firms.

Energex[483] and Ergon[484] raised capitalisation practices as a factor that may provide them with a cost disadvantage on opex cost benchmarking. Energex and Ergon considered that they would be disadvantaged in Economic Insights' benchmarking because they expense their IT costs.

We have not provided Ergon Energy and Energex with adjustments for differences in capitalisation rates because their opex, as a percentage of totex, are similar to those of the comparison firms. This suggests that while they may expense more IT related costs than other service providers that these policies are offset by capitalising a higher percentage of costs in other areas.

Although we consider that differences in capitalisation practices will not to lead to material differences in opex between the Queensland service providers and the comparison firms, we have included it in our adjustment for immaterial factors. Economic Insights' SFA model does not include a variable that directly accounts for differences capitalisation practices. Also as discussed above, differences in capitalisation practices may lead to differences in opex that are not related to efficiency and are not accounted for in Economic Insights' SFA model.

Ergon Energy is likely to have a cost advantage as it tends to expense fewer costs than the comparison firms. This is because in Figure A.20 and Figure A.21 above they appear to capitalise more of their costs than the comparison firms, which may indicate it has a preference for capital solutions over operating expenditure relative to the comparison firms. As a result, capitalisation practices contribute negative 0.5 per cent to the adjustment for immaterial OEFs for Ergon Energy. Conversely, we have provided a positive 0.5 per cent adjustment for Energex. This is because although Figure A.20 shows that in the past it expensed less of its costs than the comparison firms, Figure A.21 shows that in the future it will expense slightly more of its costs. As a result we consider that Energex's capitalisation practices may provide it a slight cost disadvantage on opex benchmarking.

Communication networks

We are not satisfied that an OEF for the availability of commercially available communication networks would meet our materiality or duplication OEF adjustment criteria. To the extent that service providers in low customer density areas may have to use alternative solutions where there is no mobile telephone coverage, this will be correlated with customer density. Also, three of the five comparison firms also face similar challenges in providing network services.

In support of Essential Energy's revised proposal, Essential Energy's COO, Mr. Humphreys, submitted that Essential Energy is unique in terms of the need to provide

483 Energex, Response to Information Request EGX001, 17 December 2014, pp. 7–8.

484 Ergon, Response to Information request ERG002, 19 December 2014, p. 20.

a two way radio network across 95 per cent of NSW.[485] Mr Humphreys also submitted that there is no commercial service available that provides state wide coverage with required reliability at an economic cost.

The need for two way communication in areas where there are limited commercial alternatives will be correlated with customer density. This is because the fewer customers there are in a service area, the less likely it is to be covered by a commercial communications network. As Economic Insights' SFA model accounts for customer density, as discussed above, we are not satisfied that it does not appropriately account for the availability of commercial communications networks.

Also an adjustment for differences in communication networks is not likely to meet the materiality OEF adjustment criterion. The necessity to provide an extensive two way communication system between control room and field staff, where there are limited commercial options, is not unique to Essential Energy. Other rural service providers, including the comparison firms AusNet Services, Powercor, and SA Power Networks face similar challenges providing a reliable communication system. There are areas in all three of those service providers' network areas that do not have mobile telephone coverage.[486]

Contaminated land management

We are not satisfied that an OEF adjustment for contaminated land management would meet the exogeneity or materiality OEF criteria. To the extent that electricity distribution assets have the potential to contaminate land, all service providers must manage this risk. The cost consequences of not managing this risk prudently in the past should not be visited on consumers.

In response to questions about its OEFs, Ergon Energy informed us that it considered that it has inherited sites that have soil contamination.

> "Ergon Energy was formed from six separate regional Electricity Boards in 1999. Those boards we similarly amalgamated by other more multitudinous organisations. Environmental obligations were less stringent in times past. Ergon Energy has “inherited” sites from these various legacy organisations, typically old generation sites that contain contaminated soil.
>
> In addition, past practices included use of creosote and other termiticides about the bases of poles. This has resulted in impacts upon livestock and incurs clean-up and management costs."[487]

485 Gary Humphreys, *Statement of Gary Humphries Chief Operating Officer Essential Energy*, 19 January 2015, pp. 12 to 13.

486 Telstra, Our Coverage, available at: www.telstra.com.au/mobile-phones/coverage-networks/our-coverage [last accessed: 10 April 2015].

487 Ergon Energy, Response to AER Information Request AER ERG002, 17 December 2014, p. 22.

Ergon Energy considers it is at a cost disadvantage as it must incur opex to remediate these sites.

We are not satisfied that an OEF adjustment for contaminated land management would meet the materiality OEF adjustment criterion. All NEM service providers have obligations to prevent land contamination due to the operations of their networks.[488] Where environmental regulations were not as stringent in the past due to a lack of knowledge industry wide, this is a problem that would have affected all service providers. Therefore if this were the case, all service providers would face similar problems with contaminated land.

In addition, we consider that an OEF adjustment for contaminated land management would not satisfy the exogeneity OEF criterion. A prudent service provider would take appropriate action to minimise the risk of land contamination associated with its activities.

In some circumstances land contamination regulations are different across jurisdictions. In this case a prudent service provider operating under the less stringent regulations would have a duty of care to appropriately manage its environmental risk being mindful of obligations in other jurisdictions. If a service provider did not undertake sufficient risk mitigation, where best industry practice is to manage that risk, this is a reflection of the quality of that service provider's management. The costs of such mismanagement should not be visited on consumers.

In the case that a service provider acquired assets with land contamination from another service provider, in a competitive market, the cost of that remediation will be factored into the price of the acquisition. That is the firm responsible for the contamination will have paid for the future remediation costs by receiving a lower payment for the contaminated assets. As a result end users would not need to pay for contaminated land remediation.

Outsourcing

We are not satisfied that an OEF adjustment for differences outsourcing practices would meet the exogeneity OEF adjustment criterion. Service providers choose to what extent they outsource.

In response to our 2014 draft decision for ActewAGL, Advisian raised opportunities for outsourcing as an OEF that might lead to material differences in opex.[489] Advisian noted that the small size of the ACT and the small number of network service providers in its area prevents ActewAGL from utilising contractors in a similar manner to the comparison firms. Advisian considered that the smaller amount of available work

[488] For example part seven of the *Environmental Protection Act 1970* sets out the responsibilities of the Victorian service providers with regard to land contamination.

[489] Advisian, Opex Cost Drivers: ActewAGL Distribution Electricity (ACT), 16 January 2015, pp. 95–98.

prevents contractors from achieving efficiencies that are available in denser areas serviced by a greater number of service providers.

We consider that the scale of the Queensland service providers would allow them to support a mature and efficient contracting market. Energex has more customers than any of the comparison firms. Ergon Energy has a similar amount of customers to Powercor and more than AusNet Services, CitiPower and United Energy. As a result we consider that the Queensland service providers have the opportunity to outsource. The extent to which they do or do not is a management decision.

Advisian also notes that service providers must retain sufficient in house capacity to act as an informed purchaser when interacting with contractors. [490] We do not consider that this would limit the Queensland service providers' ability to assess contractors' bids. The amount of expertise that would need to be maintained is minimal.

Reliability outcomes

We are not satisfied that an OEF adjustment for reliability outcomes is not necessary. It raises the first and third OEF criterion. We are not satisfied that an OEF adjustment for reliability outcomes would meet the duplication and exogeneity OEF adjustment criteria. Reliability is appropriately captured by Economic Insights' Cobb Douglas SFA model. Further, reliability outcomes are to some extent within management control.

In response to our draft decision for NSW and ACT service providers the service providers and their consultants submitted that the benchmarking used to estimate efficient, prudent base year opex did not incorporate reliability.[491] PEG and Advisian also had some detailed comments regarding the incorporation of reliability into our benchmarking analysis.[492] We address these concerns below. In this section we also outline why we consider our estimate of base opex is sufficient for the QLD service providers to meet their minimum reliability standards.

Consideration of reliability in setting our base year opex

Economic Insights' MTFP and opex MPFP benchmarking indicated that the QLD service providers could provide their current levels of reliability at much lower cost. These benchmarking models included the number of customer minutes off supply as a negative output. Hence, poor reliability would be reflected in poor MTFP and opex MPFP performance.

---

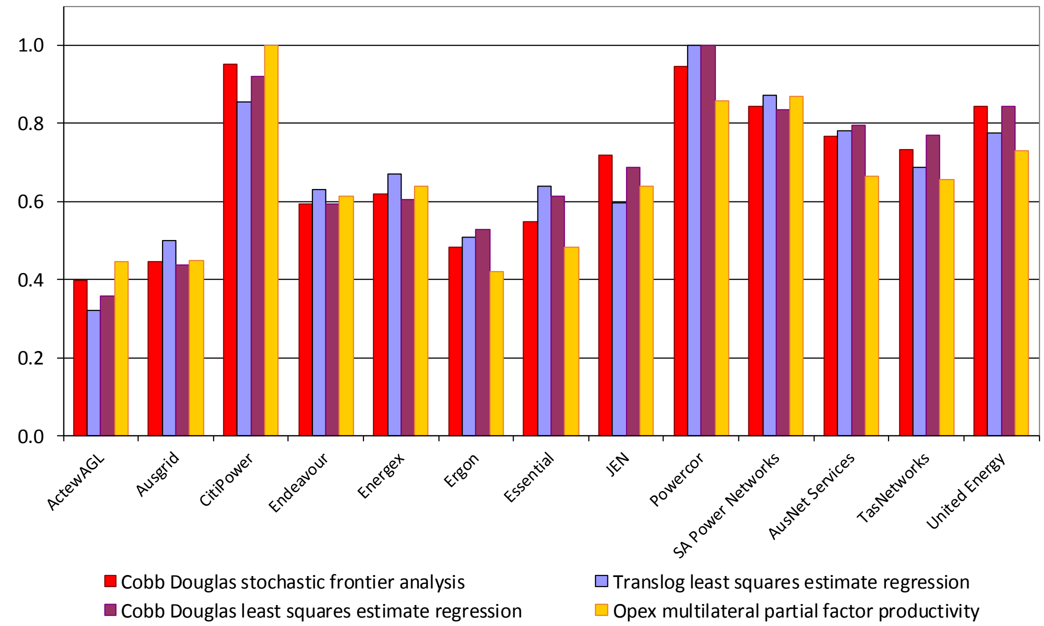
490 Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT*), 16 January 2015, p. 97.

491 ActewAGL, *Revised regulatory proposal*, 2015, p. 163. Advisian, 2015, p. 59. Essential, *Revised regulatory proposal*, 2015, pp. 42–44. ActewAGL, *Revised regulatory proposal*, 2015, pp. 61–79. AECOM, *Impact of AER Draft Determination on Service and Safety*, 2015, p. 20. CEPA, *Expert report*, 2015, p. 32. (CEPA, 2015). Ausgrid, *Statement of Chief Operating Officer of Ausgrid (CONFIDENTIAL),* January 2015. Jacobs, *Regulatory Revenue Decision, Reliability Impact Assessment*, 2015, p. 12.

492 Advisian, *Review of AER benchmarking, 2015*, p. 59. PEGR, 2015, p. 51.

Figure A.22 shows Economic Insights' opex MPFP, SFA and LSE scores for each of the service providers. This figure indicates that, measured under all our different economic benchmarking techniques, Queensland service providers could provide their services at lower cost over.

Figure A.22 Distributor average opex efficiency scores, 2006−13



Importantly, the opex MPFP scores are closely aligned with the efficiency scores of our Cobb Douglas SFA model. This is demonstrated by the two sets of efficiency scores being highly correlated with a correlation coefficient of 0.95. This means that to the extent that reliability performance is different across service providers, its impact on opex efficiency is not significant. Therefore, we consider the Cobb Douglas SFA model reasonably reflects the efficient and prudent costs of providing a standard control services, taking into account reliability performance.

Figure A.23 shows the relationship between the number of interruptions per customer (SAIFI) and customer density.

Figure A.24 shows the relationship between the average minutes off supply per customer (SAIDI) and customer density.

Figure A.23 SAIFI against customer density

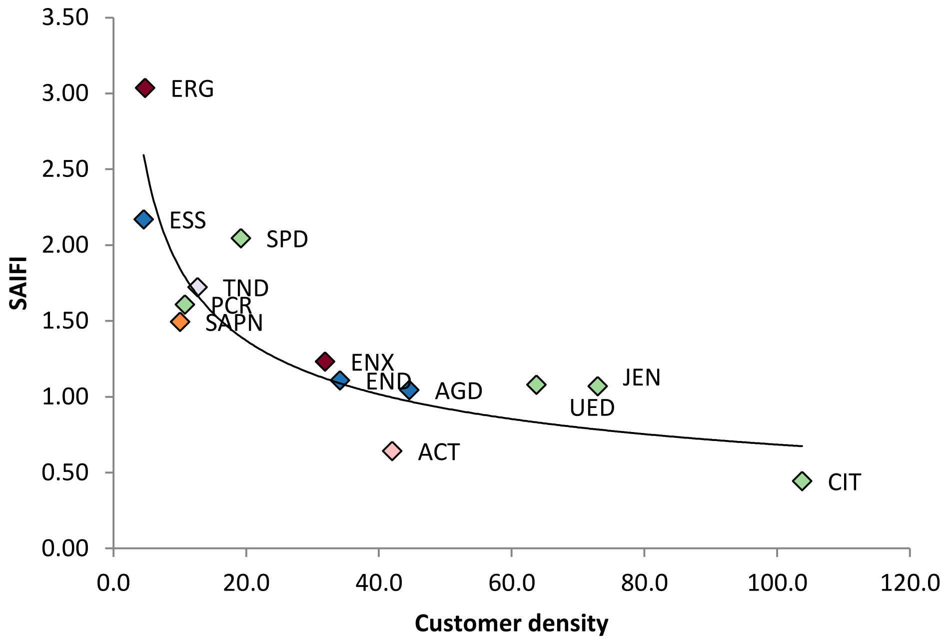
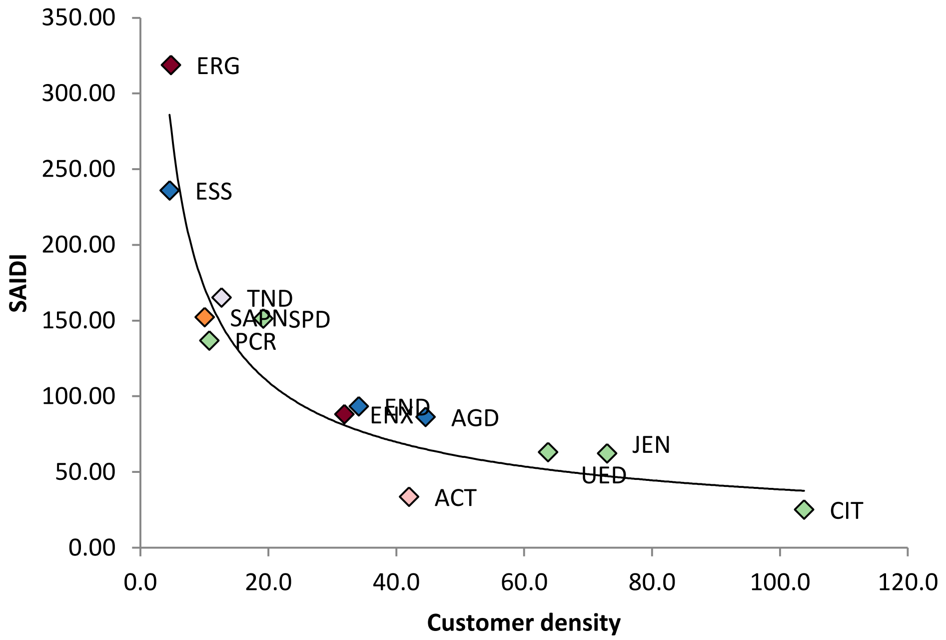


Figure A.24 SAIDI against customer density



As shown in these figures there is an inverse relationship between customer density and reliability. This is expected to be the case as less dense networks will have more exposed lines per customer. Holding everything else constant, the more exposed lines within a network, the greater the chance for incidences that will adversely affect reliability.

Most networks have a level of reliability that is close to their expected level given their customer density, as reflected by the reliability scores being close to the trend line. This indicates that the reliability performance of the benchmark service providers is not materially different from that of the QLD service providers.

Detailed criticisms

In response to our draft determination the consultants of the NSW and ACT service providers, Advisian and PEG raised some detailed concerns regarding the incorporation of reliability into our benchmarking analysis. We address these concerns below.

Advisian

On the issue of reliability, Advisian submitted:

> 1) "The “ceteris paribus” assumption of constant reliability implicit in the benchmark model does not hold, and some adjustment is necessary to reflect changes in reliability, an issue not dealt with at all in the preferred SFA model.
>
> 2) Economic Insights' reliance on analysis period averages for its benchmarking models means that the effect of declining reliability performance on opex over the analysis period is not captured in its models (which by implication assumes that opex is driven by absolute SAIDI). In practice the relationship between opex and reliability is driven by a combination of the absolute level that has historically been achieved, the specific network environment and the change in SAIDI over the analysis period.
>
> 3) The trade-off between SAIFI and CAIDI to achieve a SAIDI target highlights that reliability can be achieved by a combination of Opex and Capex programs. No attempt has been made in the AER’s benchmarking to “normalise” the approaches taken by distributors in this regard. This gives rise to the potential for what otherwise may be a sensible and efficient Opex / Capex trade off being judged as an Opex efficiency / inefficiency."[493]

We address these points below.

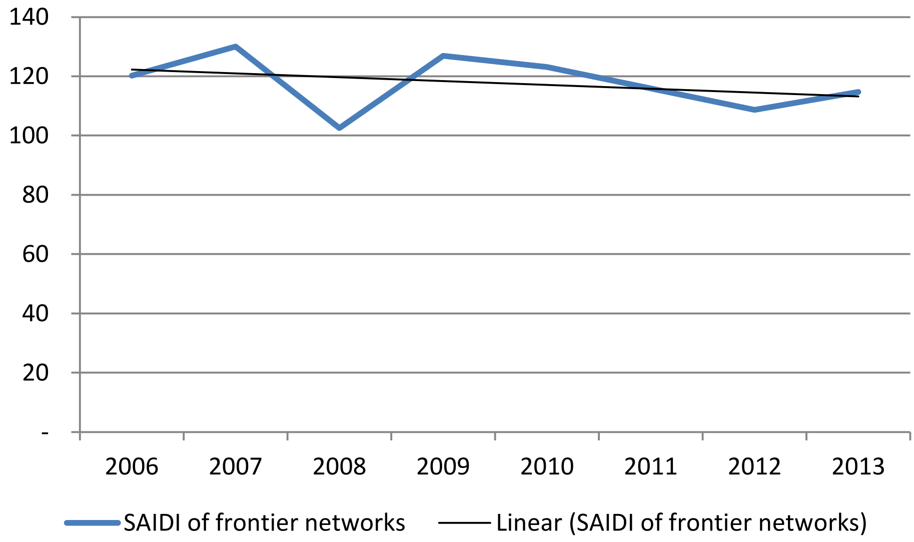
Advisian submitted that the frontier networks have exhibited decreasing reliability performance. As such it considered that the assumption of constant reliability in the AER's modelling does not hold and that the AER's benchmarking should be adjusted to reflect this.

We do not consider that the frontier networks have exhibited decreasing reliability performance. On both SAIDI and SAIFI measures the performance of the frontier networks has improved. Figure A.25 shows the weighted average SAIDI of the frontier

493 Advisian, *Review of AER benchmarking*, 2015, p. 59.

networks over the benchmarking period.[494] This shows that the SAIDI of the frontier networks has improved over the benchmarking period.

Figure A.25 SAIDI of frontier networks against long term average

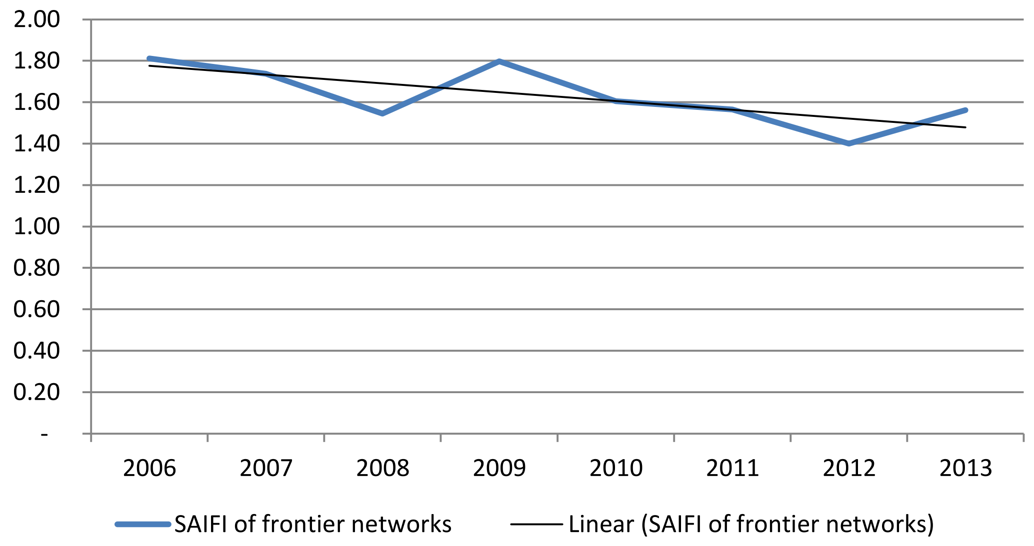


Note: SAIDI is calculated excluding excluded outages and MED days consistent with Advisian's approach.

Figure A.26 presents the SAIFI performance of the frontier networks. Again under this analysis SAIFI of the frontier networks has improved over the benchmarking period. Figure A.26 shows that SAIFI has been improving at a faster rate than SAIDI for the frontier networks. This means that CAIDI of the frontier networks will appear to deteriorate over time.

[494] The weighted average has been calculated based upon customer numbers in accordance with our approach to calculating the benchmarking frontier. Advisian also indicates that it calculates a weighted average however does not outline how it did so. Advisian argues that under its weighted average the performance of the networks has deteriorated. This is contrary to our analysis.

Figure A.26 SAIFI of frontier networks against long term average



Note: SAIDI is calculated excluding excluded outages and MED days consistent with Advisian's approach.

Advisian stated that CAIDI for the frontier networks has declined across the benchmarking period. We agree that this is the case, but consider that this is not a concern. CAIDI represents the average time required to restore service. [495] CAIDI is not a measure of the detriment of outages to consumers. The IEEE calculate SAIDI in the following manner:[496]

$$CAIDI = \frac{SAIDI}{SAIFI}$$

Under this calculation CAIDI will deteriorate if SAIFI improves at a faster rate than SAIDI. This is the case for the frontier networks. However, under this scenario customers experience fewer interruptions and fewer minutes off supply and are hence better off.

Advisian submitted that Economic Insights' reliance on analysis period averages for its benchmarking models means that the effect of declining reliability performance on opex over the analysis period is not captured in its modelling.[497] As noted above, this statement appears to be incorrect as reliability performance for the frontier networks as measured by SAIDI and SAIFI has improved over the period according to our measures.

---

495 IEEE Power Engineering Society, *IEEE Guide for Electric Power Distribution Reliability Indices*, 2004, p. 5.

496 IEEE Power Engineering Society, *IEEE Guide for Electric Power Distribution Reliability Indices*, 2004, p. 5.

497 Advisian. 2015, p. 59.

Advisian also submitted that that the trade-off between SAIFI and CAIDI to achieve a SAIDI target highlights that reliability can be achieved by a combination of Opex and Capex programs.[498] Advisian submitted that no attempt has been made in the AER's benchmarking to "normalise" the approaches taken by distributors in this regard.

As we point out in our consideration of capitalisation policies above, the Queensland networks have spent more on capex over the benchmarking period than the frontier networks. This should put these networks at an advantage under our benchmarking analysis. This is because the additional expenditure on capex should reduce outages and improve their opex performance under our benchmarking analysis.

Further, we note that the frontier networks have significantly increased their opex on maintenance and vegetation management.[499] This additional opex should reduce outages caused by vegetation and asset failure. However increasing opex will disadvantage the frontier networks under our benchmarking analysis of opex. This is because, as Advisian states, these networks could have instead undertaken capital programs to reduce outages. As such, we do not consider that normalisation of the results to account for the trade-off between SAIFI and CAIDI is necessary.

Pacific Economic Group Research

PEGR questioned the way in which reliability was included in the scale index:

> The impact of reliability on opex is a complicated empirical issue. Good reliability may require higher opex, but it also depends on weather, forestation, system undergrounding, AMI, and system reinforcements. EI's approach to reliability unfairly favours urban utilities in Victoria and ACT since these utilities enjoy favourable reliability operating conditions.[500]

In response to this comment Economic Insights notes that PEGR does not provide an explanation how the Victorian and ACT service providers differ from the NSW urban service providers which face broadly similar 'reliability operating conditions'. Rather, Economic Insights notes that it is likely that the Victorian and ACT distributors have focussed more on improving their reliability.[501]

Management control of reliability

We consider that there are a number of actions that management can undertake in order to control the level of reliability within their networks. This includes spending more on vegetation management and maintenance. Advisian also notes actions that management can take to manage reliability.[502] Though outages are often caused by

498 Advisian. 2015, p. 59.

499 From 2008–9 to 2012–13 the frontier networks increased their expenditure on vegetation management and maintenance on average by 171 per cent and 77 per cent respectively (in nominal terms).

500 PEGR, 2015, p. 51.

501 Economic Insights, 2015, pp. 5–6.

502 Advisian, Review of AER benchmarking, 2015, p. 59.

exogenous circumstances, reliability outcomes are not fully exogenous to management control.

Further, in our benchmarking analysis we apply the Institute of Electrical and Electronics Engineers standard to exclude the effects of major events that are caused by to extreme weather or other events. Consequently reliability outcomes that we have included in our benchmarking analysis reflect business as usual circumstances. Thus the reliability in our benchmarking analysis relates to events that are within management control.

Meeting reliability standards

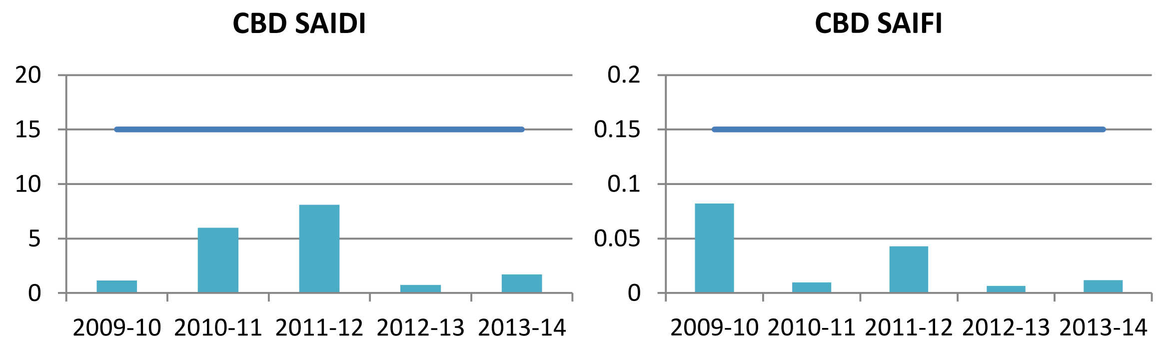
Under the NER we must set opex at the level consistent with the operating expenditure criteria. This includes the prudent, efficient opex to meet reliability standards.[503]

We consider that our estimate of base opex reasonably reflects the efficient and prudent costs for meeting reliability standards. Based on our benchmarking analysis, as outlined above, we consider that that the Queensland service providers can deliver their current levels of reliability at lower cost. Our base year opex is sufficient for the Energex and Ergon Energy to maintain their reliability at its current level as the base year opex allowance is based upon Energex and Ergon Energy's reliability over the benchmarking period.

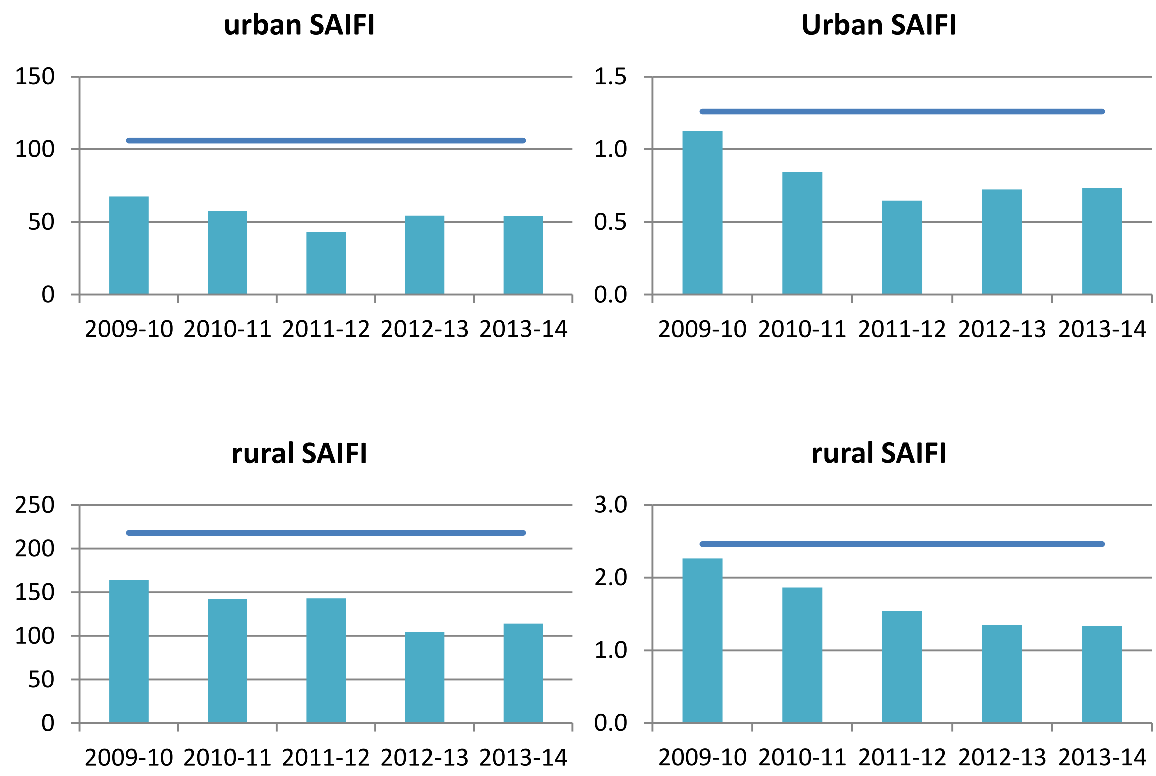
If the current level of reliability was worse than the minimum reliability standards then the opex allowance might not reflect the costs of meeting these standards. However, the Queensland service providers have been outperforming their minimum reliability standards.

Figure A.27 and Figure A.28 show that Ergon Energy and Energex have outperformed their reliability targets in almost every instance over the period.

Figure A.27 Energex's performance against its current reliability standards

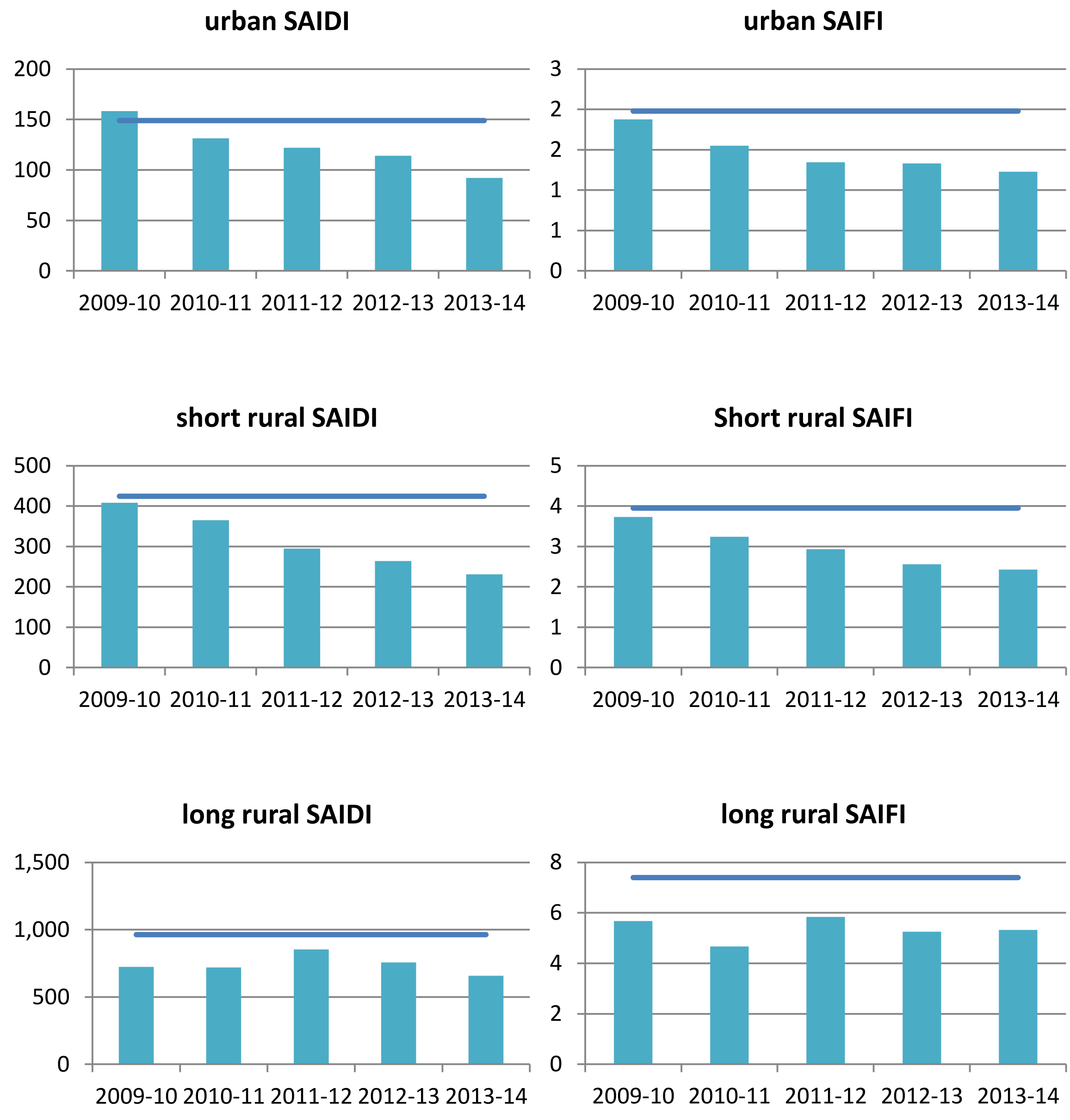


[503] NER cl. 6.5.6 (a) and (c)



Source: AER analysis

Figure A.28 Ergon Energy's performance against its current reliability standards



Source: AER analysis

Safety outcomes

We are not satisfied an OEF adjustment for service providers' safety outcomes meets the duplication OEF adjustment criterion. Economic Insights' SFA model implicitly account for safety. This is because the comparison firms operate safe networks.

The Victorian service providers operate safe networks. The Victorian service providers are required under Part 10 of the *Electricity Safety Act 1998* to submit Electricity Safety Management Schemes to Energy Safe Victoria (ESV). In addition to this they are also required to submit Bushfire Mitigation Plans and Electric Line Clearance Management Plans. [504]

ESV noted that in 2012 overall management of the Victorian Networks was good. [505] ESV noted that in 2011 the performance of the Victorian Networks, with regard to asset failure, was consistent with the performance of networks elsewhere in Australia and that in other areas they performed adequately.[506] ESV found in 2010 that overall there was a good standard of inspection and timely repair by the industry although some service providers performed better than others.[507] More recently, in 2014, ESV noted:

- The Victorian service providers have comprehensive Electricity Safety Management Systems, many supplemented by other management systems and certification such as PAS 55, ISO 9001, ISO 14001, AS4801 and OHSAS 18001[508]
- Asset maintenance in Victoria, in accordance with bushfire mitigation plans, was adequate for the 2013−2014 bushfire season, with no areas of non-compliance observed [509]
- In general, the Victorian service providers' Electric Line Clearance Management Plans were clear, well presented and that there was a strong connection between safety plans and activities in the field[510]
- Despite the extensive effort put into condition assessment and asset replacement, failure rates in Victoria had increased. While some service providers, notably United Energy, were behind schedule in their asset replacement programs all would be able to complete their five year programs by 2015[511]
- The number of fire starts in Victoria was above the F factor set by the AER, partly due the increasing age of assets and partly due to adverse weather conditions.[512]
- All of the Victorian service providers were on schedule to meet the electric line clearance requirements as agreed upon with ESV. Although CitiPower and Powercor were granted 12 months extensions from the original timeframes.[513]
- The Victorian service providers go to considerable lengths to prevent unauthorised access and ensure that assets are secure[514]
- The underlying trend for serious injuries from electrical causes to the public and Victorian service providers workers was similar to previous years[515]

---

504 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 5.
505 ESV, *Safety performance report on Victorian Electricity Networks 2012*, June 2013, p.7.
506 ESV, *Safety performance report on Victorian Electricity Networks 2011*,August 2012, p. i.
507 ESV, *Safety performance report on Victorian Electricity Networks 2010*, 2011, p. i.
508 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 24.
509 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 26.
510 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, pp. 29–30.
511 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, pp. 31–50 and 61–78.
512 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, pp. 61–78.
513 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, pp. 50–60.
514 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 78.
515 ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 82.

