Draft decision

Essential Energy distribution determination

2015–16 to 2018–19

Attachment 6: Capital expenditure

November 2014

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Note

This attachment forms part of the AER's draft decision on Essential Energy's 2015–19 distribution determination. It should be read with other parts of the draft decision.

The draft 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

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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Contents

Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	aggregate service revenue requirement
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

Shortened form	Extended form
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
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

6 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of standard control services. The return on and of forecast capex are two of the building blocks that form part of Essential Energy's total revenue requirement.[1]

We generally categorise capex as either network or non-network capex. Network capex includes growth-driven capex and non-load driven capex. Growth-driven capex includes augmentations and new connections. Non-load driven capex includes replacement and refurbishment capex. Non-network capex covers expenditure in areas other than the network and includes business information technology (IT) and buildings/facilities.

This attachment sets out our draft decision on Essential Energy's proposed total forecast capex. Further detailed analysis is in the following appendices:

Appendix A - Capex associated with each of the capex drivers that underlie Essential Energy's proposed total forecast capex

Appendix B - Overview of our assessment approaches

Appendix C - Demand

Appendix D - Real cost escalation

Appendix E - Operating and environmental factors

Appendix F - Predictive modelling approach and scenarios.

6.1 Draft decision

We are not satisfied that Essential Energy's proposed total forecast capex of $2,619 million ($2013–14) reasonably reflects the capex criteria. Our alternative estimate of Essential Energy's total forecast capex for the 2014–2019 period that we are satisfied reasonably reflects the capex criteria is $1,934 million ($2013–14).[2] Table 6-1 outlines our draft decision.

Table 6-1 Our draft decision on Essential Energy's total forecast capex (million $2013–14)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Essential Energy's proposal	545.4	519.1	527.6	514.5	512.1	2,618.7
AER draft decision	425.7	385.3	386.3	370.2	366.8	1,934.3
Difference	119.7	133.8	141.3	144.3	145.3	684.4
Percentage difference	21.9%	25.8%	26.8%	28.0%	28.4%	26.1%

Source: AER analysis.
Note: Numbers may not total due to rounding.

A summary of our reasons and findings for our draft decision that we present in this attachment and appendix A are set out in Table 6-2. It is important to recognise that our decision is about Essential

1 NER, cl. 6.4.3(a).
2 This amount is subject to removal of Essential Energy's labour cost adjustment based on real cost escalation and replacement with labour cost adjustment based on the historical average.

Energy's total forecast capex for the 2014–2019 period. We are not approving a particular category of capex or a particular project, but rather an overall amount. However, as part of our assessment, we necessarily review the categories of expenditure and some particular projects in order to test whether Essential Energy's proposed total forecast capex reasonably reflects the capex criteria. This is explained further in our assessment approach at appendix B. It follows that our findings and reasons on the capex associated with specific capex drivers, as set out below and in appendix A, are part of our broader analysis and are not intended to be considered in isolation.

Table 6-2 Summary of AER reasons and findings

Issue	Reasons and findings
Forecasting methodology, key assumptions and past capex performance	Our concerns with Essential Energy's forecasting methodology and key assumptions are material to our view that we are not satisfied that its proposed total forecast capex reasonably reflects the capex criteria. In particular: ▪ Essential Energy's forecasting methodology applies a bottom-up assessment but not a top-down assessment. We consider a top down assessment critical in deriving a total forecast capex allowance that reasonably reflects the capex criteria. We also find that Essential Energy's forecasting methodology incorporates an overly conservative risk assessment which does not adequately justify the timing and priority of its proposed forecast capex. ▪ We have concerns with how Essential Energy has formulated and applied its key assumptions in relation to demand and customer forecasts and forecast materials escalation rates and labour escalation rates. We also observe that Essential Energy's past capex performance reveals that its capital efficiency has been declining over time and is one of the lowest among the distribution networks in the NEM. This strongly suggests that efficient reductions in capex are achievable. This observation provides context for our analysis of specific capex drivers in Appendix A. In determining our alternative estimate we have addressed the concerns we have with Essential Energy's forecasting methodology and key assumptions. Specifically, we have undertaken a top-down assessment by applying our assessment techniques of economic benchmarking, trend analysis and an engineering review. We have also addressed the deficiencies in Essential Energy's key assumptions about demand, forecast materials escalation rates and labour escalation rates.
Augmentation capex (augex)	We do not accept Essential Energy's proposed augex forecast of $744.6 million ($2013–14), excluding overheads. On the basis of the information before us, these amounts are overstated and exceed the amount required to achieve the capex objectives. Essential Energy's forecast is based on out-dated demand forecasts and did not take account of the savings that could be achieved through risk based cost benefit analysis assessment techniques in the context of the revisions to its licence conditions. The Essential Energy proposed augex forecast also did not take into account the most recent changes to the value of customer reliability (VCR). We have instead included an amount of $475.2 million ($2013–14) of forecast augex in our alternative estimate that we are satisfied reasonably reflects the capex criteria. This amount is 36.18 per cent less than Essential Energy's proposal. To arrive at this reduction we: ▪ reduced Essential Energy's augex forecast by approximately 20.2 per cent to account for updated spatial demand forecasts ▪ applied a further 20 per cent reduction to account for the absence of Essential Energy applying a risk-based cost benefit analysis technique. This reduction takes into account the observed trend in augex that shows that there is excess capacity in the network that remains to be more efficiently utilised. Our estimate does not

Issue	Reasons and findings
	reflect the change in VCR. We expect that Essential Energy will assess and incorporate the changes to the VCR in its total forecast capex as part of submitting its revised regulatory proposal.
Customer connections capex	We are satisfied Essential Energy's proposed connections forecast of $366.08 million ($2013/2014), excluding overheads, is consistent with the capex objectives. Hence, we will make an allowance for this in determining the total capex forecast for the 2014–2019 period. We consider the trend of Essential Energy's connections capex forecast is not unreasonable compared with the forecast drivers in construction activity in commercial and industrial, and multi-dwelling residential premises. We therefore consider this amount will allow Essential Energy to achieve the capex objectives. We also accept Essential Energy's proposed capital contributions forecast of $336.11 million ($2013/2014), as we consider it is consistent with Essential Energy's forecast level of connection works which we are also accepting. We consider that capital contributions are mostly driven by connection and augmentation works, and in its revised proposal, we expect Essential Energy to clearly explain how capital contributions should be allocated to each capex driver.
Replacement capex (repex)	We have not accepted Essential Energy's proposed forecast repex of $856 million ($2013–14), excluding overheads. On the basis of the information before us, this amount is overstated and exceeds the amount required to achieve the capex objectives. This is based on the following: ▪ Essential Energy's proposal is around 59 per cent higher than Essential Energy's historical trend (inclusive of overheads) and compares unfavourably on a number of category level benchmarks which we have taken into account. ▪ Our consultant, EMCa has found a number of issues with Essential Energy's proposal which we accept. These issues include Essential Energy using overly conservative risk criteria and multiple contingency allowances that systematically overstate its costs, not adequately justifying the timing of its proposal at the project/program level, relying on network age and condition information that is at times inconsistent and contradictory. ▪ The network health indicators concerning the condition of Essential Energy's assets do not support a significant increase in repex relative to the longer term trend of actual repex that Essential Energy has spent in past regulatory control periods. ▪ Essential Energy faced significant capex deliverability challenges during the 2009–2014 regulatory control period. We have found no evidence to suggest that Essential Energy is better equipped to deal with or will not face these same challenges during the 2014–2019 period. We have instead included an amount of $675 million ($2013–14), excluding overheads in our alternative estimate for the 2014–2019 period. This amount will allow Essential Energy to achieve the capex objectives. In particular, this amount is at the lower end of the range from our predictive model which takes into account Essential Energy's asset replacement practices and forecast costs. This is consistent with our view of Essential Energy's long-term repex requirements as evidenced by its past expenditure and will provide Essential Energy with a reasonable opportunity to recover at least its efficient costs.
Non-network capex	We have accepted and included Essential Energy's forecast non-network capex of $306.4 million ($2013–14) in our substitute estimate. We find that Essential Energy's forecast non-network capex is 46 per cent lower than actual non-network capex during the 2009–2014 regulatory control period. We also find that the longer term trends in non-network capex suggest that Essential Energy has forecast capex for this category at historically low levels.

<table>
<tr><th>Issue</th><th>Reasons and findings</th></tr>
<tr><td>Capitalised overheads</td><td>We have not accepted Essential Energy's s proposed forecast capex of $681.0 million ($2013–14) for capitalised overheads. This proposal is not consistent with the reduced amounts of capex associated with other capex drivers that we have included in our alternative estimate. It is also not consistent with the 31 per cent average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period.

We have instead included an amount of $478.6 ($2013–14) million in our alternative estimate. This amount is consistent with the other amounts of capex that we have included in our alternative estimate and the amount of actual capitalised overheads that Essential Energy spent in the 2009–2014 regulatory control period.</td></tr>
<tr><td>Real cost escalators</td><td>We have not accepted Essential Energy's proposed real escalation of commodity prices. We also have not accepted Essential Energy's proposed real escalation of labour prices. Our reasons for this are:
The degree of the potential inaccuracy of commodities forecasts due to:
recent studies which show that forecasts for example of crude oil spot prices based on futures prices do not provide a significant improvement compared to a 'no-change' forecast for most forecast horizons, and sometimes perform worse
evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than 'no change' forecasts; and
the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $USD to $AUD). A review of the economic literature of exchange rate forecast models suggests a "no change" forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.
The limited evidence available to us neither supports or confirms how accurately Essential Energy's commodities escalation forecasts are likely to reasonably reflect changes in prices paid by Essential Energy for physical assets in the past. Therefore, it is not open to us to conclude that Essential Energy's forecasts are reliable and accurate..
Essential Energy has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that may affect the commodities forecast.
Our alternative estimate instead incorporates a real cost escalation of zero per cent which, on the basis of the information before us, we consider is likely to provide a more reliable estimation for the price of cost inputs used by Essential Energy to provide network services.

We have also not accepted Essential Energy's proposed real escalation of labour prices on the basis of our reasoning in the Opex rate of change Appendix. In particular, we have forecast labour price change for the 2014–2019 period based on an average of the forecasts for the electricity, gas, water and waste services sectors from Deloitte and Independent Economics. Historically, an average has better reflected actual labour price changes for the electricity, gas, water and waste services sectors. We have not reduced Essential Energy's total forecast capex to reflect this reduction in labour rates as we require further information (i.e. labour costs as a proportion of total forecast capex). We expect Essential Energy to provide this information in its revised regulatory proposal.</td></tr>
</table>

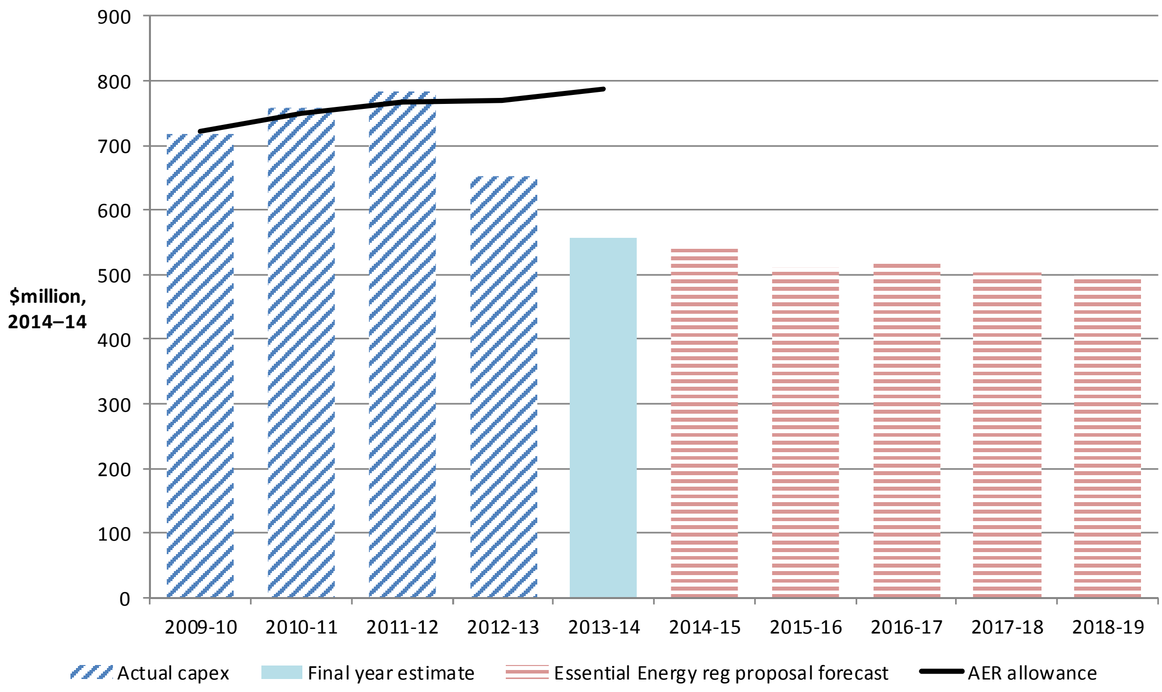
Source: AER analysis.

6.2 Essential Energy's proposal

Essential Energy proposed total forecast capex of $2,619 million ($2013–14) for the 2014–2019 period.

Figure 6-1 shows the reduction between Essential Energy's proposal for the 2014–2019 period and the actual capex that it spent during the 2009–2014 regulatory control period. This proposed reduction in capex is mainly attributable to decreases in expenditure to meet changes in demand and the removal of design planning standards.

Figure 6-1 Essential Energy's total actual and forecast capex 2009–2019



Source: Historical: IPART Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010–11 to 2013–14); 2014–2019 period: Essential Energy Reset RIN, Table 2.1.1 - Standard control services capex).

6.3 Assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, outlines our assessment techniques, and explains how we build an alternative estimate of total forecast capex against which we compare that proposed by the service provider.

We will accept Essential Energy's proposed total forecast capex if we are satisfied that it reasonably reflects the capex criteria.[3] If we are not satisfied, we substitute it with our alternative estimate of Essential Energy's total forecast capex that we are satisfied reasonably reflects the capex criteria.[4] The capex criteria are:

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives

3 NER, cl. 6.5.7(c).
4 NER, cl. 6.5.7(d).

- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The Australian Energy Market Commission (AEMC) noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[5] The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to: [6]

- meet or manage the expected demand for standard control services over the period
- comply with all regulatory obligations or requirements associated with the provision of standard control services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of standard control services and maintain the reliability and security of the distribution system
- maintain the safety of the distribution system through the supply of standard control services.

Importantly, our assessment is about the total forecast capex and not about particular categories or projects in the capex forecast. The Australian Energy Market Commission (AEMC) has expressed our role in these terms:[7]

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

In deciding whether we are satisfied that Essential Energy's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.

The capex factors are:[8]

- the AER's most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient DNSP over the relevant regulatory control period
- the actual and expected capex of the DNSP during the preceding regulatory control periods
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP 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 capex forecast is consistent with any incentive scheme or schemes that apply to the DNSP
- the extent to which the capex forecast is referable to arrangements with a person other than the DNSP that, in the opinion of the AER, do not reflect arm's length terms
- whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project

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

6 NER, cl. 6.5.7(a).

7 AEMC Economic Regulation Final Rule Determination, p. vii.

8 NER, cl. 6.5.7(e).

- the extent to which the DNSP has considered, and made provision for, efficient and prudent non-network alternatives.

In addition, the AER may notify the DNSP in writing, prior to the submission of its revised regulatory proposal, of any other factor it considers relevant.[9]

In taking these factors into account, the AEMC has noted that:[10]

> …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.

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

More broadly, we also note that in exercising our discretion, we take into account the revenue and pricing principles which are set out in the National Electricity Law.[11]

Recent AEMC rule changes

The rule changes the AEMC made in November 2012 require us to make and publish an Expenditure Forecast Assessment Guideline for Electricity Distribution (released in November 2013). The Guideline sets out the AER's proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For Essential Energy, our framework and approach paper (published in January 2014) stated that we would apply the guideline, including the assessment techniques outlined in it. We may depart from our Guideline approach and if we do so, need to explain why. In this determination we have not departed from the approach set out in our Guideline.

As part of these rule changes, the AEMC also emphasised the role of benchmarking in our assessment of capex. In particular, we are now required to produce annual benchmarking reports. This is also a capex factor that we are now required to consider in assessing a capex proposal.[12] The AEMC removed the focus on a business' 'individual circumstances' as it could be an impediment to the use of benchmarking by the AER.[13]

Further to the 2012 rule change, the AEMC in a 2013 rule change, amended the expenditure objectives. This addressed the problem that the previous expenditure objectives relating to reliability, security and quality of supply: [14]

> …could be interpreted so that the expenditure an NSP includes in its regulatory proposal is to be based on maintaining the NSP's existing levels of reliability, security or quality, even where an NSP is performing above the required standards for these measures, or where required standards for those measures are lowered.

Consequently, where standards have been lowered for reliability or security and supply, the expenditure objectives now clarify that Essential Energy does not need to maintain, and does not need the expenditure to maintain, the previous level of performance.

9 NER, cl. 6.5.7(e)(12).
10 AEMC, *Economic Regulation Final Rule Determination*, p. 115.
11 NEL, sections 7A and 16(2).
12 NER, clause 6.5.7(e)(4).
13 AEMC, *Economic Regulation Final Rule Determination*, November 2012, p. 97.
14 AEMC, Final Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 No. 5, p. ii.

Building an alternative estimate of total forecast capex

Our starting point is the service provider's proposal.[15] We then considered the service provider's performance in the previous regulatory control period to inform our alternative estimate. We also reviewed the proposed forecast methodology and the service provider's reliance on key assumptions that underlie its forecast.

We then applied our specific assessment techniques, outlined below, to develop and estimate and assess the economic justifications that the service provider put forward. The specific techniques that we have used in this draft decision include:

- economic benchmarking—to assess a business's overall efficiency (and trends in efficiency) compared with other businesses, drawing on our annual benchmarking report
- trend analysis—forecasting future expenditure based on historical information, especially for recurrent and predictable categories of expenditure
- category level analysis—to allow for the development of metrics which can be benchmarked over time and between businesses
- predictive modelling—including the replacement capex (repex) model and augmentation capex (augex) model
  - the repex model is used to assess whether the business' repex proposal is reasonable given assumed and benchmarked asset lives and unit costs
  - the augex model is used to assess whether the proposed amount of augex is reasonable given the level of demand growth.
- engineering review—including review of a DNSP's governance and risk and asset management processes, review of specific projects/programs and cost-benefit analysis to test whether the proposed expenditure is efficient and prudent.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, the techniques that focus on sub-categories are not conducted for the purpose of determining at a detailed level what projects or programs of work the service provider should or should not undertake. They are but one means of assessing the overall total forecast capex required by the service provider. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve projects. Once we approve total revenue, which will be determined by reference to the AER's analysis of the proposed capex, the service provider will have to prioritise its capex program given the prevailing circumstances at the time (such as demand and economic conditions that impact during the regulatory period). Most likely, some projects or programs of work that were not anticipated will be required. Equally likely, some of the projects or programs of work that the service provider has proposed for the regulatory control period will not be required. We consider that acting prudently and efficiently, the service provider will consider the changing environment throughout the regulatory period and make sound decisions taking into account their individual circumstances.

Many of our techniques encompass the capex factors that we are required to take into account. These techniques are discussed in more detail in appendix B.

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15 AER, *Expenditure Forecast Electricity Transmission Guideline*, p. 9; see also AEMC, *Economic Regulation Final Rule Determination*, pp. 111 and 112.

As explained in our Guidelines:

> Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex … forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.[16]

In arriving at our estimate, we have had to weight the various techniques used in our assessment. How we weight these techniques will be determined on a case by case basis using our judgement as to which techniques are more robust. We also need to take into account the various interrelationships between the total forecast capex and other components of a service provider's transmission determination. The other components that directly affect the total forecast capex are forecast opex, forecast demand, the service target performance incentive scheme, the capital expenditure sharing scheme, real cost escalation and contingent projects. We discuss how these components impact the total forecast capex in Table 6-4.

Underlying our approach are two general assumptions:

- Capex criteria relating to a prudent operator and efficient costs are complementary such that prudent and efficient expenditure reflects the lowest long-term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[17]
- Past expenditure was sufficient for Essential Energy to manage and operate its network in that previous period, in a manner that achieved the capex objectives.[18]

After applying the above approach, we arrive at our estimate of the total capex forecast.

Comparing the service provider's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the service provider's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the service provider's proposal. The service provider's forecast methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[19]

> 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.

We have not relied solely on any one technique to assist us in forming a view as to whether we are satisfied that a service provider's capex proposal reasonably reflects the capex criteria. We have necessarily drawn on a range of techniques as well as our assessment of demand and real cost escalators.

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16 AER Expenditure Forecast Electricity Distribution Guideline, p. 12.
17 AER, *Expenditure Forecast Electricity Distribution Guideline*, pp. 8 and 9.
18 AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 9.
19 AEMC, *Economic Regulation Final Rule Determination*, p. 112.

Where we approve a service provider's proposed total forecast capex or where we substitute our alternative estimate of total forecast capex, it is important to recognise that the service provider is not precluded from undertaking unexpected capex works, if the need arises, and despite the fact that such works did not form part of our assessment in this determination. As noted above, we anticipate that a service provider will prioritise their capex program of works. Where an unexpected event leads to an overspend of the capex amount approved in this determination as part of total revenue, a service provider will only be required to bear 30 per cent of this cost if the expenditure is found to be prudent and efficient. Further, for significant unexpected capex, the pass-through provisions provide a means for a service provider to pass on such expenses to customers where appropriate. For these reasons, in the event that the approved total revenue underestimates the total capex required, we do not consider that this should lead to undue safety or reliability issues. Conversely, if we overestimate the amount of capex required, the stronger incentives put in place by the AEMC in 2012 should lead to a business spending only what is efficient, with the benefits of the underspend being shared between businesses and consumers.

6.4 Reasons for draft decision

We are not satisfied that Essential Energy's total forecast capex reasonably reflects the capex criteria. We compared Essential Energy's capex forecast to a capex forecast we constructed using the approach and techniques outlined above. Essential Energy's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6-3 sets out the capex amounts by capex driver that we have included in our alternative estimate of Essential Energy's total forecast capex for the 2014–2019 period.

Table 6-3 Our assessment of required capex by capex driver ($ million 2013–14)

Category	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Augmentation	113.9	100.2	90.0	87.1	84.1	475.3
Connection	95.3	66.8	70.4	66.8	66.8	366.1
Replacement	121.1	130.2	142.2	140.0	142.3	675.8
Non-network	81.2	59.0	61.1	53.8	51.4	306.5
Capitalised overheads	105.0	94.7	94.0	92.0	92.9	478.6
Materials escalation adjustment	- 1.4	- 4.7	- 7.0	- 8.6	- 9.9	- 31.6
Gross capex	515.1	446.1	450.6	430.9	427.6	2 270.3
Customer contributions	89.4	60.8	64.4	60.7	60.8	336.1
Net capex	**425.7**	**385.3**	**386.3**	**370.2**	**366.8**	**1 934.3**

Our assessment of Essential Energy's forecasting methodology, key assumptions and past capex performance are discussed in the section below. In relation to past performance, we specifically consider the impact on expenditure of past licence conditions for reliability and network design and planning standards, and the removal of those conditions as of 1 July 2014.

6.4.1 Forecasting methodology

Essential Energy is required to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[20] It is also required to include this information in its regulatory proposal.[21]

The main points of Essential Energy's forecasting methodology are:[22]

- There are 15 asset management or capital plans.
- These asset management plans are supported by regional planning reports, a distribution network growth strategy, a reliability strategic plan and quality of supply strategic plan, a network technology strategic plan and a non-system assets business plan.
- Each capital plan is based on meeting one or more of its capex drivers (growth, asset condition and safety, reliability compliance and network support).
- A bottom up assessment was applied to derive its forecast capex for major projects (at sub-transmission network and zone substation level and for some areas at a high voltage distribution feeder level). A top down assessment was undertaken at the distribution network level and was undertaken for all of its capital plans except for its distribution capacity plan and reliability investment plans.
- Essential Energy’s approved cost allocation method was applied so that all forecast capex is allocated to standard control services.

We have identified three aspects of Essential Energy's forecasting methodology which indicate that its methodology is not a sufficient basis on which to conclude that its proposed total forecast capex reasonably reflects the capex criteria.

First, Essential Energy's forecasting methodology applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for a significant portion of its capex categories. In our view, applying a top-down assessment is a critical part of the process in deriving a forecast capex allowance. It indicates that some level of overall restraint has been brought to bear. This is an important factor for us to consider in deciding whether we are satisfied that a proposed forecast capex allowance reasonably reflects the capex criteria. In particular, to derive an estimate of capex by solely applying a bottom-up assessment does not itself provide any evidence that the estimate is efficient. Bottom-up assessments have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level. Whereas reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency. Whilst in certain very limited circumstances, a bottom up build may be a reasonable approach to justifying expenditure, this is not the case when looking at aggregated areas of expenditure or at the portfolio level. However, simply

[20] NER, cll. 6.8.1A and 11.56.4(o); Essential Energy, *Expenditure Forecasting Approach: 2014–19 Regulatory Proposal*, November 2013.

[21] NER, cl. S6.1.1(2); Essential Energy, *Regulatory Proposal*, May 2014, pp. 50–55; Essential Energy, *Expenditure Forecasting Approach: 2014–19 Regulatory Proposal*, November 2013, May 2014, pp. 8–12.

[22] Essential Energy, *Regulatory Proposal*, May 2014, pp. 50–55.

aggregating estimates is unlikely to result in a total forecast capex allowance that we are satisfied reasonably reflects the capex criteria. Our review reflects the submission made by the National Generators Forum:[23]

> Historically, regulatory assessments of capital expenditure programs have predominantly incorporated bottom up assessments of a sample of projects and / or programs, with minimal top down assessment of the overall level of capex, underlying drivers and impacts on network prices. Given the substantial information asymmetry between DNSPs and regulators, past approaches have had limited success in determining an efficient overall level of capex for NSW DNSPs. It is far more difficult for a regulator to reject capital expenditure proposals on an individual project-by-project basis compared to setting a top down overall efficient level of capex within which DNSPs can prioritise individual projects.