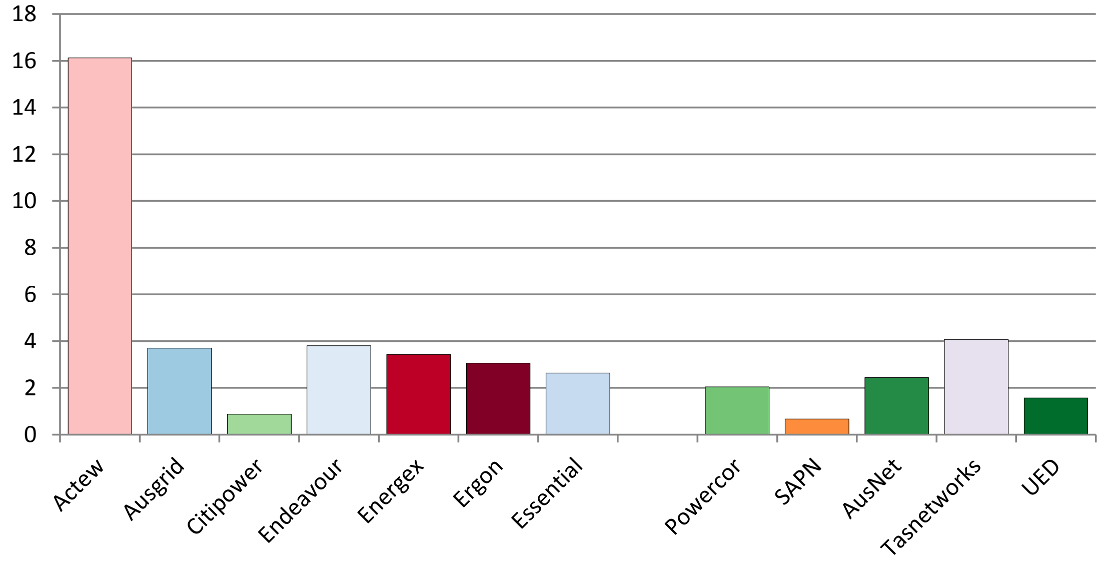
- There were some opportunities for improvement and areas requiring attention in the Victorian service provider's work practices[516]

We note that ESV highlighted issues relating to fire starts, asset failures, and work practices. ESV notes that the increase in fire starts in 2013 may be due to adverse weather conditions and aging assets. The replacement rate of assets relates to repex, not opex. On concerns about work practices, we note that service providers in Victorian tend to have higher levels of workplace safety than other areas of the NEM. This is discussed below.

Other measures of network safety also suggest that the comparison firms perform similarly or better than the Queensland service providers. These measures include LTIFR and vegetation contacts with assets.

On Lost Time Injury Frequency Rate (LTIFR) the comparison firms generally tend to outperform the ACT, NSW, and Queensland service providers. LTIFR measures the number of injuries suffered in the workplace that lead to one or more shifts being missed for every million hours worked. The LTIFR for the NEM service providers over the 2009 to 2013 period is shown below.

Figure A.29 LTIFR for NEM service providers 2009 to 2013



Source: ActewAGL,[517] Ausgrid,[518] AusNet Services,[519] CitiPower,[520] Endeavour Energy,[521] Energex,[522] Ergon Energy,[523] Essential Energy,[524] Powercor, [525] SAPN,[526] TasNetworks,[527] United Energy.[528]

[516] ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 87.

[517] ActewAGL, Response to Information Request AER ACTEW 053, 9 February 2015.

[518] Ausgrid, Response to Information Request AER AUSGRID 044, 23 January 2015.

[519] AusNet Services, Response to LTIFR Information Request, 9 January 2015.

[520] CitiPower, Response to Information Request on LTIFRs, 2 February 2015.

[521] Endeavour Energy, Response to Information Request AER Endeavour 037, 16 January 2015.

Note[529]

On vegetation contacts causing fires per 1000km of overhead route line length, the comparison firms tended to have similar performance to the NSW and Queensland distributors, with ActewAGL having a higher number of defects.[530] [531] [532]

Based on the above evidence, we consider that the comparison firms operate safe networks at lower levels of opex such that no OEF adjustment is necessary to account for safety.

Risk appetite

We are not satisfied that an OEF adjustment for differences in the risk appetites of service providers' network owning corporations would meet the exogeneity OEF adjustment criterion. Service providers choose their risk appetite.

Part of the role of a corporation's management is to select the level of risk that they are willing to bear.[533] The quality of a firm's management is an endogenous factor that does not require an adjustment.[534]

Unregulated Services

We are not satisfied that an OEF adjustment for differences in the unregulated services that service providers engage in would meet the exogeneity OEF adjustment criterion. The extent to which a service provider engages in unregulated activities is under management's control.

In response to our 2014 draft decision for ActewAGL, Advisian submitted that ActewAGL will have a cost disadvantage relative to the comparison firms because of differences in the provision of unregulated activities.[535] Advisian submitted that the

---

522 Energex, Response to Information Request AER Energex, 23 January 2015.

523 Ergon Energy, Response to Information Request AER Ergon008, 7 January 2015.

524 Essential Energy, Response to Information Request AER Essential 033, 23 January 2015.

525 CitiPower, Response to Information Request on LTIFRs, 2 February 2015.

526 SA Power Networks, Response to Information Request AER SAPN 012, 20 January 2015.

527 TasNetworks, Response to LTIFR information request, 21 January 2015.

528 United Energy, Response to LTIFR Information Request, 27 January 2015.

529 ActewAGL changed its reporting systems in 2011 therefore its datum only covers the period July 2011 to December 2013. TasNetwork's datum does not include contractors prior to 2012. Endeavour, Essential and SAPN data do not included contractors. AusNet's Datum relates to its gas, distribution and transmission business segments. Jemena is not displayed because it claimed confidentiality over its datum.

530 Category Analysis RIN Responses to template 2.7 and Economic Benchmarking RIN Responses to templates 6 and 8.

531 Ausgrid, Response to Information Request Ausgrid 052, 17 February 2015.

532 Endeavour, Response to Information Request Endeavour 044, 16 February 2015.

533 Nocco, B. W. and Schultz, R. M. 2006, *'Enterprise Risk Management: Theory and Practice', Journal of Applied Corporate Finance, vol. 18, no. 4*, p. 11.

534 AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers)*, November 2012, p. 113.

535 Advisian, Opex Cost Drivers: ActewAGL Distribution Electricity (ACT), 16 January 2015, p. 98.

volume or appetite for pursing unregulated revenue is fundamentally an internal matter for service providers', and therefore an OEF adjustment for the scale of unregulated activities is inappropriate.[536] However, Advisian submitted that ActewAGL is prevented from providing unregulated services because of its geographically isolated position.

We are not satisfied that the Queensland service providers do not have opportunities to provide unregulated services. This is because they have large markets available to them. Energex has more customers than any of the comparison firms. Ergon Energy has a similar amount of customers to Powercor and more than AusNet Services, CitiPower and United Energy. Additionally the Queensland service providers do provide unregulated services. For example, Ergon owns Nexium. Nexium is a communications company fully owned by Ergon Energy that provides broadband across regional and remote Queensland.[537]

Work and operating procedures

We are not satisfied that an adjustment for work and operating procedures would meet the exogeneity OEF adjustment criterion. Work and operating procedures are under the direct control of service providers' management.

It is the role of service providers' management to seek and implement ways to improve the effectiveness and efficiency of the service provider's work and operating procedures. Because the effectiveness and efficiency of a service providers' work and operating procedures are a result of the quality of a service providers management, they are endogenous to the business and we do not consider it appropriate to account for them when benchmarking.[538]

Work conditions

We are not satisfied that an OEF adjustment for differences in work conditions would meet the exogeneity OEF adjustment criterion. Service providers' managements are able to negotiate the agreements that they make with their workers.

The service providers in the NEM all have enterprise agreements.[539] A service provider's management has discretion in reaching an agreement that it strikes with its workforce. The deal that it makes represents a trade-off. The agreement might provide for lower wage rates in return for higher non-salary conditions. Alternatively, it might provide higher wage rates in exchange for productivity improvements. This is a

---

536 Advisian, Opex Cost Drivers: ActewAGL Distribution Electricity (ACT), 16 January 2015, p. 86.

537 Nexium, Products & Services, available at: https://www.nexium.net.au/products-and-services [last accessed 26 March 2015].

538 AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers)*, November 2012, p. 113.

539 Fairwork commission, *Find an agreement*, available at: https://www.fwc.gov.au/awards-and-agreements/agreements/find-agreement. [last accessed 20 August 2014].

simplification of reality but it illustrates the trade-off. Depending on the service provider's goals, it may be efficient to negotiate various entitlements with employees.

The two service providers with the highest efficiency scores on our Cobb Douglas SFA opex cost function, Powercor and CitiPower, have on average the highest and second highest labour cost per average staffing level in the NEM.[540] Both of these service providers are Victorian, but economy wide Victorian wage rates are on average lower than those in the ACT, NSW, and Queensland.[541] Although their average wage is higher than the other service providers their opex, which is mostly comprised of labour costs, per customer is lower than firms in the ACT, NSW, and Queensland.

We therefore do not consider it appropriate to make an adjustment for work conditions.

A.6.5 Geographic factors

Bushfire risk

We are satisfied that bushfire risk provides a cost advantage to the Queensland service providers. An OEF adjustment for differences in bushfire risk between the Queensland service providers and the comparison firms satisfies the exogeneity and duplication OEF adjustment criteria. While service providers can take action to manage their bushfire risk, the natural environment and regulations with which they must comply are beyond their control. Also, bushfire risk is not explicitly accounted for in Economic Insights' SFA model. However, while differences in bushfire risk seem to lead to material differences in opex between Ergon Energy and the comparison firms, vegetation density in Energex's service area may offset this advantage.

Based on the evidence available to us, it seems that the Queensland service providers do not face the same level of bushfire risk as the comparison firms. The information available suggests bushfire risk is higher in parts of Victoria and South Australia, where the comparison firms operate, than in Queensland. Information on the impact of bushfires and the regulations relating to bushfires that apply in Victoria and Queensland also suggest that bushfire risk is higher in Victoria. The value of step changes and pass through applications after the Black Saturday bushfires provide an indication of the cost disadvantage that the Victorian service providers may face due to relatively higher bushfire risk.

Although some of our comparison firms are not likely to face high bushfire risks, such as CitiPower, we have weighted the Queensland service provider's efficiency target according to the number of customers that the comparison firms have. This means that the efficiency target is weighted towards predominantly rural service providers with higher bushfire risk.

540 Category Analysis RIN responses. Template 2.11: Labour.

541 ABS, 6302.0 - Average Weekly Earnings, Australia, May 2014.

Environmental risk

Information on the historical costs, forecast costs, occurrences of past major bushfires, deaths as a result of bushfires, and bushfire mapping all indicate that the environmental risk of bushfire is higher in Victorian and South Australia.

Data collected by the Bureau of Transport Economics shows that on average over the period 1967 to 1999 bushfires caused 87 times more in economic losses in Victoria than in Queensland. We have also normalised the average annual cost of bushfires by Gross State Product. This is to prevent population and physical size from interfering with comparisons. While not a perfect measure, we are satisfied that it is preferable to normalising by area or population.

Table A.12 Past cost of bushfires 1967−1999

	ACT	NSW	QLD	SA	TAS	VIC
GSP 2012/13 ($m 2013)	35 088	476 434	290 158	95 123	24 360	337 493
Average cost of bushfires 1967–1999 ($m 2013)	10.9[542]	16.8	0.4	11.9	11.2	32.4
% of GSP	0.03%	0.00%	0.00%	0.01%	0.05%	0.01%

Source: BTE[543] and ABS[544] [545] [546]

Past forecasts from Deloitte Access Economics of the total economic costs of bushfires for 2014, Table A.13 suggests that the economic cost of bushfires for 2014 is higher in Victoria and South Australia than in Queensland.

Table A.13 Forecast economic cost of bushfires for 2014

	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
GSP ($m 2013)	35 088	476 434	290 158	95 123	24 360	337 493
Forecast cost of bushfires 2014 ($m 2013)	55	45	0	46	41	178
% of GSP	0.16%	0.01%	0.00%	0.05%	0.17%	0.05%

Source: Deloitte Access Economics[547] and ABS[548] [549]

---

542 Includes costs from the 2003 Canberra bushfires

543 BTE, *Economic costs of natural disasters in Australia,* 2001, p. 35.

544 ABS, 5220.0 - Australian National Accounts: State Accounts, 2012–13

545 ABS, 6401.0 - Consumer Price Index

546 ABS, 1301.0 - Year Book Australia, 2004

547 DAE, Scoping study of a cost benefit analysis of bushfire mitigation: Australian Forest Products Association, May 2014, p. 12.

Major bushfires have also tended to occur more frequently in South Australia and Victoria than in Queensland. The table below, which shows the location, and impacts, of major Australian bushfires of the 1900 to 2008 period, demonstrates this.

Table A.14 Significant bushfires and bushfire seasons in Australia 1900–2008

Date	States	Homes destroyed	Deaths
February 14, 1926	Victoria	550	39
January 8-13, 1939	Victoria and NSW	650	79
Summer 1943-44	Victoria	885	46
February 7, 1967	Tasmania	1557	64
January 8, 1969	Victoria	230	21
February 16, 1983	Victoria and SA	2253	60
February 18, 2003	ACT	530	4
January 11, 2005	South Australia	93	9

Source: Haynes et al.[550]

Also when normalised by population, South Australia and Victoria experienced more deaths as a result of bushfire than Queensland. We have normalised by population rather than area because bushfires in unpopulated areas are unlikely to cause many deaths. This is shown in Table A.15.

Table A.15 Deaths as a result of bushfires per 100,000 people by state 1900 to 2008

	ACT	NSW	QLD	SA	TAS	VIC
Deaths	5	105	17	44	67	296
Average population 1900–2008[551]	122 524	3 804 434	1 688 122	911 524	324 896	2 818 053
Deaths per 100,000 residents	4	3	1	5	21	11

Source: Haynes et al[552] and ABS[553]

548 ABS, 5220.0 - Australian National Accounts: State Accounts, 2012–13.

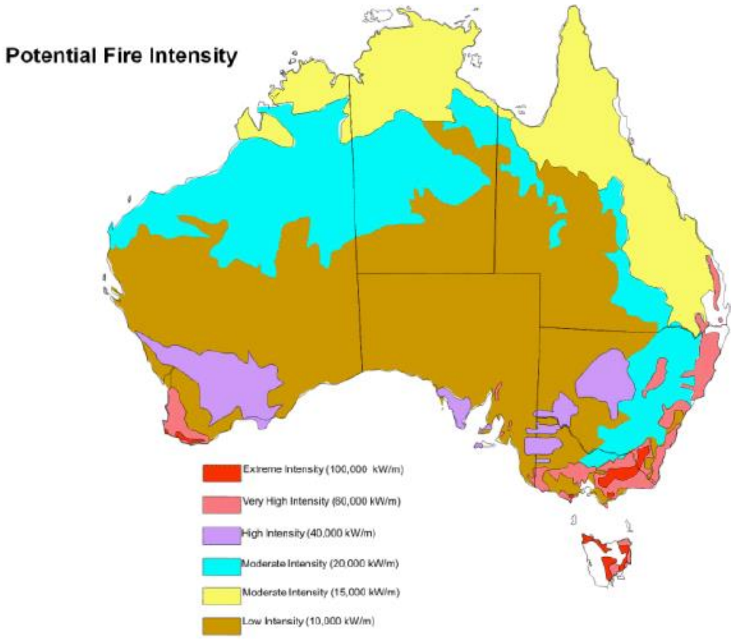
549 ABS, 6401.0 - Consumer Price Index.

550 Haynes, K. et al., Australian bushfire fatalities 1900–2008: exploring trends in relation to the 'prepare, stay and defend or leave early' policy, Environmental Science & Policy, vol. 13 no. 3, May 2010, p. 188.

551 We used the average population over 1900 to 2008 rather than the current population to account for how population size may have changed over the period.

Bushfire maps also show that most of Victoria is at high risk due to bushfires. Only a small part of South Eastern Queensland has high bushfire risk. This is shown in Figure A.30 and Figure A.31 below.

Figure A.30 Map of potential fire intensity



Source: Dr Kevin Tolhurst[554]

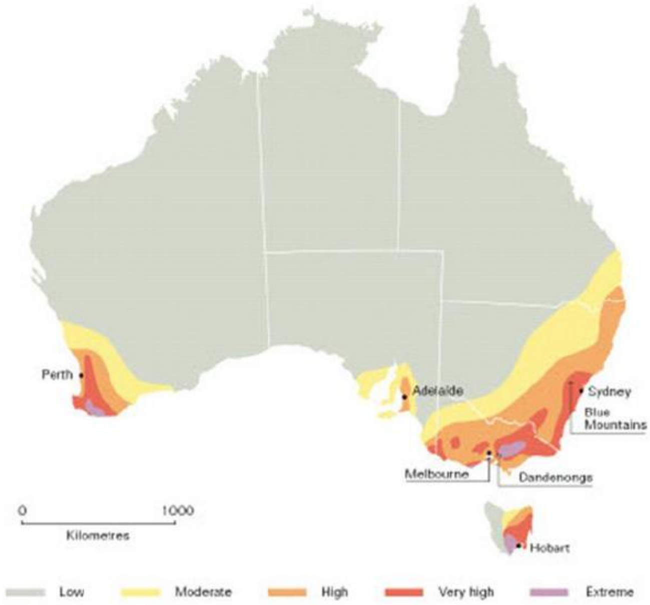
---

[552] Haynes, K. et al., *Australian bushfire fatalities 1900–2008: exploring trends in relation to the 'prepare, stay and defend or leave early' policy, Environmental Science & Policy*, vol. 13 no. 3, May 2010, p. 188.

[553] 3105.0.65.001 - Australian Historical Population Statistics, 2014

[554] Essential Energy, *Revised Proposal: Attachment 7.10*, 20 January 2015, p. 16.

Figure A.31 Map of bushfire potential zones in Australia



Source: Johnson, R. W., Blong R. J. and Ryan C.J. [555]

Bushfire mitigation obligations

Another indicator of bushfire risk is the bushfire related regulations that apply to a service provider. The regulations that a service provider must comply with are a direct imposition on a service provider's costs. The regulations related to mitigating bushfire risk were more stringent in Victoria than in Queensland for the entire benchmarking period. Additionally there were increased regulatory obligations placed on the Victorian service providers after the Black Saturday bushfires which occurred in 2009.

The vegetation management obligations for the Victorian service providers have been stricter over the benchmarking period. The Victorian *Electricity Safety (Electric Line Clearance) Regulations 2010* and *2005,* prescribe (among other things) minimum clearance spaces for power lines that are progressively stricter in areas of higher bushfire risk.[556]

The Queensland *Electrical Safety Regulation 2013* and the, proceeding regulations, set out the statutory objectives for the Queensland service providers relating to vegetation clearance. The regulations require the Queensland service providers to ensure that trees and other vegetation are prevented from coming into contact with their electric lines where it is likely to cause injury or damage to property.[557] The

555 Johnson, R. W., Blong R. J. and Ryan C.J. 1995. *Natural Hazards Potential Map of the Circum-Pacific Region: Southwest Quadrant*, 1995, pp. 51–52.

556 Electricity Safety (Electric Line Clearance) Regulations 2010, Schedule, 27 February 2013.

557 Electrical Safety Regulation 2013, s. 216.

Queensland regulations however do not mandate minimum vegetation clearance distances.[558] [559]

In the aftermath of the Black Saturday bushfires many changes were recommended to the operation and management of the Victorian distribution systems. These obligations do not exist in Queensland and include:

- Changes to the Electric Line Clearance Regulations leading to a forecast step change in opex of $205 million ($2010) over the 2011 to 2015 period[560] [561]
- Audit programs for line spreaders[562]
- Audit programs for vibration dampeners[563]
- Increased asset inspection frequencies[564]
- Audits of asset inspectors.[565]

Duty of care

While bushfire mitigation regulations are more stringent in Victoria than in Queensland, we acknowledge that the Queensland service providers may adopt some Victorian practices in exercising their duty of care. However, on the evidence before us, Victoria has greater bushfire risk than Queensland. Therefore, one would expect that less expenditure would be required to mitigate those risks in Queensland.

Additionally, although the Queensland service providers must take notice of events in other jurisdictions in exercising their duty of care, any changes to their practices would be in response to their individual risks. This continual evolution of the duty of care is something all service providers will face. For example, even before the Black Saturday bushfires Powercor began trialling LiDAR technology.[566]

On balance we are satisfied that in discharging their duty of care, the Queensland service providers would adopt some of the bushfire mitigation practices of the Victorian

---

558 Energex, Response to AER information request AER EGX 021, 12 February 2015, p. 6.

559 Ergon Energy, Response to AER information request AER Ergon 026, 13 February 2015, p. 6.

560 AER, *Victorian electricity distribution network service providers: Distribution determination 2011–2015 – Final Decision appendices*, September 2012, p. 301.

561 AER, Final Decision: CitiPower Ltd and Powercor Australia Ltd vegetation management forecast operating expenditure step change, 2011–2015, August 2012, p. 2.

562 Victorian Government, *Implementing the Government's Response to the 2009 Victorian Bushfires Royal Commission*, May 2011, p. 61.

563 Victorian Government, *Implementing the Government's Response to the 2009 Victorian Bushfires Royal Commission*, May 2011, p. 61.

564 Victorian Government, Implementing the Government's Response to the 2009 Victorian Bushfires Royal Commission, May 2011, p. 59.

565 Energy Safe Victoria, Regulatory Impact Statement: Electricity Safety (Bushfire Mitigation) Regulations 2013, 25 February 2013, p. 3.

566 IJM Consulting, Bushfire Mitigation Powercor Australia: Final Audit Report 2008, Audit Report, p. 4.

providers. However, a prudent and efficient service provider would only do this to the extent that the risks it faces warrant it.

Impact of differences on opex

Differences in bushfire risk and related regulations between the comparison firms and each of the Queensland service providers will provide the Queensland service providers with a cost advantage.

Differences in bushfire risk have the potential to create material differences in the opex required to operate the comparison firms' opex relative to the both of the Queensland service providers. In Victoria for the 2011–2015 period, the increase in regulatory obligations related to bushfires was forecast to account for 9.0 per cent of total opex.[567] [568] [569] [570] [571] [572] [573] [574] [575] Although a prudent service provider would take into consideration changes in practices in other states, it would only adopt those practices to the extent that they are appropriate given their circumstances. On the evidence in front of us, in general, Victoria faces higher risk of bushfires than Queensland. Additionally, our examination of vegetation management regulations, the most costly part of electricity service providers' bushfire mitigation practices, show the requirements in Victoria are stricter.

Although we consider it is likely that the Victorian service providers will have a cost disadvantage relative to the Queensland service providers due to differences in bushfire risk and related regulatory obligations, we consider there will be some mitigating factors. The change in regulations only came about after the Black Saturday bushfires. All service providers have a duty of care. Also, other factors will affect bushfire mitigation costs such as vegetation density, urbanity, undergrounding, and divisions in responsibility for vegetation management. We note that urbanity (customer density) and undergrounding are accounted for in Economic Insights' SFA model so we have focussed on the effect of the timing of the change, duty of care, and vegetation density.

Although the increase in opex associated with the new bushfire risk mitigation obligations for the Victorian service providers was quite large, it only affected the end

---

[567] AER, *Final decision: CitiPower Ltd and Powercor Australia Ltd vegetation management forecast operating expenditure step change*, August 2012, p. 2.

[568] AER, *CitiPower Pty Distribution determination 2011–15*, September 2012, p. 17.

[569] AER, *Powercor Australia Ltd Distribution determination 2011–15*, October 2012, p. 26.

[570] 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

[571] AER, *Final decision - appendices: Victorian electricity distribution network service providers - Distribution determination 2011–2015*, October 2011, p. 301–304.

[572] 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.

[573] AER, *SPI Electricity Pty Ltd Distribution determination 2011–2015*, August 2013, p. 20.

[574] AER, *Jemena Electricity Network (Victoria) Ltd: Distribution determination 2011–2015*, September 2012, p. 22.

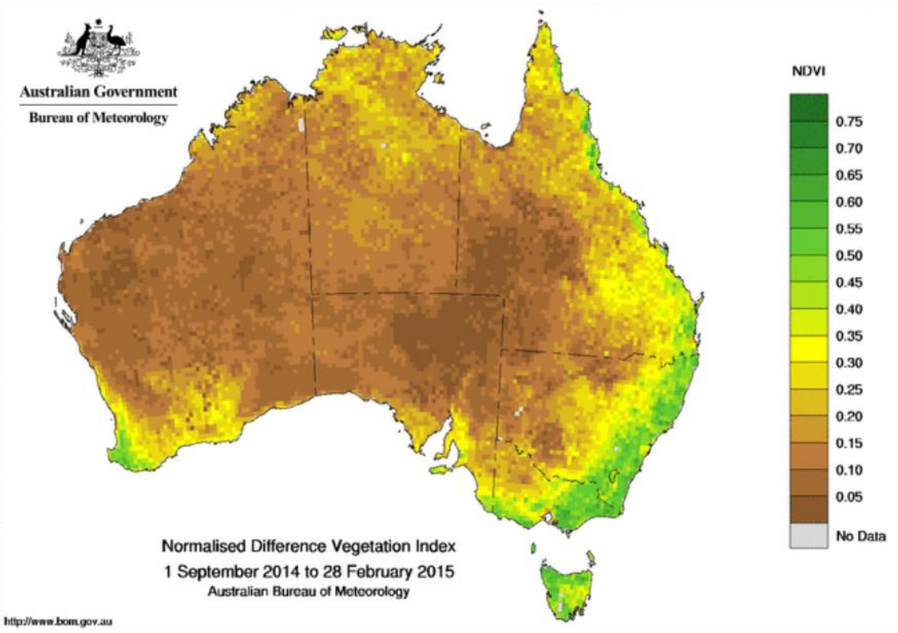
[575] AER, *United Energy Distribution: Distribution determination 2011–2015*, September 2012, p. 19

of the benchmarking period. The new obligations came into effect at various times from 2010. As a result they only affected the last three years of the benchmarking period. This more than halves the effect of the impact of the change in regulations on the benchmarking results.

As mentioned above all service providers have a duty of care. As a result they must take all reasonable measures to ensure the safety of their networks. As the Queensland service providers face a much lower risk of bushfire than those in Victoria, it is not likely they would need to adopt the practices required in Victoria after the Black Saturday bushfires. However, the Victorian service providers were still affected by the regulations for the final three years of the benchmarking period.

Energex has higher vegetation density in its rural service areas than some of the comparison firms (shown in Figure A.32 below). This may offset some of the effect of the more stringent bushfire regulations in Victoria. The fact that AusNet, which operates in a higher vegetation density region than Powercor, required a similar increase in expenditure for the increase in vegetation clearance obligations to Powercor, despite having only half the network length, supports this conclusion. On the other hand, vegetation density in Energex's network area may not be as great an issue as service providers' lines are often run through road easements or paddocks. Also, as a percentage of opex, Energex spends less on vegetation management than AusNet, Powercor, and SA Power Networks.[576] [577]

Figure A.32 Normalised Difference Vegetation Index: 6 Month Average September 2014 to 28 February 2015



576 Category Analysis RIN response data, template 2.1 Expenditure Summary.

577 Economic Benchmarking RIN response data, template 3 Opex.

Source: Bureau of Meteorology[578]

We are satisfied that the more stringent vegetation management obligations and bushfire risks in Victoria are likely to outweigh the higher vegetation density in Energex's service area. The forecast percentage increases in opex due to the change in bushfire regulations for Powercor and AusNet were 11.5 and 11.3 per cent respectively. These are almost as large as the average percentage of opex that Energex spent on vegetation management during the 2009 to 2013 period; 15 per cent.[579] [580]

On balance we are satisfied that the Victorian service providers will face a cost disadvantage relative to the Queensland service providers due to differences in bushfire risk and related regulations. However, the vegetation density in Energex's Network means it is uncertain if those differences will lead to a material cost advantage for Energex. As a result we have decided to treat bushfire risk as an immaterial OEF for Energex. An adjustment for bushfire risk satisfies the exogeneity OEF criteria. The geographic characteristics and settlement patterns of a network area are beyond the control of service providers. An adjustment for bushfire risk would also satisfy the duplication OEF criteria, Economic Insights' SFA model does not account for differences in bushfire risk. Therefore, in accordance with our treatment of immaterial OEFs for we have provided a negative 0.5 per cent adjustment to Energex's benchmarking results to account for differences in bushfire risk.

However, Ergon Energy does not appear to have any material offsetting factors. Figure A.32 above shows that overall Ergon has vegetation density comparable to western Victoria. Ergon spends a similar percentage of opex, 15 per cent, on vegetation management as SA Power Networks, and less than Powercor (18 per cent) and AusNet (22 per cent).[581] As a result we are satisfied that the step changes in Victoria to address changes in bushfire related regulations represent a cost disadvantage for the Victorian service providers relative to Ergon Energy.

With regard to the quantum of the OEF adjustment for Ergon, we consider that it should take into account that we base efficiency rankings on average performance over the 2005–06 to 2012–13 period and that not all comparison firms are Victorian. Therefore, we should base the OEF adjustment on the average effect of the OEF on the comparison firms over the benchmarking period. The new regulatory obligations only came into force in Victoria in 2010/11 so the Victorian service providers only had this cost disadvantage in the final three years of the benchmarking period. SA Power Networks did not have this disadvantage. We have therefore weighted the bushfire risk OEF adjustment by the customer numbers of the comparison firms and the length of the benchmarking period affected.

---

[578] Bureau of Meteorology, Six-monthly NDVI Average for Australia, available at http://www.bom.gov.au/jsp/awap/ndvi/index.jsp [last accessed 1 March 2015].

[579] Category Analysis RIN response data, template 2.1 Expenditure Summary.

[580] Economic Benchmarking RIN response data, template 3 Opex.

[581] Category Analysis RIN data, template 2.1 Expenditure Summary.

We are satisfied that it is necessary to provide a negative 2.6 per cent OEF adjustment for differences in bushfire regulations between the Ergon Energy and the comparison firms. The first step is to calculate the customer weighted percentage impact of the forecast increase in opex due to the changes in bushfire mitigation obligations on opex for the comparison firms (6.85 per cent). As these changes were only in place for the last three years of the eight year benchmarking period, we then multiplied the weighted percentage impact by three and then divided by eight. In this manner we have taken into the fact that these obligations do not apply to SA Power Networks, and that they were only in place for part of the benchmarking period.

Corrosive environments

We are not satisfied that an OEF adjustment for corrosive environments meets the materiality OEF adjustment criterion. All service providers have assets that corrosive elements affect.

In support of Ausgrid's 2014 regulatory proposal, Evans and Peck raised the issue of corrosion as an OEF. They consider that the presence of corrosive atmospheres containing things such as salts (in coastal environments) and acid sulphates (in soils) affect maintenance costs.[582]

While salts affect assets in coastal areas, dusts affect assets in inland areas. While all service providers will be affected to some extent, the differences in the corrosive elements in each area will lead to differences in design and operational considerations that may affect opex. Sufficient evidence was not provided to show that these differences would be material.

However, in accordance with our treatment of immaterial OEFs we have provided a positive 0.5 per cent adjustment for differences in exposure to corrosive elements. Although an OEF adjustment for differences in exposure to corrosive elements is not likely to lead to material differences in opex, the differences they do cause would meet the exogeneity and duplication OEF criteria. The prevalence of corrosive compounds in a network area is beyond service providers' control and Economic Insights' SFA model does not have a variable to account for it. We have provided a positive 0.5 per cent adjustment because it is unclear if differences in exposure to corrosive elements will lead to a cost advantage or disadvantage for the Queensland service providers relative to the comparison firms.

Cyclones

We are satisfied that an OEF adjustment is necessary for the increased network switching and emergency response operations resulting from cyclones. It satisfies all OEF criteria. Cyclones are beyond service providers' control. Cyclones can lead to

582 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

material differences in opex between service providers. Cyclones are not accounted for elsewhere in Economic Insights' SFA model.

Ergon Energy stated that cyclones present a unique problem for it. It noted that cyclones impact Queensland's coastal areas at a rate of around one to two events per year. Cyclones increase the likelihood of outages and lead to increased network switching and emergency response operations.[583]

We are satisfied that cyclones impose costs on Ergon Energy that other service providers in our benchmarking dataset do not face.

Ergon Energy provided the expenditure it incurred as a result of each of the major cyclones that impacted its region during the benchmarking period.[584] The opex associated with the events was $84 million (2014–15). This represents 3.4 per cent of Ergon Energy's network services opex over the same period. As this represents an increase of increase on ActewAGL's historical opex, it must be adjusted to the increase in efficient opex as discussed in the calculation of OEFs section above. After adjustment, the cyclones OEF represents an increase in efficient opex of 4.6 per cent.

Environmental Variability

We are not satisfied that an OEF adjustment for environmental variability would meet the materiality OEF adjustment criterion. Intra-network environmental variability will not lead to material differences in opex.

In its regulatory proposal Ergon Energy raised intra-network environmental variability as an issue that would lead to material differences in opex between it and the comparison firms.[585] Ergon Energy submitted metrics on the variability of temperature, rainfall, and humidity to support this claim. These metrics showed that Ergon has the highest level of intra-network variability in humidity, rainfall, and temperature. Ergon considers this variability of environment within its network presents Ergon Energy with a significant challenge in the development of optimal maintenance schedules and resource allocation. Ergon did not quantify the effect of these scheduling and logistic issues on its opex. Further, Ergon Energy did not adequately explain the link between environmental variability and increased maintenance scheduling costs or resource allocation costs.

We are not satisfied that differences in environmental variability will lead to material differences in opex. In developing maintenance schedules and managing inventories, all service providers must manage a large range of assets. The major driver of this heterogeneity is technological change. As the technology of electricity distribution advances over time, service providers install different types of assets. However, the older assets, based on a different technology remain. Managing this complexity is one of the core competencies of an asset manager. Ergon has provided no information that demonstrates that the incremental complexity involved in managing the potential

---

583 Ergon Energy, Response to information request AER Ergon 02, 18 December 2014, pp. 9–10.

584 Ergon Energy, *Regulatory proposal: Attachment 06.02.03*, 22 October 2014, p. 15.

585 Ergon Energy, *Regulatory Proposal: Attachment 0A.01.01*, 31 October 2014, pp. 12–13.

differences in assets in different environmental zones will materially add to the challenges that all service providers face.

Additionally we note that the majority of the comparison firms (AusNet services, Powercor, and SA Power Networks) are predominantly rural service providers that must operate in environmentally diverse circumstances.

However, as this factor satisfies the exogeneity and duplication OEF criteria, we have included it in our OEF adjustment for immaterial factors. As the majority of comparison firms are rural service providers, the customer weighted average comparison firm is likely to operate in a service area with a more variable climate than Energex. However, as the comparison firms include CitiPower and United Energy, Energex is likely to have a cost disadvantage. An OEF adjustment for environmental variability is also likely to satisfy the exogeneity and materiality OEF adjustment criteria. Differences in environment within a network's service are beyond service providers' control and Economic Insights' SFA model does not capture differences in environmental variability. As a result we have provided a negative 0.5 per cent adjustment to Energex and a positive 0.5 per cent adjustment to Ergon in our OEF adjustment for immaterial factors.

Fire ants

We are not satisfied than an OEF for fire ants would meet the materiality OEF adjustment criterion. Fire ant management is a very small part of Energex's costs.

In response to questions on its OEFs, Energex submitted that fire ant management would provide it with a material cost disadvantage.[586] This is because it must incur expenditure to prevent the spread of fire ants as a result of its activities.

The *Plant Protection Act 1989* regulates fire ant risk areas. Large parts of Energex's area of are restricted areas due to fire ant risk. Under Energex's Fire Ant Risk Management Plan, approved by a Queensland Government Inspector, Energex undertakes inspections and regular training for relevant staff.[587] Table A.16 shows Energex's estimated fire ant related expenditure.

Table A.16 Estimated expenditure relating to fire ants ($ nominal)

	2010−11	2011−12	2012−13	2013−14
Compliance reporting	$9,800	$9,900	$10,200	$10,500
Staff training	$71,700	$72,800	$74,600	$76,800
Annual substation inspections	$39,200	$39,800	$40,800	$42,000
Annual	$1,400	$1,400	$1,500	$1,500

586 Energex, Response to AER information request AER Energex 001, 17 December 2014, p. 6.

587 Energex, Response to AER information request AER EGX 001(A), 17 December 2014, p. 6.

	2010–11	2011–12	2012–13	2013–14
communications tower inspections				
Annual development site inspections	$21,000	$21,300	$21,900	$22,500
Monthly hub/depot inspections	$61,600	$62,600	$64,100	$66,000
Total	$205,000	$208,000	$213,000	$219,000

Source: Energex, Response to information request EGX015.

We have included fire ant management in our total immaterial OEF adjustment. In 2013/14 fire ant management accounted for $219,000 ($nominal). If this is added to our estimate of base opex for Energex, it leads to a 0.1 per cent increase in opex. Therefore we have used this amount to represent the cost of fire ant management in our immaterial OEF adjustment.

Ergon Energy did not provide any evidence to suggest that it was similarly affected. As a result we are not satisfied that that it requires an OEF adjustment for fire ants.

Grounding conditions

We are not satisfied that an OEF for grounding conditions would meet the materiality OEF adjustment criterion. The installation of earth grids is a very small part of service providers' costs. There is no evidence to suggest that there are material differences in grounding conditions between the Queensland service providers and the comparison firms.

Electricity distribution requires the use of earthing or grounding connection to aid in the protection and monitoring of the network. In rural areas, service providers use the earth as the return path for some forms of electricity distribution. These systems require service providers to create an electrical earth, usually from embedding conductors or rods in the ground. The effectiveness of these earths varies depending on the soil type and the amount of moisture in the soil.

The installation and maintenance of earth grids are a very small part of service provider's costs. Further, all service providers will have areas of their networks that provide challenging grounding conditions. Although there may be differences in grounding costs between networks, there is not sufficient evidence to conclude that these differences are material.

However, in accordance with our treatment of immaterial OEFs we have provided a positive 0.5 per cent adjustment for differences in grounding conditions. An adjustment for grounding conditions would satisfy the exogeneity and duplication OEF criteria. Soil conditions are beyond service providers' control and Economic Insights' SFA model does not have a variable that accounts for them. We have provided a positive 0.5 per cent adjustment because it is unclear if differences in grounding conditions will lead to a cost advantage or disadvantage for the Queensland service providers relative to the comparison firms.

Humidity and rainfall

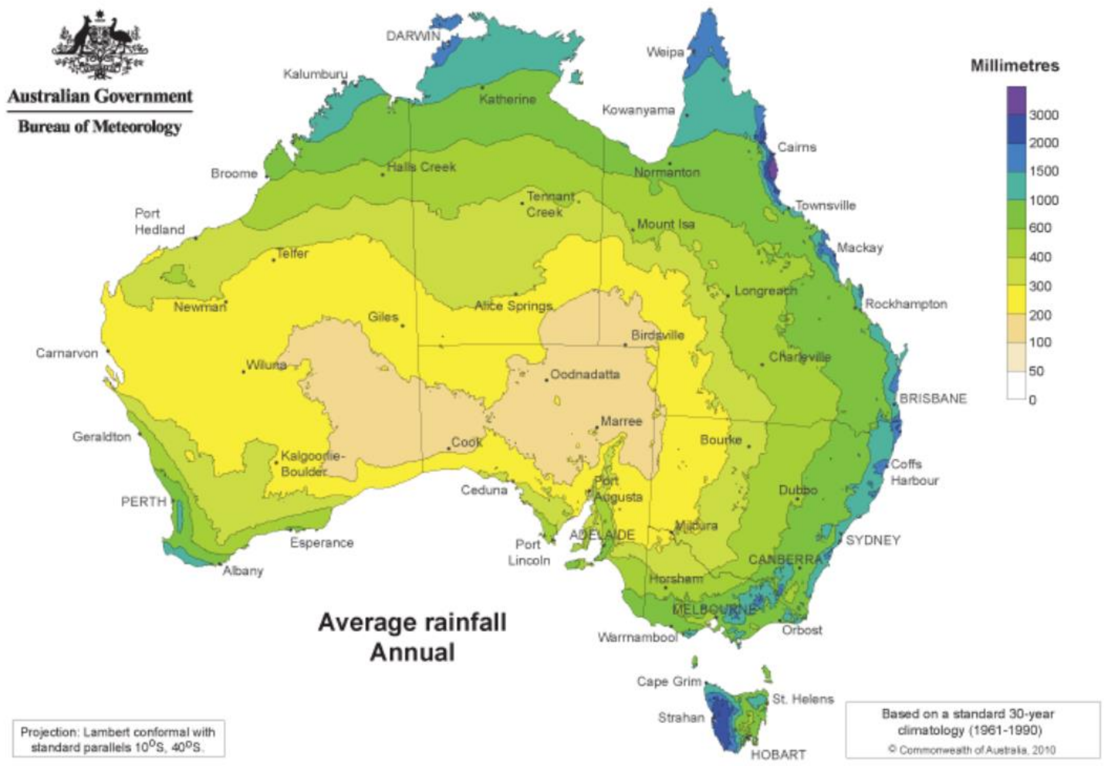
We are not satisfied that an OEF for differences in humidity and rainfall would meet the materiality OEF adjustment criterion. Differences in humidity are will have a greater impact on asset replacement than maintenance costs.

In response to questions from the AER about the effect of rainfall and humidity on poles, cross arms, transformers and assets using SF6 as an insulator, Ergon Energy submitted that high rainfall and humidity increases the degradation of timber assets.[588] It also submitted that asset failures in high rainfall areas make up 40 per cent of asset failures although they only make up five per cent of the area of Queensland.[589] Ergon Energy also stated that it has a special inspection program for pole top structures in areas that have rainfall of above 1500mm per annum. This leads to inspection costs being higher for poles in its higher rainfall areas.

When we asked Ergon Energy about the impact rainfall and humidity on poles, cross arms, transformers and assets using SF6 as an insulator, Ergon Energy only provided evidence to suggest that costs were higher for cross arm maintenance. Ergon Energy provided a comparison of the number of asset failures in high rainfall areas and low rainfall areas. However Ergon Energy did not indicate what percentage of its assets were in high rainfall areas. The only evidence that higher rainfall and humidity lead to increased opex that Ergon Energy provided relates to cross arm maintenance. Ergon Energy stated that it carries out more expensive cross arm inspections in high rainfall areas. However, Ergon Energy provided no evidence to indicate that the benefit of these inspections outweighs the additional costs relative to the aerial inspections used by other service providers to inspect cross arm health. Further only small parts of Energex and Ergon Energy's service areas are subject to average rainfalls in excess of 1500mm a year. See Figure A.33 below.

588 Ergon Energy, Response to information request ERG002(3), 18 December 2014, pp. 12–14.

589 Ergon Energy, Response to information request ERG018(3), 30 January 2015, p. 5.



Source: Bureau of meteorology[590]

In response to our November 2014 draft decision, Essential Energy submitted that we had not taken into account differences in the rate of fungal rot.[591] Essential Energy presented two maps produced by the CSIRO that indicated that wooden objects in areas of Queensland and Northern NSW are more prone to fungal rot than Victoria. Essential Energy stated this would lead to greater pole maintenance costs. Essential Energy provided no quantification of the impact that these differences would have on opex.

We agree with Essential Energy that wooden poles in the North Eastern Coastal areas of Australia will be more susceptible to fungal rot than poles in the comparison firms' service areas. However, we do not consider that this will lead to material differences in opex between the comparison firms and the Queensland service providers. This is because fungal rot is more likely to lead to increased pole replacement rather than increased maintenance costs. Maintenance activities for poles are predominantly inspection and antifungal treatment. These are generally carried out at the same time.

The Victorian service providers are required to inspect their assets every three years in Hazardous Bushfire Risk Areas and every five years in Low Bushfire Risk Areas.[592]

---

590 Bureau of Meteorology, Annual Rainfall Average: Product Code: IDCJCM004, available at http://www.bom.gov.au/jsp/ncc/climate_averages/rainfall/index.jsp [last accessed 18 March 2015].

591 Essential Energy, *Revised Proposal: Attachment 7.4*, 20 January 2015, p. 30 to 31.

592 Electricity Safety (Bushfire Mitigation) Regulations 2013, Regulation 6.

This practice has been in place since 2011.[593] Ergon[594] and Essential[595] generally inspect their pole assets and pole top assets every four years. Ausgrid[596] and Energex[597] reported five year inspection cycles and Endeavour Energy[598] reported four and a half year cycles.

We note that the increased rate of timber degradation in NSW and Queensland may manifest itself in higher replacement rates. Our repex model takes this into account by using observed replacement rates as the basis for forecast replacement quantities.

On balance, we are not satisfied that differences in rainfall and humidity are likely to lead to material increases in opex between the Queensland service providers and the comparison firms. However, we consider that the increased susceptibility of timber to fungal rot in Queensland may indicate that the Queensland service providers have a marginal cost disadvantage relative to the comparison firms. An adjustment for humidity and rainfall would satisfy the exogeneity and duplication criteria. The weather and climate are beyond the control of service providers and there is no variable in Economic Insights' SFA model that accounts for differences in humidity between the NEM service providers. In accordance with our approach to immaterial OEFs, we therefore consider it appropriate to provide a positive 0.5 per cent adjustment for differences in humidity and rainfall to the Queensland service providers.

Shape factors

We are not satisfied that an OEF adjustment for shape factors would meet the duplication OEF adjustment criterion. To the extent that service providers must extend their networks to accommodate natural boundaries, Economic Insights' SFA models account for this through circuit length.

Advisian stated that natural boundaries, such as water and national parks, surrounding electricity networks impose costs on service providers.[599] These costs manifest themselves through imposing constraints on network planning.

We are not satisfied that Economic Insights' SFA model does not suitably account for the effect of shape factors through circuit length. Although some service providers may be required to traverse or travel around natural boundaries, when this occurs, the service providers' line length will also increase. As circuit length is an output variable in Economic Insights' SFA model it accounts for this effect.

593 Electricity Safety Amendment (Bushfire Mitigation) Regulations 2011, Regulation 7.

594 Ergon Energy, Response to information request ERG018(3), 30 January 2015, p. 5.

595 Essential Energy, Response to Category Analysis RIN template 2.8 (2013–14).

596 Ausgrid, Response to Category Analysis RIN template 2.8 (2013–14).

597 Energex, Response to Category Analysis RIN template 2.8 (2013–14).

598 Endeavour Energy, Response to Category Analysis RIN template 2.8 (2013–14).

599 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 45 and p. 46.

Skills required by service providers

We are not satisfied that an OEF adjustment for differences in skills required by service providers would meet the materiality OEF adjustment criterion. Differences in the skills required by service providers are not likely to lead to material differences in costs. All service providers require broadly the same skills.

As service providers operate in different environments, they may require different skills. For example, rural networks may hire pilots to carry out asset inspections and transport staff and equipment. However, overall, service providers require employees with similar qualifications and skills. We note that we are benchmarking the same core services provided by all networks.

We have included this factor as part of the allowance for immaterial OEFs. This is because although differences in the skills required by service providers are unlikely to lead to material differences in opex, it is logical that there will be some differences. An adjustment for differences in skills required would satisfy the exogeneity OEF adjustment criterion. Different environmental conditions may require specialised expertise not required by other NEM service providers. Also differences in the skills required are not accounted for in Economic Insights' SFA model. As there is uncertainty as to which service providers will have cost advantages on this OEF we have provided a positive 0.5 per cent OEF for differences in skills required by service providers.

Extreme weather events

We are satisfied that an OEF adjustment for differences in exposure to extreme weather events satisfies all our OEF adjustment criteria. The weather is beyond service providers' control. Given service providers operate in geographically different areas, they will be subject to differing amounts of extreme weather. Extreme weather has the potential to materially affect service providers' opex. Systematic exposure to extreme weather not accounted for in Economic Insights' SFA model.

In support of its 2014 regulatory proposal, Ausgrid submitted a report by Advisian (formerly known as Evan's and Peck) that identified major weather events as an OEF that may affect benchmarking results.[600] Advisian present analysis from the Bureau of Transport Economics (BTE) that estimate the magnitude of the costs imposed by disasters in Australia. These costs include the estimated costs of bushfires, cyclones, earthquakes, floods, landslides, and severe storms in Australia over the period 1967−1999.[601]

We are satisfied that differences in exposure to extreme weather events are likely to create material differences in opex between the Queensland service providers and the

---

600 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, pp. 66–7.

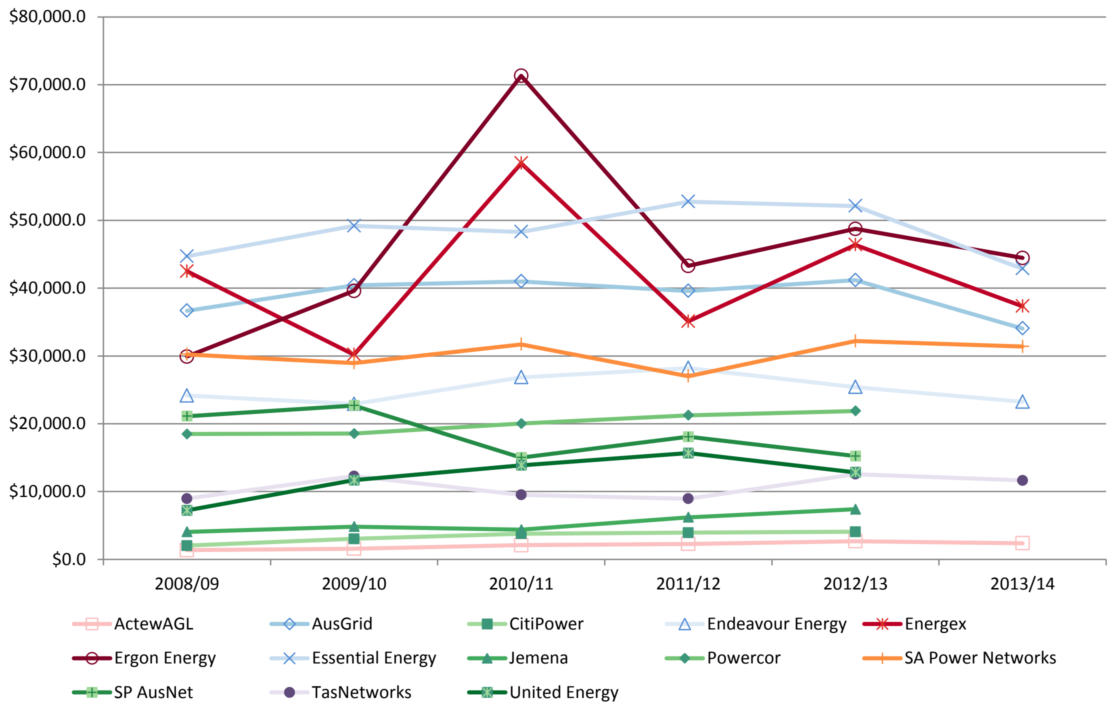
601 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 66.

comparison firms. Extreme weather events are likely to affect opex predominantly through emergency expenditures. As severe storms cause asset failures, service providers must expend resources to make their networks safe and restore supply in the short term, while those assets are being replaced.

In response to questions on its operating environment, Energex identified three significant events that materially increased its costs during the 2000/9 to 2012/13 period.[602] The Gap storm in November 2008, the Brisbane floods in 2011, and ex tropical cyclone Oswald in 2013.

Data from the category analysis RIN provides evidence that the impact of extreme weather events is material. The trend in category analysis over the 2009 to 2014 period shows that Energex's emergency response above its average in the years that significant events identified by Energex took place. This can be seen in Figure A.34 below. We note that during 2010/11 Ergon Energy's area was also affected by cyclones. As cyclones generally do not reach Energex's service area at full strength, we have considered the effect of cyclones separately above.

Figure A.34 Annual Emergency response expenditure for 2009 to 2014 ($000 2014)



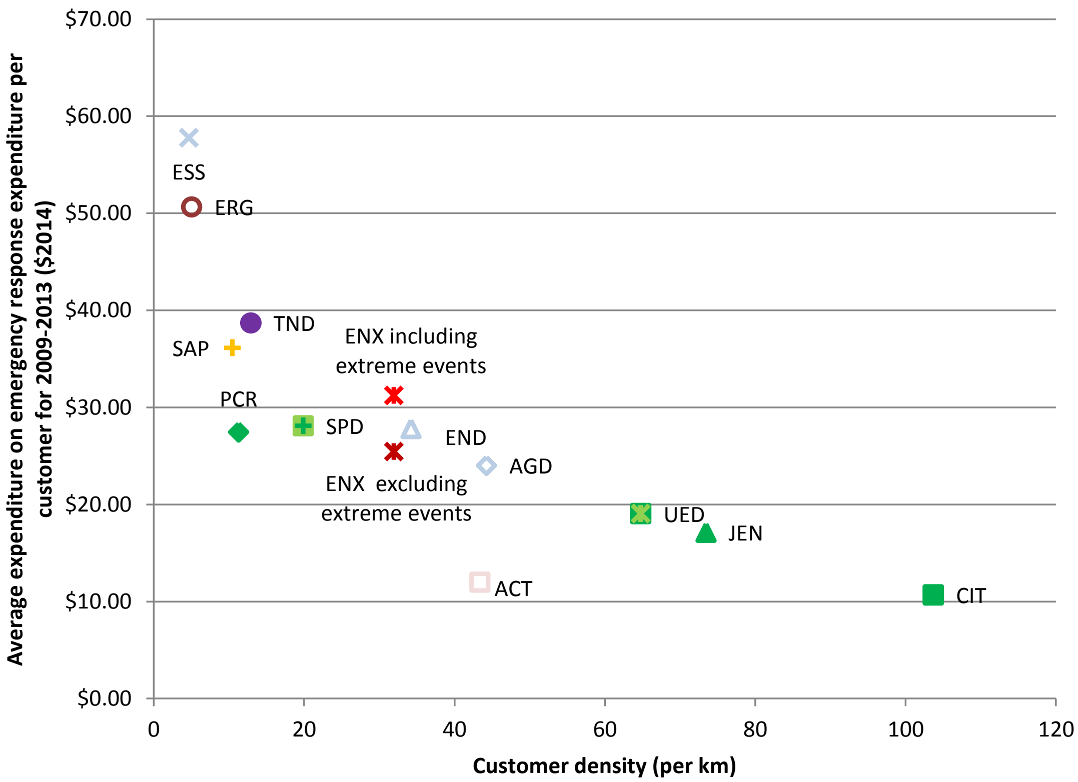
Source: Category analysis RIN data, AER analysis[603]

602 Energex, Response to AER information request AER EGX 001, 17 December 2014, p. 4.

603 Victorian data for 2014 not available at time of analysis.

To analyse the effect of extreme weather on Energex's opex, we compared Energex's emergency response costs to the comparison firms' costs. Figure A.35 below shows average emergency response expenditure per customer for the 2009 to 2014 period against customer density. There are two data points for Energex. One including the years with the three extreme weather events identified by Energex, and another excluding those years.

Figure A.35 average emergency response per customer for 2008/09 to 2013/14 against customer density ($000 2014)



When the extreme weather events are excluded Energex's average emergency response expenditure per customer falls to the trend for the comparison firms. This suggests that, excluding extreme weather events, Energex's emergency response expenditure is comparable to that of the comparison firms.

In the absence of more detailed information, we have used the above finding to estimate the impact of extreme weather events on the Queensland service providers' opex. The average annual expenditure on emergency response for Energex, was $7.4 million ($2014) higher than it would have been excluding the identified significant events. On average over the 2008/09 to 2013/14 period, Energex has incurred $352.3 ($2014) million in network services opex annually. As this represents an increase of 2.2 per cent increase on historical opex, it must be adjusted to the increase in efficient opex as discussed in the calculation of OEFs section above. After adjustment the extreme weather OEF represents an increase in efficient opex of 2.7 per cent for Energex.

We also asked Ergon for information about the major weather events that affect it. With the exclusion of the costs associated with cyclones, Ergon Energy did not provide any quantification of these costs.[604] Nonetheless, we consider that many of the extreme weather phenomena that affect Energex are likely to affect Ergon Energy with similar frequency. This is because coastal areas in Queensland share many similar climatic characteristics. In the absence of more detailed information from Ergon Energy, we have used the impact of extreme weather events on Energex to estimate the effect on Ergon Energy. Therefore we have also provided an OEF adjustment for extreme weather events, in addition to that identified for cyclones, to Ergon Energy. As the factor to convert OEF adjustments calculated as a percentage increase on historical costs to an adjustment to efficient costs in is higher for Ergon Energy, we have the OEF adjustment is 3.0 per cent adjustment for Ergon Energy.

Temperature

We are not satisfied that an OEF adjustment for differences in temperature across service providers' network areas would meet the duplication OEF adjustment criterion. Economic Insights' SFA model take into account ratcheted maximum demand.

Ausgrid's consultant Advisian stated differences in temperature provide some service providers cost advantages as differences in air conditioning penetration affect peak demand. Advisian submit the number and duration of warm days is greater in NSW and Queensland when compared to Victoria, stating it is reasonable to assume that this exposes the NSW and Queensland service providers to air conditioning penetration increases more than Victorian and SA service providers.[605]

We are not satisfied that ratcheted peak demand captures all increases in demand including those due to differences in air conditioning penetration. Economic Insights' SFA model includes ratcheted peak demand as an output variable.

Termite exposure

We are satisfied that an OEF adjustment for differences in termite exposure between the Queensland service providers and the comparison firms would satisfy all of our OEF adjustment criteria. The range of termites is beyond service providers' control. Termite management can be a material cost. There are no variables in economic Insights' SFA model for difference in termite exposure.

In response to our 2014 draft decision, the NSW service providers' consultant, Huegin, raised termites as an OEF that may lead to differences in opex between the NSW service providers and the comparison firms.[606] Ergon Energy also raised this point in its

---

[604] Ergon Energy, Response to AER information request AER Ergon 002, 17 December 2014, pp. 10–11.

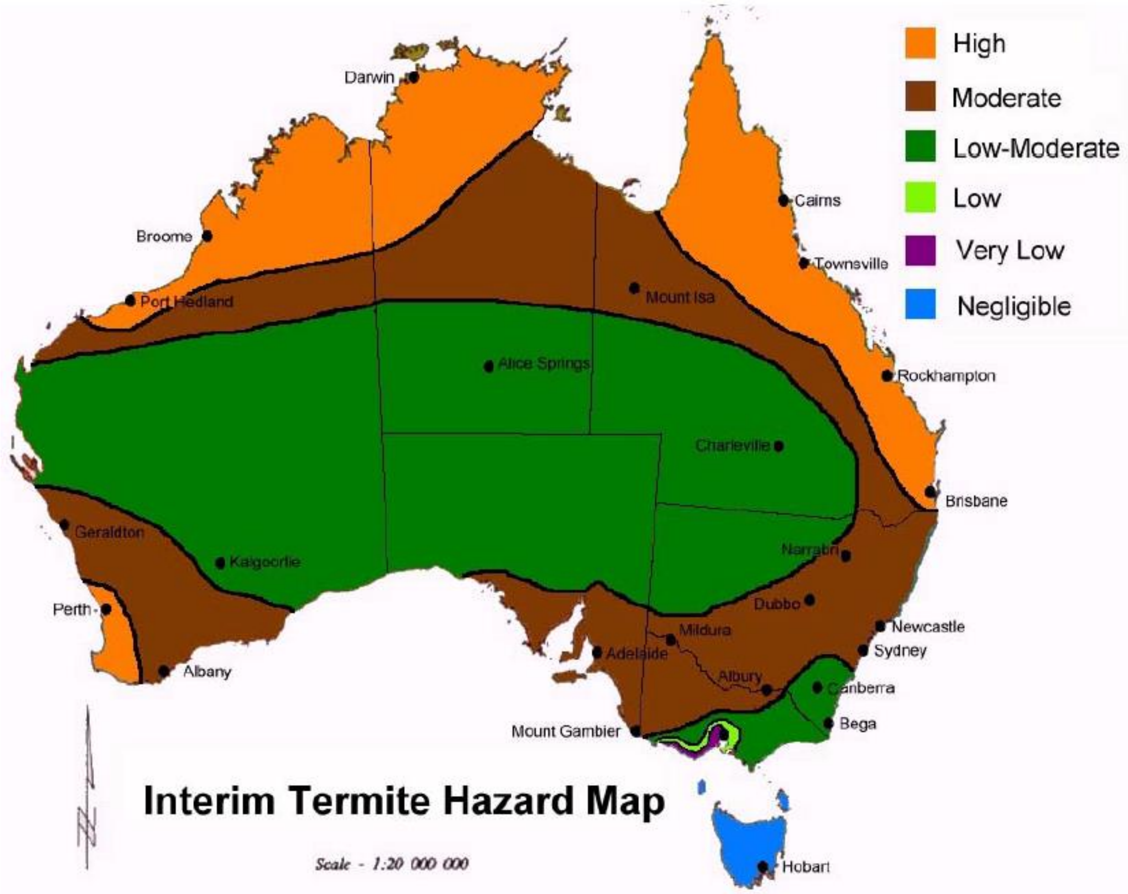
[605] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 64–65.

[606] Huegin, *Response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER*, January 2015, p. 47.

regulatory proposal.[607] Both Huegin and Ergon Energy submitted different maps to substantiate their claims. Both broadly show that Southern and Eastern Victoria are low risk, North Western Victoria and NSW are moderate risk, and coastal Queensland is high risk. It is not clear what the source of the data behind these maps is.

The CSIRO has published a similar map,[608] based on surveys of the incidence of termites and termite infestations of dwellings across Australia. It is shown below in Figure A.36.

Figure A.36 CSIRO Termite Hazard Map of Australia



In its 2011 regulatory proposal, Powercor requested a step change for increased expenditure on treating termite infested poles. Powercor forecast that over the 2011 to 2015 period its average annual expenditure on termite management would be $0.3 million ($2010) per year.[609] Using this figure in conjunction with data from Powercor's response to the Category Analysis RIN, this indicates that the average cost of termite treatment per wooden pole for Powercor is around $1 per annum ($2014−15). Ergon

---

[607] Ergon Energy, *Regulatory Proposal: Attachment 0A.01.01*, pp. 15–16.

[608] Cookson, L.J. and Trajstman, A.C., Termite Survey and Hazard Mapping, June 2002, p. 34.

[609] AECOM, Climate change impact assessment on Powercor Australia for 2011–2015 EDPR, 30 September 2009, pp. 70–75.

Energy, also provided some information that showed the average opex for responding to asset failures caused by termites was 22.7 per cent of the cost of treating infested poles for the 2011/12 to 2013/14 period.[610] Therefore we estimate that the average total cost of treating infested poles and responding to termite induced asset failures is $1.23 ($2014−15) per wooden pole for Powercor.[611]

We estimated termite management costs per pole for the Queensland service providers and the comparison firms. We multiplied the unit cost of treatment for Powercor by different rates, depending on the location of the relevant firm and infestation rates from the CSIRO.[612] [613] This was to account for differences in infestation rates across service areas.

We estimate that Energex and Ergon Energy would spend $1.7 ($2014−15) more per pole than the customer weighted average of the comparison firms for termite management. Multiplying the marginal termite management cost per wooden pole by the number of wooden poles for each service provider,[614] provides an estimate of the value of the cost disadvantage. The annual disadvantage is $0.7 million and $1.6 million ($2014−15) for Energex and Ergon respectively. Adding these figure to the efficient opex, determined by the SFA model, suggests a 0.2 per cent, and 0.5 per cent cost disadvantage for Energex and Ergon Energy respectively.

Although the effect of termites on Energex's opex is immaterial, in accordance with our approach to quantifying immaterial OEFs, we will provide an OEF adjustment that reflects the quantified impact.

As a result we consider that OEF adjustments of 0.2 per cent and 0.5 per cent for Energex and Ergon respectively are appropriate.

Topographical conditions

We are not satisfied that an OEF adjustment for topographical conditions would meet the materiality OEF adjustment criterion. All service providers are likely to have areas where topography adversely affects costs.

Advisian, in a report commissioned by Ausgrid in support of its 2014 regulatory proposal, stated that service providers in NSW and Victoria have a natural cost advantage due to the topography of those regions.[615] They do not explain why they consider this is the case for NSW, but they do mention that the major population

---

610 Ergon Energy, Response to AER Information Request AER ERG 018(4), 6 February 2015, p. 2.

611 1.23=1*1.227

612 Cookson, L. J. and Trajstman, A. C., Termite Survey and Hazard Mapping, June 2002, pp. 6 and 29.

613 We assumed the Queensland service providers, AusNet, CitiPower, and UED were respectively 204 per cent, 93 per cent, 42 per cent, and 52 per cent as likely to be affected by termites as Powercor. These are based on incidence rates from Cookson and Trajstman's termite survey.

614 The number of wooden poles for each service provider was taken from the category analysis RIN responses.

615 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 41.

centres of Victoria are flat with little vegetation. Advisian provided three maps that use different scales to support this. The AEMC also raised topography as an exogenous factor that may affect benchmarking.[616]

Adverse topographical conditions may affect some NEM service providers. For example, the Great Dividing Range runs through some distribution network areas. Operating in mountainous regions may lead to higher costs in some operating areas such as maintenance, emergency response, and vegetation management due to access issues, even if this is not likely to be a material cost. We note that AusNet Services, the comparison service provider at the benchmark comparison point, has a more mountainous operating environment than the Queensland service providers. However, most of the comparison service providers operate in a relatively flat area compared to Queensland service providers. Therefore, the Queensland service providers may have a cost disadvantage relative to the comparison service providers due to topography.

We are not satisfied that an adjustment for topographical conditions meets the materiality OEF adjustment criterion. Many service providers are likely to be affected by topography to some extent. Further, no service provider has provided any evidence of the quantum of the cost advantage that operating in relatively flat terrain may afford.

However, in accordance with our treatment of immaterial OEFs we have provided a positive 0.5 per cent adjustment for differences in topography. An adjustment for topography would satisfy the exogeneity and duplication OEF criteria. The landforms in service providers' network areas are beyond their control and there is no variable in Economic Insights' SFA model to account for differences in topography. We have provided a positive 0.5 per cent adjustment because it is unclear if differences in topography will lead to a cost disadvantage for the Queensland service providers relative to the comparison firms.

A.6.6 Jurisdictional factors

Building regulations

We are not satisfied an OEF adjustment for differences in building regulations across jurisdictions would meet the materiality OEF adjustment criterion. The Building Code of Australia (BCA) provides a set of nationally consistent, minimum necessary standards of relevant safety (including structural safety and safety from fire), health, amenity and sustainability objectives for buildings and construction.[617]

---

[616] AEMC, *Rule determination: National Electricity Amendment (Economic Regulation of Network Service Providers)*, November 2012, p. 113.

[617] ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board. [last accessed 4 September 2014].

In support of Ausgrid's 2014 regulatory proposal, Advisian identified differences in building regulations as an OEF that may affect benchmarking results.[618] Advisian do not provide any explanation as to how this may impede like for like comparisons.

The Australian Building Codes Board (ABCB) is a Council of Australian Government standards writing body that is responsible for the National Construction Code (NCC) that comprises the BCA and the Plumbing Code of Australia (PCA). It is a joint initiative of all three levels of government in Australia and was established by an inter-government agreement (IGA) signed by the Commonwealth, States and Territories on 1 March 1994. Ministers signed a new IGA, with effect from 30 April 2012.[619] The BCA contains technical provisions for the design and construction of buildings and other structures, covering such matters as structure, fire resistance, access and egress, services and equipment, and energy efficiency as well as certain aspects of health and amenity.[620]

We are not satisfied that an OEF adjustment for differences in building regulations is necessary because there will not be material differences in opex between service providers in different jurisdictions due to consistent building regulations. However as there may be some slight differences in the application and enforcement of the regulations across jurisdictions.

Therefore in accordance with our treatment of immaterial OEFs we have provided a positive 0.5 per cent adjustment for differences in building regulations. Although immaterial, an adjustment for differences in building regulations would satisfy the exogeneity and duplication OEF adjustment criteria. Building regulations are not determined by service providers and there are no variables in Economic Insights' SFA model that account for differences in them.

Capital contributions

We are not satisfied that an OEF adjustment for differences in capital contribution policies meets the duplication OEF adjustment criterion. Economic Insights' SFA model uses network services data, which exclude services for which capital contributions are payable.

In support of Ausgrid's 2014 regulatory proposal, Advisian stated differences in capital contribution policies may affect benchmarking of service providers.[621] Advisian stated that differences in capital contributions policies make it difficult to draw any conclusions on the effect of capital contributions on different service providers.

---

618 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 5.

619 ABCB, About the Australian Building Codes Board, available at; www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

620 ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board, [last accessed 22 March 2015].

621 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 31–32.

We are not satisfied that differences in capital contribution policies affect the data used in Economic Insights' SFA model. Therefore, an adjustment for differences in capital contribution policies does not meet the duplication OEF adjustment criterion. Users will make a capital contribution when they connect to the network, depending on the type of connection, or require a change to their connection. New connections and changes to connections are connection services for the purpose of our economic benchmarking RIN.[622] Network services do not include connection services in our economic benchmarking RIN.[623] Because the data that is used in Economic Insights' SFA model exclude connection services, capital contributions cannot affect the results of the benchmarking.

Contestable services

We are not satisfied that an OEF adjustment for differences in contestable services across jurisdictions would meet the duplication OEF adjustment criterion. Economic Insights' SFA model only uses costs incurred in providing network services. Network services do not include contestable services.

In their 2014 regulatory proposals Ausgrid, Endeavour Energy and Essential Energy all raised contestability of services as an OEF that will affect benchmarking results.[624] [625] [626] Beyond saying that they 'play a major part in explaining differentials in cost structures' none of the NSW service providers gave any explanation of how differences in markets for contestable services would affect benchmarking.

Economic Insights' SFA model only includes costs incurred in providing network services. Contestable services are not included in network services. Because we have excluded contestable services from network services data, contestable services cannot affect benchmarking that uses network services data.

Cultural heritage

We are not satisfied that an OEF adjustment for differences in cultural heritage management across jurisdictions would meet the materiality OEF adjustment criterion. We do not see evidence to suggest that differences in cultural heritage management requirements would lead to material differences in opex.

In response to questions from the AER on the OEFs that materially affect its costs, Ergon Energy submitted that cultural heritage obligations impose additional

---

622 AER, *Economic Benchmarking RIN for distribution service providers: Instructions and Definitions*, November 2013, p. 44.

623 AER, *Economic Benchmarking RIN for distribution service providers: Instructions and Definitions,* November 2013, p. 44.

624 Ausgrid, *Attachment 5.33* to *Revenue proposal*, p. 3.

625 Endeavour, *Attachment 0.12* to *Revenue proposal*, p. 3.

626 Essential *Attachment 5.*4 to *Revenue proposal*, p. 5.

management and operational costs on it.[627] Specifically Ergon Energy identified staff training and awareness, special alert and management processes and additional operational precautions for native title cultural heritage. Ergon Energy provided a map showing areas where native title has been found to exist and where claims have been made. Ergon Energy did not quantify the costs it incurs for its native title or other cultural heritage programs.

Many service providers have cultural heritage obligations. For example, the Victorian service providers most comply with the *Planning and Environment Act 1987*, the *Heritage Act 1995*, and the *Aboriginal Heritage Act 2006* in providing services. The Queensland service providers have not provided evidence to suggest the costs they incur to meet their obligations will be materially different to comparison firms.