As we stated in our Forecast Expenditure Guidelines, we intend to assess forecast capex proposals through a combination of top down and bottom up modelling.[24] Our top-down assessment of Essential Energy's proposed forecast is a material consideration in determining whether we are satisfied if it reasonably reflects the capex criteria.

A top-down assessment should also clearly evidence a holistic and strategic consideration or assessment of the entire forecast capex program at a portfolio level. It should also demonstrate how the forecast capex proposal has been subject to governance and risk management arrangements. In turn, these arrangements should demonstrate how the timing and prioritisation of certain capital projects or programs has been determined over both the short and the long-term. It should also demonstrate that the capex drivers, such as asset health and risk levels, are well defined and justified. In particular, asset health and risk level metrics are key elements of capex drivers. While there is some evidence of a top-down approach across some asset classes, Essential Energy's forecast methodology does not demonstrate all of the elements.

The range of assessment techniques available to us provides for a top-down assessment. These techniques enable us to test whether an estimate that results from a bottom-up assessment might be efficient. We have applied top down assessments to the overall level of expenditure as well as each major sub-category of capex. The combination of our techniques informs our decision as to whether the proposed total capex forecast reasonably reflects the capex criteria.

Second, Essential Energy's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is overly conservative. This is evident in Essential Energy not fully justifying the timing and priority of its proposed forecast capex. Ultimately, this overly conservative approach to risk means that Essential Energy is forecasting more capex in the 2014–2019 period than is necessary to achieve the capex objectives. In particular, Essential Energy does not demonstrate that it has properly considered the extent to which its programs or projects can be deferred to the 2020–2025 regulatory control period. An overly conservative risk approach is likely to result in a forecast capex allowance that is greater than what is required to achieve the capex objectives. The same views have also been expressed by EMCa in their review of Essential Energy's proposed repex.[25]

Finally, Essential Energy's forecast methodology lacks a clear delivery strategy or plan.

Essential Energy underspent its forecast capex allowance by around 21 per cent in the 2009–2014 regulatory control period. Essential Energy submitted that the key reasons for the underspend include

[23] National Generators Forum, Submission to the Revenue Determinations (2014–2019) of the NSW Distribution Network Service Providers, p. 9.
[24] AER, *Expenditure Forecast Electricity Distribution Guideline*, November 2013, p. 17.
[25] EMCa, pp. iii..

having more detailed information than was the case in 2007–08, a review of deferrals in light of the adverse impacts on consumers of large electricity price increases, actual unit costs being higher than forecast and challenges and resource constraints in delivering a large capex program.[26] It is the last reason here that concerns us.

In our view, given the delivery challenges Essential Energy faced during the 2009–2014 regulatory control period, it is concerning that its forecast methodology does not include a delivery strategy. This is despite Essential Energy submitting that it has recognised some of the shortcomings of the 2009–2014 regulatory control period and the fact that the capital program underlying Essential Energy's proposed forecast capex for the 2014–2019 period differs significantly from that of the 2009–2014 regulatory control period. For these reasons, we consider that Essential Energy's proposed total forecast capex carries significant deliverability risks. Whilst Essential Energy submits that it has recognised some of the shortcomings of the 2009–2014 regulatory control period, there is still no clear delivery strategy.

6.4.2 Key assumptions

The National Electricity Rules (NER) require Essential Energy to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex and a certification by its directors that those key assumptions are reasonable.[27]

Essential Energy's key assumptions are:[28]

- legal and organisational structure
- amendments to reliability and planning licensing conditions that took effect on 1 July 2014
- strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network
- the spatial demand and customer connection forecasts
- forecast labour cost escalation has been set consistent with Essential Energy's enterprise bargaining agreement
- its customer engagement in accordance with the stakeholder engagement process outlined in the NER.

To the extent that Essential Energy has relied on its key assumptions to justify its capex proposal, we have addressed these key assumptions in Appendix C (demand forecasts), Appendix A (the impact of the amendments to the reliability and planning conditions) and Appendix D (forecast labour escalation rates).

In addition, we have some specific concerns about Essential Energy's key assumption about its legal and organisational structure. Essential Energy submits that its "current ownership and legal structure [does] not incorporate any impacts associated with a potential change of ownership … [and] this is a reasonable assumption basis given that there has been no formal announcement by the current owner that a sale of the company will proceed in the 2014–19 period".[29] This appears to imply that a

[26] Essential Energy, Regulatory Proposal, May 2014.
[27] NER, cll. S6.1.1(2), (4) and (5).
[28] Essential Energy, *Regulatory Proposal*, May 2015, p. 54; Essential Energy, *Regulatory Proposal*, Attachment 0.06.
[29] Essential Energy, *Regulatory Proposal*, Attachment 0.06, May 2014, p. 3.

change in ownership, if it were to occur, would affect the amount of forecast capex that would be required to achieve the capex objectives. In our view, this is not the case and there is no logical basis for this assumption.

6.4.3 Essential Energy's capex performance

We have looked at a number of historical metrics of Essential Energy's capex performance against that of other DNSPs in the NEM. We also compare Essential Energy's proposed forecast capex allowance against historical trends. These metrics are largely based on outputs of the annual benchmarking report and other analysis undertaken using data provided by the DNSPs for the annual benchmarking report. This includes Essential Energy's relative partial and multilateral total factor productivity (MTFP) performance, capex and RAB per customer and maximum demand, and Essential Energy's historic capex trend.

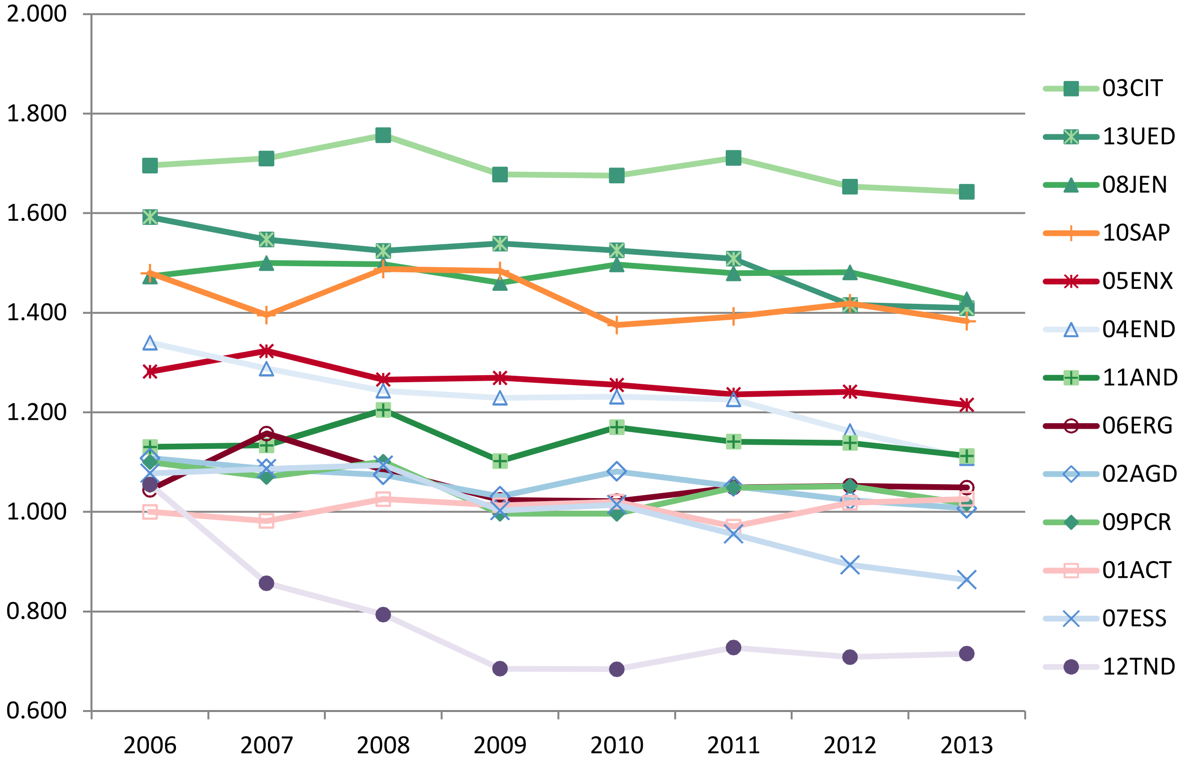
Together, these metrics strongly suggest that Essential Energy's capex efficiency, compared to other DNSPs, is one of the lowest in the NEM. These strongly suggest that there is the potential for efficiencies to be found in Essential Energy's proposed forecast capex for the 2014–2019 period. In particular, these metrics suggest capex reductions of up to 50 per cent for Essential Energy to bring it in line with the Victorian and South Australian DNSPs.

While these results are not a direct input into our alternative estimate of Essential Energy's capex forecast, they inform us of Essential Energy's relative capital efficiency and whether efficient reductions to its capex forecast is achievable. We consider that it is reasonable to benchmark Essential Energy's capex efficiency against the other DNSPs in the NEM in this way. This is because, in our view, the differences in operating and environmental factors between the DNSPs are not material. We discuss this in Appendix E.

Partial factor productivity of capital and multilateral total factor productivity

Figure 6-2 shows a measure of partial factor productivity of capital taken from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. Essential Energy had the second lowest level of partial factor productivity of capital of the DNSPs in the NEM, and the lowest of the NSW and ACT DNSPS. It is substantially lower than the Victorian and South Australian DNSPs.

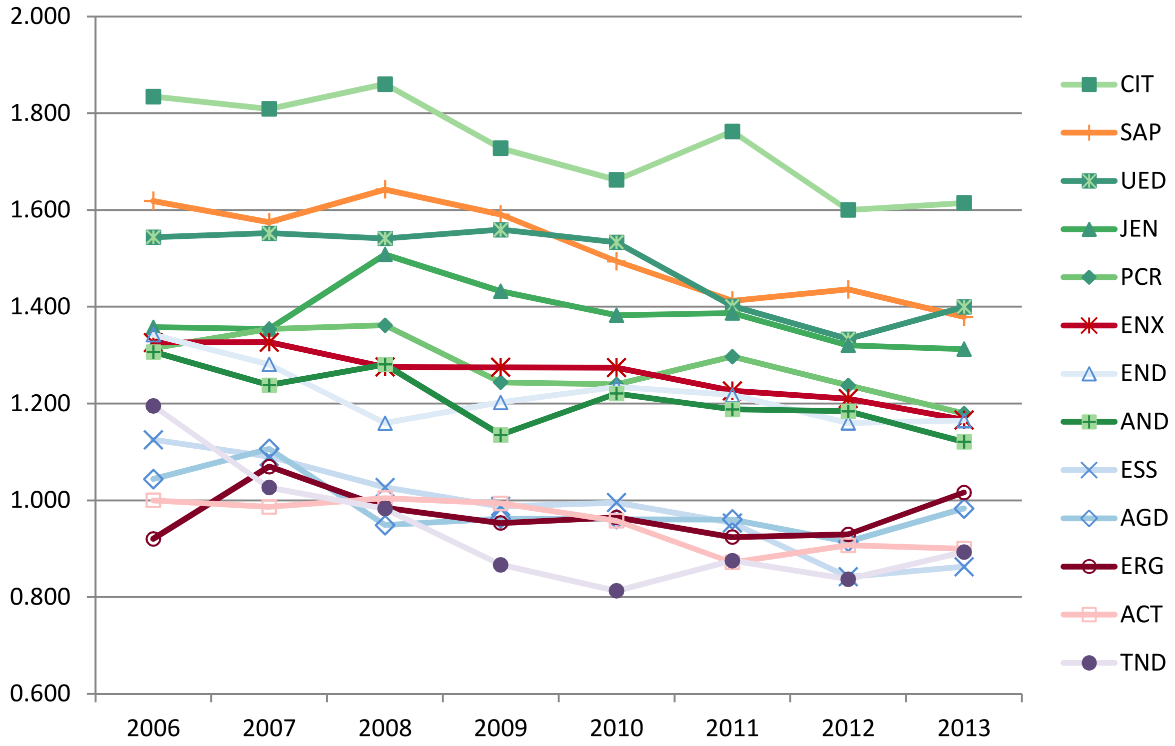
Figure 6-2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER annual benchmarking report.

Figure 6-3 shows that Essential Energy also recorded the lowest level of MTFP in the NEM across the DNSPs. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (customer numbers, ratcheted maximum demand, reliability, circuit line length and energy delivered). Across all of these measures, the Victorian and South Australian DNSPs significantly outperformed Essential Energy's.

Figure 6-3 Multilateral total factor productivity



Source: AER annual benchmarking report.

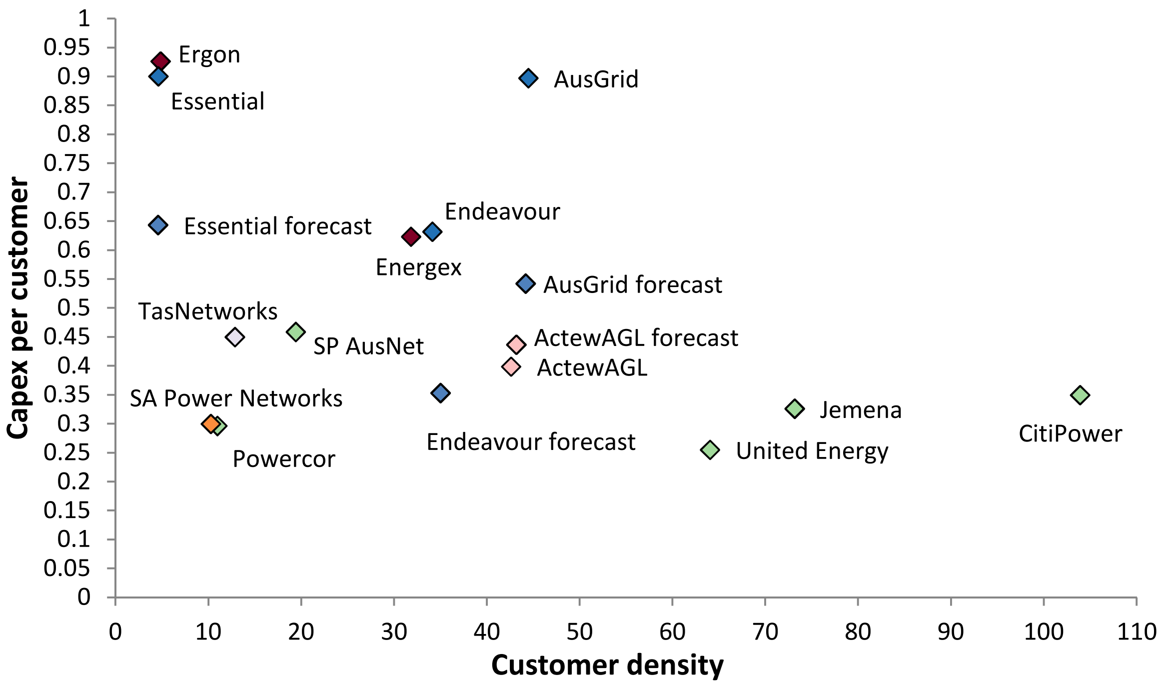
Relative capex efficiency metrics

Figure 6-4 and Figure 6-5 shows capex per customer and per maximum demand, against customer density. Capex is taken as a five year average for the years 2008–12. For the NSW DNSPs and ActewAGL, we have also included the businesses' proposed capex for the 2014–2019 period. We have considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6-4 shows that Essential Energy had one of the highest levels of capex per customer in the NEM for the 2008–2012 period. Essential Energy's capex per customer will reduce for the 2014–2019 period based on their proposed forecast capex. However, Essential Energy's capex per customer is still high when compared with the Victorian and South Australian DNSPs. Essential Energy's proposed forecast capex for the 2014–2019 period would have to reduce by approximately 48 per cent in order for its capex per customer to be comparable to that the average $3,300 per customer achieved by the Victorian and South Australian DNSPs in 2008–2012.

The results also show that Essential Energy has achieved similar levels of capex per customer as Ausgrid, despite Ausgrid having higher customer density. However, Essential Energy's relatively high capex per customer cannot be wholly explained by the basis of customer density as a number of other DNSPs have achieved lower levels of capex per customer despite having similar levels of customer density.

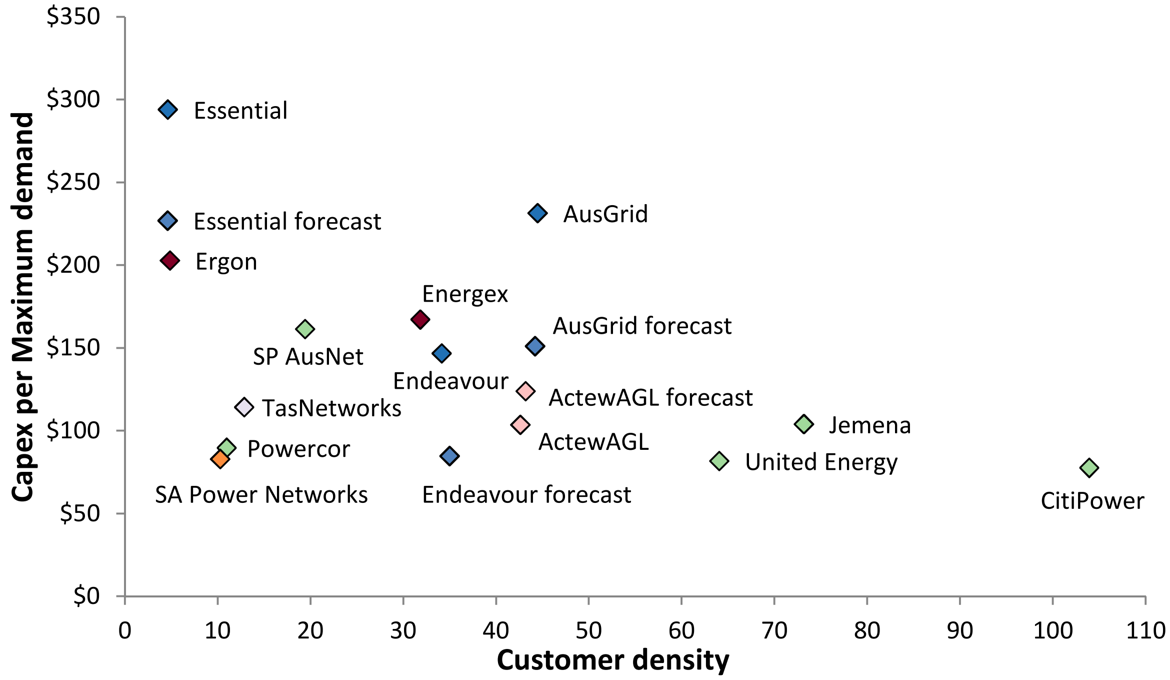
Figure 6-4 Capex per customer (000s, $2013-14), against customer density



Source: AER analysis.

Figure 6-5 shows that Essential Energy had the highest level of capex per maximum demand for the 2008–2012 period. Capex per maximum demand is forecast to reduce for Essential Energy in the next period but is still the highest in the NEM. Essential Energy's proposed forecast capex for the 2014–2019 period would have to reduce by approximately 56 per cent in order for its capex per maximum demand to be comparable to the average of $99,500 per maximum demand achieved by the Victorian and South Australian DNSPs in 2008–2012.

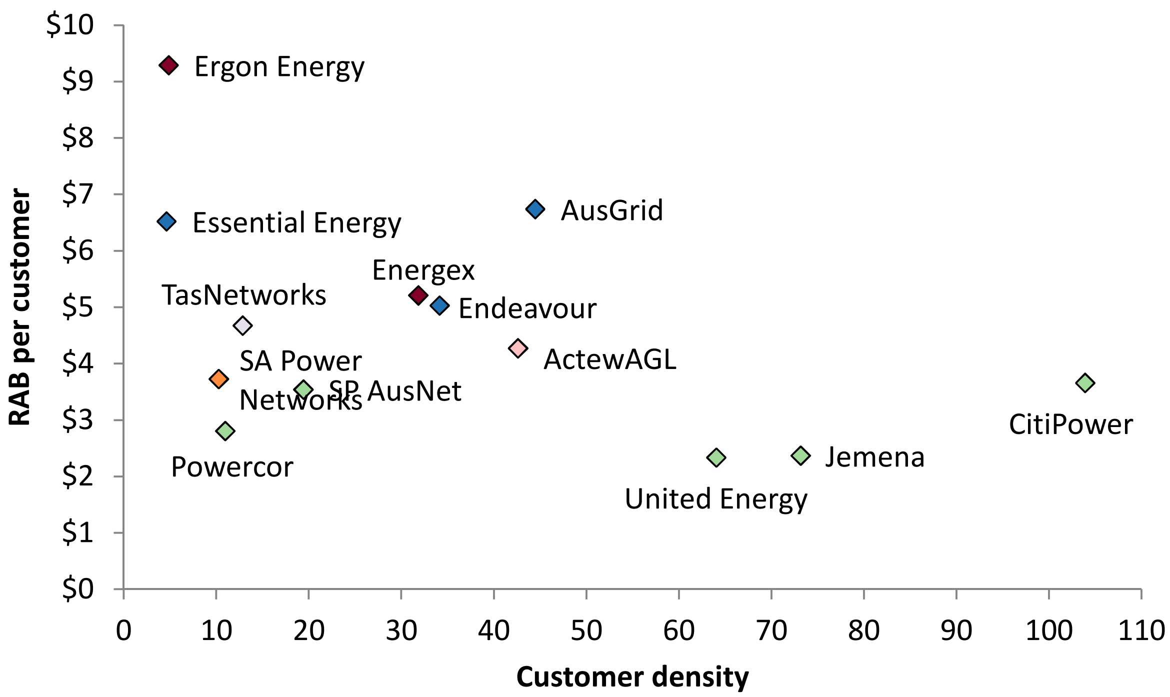
Figure 6-5 Capex per maximum demand (000s, $2013-14), against customer density



Source: AER analysis.

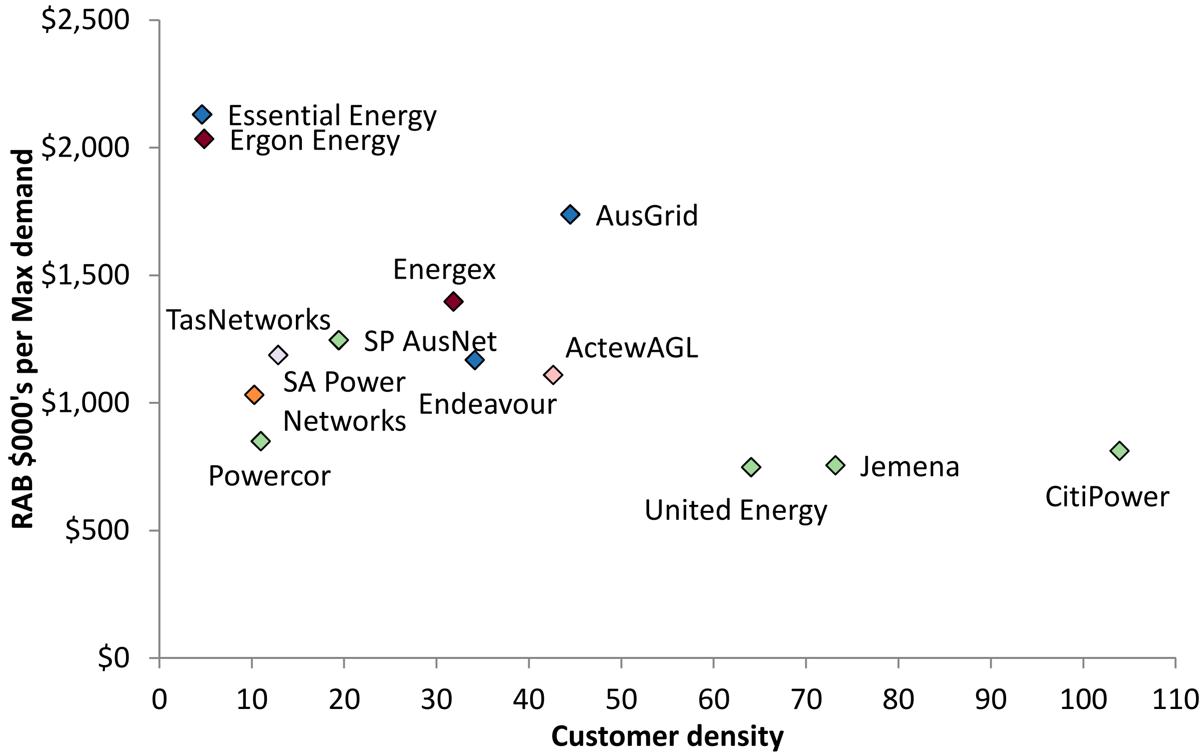
Figure 6-6 and Figure 6-7 and show that the comparative ranking for the DNSPs is similar when the RAB is used instead of capex. Specifically, as at 2013, Essential Energy had one of the highest levels of RAB per customer and RAB per maximum demand in the NEM.

Figure 6-6 RAB per customer (000s, $2013-14), against customer density



Source: AER analysis.

Figure 6-7 RAB per maximum demand (000s, $2013-14), against customer density



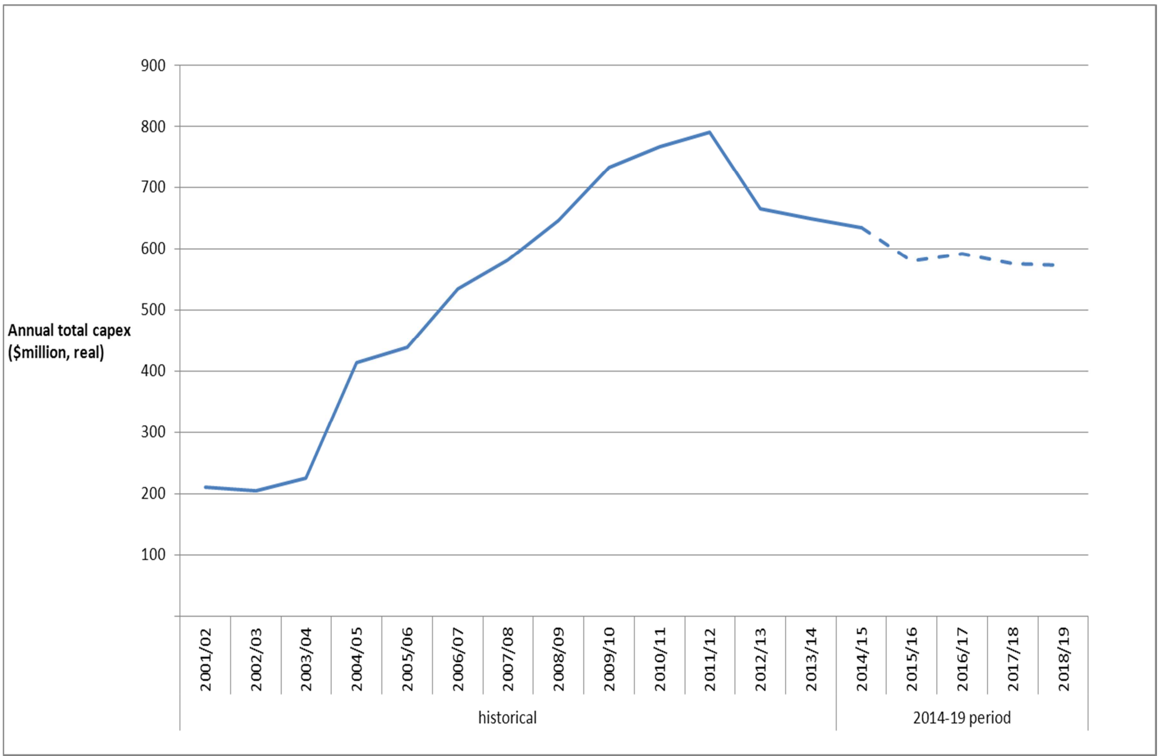
Source: AER analysis.

Essential Energy historic trend and licence conditions

We have also considered how Essential Energy's capex allowance should change to reflect current trends in demand and changes in licence conditions. Networks NSW has commented that at the time of submitting their regulatory proposals for the previous determination, the DNSPs needed to address the legacy of previous under-investment in their networks. While, it is arguable that earlier periods may reflect unsustainable expenditure, for these reasons outlined below, the 2009–2014 regulatory period is likely to overstate capex levels. This means that it may be appropriate for us to compare Essential Energy's capex proposal for the 2014–2019 period against the long term historical trend in capex levels.

Figure 6-8 shows actual historic capex and proposed capex between 2001–12 and 2018–19. This figure shows that Essential Energy's proposed capex for the 2014–2019 period is relatively high when compared with the historical average.

Figure 6-8 **Essential Energy total capex (including overheads)—historical and forecast for 2014–2019 period**



Source: Historical: IPART Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010–11 to 2013–14) 2014–2019 period: Ausgrid's Reset RIN, Table 2.1.1 - Standard control services capex).

A key driver of capex from 2005 was the NSW licence conditions around design standards. These were removed in July 2014.

On 1 August 2005, the NSW Minister for Energy & Utilities introduced the New Licence Condition for NSW DNSPs requiring certain reliability and network design and planning standards to be met.

These changes increased the capex requirements of the NSW DNSPs. As the 2004–2009 regulatory determination had already been made, the NSW DNSPs applied to the NSW Independent Pricing and Regulatory Tribunal (IPART) to have these costs passed through to customers. IPART approved a pass through of $624.2 million for Essential Energy.[30]

These cost pass throughs explain a significant proportion of the capex increases from 2005–06 to 2008/09, even before the even greater capex increases for the 2009–2014 regulatory control period were proposed. The licence conditions were subsequently amended in December 2007 to delay implementation of some of the requirements (though the DNSPs had already received their pass throughs).[31]

The recent amendment to the licence conditions, which took effect from 1 July 2014, removed the design planning requirements. Previously, NSW DNSPs were required to design and plan their networks to a specified standard. Without these standards, NSW DNSPs can decide how to design

30 IPART, *NSW Distribution Network Cost Pass Through Review - Statement of Reasons for decision*, 5 May 2006.
31 See http://www.ipart.nsw.gov.au/files/9c9eef97-8a35-4b95-901a-a16900bdef9b/.

and plan their network to meet the specified reliability (and customer service) standards. In particular, the businesses should only be undertaking capex where the benefits outweigh the costs.

Removing the design planning requirements should reduce capex requirements for NSW DNSPs. The Australian Energy Market Operator (AEMO) estimated:

> NSW customers could save up to $50 a year on their electricity bills from 2015 without any detrimental effect to current reliability levels if a probabilistic approach to distribution reliability was adopted over the current and next financial year.[32]

The Australian Energy Market Commission (AEMC) estimated that capex could reduce by $140 million under the modest reduction scenario to $530 million under the extreme reduction scenario' over a five year timeframe for the three NSW DNSPs.[33]

Even without the change in standards, it could be expected that NSW DNSPs' capex would come down for the 2014–2019 regulatory control period given the significant capex invested from 200506 to meet the standards. As noted by the AEMC:

> We note that significant investment has been made since the NSW distribution reliability requirements were increased in 2005 and that future investment will be incremental in order to maintain reliability at the current level.[34]

Relevantly, the recent rule change to the expenditure objectives in the NER means that Essential Energy does not need to maintain, and does not need the expenditure to maintain, the previous level of performance that was required prior to 1 July 2014.[35] Where regulatory obligations or requirements associated with the provision of services apply, as they do here in relation to reliability standards, it is sufficient that a DNSP comply with those standards; there is no requirement that they maintain the higher historical levels of performance such that they would exceed the levels required to meet those standards. The AEMC in making this rule change concluded that it would likely promote efficient investment in, and operation of, network services, in part because:

> It will provide clarity on the level of reliability, security and quality that NSPs should use in their proposed expenditure for the regulatory control period. In the same way it will also provide clarity to the AER about the level of reliability, quality and security that it should use in assessing the NSP's proposals and determining the expenditure allowance. The rule provides this clarity by allowing the decision of the body with the responsibility for setting the standard to be given effect to as part of the regulatory determination process. This should result in a more efficient outcome, as this body has been chosen as best placed to make the decision.[36]

Our reasoning therefore is based on the current reliability standards that apply to DNSPs.

We consider that the change in licence conditions is likely one of the key reasons for the reduction in capex proposed by Essential Energy for the 2014–2019 regulatory control period. However, it has not reduced to the levels that existed prior to the licence conditions being introduced. Given the recent changes in licence conditions, we consider the period prior to 2005 should be the benchmark for assessing the level of capex for the 2009–2014 regulatory control period.

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32 AEMO, *Submission to AEMC's Review of Distribution Reliability Outcomes and Standards, Draft Report - NSW Workstream*, p. 1.

33 AEMC, *Review of Distribution Reliability Outcomes and Standards, Final Report - NSW Workstream*, 31 August 2012, p. vi, http://www.aemc.gov.au/media/docs/NSW-workstream-final-report-160466c4-733b-4cf2-b4e3-4095c6d9819b-0.pdf.

34 AEMC, *Review of Distribution Reliability Outcomes and Standards, Final Report - NSW Workstream*, 31 August 2012, p. iii, http://www.aemc.gov.au/media/docs/NSW-workstream-final-report-160466c4-733b-4cf2-b4e3-4095c6d9819b-0.pdf.

35 AEMC, *Final Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 No. 5.*

36 AEMC, *Final Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 No. 5*, pp. 7-8.

6.4.4 Interrelationships

There are a number of interrelationships between Essential Energy's total forecast capex for the 2014–2019 period and other components of its distribution determination that we have taken into account in coming to our draft decision. Table 6-4 summarises these other components and their interrelationships with Essential Energy's total forecast capex.

Table 6-4 Interrelationships between total forecast capex and other components

Other component	Interrelationships
Total forecast opex	There are elements of Essential Energy's total forecast opex that are interrelated with its total forecast capex. These are: ▪ the labour cost escalators that we approved in (refer Opex rate of change Appendix)] ▪ the amount of maintenance opex that is reflected in Essential Energy's opex base year that we approved in (refer to Attachment 7] The labour cost escalators are interrelated because Essential Energy's total forecast capex includes expenditure for capitalised labour. As to the amount of maintenance opex, although we did not approve a specific amount of maintenance opex as part of assessing Essential Energy's total forecast opex, it is interrelated. This is because the amount of maintenance opex that is reflected in Essential Energy's opex base in part determines the extent to which Essential Energy needs to spend repex during the 2014–2019 period.
Forecast demand	Forecast demand is interrelated with the amount of forecast growth driven capex that is included in Essential Energy's total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
CESS	The CESS is interrelated to Essential Energy's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, or that it reasonably reflects the capex criteria. As we noted in the capex criteria table above, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from Essential Energy's regulatory asset base. In particular, the CESS will ensure that Essential Energy bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Essential Energy can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, Essential Energy risks having to bear the entire overspend.
STPIS	The STPIS is interrelated to Essential Energy's total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2014–2019 period. This is because such expenditure should be offset by rewards provided through the application of the STPIS (of which our incentive rates ensures that such rewards reflect the value customers place on reliability improvement).
Contingent project	A contingent project is interrelated to Essential Energy's total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of Essential Energy's total forecast capex for the 2014–2019 period. We did not identify any contingent projects for Essential Energy during the 2014–2019 period.

Source: AER analysis.

6.4.5 Consideration of the capex factors

In applying our assessment techniques to determine whether we are satisfied that Essential Energy's proposed total forecast capex and our alternative estimate reasonably reflects the capex criteria, we have had regard to the capex factors. Where relevant, we have also had regard to the capex factors in assessing the forecast capex associated with its underlying capex drivers as set out in appendix A. Table 6-5 summarises how we have taken into account the capex factors.

Table 6-5 AER consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient DNSP over the relevant regulatory control period	We have had regard to our most recent benchmarking report in assessing Essential Energy's proposed total forecast capex and in determining our alternative estimate for the 2014–2019 period. This can be seen in the metrics we used in our assessment of Essential Energy's capex performance.
The actual and expected capex of Essential Energy during any preceding regulatory control periods	We have had regard to Essential Energy's actual and expected capex during the 2009–2014 and preceding regulatory control periods in assessing its proposed total forecast capex and in determining our alternative estimate for the 2014–2019 period. This can be seen in our assessment of Essential Energy's capex performance. It can also be seen in our assessment of the forecast capex associated with each of the capex drivers that underlie Essential Energy's total forecast capex. In these cases, we have applied trend analysis which is reasonably likely to be recurrent in nature (e.g. compliance related expenditure, non-network related expenditure and replacement related expenditure).
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by Essential Energy in the course of its engagement with electricity consumers	We have had regard to the extent to which Essential Energy's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Essential Energy. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Essential Energy's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.
The relative prices of operating and capital inputs	We have had regard to the relative prices of operating and capital inputs in assessing Essential Energy's proposed real cost escalation factors for materials. We discuss this in Appendix D.
The substitution possibilities between operating and capital expenditure	We have had regard to the substitution possibilities between opex and capex. We have considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between Essential Energy's total forecast capex and total forecast opex in Table 6-4above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to Essential Energy	We have had regard to whether Essential Energy's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Essential Energy's total forecast capex and the application of the CESS and the STPIS in Table 6-4 above.
The extent to which the capex forecast is referable to	We have had regard to whether any part of Essential Energy's

Capex factor	AER consideration
arrangements with a person other than the DNSP that do not reflect arm's length terms	proposed total forecast capex or our alternative estimate that is referable to arrangements with a person other than Essential Energy that do not reflect arm's length terms. We did not identify any parts of Essential Energy's proposed total forecast capex or our alternative estimate that is referable in this way.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We have had regard to whether any amount of Essential Energy's proposed total forecast capex or our alternative estimate that relates to a project that should more appropriately be included as a contingent project. We discuss this in Appendix X. We did not identify any such amounts that should more appropriate be included as a contingent project.
The extent to which Essential Energy has considered and made provision for efficient and prudent non-network alternatives	We have had regard to the extent to which Essential Energy made provision for efficient and prudent non-network alternatives as part of our assessment of the capex associated with the non-network capex driver. We discuss this further in Appendix A.
Any relevant final project assessment report (as defined in clause 5.10.2 of the NER) published under clause 5.17.4(o), (p) or (s)	There are no final project assessment reports relevant to Essential Energy for us to have regard to.
Any other factor the AER considers relevant and which the AER has notified Essential Energy in writing, prior to the submission of its revised regulatory proposal under cl.6A.12.3, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

A Assessment of forecast capex drivers

As we discuss in attachment 6, we are not satisfied that Essential Energy's proposed total forecast capital expenditure (capex) reasonably reflects the capex criteria. This conclusion is based in part on our analysis of the capex drivers that underlie Essential Energy's forecast capex for the 2014–2019 period as set out in this Appendix. This analysis also explains the basis for our alternative estimate of Essential Energy's total forecast capex that we are satisfied reasonably reflects the capex criteria.

This appendix considers each capex driver as follows:

Section A.1: augmentation capex (augex)

Section A.2: customer connections capex

Section A.3: asset replacement capex (repex)

Section A.4: non-network capex

Section A.5: capitalised overheads

Section A.6: demand management.

A.1 AER findings and estimate for augex

Growth driven capex is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability. Growth-driven capex includes augmentations and new connections.

A.1.1 Position

Essential Energy proposed $744.6 million ($2013–14) for forecast augex over the 2014–2019 period. This is 43.8 per cent less than the actual augex that it spent during the 2009–2014 regulatory control period. We do not accept Essential Energy's proposal. We have instead included an amount of $475.2 million ($2013–14) for forecast augex in our alternative estimate, a reduction of 36 per cent.

This amount is sufficient to provide Essential Energy with a reasonable opportunity to recover at least the efficient costs to build its network to meet demand and reliability requirements.

In coming to our view we applied:

- trend analysis, comparing the proposed augex with historic expenditure levels, taking into account changes in demand, network capacity and design and planning standards to assess whether the forecast is within a reasonable range to allow Essential Energy to meet expected demand, and comply with relevant regulatory obligations[37]
- an engineering review undertaken by WorleyParsons of Essential Energy's forecasting processes and methodology to assess whether Essential Energy's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives

[37] NER, cl. 6.5.7(a)(3).

- the augex model to generate trends in asset utilisation, to assess Endeavour Energy's need for network augmentation.[38]

Based on this analysis, our reasons for not accepting Essential Energy's proposal and including $475.2 million ($2013–14) for forecast augex in our alternative estimate instead are as follows.

First, the trend in augex shows that Essential Energy has proposed moderate reductions to its augex in comparison to the 2009–2014 regulatory control period. However, the reduction in augex is considerably less than the other New South Wales distribution network service providers (NSW DNSPs) that face similar trends in demand and excess network capacity. Given the level of excess network capacity, low system demand growth and moderate pockets of growth, we consider that Essential Energy has proposed higher augex than it requires to meet the demand growth in its network.

Second, 56 per cent of Essential Energy's augex forecast was based on capacity requirements for their HV network. Essential Energy provided a draft of their 2014 demand forecasts that show a reduction in ratcheted demand of 35.67 per cent. We have used Essential Energy's draft 2014 spatial demand forecasts to reduce the expenditure required for its HV feeders by 35.67 per cent. This follows from analysis by Ausgrid which concluded a positive linear relationship exists between a change in forecast demand and expenditure requirements for HV feeders.

Third, based on independent advice from WorleyParsons, it is evident that Essential Energy's augex forecast is biased because it has not sufficiently taken into account the impact of the changes to the NSW licence conditions design standards that took effect on 1 July 2014.[39] WorleyParsons concluded that Essential Energy could achieve efficiency gains by applying a risk-based cost benefit analysis assessment techniques to new and ongoing programs of work. In light of this advice, and the observed trend in augex, we have applied a further 20 per cent reduction to account for the absence of Essential Energy applying a risk-based cost benefit analysis technique. In our view, this reduction will not put at risk Essential ability to recover at least its efficient costs.

Fourth, Essential Energy's proposed expenditure forecast for HV feeders is also higher than we would expect given the downwards trend in the costs of HV feeders since 2012. This coincides with the increased efficiencies brought about by Networks NSW. This reduction suggests that proposed expenditure on HV feeders and other augmentation related expenditure should be lower. However, we have not made a specific reduction to account for the downwards trend in HV feeders expenditure.

Finally, the recent VCR results published by AEMO suggest that Essential Energy's customers are willing to accept greater risk in the reliability of electricity supply than is currently being applied by Essential Energy. This suggests that the augex forecast is likely to be higher than the amount that Essential Energy's customers are willing to pay for. This also suggests that some projects currently included in Essential Energy's proposal may not be required once a cost-benefit analysis incorporates the new VCR values.

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38 The augex model has been developed to derive an estimate of required augex based on predicted augmentation requirements (based on demand and asset utilisation) and unit costs. However, we have not relied heavily on the augex model for this reset. This is because much of the augex in the 2009-2014 period was due to compliance with the design standard in the licence conditions rather than reflecting growth in demand. Indeed, the negative demand growth and positive growth in augex in some network segments resulted in the model being unable to produce reliable benchmark results from the previous period. Therefore, for this decision we have only had regard to trends in utilisation rates in a qualitative sense. We will apply the augex model to a greater degree in future determinations as we build up our dataset.

39 In addition, unlike the other NSW DNSPs, Essential has not issued an interim planning standard to address the removal of deterministic design standards from the NSW licence conditions.

We recognise that Essential Energy's augex forecasts were made in advance of the changes to the VCR. We have not quantified the extent to which these changes impact upon Essential Energy's forecast and so our estimate for the purpose of this draft decision does not reflect the change in VCR. However, we expect that Essential Energy will assess and incorporate the changes to the VCR in its total forecast capex as part of submitting its revised regulatory proposal. Table A-1 below sets out a breakdown of the amount of forecast augex we have included in our alternative estimate.

Table A-1 AER's alternative estimate of augex ($2013–2014, million)

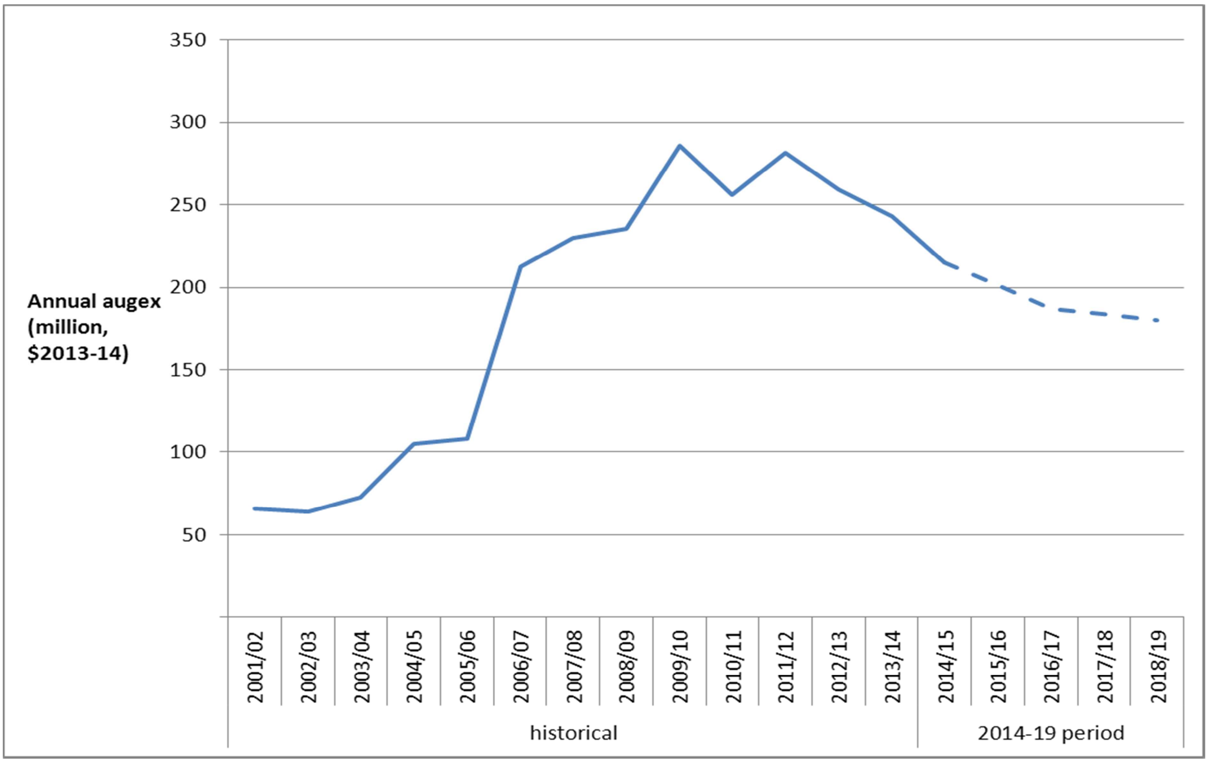
	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Augex forecast	169.1	154.8	143.7	140.3	136.7	744.6
Demand adjustment to HV network augex	-26.8	-29.5	-31.3	-31.5	-31.6	-150.6
Augex forecast with demand adjustment	**142.4**	**125.3**	**112.4**	**108.8**	**105.1**	**594.0**
Further 20% reduction	-28.5	-25.1	-22.5	-21.8	-21.0	-118.8
AER revised augex forecast	113.9	100.2	89.9	87.0	84.1	475.2

Source: AER analysis.

Trend Analysis

Figure A-1 shows the trend in augex between 2001 and 2019. This trend shows that Essential Energy proposes similar levels of augex to what it spent between 2006 and 2009.

Figure A-1 Essential Energy's augex (including overheads) historic actual and proposed for 2014–2019 period ($2013–14, million)



Source: Essential RIN, Essential proposal, AER analysis.

Note: All figures up to 2013–14 denote actual expenditure. Figures from 2014–16 to 2018–19 are Essential Energy's forecasts. All figures include allocate capitalised network and corporate overheads on the basis of augex as proportion of total capex.

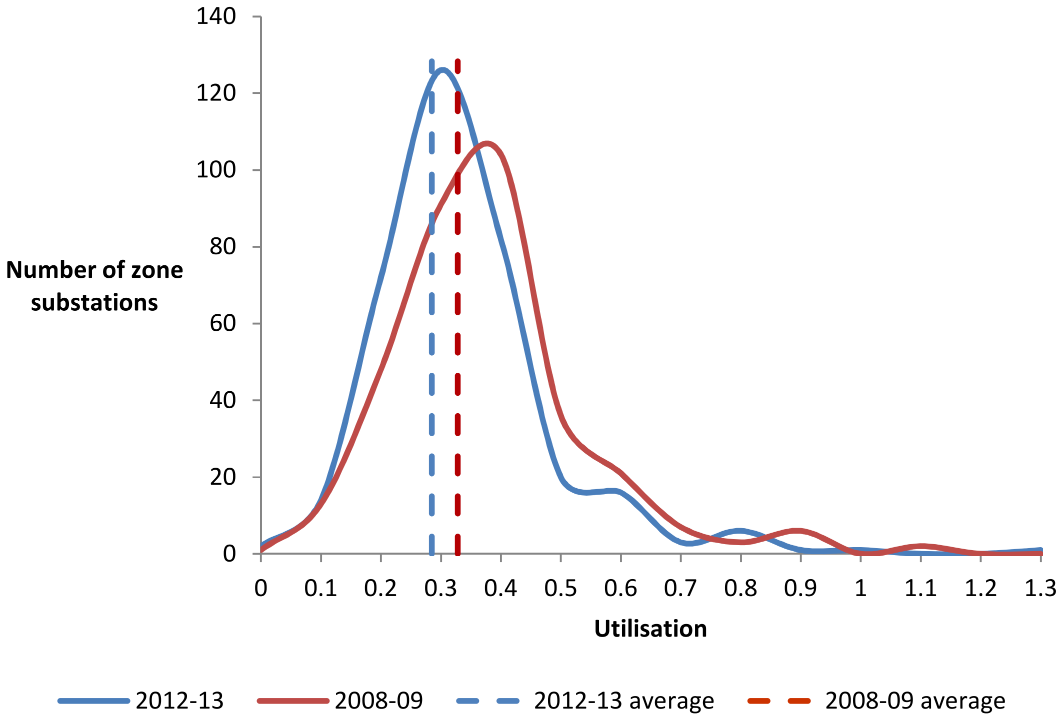
We would expect Essential Energy to propose lower levels of augex for the 2014–2019 regulatory control period due to the combination of:

- low demand growth — as discussed in appendix C, the available evidence points to slow demand growth (and a possible fall in demand) in Endeavour's network over the 2014–2019 period. This forecast trend in demand is lower than in previous regulatory determinations.
- the change in network design standards — a key driver of Essential Energy's capex from 2005 was the network design standards in its NSW licence condition. These design requirements led to significant augmentation investment over the previous regulatory period, increasing the levels of network capacity. The NSW Government removed these standards within Essential Energy's licence conditions in July 2014.[40]
- declining asset utilisation — the increase in augmentation works and decrease in actual demand over the 2014–2019 regulatory control period increased levels of excess capacity in the network (as evident in Figure A-2 and Figure A-3 below).

Figure A-2 and Figure A-3 show decreasing utilisation levels at Essential Energy's zone substations and HV feeders, respectively, between 2008–09 and 2012–13. Taken together with the low demand growth, this suggests there is excess capacity in the network that needs to be utilised ahead of additional augmentation investment.

[40] The changes in the licence condition design standards are relevant to the AEMC's 2013 amendments to the expenditure objectives. The amendments sought to address the problem that the previous expenditure objectives, as stated by the AEMC, “could be interpreted so that the expenditure an NSP includes in its regulatory proposal is to be based on maintaining the NSP's existing levels of reliability, security or quality, even where an NSP is performing above the required standards for these measures, or where required standards for those measures are lowered.” Consequently, where standards have been lowered for reliability or security and supply, the expenditure objectives now clarify that Ausgrid does not need to maintain, and does not need the expenditure to maintain, the previous level of performance. See AEMC, *Final Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 No. 5*, p. ii.

Figure A-2 Essential Energy zone substation utilisation profile



Source: AER analysis; augex model.

Note: Utilisation is the ratio of maximum demand and the normal cyclic rating of each substation for the specified years.[41] Figure A-2 shows the number of Essential Energy's total zone substations at each utilisation band.