Therefore we are not satisfied that differences in cultural heritage obligations will lead to material differences in opex between the Queensland service providers and the comparison firms. However, there is likely to be some differences in obligations that will lead to immaterial differences in opex. An adjustment for differences in cultural heritage obligations would also satisfy the exogeneity and duplication OEF adjustment criteria. Cultural heritage obligations are not determined by service providers and there are no variables in Economic Insights' SFA model that account for differences in them. As the direction of cost advantage is unclear, we have included an adjustment of positive 0.5 per cent for differences in cultural heritage obligations in our adjustment for immaterial factors.

Division of vegetation management responsibility

We are satisfied that it is necessary to provide an OEF adjustment for the division of responsibility for vegetation management. An OEF for the division of responsibility between the Queensland service providers and the comparison firms satisfies all three of our OEF adjustment criteria. The division of responsibility for vegetation management is determined by state governments. It is likely to lead to a material difference in costs between the Queensland service providers and the comparison firms. Also, Economic Insights' models do not have any variables that account for differences in the division of vegetation management responsibility.

ActewAGL,[628] Ausgrid,[629] Endeavour Energy,[630] Ergon Energy[631] [632]and Essential Energy,[633] have all raised the division of responsibility for vegetation management as a factor that may affect benchmarking results. For example in Queensland, service

627 Ergon Energy, Response to AER information request Ergon 002, 17 December 2014, p. 7–9

628 ActewAGL, *Revised Proposal*, 20 January 2015, p. 199.

629 Ausgrid, *Revised Proposal*, 20 January 2015, p. 149.

630 Endeavour Energy, *Revised Proposal*, 20 January 2015, p. 176.

631 Ergon Energy, Response to information request Ergon 002, 19 12 2014, p. 21.

632 Ergon Energy, *Submissions on the Draft Decisions: NSW and ACT distributions 2015–16 to 2018–19*, 13 February 2015, p. 19.

633 Essential Energy, *Revised Proposal*, 20 January 2015, p. 189.

providers are responsible for vegetation clearance from all network assets.[634] [635] In others states other parties, notably councils and roads authorities, are responsible for some vegetation clearance. As a result some service providers must undertake additional vegetation management in the provision of network services.

Overall, we are satisfied that differences in the division of responsibility for vegetation management are likely to lead to material differences in opex between the Queensland service providers and the comparison firms. Service providers in Victoria and South Australia share responsibility for vegetation management of their networks with other parties, while the Queensland service providers do not.

Section 216 of the *Electricity Safety Regulation 2013* requires the Queensland service providers to keep vegetation from all overhead lines that form part of their networks.

In Victoria, Sections 84A to 84D of the *Electricity Safety Act 1998* set out the division of responsibility for vegetation management between service providers and other parties.[636] [637] [638] Landholders are responsible for vegetation management of any lines that exclusively service their property. Councils are responsible for vegetation management of any trees on public land in a declared area.[639] Service providers are responsible for vegetation management of all other trees that encroach on their network.

In South Australia, Part 5 of the *Electricity Act 1996 (SA)* and the *Electricity (Principles of Vegetation Clearance) Regulations 2010* set out the division of responsibility for vegetation management between service providers and other parties.[640] Under this legislation SA Power Networks is responsible for clearance of all lines with three exceptions. SA Power Networks is not responsible where it has entered into a vegetation clearance scheme with a council under section 55(1a) of the *Electricity Act 1996 (SA)*. There are no such agreements with councils currently in place.[641] SA Power Networks is not responsible for clearance of cultivated vegetation from private powerlines.[642] SA Power Networks is also not responsible for clearing trees encroaching on powerlines where the tree was planted in contravention of the (Principles of Vegetation Clearance) Regulations 2010 schedule 2.[643]

---

634 Ergon Energy, Response to information request AER Ergon 026(1), 13 February 2015, p. 4.

635 Energex, Response to information request AER Energex 021, 13 February, p. 3.

636 CitiPower and Powercor, Response to information request on vegetation management responsibility, 17 February 2015, p. 2.

637 Jemena, Response to information request on vegetation management responsibility, 13 February 2015, p. 1.

638 AusNet Services, Response to information request on vegetation management responsibility, 16 February 2015, p. 1.

639 Declared areas are urban areas where the local council has responsibility for vegetation management as declared under section 81 of the *Electricity Safety Act 1998* by the Governor in Council.

640 SA Power Networks, Response to information request AER SAPN 021, 13 February 2015, p. 1.

641 SA Power Networks, Response to information request AER SAPN 021, 13 February 2015, p. 1.

642 SA Power Networks, Response to information request AER SAPN 021, 13 February 2015, p. 1.

643 Electricity Act 1996 (SA), subsection 55(3).

We are satisfied that differences in the division of responsibility for vegetation management in Victoria, South Australia and Queensland will lead to material differences in opex between the Queensland service providers and comparison firms. The comparison firms all share responsibility for vegetation management with other parties. The Queensland service providers do not.

To quantify the effect that differences in the division of vegetation management may have, we have used two sources of information. We used the 2014 Electric Line Clearance regulatory impact statement and information gathered from the comparison firms, and the Queensland service providers RIN data.

The 2014 Electric Line Clearance regulatory impact statement provides some information on the division of vegetation management costs between service providers and councils in Victoria.[644] Information from the regulatory impact statement suggests that the Councils are responsible for 24 per cent of electricity distribution and transmission vegetation management costs in Victoria. We asked the Victorian service providers to provide information on what percentage of their networks councils and other parties have responsibility for vegetation management. Of the comparison firms, only AusNet services provided an estimate of the length of its network that councils have responsibility for vegetation management.[645] [646] [647] The reason for this is that often service providers and councils will be responsible for vegetation management of different trees on the same span. This made it difficult for some Victorian comparison firms to estimate what percentage of their network other parties are responsible for. However, AusNet services indicated that it shared responsibility for vegetation management with councils for 12 per cent of its overhead route line length.

On this information, councils would appear to be responsible for somewhere between 24 per cent and 12 per cent of vegetation management in Victoria. For the purpose of estimating the opex impact created by differences in the division of responsibility for vegetation management, we have assumed that councils are responsible for 18 per cent of vegetation management in Victoria. We have taken the midpoint of the two figures available to us. We consider that it is likely that councils will have higher vegetation management costs than network service providers. Councils will have different vegetation management objectives to service providers. In general, councils will be more concerned with maintaining the visual amenity of trees and less concerned with minimising costs than service providers. This is likely to increase the costs of their vegetation management programs relative to the comparison firms.

---

[644] Energy Safe Victoria, *Regulatory Impact Statement: Electricity Safety (Electric Line Clearance) Regulations 2015*, September 2014, p. 51.

[645] AusNet Services, *Response to AER information request on division of responsibility for vegetation management in Victoria*, 16 February 2015, pp. 2–3.

[646] United Energy, *Response to AER information request on division of responsibility for vegetation management in Victoria*, 20 February 2015.

[647] CitiPower/Powercor, *Response to AER information request on division of responsibility for vegetation management in Victoria*, 17 February 2015.

We have assumed that councils in SA are responsible for a similar amount of vegetation management as their Victorian Counterparts. This is because other parties should be responsible for some vegetation management under Part 5 of the *Electricity Act 1996*.

As a result we consider that an OEF adjustment of 3.4 per cent and 4.1 per cent is appropriate for Energex and Ergon Energy respectively. This is because the percentage of network services opex that vegetation management accounts for is 15 and 16 per cent for Energex and Ergon Energy respectively. If roughly 18 per cent of the Queensland service providers' vegetation management was undertaken by councils, Energex and Ergon's opex would be 2.8 and 3 per cent lower than they are currently. As these figures are increases on historical opex, as described in the calculation of OEFs section above, they must be adjusted before they can be used as OEF adjustments to the efficient base year opex forecast by the SFA model. After adjustment, the division of responsibility for vegetation management OEF represents an increase on the efficient level of base opex of 3.4 per cent and 4.1 per cent respectively for Energex and Ergon Energy.

Environmental regulations

We are not satisfied that an OEF adjustment for differences in environmental regulations across jurisdictions would meet the materiality OEF adjustment criterion. Environmental regulations are not likely to create material differences in costs between the Queensland service providers and the comparison firms.

Ergon Energy and Energex submitted that differences in environmental regulations would lead to material differences in opex.[648] [649]

We investigated how environmental regulations may lead to material differences for the opex that service providers require, but were unable to find any reliable evidence that such differences exist. The way various jurisdictions administer environmental regulation varies considerably.[650] While the Commonwealth has some involvement, most environmental planning functions are carried out by state or local governments. We consider it is likely that differences in environmental regulations faced by service providers will lead to differences in costs, but we do not have any evidence to suggest that these differences are material.

While we are not satisfied that an adjustment for environmental regulation would not lead to material differences in opex, we have included this factor as part of the allowance for immaterial OEFs. An OEF adjustment for environmental obligations would satisfy the exogeneity and duplication OEF criteria. Environmental obligations are not determined by service providers and Economic Insights' SFA model does not

---

648 Ergon Energy, Response to AER information request AER Ergon 002, 17 December 2015, pp. 7 – 9.

649 Energex, Response to AER information request AER Energex 001, 17 December 2014, pp. 2–4.

650 Productivity Commission, *Performance Benchmarking of Australian Business Regulation: Local Government as Regulator*, July 2012, p. 386–390.

include any variables that account for differences in them. We have provided a positive 0.5 per cent OEF in our collective adjustment for immaterial OEFs because it is unclear if environmental obligations will lead to a cost advantage or disadvantage to Ergon Energy and Energex.

Occupational Health and Safety regulations

We are satisfied that it is necessary to provide the Queensland service providers with a positive 0.5 per cent OEF adjustment for differences in Occupational Health and Safety Regulations (OH&S). This is because an OEF adjustment for OH&S regulations satisfies all three OEF criteria. OH&S regulations are outside of the control of service providers. Differences in OH&S regulation are likely to create material differences in opex between the Queensland service providers and the comparison firms. Economic Insights' SFA model does not account for differences in OH&S regulations.

In support of Ausgrid's 2014 regulatory proposal, Evans and Peck identified differences in OH&S regulations as an OEF that may affect benchmarking results.[651] Evans and Peck did not provide any explanation as to how this may impede like for like comparisons

In the NEM, all jurisdictions, except Victoria, have enacted the Work Health and Safety Act and Work Health and Safety Regulations.[652] While enforcement activities may vary slightly across jurisdictions the main cost driver of OH&S costs will be the regulations and law with which businesses must comply. In this respect, we are satisfied that there will not be material cost differences between jurisdictions that have enacted the model laws. However, there is likely to be a cost differential between service providers in Victoria and those in other jurisdictions. Because the comparison firms are predominantly Victorian, this is likely to likely to lead to cost differentials between the comparison firms and the Queensland service providers.

We are satisfied that a positive 0.5 per cent OEF adjustment for the Queensland service providers is appropriate. The Victorian state government employed PricewaterhouseCoopers (PwC) to estimate the costs of implementing the new OH&S laws would impose on commerce in Victoria. According to PwC, the annual impost of the implementing the laws would be up to $796 million ($2011–12).[653] The Gross State Product for Victoria in FY 2012 was $328 595 million ($2011–12).[654]

This would mean that the impact of complying with the new OH&S laws on the Victorian economy would be equivalent to 0.24 per cent of Gross State Product.

---

[651] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 38.

[652] Safework Australia, Jurisdictional progress on the model work health and safety laws, available at: thehttp://www.safeworkaustralia.gov.au/sites/swa/model-whs-laws/pages/jurisdictional-progress-whs-laws. [last accessed 4 September 2014]

[653] PricewaterhouseCoopers, *Impact of the Proposed National Model Health Work and Safety Laws in Victoria*, April 2012, p.7.

[654] ABS, *5220.0 - Australian National Accounts: State Accounts, 2011-12*, November 2012.

Electricity distribution work environments may present more danger than the average work environment across the economy. With this in mind, a 0.24 per cent adjustment may underrepresent the potential cost advantage for Victorian Electricity distribution businesses. The PwC report suggests that the annualised ongoing costs for power generators would be almost two and a half times greater than for the majority of other businesses.[655]

Therefore, we have assumed that an electricity service provider would face two and a half as many costs due to a change in OH&S laws compared to the average of the Victorian economy. This suggests that relative to a Victorian service provider, service providers in other NEM jurisdictions require 0.6 per cent more opex. When this is weighted by the proportion of customers Victorian service providers have of the comparison firms, this leads to a 0.5 per cent adjustment.[656]

Ergon Energy's consultant, PwC, made a submission on our OEF adjustment for differences in jurisdictional OH&S differences.[657] PwC made four observations on our application of its findings to estimate an OEF adjustment for differences in OH&S obligations. PwC stated its report on the impact of the WHS laws only considered the potential costs borne by Victorian businesses. It stated that the total cost of complying with the new WHS laws was not considered. It stated that its findings do not directly reflect costs facing network service providers. It also considered normalising the annualised cost by Victoria's Gross State Product (GSP) could be misleading. We address each of these comments below.

The OEF adjustment for OH&S obligations is designed to quantify the effect of the cost advantage that the Victorian service providers have over other service providers. As the report estimates the cost of transitioning to the WHS laws for Victoria, it provides an estimate of the cost avoided by Victorian businesses by not having to comply with the WHS laws. We also note that PwC has provided no evidence that the costs of complying with the WHS laws would be different in Queensland than Victoria.

It is not appropriate to consider the total cost of complying with and implementing the WHS laws for the purpose of an OEF adjustment. OEF adjustments are not required for non-recurrent costs. Providing an OEF for non-recurrent costs treats those costs as if they were recurrent. Economic Insights' benchmarking results are used as the basis for our forecast of opex. If we adjust the benchmarking results with an OEF adjustment for non-recurrent costs, it has the effect of including those non-recurrent costs in our forecast of opex. Essentially, providing an OEF adjustment for non-recurrent costs

---

655 PricewaterhouseCoopers, *Impact of the Proposed National Model Health Work and Safety Laws in Victoria*, April 2012, p. 9.

656 We note that we have not provided a step change to Transgrid for the change in Work Health and Safety legislation. We note that although the change from the NSW laws to the model laws may not be material it appears that the change from the Victorian laws to the model laws may be.

657 PricewaterhouseCoopers, *Review of AER's methodology of adjusting for differences in occupational health and safety obligations*, 12 February 2015.

leads to those costs being treated as recurrent costs. This is not appropriate because it would provide an allowance for costs that will not be incurred.

The challenges in safely operating high voltage assets that network service providers must take into account will be similar to those that power generators face. Although PwC's report's findings show that the costs of adopting the laws are not uniformly distributed across Victorian businesses we have taken steps to account for this. We adjusted the average impact across the Victorian economy to reflect the observed differences between most firms surveyed and the business type that most resembled the network service providers: power generators. We note that network service providers are likely to incur higher costs for OH&S obligations than power generators due to their scale. This is why we adopted a percentage adjustment, calculated using the average cost to the Victorian economy,[658] rather than the average annualised cost per power generator, which was only $5,210 ($2011−12). PwC did not propose an alternative method to account for differences between the stage average and network service providers.

Using Victorian Gross State Product (GSP) to estimate the materiality of regulatory changes within Victoria is appropriate. Volatility in growth rates across states will not affect this. We estimated the percentage of goods and services produced in Victoria that the annualised increase in OH&S costs would have accounted for if they were incurred in 2012. The estimate of GSP used was from 2012. The estimates of compliance costs which formed the basis for PwC's report were also from financial year 2012. Because we are comparing two figures that relate to the same state, variability between states will not affect the comparison.

Licence conditions

We are satisfied that it is necessary to provide an OEF adjustment for differences in licence conditions across jurisdictions for Ergon Energy. The adjustment is positive 0.7 per cent. An OEF adjustment for differences in licence conditions meets all of our OEF adjustment criteria. Past licence conditions are likely to materially affect opex, because they mandated that the Queensland service providers install significant redundant capacity they may not have in the absence of those conditions. Economic Insight's SFA model will only account for feeders installed to meet those standards, not substation capacity. On the basis of the Economic Benchmarking RIN and Category Analysis RIN data the effect on opex of the past licence conditions is greater than 0.5 per cent of opex for Ergon Energy, but not for Energex.

[658] The annual costs forecast by PwC for the implementation of the new OH&S laws were equivalent to 0.24 per cent of the Gross State Product of Victoria in financial year 2012. Because electricity distribution work environments may present more danger than the average work environment across the economy we multiplied this amount by 2.5. The PwC report suggests that the annualised ongoing costs for power generators would be almost two and a half times greater than for the majority of other businesses. This suggests that the Victorian service providers have a 0.6 per cent cost advantage relative to the other NEM service providers. However, as SA Power Networks accounts for 21 per cent of the comparison firm's customers, the customer weighted average cost advantage the comparison firms have is 0.5 per cent.

In response to our November 2014 draft decisions, ActewAGL and the NSW service providers' consultant Advisian noted that the number of assets that a service provider uses to operate its network will drive its operating costs.[659] [660] In particular, Advisian raised the effect of assets installed for the purpose of compliance with planning standards in schedule 1 of the 2005 and 2007 NSW licence conditions.

We note that from financial year 2005[661] to financial year 2012[662] [663] the Queensland service providers were required to meet N-1 reliability standards on bulk supply substations and zone substations. Energex was also required to have N-1 redundancy on sub-transmission feeders.

We consider capital investment to meet jurisdictional planning requirements may warrant an OEF adjustment. This is because the planning requirements are determined by parties beyond service providers' control. Therefore it satisfies the exogeneity OEF. It is also not accounted for in the ratcheted demand variable in Economic Insights' SFA model. This is because it required the Queensland service providers to install transformer capacity that was not required to meet peak demand.

We also consider that an OEF adjustment for capex to meet planning requirements is not sufficiently captured by the variables in the SFA model. While expenditure on feeder redundancy will be captured by the circuit length variable, not all expenditure in transformer capacity redundancy is captured by the ratcheted maximum demand variable. Circuit length captures the effect of investment in new feeders because each new feeder installed will increase the circuit length variable. This in turn will increase the opex forecast by Economic Insights SFA model. However, increases in transformer capacity do not increase the ratcheted demand variable. As a result, the SFA model will forecast no change in required opex where there is an increase in transformer capacity that is not made in response to an increase in demand.

We have estimated the impact of the increased transformer capacity required to meet the 2004/05 planning requirements using the Economic Benchmarking and Category Analysis RIN responses. The Economic Benchmarking RIN responses provide data on the amount of transformer capacity at the subtransmission and zone substation level. The Category Analysis RIN provides some indication of the amount of expenditure that is related to maintaining those assets. Both the RINs provide information at the zone substation level. We have estimated the share of opex attributable to subtransmission substation maintenance using data from Ausgrid's category analysis RIN responses. This is because Ausgrid provides data on the costs associated with its dual function

---

[659] Advisian, *Review of AER benchmarking: Networks NSW*, 16 January 2015, pp. 41 –46.

[660] Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT),* 16 January 2015, p. 50.

[661] Blanch, S. Camp, J. and Sommerville, D., *Electricity Network Capital Program Review 2011: Detailed report of the independent panel*, 2011, p. 28.

[662] Direction Notice issued to Energex by the Queensland Government under section 115 of the Government Owned Corporations Act 1993 (Qld), February 2012.

[663] Direction Notice issued to Ergon Energy by the Queensland Government under section 115 of the Government Owned Corporations Act 1993 (Qld). February 2012.

assets and its single function assets separately. Neither Ergon Energy nor Energex have any assets classified as dual function.

To estimate the increase in transformer capacity due to the planning standards for each service provider, we have used the percentage increase in transformer capacity less the percentage increase in ratcheted maximum demand over the 2006 to 2013 period. The Economic Benchmarking RIN data indicate that after accounting for increases in demand, Energex and Ergon Energy's subtransmission and zone substation transformer capacities increased by −4 per cent and 15 per cent respectively. We note that this indicates that Energex was able to use previously existing capacity to absorb some of the increase in demand its network experienced over the benchmarking period.

To estimate the percentage of opex the Queensland service providers expend on zone substation transformer maintenance, we used data from the Category Analysis RIN. Specifically, we used the amounts the Queensland service providers allocated to zone substation maintenance in response to template 2.7 of the Category Analysis RINs. In financial year 2014 Energex and Ergon Energy reported that zone substation maintenance made up 2.4, and 3.8 per cent of opex respectively. To estimate the impact of subtransmission maintenance, we found what percentage zone substation maintenance was of total maintenance (29 per cent) for Ausgrid and applied this percentage to Ausgrid's dual function asset maintenance opex. This results in an estimate of 0.3 per cent of opex being attributable to subtransmission substation maintenance.

This suggests that the amount of opex required to maintain the mandated transformer capacity is −0.1 per cent ([1−{1/0.96}] x 2.7), 0.5 per cent ([1−{1/1.15}]x4.1) of historical opex for Energex and Ergon Energy respectively. These percentages represent increases on historical costs. As described in our section on the calculation of OEFs, these percentages must be adjusted before they can be used as an OEF adjustment to the efficient base year costs forecast by the SFA model. When adjusted these figures imply a −0.1 and 0.7 per cent adjustment to the efficient base level of opex for Energex and Ergon Energy respectively. Therefore an OEF adjustment for transformer capacity installed to meet the 2004/05 planning standards satisfies the materiality OEF adjustment criterion for Ergon Energy. We note that the calculated adjustment for Energex is negative because demand rose faster than Energex's zone substation transformer capacity. As the N-1 requirements would not have decreased Energex's opex, we have assumed that the adjustment for Energex should be zero rather than negative 0.1 per cent.

Mining boom cost impacts

We are not satisfied that an OEF adjustment for differences in in the impact of the mining boom between service providers meets the materiality OEF adjustment criterion. Localised shocks to accommodation costs are not likely to be material at the total opex level.

Ergon Energy stated that it considers that the mining boom has increased its labour costs and accommodation costs in remote areas near mines.[664] Ergon Energy did not quantify the effect of the mining boom on its labour or accommodation costs. We have considered differences in work conditions in the endogenous factors section above.

We are not satisfied that increased accommodation costs in remote communities situated near mines will lead to material increases in opex. This is because the areas affected are likely to only represent a small part of Ergon Energy's network. We also note that this disadvantage is likely to decrease during the forecast period as the mining boom enters its second phase. Nonetheless, Ergon Energy is likely to have some cost disadvantage due to the impact of the mining boom on remote communities. An adjustment for the effects of the mining boom would satisfy the exogeneity and duplication OEF adjustment criteria. The mining boom was caused by global economic forces beyond the control of service providers' control and there is no variable in Economic Insights' SFA model that accounts for differences in the effects of the mining boom. As a result the effect of the mining boom on accommodation costs in remote communities contributes 0.5 percentage points to the OEF adjustment for immaterial factors for Ergon Energy.

Planning regulations

We are not satisfied that an OEF adjustment for differences in planning regulations across jurisdictions would meet the materiality OEF adjustment criterion. Differences in planning regulations are not likely to create material differences in opex across jurisdictions.

In support of Ausgrid's 2014 regulatory proposal, Evans and Peck identified differences in planning regulations as an OEF that may affect benchmarking results.[665] Ergon Energy also raised this point with respect to mining leases. Ergon Energy stated that Queensland legislation imposed special requirements when working on mining leases.[666] Ergon Energy provided no quantification of what impact these requirements would have on opex.

The Productivity Commission carried out a review of planning regulations in April 2011.[667] The finding of this review was that given the extent of differences, it is a challenge to compare the planning systems of the states and territories: individual indicators are often heavily qualified and thus so are comparisons between

---

664 Ergon Energy, Response to AER Information Request AER ERG002, 17 December 2014, p. 23.

665 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 6.

666 Ergon Energy, Response to AER Information Request AER ERG002, 17 December 2014, p. 21.

667 Productivity Commission, *Performance Benchmarking of Australian Regulation: Review of Planning Regulations*, April 2011.

jurisdictions.[668] As a result, the Productivity Commission did not attempt to construct an overall 'league table' of state and territory performance.[669] This suggests that although planning regulations differ across jurisdictions, and are therefore likely to create some differences in costs, that differences in planning regulations are not likely to lead to material differences in costs.

We are not satisfied that the Queensland service providers have identified planning regulations that would materially increase their opex relative to the comparison firms. However, we have included a positive 0.5 per cent adjustment for the Queensland service providers in our adjustment for immaterial factors. It is likely that there will be some difference between service providers due to differences in planning regulations, and there is uncertainty of the direction of the cost advantage. Also, an OEF adjustment for difference in planning regulations would meet the exogeneity and duplication OEF adjustment criteria. Planning regulations are not determined by service providers and Economic Insights' SFA model does not include variables to account for differences in planning regulations.

Private power poles

We are not satisfied that an OEF adjustment for private power poles satisfies the materiality OEF criterion.

Ergon Energy stated that many of its customers own power poles. It is required to perform a brief inspection of first-in poles (at the connection boundary point) to help ensure the pole is serviceable. We note the service providers in Victoria are required to inspect private electric lines up to the point at which the line connects to a building or other structure (not including a pole).[670]

Consequently, the requirement for the Queensland service providers to inspect only first-in poles will reduce their inspection costs relative to Victorian service providers, all else equal. However, there is not sufficient evidence to conclude that these differences will lead to material differences in opex. As it is likely to provide the comparison firms with a cost disadvantage we have included a negative 0.5 per cent OEF adjustment for this factor in our adjustment for immaterial factors. It is also appropriate to include this OEF in our collective adjustment for individually immaterial OEFs because it satisfies the exogeneity and duplication OEF adjustment criteria. Regulations on the inspection of private power poles are set by state governments and there are no variables that account for those factors in Economic Insights' SFA model.

Taxes and levies

We are satisfied that it is necessary to provide the Queensland service providers an OEF adjustment to account for jurisdictional differences in taxes and levies. This is

---

668 Productivity Commission, review of planning regulations, April 2011, Volume 1, p. XXVIII.

669 Productivity Commission, review of planning regulations, April 2011, Volume 1, p. XXXI.

670 *Electricity Safety Act 1998*, s. 113(F)(1); Electricity Safety (Bushfire Mitigation) Regulations 2013, r. 8.

because it satisfies all three of our OEF criteria. Taxes and levies are beyond the control of service providers. The effect of Queensland specific taxes and levies is greater than our materiality threshold for OEFs. Also, there is no variable in Economic Insight's SFA model for taxes and levies. Therefore, we are satisfied that positive 2.7 per cent and 1.7 per cent OEF adjustments for differences in jurisdictional taxes and levies are appropriate for Energex and Ergon Energy respectively.

Ergon Energy and Energex have both stated that their benchmarking results will be affected by state specific levies.[671] [672] Both identified the Energy Safety Office (ESO) levy and Queensland Competition Authority (QCA) Levies as Queensland specific taxes that do not exist in other jurisdictions.

Energex forecast the cost of these levies would be on average $8.7 million ($2014−15)[673] over the forecast period. If this is added to our forecast base year opex this leads to a 2.7 per cent increase in Energex's opex.

Ergon Energy did not provide a forecast of the cost of the ESO and QCA levies. However, Ergon Energy did provide historical costs for the ESO and QCA levies. [674] The ESO and QCA levies combined came to $4.7 million ($2014−15) in 2013/14. We have used Ergon Energy's 2013/14 ESO and QCA levy costs to estimate the impact of levies on to our forecast base year opex. This is because the forecast ESO and QCA levies for Energex were similar to the costs in 2013/14. If $4.7 million ($2014−15) is added to our forecast base year opex for Ergon Energy this leads to a 1.7 per cent increase in its opex.

Service classification

We are not satisfied that it is necessary to provide an OEF adjustment for differences in service classification between the Queensland service providers and the comparison firms. This is because it would not satisfy the materiality or duplication OEF adjustment criteria. The Queensland service providers reported they incurred no opex for standard control services connections or metering services. Economic insights benchmarking results are not affected by service classification because they only compare network services costs.

An adjustment for service classification would not satisfy the duplication OEF adjustment criterion. Our economic benchmarking RIN data takes into account differences in service classifications across jurisdictions by using data on network services. Network services only include the provision of the core 'poles and wires' component of distribution services. They exclude other services that service providers provide including metering and public lighting. Because the benchmarking data only include information on network services, the results will only reflect differences in

671 Ergon Energy, Response to AER information request AER Ergon 002, 17 December 2014, pp. 6 – 7.

672 Energex, Response to AER information request AER Energex 001, 17 December 2014, p. 9.

673 Energex, *Regulatory Proposal*, 31 October 2014, p. 138.

674 Ergon Energy, Response to AER information request AER Ergon 002, 17 December 2014, pp. 6 – 7.

network services. Therefore, differences in the classification of standard control and alternative control services will not affect Economic Insights' SFA model.

However, while service classification will not affect the SFA model, service classification must be considered when applying the results to produce our opex forecast. This is because if we do not provide an OEF adjustment for service classification, some service providers that provide standard control services that are not network services, such as connection services and metering services,[675] will be penalised. In the forecast period Energex and Ergon classify some of the costs they incur for connection services and metering services as standard control services.

Our opex forecast, based on the Cobb Douglas SFA opex cost function, is for network services so it excludes connection services and metering services. Therefore, in order to make sure our network services forecast is comparable to Energex and Ergon Energy standard control services opex forecasts it is necessary to account for standard connection services and metering services. For the forecast period the only connection services and metering services that Energex and Ergon will classify as standard control services are: pre-connection services, small customer connection services, and type 7 metering services.[676] Neither Energex nor Ergon Energy reported any opex on standard control services connection services over the period 2005/06 to 2013/2014.[677] [678] Additionally neither service provider reported any expenditure on type 7 metering over the 2008/09 to 2013/14 period.[679] As Ergon and Energex have stated they incurred no opex for the connection and metering services that will be classified as standard control services in the forecast period, over the period 2008/09 to 2013/14, there is no need to provide an OEF adjustment.

Traffic management requirements

We are not satisfied that an OEF adjustment for traffic management would meet the materiality or duplication OEF adjustment criteria. Traffic management requirements across Australia are based on a nationally consistent standard. Differences in traffic management costs related to density will be captured by Economic Insights' SFA model.

Traffic management is the direction of motorist and pedestrian movements around worksites using temporary traffic signage and traffic controllers.

---

675 For more detail please refer to our Economic Benchmarking RIN instructions.

676 AER, Final Framework and Approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015, April 2014, p. 51.

677 Responses to Economic Benchmarking Regulatory Information Notices for 2006 to 2013, Template 3. Opex, Table 3.2, Opex consistency.

678 Responses to Economic Benchmarking Regulatory Information Notices for 2014, Template 3.2 Opex, Table 3.2.2, Opex consistency.

679 Responses to Category Analysis Regulatory Information Notices for 2014, Template 4.2 Metering, Table 4.2.2, Cost metrics.

Evans and Peck stated that traffic management regulations may affect comparison of opex across networks. They do not explain, how or whom they would affect.[680]

As noted in the customer density section above, traffic management costs generally correlate with the volume of traffic near the worksite. We consider that traffic management will have a greater overall impact on expenditure in higher density areas than in lower density areas. However, Economic Insights' SFA model accounts for this.

We recognise that each Australian state and territory has different standards for the development and implementation of traffic control plans at roadwork sites. This includes issues such as signage, speed zones, etc. Each of the states and territories has different levels of training requirements including:

- traffic management planners (approvers and designers),
- worksite supervision and control.

However, State and territory road authorities generally base their traffic control at roadwork sites requirements on AS1742 Part 3: Guide to traffic control devices for works on roads[681].

Traffic management costs generally correlate with the volume of traffic near the worksite. We consider that traffic management will have a greater overall impact on expenditure in higher density areas than in lower density areas. Economic insights' SFA model accounts for differences in customer density. For more detail see our consideration of customer density above and in our NSW/ACT draft decisions.

We have included jurisdictional differences in traffic management in our adjustment for immaterial factors. Although the density related differences in traffic management are captured in Economic Insights' SFA model, the jurisdictional differences in requirements are not. That is differences in cost due to traffic volumes are related to customer density, while differences stemming from differences in council requirements are not. These jurisdictional differences are likely to lead to some difference in cost and are not determined by service providers. As a result an OEF adjustment for traffic management would satisfy the exogeneity OEF adjustment criterion. Also, because Economic Insight's SFA model does not account for differences in traffic management regulations it would satisfy the duplication OEF adjustment criterion. This is why we have provided included a 0.5 per cent adjustment for the Queensland service providers in our consideration of immaterial factors.

680 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

681 National Approach to Traffic Control at Work Sites, Publication no: AP-R337/09, Austroads 2009, p.1.

A.6.7 Network factors

Advanced metering infrastructure

We are not satisfied that an OEF adjustment for differences in Advanced Metering Infrastructure (AMI) deployments would satisfy the OEF adjustment criteria. The ability to share overheads between network services and other services is a business decision on service diversification. Pursuing the ability to share overheads between network services and metering services are not likely to lead to material differences in network services opex. AMI costs are excluded from network services opex, which is the measure of opex used in Economic Insights SFA model.

In response to our 2014 draft decision Advisian, suggested the point that the Victorian service providers can share their fixed overhead costs with their AMI programs.[682] Huegin also noted that Ofgem excludes costs related to smart meter deployments.[683]

Advanced metering infrastructure is another term for smart meters. Smart meters are electricity usage meters that communicate meter readings directly to electricity service providers, eliminating the need for staff to read meters in person.

Advisian considers that this gives the Victorian service providers a cost advantage relative to other service providers. Other service providers also provide metering services, but are not making a major change in their metering fleet in the way the Victorian service providers are. Overhead costs are often shared on the basis of costs incurred by functional areas. Therefore, Advisian considers the large costs involved in the AMI deployment will allow the Victorian service providers to allocate more of their overhead costs to metering than other service providers.

There are two issues with Advisian's analysis. The first is that the extent to which a service provider can share overheads across its services is the result of management decisions. The second is that differences in AMI deployments will not materially affect network services opex.

As discussed in the unregulated services section above the extent to which service providers can share overheads across services is the result of business decisions on service diversification. Therefore an OEF adjustment for differences in AMI programs would not satisfy the exogeneity OEF adjustment criterion.

Additionally, fixed overheads are only a part of total overheads. As service providers increase in scale and scope they will incur more overheads. As a result, although the Victorian service providers are able to share fixed costs between network services and its AMI programs, the AMI programs also add to the pool of shared overheads.

---

682 Advisian, Opex Cost Drivers: ActewAGL Distribution Electricity (ACT), 16 January 2015, pp. 83–86.

683 Huegin, *Response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER*, January 2015, p. 23.

As a result we are not satisfied that an OEF adjustment for differences in AMI programs would meet the materiality OEF adjustment criterion.

We also note that Advisian's analysis relates to the Victorian service providers rather than the comparison firms. SA Power Networks, is also one of the comparison firms. We note that although SA Power Networks did not have the ability to share its fixed overheads between network services and an AMI program, it is one of the efficient service providers under all of Economic Insights' benchmarking models.

We are also satisfied that an adjustment for AMI deployments would not satisfy the duplication OEF criterion. Network services opex, which has been used in Economic Insights' SFA model excludes metering services costs. As metering services costs are not included in the network services costs, the efficiency scores from Economic Insights' SFA model will not be affected by metering services costs.

Asset age

We are not satisfied that an OEF adjustment for differences in asset age between the Queensland service providers and the comparison firms would meet the materiality OEF adjustment criterion. Asset age will only affect some opex costs. Also, the age profiles of the Queensland service providers and the comparison firms are similar, and therefore should not lead to material differences in their opex.

Not all opex categories are affected by asset age. The opex categories that will generally be affected by differences in asset age are emergency response and routine preventative maintenance on high value assets.

The amount of maintenance opex does not increase with age for all assets. Asset age will not greatly affect maintenance opex for most assets. Low value assets, such as distribution lines and transformers make up the bulk of service providers' assets. Low value assets like these are inspected on a regular basis but they will generally not incur routine maintenance interventions in the way higher voltage assets do.[684] Asset age will more often affect routine maintenance intervals for high value, strategically important, assets such as subtransmission lines and zone substations. However, maintenance on zone substations and assets operating above subtransmission lines generally only accounts for a small part of service providers' opex.

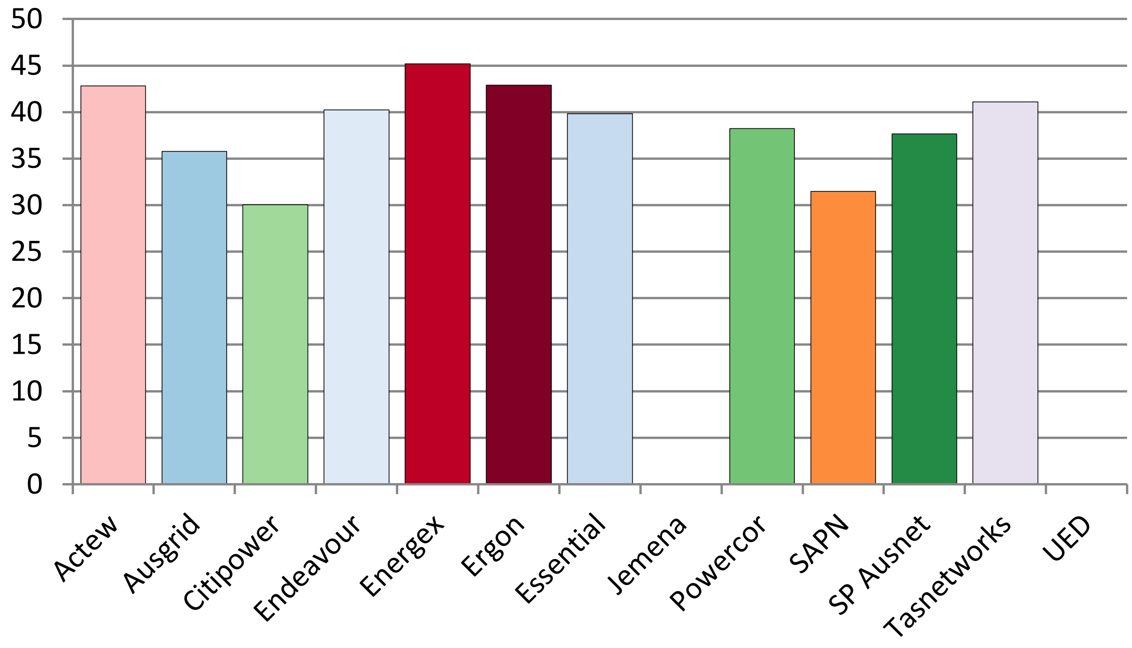
While a network with an older asset base will tend to experience more asset failures, asset failures only account for a part of emergency response costs. As assets age, they, in general, will become more likely to fail. Therefore a service provider with older assets would be more likely to incur emergency response costs for asset failure.

684 Energy Market Consulting Associates, *Relationship between Opex and Customer density for Sparse Rural Networks, 2.3.2 Routine and Non Routine Maintenance*, April 2015.

However emergency response opex is also incurred for other occurrences including: weather, 3rd party damage to the network, vegetation, and animal contact.[685]

Additionally, any differences in opex caused by differences in asset age is unlikely to be material because the weighted average remaining life (WARL) of the Queensland service providers and the comparison firms' assets seem to be similar. The WARL represents the average remaining life of a service provider's assets weighted by the value of those assets. We have two measures of WARL. One uses benchmark unit rates and asset lives based on the unit rates and replacement rates observed across the NEM (benchmark WARL) the other uses service providers' own unit rates and replacement rates (observed WARL). Figure A.37 and Figure A.38 below compare all NEM service providers' on both WARLs. We note that we have excluded Jemena and United Energy because we have some concerns with some of their asset replacement data.

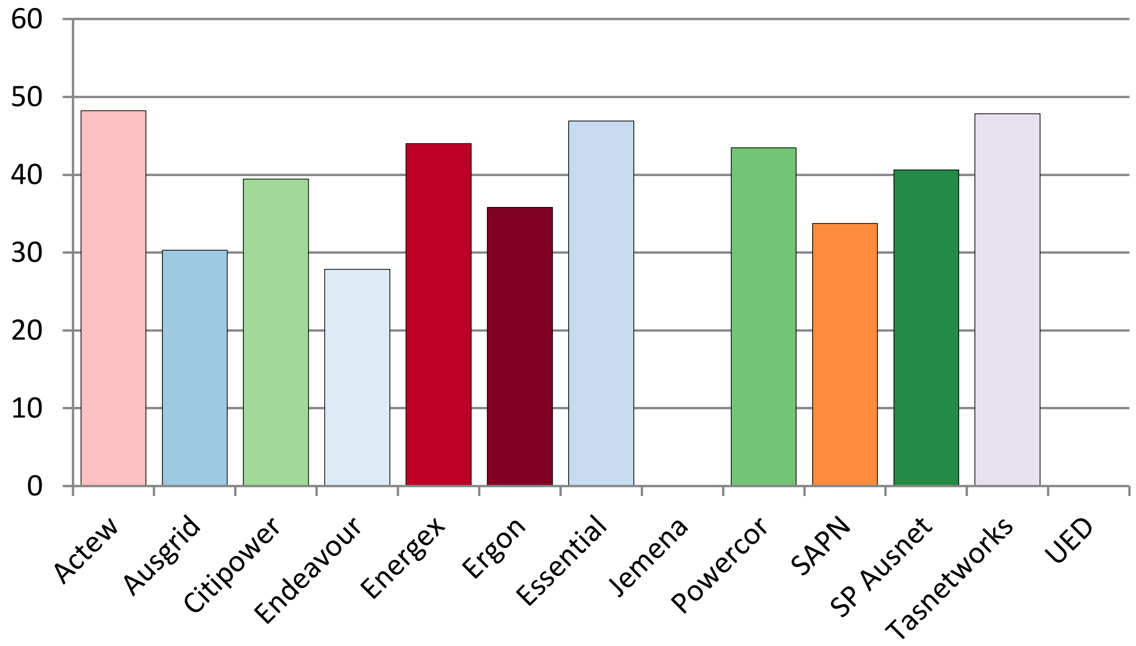
Figure A.37 Benchmarked Weighted Average Remaining Life for each NEM service provider



Source: Category analysis RIN data, AER Analysis.

685 Energy Market Consulting Associates, *Relationship between Opex and Customer density for Sparse Rural Networks, 2.3.4 Emergency Response*, April 2015.

Figure A.38 Observed Weighted Average Remaining Life for each NEM service provider



Source: Category analysis RIN data, AER Analysis.

Both the benchmarked WARL and observed WARL have strengths and weaknesses as measures. The benchmarked WARL allows comparison of service providers independent of the quality of service providers' management, because the same unit costs and standard lives are used for all service providers. The observed WARL accounts for unobservable differences between service providers as it is based on the unit rates and standard lives revealed by service providers' actions over the 2009 to 2013 period.

The drawback of the benchmarked WARL is that it treats all service providers as if they operate in the same operating environment. This is because differences in service providers' operating environment will affect their asset lives and also their unit costs.

The drawback of the observed WARL is that it is affected by service providers' management strategies. This is because the unit rates and standard asset lives realised will be affected by management decisions during the sample period.

As both WARL measures have strength and weaknesses, we have considered both in comparing the relative asset ages of the NEM service providers.

Energex has a higher remaining life than the comparison firms on both WARL measures. Ergon has a higher WARL on the benchmarked measure, but lower than AusNet, CitiPower, and Powercor on the observed measure. This suggests that Energex's asset base is relatively further from old age than the comparison firms'. However, there is some doubt about if Ergon Energy's is. As a result it is likely that

Energex has a cost advantage relative to the comparison firms due to asset age while it is unclear for Ergon Energy.

Although it will not lead to material differences in opex, asset age is likely to lead to some difference in opex between the comparison firms and the Queensland service providers. An OEF adjustment for asset age would also meet the exogeneity and duplication OEF adjustment criteria. The date a network was established is beyond service providers' control and there are no variables in Economic Insights' SFA model that account for it. Therefore we have included an adjustment for asset age in our adjustment for immaterial factors for both Energex and Ergon Energy. As Energex appears to have a cost advantage we have provided a negative 0.5 per cent adjustment. As there is some uncertainty of the direction of the advantage for Ergon Energy we have provided a positive 0.5 per cent adjustment.

Asset volumes

We are not satisfied that an OEF adjustment for the volume of assets used to provide services over its network would meet the exogeneity or duplication OEF adjustment criteria. Network service providers have direct control over the assets that they choose to install and Economic Insights SFA model accounts for the drivers of asset installation.

In response to our 2014 draft decision for the ACT and NSW service providers, ActewAGL, Advisian, the NSW Chief Operating Officers, and ActewAGL's General Manager of Asset Management submitted that the number of assets that a service provider uses to operate its network will drive its operating costs.[686] [687] [688] [689] [690] [691] Advisian submitted that it considers that the variables in Economic Insights' SFA model ignore the cost of maintaining a larger number of assets. In particular, Advisian raised these points with regard to line length and transformer capacity. We address line length above in our consideration of customer factors.

In general, we consider that demand side variables should be used to determine the benchmark opex required. This is because it is a good measure of the capacity that a service provider must maintain to provide distribution services. Using measures driven by the value of assets[692] or volume of assets installed runs the risk of rewarding service providers for inefficiently overinvesting. As a result, such expenditure would not meet the exogeneity OEF criterion. This is because the extent of investment in assets to meet the realised customer demand is at the discretion of the service provider.

686 Advisian, *Review of AER benchmarking: Networks NSW*, 16 January 2015, pp. 41–54.
687 Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT),* 16 January 2015, pp. 45 –59.
688 Trevor Armstrong, *Statement of Trevor Armstrong Chief Operating Officer Ausgrid*, 19 January 2015, pp. 31.
689 Gary Humphreys, *Statement of Gary Humphries Chief Operating Officer Essential Energy*, 19 January 2015, p. 4
690 Stephen Devlin, *Witness Statement*, 13 February 2015, p. 8.
691 Stephen Devlin, *Witness Statement*, 13 February 2015, p.8.
692 CEPA, *Benchmarking and Setting Efficiency Targets for the Australian DNSPs*, 19 January 2015, p. iv–5.

Advisian submitted that the amount of transformer capacity installed by service providers is likely to affect Economic Insights' SFA results.[693] [694] Advisian considers that the ratcheted peak demand variable will not take into account the spatial element of demand or additional capacity installed for system security.

The ratcheted peak demand variable in Economic Insights' SFA model accounts for the spatial element of demand. This is because it uses non-coincident system demand. As a result service providers that have separated commercial and residential areas will not be disadvantaged in the SFA model.

Advisian also submitted that service providers should be compensated for transformer capacity installed. This is because it must be installed to meet forecast demand. [695] Therefore having excess capacity is not necessarily inefficient.

This dilemma faces all service providers. All service providers must install transformer capacity to meet forecast demand. Therefore to the extent that a service provider must invest in excess capacity, this will be captured in ratcheted maximum demand. As a result, if a service provider systematically overinvests in excess capacity transformer capacity, this is evidence that service provider's management performs relatively worse in responding to changes in demand conditions. Therefore, benchmarking on the basis of installed capacity rather than ratcheted peak demand has the potential to reward inefficient investment.

Critical National Infrastructure

We are not satisfied that an OEF for Critical National Infrastructure (CNI) meets the exogeneity OEF adjustment criteria. To the extent that a service provider decides to invest in physical security to a greater extent than other service providers, that is a management decision for the service provider.

In response to our 2014 draft decision for the NSW and ACT service providers, Huegin raised CNI as an OEF that may lead to differences in opex.[696] Huegin noted that Ofgem excludes costs associated with CNI from its totex benchmarking. CNI are electricity distribution sites designated by the UK Department of Energy and Climate Change (DECC).[697] All sites confirmed by DECC as Category 3 CNI or above are eligible for ex ante funding in accordance with the "Physical Security Upgrade Programme".[698] We note that Huegin has provided no explanation of how this relates to the Australian context.

---

693 Advisian, *Review of AER benchmarking: Networks NSW*, 16 January 2015, p. 44.

694 Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT),* 16 January 2015, pp. 51 –57.

695 Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT),* 16 January 2015, pp. 51 –57.

696 Huegin, *Response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER*, January 2015, p. 23.

697 Ofgem, RIIO-ED1: Glossary of terms, 2014, p. 6.

698 Ofgem, *RIIO-ED1: Final determinations for the slow-track electricity distribution companies: Business plan expenditure assessment*, 28 November, 2014, p. 99–100.

Ofgem provides an allowance for CNI programs in the UK following guidance from a government agency called The Centre for the Protection of National Infrastructure (CPNI)[699]. In Australia CNI projects are undertaken at the discretion of service providers following industry wide guidelines.[700]

Based on the evidence before us we are not satisfied that the Queensland service providers' regulatory responsibilities for CNI are greater than other service providers'. As a result, providing an OEF adjustment for CNI does not meet the exogeneity OEF adjustment criterion. To the extent that the Queensland service providers choose to invest more in physical security than other service providers is a decision for their management.

Customer owned distribution transformers

We are not satisfied that an OEF adjustment to account for differences in the amount of transformer capacity owned by customers would meet the materiality OEF criterion. The amount of distribution capacity owned by customers is relatively small, and the distribution transformer maintenance as a percentage of opex is also small. As a result, the maintenance avoided by service providers with customers who own their substations is not considered material.

In some cases, customers take electricity from service providers at higher voltages. In these cases the customer will own and operate transformer equipment to deliver electricity to the voltages they require for their uses. By not having to maintain distribution transformer equipment to service those customers, service providers gain a cost saving when compared against energy and demand throughput.

We estimate that differences in distribution transformer capacity owned by customers will lead to a cost advantage of 0.1 per cent and 0.3 per cent for Energex and Ergon Energy respectively.

Distribution substation maintenance only accounts for on average 1.5 and 1.9 per cent of Energex and Ergon Energy's network services opex respectively.[701] Energex and Ergon Energy own 86.7 and 82.5 per cent of distribution transformer capacity connected to their networks.[702] The Frontier firms on average, weighted by customer numbers, own 93.9 per cent of distribution transformer capacity. [703] On this basis Energex and Ergon Energy's distribution substation maintenance opex may be 7.7 and 12.1 per cent lower than they would be if their customers owned a similar percentage of distribution transformers as the frontier service providers' customers. This is equivalent to a 0.1 and 0.3 per cent cost advantage at the total network services opex level for Energex and Ergon Energy respectively. As these figures represent decreases in the Queensland service providers' historical opex, they must be adjusted to the

[699] Seconomics, *National Grid Requirements*, 31 January 2013, p. 40.
[700] ActewAGL, *Regulatory Proposal*, June 2008, p. 64.
[701] Category Analysis RIN responses, template 2.8.
[702] Economic Benchmarking RIN response, template 6. Physical assets.
[703] Economic Benchmarking RIN responses, template 6. Physical assets.

decrease in efficient opex as described in our section on the calculation of OEFs section above. After adjustment the customer owned distribution transformer OEF adjustment represents a decrease in efficient opex of 0.1 and 0.4 per cent for Energex and Ergon Energy respectively.

Following our approach to accounting for immaterial factors we have included differences in the amount of customer owned distribution transformer capacity in our adjustment for immaterial OEFs. An OEF adjustment for differences in customer owned distribution transformer capacity would meet the exogeneity and duplication OEF adjustment criteria. The number of customers that take electricity at high distribution voltages is not determined by service providers and there are no variables in Economic Insights' SFA model to account for it. Given that we are able to estimate the potential cost impact of differences in ownership of distribution transformer capacity, we have used these figures for the relevant contribution to the immaterial factors OEF adjustments.

Demand management

We are not satisfied that an OEF adjustment for differences in the demand management in service providers' would meet the duplication OEF adjustment criterion. Demand management is a capex opex trade-off. We have considered the impact of capex opex trade-offs under the capitalisation practice OEF.

Energex identified demand management costs as a factor that may increase its opex relative to the comparison firms.[704] Energex noted that the AER forecast $158 million for demand management in our 2010–15 distribution determination.

Demand management is the use of various strategies to change customers' electricity use. By changing energy use, service providers can avoid the need for large investments in network upgrades to meet a peak demand that only occurs for a small part of the year. In this way service providers can reduce their capex by using opex.

The decision to undertake demand management is a capex opex trade-off. Service providers face many of these trade-offs. Other examples include the choice to rent or buy depots, to run lines over or underground, to replace or maintain. We consider that where a capex opex trade-off exists, the decision on whether to provide an OEF adjustment should be considered in the broader context of service providers' capex to opex ratio. This is because a service provider may utilise a solution that is opex intensive in one area, but overall may have a preference for capital intensive solutions. In this situation providing a positive OEF adjustment for an opex intensive solution would over-compensate the service provider. This is because focusing only on opex capex trade-off OEFs that disadvantage the Queensland service providers will upwardly bias the total OEF adjustment.

[704] Energex, Response to AER information request AER EGX 001(A), 17 December 2014, p. 8.

In our capitalisation practices section we compare the capex opex ratios for the NEM service providers. Figure A.20 and Figure A.21 show that the Queensland service providers capitalise a similar amount of their costs to the comparison firms.

Therefore, we are not satisfied that differences in opex due to demand management in service provider's networks are not accounted in our consideration of capitalisation practices.

We have also considered increases in demand management in our step change appendix.

Line sag

We are not satisfied that an OEF adjustment for line sag would meet the exogeneity OEF criterion. A prudent service provider would design its network to take into account the demand it services and the environment it operates in. Specifically, network businesses design and construct overhead lines so that they are compliant with the statutory obligations under all standard operating conditions.

Overhead electrical lines expand when heated and this results in the “sag” of the line increasing. Line heating is caused by environmental factors and by the delivery of energy through the line.

Ergon Energy raised the point that high loads and temperatures lead to significant conductor sag. As Ergon Energy is obliged to maintain regulatory clearances of all conductors, its opex includes a system of measuring and actively repairing line sag to ensure regulatory compliance.[705]

All NEM service providers use similar line design criteria to account for sag which take into account, among other things, ambient temperature, solar radiation, and wind speed. The extent to which a service provider finds that it has a systemic issue with regard to line sag is a reflection of the quality of its management in applying the line design criteria. As a result an OEF adjustment for line sag would not satisfy the exogeneity OEF adjustment criterion.

Network Accessibility

We are not satisfied that an OEF adjustment for differences in network accessibility satisfies all of our OEF adjustment criteria. The most cost effective route for a line may not always be in areas that are easily accessible. The opex of access route maintenance for Ergon Energy is a material part of Ergon Energy's network services opex. There is no variable in Economic Insights SFA model for differences in network access.

[705] Ergon Energy, AER information request AER Ergon 002, 17 December 2014, p. 14.

In response to AER questions, Ergon Energy indicated that it considered differences in network accessibility as an OEF that materially affects its costs.[706] Vegetation management, line maintenance and asset inspections require access to assets. Ergon Energy considers that high rainfall results in significant damage to access tracks due to washouts, vegetation growth and subsidence. When asked, Ergon Energy did not provide evidence of differences in costs in access track maintenance between high and low rainfall areas of its network.[707] Nonetheless, economic benchmarking RIN data indicates that Ergon Energy has a greater percentage of its network that does not have standard vehicle access than the comparison firms. In 2013/14, 36 per cent of Ergon Energy's network did not have standard vehicle access. In comparison, the weighted average for the comparison firms was only 5 per cent.[708] As a result we consider that Ergon Energy is likely to have a cost disadvantage relative to the comparison firms on access track maintenance.

Ergon Energy indicated that over the 2010 to 2014 period, on average it incurred $4.9 million ($2014−15) per annum for access track maintenance at a cost of $97 per kilometre of network route with non-standard vehicle access. [709] [710] This represented 1.23 per cent of Ergon Energy's network services opex over the same period.

Using the unit rate for Ergon Energy's access track maintenance, and route line lengths without standard vehicle access, we estimated the percentage of network services opex that the comparison firms expend on access track maintenance. Using these figures we estimate that in 2014, the percentage increase in the comparison firms' network services opex, weighted by customer numbers, due to access track maintenance was 0.15 per cent. Assuming all else equal, this indicates that differences in access track maintenance lead to a 1.1 per cent increase in opex for Ergon Energy relative to the comparison firms.[711]

Using the same method for Energex, we estimate that access track maintenance accounts for an increase of 0.05 per cent in Energex's network services opex. This implies that, relative to the comparison firms, Energex has a 0.1 per cent cost advantage on access track maintenance costs.

Network control centres (Ergon Energy)

We are not satisfied that an OEF adjustment for network control centres meets the materiality OEF adjustment criterion. Operating two network control centres instead of one is not likely to lead to material differences in opex.

Ergon Energy stated that it operates two geographically separate and fully functional network operations control centres. It staffs both control centres at all times. It

---

706 Ergon Energy, Response to information request AER Ergon 02, 17 December 2014, p. 13.
707 Ergon Energy, Response to information request AER Ergon 018(3), 30 January 2015, p. 7.
708 Benchmarking RIN responses, 2013 and 2014, Template 8. Operating Environment.
709 Ergon Energy, Response to information request AER Ergon 018(3), 30 January 2015, p. 7.
710 Ergon Energy, Economic Benchmarking RIN responses, 2013 and 2014, Template 8. Operating Environment.
711 1.1 = ((101.2/100.1)–1)x100

considered the duplication was necessary to reduce the risk of control centre failure during natural disaster situations, most notably during cyclones. It considered there was no practical location within its geographic footprint that was immune to these risks.

In the event one of the control centres needs to be shut down its operations can be transferred to the other control centre. To cater for such scenarios, Ergon Energy has established staffing levels and capability sufficient for each network operations control centre to manage various critical functions across the entire state in the short term. Ergon Energy can transfer its workforce from the closed control centre to the operating control centre for long term management abilities.

However, Ergon Energy is not required to operate its network control centres from within its geographic footprint. For example, when Ergon Energy last formally reviewed the costs and benefits of having two geographically separate network control centres in 2003 it considered the option of operating a 'cold site' outside of its geographic footprint. Further, other service providers operate shared network control centres, such as CitiPower and Powercor and Jemena and United Energy Distribution.[712]

When Ergon Energy last formally reviewed the costs and benefits of different control centre options, it considered the option of operating two control centres in the one city. The second 'cold' site would provide redundancy for the main 'hot site'. We note that, in Ergon Energy's review this option had the same opex as operating two hot sites in different cities. Given this, there is not sufficient evidence to conclude that the operation of two control centres will lead to a material difference in opex.

As Ergon Energy stated that the opex for running a hot and a cold network control centre is equivalent to running two hot sites we consider no OEF adjustment required.

Past ownership

We are not satisfied that an OEF adjustment for past ownership would meet the exogeneity or material OEF adjustment criteria. The AEMC stated that the nature of ownership should not be taken into account as it is endogenous. Managing a fleet of various asset types installed in response to different management, environmental, demand, and technological circumstances is a core business function of electricity network service providers.

In response to our 2014 draft decision, Essential Energy raised intra-network variability as an issue that would lead to material differences in opex between it and the comparison service providers.[713] It stated that the legacy of being an amalgamation of different service providers with different practices and standards would lead to it having a cost disadvantage relative to the Victorian service providers. Essential Energy provided no practical examples of how these differences would lead to it having a cost disadvantage. It is not clear how Essential Energy considers this will affect costs, but one interpretation is that Essential Energy's precursor organisations may have adopted

[712] Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT)*, 16 January 2015. p. 90.

[713] Essential Energy, *Revised Proposal: Attachment 7.4*, p. 25.

different technologies, potentially leading to increased complexity in asset management. We note that the other NSW service providers are also the amalgamation of various service providers.[714] Ausgrid and Endeavour Energy did not raise this as an issue that would materially affect their costs. Energex and Ergon Energy also did not raise this issue.

The Victorian service providers did not inherit a highly homogenous network derived from one legacy network. Up until privatisation there were 12 municipal service providers,[715] known as Municipal Electricity Undertakings, operating across the Melbourne area in addition to the State Electricity Commission of Victoria. CitiPower, Jemena, Powercor and United Energy all own assets that were previously owned by one or more of these Municipal service providers.

Additionally, all of the NEM Electricity service providers must manage a variety of different assets installed in response to different circumstances. The optimal choice of asset will depend on the technology available at the time, the demand the asset must serve, and the environment in which the asset is being installed. All service providers will have a variety of different assets installed at different times.

Further Essential Energy has not demonstrated that if its asset base is more heterogeneous, that any such difference in heterogeneity will lead to a material increase in costs.

Therefore we are not satisfied that differences in past ownership between the Queensland service providers and the Victorian service providers will lead to material differences in opex.

We are also not satisfied that an adjustment for differences in past ownership would satisfy the exogeneity OEF adjustment criterion. The nature of ownership of service providers is an endogenous factor.

Proportion of 22kV and 11kV lines

We are not satisfied an OEF adjustment for the proportions of 22kV and 11kV lines in the network would meet the materiality OEF adjustment criterion. Operating a network using a 22 kV high-voltage distribution system rather than an 11kV high-voltage distribution system is unlikely to create material differences in opex between service providers.

Evans and Peck stated that because Victoria operates a 22 kV high-voltage distribution system they have a cost advantage over service providers that operate 11kV

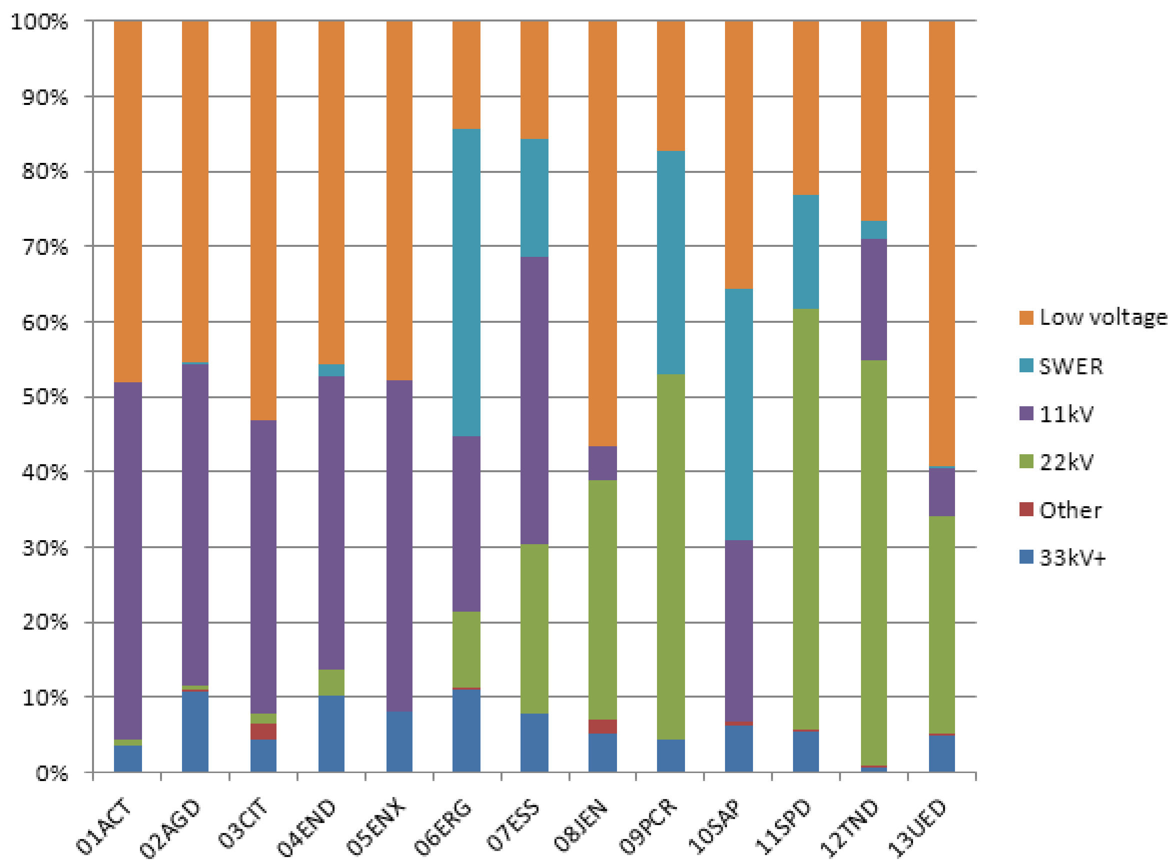
[714] Stewart Smith, *Electricity and Privatisation, NSW Parliamentary library research service*,1997, p. 3.

[715] Victorian Government, Victorian Government Gazette, No 54 1961, 3 July 1961.

distribution systems.[716] They stated that this \cost advantage will manifest itself in lower operation and maintenance costs. [717]

Each of the Queensland service providers operates a high-voltage distribution network that is predominantly 11kV although 22kV forms a significant proportion of Ergon's network. The comparison firms operate both 11kV and 22kV high voltage distribution networks. The Victorian service providers have mostly changed their high-voltage networks to a 22kV model with the notable exception of CitiPower. CitiPower maintains a predominantly 11kV high-voltage distribution network. SA Power Networks also has a predominantly 11kV high-voltage distribution network.

Figure A.39 Line voltages by length (Average 2006 to 2013)



Source: Economic Benchmarking RIN, AER analysis.

716 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 17.

717 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.

The high-voltage distribution networks are the key means for the distribution of electricity over middle distances such as between suburbs and across small regional areas.

Simplistically, a doubling of the voltage will provide a doubling of the capacity of the line. In the case of high-voltage lines, a 22kV line will potentially have twice the capacity of an 11kV line. The 22kV line can also cover a greater distance than an 11kV line serving the same electrical load.

In practice, this will result in an 11kV network design that has more 11kV feeders to service the same customer loads and a larger number of lower capacity zone substations to service these feeders. On the other hand, a 22kV network design will have fewer feeders and a smaller number of higher capacity zone substations. We note that while there will be more feeders in an 11kV system, the total length of feeders will be roughly the same.

Additionally, the comparison firms include service providers with both 22kV and 11kV network configurations. Powercor and AusNet, and CitiPower and SAPN, represent the two extremes in terms of 11kV and 22kV networks - Powercor and AusNet are predominantly 22kV systems while CitiPower and SAPN have predominantly 11kV systems.

In conjunction these two points indicate that this the proportion of 11kV and 22kV lines in a service providers' network is not material to overall performance.

In accordance with our approach to estimating the combined effect of OEFs that do not meet the materiality OEF adjustment criterion, we have accounted for differences in high voltage distribution systems in our immaterial OEF adjustment. Although it does not satisfy the materiality criterion, an adjustment for the proportions of 22kV and 11kV lines would satisfy the exogeneity and duplication criteria. The technology that was available at the time a network was established is beyond service providers' control. Economic Insights' SFA model dos not include any variables that account for the proportion of 11kV and 22kV lines. The Queensland service providers operate 11kV high voltage distribution networks. The comparison firms mostly operate 22kV high voltage distribution networks. In theory operating a 22kV network would provide a small reduction in opex costs. Therefore differences in high voltage distribution systems contributes 0.5 per cent to the immaterial factor adjustments for the Queensland service providers.

Proportion of wooden poles

We are not satisfied that an OEF adjustment for differences in the proportion of wooden poles in service providers' networks would not meet the duplication OEF criterion. The decision on whether to use wooden, concrete, steel, or fiberglass poles is a trade-off between capex, opex and service levels. We have considered the impact of capex opex trade-offs under the capitalisation practices OEF and service levels under reliability outcomes.

In response to our 2014 draft decision, Essential Energy raised the proportion of wooden poles in its network as a factor that may increase its opex relative to the comparison firms.[718] It submitted that because wooden poles make up a greater part of its network than the comparison firms it is more exposed to the effects of timber decay than other service providers. Essential Energy did not provide any quantification of the effect that this may have on its costs.

In its regulatory proposal Ergon Energy submitted that it operated in the area with the worst conditions for pole degradation in Australia.[719] Ergon Energy stated that analysis of climatic factors across its networks supported this position. We asked Ergon Energy to provide this modelling. Ergon Energy submitted it was not able to provide this analysis because Ergon Energy does not have access to the model itself. The analysis belongs to Huegin Pty Ltd. and all rights are vested with Huegin and therefore Ergon Energy legally cannot provide this model to the AER.[720]

The decision on whether to use wooden, concrete, steel, or fiberglass poles is a capex opex trade-off. This is because higher capital cost poles are generally less opex intensive. For example concrete poles do not require the inspection drillings and anti-fungal treatments that wooden poles do. However concrete poles are more costly to install.

Service providers face many of these capex opex trade-offs. Other examples include the choice to rent or lease depots, to run lines over or underground, to replace or maintain. We consider that where a capex opex trade-off exists the decision on whether to provide an OEF adjustment should be considered in the broader context of service providers' capex to opex ratio. This is because a service provider may utilise a solution that is opex intensive in one area, but overall may have a preference for capital intensive solutions. In this situation providing a positive OEF adjustment for an opex intensive solution would over-compensate the service provider. This is because there will be other areas of their operations where it utilises capital intensive solutions but will not receive negative OEF adjustments.

In our capitalisation practices section we compare the capex opex ratios for the NEM service providers. Figure A.20 and Figure A.21 show that the Queensland service providers capitalise a similar amount of their opex to the comparison firms. We have included an adjustment for differences in capitalisation practices in our collective adjustment for individually immaterial factors.

Therefore, we are not satisfied that differences in opex due to the proportion of wooden poles in service provider's networks are accounted in our consideration of capitalisation practices.

718 Essential Energy, *Revised Proposal: Attachment 7.4*, 20 January 2015, p. 32.

719 Ergon Energy, *Regulatory Proposal: Attachment 0A.01.01*, pp. 14.

720 Ergon Energy, Response to AER Information request Ergon 018(6), 6 February 2015, p. 1.

Rising lateral mains

We are not satisfied that an OEF adjustment for rising lateral mains would meet the materiality OEF adjustment criterion. Service providers in the NEM are generally not responsible for maintaining mains within apartment complexes.

Rising and lateral mains are three phase mains, or busbars, that run through apartment buildings to which multiple service lines are connected.[721]

In response to our 2014 NSW and ACT draft decisions, Huegin raised rising and lateral mains as an OEF that may lead to differences in opex.[722] Huegin noted that Ofgem excludes costs associated with rising and lateral mains from its totex benchmarking. In the UK some service providers have a significant amount of mains running throughout apartment complexes.[723] Ofgem adjusts its totex benchmarking to remove costs associated with those assets.[724] Huegin did not provide any indication of why this may be an issue in the NEM.

We are not satisfied that it is necessary to provide an OEF adjustment for rising and lateral mains. While some service providers in the UK have substantial rising and lateral mains fleets, in general NEM service providers do not run electricity distribution mains through apartment complexes. In NEM jurisdictions, usually the demarcation between the service providers' assets and customers' assets is either at the boundary of the customer's property or on the outside of the customer's building. In some situations, service providers do own mains that run through a customer's premises that supply a substation. However, all NEM service providers have some substations located on customers' premises and there is no indication that this provides a cost disadvantage where it occurs. Aside from mains that supply substations, it is exceedingly unusual for a service provider to own distribution mains within an apartment building.

We are not satisfied that an adjustment for rising and lateral mains satisfies the materiality OEF criterion. In general NEM service providers do not own, and are not responsible for maintaining rising and lateral mains. As a result we estimate that rising lateral mains maintenance will lead to no differences in the opex incurred by NEM service providers.

---

721 Ofgem, RIIO-ED1: Glossary of terms, 2014, p. 23.

722 Huegin, *Response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER*, January 2015, p. 23.

723 SP Energy Networks, *SP Energy Networks 2015-2023 Business Plan: Annex Rising Mains and Laterals Strategy*, March 2014, pp. 3–4.

724 Huegin, *Response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER*, January 2015, p. 23.

Solar uptake

We are not satisfied that an OEF adjustment for the high take-up of solar photovoltaic (PV) installations in the Queensland service providers' networks satisfies the materiality OEF adjustment criterion.

Ergon Energy stated that it has had a very high take-up of solar photovoltaic (PV) installations with more than 16 per cent of Queensland households now with PV systems. In addition, 15 per cent of Queensland households are looking to either purchase more panels or acquire solar PV in the next two years.[725] It stated that most installations to date do not control terminal voltage resulting in an increasing level of voltage management complaints. As a consequence it incurs opex identifying and managing these issues.[726]

Energex stated solar PV had impacted its network field operating costs due to an increase in voltage complaints, investigations and requirement to re-balance the loading on the three phase network.[727]

We looked to compare the uptake of PV installations in the Queensland service providers' networks and the associated expenditure to the uptake and expenditure for the comparison firms. We compared the number of solar PV installations deemed by the Clean Energy Regulator per customer in each jurisdiction.[728] The number of deemed solar installations was greatest in South Australia. SA Power Networks, the sole service provider in South Australia, is one of the comparison firms.

Table A.17 Deemed PV installations per 100 connections

	Deemed small scale solar installations per 100 connections
ACT	8.7
NSW	8.7
Queensland	20.8
South Australia	21.5
Victoria	9.1

Source: Clean Energy Regulator; AER analysis.