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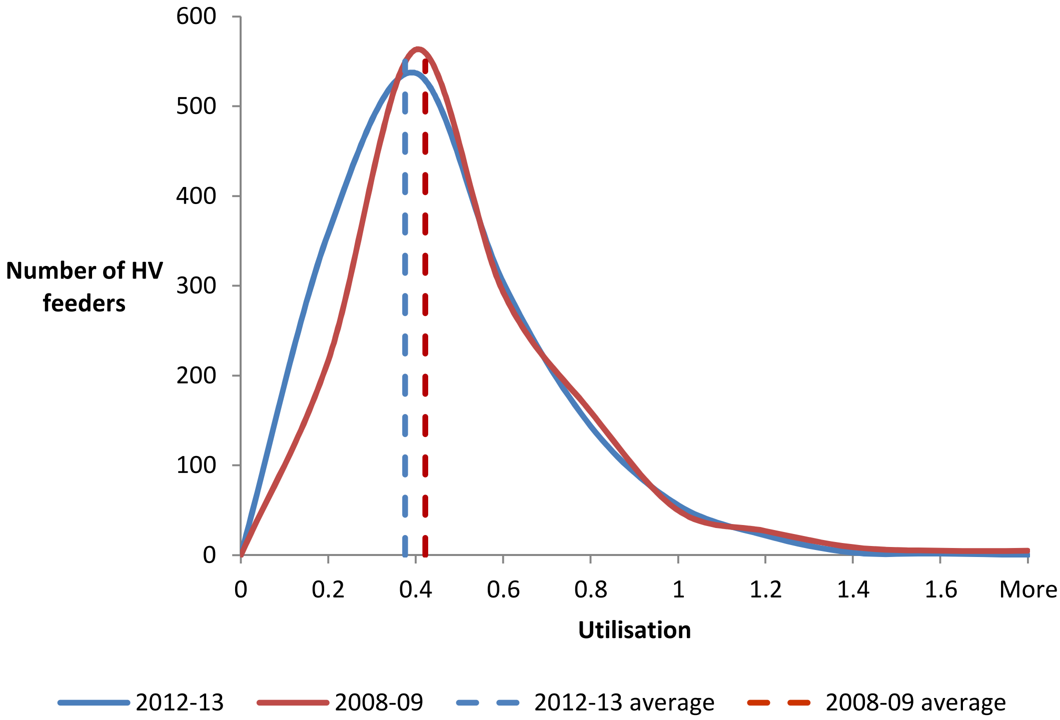
[41] Normal cyclic rating is the maximum peak loading based on a given daily load cycle that a substation can supply each day of its life under normal conditions resulting in a normal rate of wear.

Figure A-3 HV feeder utilisation 2008–09 and 2012–13



Source: AER analysis; augex model.
Notes: Utilisation is the ratio of maximum demand and the thermal rating of each feeder for the specified years.[42] Figure A-3 shows the number of Essential Energy's total HV feeders at each utilisation band.

The AER's Consumer Challenge Panel (CCP Subpanel 1) submitted that the general decline in asset utilisation between 2006 and 2013 provides an estimate of the significant excess capacity on Essential Energy's network.

While Essential Energy has proposed a 43.8 per cent reduction in augex compared with the actual augex it spent in the 2009–2014 regulatory control period, this reduction is significantly less than the 76 per cent reduction proposed by Ausgrid and the 61 per cent reduction proposed by Endeavour Energy. On the basis of this comparison, we consider that it is reasonable to suggest that Essential Energy could have proposed greater reductions in augex. This is because the NSW DNSPs all face similar trends in demand growth, exhibit similar levels of excess network capacity, and there is not anything materially different between their governance structures that would preclude Essential Energy from achieving further cost reductions. In arriving at this view, we recognise that parts of the Essential Energy network are sparsely populated compared to Ausgrid and Endeavour Energy; however, the proportionate impact of this difference is not material.

Nonetheless, there may be a need for augmentation work in specific areas where demand is increasing, for example new residential developments. Essential Energy proposed that it will need to invest in augex to meet pockets of growing demand in its network. Essential Energy notes that only a modest portion of proposed augex is required to meet the growing demand of specific network areas which are in diverse areas compared to the overall trend of flat demand across its network.[43] However, Essential Energy does not identify which specific areas of its network are constrained nor

[42] Thermal rating is the maximum rating assigned to a line or cable under normal operational conditions, that is, resulting in a normal life expectancy.
[43] Essential Energy, *Regulatory proposal*, May 2014, p. 44.

provide evidence of existing assets being over-utilised and the investment required to address these constraints.

In its regulatory proposal, Essential Energy provided the spatial demand forecast for each major substation in its network that it produced in 2013 (2013 forecasts). Essential Energy forecast that 77 per cent of substations would on average grow positively over the 2014–2019 period. During our draft determination process, Endeavour provided us with draft updated spatial demand forecasts (2014 forecasts). As Table A-2 shows, on average, the number of major substations with expected positive demand growth rates rose by 8 per cent between the 2013 and 2014 forecasts.

Table A-2 Number of major substations with positive forecast demand growth rates

	2015/16	2016/17	2017/18	2018/19	Average
2014 forecasts	303	311	310	311	314
2013 forecasts	292	291	293	292	292
Per cent increase	3.8	6.9	5.8	6.5	7.5

Source: Essential Energy, Reply to AER Essential 032 - updated demand forecasts, 3 November 2014; AER analysis.
Notes: 'Per cent reduction' denotes the percentage reduction in the number of major substations with positive demand forecast growth rates between the 2013 forecasts and the 2014 draft forecasts.

This increase in the number of major substations with expected positive demand growth provides some evidence to support Essential Energy's augmentation requirements. However, between the 2013 and 2014 forecasts, 62 per cent of substations forecast a drop in demand. This provides evidence that Endeavour's augex forecast should be lower than it proposed.[44] We estimate the likely impact of this drop in demand in the section below.

The EMRF also submitted that Essential Energy's forecast augex is overstated due to significant past expenditure and low demand forecasts:

> These two observations make the EMRF consider that the [2014–2019] augmentation capex is too high because:
>
> 1. If the network was still being augmented in [2009–2014] despite a falling demand and consumption, then Essential would have provided assets that reflected the need for growth forecast but were not needed due to the changed circumstance and are therefore likely to be oversized for the demand expected during AA4. Whilst there is likely some need for localised extensions to the network, it is unlikely that significant reinforcement of the network will be required due to the modest growth forecast.
>
> 2. During period [2005-2009] there was significant growth in demand and consumption, yet the augmentation capex forecast for [2014–2019] is of a similar magnitude to that incurred in [2005-2009]. If the capex for [2005-2009] was sufficient to manage the widespread growth seen at the time, then it would be expected that the capex needed for a period of relative static growth would need considerably less augmentation capex, especially after the over-building seen in [2009–2014]
>
> …
>
> Overall, the EMRF considers that the forecast augmentation capex is overstated and should be significantly less than sought by Essential.[45]

[44] While we understand Endeavour has not yet finalised these updated demand figures, they indicate how Endeavour Energy's demand forecasts will likely change in its revised regulatory proposal.

[45] EMRF submission, p. 81

Overall, we consider that Essential Energy has not reduced augex as much as would be expected given the significantly reduced network-wide requirements for augmentation and considering the reduced augex proposed by the other NSW DNSPs under similar demand and capacity conditions. It is not clear from the evidence that Essential Energy's relatively high augex forecast is explained by the need to meet areas of growing demand or the different characteristics of the sparsely populated parts of the Essential Energy network.

Engineering review of forecasting methodology

We engaged engineering consultant WorleyParsons to review whether there are any systematic issues that may result in biases in Essential Energy's augex forecasts.[46]

We asked WorleyParsons to identify whether:

- Essential Energy's forecast is a reasonable forecast of the unbiased efficient cost of maintaining performance at the required or efficient service levels
- Essential Energy's risk management processes are prudent and efficient, and
- Essential Energy's costs and work practices are prudent and efficient.

To conduct this review, WorleyParsons reviewed a sample of Essential projects or programs:

- High expenditure/carryover at start of the 2014–2019 period
- Rescheduled sub transmission/zone substation projects
- Deferred sub transmission/zone substation projects
- HV feeders
- Design planning criteria
- Work practices.

The sampling of the Essential Energy's augex projects or programs then focussed on assessing Essential Energy's forecast expenditure given the changes to the licence conditions for the new period and the transition from a deterministic planning methodology for assessing investments to a probabilistic or risk-based cost-benefit analysis methodology.

WorleyParsons found that Essential Energy's augex costs are likely to be higher than would be incurred by a prudent and efficient service provider due to conservative approaches to asset and risk management.[47] The key findings to support this conclusion were:

- Essential Energy has only given limited consideration to the impact of the changes to the NSW licence conditions design standards from 1 July 2014. Furthermore, significant expenditure based on the previous conditions has been deferred or rescheduled into the 2014–2019 period. Unlike

46 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014.

47 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014, p. 22

the other NSW DNSPs, Essential has not issued an interim planning standard to address the removal of deterministic design standards from the NSW licence conditions.[48]

- There has been little indication that risk-based assessments have been used in developing expenditure forecasts for new projects or in the review of deferred projects. Essential Energy recognises that improved processes will be required going forward to promote a prudent approach to the actual commitment of expenditure during the period and for future planning; however they do not remove biases in the existing regulatory proposal forecasts.[49]

- Expenditure on HV feeders is a major component of Essential Energy's augex forecast. WorleyParsons analysis of the four largest HV feeder growth programs (voltage constraints, thermal constraints, fault level constraints and customer connections) revealed that expenditure forecasts for HV feeders have been based on the average expenditure in this segment over the past two years, including an estimate of 2013–14 expenditure. There has been a downwards trend in the costs of augmenting HV feeders since 2012, and the actual expenditure in 2013–14 was lower than estimated. This trend including the lower than forecast 2013–14 expenditure has only been partially realised in the forecast.[50]

- Essential Energy has deferred six sub-transmission and zone-substation projects into the 2014–2019 period. The projected expenditure of these projects is based on the previous licence conditions design standard. The repeal of the previous licence condition may result in changes to the scoping and staging of the projects based on the new planning methodologies being formulated by Networks NSW and the NSW DNSPs.[51]

- Under the flat overall growth projections, the rate of expenditure required to address localised growth issues is likely to continue to fall during the 2014–2019 period due to the impact of past expenditure in improving network conditions and performance.[52]

- Although the potential for cost reductions in some areas has been identified, there has not been a strong sense or evidence that Essential Energy is pursuing the most cost effective practices for delivery of its augex program. The wide geographical area covered by Essential Energy's network creates specific issues in the availability of skilled external resources in regional areas and the optimum role for deployment and operation of Essential Energy depots.[53]

Based on its observations, WorleyParsons concluded that Essential Energy could achieve efficiency gains over the 2014–2019 period through the application of risk assessment techniques and consideration of alternatives to projected programs of work would be expected to identify reductions and deferment in the timing of augex.[54] Furthermore, in relation to projects deferred to the 2014–2019

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48 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, pp. 21-22.

49 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, pp. 23-24.

50 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, pp. 19-21, and 23.

51 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, pp. 18-19.

52 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 23.

53 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 23.

54 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 23.

period, assessment of alternatives and other potential changes could reduce costs as part of the ongoing planning review and investment approval processes.[55]

We consider that Essential Energy could efficiently make a 20 per cent reduction to its augex projects by applying these factors. This is reasonable in light of the advice of WorleyParsons in relation to Endeavour Energy. For Endeavour Energy, WorleyParsons noted that the application of risk based cost benefit analysis assessment techniques had the potential to reduce expenditure by between 10 and 20 per cent.[56] We also do not consider that there is anything so materially different between the governance structures of Essential Energy and Endeavour Energy that would suggest that similar cost reductions were not achievable.

However, we have observed that Endeavour Energy proposed significant reductions in its augex forecast compared to the 2009–2014 regulatory control period, whereas Essential Energy's reductions are more moderate (Essential Energy's proposed reductions are approximately 33 per cent less than Endeavour Energy's). Therefore, taking into account our trend analysis, we consider that Essential Energy can efficiently meet a higher reduction in its augex without putting at risk its ability to recover at least its efficient costs.

Second, in relation to the forecast HV feeders expenditure, Essential Energy can recognise the actual level of expenditure for 2013-14 rather than the estimate and that the downwards trend in expenditure since 2012-13 will likely continue as a consequence of the impact on network conditions and performance of past augmentation.[57] Figure A-4 shows as a blue column the historic expenditure (of the four largest HV feeder growth programs – voltage constraints, thermal constraints, fault level constraints and customer connections) used by Essential Energy (including an estimate for 2013–14) to forecast the expenditure. Evident from the graph is the 30 per cent reduction in expenditure in 2012–13, and a further 12 per cent reduction in 2013–14 (using the actual expenditure (the light green column). The green column shows an alternative forecast trend for these programs.

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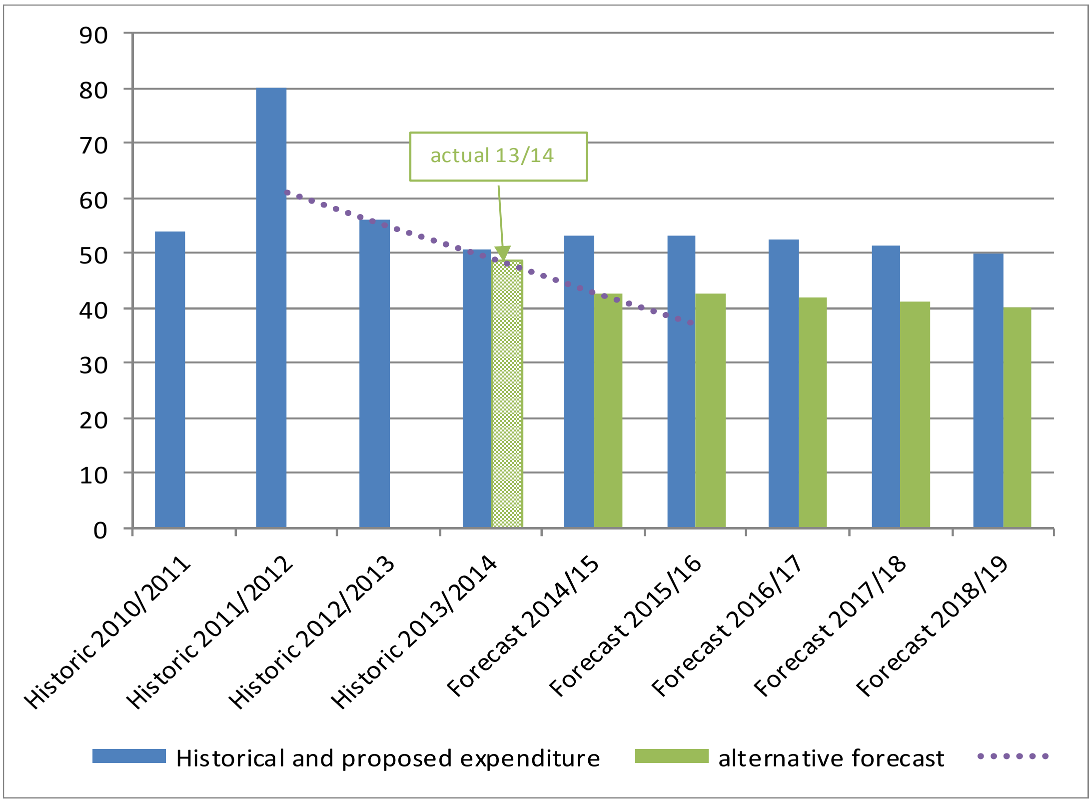
[55] WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 19.

[56] WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 8.

[57] WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 21.

Figure A-4 Historic and alternative HV feeder growth program expenditure (million $2013-14)



Source: AER analysis.

These efficiency gains are not reflected in the augex forecast, and hence this forecast is higher than would be incurred by a prudent and efficient service provider. We have taken these findings into account when forming our conclusion on Essential Energy's proposed augex forecast.

Change in value customers place on electricity reliability

In October 2014, subsequent to the submission of Essential Energy's regulatory proposal, AEMO published the results of its national Value of Customer Reliability (VCR) review. The VCR represents, in dollars per kilowatt hour, the willingness of customers to pay for the reliable supply of electricity. Generally speaking, a low VCR figure means that customers place less value on additional capital and operating expenditure that leads to increased reliability, if this leads to higher electricity prices.

As set out in Table A-3, the results of AEMO's study reveals that VCRs are now lower than in previous studies of VCR in New South Wales, with the lower VCRs driven primarily by commercial and agricultural customers. WorleyParsons also observed that the published VCR values are lower than the value used by Essential Energy which had been derived from the AER Service Target Performance Incentive Scheme.[58]

[58] WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 –2019*, 17 November 2014, p. 21.

Table A-3 2014 AEMO VCR results

VCR ($ per kWh)	NEM-wide	NSW	Previous study: 2007 NSW VCRs
Overall	39.00	38.35	43.25
Residential	25.95	26.53	21.19
Agricultural (average)	47.67	47.67	84.32
Commercial (average)	44.72	44.72	84.32
Industrial (average)	44.06	44.06	39.52

Source: AEMO.[59]
Note: The 2007 NSW VCR results have been adjusted for inflation.
Overall estimates of the VCR exclude direct connect customers.

A lower VCR suggests that customers are more accepting of risk in terms of reliability of electricity supply. A network operator acting prudently should take risk into account when assessing the need for particular projects. For example, some projects currently included in Essential Energy's proposal may not be required once a cost-benefit analysis incorporates the new VCR values. This would promote efficient investment, as customers would pay no more than they are willing to bear for the reliable supply of electricity.

We recognise that Essential Energy's augex forecasts were made in advance of the changes to the VCR. We expect that Essential Energy will assess the changes to the VCR in the context of submitting a revised regulatory proposal. For the purposes of making this draft decision, rather than make a specific adjustment for the significant reduction in VCR, we have used it to inform our judgement on the appropriate total augex forecast that we consider reasonably reflects the capex criteria, taking into account all the other evidence discussed in this section.

We note that a change in VCR has the most significant implications for augex because it changes the need for additional investment in capacity and reliability. However, it can also impact the need for repex. This is considered in section A.3.

HV feeders and revised demand forecasts

Essential Energy's forecast augex of $422.23 million ($2013–14) for HV feeders makes up 56 per cent of its total augex forecast. Table A-4 summarises the components of Essential Energy's HV feeder augex forecast.

59 AEMO, *Value of customer reliability review: Final Report*, September 2014, pp. 2, 18, 30; Oakley Greenwood, *Valuing reliability in the NEM*, March 2011, pp. 32–33.

Table A-4 Essential Energy augex forecast for HV feeders ($2013–2014, million)

Project type	2014/15	2015/16	2016/17	2017/18	2014/15
Overhead HV feeder augmentations	67.2	73.9	78.4	79.0	79.2
Underground cables HV feeder augmentations	7.9	8.7	9.2	9.3	9.3
Total HV feeder augmentations	**75.1**	**82.7**	**87.7**	**88.3**	**88.5**

Source: Essential Energy RIN.

As we noted previously, Essential Energy provided updated demand spatial forecasts for each of its major substations (2014 forecasts). While we understand Essential Energy has not yet finalised these figures, they indicate how Essential Energy's demand forecasts will likely change in its revised regulatory proposal.

We consider that a reduction in forecast demand will lead to a proportionate reduction to Essential Energy's HV feeder augex program. This follows from analysis by Ausgrid which concluded a positive linear relationship exists between a change in forecast demand and expenditure requirements for HV feeders.[60] We consider an equivalent relationship exists between demand and HV feeder expenditure for Essential Energy and applies equally in the same circumstances as Ausgrid. This is because Ausgrid's HV feeder forecast model (its '11kV model') is general enough to apply to other HV distribution networks. We consider that there is nothing materially different between the requirements for augmentation driven by demand for DNSPs in general. This would suggest that similar cost reductions are achievable across all NSW

We have estimated the impact of these changes in demand on Essential Energy's HV feeders forecast, as we describe below.

We consider ratcheted demand provides a reasonable indication of the potential need for augmentation, where it is the most effective to do so (demand management is an alternative to augmentation, as discussed in section A.6).[61] Ratcheted demand is a useful way to keep track of the highest expected demand in a time series. This is important because decisions to augment the network (or otherwise) depend on being able to meet the highest forecast demand for a given period.

Table A-5 summarises the reduction in demand using a ratcheted demand approach. We first summed the ratcheted demand for all major substations for the 2018–19 regulatory year. We then subtracted the summed ratcheted demand for all major substations for the 2014–15 regulatory year. Based on our analysis, Essential Energy expects a 25.4 MVA, or 35.67 per cent, reduction in ratcheted demand in the 2014 forecasts.[62]

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60 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014– 2019*, 24 October 2014, section 3.4.3, WorleyParsons were engaged by the AER.

61 Ratcheted demand shows a time series in which the demand for a particular year is recorded only if it is higher than demand for previous years. For example, if demand in years 1, 2 and 3 are 90MW, 100MW and 95MW, respectively. The ratcheted demands for those years are 90MW, 100MW and 100MW, respectively. If a DNSP expects demand on a zone substation to peak in year *t* of a period, it will generally base its augmentation decision on the year *t* forecast even if it predicts slightly lower demand in subsequent years.

62 Essential's forecast, in its regulatory proposal, 314 MVA of additional demand throughout its major substations in the 2014–2019 period. Essential reduced this forecast to 273.8 MVA of additional demand in the 2014 forecasts.

Table A-5 Ratcheted demand (MVA)

	Difference between aggregated 2018/19 and 2014/15 forecasts
2014 forecasts	45.9
2013 forecasts	71.3
MVA reduction	25.4
Per cent reduction	35.67

Source: Essential Energy, Reply to AER Essential 032 - updated demand forecasts, 3 November 2014; AER analysis.

We applied a 35.67 per cent reduction to HV feeders components of Essential Energy's augex forecast (as listed in its RIN). Table A-6 shows that applying the 35.67 per cent demand adjustment reduces the expenditure forecast for HV feeder augmentations to $271.62 million ($2013–14). This is a reduction of $150.61 million ($2013–14) compared to Essential Energy's proposal for HV feeders.

Table A-6 Revised HV feeder augmentation program ($2013–14, million)

Project type	2014/15	2015/16	2016/17	2017/18	2018/19
Overhead HV feeder augmentations	43.2	47.6	50.4	50.8	50.9
Underground cables HV feeder augmentations	5.1	5.6	5.9	6.0	6.0
Total HV feeder augmentations	**48.3**	**53.2**	**56.4**	**56.8**	**56.9**
Reduction	26.8	29.5	31.3	31.5	31.6

Source: AER analysis.

A.2 AER findings and estimates for customer connections capex

The contestability framework in New South Wales allows customers to choose their own accredited service provider and negotiate efficient prices for connection services.[63] Given the competition between service providers, we do not regulate the majority of connection services in New South Wales. The forecast customer connections capex that is included in Essential Energy's total forecast capex is driven by augmentation and extensions to the shared distribution network to connect new commercial and industrial and residential customers.

A.2.1 Position

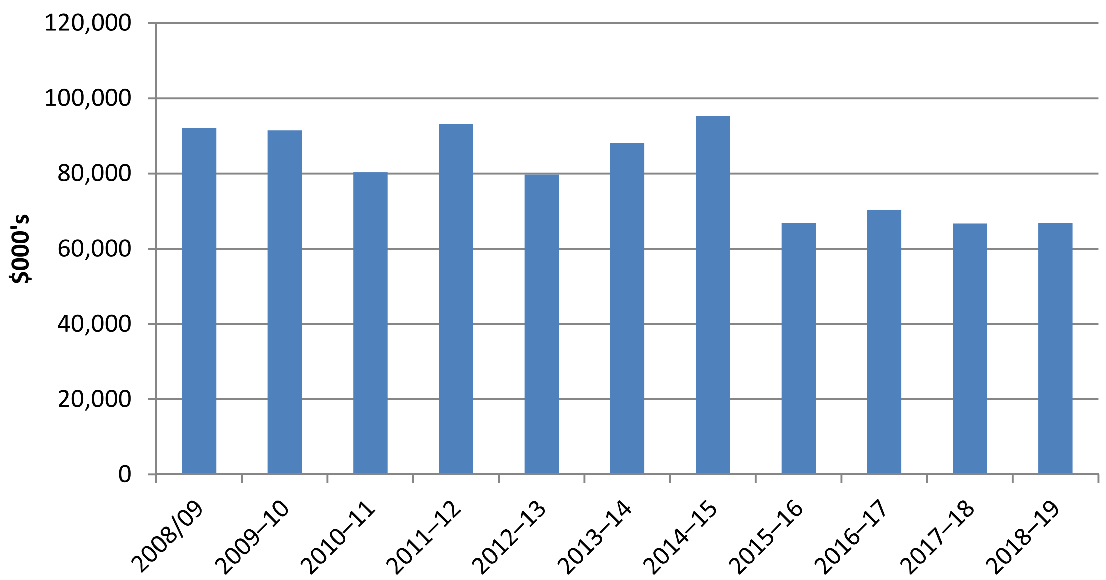
Essential Energy proposed connections capex of $366.08 million ($2013–14) for customer connections capex over the 2014–2019 period. This is approximately 12.3 per cent of Essential Energy's proposed total forecast capex and is 30 per cent less than the actual customer connections capex it spent during the 2009–2014 regulatory control period. Figure A-5 depicts the historical and forecast capex profile over the 2009–2019 period. We accept Essential Energy's proposal and will include it in our alternative estimate.

Table A-7 Essential Energy connections capex ($2013–14, million)

Customer-initiated service category	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Essential Energy proposed	95.32	66.79	70.39	66.75	66.83	366.08
AER approved	95.32	66.79	70.39	66.75	66.83	366.08

Source: Essential Energy RIN.

Figure A-5 Essential Energy connections capex



Source: Essential Energy RIN.