The number of deemed solar installations per customer is just under three times greater in Queensland than Victoria, where all the other comparison firms are located. Ergon Energy stated that it identifies quality of supply issues primarily through customer complaints. It has conducted analysis that found network testing and

725 Ergon Energy, Response to information request AER Ergon 02, 17 December 2014, p. 23.

726 Ergon Energy, Response to information request AER Ergon 02, 18 December 2014, p. 23.

727 Energex, Response to information request AER EGX 001 Question A, 17 December 2014, p. 9.

728 Clean Energy Regulator, Small-scale installations by postcode, available at: http://ret.cleanenergyregulator.gov.au/REC-Registry/Data-reports [last accessed 31 March 2015].

customer complaints under reported actual voltage management issues by a factor of up to ten times that of the actual network issues.[729] By contrast, the Victorian comparison firms can use advanced metering infrastructure (AMI) data to identify the presence of steady state voltage violations.[730] Consequently we consider that the Victorian service providers may identify more steady state voltage violations resulting from PV installations than do the Queensland service providers.

Given this, there is not sufficient evidence to conclude that the high rate of PV installations in Queensland will lead to a material difference in opex due to higher quality of supply rectification expenditure.

We also looked at the costs associated with the administration of solar PV connections. We found that, on a per customer basis, Energex's costs for the administration of solar PV connections, were a little lower than those for SA Power Networks. The difference was consistent with the slightly higher uptake of PV in South Australia. Ergon Energy, however, did not provided detailed information on its PV connection administration costs. It only provided an estimate provided by Synergies Economic Consulting of the total cost over the period 2010–11 to 2014–15. We note this period had not finished at the time Ergon Energy provided this estimate. The estimate suggested that, on a per customer basis, Ergon Energy's PV connection administration costs were approximately four times those of Energex and SA Power Networks. Ergon Energy provided no reason for why its costs should be significantly greater than Energex or SA Power Networks'.

We would expect, however, that Energex and Ergon Energy's PV connection administration costs would be higher, than those of the Victorian comparison firms due to the higher PV uptake in Queensland. However, there is not sufficient evidence to conclude that the high rate of PV installations in Queensland will lead to a material difference in opex due to higher PV connection administration costs. An adjustment for differences in PV penetration would meet the exogeneity and materiality OEF adjustment criteria. The decision to install PV is a customer's choice and there are no variables to account for differences in PV penetration rates in Economic Insights' SFA model. As a result we have included differences in opex due to solar PV installations as a 0.5 percentage point increase in our immaterial OEF adjustments for Energex and Ergon Energy.

Subtransmission

We are satisfied that it is necessary to provide an OEF adjustment for differences in subtransmission network configuration between the Queensland service providers and the comparison firms. An adjustment for differences in subtransmission network configuration raises all of our three OEF adjustment criteria. The boundary between transmission and distribution networks is the result of historical decisions made by

---

[729] Ergon Energy, Response to information request AER Ergon 018(2)(a), 6 February 2015, p. 7.

[730] AER, V*ictorian electricity distribution network service providers distribution determination: Final decision - appendices*, October 2010, pp. 333–340.

state governments when dividing electricity networks. Differences in subtransmission configuration are likely to lead to material differences in the cost of providing network services. Differences in subtransmission configurations are not accounted for elsewhere in Economic Insights' SFA model.

In support of Ausgrid's 2014 regulatory proposal, Ausgrid's consultant Advisian (formerly known as Evans and Peck) stated that Victoria and Tasmania have a natural cost advantage because they have simpler subtransmission networks. The factors it cites include shorter total length of installed subtransmission cables,[731] less subtransmission transformer capacity installed[732] and fewer transformation steps.[733] Advisian conclude the greater size and complexity of subtransmission networks in NSW and Queensland are likely to manifest themselves in larger asset bases and that this will flow through to higher opex.

The transition point between transmission and distribution varies across jurisdictions and within service providers. All service providers take supply from transmission Grid Exit Points (GXPs) across a range of voltages. We agree with the above observations that the NSW service providers own and operate a proportionally larger group of assets at the higher voltages. Queensland GXPs are also typically at the higher voltage levels than those of other states. Tasmania has the lowest GXP voltages of all the NEM service providers on average. We also note the dual sub-transmission transformation step that accompanies the higher sub-transmission voltages. NSW, Queensland, and South Australia have all reported dual transformation assets.[734]

We are satisfied that an OEF adjustment is appropriate because the divisions between transmission and distribution service providers represent boundaries that are outside the control of service providers. In addition, the information available to us indicates that subtransmission assets may be up to twice as costly to operate as other distribution assets.

Further, Economic Insights' SFA model does not include a variable to account for the proportion of undergrounding. Therefore part of the differences in service providers' costs observed in Economic Insights' economic benchmarking will be due to differences in subtransmission configuration.

To assess the potential impact of the differences in subtransmission networks we investigated a number of approaches including:

- comparison of RAB values[735]

---

731 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 14.

732 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 18.

733 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 21.

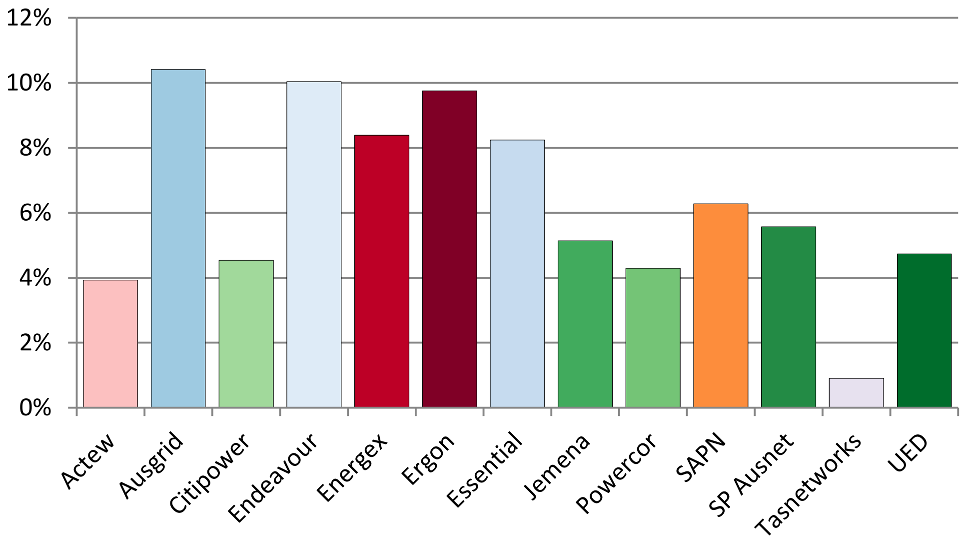
734 Economic Benchmarking RIN data.

735 Economic Benchmarking RIN data.

- comparison of replacement values[736]
- two stage transformation capacity comparisons[737]
- overall substation capacity comparisons[738]
- line length values.[739]

The most robust and consistent data set that we have for the above measures was on line length. We selected that data set because we have information to compare the volume of subtransmission assets and the operating costs of subtransmission assets by line length. This was not the case for other data sets. Figure A.40 below provides the subtransmission line length as a percentage of total line length for each service provider.

Figure A.40 Subtransmission circuit length as a percentage of total circuit length



Source: Economic Benchmarking RINs

The above figure shows that subtransmission lines represent a small proportion of total network line length. Subtransmission lines for Energex make up 8.4 per cent of its network. Subtransmission lines make up 9.8 per cent of Ergon Energies network. The average, weighted by customer numbers, for the comparison firms was 5.3 per cent.

Information from Ausgrid's regulatory accounts indicates that by length, their 66kV and 132kV assets are just under twice as costly to operate as their distribution network.

---

736 Category Analysis RIN data.
737 Economic Benchmarking RIN data.
738 Economic Benchmarking RIN data.
739 Economic Benchmarking RIN data.

Ausgrid's regulatory accounts provide the opex of operating the 66kV and 132kV part of their network and separately the opex for the rest of their network. These figures suggest that per kilometre, Ausgrid's 66kV and 132kV assets are twice as expensive to operate as their other assets.

To calculate the OEF adjustment for each service provider, we have subtracted the percentage that subtransmission lines represent of total lines operated by the weighted average of the comparison firms from that for the relevant service provider.

We note that 132kV and 66kV lines are likely to be more expensive to operate than 33kV lines. As a result we consider that this adjustment is likely to slightly favour service providers with more 33kV subtransmission assets.

Using the methodology described above, the recommended adjustment to the opex comparisons for this factor are therefore:

- Energex: 3.2 per cent[740]
- Ergon Energy: 4.6 per cent.[741]

SWER

We are not satisfied that an OEF adjustment for the proportion of Single-wire earth-return (SWER) included in a network would meet the exogeneity or duplication OEF adjustment criteria. The proportion of SWER included in a network is a result of past management decisions and it will be correlated with customer density, which is captured in Economic Insights' SFA model.

In response to our draft decision for the ACT and NSW service providers, Advisian,[742][743] CEPA,[744] and Synergies[745] raised the point that the cost of operating SWER lines is different to other lines. Advisian and CEPA submitted that SWER is cheaper to operate than other lines. Synergies on the other hand submitted that it is more expensive to operate because it is less reliable, which results in greater network restoration costs.

SWER is a mature technology that has been available to network service providers for decades. SWER systems are low capital and maintenance cost distribution systems, which have been installed and operated in many rural parts of the world. The high cost of network extension to rural areas, which are often characterized by scattered communities with low load densities, requires the use of low cost options to ensure

---

740 8.5 – 5.3 = 3.2.

741 9.9 – 5.3 = 4.6.

742 Advisian, *Opex Cost Drivers: ActewAGL Distribution Electricity (ACT)*, 16 January 2015, pp. 57–59.

743 Advisian, *Review of AER benchmarking: Networks NSW*, 16 January 2015, pp. 50–52.

744 CEPA, *Benchmarking and Setting Efficiency Targets for the Australian DNSPs*, 19 January 2015, pp. 26, 30, and 68.

745 Synergies, *Concerns over the AER's use of benchmarking as it might apply in its forthcoming draft decision on Ergon*, January 2015, p. 26

economic viability. In SWER power distribution networks, the earth itself forms the current return path of the single phase system leading to significant cost savings on conductors, poles and pole top hardware compared to conventional systems. However, challenges exist in SWER with regard to voltage management, reliability, earthing and safety as well as the dependence on earth conductivity to supply consumer loads.

A 2009 study by PB Associates identified SWER as the most cost effective option for the connection of remote customers.[746] This study showed that SWER supplies were less than half the cost of other overhead solutions. This is supported by a World Bank review of SWER undertaken in 2006.[747]

An OEF adjustment for SWER does not meet the exogeneity OEF adjustment criterion. Service providers have had the ability to use SWER in low demand low density areas of their networks. SWER has been available for use in Australia since the first half of the 20th century. To the extent that SWER is a cheaper method to distribute electricity, its use or absence, is a reflection of past managerial efficiency or inefficiency.

To the extent that SWER can be used in low density low demand environments, the effect of SWER on opex will be correlated with customer density. As Economic Insights SFA model accounts for customer density, it will also account for the proportion of SWER used by a service provider. As mentioned in our 2014 draft decision for NSW and ACT service providers, in our consideration of customer density, asset complexity will be correlated with customer density. In this case, SWER is a less complex asset designed to serve low loads through a single wire instead of multiple circuits.

Transmission connection point charges

We are not satisfied that an OEF adjustment for transmission connection point charges would meet the duplication OEF adjustment criterion. Transmission connection point charges have been excluded from network services opex: the opex data used in Economic Insights' SFA model.

Transmission connection point charges are charges for electricity transmission services.

In response to our draft decision for NSW and ACT service providers, Huegin raised transmission connection point charges as an OEF that may lead to differences in opex.[748] Huegin noted that Ofgem excludes transmission connection point charges from its totex benchmarking.

---

746 Parsons Brinckerhoff, *Indicative costs for replacing SWER lines*, 28 August 2009, p. iv.

747 The World Bank, *Sub-Saharan Africa: Introducing Low-cost Methods in Electricity Distribution Networks*, October 2006, p. xvi.

748 Huegin, *Response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER*, January 2015, p. 23.

A.7 The benchmark comparison point and adjustments to base opex

The purpose of any adjustment to base opex is to develop an appropriate starting point from which to build our alternative estimate of forecast opex that we are satisfied will reasonably reflect the opex criteria. We do this using a range of techniques, including benchmarking. If we make an adjustment to base opex, it is not the end of our assessment, merely one stage of it. However, the effect of removing spending from base opex that does not reflect the opex criteria can be significant because service providers rely heavily on total actual opex incurred in the base year in their revised proposals to develop their proposed forecast.

If our analysis indicates that a service provider's base opex is materially inefficient for the purposes of forecasting opex in the coming regulatory control period even after its individual circumstances (such as exogenous factors) are accounted for, it would not be appropriate to use the base opex for the purpose of constructing a forecast that is intended to reflect the opex criteria. If we relied upon unadjusted revealed costs to build a forecast, it would include spending that does not reflect the opex criteria for each year of the new regulatory period.

Accordingly, making an appropriate adjustment to base opex is an important part of our assessment approach in circumstances where we find evidence for material inefficiency in the base year costs. This issue has been the subject of a range of submissions and responses from stakeholders.

This part of our decision is, essentially, about how much of the actual opex of a service provider in the base year does not reasonably reflect the opex criteria when reviewed using the approach we are applying for the 2014–19 period.

A.7.1 Preliminary position

Having considered all the relevant evidence we consider there is material inefficiency in Energex's and Ergon Energy's base year opex. To rely on their revealed expenditure in the base year when developing our alternative forecast would result in an estimate of total forecast opex that would not reasonably reflect the opex criteria. For the purposes of constructing an alternative opex forecast that we think will reasonably reflect the opex criteria, we have adjusted their base opex amounts downwards by an appropriate margin having regard to the RPPs, the opex factors and the NEO.

We disagree with submissions made by Ergon Energy to the NSW and ACT draft decisions that advocate we should abandon our benchmarking techniques and the extent to which we rely upon our benchmarking results.[749] Therefore, we continue to

[749] Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, pp. 9–22.

place significant weight on the results of Economic Insights' preferred model (Cobb Douglas SFA) in estimating necessary reductions in base opex.

However, in light of submissions from service providers, we have reconsidered our approach to determining the most appropriate way to make an adjustment.[750] As we explain in the Guideline, our preference is to rely on revealed expenditure as an appropriate basis for forecasting efficient, prudent and realistic opex when service providers are appropriately responding to the incentive framework. Therefore, rather than adjusting all service providers below the most efficient performer (the frontier) the Guideline approach is to adjust revealed opex when our analysis demonstrates it is *materially* inefficient.[751]

We have looked to international regulators' application of benchmarking for guidance on benchmark comparison points. However, while many regulators apply benchmarking, the application differs across regulatory regimes. Rather, when determining the appropriate point at which to make an adjustment to expenditure, they do so having regard to their regulatory framework and the task before them. Similarly, we have decided on the benchmark comparison point (the threshold at which we make an adjustment to base opex) having regard to our regulatory framework and the task before us.

We have decided, on balance, for this decision the appropriate benchmark comparison point is the lowest of the efficiency scores in the top quartile of possible scores rather than the average approach we used in our draft decisions for the ACT and NSW service providers. This is equivalent to the efficiency score for the business at the bottom of the upper third (top 33 per cent) of companies in the benchmark sample (represented by AusNet Services). Our approach of using benchmarking as a basis for making adjustments to opex is consistent with Ofgem's approach.[752]

This reduces the benchmark comparison point we previously applied from 0.86 to 0.77. In making this change to our approach, we have carefully considered the submissions we have received, the requirements in the NEL and NER, the Guideline approach and the advice of Economic Insights. The purpose of assessing base opex under the Guideline approach is to identify material inefficiency. We must ensure, therefore, that our comparison point appropriately reflects our satisfaction that a service provider's revealed opex is *materially* inefficient before we reduce it.

This change reduces our estimate of the necessary adjustments to base year opex significantly. However, given this is our first application of economic benchmarking, our view is this application is appropriate for this preliminary determination. That is, we

750 Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, pp. 9–22.

751 AER, *Expenditure Forecast Assessment Guideline*, November 2013, p. 22.

752 Noting that Ofgem now assesses total expenditure rather than capex and opex separately. See, for example, Ofgem, *RIIO-ED1–Final determinations for the slow-track electricity distribution companies-Overview*, 28 November 2014, Chapter 4.

have allowed a wide margin between the frontier firm (0.95) and the benchmark comparison point (0.77). Service providers should be aware, however, that as we refine our approach and receive more data, we may reduce the size of that margin when making adjustments to base opex to develop alternative opex forecasts.

Applying this approach, we have decided to adjust Energex's and Ergon Energy's revealed expenditure by $63.6 million (15.5 per cent) and $36.5 million (10.7 per cent), respectively. Table A.18 shows the resulting adjustments. The adjustments incorporate:

- a reduced benchmark comparison point of 0.77 in Economic Insights' SFA model
- an allowance for exogenous circumstances of 17 per cent for Energex and 24 per cent for Ergon Energy based on our detailed assessment set out in section A.6.

These adjustments are consistent with the approach we have outlined in the Guideline and allow us to develop a forecast that best reflects the opex criteria in the NER to achieve the NEO.[753]

Table A.18 Final decision base opex adjustments

	Energex	Ergon
Proposed base opex, nominal	572.0	422.1
-feed in tariff, nominal	-167.1	-75.9
- debt raising costs, nominal	-4.5	-5.19
- Service classification change, nominal	-13.6	-20.2
Adjusted total opex, nominal	386.8	320.8
Base opex, real 2013–14 (end of year)	411.3	341.1
Substitute base, real 2013–14 (end of year)	**347.7**	**304.6**
Difference in base opex	63.6	36.5
Percentage base opex reduction	**15.5%**	**10.7%**

Source: AER analysis.

A.7.2 Reasons for preliminary position

In the ACT and NSW review process, ActewAGL and the NSW service providers submitted common issues regarding how we make adjustments to base year opex. Ergon Energy also provided a submission to that review process that raised similar

[753] AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, pp. 10.

issues.[754] We have carefully considered these submissions as part of our decision on the appropriate benchmark comparison point and the adjustment process.

The appropriate benchmark comparison point

Service providers have submitted that our approach to adjustments is different to that of other regulators.[755] ActewAGL contends, for example, that we have erred by placing reliance on a single benchmarking model as different benchmarking approaches imply differing base year opex adjustments.[756] Ergon Energy and its consultants also submit that:[757]

- our efficiency gap is large and inconsistent with international precedent
- our application of benchmarking results is inconsistent with international practice and literature
- our target is not appropriately cautious when compared to Economic Insights' previous views as expressed in publications.

The service providers have also submitted that, by using average efficiency scores as the basis for our adjustment, we have used a 'false frontier'[758] and, additionally, that our roll forward approach has been applied incorrectly.[759]

In light of submissions, we have reconsidered our approach to making an adjustment and we have modified it appropriately for this final decision. This involves consideration of the appropriate technique, the benchmark comparison point and the appropriate application of our technique.

The best technique for the adjustment

Consistent with our approach in the NSW and ACT draft decisions, we continue to adopt Economic Insights' recommendation to rely on the Cobb Douglas SFA model as the preferred technique upon which we base an adjustment to revealed opex. Our rationale for this is SFA is the most statistically superior method because it directly estimates efficiency, separate from the error term.[760] We provide more detail on Economic Insights' preference to use SFA in section A.4.

---

754 Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, pp. 9–22.

755 ActewAGL, *Revised Regulatory Proposal*, 2015, pp. 117, 126, p. 127–129, Ausgrid, *Revised regulatory proposal*, 2015, pp. 139–140.

756 ActewAGL, *Revised Regulatory Proposal*, 2015, p. 118.

757 Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19*, 13 February 2015, pp. 9–22.; Frontier Economics (Ergon), 2015.

758 Ausgrid, *Revised Regulatory Proposal*, pp. 143–144; ActewAGL *Revised Regulatory Proposal*, pp. 166–175.

759 ActewAGL *Revised Regulatory Proposal*, p. 166; Frontier Economics, (NSW), 2015, p.97, PEGR, 2015, p.64. CEPA, (NSW) 2015, p.35.

760 Economic Insights (2014), section 5.

The benchmark comparison point

We have reconsidered the appropriate benchmark comparison point following submissions on our approach. In doing so, two questions are relevant:

- should the benchmark comparison point be the best performing business?
- if not, what is the appropriate point at which we are satisfied there is evidence of material inefficiency in the base opex?

Should we use the best performing business as our comparison point?

We explain in the Guideline that our preference is to rely on revealed expenditure as an appropriate basis for forecasting efficient, prudent and realistic opex when service providers are appropriately responding to the incentive framework. Therefore, we created a threshold in the Guideline—we would adjust revealed opex when our analysis demonstrates it is *materially* inefficient.[761]

The first opex criterion (efficient costs) suggests that the most appropriate benchmark comparison point may be the top performing business because economic theory would not consider a lower point to be efficient. The theoretical comparison point is therefore 0.95. However, the NER also contain the qualifier 'reasonably reflects'.[762] This provides us with discretion to determine how far from the frontier a service provider must be before we are satisfied, in accordance with the Guideline approach, that it is 'materially inefficient'.

In determining what is 'materially inefficient', we recognise that there should be an appropriate margin for forecasting error, data error and modelling issues. Our view is, therefore, that using this discretion it is appropriate to choose a lower comparison point than the frontier firm.

In the NSW and ACT draft decisions, we adopted this approach. On Economic Insights' recommendation, we used the weighted average efficiency scores of all service providers with efficiency scores greater than 0.75 as the benchmark comparison point.[763] This enabled us to incorporate a margin for potential data and modelling issues, and resulted in a comparison point of 0.86. However, submissions by the service providers and their consultants consider our draft decision approach was inconsistent with approaches taken by other regulators such as Ofgem, Norway, the NZCC (New Zealand Commerce Commission) and the OEB (Ontario Energy Board).[764]

---

761 AER, *Expenditure Forecast Assessment Guideline*, November 2013, p. 22.

762 NER, cl. 6.5.6(c) states:

The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period ***reasonably reflects*** *each of the following (the operating expenditure criteria):*

(1) ***the efficient costs*** *of achieving the operating expenditure objectives…*

763 Economic Insights (2014), section 7.

764 Ausgrid, pp. 150–151, Attachments 1.05 and 1.07.

What is the appropriate benchmark comparison point?

Having considered the service providers' submissions, we turned our mind to how international regulators have applied benchmarking. However, we have found that no uniform approach exists. International regulators use benchmarking to, for example:[765]

- assess efficient opex (UK, Ireland)
- determine industry-wide productivity growth (NZ, Germany)
- group service providers and assign group-specific stretch factor as part of the X factor (Ontario, NZ, Japan)
- apply model results directly to allowed revenue/price formula (Netherlands, Austria, Germany, Denmark, Finland, Norway)
- Form basis of negotiation (California).

In terms of setting the benchmark comparison point:[766]

- the NVE in Norway, where the regulatory regime is to set total cost, uses an industry average firm
- the EMA in Finland uses a firm-specific target (based on an average of DEA and SFA results) to determine efficient opex
- the OEB in Canada has previously used firm-specific stretch factors assigned to three cohorts (0.2% top quartile, 0.4% middle two quartiles and 0.6% bottom quartile) to set efficient opex
- the NZCC in New Zealand, where the regime is based on total cost, determines industry-wide productivity growth to determine the X factor
- Ofgem in the UK has weighted three models together and set the frontier (based on the upper quartile company) after they have been combined.[767]

Therefore, regulators choose benchmark comparison points on the basis of the task in hand in the context of the legislative frameworks under which they operate. The comfort we can take from this is that the most appropriate approach is to determine a benchmark comparison point in accordance with our regulatory framework.

We have decided, on balance, for this decision the appropriate benchmark comparison point is the lowest of the efficiency scores in the top quartile of possible scores rather than the average approach we used in our draft decisions for the ACT and NSW service providers. This is equivalent to the efficiency score for the business at the bottom of the upper third (top 33 per cent) of companies in the benchmark sample

---

765 ACCC/AER, *Benchmarking Opex and Capex in Energy Networks, ACCC/AER Working Paper number 6*, May 2012.

766 ACCC/AER, *Benchmarking Opex and Capex in Energy Networks, ACCC/AER Working Paper number 6*, May 2012.

767 CEPA, (NSW) 2015, pp. 30–31.

(represented by AusNet Services). Our revised comparison point is appropriate for the following reasons.

First, our previous averaging approach produced an unusual result for service providers ranked in the top quartile of efficiency scores, but below the average of that top quartile. These service providers would require an efficiency adjustment to reach the average benchmark comparison point (because their scores are below the average) despite being efficient enough to be ranked in the top quartile and, hence, included in the average.

Second, given it is our first application of benchmarking, it is appropriate to adopt a cautious approach. We have decided to increase the margin for error for modelling and data issues provided for in the NSW/ACT draft decision (which reduced the benchmark comparison point from 0.95 to 0.86).

Third, we consider this approach better achieves with the NEO and RPPs. In particular we have considered:[768]

- the principle that we should provide service providers with an opportunity to recover at least their efficient costs
- we wish to create a high-powered efficiency incentive (which supports making an adjustment when it is clear there is material inefficiency in revealed costs) but we are mindful of providing sufficient stability to promote efficient investment
- our decision should allow a return that is commensurate with both regulatory and commercial risks.

A number of service providers, representing more than a third of the NEM, and operating in varied environments, are able to perform at or above our benchmark comparison point. We are confident that a firm that performs below this level is, therefore, spending in a manner that does not reasonably reflect the opex criteria. An adjustment back to an appropriate threshold is sufficient to remove the material over-expenditure in the revealed costs while still incorporating an appropriately wide margin for potential modelling and data errors and other uncertainties. Economic Insights agrees that this approach is appropriate.[769]

Our approach of using benchmarking as a basis for making adjustments to opex is also consistent with Ofgem's approach.[770]

This approach results in a comparison point significantly lower than the frontier firm's efficiency. Reducing the efficiency target from 0.95 (CitiPower) to 0.86 represented a 9 per cent allowance for the service providers. Changing the target to 0.77 (AusNet

---

[768] NEL, s. 7A.

[769] Economic Insights (2015), section 5.1

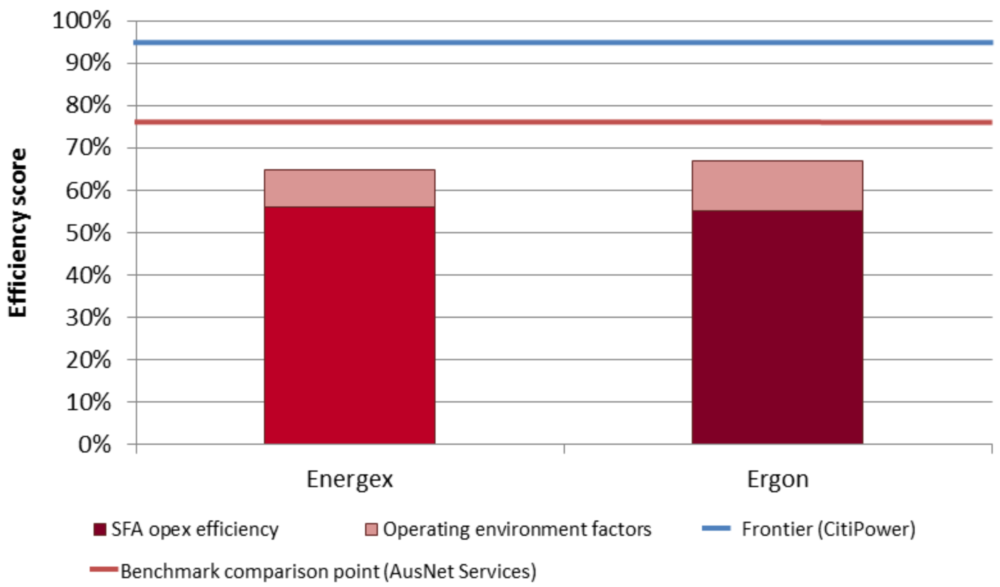
[770] Noting that Ofgem now assesses total expenditure rather than capex and opex separately. See, for example, Ofgem, RIIO-ED1–Final determinations for the slow-track electricity distribution companies-Overview, 28 November 2014, Chapter 4.

Services) increases that reduction by a further 10 per cent. Overall, this is a 19 per cent reduction from the frontier firm under the SFA model.

Figure A.41 below shows the efficiency scores for the QLD service providers compared to our benchmark comparison point, represented by the red line (AusNet Services). The blue line represents the frontier firm (CitiPower).

Our operating environment factor adjustments are percentage adjustments relative to the frontier. Therefore, the operating environment factor adjustments in Figure A.41 will not reflect the absolute percentages reported above. That is, the light red proportion represents 17 per cent (Energex) and 24 per cent (Ergon Energy) of the total efficiency score rather than an addition of 17 or 24 percentage points on top of the SFA opex efficiency score.

Figure A.41 Comparison of raw SFA efficiency scores to the revised benchmark comparison point, adjusted for operating environment factors



Source: AER analysis.

Note: The raw SFA efficiency scores displayed are 'rolled forward' from a period-average basis (for 2006-2013) to the 2012–13 base year. We explain this below in our discussion of the adjustment process.

Figure A.41 demonstrates an appropriately conservative difference between the frontier firm and our benchmark comparison point. As we refine our approach and continue to receive more data—all service providers must submit data each year— we may revise our benchmark comparison point when making adjustments to base opex to develop alternative opex forecasts.

The adjustment process

The mechanics of determining the adjustment include several steps. In essence, it involves using the SFA model to estimate average period efficiency, which we adjust to take into account the reduced the benchmark comparison point and operating environment factor allowances. We then roll this average period efficient opex forward to the 2012–13 base year to compare efficient base opex to the service provider's reported base opex.

Some service providers submit that both using an average approach and rolling it forward are inappropriate.[771] Here, we clarify why we consider our approach is appropriate.

Average period efficiency scores

A key reason we use average period efficiency scores is because they moderate the impact of year-specific fluctuations not under the control of the service provider (such as weather conditions) while also reducing the scope for the service provider to strategically reduce its reported opex in a single, nominated benchmark year. [772]

Average efficiency results also provide us with a better estimate of underlying recurrent expenditure not influenced by year on year changes, which we require for the Guideline approach to estimating total forecast opex.

In addition, because the sample period is the eight years from 2006 to 2013, Economic Insights considers the average is sufficiently recent to avoid the potential loss of current relevance.[773] Economic Insights also considers the performance gap has not narrowed for the following reasons:[774]

- the Victorian service providers experienced a negative rate of technical change (which leads to a negative rate of opex partial productivity growth) due to allowed step changes following the implementation of Victorian Bushfires Royal Commission recommendations
- the SFA and LSE models calculate average efficiency levels over the period and these averages incorporate the influence of the situation at the end of the period. That is, they calculate average efficiency for the period rather than midpoint efficiency. Therefore, because the efficiency score is an average, it already partially allows for changed conditions at the end of the period (assuming they have in fact changed).

Rolling forward average scores to the base year

Because we compare average efficiency, we must 'roll forward' the average efficient opex to the 2012–13 base year, because that is the relevant starting point for estimating total forecast opex that reasonably reflects the opex criteria. We do this by applying the measured rate of change, which accounts for the difference between

---

[771] Ausgrid, *Revised Regulatory Proposal*, pp. 143–144; ActewAGL *Revised Regulatory Proposal*, pp. 166–175; Frontier Economics, (NSW), 2015, p.97, PEGR, 2015, p.64. CEPA, (NSW) 2015, p.35.

[772] Economic Insights (2015), section 4.1.

[773] Economic Insights (2015), section 4.1.

[774] Economic Insights (2015), section 4.3.

output, price and productivity in the 2012–13 base year and at the period average (2006 to 2013).[775] The rate of change value varies for each service provider due to differing growth rates.

Rolling forward average efficiency to the 2012–13 base year allows for differences in service providers' relative opex growth rates between the average and the base year. This means that if a service provider has increased its constant price opex between the average of the period and 2012–13 by less than that which the rate of change formula allows, it would receive a smaller base year opex reduction compared to that implied by its average efficiency score.

Conversely, if the service provider has increased its constant price opex by more than that which the rate of change formula allows, it would receive a larger base year opex reduction compared to that implied by its average efficiency score.[776]

Final decision adjustments

Table A.19 and Table A.20 demonstrate the steps involved in making the adjustment to Energex's and Ergon Energy's base year opex.

Table A.19 Steps for making the adjustment to base opex – Energex

	Description	Output	Calculation
Step 1 – Start with Energex's average opex over the 2006 to 2013 period	Energex's network services opex was, on average, \$315.3 million (\$2013) over the 2006 to 2013 period.	\$315.3 million (\$2013)	
Step 2 —Calculate the raw efficiency scores using our preferred economic benchmarking model	Our preferred economic benchmarking model is Economic Insights' Cobb Douglas SFA model. We use it to determine all service providers' raw efficiency scores. Based on Energex's customer numbers, line length, and ratcheted maximum demand over the 2006 to 2013 period. Energex's raw efficiency score is 61.8 per cent.	61.8 per cent[777]	
Step 3—Choose the comparison point	For the purposes of determining our alternative estimate of base opex, we did not base our estimate on the efficient opex estimated by the model.	76.8 per cent[778]	

[775] This differs slightly from the rate of change we apply in Appendix B. While the approach is the same, to trend base opex forward over the forecast period, we apply forecast growth. When rolling forward average efficient opex, we apply measured growth because we can observe what has actually changed between the period average and the base year.

[776] Economic Insights, 2015, section 4.2.

[777] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 37.

[778] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 37.

	Description	Output	Calculation
	The comparison point we used was the lowest of the efficiency scores in the top quartile of possible scores (represented by AusNet Services). According to this model AusNet Services opex is 76.8 per cent efficient based on its performance over the 2006 to 2013 period. Therefore to determine our substitute base we have assumed a prudent and efficient Energex would be operating at an equivalent level of efficiency to AusNet Services.		
Step 3— Adjust Energex's raw efficiency score for operating environment factors	The economic benchmarking model does not capture all operating environment factors likely to affect opex incurred by a prudent and efficient Energex. We have estimated the effect of these factors and made a further adjustment to our comparison point where required. We have determined a 17.1 per cent reduction to the comparison point for Energex based on our assessment of these factors. Material operating environment factors we considered were not accounted for in the model include division in responsibility for vegetation management and extreme weather.	65.6 per cent	= 0.768 / (1 - 0.171)
Step 4—Calculate the percentage reduction in opex	We then calculate the opex reduction by comparing Energex's efficiency score with the adjusted comparison point score.	5.7 per cent	= 1 – (0.618 / 0.656)
Step 5—Calculate the midpoint efficient opex	We estimate efficient opex at the midpoint of the 2006 to 2013 period by applying the percentage reduction in opex to Energex's average opex over the period. This represents our estimate of efficient opex at the midpoint of the 2006 to 2013 period.	297.2 million ($2013)	= (1 – 0.057) × 315.3 million
Step 6— Trend midpoint efficient opex forward to 2012–13	Our forecasting approach is to use a 2012–13 base year. We have trended the midpoint efficient opex forward to a 2012–13 base year based on Economic Insights' opex partial factor productivity growth model. It estimates the growth in efficient opex based on growth in customer numbers, line length, ratcheted maximum demand and share of undergrounding. It estimated the growth in efficient opex based on Energex's growth in these inputs in this period to be 10.02 per cent.	327.0 million ($2013)	= 297.2 × (1+ 0.1002)
Step 7—Adjust our estimate of 2012–13 base year opex for CPI	The output in step 6 is in real 2013 dollars. We need to convert it to real 2014–15 dollars for the purposes of forming our substitute estimate of base opex. This reflects two and a half years of inflation. This is our estimate of base opex.	347.7 million ($2014–15)	= 327.0 × (1 + 0.063)

Source: AER analysis

Table A.20 Steps for making the adjustment to base opex – Ergon Energy

	Description	Output	Calculation
Step 1 – Start with Ergon Energy's average opex over the 2006 to 2013 period	Ergon Energy's network services opex was, on average, $340.4 million ($2013) over the 2006 to 2013 period.	$340.4 million ($2013)	
Step 2 —Calculate the raw efficiency scores using our preferred economic benchmarking model	Our preferred economic benchmarking model is Economic Insights' Cobb Douglas SFA model. We use it to determine all service providers' raw efficiency scores. Based on Ergon Energy's customer numbers, line length, and ratcheted maximum demand over the 2006 to 2013 period. Ergon Energy's raw efficiency score is 48.2 per cent.	48.2 per cent[779]	
Step 3—Choose the comparison point	For the purposes of determining our alternative estimate of base opex, we did not base our estimate on the efficient opex estimated by the model. The comparison point we used was the lowest of the efficiency scores in the top quartile of possible scores (represented by AusNet Services). According to this model AusNet Services opex is 76.8 per cent efficient based on its performance over the 2006 to 2013 period. Therefore to determine our substitute base we have assumed a prudent and efficient Ergon Energy would be operating at an equivalent level of efficiency to AusNet Services.	76.8 per cent[780]	
Step 3— Adjust Ergon Energy's raw efficiency score for operating environment factors	The economic benchmarking model does not capture all operating environment factors likely to affect opex incurred by a prudent and efficient Ergon Energy. We have estimated the effect of these factors and made a further adjustment to our estimate where required. We have determined a 24.4 per cent reduction to Ergon Energy's comparison point based on our assessment of these factors. Material operating environment factors we considered were not accounted for in the model include Ergon Energy's the division of responsibility for vegetation management and extreme weather.	61.7 per cent	= 0.768 / (1 - 0.244)
Step 4—Calculate the percentage reduction in opex	We then calculate the opex reduction by comparing Ergon Energy's efficiency score with the adjusted comparison point score.	22.0 per cent	= 1 – (0.482 / 0.617)
Step 5—Calculate the	We estimate efficient opex at the midpoint of the	265.6 million	= (1 – 0.220) ×

[779] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 37.