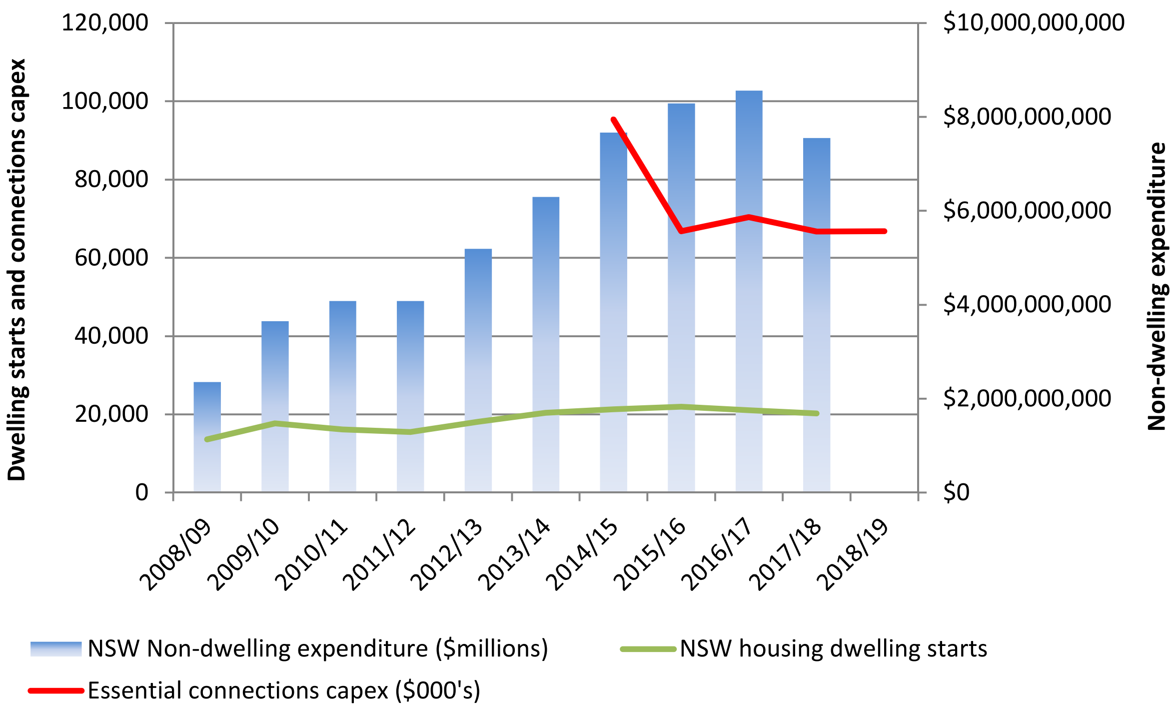
63 AER, Stage 1 Framework and Approach – NSW electricity distribution network service providers, p. 16.

Essential Energy submitted that its proposal is justified because of the low growth expected over the 2014–2019 period and significant program of augmentation work that it completed over the 2009–2014 regulatory control period.[64]

Figure A-6 shows that the trend of Essential Energy's proposed connections capex is not unreasonable when compared with the trend of forecast drivers in construction activity in commercial and industrial, and residential premises. There is a lag between dwelling starts and the time taken to connect to the distribution network, which explains the delay between trends of the two series.

PIAC urged us to investigate the funding requirements arising out of forecast connection works between high-density developments and urban or rural customers.[65] We consider Essential Energy's mix of forecast connection works is consistent with its customer base, forecast construction activity, and not biased toward works whose costs are recovered across the whole customer base.

Figure A-6 Essential Energy connections capex and NSW construction activity



Source: BIS Shrapnel,[66] Essential Energy,[67] Housing Industry Association.[68]

A.2.2 Assessment of capital contributions

Capital contributions include the value of assets constructed by third parties which are operated by Essential Energy, and payments from customers who directly benefit from connection services which are not contestable. We have subtracted Essential Energy's proposed capital contributions from gross capex to calculate net capex.

64 Essential Energy, *Regulatory proposal*, May 2014, p. 56.
65 PIAC, *Submission to NSW revenue proposals*, p. 39.
66 BIS Shrapnel, *Building in Australia 2013–2028*, table 5.1.
67 Essential Energy, RIN template 2.1, June 2014.
68 Housing Industry Association, http://hia.com.au/en/businessinfo/economicinfo/housingforecasts.aspx, accessed 18 November 2014.

We accept Essential Energy's proposed capital contributions forecast of $336.11 million, as we consider it is consistent with Essential Energy's forecast level of connection works which we are also accepting. We consider that capital contributions are mostly driven by connection and augmentation works, and in its revised proposal, we expect Essential Energy to clearly explain how capital contributions should be allocated to each service.

Table A-8 Essential Energy capital contributions ($2013/14, million)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Essential Energy proposed	89.38	60.82	64.39	60.73	60.78	336.11
AER approved	89.38	60.82	64.39	60.73	60.78	336.11

Source: Essential Energy RIN.

A.3 AER findings and estimates for replacement capital expenditure

Replacement capital expenditure (repex) is non-demand driven capex. It involves replacing an asset with its modern equivalent where the asset has reached the end of its economic life. Economic life takes into account existing asset's age, condition, technology or operating environment. In general, we classify capex as repex where the expenditure decision is primarily based on the existing asset's inability to efficiently maintain its service performance requirement.

A.3.1 Position

Essential Energy proposed $857 million ($2013–14) of forecast repex (excluding capitalised overheads).

We do not accept Essential Energy's proposal. We have instead included an amount of $676 million ($2013–14) in our alternative estimate, a reduction of 21 per cent.

In determining our alternative estimate we applied the following assessment techniques:

- benchmarking at the expenditure category level and trend analysis of historical actual and expected repex
- an engineering review of repex proposals
- predictive modelling of repex requirements.

In summary, we found that:

- Essential Energy's proposed repex is around 59 per cent higher than its long term average.
- Controlling for network scale characteristics, Essential Energy does not compare favourably to that of other service providers in the NEM.
- In relation to the likely condition of Essential Energy's assets, the substantial increase in spare network capacity during the 2009–14 regulatory control period provides an operating environment that should reduce the rate of deterioration of Essential Energy's assets over the 2014–2019 period.

- An engineering review carried out by EMCa found that there are systemic issues with Essential Energy's forecast that mean its proposal is likely to significantly overstate the amount of repex required to meet the capex objectives. In particular, Essential Energy is likely to be replacing assets many assets too early than is necessary to meet the capex objectives

- Our predictive modelling suggests that Essential Energy's proposal is likely to be overstated. This demonstrates that Essential Energy's asset replacement requirements are likely to be materially lower. The range of reasonable outcomes based on our modelling is between $590 million and $682 million for the six modelled asset categories. This is a 12 to 24 per cent reduction in Essential Energy's proposal, excluding capitalised overheads.

- For categories that were not included in predictive modelling, we are satisfied that a total of $86 million is likely to be a prudent and efficient level of repex. When added this amount to the modelled component, this gives a reasonable range for total repex of between approximately $676 million and $768 million.

- There is the real potential for Essential Energy to face deliverability constraints in the 2014–2019 period. This casts material doubt on whether Essential Energy's forecast repex forecast is a realistic expectation of the cost inputs required to achieve the capex objectives.

The amount of forecast repex that we have included in our alternative estimate is $676 million (2013-14), excluding capitalised overheads. This is 21 per cent less than Essential Energy's proposal. This amount ensures that Essential Energy will be provided with a reasonable opportunity to recover at least its efficient costs. It will also minimise the potential for Essential Energy to over-invest or under-invest in repex during the 2014–19 period. We have included this amount of repex in our alternative estimate of forecast total capex.

Trend analysis and benchmarking

Essential Energy's proposed forecast repex for the 2014–19 period exceeds its historical trend (based on the time series data available). Notably, its historical repex is also relatively high in comparison to other service providers in the NEM. Specifically, we have considered:

- trends in Essential Energy's actual repex over time to allow comparison with actual repex in previous regulatory control periods

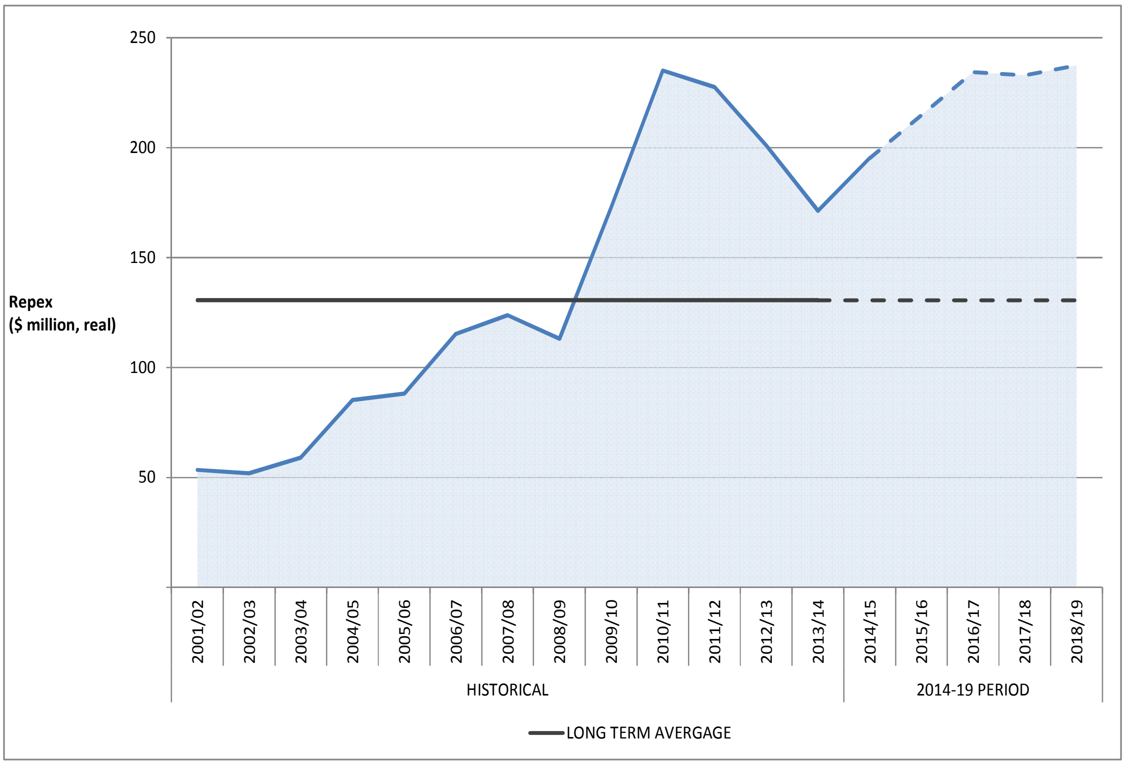
- Essential Energy's actual repex relative to other service providers in the NEM for selected performance metrics that may provide an indication of relative efficiency

- relevant indicators used to inform us of the condition of Essential Energy's network assets.

Historical trends

Figure A-7 shows the trend in Essential Energy's historical and proposed repex. It also shows Essential Energy's actual long term average across the same time period.

Figure A-7 Essential Energy's repex including overheads historic actual and proposed for 2014–2019 period ($ million June 2014)



Source: Historical: IPART Regulatory Accounts (prior to 2010–11) and AER Annual RINs (2010–11 to 2013–14)
2014–2019 period: Essential Energy's Reset RIN, Table 2.1.1 - Standard control services capex (allocating capitalised network and corporate overheads on the basis of repex as proportion of total capex)

As we discuss in attachment 7, during the 2009–2014 regulatory control period, Essential Energy arguably spent in excess of its historical trend in part to 'catch up' on expenditure which may not have been sustainable in earlier regulatory control periods. In our view, this suggests that a long term trend provides a relevant baseline regarding Essential Energy's underlying repex requirements. In submissions to the AER, Networks NSW noted:

> Despite the significant inroads made by Essential Energy during the 2009-14 period, the average age of the distribution network has continued to increase, and an ongoing investment program is needed to limit maintenance and breakdown costs and manage safety (including public safety), environmental and other risks.[69]

Figure A-7 shows that Essential Energy's proposed forecast repex of $1,142 million (real 2013–14) for the 2014–2019 period significantly exceeds its long term average.[70] This is a 59 per cent increase above its long term average repex[71] and a 11per cent increase in the amount incurred in the most recent regulatory control period.[72]

69 Networks NSW, *DNSPs' Response to the AER's Issues Paper,* 8 August 2014, p. 9.

70 Essential Energy's Reset RIN - Table 2.1.1 - Standard control services capex (after allocating capitalised network and corporate overheads on the basis of repex as proportion of total capex).

71 The long term average is calculated as the average actual repex (including overheads) between 2001–02 and 2013–14, sourced from IPART Regulatory Accounts (prior to 2010–11) and AER Annual RINs (2010–11 to 2013–14).

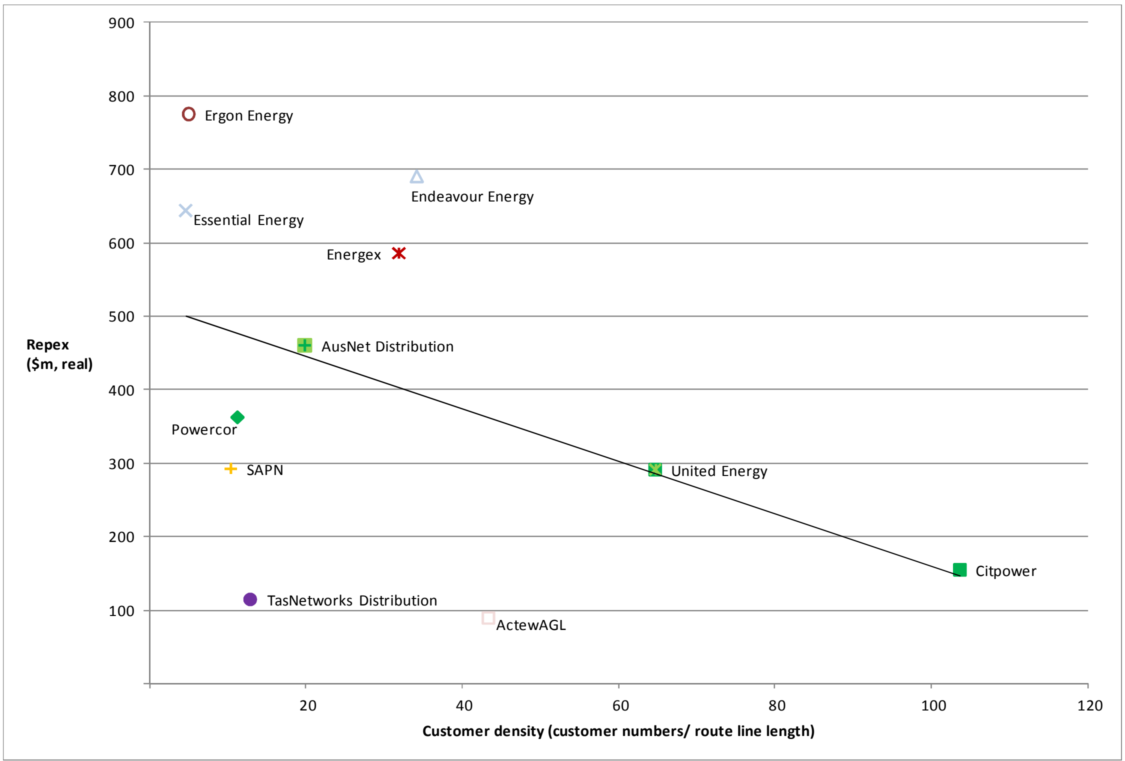
72 IPART Regulatory Accounts (2009–10) and AER Annual RINs (2010–11 to 2013–14).

Relationship between total repex and network scale

Network scale characteristics, such as the number of customers a service provider serves, its size, operating environment and asset mix, have a bearing on the amount of repex a service provider incurs. For this reason, in assessing the relative efficiency of Essential Energy's historical repex against that of other service providers, we have applied a series of normalisation factors to account for the impact of network size when making comparisons of total repex.

In particular, we have used two measures of network density: customer density and capacity density.[73] These measures account for the number of network assets across a physical area. We have also applied these measures to the total repex for each service provider across the 2008–13 period to assess the relationship between total repex and network scale. Figure A-8 shows this for customer density across service providers.

Figure A-8 Repex across the NEM normalised for customer density



Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
Customer Numbers and Route Line Length: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence)
(Ausgrid excluded as it is a significant outlier).

In general, Figure A-8 shows that total repex decreases as customer density increases. When we average repex normalised for customer density across the 2008–13 period, we observe a wide range across the service providers. Notably, Ergon Energy and Essential Energy (predominantly rural networks) incur relatively more repex than service providers with a similar customer density. When considering these metrics we have been mindful that Essential Energy has 57.6 per cent of its assets on rural long feeders. [74]

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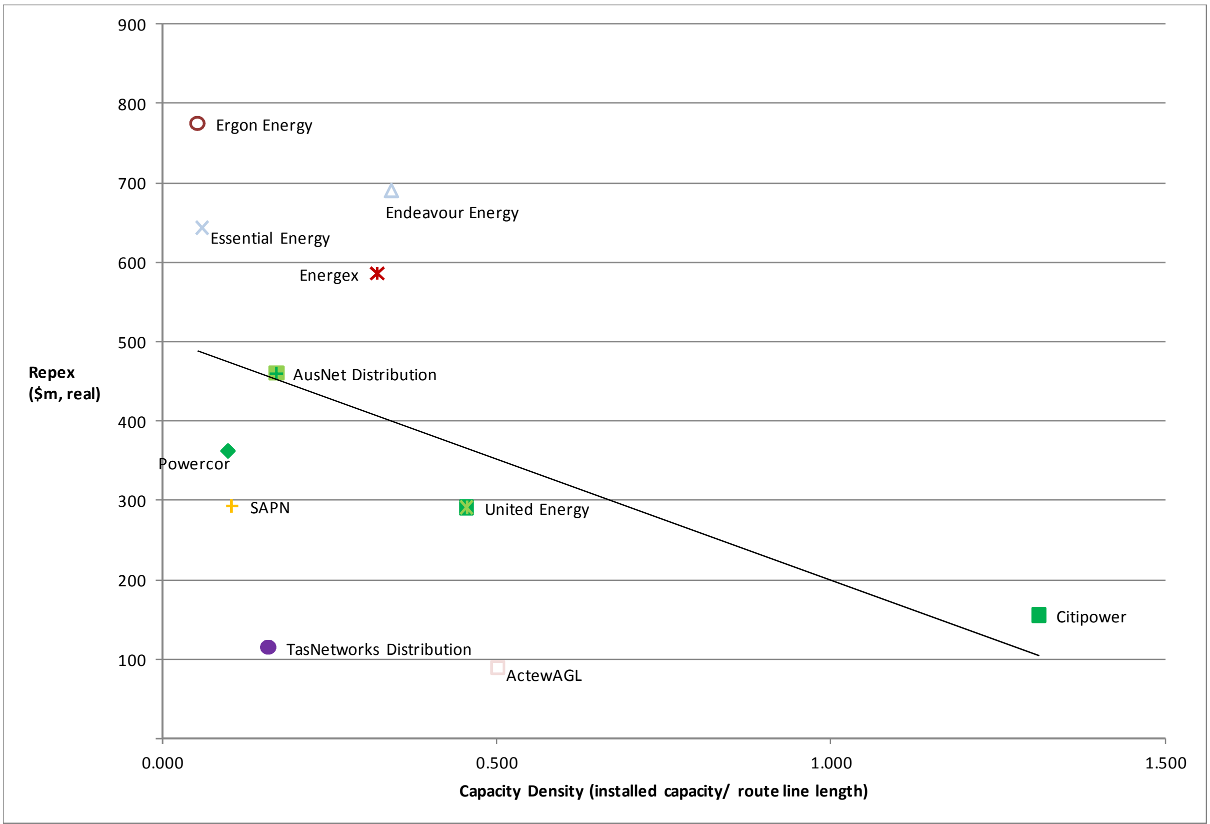
73 Customer density is customer numbers divided by route line length.
74 Length of lines assets (overhead conductors and underground cables) by feeder type.

We received feedback from some service providers that normalising total repex for capacity density is important to understanding the impacts of network scale on total repex.[75] We understand capacity density to be the quotient of installed capacity and network length. Figure A-9 shows the relationship between repex and capacity density across the service providers.

Figure A-9 Repex across the NEM normalised for capacity density



Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
Installed capacity: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence)
(Ausgrid excluded as it is a significant outlier).

Comparing Figure A-8 with Figure A-9 shows that there are similar relationships when normalising total repex by customer density and capacity density.

Essential Energy compares unfavourably under both density measures. Further, these measures suggest that predominately rural based networks incur higher repex than urbanised networks. When considering whether a network is relatively rural or urban we have also taken into account the length of lines in commission by feeder type. That is, the length of overhead conductors and underground cables installed on CBD, urban, rural short and rural long feeders. We have been mindful that Essential Energy has a significant proportion of assets on rural long feeders and is likely to incur relatively more repex when compared with more urbanised service providers.

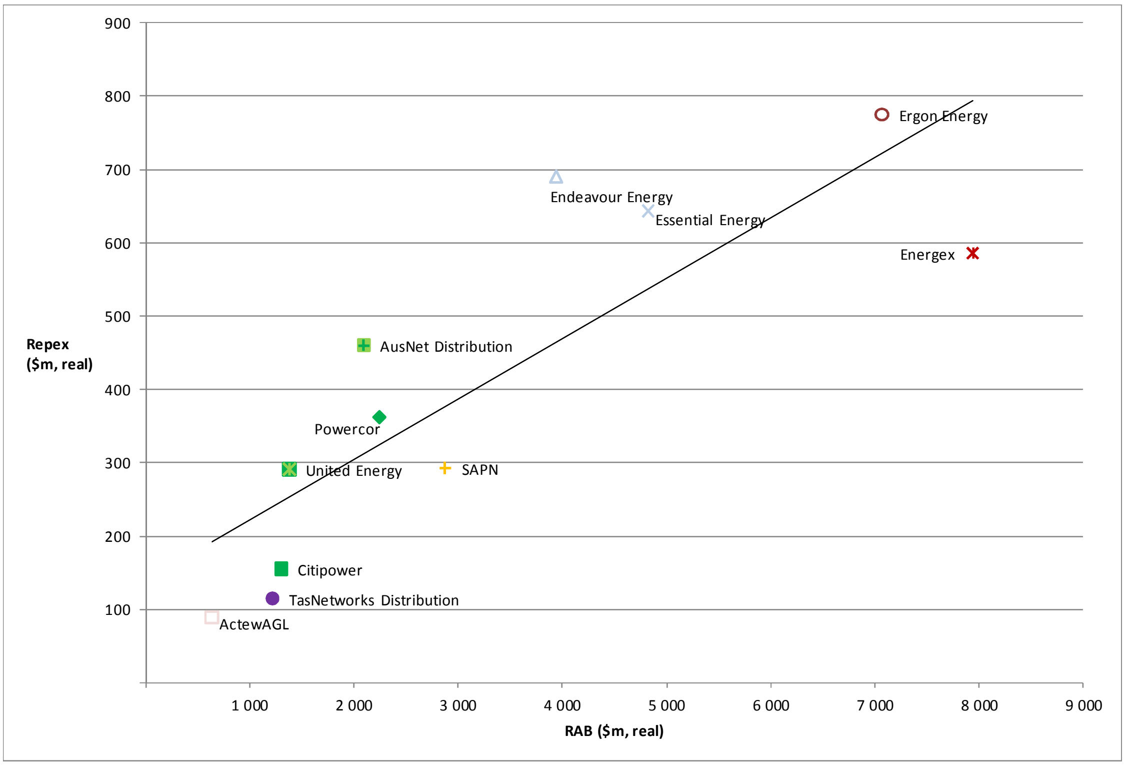
Size of asset base

In addition, the size of a service provider's regulatory asset base (RAB) will affect the amount of repex it incurs. This is because the more assets that exist on a network, the more there are that will

75 NSP Responses to AER Category analysis circulated 15 August 2014.

eventually need to be replaced. Figure A-10 compares service providers on the basis of the cumulative repex incurred across the 2008-13 period as a proportion of their opening RABs, which we have used to proxy the number of assets that exist on a network.

Figure A-10 Proportion of asset base replaced in the 2008–13 period



Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
RAB: EBT and Reset RINs - 3.4 Operational data
We have approximated each distributors asset base as its initial RAB as at 2008
(Ausgrid excluded as it is a significant outlier).

Figure A-10 shows there is a positive correlation between the size of a RAB and the repex a service provider incurs.

The service providers have submitted that repex depends not only on the size of their RABs, but the characteristics of their RAB as well.[76] Some service providers also submitted that this measure fails to account for the age and condition of the RAB, any capex and opex trade-offs, whether a service provider employs a deterministic or probabilistic replacement strategy and the stage of a service provider's particular investment cycle (noting the limited number of years used to determine service providers propensity for replacement (repex being the aggregate of only five years of expenditure as shown in Figure A-10).[77]

Whilst we acknowledge the limitations outlined above, this measure indicates that Essential Energy has incurred above average proportion of repex relative to the size of its RAB when compared with other service providers.

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[77] NSP Responses to AER Category analysis circulated 15 August 2014.