[780] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 37.

	Description	Output	Calculation
midpoint efficient opex	2006 to 2013 period by applying the percentage reduction in opex to Ergon Energy's average opex over the period. This represents our estimate of efficient opex at the midpoint of the 2006 to 2013 period.	($2013)	340.4 million
Step 6— Trend midpoint efficient opex forward to 2012–13	Our forecasting approach is to use a 2012–13 base year. We have trended the midpoint efficient opex forward to a 2012–13 base year based on Economic Insights' opex partial factor productivity growth model. It estimates the growth in efficient opex based on growth in customer numbers, line length, ratcheted maximum demand and share of undergrounding. It estimated the growth in efficient opex based on Ergon Energy's growth in these inputs in this period to be 7.85 per cent.	286.5 million ($2013)	= 340.4 × (1+ 0.0785)
Step 7—Adjust our estimate of 2012–13 base year opex for CPI	The output in step 6 is in real 2013 dollars. We need to convert it to real 2014–15 dollars for the purposes of forming our substitute estimate of base opex. This reflects two and a half years of inflation. This is our estimate of base opex.	304.6 million ($2014–15)	= 286.5 × (1 + 0.063)

Source: AER analysis

A.8 Adjustments to base year expenditure

Ergon Energy made adjustments to its base year expenditure to forecast its expenditure for the 2015–20 regulatory control period. We considered each of these adjustments, and whether we need to make each of these adjustments, when we derived our alternative estimate of total opex.

A.8.1 One-off events

Ergon Energy made adjustments to its base year expenditure to remove expenditure related to specific one-off or unusual events that it considered were not representative of a typical year of recurrent opex.[781] We considered these adjustments when assessed Ergon Energy's forecasting method (appendix D).

A.8.2 Movements in provisions

Ergon Energy made eight adjustments to its base opex relating to provisions:[782]

1. restructuring
2. employee benefits on-cost provisions

[781] Ergon Energy, 06.01.01 Forecast Expenditure Summary—Operating Costs, December 2014, p. 11.

[782] Ergon Energy, 06.01.01 Forecast Expenditure Summary—Operating Costs, December 2014, p. 12.

3. rehabilitation
4. other
5. annual leave
6. long service leave
7. vested sick leave
8. super on employee entitlements.

We stated in the Guideline that we would likely assess base year expenditure exclusive of any movements in provisions that occurred in that year.[783] The value of provisions is estimated using value and timing assumptions regarding liability that have yet to be paid out. These assumptions are sometimes changed, altering the value of provisions. This will change not only the value of the liabilities accrued in the year in question, but also liabilities accrued in prior years that have not yet been paid out. This is one reason why we consider movement in provision may not reflect the expenditure incurred in a given year.

However, we have not explicitly removed movements in provisions from Ergon Energy's base year opex because we have applied an efficiency adjustment. This efficiency adjustment implicitly removes movements in provisions by setting base opex equal to a benchmark amount. We derived this benchmark amount from multiple data points from multiple service providers across multiple years, effectively removing movements in provisions.

A.8.3 Reclassification of services

Ergon Energy' base year expenditure included $20.2 million (nominal) for services that will not be classified as standard control services for the 2015–20 regulatory control period.[784] We have removed this expenditure from Ergon Energy' base year expenditure to develop our alternative opex forecast.

---

783 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 22.

784 Ergon Energy, 06.02.06 Base Step Trend Database, December 2014.

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 opex that reflects the opex criteria for each year of a regulatory control period might differ from expenditure in the base year.

As set out in our Expenditure Forecast Assessment Guideline (our Guideline), we have developed an opex forecast incorporating the rate of change to account for the following factors:[785]

- price growth
- output growth
- productivity growth.

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

B.1 Position

On average, our forecast of the overall rate of change used to derive our alternative estimate of opex is higher than Ergon Energy's over the forecast period. Table B.1 shows Ergon Energy's and our overall rate of change in percentage terms for the 2015–20 regulatory control period. We consider that applying our methodology to derive an alternative estimate of opex will result in a forecast that reasonably reflects the efficient and prudent costs faced by Ergon Energy given a realistic expectation of demand forecasts and cost inputs.

The differences in each forecast rate of change component are:

- our forecast of price growth is on average 0.82 percentage points lower than Ergon Energy's
- our forecast of productivity growth is 0.97 percentage points lower than Ergon Energy's.
- there is no material difference between output growth

We discuss the reasons for the difference between each rate of change component below.

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

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

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Ergon Energy			1.43	1.52	1.54	1.51	1.58
AER	1.33	0.50	1.35	1.86	1.59	2.05	1.76
Difference			–0.08	0.34	0.05	0.53	0.18

Source: AER analysis.

B.2 Ergon Energy proposal

Table B.2 shows Ergon Energy's proposed annual change in opex for each rate of change component reported in Ergon Energy's reset RIN. Ergon Energy's rate of change methodology is broadly consistent with the opex rate of change approach set out in our Guideline. However, Ergon Energy attributed economies of scale to output growth. Economies of scale are considered under our assessment of productivity in our Guideline.[786] Ergon Energy also adopted a labour price growth based on the Average Weekly Ordinary Time Earnings (AWOTE) rather than our preferred measure the Wage Price Index (WPI).[787]

We discuss each of these components below.

Table B.2 Proposed opex by rate of change drivers ($'000, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20
Proposed opex	349 601	356 054	363 606	372 904	378 950
Price growth	3 271	4 342	4 904	4 963	4 650
Output growth	5 269	4 391	4 049	4 064	4 817
Productivity growth	–3 501	–3 390	–3 443	–3 491	–3 550

Source: Ergon Energy response to AER information request 017 and AER analysis.

Note: The amounts attributable to growth are in incremental terms. That is, they represent the increase in opex relative to the previous year (not the base year) that is due to price, output or productivity growth.

Forecast price growth

Ergon Energy engaged Jacobs to forecast material and labour price growth for its regulatory proposal.[788]

Jacobs recommended no real price growth for materials and other costs.[789]

786 AER, *Better regulation explanatory statement draft expenditure forecast assessment guidelines for electricity transmission and distribution*, August 2013, p. 36.

787 Jacobs, *Cost escalation factors 2015–20*, 10 October 2014, p. 36.

788 Jacobs, *Cost escalation factors 2015–20*, 10 October 2014, p. 4.

Jacobs' forecast of utility sector labour is based on the EGWWS AWOTE and its contractor labour is based on the professional services sector AWOTE.[790]

The annual percentage change for Ergon Energy's forecast price growth are in Table B.3.

Table B.3 Proposed price growth (per cent)

Escalation rates	2015–16	2016–17	2017–18	2018–19	2019–20
Utility sector labour	1.50	1.61	1.62	1.62	1.62
Contractors	1.40	1.48	1.50	1.48	1.48

Source: Jacobs, Cost escalation factors 2015–20, p. 37.

Forecast output growth

Ergon Energy proposed customer growth and network growth as its two output growth drivers. Customer growth is based on Ergon Energy's forecast customer numbers from its econometric demand forecast model. Network growth is calculated as a simple average of the forecast annual growth rate in zone substation capacity, distribution line length and the number of distribution transformers.[791]

Ergon Energy's applied its network growth driver to network operating costs and network maintenance costs. Ergon Energy applied its customer growth to other operating and maintenance costs and overheads.[792]

Ergon Energy's proposed annual growth rates for its output drivers are in Table B.4.

Table B.4 Proposed output drivers (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
Length of distribution lines	0.26	0.28	0.26	0.14	0.14
Distribution transformers	2.10	2.29	2.10	2.08	2.08
Capacity of zone substations	1.90	0.40	0.29	0.38	1.27
Network growth	1.42	0.99	0.88	0.87	1.16
Customer growth	1.64	1.80	1.65	1.64	1.65

Source: Ergon Energy, Forecast expenditure summary, p. 21.

789 Jacobs, *Cost escalation factors 2015–20*, 10 October 2014, p. 6.

790 Jacobs, *Cost escalation factors 2015–20*, 10 October 2014, 10 October 2014, p. 32, p. 36.

791 Ergon Energy, *Forecast expenditure summary – operating costs*, 31 October 2014, p. 19.

792 Ergon Energy, *Forecast expenditure summary – operating costs*, 31 October 2014, pp. 22–23.

Forecast productivity growth

Ergon Energy adjusted its output drivers reflect the economies of scale achievable for its network growth and customer growth drivers.[793]

Ergon Energy also included a one per cent per annum productivity growth factor applied to all direct and support costs.[794]

Rate of change

The rate of change approach applies a percentage change to the previous year's opex.

Table B.2 above expresses the impact of each rate of change component in dollar terms. To allow for a like with like comparison, we have expressed each of Ergon Energy's rate of change components in annual percentage terms below in Table B.5.

The values in Table B.5 represent the incremental change in percentage terms of each rate of change component from the previous year's opex.

Table B.5 Ergon Energy's opex rate of change (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
Price growth	0.94	1.24	1.38	1.37	1.25
Output growth	1.51	1.26	1.14	1.12	1.29
Productivity growth	1.00	0.97	0.97	0.96	0.95
Overall rate of change	1.43	1.52	1.54	1.51	1.58

Source: Ergon Energy, Response to information request 017 and AER analysis.

B.3 Assessment Approach

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

The rate of change itself is a build-up of various components to provide an overall holistic number that represents our forecast of annual change in overall opex during the 2015–20 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 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:

793 Ergon Energy, *Forecast expenditure summary – operating costs*, 31 October 2014, p. 24.

794 Ergon Energy, *Forecast expenditure summary – operating costs*, 31 October 2014, p. 24.

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

Where Δ denotes the proportional change in a variable.

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

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

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

Price growth

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

To determine the appropriate forecast change in labour prices we assessed forecasts from Jacobs, PricewaterhouseCoopers and Deloitte Access Economics. These forecasts are based on the consultants’ view of general macroeconomics trends for the utilities industry and the overall Australian economy. We discuss our consideration of the choice of labour price forecast in section B.4.3.

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 these measures. We have chosen the same output growth measures and weightings as used in Economic Insight's economic benchmarking report.[795] This ensures we measure output growth consistently through time and across service providers.

We obtained the historical output growth for Ergon Energy from our Economic Benchmarking RIN. The Economic Benchmarking RIN provides a consistent basis to benchmark the inputs and outputs of each service provider. This allows us to consistently compare the change in output overtime and across service providers.

We calculated forecast output growth based on forecasts obtained from the reset RIN which was prepared on the same basis as the Economic Benchmarking RIN.

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

More information on how we have estimated output growth is discussed in section B.4.4.

Productivity

Our based our change in productivity measure on our expectations of the productivity an efficient service provider in the distribution industry can achieve. We based forecast productivity on analysis from Economic Insights' economic benchmarking analysis.[796] However, we have also assessed whether the historical productivity from 2006–13 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.

---

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

[796] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 38.

In the explanatory statement to our Guideline we noted that we would apply a rate of change to estimate final year opex (taking into account an efficiency adjustment, if required), to account for the shift in the productivity frontier.[797]

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.[798]

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

More information on how we have estimated productivity growth is discussed in section B.4.5.

Other considerations

Interaction with our base opex and step changes

As noted above, we use the rate of change approach in conjunction with our assessment of base opex and step changes to determine total opex. We cannot make adjustments to base opex and step changes without also considering its effect on the opex rate of change, and, in particular, productivity.

For example, if we adjust an inefficient service provider's base we must also set forecast productivity growth to reflect an efficient service provider's productivity growth.

This interrelationship is also important for our step change assessment. Historical data influences our forecast rate of change. Our measured productivity will include the effect of past step changes which typically increase a service provider's inputs. This will lower our measured productivity. If we include an allowance for step changes in forecast opex and we don't take this into account in our productivity forecast, there is a risk that a service provider will be overcompensated for step changes.[799]

Comparison with our previous cost escalation approach

Under our previous approach to setting the trend in opex, we assessed real cost escalations (this is similar to price growth) and output growth separately. We assessed

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

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

[799] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 42.

any productivity growth based on labour productivity for real cost escalations and economies of scale for output growth.

This approach was less robust than our opex rate of change approach because accounting for both labour productivity and economies of scale separately could result in double counting productivity effects.

In practice, this meant that we could either apply labour productivity or economies of scale but not both. In our recent determinations we applied an adjustment for economies of scale rather than labour productivity. However, we noted this approach did not account for all sources of productivity growth and that a single productivity measure would be more accurate.[800]

B.4 Reasons for position

We have separated the sections into the three rate of change component to provide greater detail on how we have estimated our forecast rate of change. Where relevant we have compared these components to Ergon Energy's rate of change using information provided in the reset RIN.

B.4.1 Overall rate of change

We have adopted a higher rate of change than Ergon Energy's to forecast our overall opex. Table B.6 shows Ergon Energy's and our overall rate of change and each rate of change component for the 2015–20 regulatory control period.

This difference is driven by our different forecasts for price growth and productivity growth components.

Our forecast price growth is lower than Ergon Energy's. This is driven by the difference in labour price growth. Ergon Energy used Jacobs' forecast of the average weekly ordinary time earnings (AWOTE) for the Queensland electricity, gas, water and waste services (EGWWS) industry. Whereas, we used an average of Deloitte Access Economics and PricewaterhouseCooper's (PwC) forecast of the wage price index (WPI) for the Queensland EGWWS industry.

There is no material difference between Ergon Energy's and our forecast output growth. Although Ergon Energy's network growth for transformers and substation capacity is higher than the change in maximum demand, this is offset by economies of scale.

Our forecast productivity growth of zero per cent is based on the forecast productivity that can be reasonably achieved by Ergon Energy given our efficiency adjustment to Ergon Energy's base opex. This forecast of productivity is lower than Ergon Energy's forecast productivity growth.

---

800 AER, *Final decision SP AusNet Transmission Determination 2014–15 to 2016–17*, January 2014, pp. 64–65.

However, we consider Ergon Energy's forecast productivity to reflect the 'catch up' to the efficient frontier which is no longer relevant in our alternative opex forecast which assumes an efficient base level of opex. We would expect the productivity growth an efficient service provider could achieve would be less than a service provider not on the frontier.

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

The reasons for the differences between each rate of change component are discussed below.

Table B.6 AER and Ergon Energy's overall rate of change (per cent)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Ergon Energy							
Price growth			0.94	1.24	1.38	1.37	1.25
Output growth			1.51	1.26	1.14	1.12	1.29
Productivity growth			1.00	0.97	0.97	0.96	0.95
Overall rate of change			1.43	1.52	1.54	1.51	1.58
AER							
Price growth	0.24	0.23	0.22	0.46	0.45	0.46	0.48
Output growth	1.08	0.27	1.13	1.40	1.14	1.58	1.27
Productivity growth	–	–	–	–	–	–	–
Overall rate of change	1.33	0.50	1.35	1.86	1.59	2.05	1.76

Source: AER analysis.

B.4.2 Our estimate of the rate of change for 2013–14 and 2014–15

Under our guideline forecasting method, we estimate final year opex as the determined opex allowance for the final year minus the cumulative efficiency gain made up to the base year (which is the underspend in that year). In other words, we take the reported opex in the base year and add the difference between the opex allowance for the final year and the allowance for the base year. This will include price growth included in the allowance for 2013–14.

Thus the opex forecast assumes the distributor makes no efficiency gains after the base year. This allows the distributor to retain the efficiency gains it makes in the final year for five years through the opex forecast. However, because the EBSS will not apply in the 2015−20 regulatory control period, there is no need to estimate final year opex this way. Consequently we have adjusted our opex model to apply the forecast rate of change from the base year (that is 2012–13) not the final year.

B.4.3 Price growth

For the forecast opex price growth we adopted a 62 per cent weighting for labour price and 38 per cent non-labour. Our forecast for the labour price growth is based on forecast WPI of the Electricity, Gas, Water and Waste services (EGWWS) industry and our forecast for no-labour price growth is the CPI.

Table B.7 AER and Ergon Energy's forecast real price growth (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
Ergon Energy					
Utilities labour	1.50	1.61	1.62	1.62	1.62
Professional services	1.40	1.48	1.50	1.48	1.48
Materials	–	–	–	–	–
Overall	0.94	1.24	1.38	1.37	1.25
AER					
Labour	0.36	0.74	0.72	0.74	0.77
Non-labour	–	–	–	–	–
Overall	0.22	0.46	0.45	0.46	0.48

Source: AER analysis; Jacobs, Cost Escalation factors 2015–20, 10 October 2014, p. 37.

The difference in the forecast price growth is driven primarily by the following reasons:

- the opex weighting between labour and non-labour—generally the more weight attributed to labour, the higher price growth. Ergon Energy has a higher proportion of internal labour than us, and
- Ergon Energy proposed a higher labour forecast based on advice from its consultant than our labour forecast.

These two factors are discussed in detail below.

Opex price weightings

Forecast price growth is weighted to account for the proportion of opex that is labour and non-labour.

We have adopted a 62 per cent weighting for labour and 38 per cent for non-labour. The labour component is forecast based on the Electricity, Gas, Water and Waste Services (EGWWS) industry and the non-labour component is forecast based on the consumer price index (CPI).

We have based these weightings on Economic Insight's benchmarking analysis which applied weight of 62 per cent EGWWS wage price index (WPI) for labour and 38 per cent for five producer price indexes (PPIs) for non-labour. The five PPI's cover business, computing, secretarial, legal and accounting, and public relations services.[801] These opex weightings are based on Pacific Economic Group's (PEG) analysis of Victorian electricity distribution service providers' regulatory accounts data.[802]

We consider the weightings from PEG's analysis represent reasonable benchmark weightings for efficient frontier.

In response to our information request, regarding Ergon Energy's labour and non-labour weights for opex, Ergon Energy provided us with its direct opex weights which excluded overheads.[803] Although Ergon Energy did not provide us with the labour and non-labour weights for total opex we can determine Ergon Energy's proportion of labour based on its proposed labour price growth and its overall price growth.

For example, Ergon Energy proposed a labour price growth of 1.62 per cent in 2017–18 and an overall price growth of 1.38 per cent for the same year.[804] Based on our analysis we consider Ergon Energy to have a higher proportion of labour in its opex than us. This higher proportion of labour is a significant driver of the difference between the two forecast price growth.

We have also adopted these output weights in our recent determinations for NSW and ACT distribution determinations.[805] We consider these weightings represent the weightings for a prudent firm because it has been used in previous economic benchmarking analysis by Pacific Economic Group Research and Economic Insights.[806]

Forecast of producer price indices and CPI

For the purposes of forecasting we have applied the forecast CPI rather than forecasts for each PPI. We recognise that the use of PPI's for historical purposes and CPI for forecasts may be inconsistent. However, sensitivity analysis from Economic Insights showed there to be no material difference between using the CPI or PPI in the

---

801 Economic Insights, *Measurement of Inputs for Economic Benchmarking of Electricity Network Service Providers*, 22 April 2013, p. 4.

802 Pacific Economics Group*, TFP research for Victoria's Power Distribution Industry, Report prepared for the Essential Services Commission*, 2004.

803 Ergon Energy, *Response to information request 021*, 31 January 2015.

804 The 0.40 per cent price growth value has been calculated based on the incremental change in price growth component relative to the previous year's proposed opex.

805 AER, *Ausgrid draft decision attachment 7: operating expenditure*, November 2014, p. 221; AER, *Endeavour Energy draft decision attachment 7: operating expenditure*, November 2014, p. 220; AER, *Essential Energy draft decision attachment 7: operating expenditure*, November 2014, p. 219; AER, *ActewAGL draft decision attachment 7: operating expenditure*, November 2014, p. 202.

806 Economic Insights, *Measurement of Inputs for Economic Benchmarking of Electricity Network Service Providers*, 22 April 2013, p. 4.

economic benchmarking results. This is because the change in PPI's follows a similar trend to the change in CPI.[807]

To forecast CPI we adopt the Reserve Bank of Australia's (RBA's) Statement of Monetary Policy and for the years beyond that we apply the mid-point of the RBA's target band. We consider forecasts of the CPI to be more robust than forecasts of the PPI's because the CPI is a more aggregated measure and forecasts of the CPI are more readily available. Further the CPI is subject to the RBA's Statement of Monetary Policy's target band which provides a more robust basis for economists to produce their forecasts. For this reason we have used forecast CPI, rather than PPI's, to forecast the non-labour component of price growth. Economic Insights noted that while the use of these PPIs is likely to be more accurate for historic analysis, it is unlikely to be practical for applications requiring forecasts of the opex price index such as the rate of change. This is because it is very difficult to obtain price forecasts at a finely disaggregated level other than by simple extrapolation of past trends.[808]

If the forecasts of the five PPI's can be forecast with similar accuracy to the CPI, then we would consider the five PPI's to also be an appropriate opex price deflator. However, at this stage we do not consider robust forecasts of the five PPI's are available.

The Consumer Challenge Panel noted that during the current financial year commodities prices have fallen.[809]

Labour price growth

Our choice of the labour price measure seeks to reflect the efficient labour price for an efficient service provider on the opex frontier. To determine the efficient labour price we require a forecast of the benchmark labour price. We consider forecasts of the EGWWS industry, produced by expert forecasters, to be an appropriate benchmark for Ergon Energy's labour price. This is because the EGWWS classification includes labour in the electricity industry and provides a benchmark labour price for comparable staff within the utilities industry. Since Ergon Energy's labour is classified within the EGWWS industry, this provides a reasonable comparison with similar labour.

Labour industries

We consider only EGWWS labour should be applied for the labour component of price growth.

Ergon Energy commissioned opex labour forecasts for the following industries:

---

807 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 13.

808 Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 13.

809 Consumer challenge panel, *Consumer challenge panel (CCP2 panel) submission on Energex and Ergon Energy capex and opex proposals*, 30 January 2015, p. 25. p. 24.

- utilities
- professional services.

The labour price forecasts for these industries are then applied to varying degrees depending on the type of labour.[810]

The Australian Bureau of Statistics (ABS) previously advised:

> ... regardless of the type of job, if the job was selected from a business classified to the electricity, gas, water and waste services industry, the jobs pay movements contributes to this industry.[811]

The ABS takes into account the nature of the business, not the nature of the work undertaken, when allocating a job to an industry. The ABS labour price statistics for the EGWWS industry reflects both specialised electricity distribution network related labour and general labour.

We consider regardless of the nature of the task, if labour is employed by a business that operates in the utilities industry, then it should be escalated by the EGWWS industry forecast. For this reason we have adopted the EGWWS classification for all labour.

Choice of labour forecast

To forecast labour we have adopted the average of Deloitte Access Economics and PricewaterhouseCoopers wage price index (WPI) forecasts for the EGWWS sector proposed by Energex. We do not consider Ergon Energy's AWOTE based forecasts to be a reasonable forecast of the labour price under our benchmarking approach.

The sections below discuss why we prefer WPI over AWOTE under our benchmarking approach and how we have forecast an alternative labour price measure based on other sources of data.

Forecast AWOTE

In our Guidelines we noted that the difference between using AWOTE and the WPI would be reduced if the corresponding productivity measure matches the labour price measure.[812]

The AWOTE includes price growth for changes in the compositional of labour. That is, it captures the price impact of using more or less higher skilled labour. Meanwhile, the WPI holds the composition of the work force constant and attempts to capture the price of a standard work week of labour of a given classification.

---

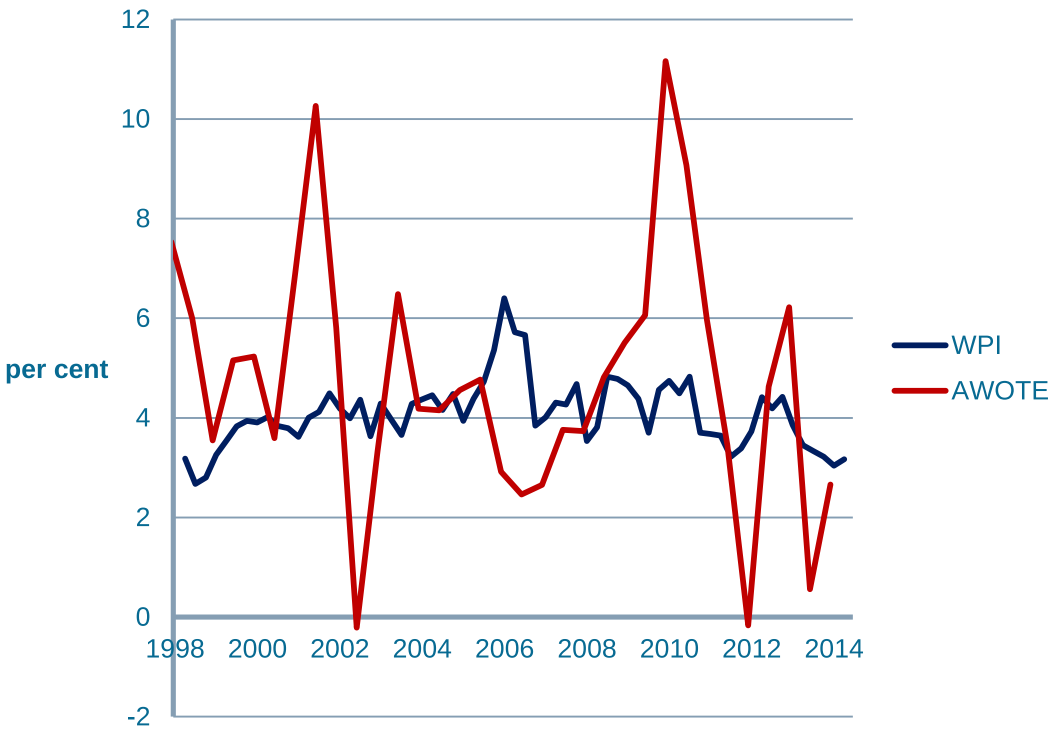
810 Ergon Energy, *Forecast expenditure summary – operating costs*, 31 October 2014, p. 23

811 ABS, *Email from Kathryn Parlor to Fleur Gibbons*, 8 July 2010.

812 AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 30.

Due to the inclusion of compositional productivity, AWOTE tends to be more volatile than the WPI. This makes it more difficult to forecast. This volatility can be seen in Figure B.1, which shows the AWOTE and WPI for the EGWWS industry from 1998 to 2014.

Figure B.1 EGWWS AWOTE and WPI 1998–2014 (per cent)



Source: ABS 6302.0 table 10H, ABS 6345.0 table 9b and AER analysis.

We have used WPI in previous decisions, given concerns about the volatility of the AWOTE.[813] We do not consider there to be sufficient advantages to using the AWOTE over the WPI for us to change our established methodology of using an average of available consultant forecasts of the EGWWS WPI.

In regards to the long term trend of labour price, Jacobs noted the growth in unit labour prices trend near CPI. In other words, the growth in an average worker's wages is approximately equal to CPI plus labour productivity improvements.[814]

We agree that over the long term, productivity adjusted labour should be equal to CPI. We note that Ergon Energy has not explicitly applied a productivity adjustment that includes compositional productivity.

---

[813] AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2012, pp. 57–59.

[814] Jacobs, *Cost escalation factors 2015–20*, 10 October 2014, p. 31.

Forecast WPI

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.

This is based on our previous analysis in relation to SP AusNet's gas distribution network which was corroborated by Professor Borland.[815] When considering appropriate labour price growth forecasts for the SP AusNet gas distribution network we adopted an average of the forecasts prepared by Deloitte Access Economics (DAE) and BIS Shrapnel. We took this approach because DAE typically forecasts lower than actual WPI and BIS Shrapnel typically forecast higher than actual WPI for the Australian EGWWS sector.

Previous analysis by DAE and the AER showed that DAE under forecasted price growth at the national level. In contrast BIS Shrapnel over forecasted price growth and by a greater margin.[816]

We previously adopted the average of the forecasts from BIS Shrapnel and DAE to obtain a labour price measure for SP AusNet's gas distribution network.[817]

We also averaged DAE and Independent Economics forecasts for the NSW and ACT electricity distribution networks.[818]

Ergon Energy did not provide an alternative WPI forecast. However, Energex commissioned PricewaterhouseCoopers to forecast the WPI for the Queensland EGWWS industry.[819]

PwC's forecast of the Queensland EGWWS sector is based on the Queensland Treasury and Trade (QTT) forecasts, produced as part of its annual budgeting processes. The QTT forecasts from 2014–15 to 2016–17 and PwC considered that QTT's forecast of 3.5 per for 2016–17 is likely to reflect the broader market trends to 2019–20.[820]

The QTT's methodology for forecasting the wage price index is not discussed in detail in its Budget Strategy and Outlook papers. However, we see no reason to discount the QTT's forecast since they broadly reflect the current market conditions.

---

815 AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17, Part 3: Appendices*, March 2013, p. 7.

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

817 AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17, Part 3: Appendices*, March 2013, p. 7.

818 AER, *Ausgrid draft decision attachment 7: operating expenditure*, November 2014; AER, *Endeavour Energy draft decision attachment 7: operating expenditure*, November 2014; AER, *Essential Energy draft decision attachment 7: operating expenditure*, November 2014; AER, *ActewAGL draft decision attachment 7: operating expenditure*, November 2014.

819 AER, *Energex preliminary decision attachment 7*.

820 PricewaterhouseCoopers, *Forecast cost escalation rates*, 4 March 2014, p. 15.

However, DAE forecasts Queensland WPI to be higher than the WPI for the Queensland utilities sector.[821] This indicates that using a forecast of Queensland WPI to forecast Queensland utilities may result in an upwardly biased forecast.

We note our consultant DAE's has previously under forecast the EGWWS WPI at the national level.[822] We consider an average of PwC's and DAE's forecast would offset this bias and produce the best forecast available of the Queensland EGWWS WPI.

The Queensland Council of Social Service (QCOSS) noted that Ergon Energy's proposed labour price growth are too high based on the current economic climate and expect wage growth to be at or below inflation.[823]

SPA Consulting considers that the end of the mining boom made it easier to obtain skilled labour at more competitive rates and that Ergon Energy's enterprise bargaining agreement do not reflect the wages of an open labour market.[824]

The Consumer Challenge Panel (CCP) noted that the electricity industry is in contraction due to declining demand for its services and consider labour price increases in excess of CPI are likely to have placed too heavy a reliance on the use of historical trends to predict future trends.[825]

The CCP further noted that the Queensland Government Independent Review Panel on Network Costs found that Queensland NSPs' labour costs are significantly higher than they should be, and must ensure that EBA outcomes are not treated as a "pass through."

We note that the labour price growth we have applied use current economic data to forecast and they reflect current market conditions. We note that neither Ergon Energy nor our proposed labour price growth directly uses Ergon Energy's EBA outcomes.

Labour productivity

Our preferred approach to productivity is to adopt an overall electricity distribution specific productivity adjustment rather than adjusting the forecast EGWWS labour price growth for EGWWS labour productivity.

---

[821] Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, pp. 9, 11.

[822] AER, *Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17, Part 3: Appendices*, March 2013, p. 7.

[823] Queensland Council of Social Service, *Understanding the long term interests of electricity customers*, 30 January 2015, p. 67.

[824] SPA Consulting, *Submission to the Australian Energy Regulator: Queensland distribution determination for the period 2015–20*, 30 January 2015, p. 4.

[825] Consumer challenge panel, *Consumer challenge panel (CCP2 panel) submission on Energex and Ergon Energy capex and opex proposals,* 30 January 2015, p. 24.

Independent Economics supported the use of electricity distribution specific productivity rather than EGWWS wide productivity:[826]

> There are significant difficulties in measuring productivity in the utilities sector generally and the electricity distribution sector in particular. Hence, it is suggested adjusting for productivity is better undertaken on the basis of a detailed assessment of specific sources of productivity gains within the industry rather than attempting to infer productivity gains using the broader data published by the ABS.

Since the data for a distribution industry specific productivity measure is available from our economic benchmarking analysis, and this is preferred over an EGWWS labour productivity adjustment, we have applied a distribution industry specific measure.

We further discuss how we have accounted for productivity in section B.4.5

B.4.4 Output growth

Ergon Energy proposed a different methodology than our own to forecast output growth. However, once economies of scale are excluded there is no material difference between Ergon Energy's forecast output growth and our own.

We have adopted the following output growth measures and their respective 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 in our opex cost function analysis to measure productivity. This approach is consistent with our Forecast Expenditure Assessment Guidelines.[827]

The outputs measures chosen by Economic Insights were based on three selection criteria.

First, the output aligns with the NER objectives. The NER expenditure objectives for both opex[828] and capex[829] are to:

- meet or manage the expected demand for standard control services over that period

826 Independent Economics, *Labour cost escalators for NSW, the ACT and Tasmania*, 18 February 2014, p. 6.

827 AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 23.

828 NER, cl. 6.5.6(a).

829 NER, cl. 6.5.7(a).

- comply with all applicable regulatory obligations or requirements associated with the provisions of standard control services
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
    i. the quality, reliability or security of supply of standard control services
    ii. the reliability or security of the distribution system through the supply of standard control services.
- to the relevant extent:
    iii. maintain the quality, reliability and security of supply of standard control services
    iv. maintain the reliability and security of the distribution system through the supply of standard control services
- maintain the safety of the distribution system through the supply of standard control services.

Second, the output reflects services provided to customers.

Third, only significant outputs should be included. While service providers provide a wide range of services, costs are dominated by a few key outputs. Only those key outputs should be included to keep the analysis consistent with the high level nature of economic benchmarking.[830]

The process for selecting the output specification is discussed in our base opex appendix (Appendix A) and Economic Insights' benchmarking report.[831]

Our rate of change approach assumes any change in output results in the same proportional change in opex. For example, a 10 per cent increase in weighted average output results in a 10 per cent increase in opex.

Table B.8 shows Ergon Energy's and our forecast output growth. The differences in the magnitude and methodology of Ergon Energy's and our output growth are discussed below.

---

[830] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, p. 9.

[831] Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs*, 20 October 2014, pp. 9–12.

Table B.8 AER and Ergon Energy's forecast output growth

	2015 –16	2016 –17	2017 –18	2018 –19	2019 –20
AER (per cent)	1.13	1.40	1.14	1.58	1.27
AER (cumulative)	1.0113	1.0254	1.0371	1.0535	1.0669
Ergon Energy (per cent)	1.51	1.26	1.14	1.12	1.29
Ergon Energy (cumulative)	1.0151	1.0278	1.0395	1.0511	1.0647

Source: AER analysis, Ergon Energy reset RIN.

Overall Ergon Energy's output growth is nearly the same as ours even though it has included economies of scale in its forecast output growth.

Ergon Energy's output growth methodology cannot be directly compared to our output growth because its methodology accounts for economies of scale. We consider economies of scale to be a part of productivity. As discussed in our Guidelines we do not make an explicit adjustment for economies of scale due to the risk of double counting different sources of productivity.[832]

Table B.9 shows Ergon Energy's proposed network growth drivers, excluding economies of scale, and the AER's equivalent output growth components.