Asset Health Indicators

A crucial determinant of Essential Energy's repex requirements is the condition of its assets in commission. In assessing this, we have considered:

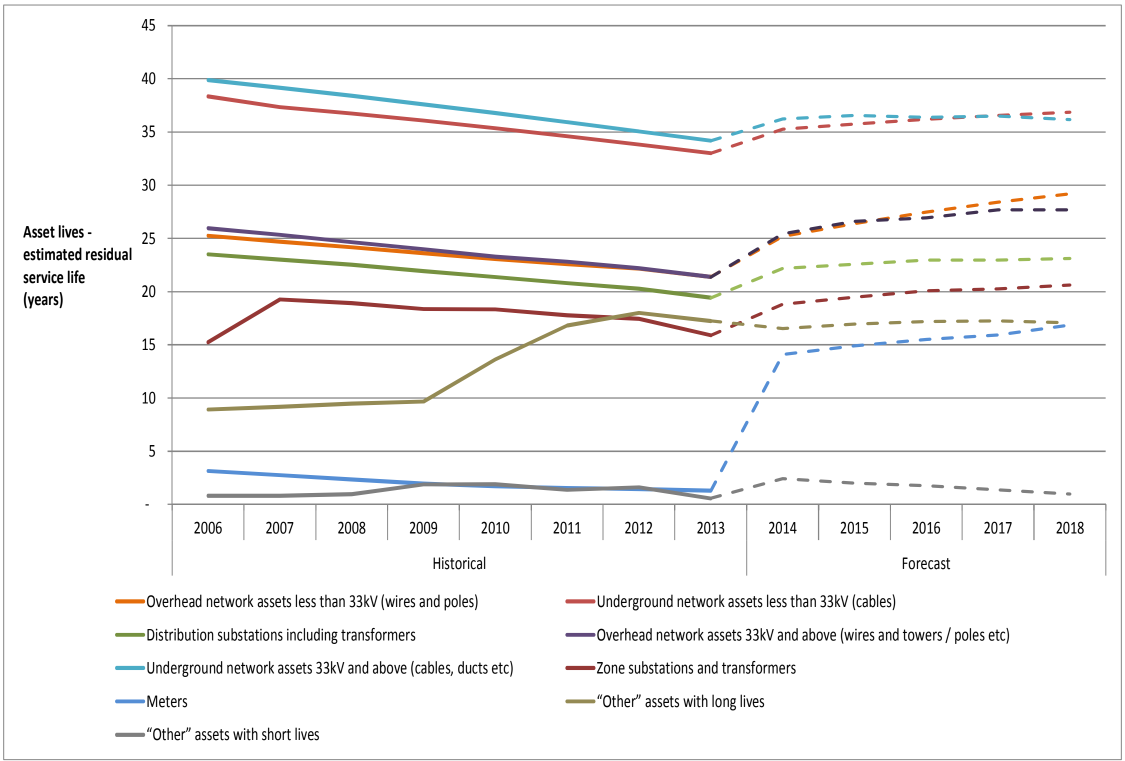
- the age of Essential Energy's network and
- utilisation of the network (where lower network utilisation should be positively correlated to asset condition).

Asset age

Asset age is a high level proxy for asset condition which can be used statistically (i.e. on a population basis) to model the repex requirements on the network. We consider that it is industry practice for service providers to include an assessment of asset age when determining its forecast repex requirements. In its submission Networks NSW stated that asset age provides an indication of asset condition.[78] Further we note Essential Energy uses asset age as an input to how it determines its asset management strategies.[79]

Figure A-11 shows for Essential Energy the estimated residual service life of different asset classes.

Figure A-11 Essential asset age – estimated residual service life



Source: Essential Energy- EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services) for historical and Essential Energy Reset RIN - 2014–2019 3.3 Assets (RAB) Table 3.3.4.2.

Figure A-11 shows that the historical trend in residual lives of Essential Energy's assets has been declining over time (for most asset classes). Using age as a proxy for health suggests that the health of Essential Energy's asset base has declined for some asset classes and for some asset classes has been maintained or improved over the last seven years. That is, some assets classes are expected, in

78 Networks NSW, *DNSPs' Response to the AER's Issues Paper,* 8 August 2014, p. 9.

79 Essential Energy, *Regulatory Proposal*, May 2014, p. 45.

aggregate, to maintain their function for a lower, the same or higher duration as they did in 2006. We note that Essential Energy is forecasting an improvement in residual service lives. However, for some asset classes, Essential Energy is forecasting higher residual lives at the end of the 2014-19 than historical levels. This suggests that Essential Energy may be seeking more repex than is necessary for some assets classes to maintain their function compared to the past.

Figure A-12 Essential Energy Asset Age Profile

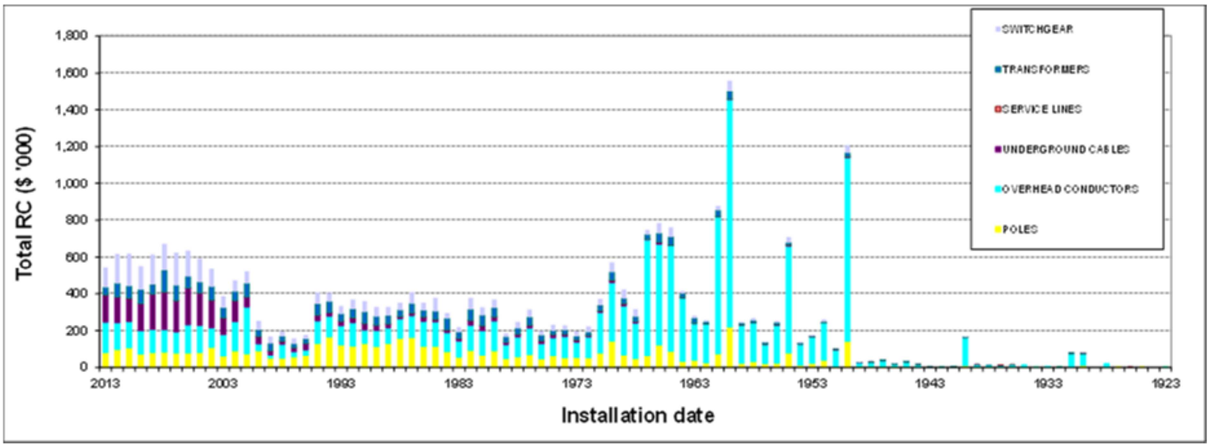


Figure A-12 shows the age of six of Essential Energy's asset groups, weighted by their replacement value. It demonstrates Essential Energy's has a relatively even spread in the commissioning of assets on its asset base across time, with some large spikes in overhead conductor installation in the 1950s and 1960s.

The asset groups that comprise Figure A-12 are presented in Figure A-13 to Figure A-18 below. Essential Energy's proposed average annual repex for the 2014–19 period is also presented as a line in these charts. For poles, transformers, overhead conductor and underground cable, there are a number of instances where the value of assets in commission for a given year equals or exceeds the average annual forecast repex. In particular, Essential Energy has reported a large population of overhead conductor that was installed in the 1950s and 1960s. For service lines and switchgear, the value of Essential Energy's assets in commission for any given year is, for the most part, below the average annual forecast of repex for the 2014-19 period.

Figure A-13 Asset age profile – Poles

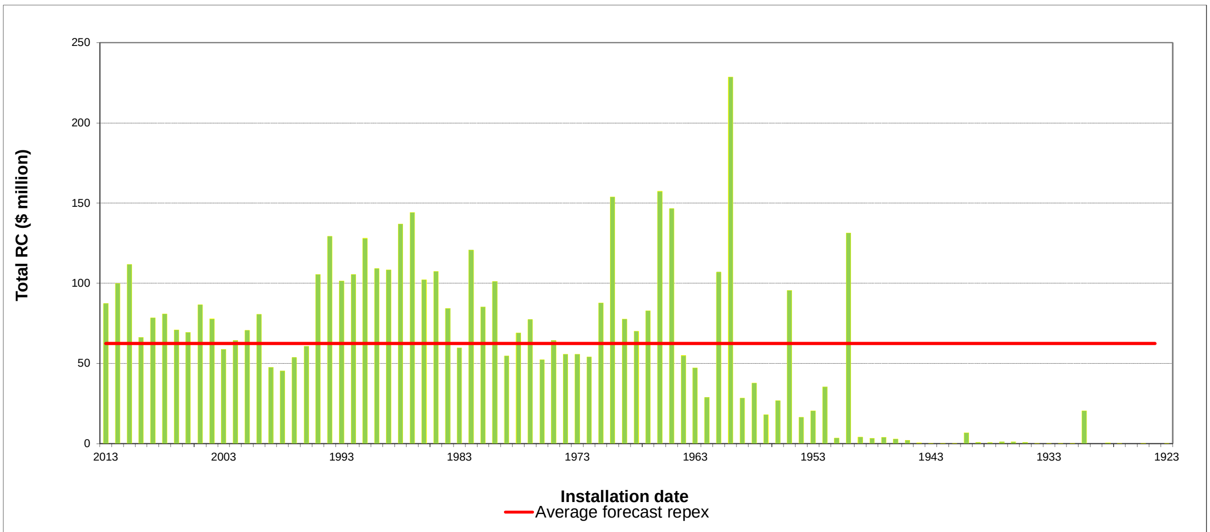


Figure A-14 Asset age profile – Overhead conductor

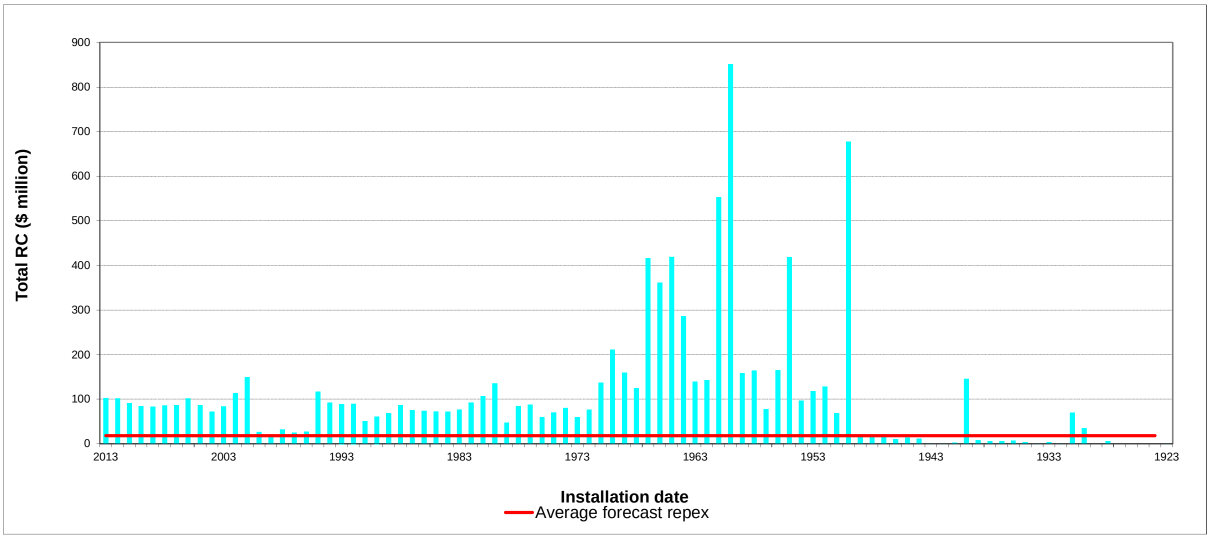


Figure A-15 Asset age profile – Underground cable

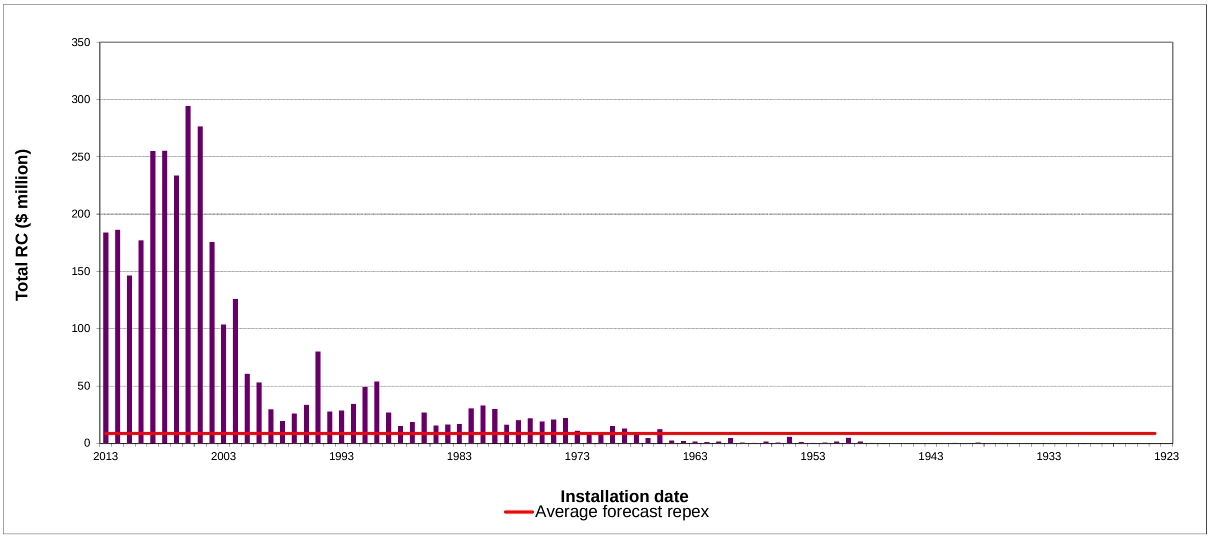


Figure A-16 Asset age profile – Service lines

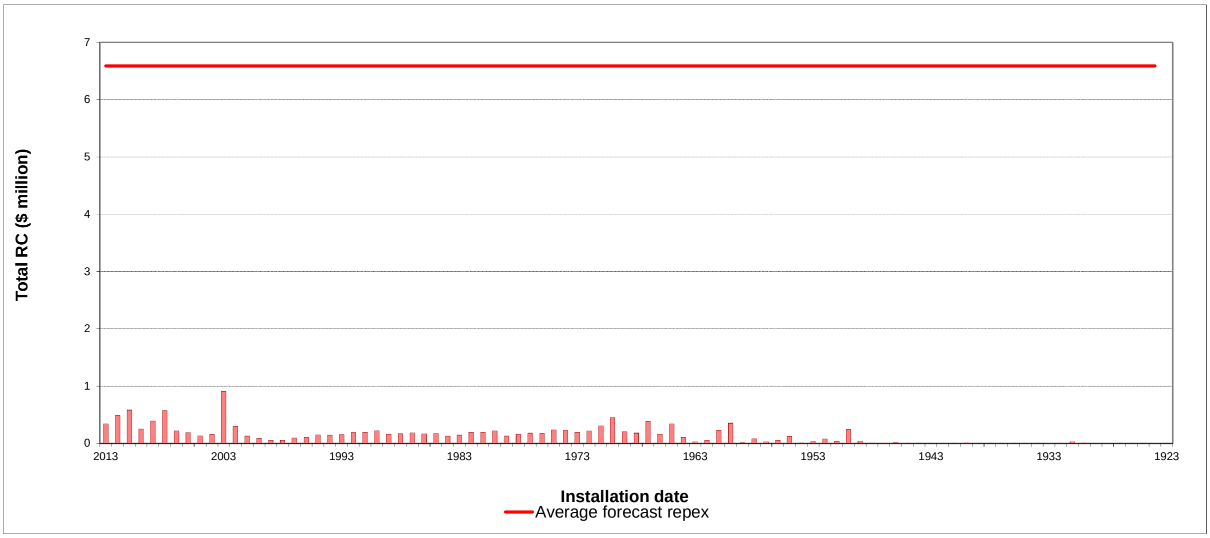


Figure A-17 Asset age profile – Transformers

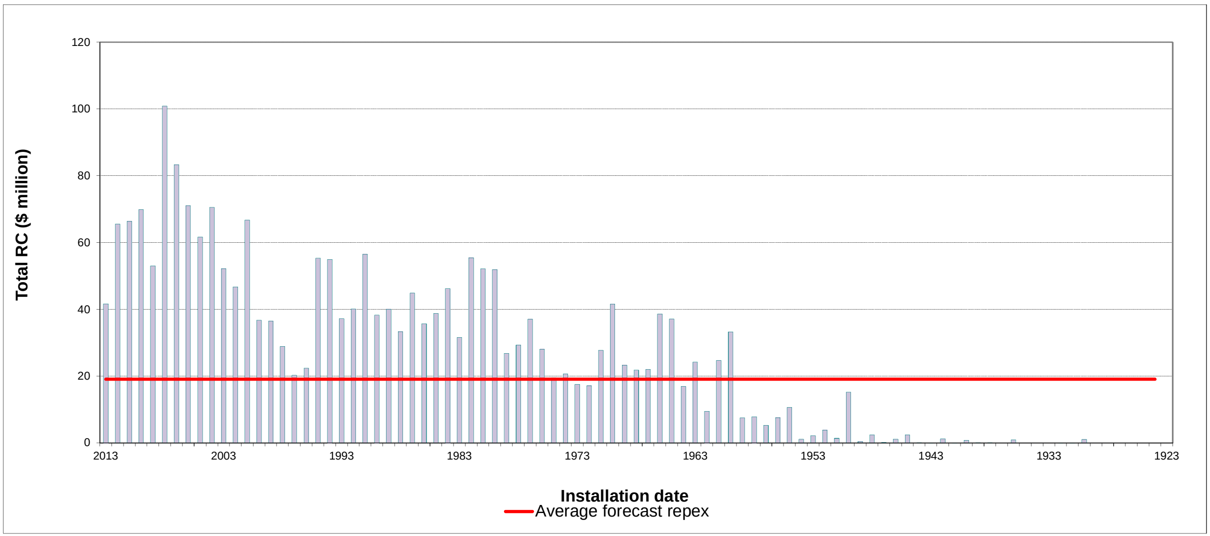
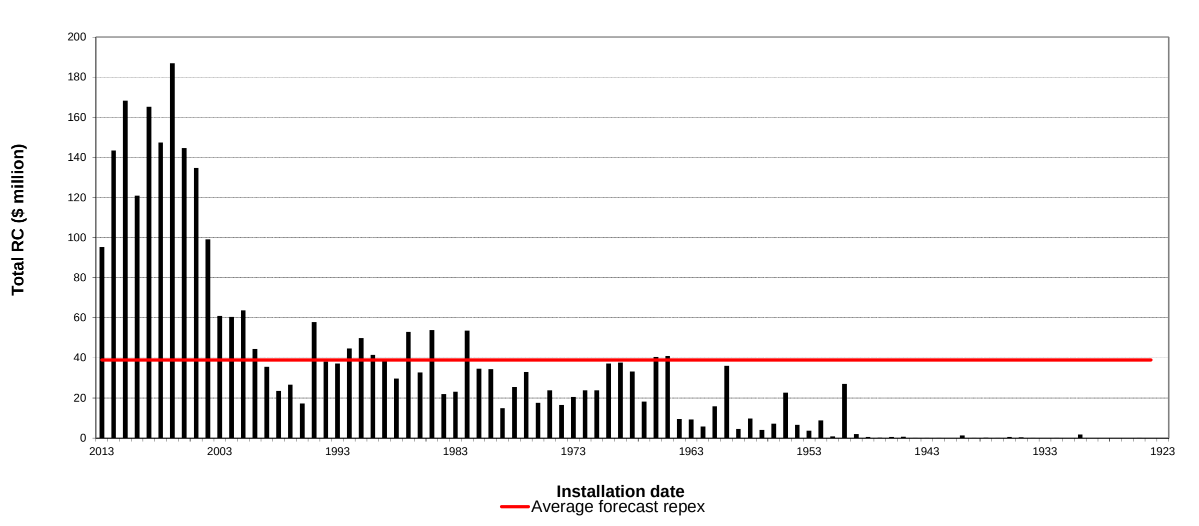


Figure A-18 Asset age profile – Switchgear



Asset utilisation

Another indicator of asset health includes changes in the utilisation level of network assets.[80] As we discuss in our assessment of augex, Essential Energy has significant spare capacity in its network based on past investments to meet expected demand that did not eventuate. In general, we expect that there is a positive correlation between asset condition and utilisation. Given Essential Energy is expected to have significantly increased spare capacity in its network during the 2014–2019 period, we consider that asset condition will also be positively impacted. This should result in reduced repex compared to the past. Similarly, the EMRF commented that:[81]

> A lightly loaded asset is likely to have a longer life than an asset an asset that is a heavily loaded asset….

We also note that with the lower expected demand and the lower value of customer reliability, the cost of in service asset failure is reduced compared to past periods. This should increase the deferral period for the efficient timing of asset replacement which should reduce replacement costs relative to the past. In addition, lower demand should provide opportunities for some assets to be replaced at a lower a capacity which should also reduce replacement costs compared to the past.

A.3.2 Engineering review of Essential Energy's proposed repex forecast

This section sets out the findings of an engineering review undertaken by EMCa that we commissioned to test Essential Energy's repex forecast against the capex criteria. In particular, we engaged EMCa to test whether Essential Energy's:

- repex forecast is reasonable and unbiased
- costs and work practices are prudent and efficient; and
- risk management is prudent and efficient.

We consider that EMCa's assessment reflects the capex criteria by seeking to assess whether Essential Energy is a prudent and efficient operator in its costs, work practices, and expectations.[82]

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80 Asset utilisation measures the proportion of maximum demand to total installed capacity on a distribution network

81 EMRF submission, August 2014, p. 20.

82 NER, cl. 6.5.7(c).

They also reflect the capex objectives and some of the capex factors that we are required to have regard to. For example, we expect a prudent operator would comply with regulatory obligations or requirements and maintain safety as part of its costs, work practices and risk management.[83] Another example is in relation to Essential Energy's actual and expected repex in the previous regulatory control period, and the substitution possibilities between repex and opex (whether to replace or maintain).[84]

Given repex was a major component of Essential Energy's proposed total forecast capex, we engaged EMCa to provide expert advice on the issues identified above. Broadly, on these aspects EMCa found that:[85]

- there are flaws in Essential Energy's repex proposal meaning its proposed forecast overstates the prudent and efficient amount it will reasonably require.
- Essential Energy's governance approach includes an asset management framework which does not yet align with good industry practice. The application of its capex governance to its repex forecast is inadequate.
- Essential Energy's repex strategies are not subject to robust options analysis, and there is a lack of cost-benefit analysis supporting the timing and volume of replacement activity. There is also a material risk Essential Energy will not be able to deliver the repex program it proposes either within the period, or efficiently.
- Essential Energy's approach to risk is overly conservative.

On these issues Essential Energy did not test positively against the capex criteria. We discuss EMCa's findings in more detail below.

EMCa findings

EMCa found that Essential Energy has not provided compelling justification for the extent to which it proposed to significantly increase repex in the 2014–2019 period. This is because:[86]

- Essential Energy applies its risk criteria overly-conservatively, and its investment decision making relies heavily on risk-based justification.
- it is unclear, at a detailed level, how Essential Energy estimated its proposed repex program.
- Essential Energy's repex strategies were not informed by robust options analysis or adequate cost-benefit analysis. Essential Energy has enough asset information to determine which assets need attention, but data quality shortcomings compromise its decision making.
- Essential Energy's options analysis is inadequate due to a lack of robust input data and assumptions. For example, in some cases only the recommended option or 'do nothing' option was considered. It was not always clear how Essential Energy derived its proposed replacement volumes.

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83 NER, cl. 6.5.7(a).

84 NER, cl. 6.5.7(e).

85 EMCa, *Technical review of regulatory proposals, Review of proposed replacement capex in Essential Energy's regulatory proposal 2014–2019*, October 2014, p, ii–iii. (EMCa, *Review of Essential Energy's repex*, October 2014).

86 EMCa, *Review of Essential Energy's repex*, October 2014, pp. 13–17.

- Essential Energy's cost-benefit analysis was not robust and was often characterised by qualitative assessment. Considering the magnitude of Essential Energy's proposed repex program EMCa would expect to see comprehensive quantitative analysis.

- Finally, EMCa could not establish how Essential Energy constructs its cost estimates, and whether or how it applies contingency amounts. EMCa are unconvinced that Essential Energy's cost estimation approach is sufficiently robust to support efficient outcomes.

EMCa notes the Networks NSW Board reduced the overall expenditure forecast originally developed within Essential Energy by 16 per cent. This decision was in response to the Board's objective of reducing expenditure, but only to the extent that a prudent risk level would be maintained. EMCa notes it is unclear how this reduction applied to repex. EMCa considers this portfolio adjustment indicates that the process used within Essential Energy was inadequate, either in terms of the prudency of the repex work proposed (volume and timing) or the cost of the work. Further, the methodology used is a useful decision support tool, but on its own will not necessarily lead to an optimal portfolio.[87]

EMCa assessed the governance and management framework that Essential Energy uses to plan and approve its repex projects and programs. Although Essential Energy's governance approach has most typical elements of good industry practice, EMCa found material issues with Essential Energy's implementation.[88] EMCa found that:[89]

- Essential Energy's capital governance framework appears to be out of date. The application of this framework to its repex forecast is also inadequate. While enhanced practices imposed by the Networks NSW Board are evident, there remains gaps in Essential Energy's processes. Its framework presents a relatively rudimentary approach to project and program governance.

- Essential Energy's asset management systems, data quality and analysis do not adequately support prudent investment decision-making and justification.

Essential Energy uses a variety of risk assessment tools and apparently applies its risk criteria over-conservatively. This reduces EMCa's confidence that Essential Energy's risk rankings are internally consistent, which reduces the likelihood of Essential Energy selecting the optimal mitigation actions. Essential Energy's approach to risk assessment often appears overly conservative due to unreasonably high frequency assumptions for major and catastrophic consequences. EMCa comment that this does not mean Essential Energy's repex programs are not required, but it does lead to a bias towards overestimating the timing and volumes of replacement activity required.[90]

EMCa has not seen evidence that Essential Energy has considered how to effectively deliver the increasing level of repex it proposes. Essential Energy has not developed a delivery strategy or plan for its proposed portfolio of work. EMCa notes that Essential Energy's proposed forecast repex is based on future programs significantly different from historical work, that is, higher volumes of smaller projects. EMCa found no evidence that Essential Energy considered these issues adequately or took them into account when considering the deliverability of its proposed forecast repex. EMCa considers

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87 EMCa, *Review of Essential Energy's repex*, October 2014, pp. i, 10–11; The Capital Allocation Selection Hierarchy (CASH) tool and Portfolio Investment Prioritisation (PIP) methodology (CASH/PIP) uses a risk assessment process to produce weighted scores and rankings for capital projects. It provides a decision support tool for portfolio management within NSW distribution service providers that allows comparison and calibration with the inputs and outputs of the other NSW distribution service providers.

88 EMCa, *Review of Essential Energy's repex*, October 2014, p. 9.

89 EMCa, *Review of Essential Energy's repex*, October 2014, pp. 8–12.

90 EMCa, *Review of Essential Energy's repex*, October 2014, pp. iii, 15.

this means Essential Energy will operate in a reactive rather than proactive manner, which will lead to inefficiencies in delivering its proposed repex program.[91]

EMCa reviewed Essential Energy's proposed repex programs for each of the high level asset categories. EMCa found Essential Energy provided justification to support its focus asset-level areas for a major proportion of its proposed forecast repex. However, EMCa identified multiple issues with Essential Energy's justification at the sub-program level:[92]

- inadequate justification for the strategy adopted
- inadequate justification of the timing for resolving condition-based issues because of inadequate risk assessment and/or inadequate economic analysis
- inadequate justification for the extent of step-changes in expenditure
- inadequate evidence of efficient costs
- lack of robust delivery management
- reliance on a risk assessment framework that differs from the corporate framework which casts doubt on the prudency of the corresponding assessment.

A.3.3 Predictive modelling

This section sets out our assessment of the findings from the predictive modelling of repex (the repex model).[93] The repex model is used to predict likely asset replacement volumes and expenditure based on the number and age of assets in service, the assumed age of replacement of these assets and their corresponding unit costs. The model uses age as a proxy for the many factors that drive individual asset replacement.[94] Our approach to developing outputs from the repex model is detailed in appendix G.

The model allows us to estimate a range of outcomes based on different inputs. We have adopted a robust approach to assessing the inputs used in the model with reference to our other techniques where relevant.

We have also adopted a robust approach to scrutinising the outcomes of the model. By examining whether both inputs and outcomes are robust, we have narrowed the range within which expenditure is likely to reasonably reflect the capex criteria. This range, in conjunction with our other analytical techniques, informs our alternative estimate.[95]

Asset groups included in the model

The repex model has been used to model replacement in six asset groups, being poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories. The process for collecting and using this data is discussed in detail in appendix G.

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[91] EMCa, *Review of Essential Energy's repex*, October 2014, pp. 8, 12.
[92] EMCa, *Review of Essential Energy's repex*, October 2014, pp. 18–30.
[93] We first used the predictive model to inform our assessment of the Victorian DNSPs' expenditure proposals in 2010 and we have undertaken extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline (see Appendix G for details on our consultation).
[94] AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013, p. 10.
[95] AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013.

In total, the assets modelled represent $770 Million or 90 per cent of Essential Energy's proposed repex.

Pole top structures and SCADA, along with specialised categories of capex defined by Essential Energy that were not classified under the six groups above, were not modelled. These represent $86 million, or 10 per cent of Essential Energy's proposed repex, and are separately assessed later in this appendix.

The process for collecting and using this data is discussed in detail in appendix G.

Analysis of the reasonable estimation range

As outlined in appendix G, we have utilised several different replacement age and unit cost inputs in our repex modelling to derive a range of estimates. The following analysis provides our view on whether these inputs are likely to lead to reasonable outcomes, having regard to our other assessment techniques. These include our benchmarking results for total capex and repex, analysis of Essential Energy's long term repex trends and evidence of forecasting bias and the overestimation of risk identified by EMCa's technical review. The inputs used in the model are:

- replacement life and age information, and expenditure and replacement volume information provided by Essential Energy (the base case model);
- replacement life information derived by using Essential Energy's replacement volumes from the last five years (referred to as "calibrated lives"); and
- unit costs and replacement lives derived by comparing information from all service providers across the NEM (benchmarked replacement lives and unit costs).

The process used to develop the calibrated replacement lives and benchmarking inputs is included in appendix G.

The base case model

The base case model uses replacement life information inputs provided by Essential Energy in its RIN (i.e. the average asset replacement life and the standard deviation of the replacement life). We applied two base case models. The first base case model was based on Essential Energy's observed costs in the past five years (historical unit cost), and the other on costs derived from its forecast expenditure (forecast unit cost). The estimates derived from these two models were $5bn and $4.4bn, respectively. These estimates are higher than Essential Energy's forecast of $770 million for the six modelled asset groups.

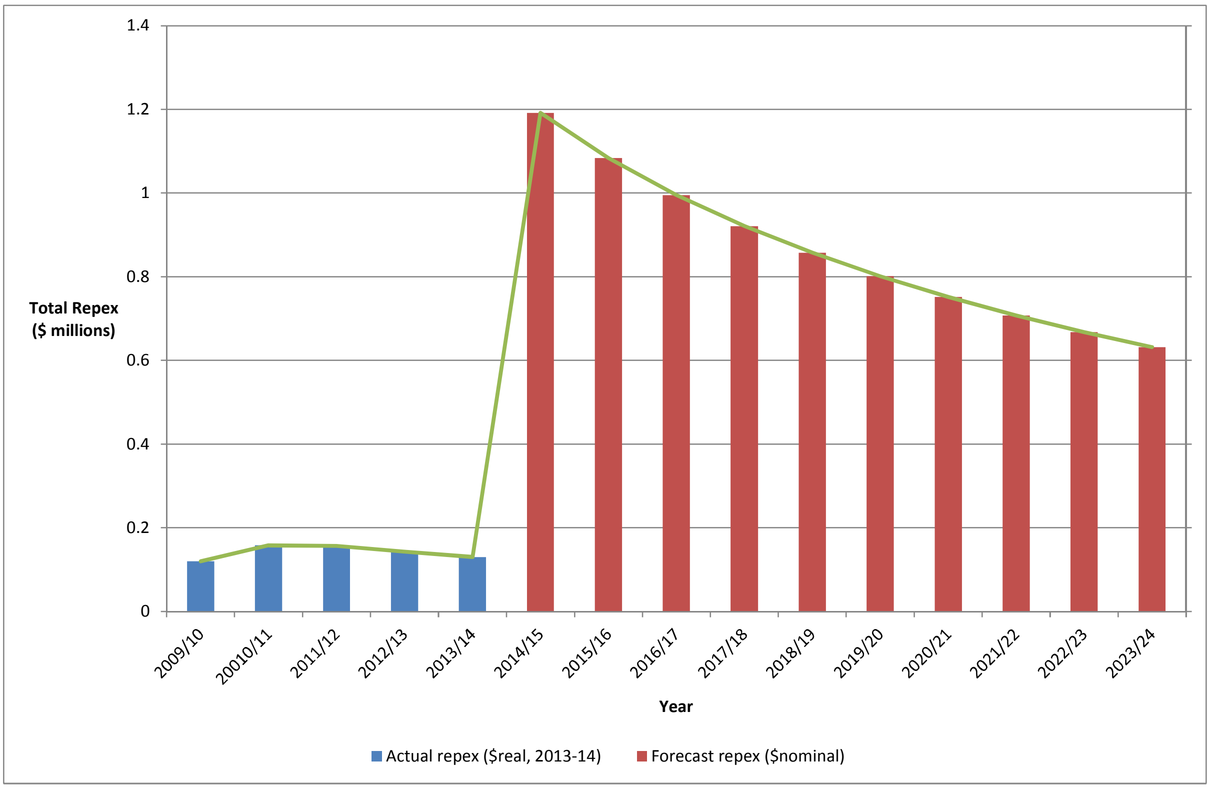
Table A-9 Base case model outcomes

Unit cost	Model outcome
Historical	$5,047.4
Forecast	$4,363.0

Source: AER analysis.

The replacement profile predicted by the repex model under the base case scenario features a sharp step-up in expenditure in the first year of the forecast, which then declines over the remainder of the period (see figure 20). This replacement profile indicates that a significant portion of the asset population currently in commission has survived to an older age than would be expected using the base case replacement life figures submitted by Essential Energy. Using Essential Energy's base case replacement lives causes the model to immediately predict the replacement of this stock of assets. This, in turn, results in a large stock of predicted asset replacements in the first year of the forecast, which then declines over time.

Figure A-19 Essential Energy's replacement expenditure from 2009–14 and expenditure predicted by the base case model



Source: Essential Energy, AER analysis.

In scrutinising the discrepancy between Essential Energy's forecast of $770 million and our base case outcomes, we consider that the base case outcomes are not credible or reliable for the reasons outlined below.

First, if Essential Energy's actual replacement lives were consistent with their base case replacement lives, we would not expect to see the observed asset replacement profile. This is because, if Essential Energy's actual asset replacement profile followed its base case replacement lives, the older assets would have:

- already reached the end of their economic (replacement) lives and so would have already been largely replaced; and
- would therefore not be expected to be in the asset age profile, or be in such insignificant volumes that it would not materially affect the outcome of repex modelling.

The 'step-up/trend down' replacement profile observed from the base case model suggests that a significant proportion of the asset population has survived longer than would be expected using Essential Energy's data. The 'survivor' assets have a material effect on the observed outcome. This outcome suggests that the base case replacement lives are shorter than those achieved in practice. We have undertaken further analysis to determine replacement life information that matches Essential Energy's actual replacement practices.[96] This work is outlined in appendix G.

Second, our detailed assessment of Essential Energy's forecasting process and assessment of asset risks identified a strong bias towards early replacement of assets, and the likelihood of systemic overestimation of repex. Furthermore, our assessment of Essential Energy's repex trends over the past 13 years showed its forecast repex to be significantly above its long-term trend. Based on these assessments, our expectation is that the prudent and efficient level of repex is likely to be materially below the outcomes in the base case modelling and materially lower than Essential Energy's forecast.

Third, further analysis of the base case model results reveals the replacement life inputs are the main drivers of the base case outcome. If the base case replacement life information is substituted with calibrated lives the model outputs are $684 million for historical unit costs and $590 million for forecast unit costs (the calibrated model is discussed in the next section). Taken together with the information from our other analytical techniques and our concerns that the base case lives do not reflect Essential Energy's actual replacement practices, we consider that the base case replacement life information provided by Essential Energy will not result in a reasonable range for repex.

The selection of unit costs also leads to materially different estimates. Inputting historical unit costs results in an estimate that is $1.6 billion higher than inputting forecast unit costs. To assess the suitability of both as inputs, we compared both to a benchmark average of unit costs for all service providers (the benchmarked model is discussed below). The forecast unit costs compare favourably with the results from benchmarked unit costs, while the historical unit costs are broadly similar to the benchmark. This suggests that Essential Energy's direct costs for repex align reasonably well with the industry average. Further, it suggests that the overstatement of expenditure that was identified in EMCa's engineering review are driven more by the volume of work undertaken rather than Essential Energy's direct cost.

The calibrated model

The calibrated model uses replacement lives and standard deviations based on Essential Energy's replacement volumes from the past five years. We applied the repex model using the calibrated replacement life data in combination with historical, forecast and benchmarked unit cost values. The benchmarked unit costs are discussed in the benchmark model section below.

Table A-10 Calibrated model outcomes

Unit cost	Model outcome
Historical	$683.9
Forecast	$589.7
Benchmark average	$682.1

[96] To take into account Essential Energy's actual asset replacement practices we have used recent historical replacement practices to approximate the mean asset replacement lives and standard deviation. This process is referred to as calibration, and is described in appendix G.

Benchmark first quartile	$554.0
Benchmark lowest	$406.9

Source: AER analysis.

Using calibrated replacement lives and Essential Energy's forecast unit costs gives an output of $711 million when historical unit costs are used and $600 million when forecast unit costs are used. Essential Energy has a very low staking rate for low voltage wooden poles in comparison with its peers. Indeed, when Ausgrid's staking rates are used in place of Essential Energy's (Ausgrid stakes about 47 per cent of its low voltage wooden poles, compared to Essential Energy's rate of about 18 per cent, the observations fall to $683 million and $589 million, respectively. EMCa noted in its findings that Essential Energy has not adequately explained its reinforcement (staking) strategy. In particular, EMCa found that Essential Energy has not made a sufficiently robust case for its adherence to its current inspection and serviceability criteria, or for the cost effectiveness of its current and proposed strategies for pole replacement.

On this basis, and taking into account the broader findings by EMCa in relation to Essential Energy's forecasting methodology and risk aversion, as well as our observation that Essential Energy has a very low pole staking rate when compared to its peers, we consider the staking rate used by Essential Energy is not appropriate for inclusion in the reasonable range. We have substituted Essential Energy's staking rates with Ausgrid's observed staking rate.

The calibrated replacement life estimate provides a substantially lower predicted volume and expenditure forecast than Essential Energy's forecast, despite essentially trending forward Essential Energy’s observed replacement practices from the 2009–14 regulatory control period. It may be expected that trending forward average replacement lives from the 2009–14 regulatory control period will lead to a similar outcome to the last period – which would in turn be similar to Essential Energy’s forecast. However, the historically high volume of asset replacement work that Essential Energy has carried out over the last five years is likely to have changed its asset age profile from five years ago. That is, by spending a large amount on repex in the last regulatory control period, Essential Energy is expected to have replaced a significant number of its older assets. This in turn may be expected to reduce the overall age of its network. If the average replacement life and standard deviation stays the same, but the network’s overall age is reduced, fewer assets will need to be replaced in the next period.

Networks NSW has noted concerns with the use of calibrated lives. Networks NSW's concerns are related to its general concerns relating to the usability and accuracy of the repex model.

> In previous determinations, the AER has used ‘calibration’ functions when the base case suggests that a far higher level of expenditure is warranted. In these cases, the AER has used most recent historical data or substituted benchmarking data to ‘refit’ the model to derive alternative outcomes. When the AER has re-calibrated the models they have found that DNSP’s proposed forecasts exceed the predicted values of the model.
>
> In our view this raises significant concerns with the validity of the model given that the ‘base case’ could produce results that the AER considered were invalid. In these cases, it would be incorrect to use a flawed model with different input data (either benchmark of past expenditure) to derive a conclusion that the AER considered was not anomalous. In our view, this is a type of backsolve to validate the use of the model.[97]

In our Explanatory Statement to the Expenditure Forecast Assessment Guideline, we addressed concerns with the model and updated the Replacement expenditure model handbook to address

[97] Networks NSW, *Report - REPEX Model Review*, May 2014. p. 11.

specific issues.[98] This concern as raised by Networks NSW in this determination was not submitted at the time we consulted on our Guideline but we acknowledge that with any modelling there is always room for disagreement. In our Explanatory Statement to our Guideline we expressly recognised that we will attempt to resolve issues with the repex model as they arise.

After considering the concerns raised by NSW Networks, our view is that these concerns are unfounded. The model is based on well-established principles of probability and normal distribution. It has been used by the AER previously and has similar characteristics to the model used by OFGEM.[99] We do not accept that the model is flawed because we use different input data. In our view, it is good practice to scrutinise the inputs having regard to the outcomes and when viewed against the regulatory proposal which is the subject of our determination.

We further note, as foreshadowed in the Explanatory Statement to our Guideline that we will use the repex model as a first pass model, in combination with other techniques.[100] It is not used in isolation, but as one of a number of analytical tools.

In this instance, for Essential Energy, the base case outcomes may be "invalid" as NSW Networks might describe our findings, but nonetheless this assists us in narrowing the range of what is reasonable by assessing the robustness of the inputs used.

Using the previous five years of data to derive a replacement life gives us an estimation of Essential Energy's actual replacement practices, informing us when an asset might be expected to be replaced due to age/condition reasons. It provides a counterpoint to the base case lives, which, as discussed above, do not accord well with the age of Essential Energy's assets in commission.

Networks NSW also made specific comments on why its last five years should not be used to derive a mean and standard deviation.

> The model may also be calibrated to compare actual levels of expenditure undertaken in the current period. We consider that this assumption may not necessarily provide a reflection of the level of expenditure needed to maintain the safety and reliability of the network. This is for 3 reasons:
>
> - A DNSP may change in planning standards or risk assessments, driving a change in replacement levels compared to the past. Indeed this was the experience encountered by NSW DNSPs in the mid 2000s when comprehensive reviews identified a need to increase levels of replacement due to under-investment in the past.
> - New standards might be imposed in terms of safety, environmental or worker safety that necessitates an increase in replacement needs.
> - A DNSP may detect a change in failure rates or risks for an asset class prompting the need to develop a proactive replacement program.[101]

As noted earlier in this attachment, the planning standards that now apply impose a lower standard on Essential Energy than those that were in place during the last regulatory period. This being the case, replacement lives derived from the last five years are more likely to overstate, rather than understate, the age/condition at which an asset may need to be replaced. We note that were these standards to change again during the 2014–19 period, whether to a higher or lower level, any change in expenditure could be accounted for via a regulatory change pass through event.

98 AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013, p277–283.
99 OFGEM, *Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment*, March 2013, p. 44.
100 AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013, p. 289.
101 Networks NSW, *Report - REPEX Model Review*, May 2014. p. 11.

Further, our draft decision is being made on the information available to us at present. Essential Energy's failure rates or risk may change in the future. This is not a valid reason to exclude the calibrated lives.

On balance, we are satisfied that the use of recent historical behaviour to derive a replacement life is a reasonable approach to finding an input for the purposes of establishing a reasonable range of repex for the 2014–2019 period. Compared to the base case lives supplied by Essential Energy, the calibrated lives estimate a lower volume of replacement, which is more in line with the results from our other assessment techniques. However, we also consider it appropriate to test the outcomes of the calibrated model against benchmarked inputs derived from other service providers.

The benchmarked model

The benchmarked model uses unit costs, replacement lives and standard deviations based on observations from all distribution service providers in the NEM. The derivation of these inputs is discussed in appendix G.

Benchmark of uncalibrated service provider submitted replacement lives

Using benchmarked replacement life inputs supplied by all service providers in the NEM (the uncalibrated benchmark replacement life) results in a large forecast volume of replacement works, and a “step-up/trend down' repex profile. This is similar to our observations of the base case above. This may indicate a systemic bias across the NEM towards reporting conservative replacement life estimates. We do not consider these results are relevant for the purposes of our assessment. As with the base case, the weight of evidence points towards Essential Energy over forecasting its replacement volumes, particularly EMCa's technical and engineering review and our observation of Essential Energy's long-term repex trend. Given this, we do not consider the uncalibrated benchmark replacement life information supplied by the service providers is suitable for use in finding a reasonable range.

Table A-11 Benchmarked model outcome – Uncalibrated average replacement life

Unit cost	Model outcome
Historical	$6,493.1
Forecast	$5,340.0
Benchmark average	$6,758.9
Benchmark first quartile	$5,046.2
Benchmark lowest	$3,514.5

Source: AER analysis.

Table A-12 Benchmarked model outcome – Uncalibrated first quartile replacement life

Unit cost	Model outcome
Historical	$4,700,449.9
Forecast	$3,918,564.3
Benchmark average	$4,809,191.4
Benchmark first quartile	$3,734,980.9

Benchmark lowest	$2,643,327.4

Source: AER analysis.

Table A-13 Benchmarked model outcome – Uncalibrated longest observed replacement life

Unit cost	Model outcome
Historical	$4,723.1
Forecast	$3,896.9
Benchmark average	$4,973.4
Benchmark first quartile	$3,799.4
Benchmark lowest	$2,691.3

Source: AER analysis.

Benchmark of calibrated replacement lives

We also calculated calibrated replacement life information for each service provider and derived benchmarks from these observations. Using the benchmarked calibrated replacement life information from all service providers in the NEM in the repex model results in a repex estimate of $876 million using forecast unit costs). Using replacement lives one quartile above the mean gives an estimate of $620 million, while using the longest observed replacement in the NEM gives an estimate of $118 million.

Essential Energy's own calibrated replacement life observation is lower than the average benchmark of calibrated replacement life across all service providers in the NEM, and sits somewhere above the upper quartile of service providers in the NEM. Using the benchmarked average calibration replacement life gives a higher estimate of repex than Essential Energy's forecast. This is because, when using the benchmarked calibrated replacement lives, a significant number of overhead conductor assets (installed between 1950 and 1960) increase the volume of that asset identified for replacement. Consistent with our approach for Ausgrid, Endeavour Energy and ActewAGL, while the calibrated benchmark replacement lives provide a useful set of results for analytical purposes, we have decided not to include them in the reasonable range. The calibrated benchmark replacement lives will reflect to some extent the circumstances of a service provider (such as their age profile) and so we have only used this information as a useful check on Essential Energy's calibrated model outcomes, and we will consider using this benchmarked data in future regulatory decisions. In this case Essential Energy's own calibrated lives are longer, in aggregate, than the industry average.

Table A-14 Benchmarked model outcome – Calibrated average replacement life

Unit cost	Model outcome
Historical	$1,157.1
Forecast	$960.2
Benchmark average	$1,174.2
Benchmark first quartile	$944.4
Benchmark lowest	$639.6

Source: AER analysis.

Table A-15 Benchmarked model outcome – Calibrated first quartile replacement life

Unit cost	Model outcome
Historical	$769.4
Forecast	$653.8
Benchmark average	$825.8
Benchmark first quartile	$627.9
Benchmark lowest	$404.0

Source: AER analysis.

Table A-16 Benchmarked model outcome – Calibrated longest observed replacement life

Unit cost	Model outcome
Historical	$529.1
Forecast	$442.4
Benchmark average	$529.7
Benchmark first quartile	$421.6
Benchmark lowest	$286.1

Source: AER analysis.

Unit costs

Using a replacement unit cost based on an average benchmark results in an estimate of $682 million for the six modelled asset groups.[102] This is higher than the outcome achieved using Essential Energy's forecast unit costs. We consider that the benchmarked average unit cost is a useful comparison with the cost of other service providers in the NEM and have included these values in the reasonable range. We have decided to exclude the outcomes of both the first quartile and the lowest unit cost unit price benchmarking. Using the lowest observed unit cost or a unit cost one quartile below the mean results in a much lower estimate of repex for Essential Energy. At the lowest unit cost, or the frontier, we are relying on a single observation, whereas the average benchmark is based on all observations from the NEM (after controlling for outliers, as discussed in appendix G). We consider the average benchmark, which is based on multiple observations, is more reflective of the average cost of replacement in the NEM.

Table A-17 Benchmarked model outcome – Unit costs

Replacement life	Unit cost	Model outcome
Calibrated	Forecast	$589.7
Calibrated	Benchmark average	$682.1

[102] The benchmarked unit costs are input into the calibrated model, and replace the forecast unit costs.

Replacement life	Unit cost	Model outcome
Calibrated	Benchmark first quartile	$554.0
Calibrated	Benchmark lowest	$406.9
NSP benchmark average (calibrated)	Forecast	$960.2
NSP benchmark average (calibrated)	Benchmark average	$1,174.2
NSP benchmark average (calibrated)	Benchmark first quartile	$944.4
NSP benchmark average (calibrated)	Benchmark lowest	$639.6

Source: AER analysis.

A.3.4 The reasonable range

The discussion above established the inputs that we consider provide a reasonable estimate of repex for Essential Energy. Based on our predictive modelling, we are of the view that an efficient level of repex for those categories that have been modelled is likely to be $590 million and $682 million. The final estimate of efficient repex will involve the weighing up of all information, and assessment techniques.

Unmodelled repex

Repex categorised as supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA) and Pole top structures in Essential Energy's RIN response was not included in the repex model. As noted in Appendix G, we did not consider these asset groups were suitable for inclusion in the model, either because of lack of commonality, or because we did not possess sufficient data to include them in the model. Together, these categories of repex account for $86 million (or 10 per cent) of Essential Energy's proposed repex.

Because we are not in a position to use predictive modelling for these asset categories, we have placed more weight on trend analysis and EMCa's findings in relation to Essential Energy's forecasting method. Our analysis of these is included below.

SCADA, network control and protection

Essential Energy has proposed repex of $28 million for SCADA. This represents a 32 per cent increase over the 2009–14 regulatory control period, or $9 million.

Essential Energy's expenditure on SCADA is relatively minor compared to its peers. The systemic issues identified by EMCa, our observations from trend analysis, benchmarking and predictive modelling indicate that this expenditure may be overstated. However, given the materiality of this proposed increase on total capex we have not conducted a detailed assessment of this asset group. Consequently, we do not propose to adjust Essential Energy's proposed repex for SCADA.

Pole top structures

Essential Energy has forecast $59 million of expenditure on pole top structures over the 2014–2019 period. Essential Energy's pole top structures repex was $32 million in the 2009–14 regulatory control period.

First, EMCa's review of Essential Energy's pole top replacement program indicated that it considered that the targeted expenditure on pole top replacement was reasonable in response to an increasing failure rate. We agree with EMCa and are satisfied that Essential Energy's forecast expenditure on pole top structures is likely to be reasonable.

A.4 AER findings and estimates for non-network capex

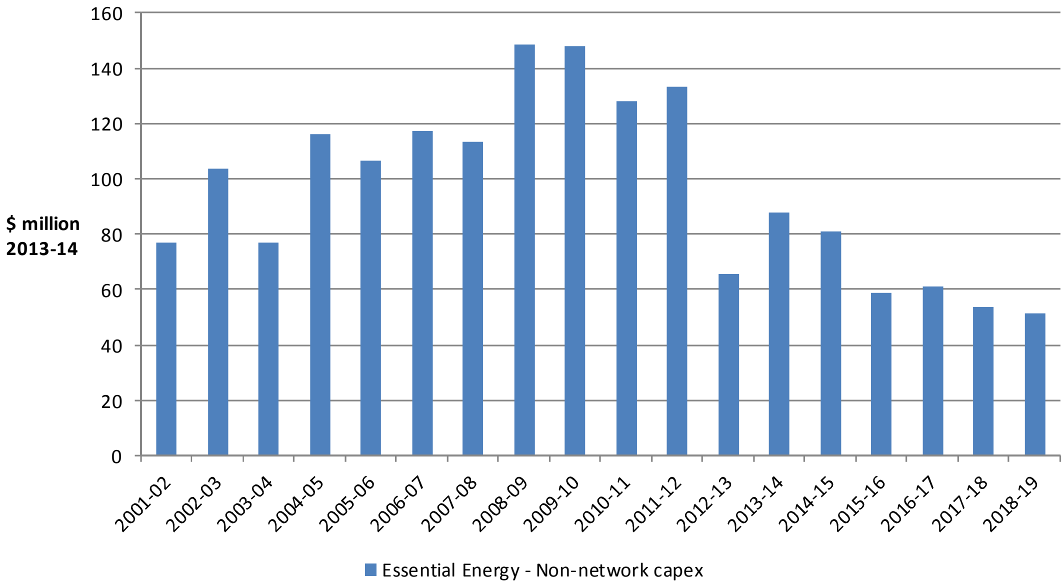
Non-network capex includes capex on information and communications technology (ICT), motor vehicles, buildings and property, and tools and equipment.

A.4.1 Position

Essential Energy forecast total non-network capex of $306.4 million for the 2014–2019 period.[103] We accept Essential Energy's forecast of non-network capex and have included it in our alternative estimate of total capex for the 2014–2019 period which reasonably reflects the capex criteria.[104]

Figure A-20 shows Essential Energy's historical non-network capex for the period from 2001–02 to 2013-14, and forecast capex for the 2014–2019 period.