Table B.9 Ergon Energy and AER network growth drivers (per cent)

	2015–16	2016–17	2017–18	2018–19	2019–20
Ergon Energy					
Lines—total overhead and underground	0.26	0.28	0.26	0.14	0.14
Capacity of zone substations	1.90	0.40	0.29	0.38	1.27
Distribution Transformers	2.10	2.29	2.10	2.08	2.08
AER					
Circuit length	0.26	0.28	0.26	0.14	0.14
Ratcheted maximum demand	–	0.77	–	2.14	0.68

Source: Ergon Energy, *06.01.01 Forecast expenditure summary—Operating costs*, October 2014, p. 21 and AER analysis

In raw output growth terms Ergon Energy's network drivers (zone substation capacity, line length and distribution transformers) are slightly higher than our output growth (line length and ratcheted maximum demand).

832 AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 36.

Our forecast customer growth rate is the same as Ergon Energy's. Customer growth accounts for 67.6 per cent of our forecast output growth, Customer growth also accounts for a significant proportion of Ergon Energy's forecast output growth because the customer growth driver has been applied to its overheads which forms 26 per cent of Ergon Energy's opex.

To measure output growth we used ratcheted maximum demand rather than a combination of zone substation capacity and distribution transformers. Ratcheted maximum demand represents the actual capacity a service provider must have to meet its customer's needs whereas zone substation capacity and transformers represent the amount of infrastructure a service provider must build to meet the capacity.

In this case, both measures produce a similar result. However, we recognise that in some circumstances these two measures can vary significantly. Due to the lumpy nature of capex, a service provider may build to meet future increases in maximum demand, this may result in a higher growth rate for capacity in the short term as more than the required amount of assets are being built. However, over the long term an efficient service provider will construct the necessary amount of assets in line with changes in ratcheted maximum demand.

We also consider applying benchmark weights for output growth to be more representative of the benchmark output growth than Ergon Energy's methodology of attributing specific growth drivers to each functional opex area. This is because Ergon Energy may not necessarily have the same break down in its functional areas as the benchmark service provider. However, in these circumstances it does not significantly contribute to the difference between Ergon Energy and our output growth.

CCP does not accept that a proportional increase in the weighted average output growth would result in the same increase in opex. The CCP also strongly disagrees with the proposed installed capacity factors. It noted that newer assets should result in lower maintenance costs. The CCP considers output growth factors should be determined on a consistent basis across all distributors.[833]

We note that we use the proportional increase for the weighted average output growth as a starting point and productivity is accounted for as a separate rate of change component. We also note that our output growth methodology uses the same output specification for all distributors. We then use the actual weighted average output growth using the distributor's reset RIN forecasts and the output weights from the opex cost function.

B.4.5 Productivity growth

We have applied a zero per cent productivity growth in estimating our overall rate of change. We base this on Economic Insights' recommendation to apply zero forecast

[833] Consumer challenge panel, *Consumer challenge panel (CCP2 panel) submission on Energex and Ergon Energy capex and opex proposals*, 30 January 2015, p. 25.

productivity growth for the distribution network service providers and our assessment of overall productivity trends for the forecast period.[834]

Ergon Energy proposed a higher productivity growth than ours. As noted above, Ergon Energy included economies of scale and a one per cent per annum productivity growth factor applied to all direct and support costs.[835]

Our Guidelines state that we will incorporate forecast productivity in the rate of change we apply to base opex when assessing opex. The forecast productivity growth will be the best estimate of the shift in the productivity frontier. [836]

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 took into account all available information. This includes Economic Insights' economic benchmarking, Ergon Energy's proposal, our expectations of the distribution industry in the short to medium term, and observed productivity outcomes from electricity transmission and gas distribution industries.

We have applied a zero productivity growth forecast for Ergon Energy for the following reasons:

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

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

Forecast outlook and historical productivity

As noted above, the forecast productivity is our best estimate of the shift in the frontier for an efficient service provider. Typically we consider the best forecast of this shift would be based on recent data. However, this requires a business as usual situation

[834] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 8 September 2014, p. 52 and Economic Insights, Response to consultants' reports on economic benchmarking of electricity DNSPs, 13 April 2015, p. 74.

[835] Ergon Energy, *Forecast expenditure summary – operating costs*, 31 October 2014, p. 24.

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

where the historical data is representative of what is likely to occur in the forecast period.[837]

Analysis from Economic Insights using MTFP and opex cost function models showed that from 2006 to 2013, the distribution industry experienced negative productivity growth.[838] This means that for 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.[839]

However, total input quantity increased by 2.8 per cent per annum from 2010 to 2013.[840] This has been driven by substantial increases in both opex and capital inputs.

We note past step changes will also decrease measured productivity, since 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.[841]

We consider the increase in bushfire safety requirements to be a one off step increase in the cost of compliance. We do not expect there to be a similar increase in the cost of bushfire safety requirements in the forecast period.

---

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

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

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

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

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

We also approved a $35.5 million ($2009–10) step change for SA Power Networks' vegetation clearance pass through as a result of changing weather conditions.[842]

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. We assess any new step changes in our step change assessment.

Other industries and proposed productivity

In estimating forecast productivity for the distribution industry we have also had regard to the electricity transmission and gas distribution industry, and distribution network service provider's productivity forecasts.[843]

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.

Further both the electricity transmission and gas distribution industries experienced positive opex productivity growth during the 2006–13 period.[844] For electricity transmission network service providers average industry productivity was 0.86 per cent and for gas distribution Jemena Gas Networks proposed an average opex productivity of 0.95 per cent of which 0.83 per cent was attributed to the shift in the frontier.[845]

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 productivity growth rates comparable to the electricity transmission and gas distribution industries.

---

[842] 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.

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

[844] 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.

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

Energex proposed $36 million in productivity savings[846] in addition to its economies of scale.

We also note Ergon Energy, SA Power Networks, ActewAGL and the NSW distributors forecast zero or positive productivity for the forecast period. Further, several forecasts indicated that increases in output will be offset by efficiency improvements. For example, ActewAGL forecast economies of scale will offset most of their output growth.[847]

Ergon Energy proposed $17 million in productivity savings.[848]

SA Power Networks and Essential Energy proposed zero per cent productivity growth.[849] Ausgrid proposed productivity savings of $47 million[850] for its standard control services.

The CCP noted that the distributors' past poor productivity performance, which the CCP considers to be due to inefficient labour practices, must not be used to justify poor productivity outcomes in future years. The CCP noted that many other asset intensive industry sectors experienced positive opex productivity growth during 2006–13 period. The CCP does not consider there is any justification for the electricity distribution sector to have lower productivity expectations than those sectors.[851]

We consider if there is robust evidence provided to us to support positive productivity in industries that are comparable to the electricity distribution industry. We will take this evidence into our consideration in assessing forecast productivity.

---

846 Energex, *2015–20 Reset RIN table 2.16.1*. To calculate the total, we have summed all the annual incremental productivity values.

847 ActewAGL, *Regulatory proposal 2015–19 Subsequent regulatory control period*, 10 July 2014, p. 233.

848 Ergon Energy, *2015–20 Reset RIN table 2.16.1*. To calculate the total, we have summed all the annual incremental productivity values.

849 Essential Energy, 2014–19 *Reset RIN* table 2.16.1 and SA Power Networks, 2015–20 Reset RIN table 2.16.1.

850 Ausgrid, *2014–19 Reset RIN* table 2.16.1.

851 Consumer challenge panel, *Consumer challenge panel (CCP2 panel) submission on Energex and Ergon Energy capex and opex proposals*, 30 January 2015, p. 25.

C Step changes

In developing our alternative opex forecast, 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 our alternative forecast, such as our estimate of base opex or the rate of change.

This appendix sets out our consideration of step changes in determining our opex forecast for Ergon Energy for the 2015–20 regulatory control period.

C.1 Position

We have not included any step changes in our alternative opex forecast. We are not satisfied that adding step changes for the cost drivers identified by Ergon Energy would lead to a forecast of opex that reasonably reflects the opex criteria.

A summary of the revenue impact is outlined below in Table C.1.

Table C.1 Preliminary position on step changes ($ million, 2014–15)

	Ergon Energy proposal	AER position
Proposed step changes		
Non-network ICT	53.7[852]	–
Non-network alternatives (demand management)	18.4	–
Bottom-up adjustments		
Parametric insurance	60.3	–
Non-recurrent expenditure		
Remediation of contaminated land	6.3	–
Regulatory reset costs	6.3	–
Overheads allocated to opex	26.3	–

[852] We note non-network ICT is an overhead and only a portion of this is allocated to standard control opex. Ergon Energy did not identify the allocation of this step change to opex. This amount represents the total cost of the overhead rather than the opex for standard control services.

C.2 Ergon Energy's proposal

Ergon Energy proposed:

- two step changes above its base level of standard control services opex for non-network ICT and non-network alternatives.[853]
- two non-recurrent expenditure adjustments, for remediation of contaminated land and regulatory reset costs. Ergon Energy noted that these adjustments differ from step changes because these adjustments are made in one or multiple years rather than on an ongoing basis.[854]
- one bottom-up adjustment for parametric insurance that was not part of its base year operating expenditure.[855]

The total revenue impact of Ergon Energy's proposed step changes, non-recurrent expenditure adjustments and bottom-up adjustment for parametric insurance was $145.0 million ($2014–15).

In addition to the step changes and base year adjustments, Ergon Energy also allocated an increase in overhead expenditure to opex over the 2015–20 regulatory control period due to its reduced capex program. The total revenue impact of the increase in overheads allocated to opex was around $26.3 million.[856]

We consider all of these adjustments function as step changes for the reasons explained in our assessment approach section below. We have assessed them as step changes in formulating our alternative opex forecast.

We note that the CCP stated that the step changes proposed by Ergon Energy would be accounted for in our determination of efficient base year opex and expect us to decline them.[857]

C.3 Assessment 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.[858] Our assessment approach is consistent with the approach specified in our Expenditure

853 Ergon Energy, *Attachment 06.01.01: Operating expenditure summary operating costs*, 6 December 2013, p. 17.

854 Ergon Energy, *Attachment 06.01.01: Operating expenditure summary operating costs*, 6 December 2013, p. 15.

855 Ergon Energy, *Attachment 06.01.01: Operating expenditure summary operating costs*, 6 December 2013, p. 26. Ergon Energy included other bottom up adjustments that are not considered as step changes under our assessment approach. The bottom up adjustment for SPARQ non capital project costs and asset service fees are discussed in our forecasting methodologies section. The demand management innovation allowance is discussed in our demand management incentive scheme section. The TUOS charges for Chumvale and Powerlink are discussed in our pricing proposal section.

856 AER calculation.

857 Consumer Challenge Panel (CCP2), *Submission on Energex and Ergon Energy capex and opex proposals*, 30 January 2015, p. 26.

858 NER, cl. 6.6.5(c).

forecast assessment guideline (the Guideline).[859] As a starting point in our assessment, we consider whether the proposed step changes in opex are already compensated through other elements of our opex forecast, such as the base opex or the 'rate of change' component. Step changes should not double count costs included in other elements of the opex forecast.

We generally consider a base level of opex consistent with the opex criteria is sufficient for a prudent and efficient service provider to meet all existing regulatory obligations. This is the same regardless of whether we forecast base level of opex based on the service provider's own costs or the benchmark operating expenditure that would be incurred by a prudent and efficient provider. 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.

In our base opex appendix A, we concluded that Ergon Energy's revealed base year costs were not consistent with the opex criteria. Therefore we have estimated an alternative base opex, consistent with the opex criteria, for the purpose of formulating our alternative total opex forecast for the 2015–20 regulatory control period. We refer to this as our estimate of base opex.

We forecast opex by applying an annual 'rate of change' to our estimate of base opex for each year of the forecast regulatory control period. 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 our estimate of base opex. 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. For example, a step change is not required for the maintenance costs of new office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year) to account for forecast network growth.[860]

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

[859] AER, *Expenditure assessment forecast guideline*, November 2013, pp.11, 24.

[860] AER, AER, *Expenditure assessment forecast guideline - Explanatory Statement*, 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.

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

Further to assessing 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 our estimate of base opex and the rate of change) that the service provider has proposed. In particular we have regard to:[861]

- whether there is a change in circumstances that affects the service provider's efficient forecast expenditure
- 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 making the step change and whether the proposal appropriately quantified all costs savings and benefits
- when this change event occurs and when it is efficient to incur expenditure, including whether it can be completed over the regulatory control period
- whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.

One important consideration is whether each proposed step change is driven by an external obligation (such as new legislation or regulations) or an internal management decision (such as a decision to increase maintenance opex). Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control. 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.[862] 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 over time if it is efficient. This means we will not allow step changes or change factors for any short-term cost to a service provider of implementing efficiency improvements. We expect the service

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

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

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

As noted above, Ergon Energy classified many changes in costs as non-recurrent expenditure or bottom-up adjustments rather than as step changes.

We state in our Expenditure forecast assessment guideline that we may add (or subtract) step changes for any costs not captured in our estimate of base opex or the rate of change that are required for forecast opex to meet the opex criteria.[864] Ergon Energy proposed these base year adjustments and non-recurrent expenditure because the amount of expenditure in its base year was not representative of its expectation of expenditure in the 2015–20 regulatory control period. Consequently, if these adjustments are required for the opex forecast to meet the opex criteria, we would add (or subtract) them as step changes in our alternative forecast.[865]

As noted, above we will have regard to a number of factors in assessing these proposed increments to base opex including the driver for the proposed expenditure, the efficient and prudent costs of the proposed expenditure and whether the costs can be met from other elements of the expenditure forecast.

C.4 Reasons for position

We have not included any step changes in our alternative opex forecast. We did not consider the step changes listed in Table C.1 reflect a change in regulatory obligations or an efficient capex/opex trade-off. We outline our reasons for this position below.

C.4.1 Non-network ICT

We have not included an increase in forecast opex associated with non-network Information Communication and Technology (ICT) in our alternative opex forecast.

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

864 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

865 We would adjust base opex rather than add a step change where we don't think the reported opex reflects the actual standard control service expenditure as classified in the forecast period. For example we would not assess a change in service classification as a step change.

Ergon Energy proposed a $51.0 million[866] ($2012–13) step change for non-network ICT overheads expenditure not reflected in its 2012–13 revealed base year. Ergon Energy noted that some of this step change was for support functions for ICT capital works that were approved for the 2010–15 regulatory control period but it did not implement the new ICT functionality until after 2012–13.[867]

We consider that ICT opex is a business as usual cost that a prudent service provider acting efficiently to deliver standard control distribution services would incur. We do not consider a step change is necessary as our estimate of base opex already provides a sufficient funding for Ergon Energy acting as a prudent service provider to efficiently deliver standard control distribution services, given its operating environment.

We also note that any change in overheads as a result of a change in outputs, for example for more ICT expenditure because of a growth in Ergon Energy's customer base, will be compensated through our opex rate of change.

The Council on the Aging (COTA) submitted that the ICT step change represents a significant increase in ICT opex and proposed that we should verify the benefits of the capex and ensure the reasonableness of the proposed charges based on competitive market rates.[868] We do not consider this to be necessary as we have already reached a view on the total opex that would reasonably reflect the efficient cost of meeting Ergon Energy's regulatory obligations.

C.4.2 Non-network alternatives (demand management)

We have not included a step change in our alternative opex forecast for Ergon Energy's demand management step change. We are not satisfied that this step change results in an efficient opex/capex trade-off.

Ergon Energy proposed a 'non-network alternatives' step change of $17.5 million ($2012–13) to avoid augex through demand management.[869]

We do not consider this step change is an efficient capex/opex trade-off for the following reasons:

- It was not clear what programs or projects would be funded by the $17.5 million ($2012–13) in additional demand management expenditure.
- The overall benefit of Ergon Energy's demand management program, in terms of capex reductions, was not clear.

We also note that Ergon Energy has included broad based demand management (BBDM) programs in its demand management program. If efficient, the main benefits of

---

[866] We note this amount represents the total cost of the overhead rather than just the proportion of the overhead allocated to opex for standard control services.

[867] Ergon Energy, *Attachment 06.01.04: Step changes for operating costs*, 31 October 2014, p. 3.

[868] COTA, *Submission to Ergon regulatory proposal*, 30 January 2015, p. 3.

[869] Ergon Energy, *Attachment 06.01.04: Step changes for operating costs*, 31 October 2014, p. 11.

demand management arise from capex deferral. We have some concerns that BBDM programs do not adequately target capex deferral.

Our assessment of this step change is outlined below.[870]

Evidence to support step change

We consider the reasons for Ergon Energy's non-network alternatives step change are not clear.

In response to our information request Ergon Energy noted that the step change increase related to:

- the assumption that external funding would not be available in the next regulatory control period
- carry over from previous 2010–15 programs, and
- the changing demand management program and reallocation of network embedded generators which results in a $2.5 million reduction ($2012–13) in opex.[871]

We note that Ergon Energy did not identify which demand management programs this step change would fund. Rather Ergon Energy noted that it allocated this step change across its committed works and planned programs.[872]

Although we requested the cost benefit analysis relating to the step change, Ergon Energy only provided the overall benefits of its committed works and planned programs.[873] For us to include Ergon Energy's non-network alternatives step change in our alternative opex forecast we would need to be satisfied that the proposed increment is efficient. We consider demand management opex can be a valid alternative to capex. However in the absence of evidence to show that it is an efficient opex/capex trade-off we cannot include an increase in opex for demand management in our alternative opex forecast.

Ergon Energy's cost benefit analysis

It is not clear to us what capex reductions will result from Ergon Energy's proposed demand management opex.

Ergon Energy noted that its total demand management opex of $60.5 million would offset its capital works program by $70–$200 million in real terms over the forecast period.[874]

---

870 We have assessed Ergon Energy's existing demand management in the context of our operating environment factors (OEF) and Ergon Energy's capitalisation practices. For more detail refer to appendix A. In this appendix we are only assessing the proposed increment to Ergon's base opex.

871 Ergon Energy, *Response to AER information request 015*, 20 January 2015, p. 3.

872 Ergon Energy, *Response to AER information request 015*, 20 January 2015, p. 4.

873 Ergon Energy, *Response to AER information request 015*, 20 January 2015, p. 5.

874 Ergon Energy, *Demand management overview 2015–2020*, 31 October 2014, p. 43.

However, we consider the calculations Ergon Energy undertook to identify the benefit of its demand management program contained several errors.

For example, Ergon Energy calculated the benefits of its new demand management programs based on an extrapolation of the benefits achieved in its 2012–13 programs.[875] We note that Ergon Energy has mistakenly multiplied the total benefits of its demand management over 2015–20, rather than the annual benefits, by five.

Similarly Ergon Energy presented annualised NPV benefits of each of its demand management programs in table 3 of its Demand Management Overview 2015–2020 attachment where in fact these are the total benefits of the projects.[876]

We would expect Ergon Energy as a part of its revised proposal to provide the costs of the benefits of its demand management step change.

Broad based demand management and indirect benefits

Ergon Energy currently undertakes several BBDM projects. BBDM relates to demand management programs aimed at a broad penetration of load reduction rather than targeting a localised capacity constraint.

We consider that demand management should be targeted and should only include costs where customers directly benefit. The benefits of BBDM on deferred capex is not clear and we consider only opex that directly translates to a quantified decrease in capex should result in an efficient opex/capex trade-off. We also note that only a portion of BBDM will have a benefit in deferring augex because the reduction in maximum demand may not be where the augex is required.

C.4.3 Remediation of contaminated land and regulatory reset costs

We have not included a step change in our alternative opex forecast for Ergon Energy's remediation of contaminated land. We do not consider a step change is necessary as our estimate of base opex already provides a sufficient allowance for Ergon Energy acting as a prudent service provider to meet all its existing regulatory obligations.

To comply with the *Environmental Protection Act 1994 (Qld)* Ergon Energy completed a project that details a list of 145 sites with extreme or high risk potential for contamination. Ergon Energy proposed more opex to lower the risks associated with contamination across Ergon Energy's portfolio of land. Ergon Energy expects that after 2020 this expense will no longer be required.[877]

[875] Ergon Energy, *Response to AER information request 015*, 20 January 2015, p. 7.

[876] We note table 3 of Ergon Energy's Demand management outcomes report 2012/13 reports the annual benefits.

[877] Ergon Energy, *Attachment 06.01.01: Operating expenditure summary operating costs*, 6 December 2013, p. 16.

As outlined in our assessment approach we are required to assess whether total opex reasonably reflects each of the opex criteria.[878] We recognise a service provider may at different times need to spend relatively less or more opex to meet some existing regulatory obligations. However, we already estimate a base level of opex which we consider reasonably reflect the cost of meeting these obligations or requirements. We do not consider we need to increase total opex just because expenditure on program or project may change.

For instance, while total opex is relatively recurrent, categories of opex, or opex on projects and programs are not recurrent. That means each year a service provider could spend more opex on some areas (such as remediation of contaminated land) and less opex on other areas. A prudent and efficient service provider could achieve compliance with existing regulations by redirecting funds from categories of opex which were expected to decline in the forecast regulatory control period. Alternatively it could do this by reprioritising its opex budget. We do not agree that a prudent and efficient service provider would need to seek additional funding from consumers above our estimate of base opex.

For the same reason as above we have not included a step change for regulatory reset costs. Ergon Energy stated that its 2012–13 base year did not include any regulatory reset costs as it begins to incur associated costs one year prior to the submission year and in the submission year.[879] As outlined above, while regulatory reset costs are one cost category that may increase relative to the base year, there are likely to be other costs that will decline. We are not convinced that our total opex forecast would need to change just because this one category of cost is expected to increase relative to the base year.

C.4.4 Parametric insurance

We have not included a step change in opex of $57.2 ($2012–13) million for Ergon Energy's parametric insurance costs in our alternative opex forecast.

Ergon Energy forecast opex for parametric insurance. This insurance is intended to provide some protection for Ergon Energy against the costs of cyclones and storms. Ergon Energy stated that historically it has not insured its electricity network assets against major damage or loss caused by storms and cyclones. This is because of a lack of available and efficiently priced insurance cover in the insurance markets. It has sought to rely on cost pass through mechanisms, where appropriate.[880] Typically, distribution network service providers are not able to, or do not deem it efficient to insure pole and wire assets, and therefore Ergon Energy is not unusual in this regard.

Parametric insurance provides organisations with a predetermined payment contingent on an exogenous trigger event, or parameter, which generally needs to be validated by

878 NER, cl. 6A.6.6(c).

879 Ergon Energy, *Attachment 06.01.01: Operating expenditure summary operating costs*, 6 December 2013, p. 16.

880 Ergon Energy, *Attachment 06.01.01: Operating expenditure summary operating costs*, 6 December 2013, p. 30.

an independent third party. Parametric insurance does not operate like traditional insurance to indemnify organisations for the actual loss incurred. It operates to provide a specific payment intended to cover part or all of the loss incurred and without any need to prove that assets are actually damaged and that costs are incurred to repair and replace them.

In assessing the costs for the proposed parametric insurance, consistent with our guideline approach, we have regard to:[881]

- what options were considered to respond to the change in circumstances
- whether the option selected was the most efficient option
- the efficient costs associated with making the step change and whether the proposal appropriately quantified all costs savings and benefits.

Ergon Energy sought quotes from two insurers. The details of the quotes are commercial in confidence so we cannot present them in this appendix.

We sought advice from AM Actuaries to whether it considered the cost of the proposed insurance appears reasonable given the risks and possible costs associated with storms and cyclones in Northern Queensland. AM Actuaries considered that the cost of the proposed insurance does not appear reasonable for several reasons.

- Even if a payment is triggered and losses are sustained, there is limited connection between the actual loss sustained and the insurance payment, hence providing limited financial protection. For example, it is possible the contract may not respond in the event of loss.
- Even if the cover responded more closely to the actual loss caused by storms, because the expected return to Ergon Energy is only half of the contract premium, AM Actuaries considered the cost is not reasonable in view of the limited protection it provides. AM Actuaries stated that while the cost is consistent with traditional insurance and provides cover in excess of that available from the traditional market, the cover is still capped and may not respond to significant loss. This is due to the relatively narrow event triggers and disconnect to actual losses occurred.
- The proposal does not appear to respond to other “storm” related natural disasters (for example, tornado and storm surge[882]). As a result, the proposed insurance may provide limited or no financial protection against losses from some cyclones or storms
- AM Actuaries considered Ergon Energy did not sufficiently assess the parametric insurance option against the alternative option of self-insurance. It considered Ergon Energy is well placed to retain a significant level of risk and finance

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

[882] Storm surge generated by a cyclone could occur and result in damage, but the cyclone may not make landfall and hence not trigger payment.

substantial losses given its level of assets and post-tax profits over the past three years. It considered a fuller discussion should include consideration of Ergon Energy’s financial capacity and limits for risk retention in accordance with its risk appetite and risk management practices.

We have not included a step change in opex of $57.2 million ($2012–13) for Ergon Energy's parametric insurance costs in our alternative opex forecast. This is for several reasons.

We note AM Actuaries advice that states the parametric insurance contract may pay out when Ergon Energy incurs no loss or may not compensate in the event of loss. We also note that even if a payment is triggered and losses are sustained, there is limited connection between the actual loss sustained and the insurance payment. We are concerned that consumers may pay $60.9 million to transfer cyclone and storm risk to a third party but in the event of a cyclone they may still bear some or most of the cost of the cyclone. That is, even if a cyclone occurs, it is possible given the nature of the triggers, no payment will be made, or it will be triggered but not cover the full cost of the storm damage. In such a case Ergon Energy may still be eligible to apply for a cost pass through.

We are also not satisfied that Ergon Energy has sufficiently demonstrated that it would be more efficient to buy parametric insurance than to self insure (retain) the risk. Given the cost of the insurance, the expected payout and the size of Ergon Energy's asset base, we consider Ergon Energy has not provided us with sufficient evidence to convince us that it is more efficient for it to purchase parametric insurance than to continue to self insure.

C.4.5 Increased overheads allocated to opex

We have not included Ergon Energy's forecast increase in opex overheads in our alternative opex forecast. We do not consider that adding these costs to our alternative opex forecast would lead to a forecast of opex that reasonably reflects the opex criteria.

Ergon Energy's opex forecast incorporates a significant increase in opex overhead expenditure over the 2015–20 regulatory control period. Ergon Energy allocates its overheads between opex and capex based on their respective share of total expenditure. Because Ergon Energy proposed a reduced capex work program, the opex share of total expenditure, and hence the overheads allocated to opex, are forecast to increase.

We estimate the share of overheads Ergon Energy has allocated to opex increases from 21.5 per cent in 2012–13 to 24.3 per cent in 2019–20. This change in allocation rate increases Ergon’s opex forecast by $26.3 million ($2014–15) over the 2015–20 regulatory control period. As this increase is not in Ergon Energy's base year or rate of change, we need to consider if we need to add it as an opex step change to our estimate of base opex.

We do not consider including a step change for increased overheads would lead to a forecast of opex that reasonably reflects the opex criteria. This is because we consider our estimate of base opex already provides a sufficient allowance for Ergon Energy to efficiently deliver standard control distribution services, given its operating environment. Overheads are a business as usual cost that would be incurred by an efficient and prudent service provider delivering standard control distribution services. We also note that any change in overheads as a result of a change in outputs, for example for growth in Ergon Energy's customer base, will be compensated through our opex rate of change.

We recognise a service provider's opex may be affected by how much of its expenditure is expensed and how much of it is capitalised. We have had regard to Ergon Energy's capitalisation policy when we assessed its operating environment factors in estimating our forecast of base opex consistent with the opex criteria (see appendix A). Therefore, our estimate of base opex already incorporates the effect of capitalisation policy differences.

D Forecasting method assessment

This appendix sets out our consideration of Ergon Energy's forecasting methodology in determining our opex forecast for Ergon Energy for the 2015–20 regulatory control period.

Our estimate of total opex is unlikely to exactly match Ergon Energy's forecast (see our assessment approach at the beginning of this opex attachment). Broadly, differences between the two forecasts can be explained by differences in the forecasting methods adopted and the inputs and assumptions used to apply the method. We have reviewed Ergon Energy's forecast method to assess whether it explains why Ergon Energy's forecast opex is higher than our own estimate. Where we have identified significant differences we have considered whether we need to amend the forecasting method we have used to derive our alternative opex estimate.

D.1 Position

We are satisfied that the Guideline forecasting method produces an opex forecast that reasonably reflects the opex criteria. We have not used category specific forecasting methods to separately forecast any of Ergon Energy's opex categories other than debt raising costs in our substitute total opex forecast. We formed our substitute forecast total opex using the Guideline forecasting method with all opex categories other than debt raising costs included in base opex.

D.2 Ergon Energy's proposal

Ergon Energy described its opex forecasting method in its regulatory proposal[883]. Ergon Energy stated that it used a base step trend method to forecast the majority of its recurrent operating expenditure. It stated that it attempted to reconcile its approach with the *Expenditure forecast assessment guideline* (the Guideline). However, it considered some departures to be necessary.[884] These departures included:

- removed one-off expenditure from the base[885]
- added forecast non-recurrent expenditure[886]
- used a bottom-up forecasting method to forecast some cost categories.[887]

[883] Ergon Energy, *Regulatory Proposal 2015 to 2020*, 31 October 2014, pp. 64–86.
[884] Ergon Energy, *Regulatory Proposal 2015 to 2020*, 31 October 2014, p. 74.
[885] Ergon Energy, *Forecast expenditure summary—operating costs*, 31 October 2014, pp. 12–14.
[886] Ergon Energy, *Forecast expenditure summary—operating costs*, 31 October 2014, pp. 15–17.
[887] Ergon Energy, *Forecast expenditure summary—operating costs*, 31 October 2014, pp. 26–31.

D.3 Assessment approach

The first part of our assessment involved identifying any differences between Ergon Energy's forecasting method and our own method as outlined in the Guideline. This involved reviewing:

- the description of Ergon Energy's opex forecasting method in its regulatory proposal[888]
- the description of Ergon Energy's opex forecasting method in appendix 06.01.01 to its regulatory proposal[889]
- the opex model used by Ergon Energy to forecast total opex.

We then examined the impact of the differences we identified. This provided an indication of the impacts of the various forecasting methods applied by Ergon Energy. Where we identified differences with significant impacts we considered whether we needed to amend our forecasting approach to ensure our alternative estimate of opex reasonably reflects of opex criteria, having regard to the opex factors.

D.4 Reasons for position

In assessing Ergon Energy's forecasting method we sought to identify if and where Ergon Energy's forecasting method departed from the Guideline forecasting method. Where Ergon Energy's forecasting method did depart from the Guideline forecasting method we considered whether this departure explains the difference between Ergon Energy's forecast of total opex and our own.

Under the Guideline forecasting method we start with the actual expenditure in a base year. If actual expenditure in the base year reasonably reflects the opex criteria we set base opex equal to actual expenditure. If not we apply an efficiency adjustment to ensure base opex reflects the opex criteria. We then apply a forecast rate of change to capture forecasting growth in prices, output and productivity. We then add or subtract any step changes to account for any other expenditure consistent with the opex criteria not captured in base opex or the rate of change.[890]

Ergon Energy's opex forecasting method differs from the Guideline forecasting approach in that it disaggregated total opex into cost categories and applied different forecasting methods to different cost categories, which it called functional areas.[891] Ergon Energy applied what it called a base step trend method to the majority of its cost categories. This method is broadly similar to the Guideline forecasting method.

[888] Ergon Energy, *Regulatory Proposal 2015 to 2020*, 31 October 2014, pp. 64–86.
[889] Ergon Energy, *06.01.01 Forecast Expenditure Summary—Operating Costs*.
[890] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–24.
[891] Ergon Energy, *06.01.01 Forecast Expenditure Summary—Operating Costs*, p. 11.

However, Ergon Energy used category specific forecasting methods for some cost categories.[892]

Using category specific forecasting methods for some opex categories may produce better forecasts of expenditure for those categories but this may not produce a better forecast of total opex. Generally it is best to use the same forecasting method for all cost categories of opex because hybrid forecasting methods (that is, combining revealed cost and category specific methods) can produce biased opex forecasts inconsistent with the opex criteria. This view is consistent with a view expressed by Frontier Economics in a previous determination process, which stated:[893]

> We consider that it would be inappropriate for the AER to review each component of controllable opex individually to see whether it conformed to the same pattern as overall controllable opex. Such 'cherry-picking' would likely result in aggregate controllable opex being systematically and inefficiently over-forecast.

This is because, once an efficient base level of opex is determined, forecast total opex can systematically exceed the efficient level of opex if a category specific forecasting method is used to forecast opex categories:

- with low expenditure in the base year, or
- with a greater rate of change than total opex.

Within total opex we would expect to see some variation in the composition of expenditure from year to year. If we use a category specific forecasting method to forecast those categories where base year opex was low, but not for those where base opex was high, our forecast of total opex will systematically exceed the efficient level of opex.

Ergon Energy, however, did the opposite and removed non-recurrent expenditure from the base year (and effectively forecast these costs to be zero in the forecast period).[894] When discussing the removal of non-recurrent costs from base opex, Ergon Energy stated:[895]

> From an efficiency perspective, Ergon Energy has removed a total of $60.5 million from the 2012–13 base year to take account of efficiencies achieved through ROAMES (i.e. improved understanding of asset condition and degradation and vegetation management) and redundancy payments associated with the corporate restructure.

[892] Ergon Energy, *06.01.01 Forecast Expenditure Summary—Operating Costs*, pp. 26–31.

[893] Frontier Economics, *Opex forecasting and EBSS advice for the SP AusNet final decision*, January 2014, p. iii.

[894] Ergon Energy, *06.01.01 Forecast Expenditure Summary—Operating Costs*, pp. 12–14.

[895] Ergon Energy, *06.01.01 Forecast Expenditure Summary—Operating Costs*, p. 12.

It is important to consider whether the opex forecast is consistent with EBSS when considering these non-recurrent increases (or decreases) in total opex.[896] By relying on the revealed expenditure in the base year, and applying the EBSS carryover, any one-off opex increase (or decrease) in the base year is share between the service provider and its customers as intended by the EBSS. Alternatively, if benchmarking shows opex to be inefficient and we adjust base opex according, this will remove the impact of any non-recurrent increases in expenditure.[897] In either case it is not necessary to adjust individual opex categories to remove (or add back) non-recurrent increases (or decreases) in opex in the base year.

Similarly, if we exclude opex categories where expenditure is rising faster than total opex then the remaining categories will be rising at a slower rate than total opex or declining. If we apply the total opex rate of change to those remaining categories then the total opex forecast will systematically exceed the efficient level of opex.

An example of this is Ergon Energy's expenditure forecast for its SPARQ non capital project costs and asset charge. As outlined in the Guideline, we escalate base year expenditure by the forecast rate of change in opex, which includes forecast price, output and productivity growth.[898] If we exclude opex categories from our opex rate of change where expenditure is rising faster than total opex then the remaining categories will be rising at a slower rate than total opex or declining. If we apply the total opex rate of change to those remaining categories then the total opex forecast will systematically exceed the efficient level of opex. Frontier Economics made this point when it reviewed the forecasting method adopted by SP AusNet to forecast its electricity transmission opex:[899]

> In our view, such ‘cherry-picking’ would likely result in aggregate controllable opex being systematically and inefficiently over-forecast. This is because with overall controllable opex fairly stable over time, the exclusion of components forecast to rise from the single base year forecasting approach would imply that the remaining components of controllable opex—those subject to the single base year approach—would exhibit a falling trend. However, as a premise of the single base year approach is that future expenditure should mimic past expenditure, using such an approach to forecast expenditure components known to be in a falling trend would tend to result in the forecasts for these components being too high. Therefore, combining a bottom-up approach for rising trend components of opex with a single base year approach for falling trend components of opex would tend to result in an overall controllable opex forecast that systematically exceeded the efficient level of expenditure.

If we separately forecast Ergon Energy's SPARQ non capital project costs and asset charge because they are expected to increase more rapidly than the total opex basket,

---

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

[897] The benchmark efficient level of opex is a function of the reported opex from multiple service providers across eight years of data. This 'averages out' the impact of one-off increases or decreases in reported opex.

[898] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–23.

[899] Frontier Economics, *Opex forecasting and EBSS advice for the SP AusNet final decision*, January 2014, p 17.

then we must also separately forecast opex items that increase less rapidly to avoid forecasting bias. Not doing so will systematically exceed the forecast opex required to meet the opex criteria. Moreover, the NER requires us to form a view on forecast total opex, rather than on subcomponents such as Ergon Energy's SPARQ non capital project costs and asset charge.

For the above reasons we have not used category specific forecasting methods to separately forecast any of Ergon Energy's opex categories in our substitute total opex forecast. We formed our substitute forecast total opex using the Guideline forecasting approach with all opex categories included in base opex.