Figure A-20 Essential Energy's non-network capex 2001-02 to 2018-19 ($million, 2013-14)



Source: Essential Energy, *Regulatory information notice*, template 2.6; Country Energy, *RIN response for 2009-14 regulatory control period, template 2.2.1*; AER analysis.

Essential Energy's forecast non-network capex for the 2014–2019 period is 46 per cent lower than actual and expected capex in the 2009–2014 regulatory control period. The forecast reduction in non-network capex is greater than Essential Energy's forecast reduction in total capex of 26 per cent.[105] This is consistent with Origin Energy's observation that where there is a material reduction in network capex costs there should also be a significant and observable reduction in support costs such as fleet, property and ICT.[106]

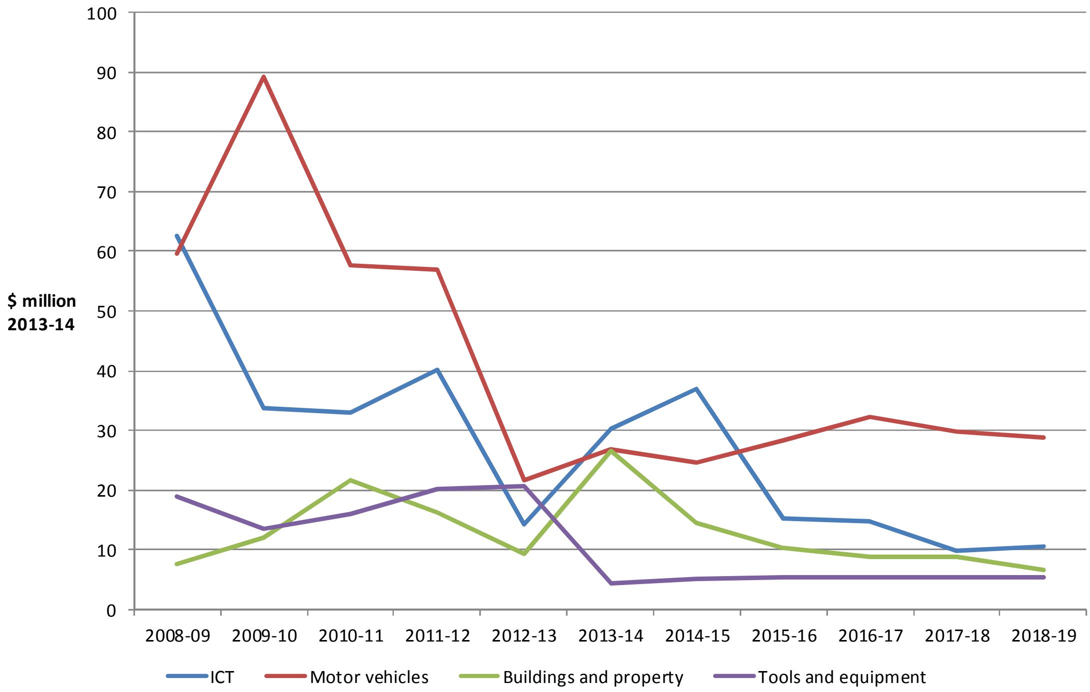
Our analysis of longer term trends in non-network capex suggests that Essential Energy has forecast capex for this category at historically low levels. Non-network capex is forecast to be lower in each year from 2015-16 to 2018-19 than in any previous year for which comparable data is available. This

103 Essential Energy, *Regulatory information notice*, template 2.6.
104 NER, cl. 6.12.1(3)(ii).
105 Essential Energy, *Regulatory proposal*, May 2014, p. 39.
106 Origin Energy, *Submission to the AER*, 8 August 2014, p. 27.

suggests that Essential Energy's forecast of non-network capex requirements in the 2014–2019 period is likely to be reasonable having regard to past expenditure.[107]

We have also assessed forecast expenditure in each category of non-network capex. Analysis at this level has been used to inform our view of whether forecast capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts which may warrant further review.[108] Figure A-21 shows Essential Energy's actual and forecast non-network capex by sub-category for the period from 2008–09 to 2018–19.

Figure A-21 Essential Energy's non-network capex by category ($million, 2013–14)



Source: Essential Energy, *Regulatory information notice*, template 2.6.

Essential Energy has forecast capex to reduce consistently across all categories of non-network capex in the 2014–2019 period. The forecast reductions in expenditure for the various categories of non-network capex range from 42 per cent for ICT up to 65 per cent for tools and equipment.[109] We are satisfied that these reductions reflect the high level drivers of expenditure in these categories and as such reasonably reflect efficient costs. For example, reduced expenditure for motor vehicle replacements reflects extended replacement cycles, fit for purpose vehicle selection and declining work volumes and staff numbers in the network business.[110] Based on our category level review of Essential Energy's forecast non-network capex, we have not identified any areas for further specific review at the project or program level. We consider that this level of expenditure, although relatively low by historical standards for some categories, is consistent with the capex criteria.[111]

107 NER, cl. 6.5.7(e)(5).
108 NER, cl. 6.5.7(e)(5).
109 Essential Energy, *Regulatory information notice*, template 2.6; AER analysis.
110 Essential Energy, *Fleet non-system business plan*, 14 May 2014.
111 NER, cl. 6.5.7(c)(1).

We note Origin Energy's submission highlighting a slight inclining trend in Essential Energy's unit cost of heavy commercial vehicles, and declining unit costs for ICT per employee.[112] In relation to Origin Energy's heavy commercial vehicle unit cost analysis, we note that the units in question are heterogeneous and that annual volatility is to be expected depending on the mix of vehicle types and sizes purchased in any given year. As noted above, we have placed more weight on expenditure trends over time. In this regard, Essential Energy has forecast a 75 per cent reduction in heavy commercial vehicle capex in the 2014–2019 period.[113]

We have also considered whether Essential Energy's forecast reduction in non-network capex reflects the substitution possibilities between opex and capex for this category of expenditure, for example undertaking building or motor vehicle maintenance versus replacement.[114] Despite the significant reductions in forecast capex, we note that Essential Energy forecast non-network opex in the 2014–2019 period to increase by less than 3 per cent in real terms compared to the 2009–2014 regulatory control period.[115] Taking this into account, we are satisfied that Essential Energy's forecast reduction in non-network capex does not simply reflect a reallocation of expenditure from capex to opex.

112 Origin Energy, *Submission to the AER*, 8 August 2014, pp. 30 and 32.
113 Essential Energy, *Regulatory information notice*, template 2.6; AER analysis.
114 NER, cl. 6.5.7(e)(7).
115 Essential Energy, *Regulatory information notice*, template 2.6; AER analysis.

A.5 AER findings and estimates for capitalised overheads

Capitalised overheads are costs associated with capital works that have been appropriately capitalised in accordance with Essential Energy's capitalisation policy. They are generally costs shared across different assets and cost centres. The amount of capitalised overheads incurred is a function of the amount of capital works that is undertaken.

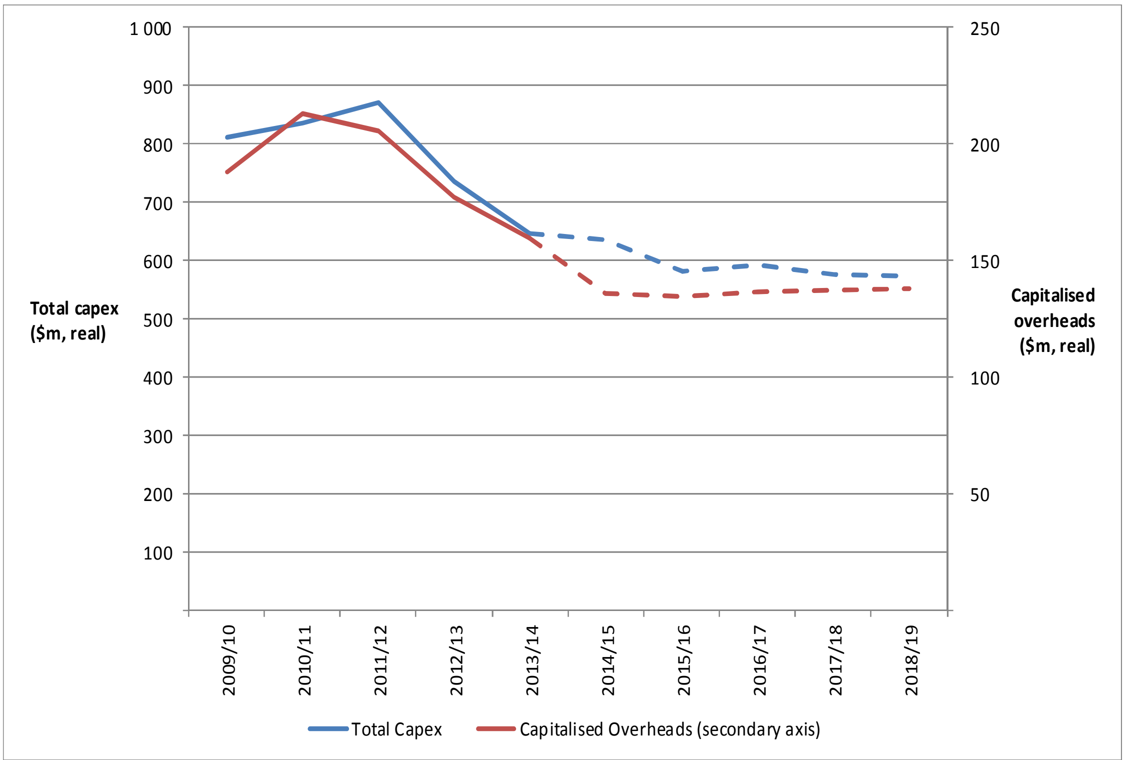
Essential Energy proposed $681.0 million ($2013–14) of forecast capitalised overheads. We do not accept Essential Energy's proposal on the basis that we expect that Essential Energy's capitalised overheads should be lower given we have reduced Essential Energy's 'base' opex such that a lower amount of overheads need to be capitalised

We have instead included an amount of $478.6 million ($2013–14) in our alternative estimate. This is 42.3 per cent less than Essential Energy's proposal. In coming to this view, we applied trend analysis to assess Essential Energy's proposal by reference to the actual capitalised overheads it incurred during the 2009–2014 regulatory control period.

Trend analysis

Essential Energy proposed $681.0 million ($2013–14) of forecast capitalised overheads, a reduction from the actual capitalised overheads that it spent during the 2009–2014 regulatory control period. As Figure A-22 shows, the reduction itself is consistent with the reduction Essential Energy's proposed total forecast capex compared to the actual (and estimated) capex that it spent during the 2009–2014 regulatory control period.

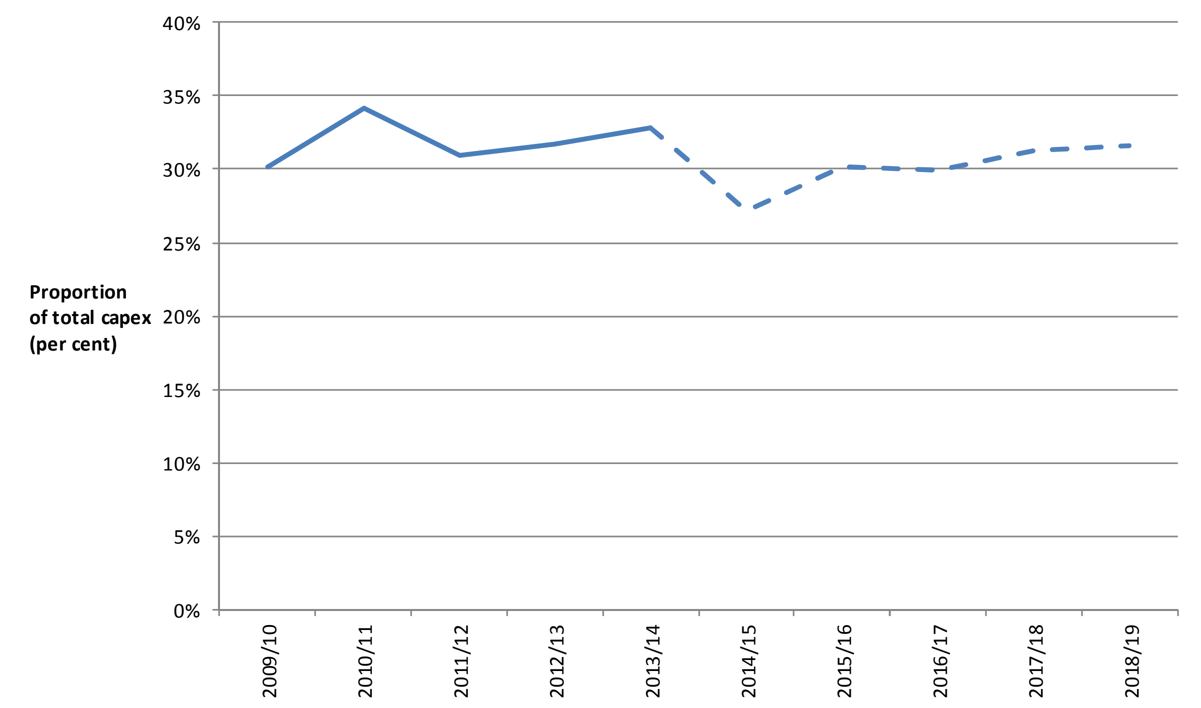
Figure A-22 Essential Energy - total capex and capitalised overheads ($ million - 2013–14)



Source: Essential Energy - Reset RIN - 2.1 Expenditure Summary - Table 2.1.1 - Standard control services capex (capitalised overheads aggregate of corporate and network capitalised overheads).

Figure A-23 shows that the average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period and that which is forecast over the 2014–2019 period is around 15 per cent.

Figure A-23 Essential Energy - capitalised overheads as a proportion of total capex (per cent)



Source: Essential Energy - Reset RIN - 2.1 Expenditure Summary - Table 2.1.1 - Standard control services capex (capitalised overheads aggregate corporate and network capitalised overheads).

A.6 AER findings and estimates for demand management

Demand management refers to any strategy to address growth in demand and/or peak demand. Demand management can have positive economic impacts by reducing peak demand and encouraging the more efficient use of existing network assets, resulting in lower prices for network users, reduced risk of stranded network assets and benefits for the environment. Demand management is an integral part of good asset management for network businesses. Network owners can seek to undertake demand management through a range of mechanisms, such as incentives for customers to change their demand patterns, operational efficiency programs, load control technologies, or alternative sources of supply (such as distributed or embedded generation and energy storage).

In some circumstances demand management can provide efficient alternatives to network investments, by deferring the need for augmentations to relieve network constraints. For example, a demand offset as a result of a demand management project may result in the deferral of construction of a new line, which would allow the existing network assets to meet growing demand in a particular area. Costs of network augmentation projects can be significantly greater than the costs of conducting demand management projects to defer an augmentation project. Deferral of network investment may result in efficiency benefits, as the same level of reliability and service is provided by a smaller, better utilised network. Demand management can also reduce the cost and impact on the timing of replacement capex. This was confirmed by another NSW network business, Ausgrid, in its regulatory proposal.[116]

A.6.1 Position

Our draft decision is to not include an explicit reference in the capex or opex forecasts for demand management. Based on the available information, we are currently of the view that it is most appropriate to rely on the incentive framework, together with the new requirements around the Regulatory Investment Test for Distribution (RIT-D) and the distribution Annual Planning Report, to drive the efficient use of demand management and share the benefits with consumers through the Capital Expenditure Sharing Scheme (CESS).

A.6.2 Our assessment

Comparison with demand management activities of peers during 2009–14

Our analysis suggests that the Essential Energy's estimate of $6 million significantly understates the amount of capex that could be deferred through efficient demand management activities. By comparison, analysis of Ausgrid's demand management activities in the 2009–14 period found that it was able to achieve a deferral of $334 million or 9.2% of its system capex portfolio based on an $8 million investment.

During 2009-14, Ausgrid spent $5,020 million (2013–14) on direct system capex (replacement and augmentation expenditure). Of this, between $1,526 million and $1,924 million (an average of $1,725 million) was spent on meeting the now rescinded "schedule 1" requirements[117]. Removing this expenditure (on the assumption that demand management was not applicable to expenditure to meet this standard) leaves a net $3,295 million on direct system capex during 2009-14. The capital deferred through the targeted demand management in 2009-14 represents 9.2 per cent of Ausgrid's system capex.

This gives a benefit cost ratio of 2.5 times its demand management investment. This result aligns with the Productivity Commission's expected demand management benefits, which estimated a medium benefit cost ratio of 2.7 for the two most relevant scenarios ("regional rollout in peaky and constrained areas", and "direct load control without smart meters").[118]

As such, we consider that the Ausgrid experience in demand management in 2009–14 might represent a reasonable benchmark to assess the capex that may be deferred by Essential in the 2014–2019 period.

Value of demand management in low demand growth environment

As discussed in the appendix C, demand growth is likely to be relatively flat across the 2014–19 period. In this demand growth environment there is a stronger economic case for the use of demand management as investment in long-life network assets can be deferred until there is a more certain need, reducing the risk of stranded network assets. Further, the option value of demand management also increases. This was confirmed by Ausgrid in its regulatory proposal:

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116 Ausgrid, *Regulatory proposal Attachment 6.12*, May 2014, p. 29.

117 The network design standards were set in its NSW licence condition. The design requirements specified in schedule 1 of the licences led to significant augmentation investment over 2009–14, increasing the levels of network capacity and redundancy. The NSW Government repealed the design standards (schedule 1) of the licence conditions in July 2014.

118 Productivity Commission, 9 April 2013, 'Electricity Network Regulatory Frameworks, Supplement to Inquiry Report, The costs and benefits of demand management for households', pp. 30.

> Across the NEM and in Ausgrid's supply area peak demand growth has slowed in recent years, departing from the previous trend of steady year-on-year growth. This has led to lower forecast growth in augmentation capital expenditures but also increased the uncertainty about the optimal capital investment strategy compared to the last regulatory period. In this more uncertain environment, the "option value" of demand management programs is enhanced for the coming years.
>
> …
>
> Lower load growth scenarios can create opportunities for DM because the demand reduction requirements to achieve capital deferrals are lower (making them easier to achieve and more cost effective), which can compensate for the less frequent opportunities for DM.

That is, rather than the value of demand management falling in times of uncertain or flat demand, its option value is likely to increase. This is primarily driven by the demand management alternatives being able to be readily renegotiated or re-purposed. For example, if a small embedded generator is used to offset the need for network reinforcement and the expected demand does not eventuate, the generator can readily be moved to another location. However, had a network solution been utilised, the investment is sunk with limited or no ability for it to be used for any other purpose, resulting in stranded or underutilised assets.

Demand management as part of business as usual

Demand management should be an integral part of good asset management for all network businesses. The primary driver for historical incentive schemes for demand management is an intention to change the past practices of the network businesses to be more accepting of demand management. The distribution Annual Planning Report, the regulatory investment test for distribution (RIT-D) and the NSW reliability and performance licence conditions all require DNSPs to consider and adopt non-network solutions where economic to do so. We are also required to have regard to the extent of non-network alternatives that a DNSP has considered and made provision for in assessing whether the capital expenditure criteria are met.

A.6.3 Conclusion on demand management

We have considered whether it is appropriate for us to determine an explicit amount of capex that could be deferred through demand management, based on the scale and positive outcomes achieved by Ausgrid during 2009–14 and the Productivity Commission report. Using this approach we could apply an explicit systems capex forecast offset for Essential of 9.2 per cent, or approximately $106 million ($2013–14). However, we would also need to assess the efficient opex required to support this capex offset. The frontier firms used in setting the efficient benchmark for our opex forecast included some allowance for demand management activities. While this demand management expenditure was forecast, we do not currently have actual expenditure data from which to accurately calculate a capex/opex trade-off.

Therefore, our draft decision is to not include an explicit reference in the capex or opex forecasts for demand management. Based on the available information, we are currently of the view that it is most appropriate to rely on the incentive framework, together with the new requirements around the RIT-D and the distribution Annual Planning Report, to drive the efficient use of demand management and share the benefits with consumers through the CESS.

However, we welcome views on whether this is the most appropriate approach in providing incentives for the optimal amount of demand management. To the extent that stakeholders consider that the long term interests of consumers may be better promoted through explicit recognition of demand management and consequential adjustments to capex and opex, we seek views on the appropriate capex/opex trade-off that should be included.

B Assessment approaches

This appendix discusses the assessment approaches we have applied in assessing Essential Energy's proposed forecast capex.

B.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. We are required to consider as it is a capex factor under the NER.[119] Economic benchmarking applies economic theory to measure the efficiency of a DNSP's use of inputs to produce outputs, having regard to environmental factors.[120] It allows us to compare the performance of a DNSP against its own past performance, and the performance of other DNSPs. Economic benchmarking helps us to assess whether a DNSP's capex forecast represents efficient costs.[121] As stated by the AEMC, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[122]

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a DNSP's efficiency with consideration given to its inputs, outputs and its operating environment. We have considered each DNSP's operating environment insofar as there are factors that are outside of a NSP's control but which affect a NSP's ability to convert inputs into outputs.[123] Once such exogenous factors are taken into account, we expect TNSPs to operate at similar levels of efficiency. One example of an exogenous factor that we have taken into account is customer density. For more on how we have forecast these measures, see our annual benchmarking report.[124]

We have calculated economic benchmarks based on actual data from the previous regulatory control period. We consider these are relevant to determining allowances for the forthcoming regulatory control period as a DNSP's capex and expenditure efficiency in the previous regulatory control period is a good indicator of its likely efficiency in the next regulatory control period. Further, any benchmark efficient level of capex in the previous period will be a useful starting point for setting the efficient level of capex in the upcoming regulatory control period, taking into account any apparent trends.

In addition to the measures in the annual benchmarking report, we have considered how DNSPs have performed on a number of overall capex metrics, including:

- capex per customer, and capex per maximum demand
- the regulatory asset base (RAB) per customer, and RAB per maximum demand.

For the purposes of this analysis, capex (calculated as a five year average) or the RAB is taken as an input. We have considered both capex and the RAB as these represent different ways of measuring how efficiently a network business is in respect of capital. Measures based on capex demonstrate how efficiently a business is using capex at a particular point in time. In contrast, the RAB reflects the stock of capital and hence, a DNSP's past capex efficiency.

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119 NER, cl. 6.5.7(e)(4).
120 AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013.
121 NER, cl. 6.5.7(c).
122 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p. 25.
123 See AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.
124 AER, *Annual Benchmarking Report*, 2014.

Customer numbers and maximum demand are used as proxies for output.[125] We have looked at customer numbers and maximum demand as these are two of the key outputs for capex. Higher customer numbers or maximum demand will both increase capex requirements. Lower cost per customer or maximum demand (other things being equal) will suggest higher capex efficiency.

For the above measures, we have normalised for customer density. Customer density is the most significant environmental factor which drives capex.[126] It is generally positively related to efficiency: a DNSP with lower customer density is likely to require more network assets to service the same number of customers, for example, than does a higher density DNSP. Since the lower density DNSP will require more inputs to produce the same level of outputs, it will appear less efficient than the higher density DNSP.

The results from the economic benchmarking give an indication of the relative efficiency of each of the DNSPs, and how this has changed over time. It indicates the likely range of forecast capex that would be required by an efficient and prudent DNSP taking into account. However, we accept that it is difficult to fully account for exogenous factors particular to each DNSP. To the extent that we are unable to adequately account for exogenous factors, we have factored this into the weighting that we have given our benchmarking, as applied to each DNSP.[127] Also, we have not relied solely on economic benchmarking. It is one technique in a wide range of techniques to assist in forming our view on the reasonableness of a DNSP's proposed forecast and where required, a substitute estimate.

B.2 Trend analysis

We have considered past trends in actual and forecast capex. This is one of the capex factors that we are required to have regard to.[128]

Trend analysis involves comparing NSPs' forecast capex and work volumes against historic levels. Where forecast capex and volumes are materially different to historic levels, we have sought to understand what has caused these differences. In doing so, we have considered the reasons given by the DNSPs in their proposals, as well as changes in the circumstances of the DNSP.

In considering whether a business' capex forecast reasonably reflects the capex criteria, we need to consider whether the forecast will allow the business to meet expected demand, and comply with relevant regulatory obligations.[129] Demand and regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will increase capex, as will growth in maximum demand. Conversely, reduced service obligations or a decline in demand will likely cause a reduction in the amount of capex required by a DNSP.

Maximum demand is a key driver of augmentation or demand driven expenditure. As augmentation often needs to occur prior to demand growth being realised, forecast rather than actual demand is relevant when a business is deciding what augmentation projects will be required in an upcoming regulatory control period. However, to the extent that actual demand differs from forecast, a business should reassess the need for the projects. Growth in a business' network will also drive augmentation

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125 For more on these measures, see the AER's Annual Benchmarking Report.

126 Economic Insights, *Economic Benchmarking of Electricity Network Service Providers Report prepared for Australian Energy Regulator*, 25 June 2013, p. 73. Energy density and maximum demand density are also potential operating environment factors. However, these are correlated to customer density so we have chosen to use customer density.

127 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p. 113.

128 NER, cl. 6.5.7(e)(5).

129 NER, cl. 6.5.7(a)(3).

and connections related capex. For these reasons it is important to consider how trends in capex (and in particular, augex and connections) compare with trends in demand (both maximum demand and customer numbers).

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important in considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected a NSP's capex requirements.

We have looked at trends in capex across a range of levels including at the total capex level, for growth related capex, for replacement capex, and for each of the categories of capex, as relevant. We have also compared these with trends in demand and changes in service standards over time.

B.3 Engineering review

We have engaged engineering consultants to assist with our review of Essential Energy's capex proposals. This has involved reviewing Essential Energy's processes, and specific projects and programs of work.

In particular, in respect of augex and repex, we have engaged engineers to consider whether Essential Energy's:

- forecast is reasonable and unbiased, by assessing whether the DNSP’s proposed capex is a reasonable forecast of the unbiased efficient cost of maintaining performance at the required or efficient service levels.
- risk management is prudent and efficient, by assessing whether the business manages risk such that the cost to the customer of achieving the capex objectives at the required or efficient service levels is commensurate with the customer value provided by those service levels.
- costs and work practices are prudent and efficient, by assessing whether the DNSP uses the minimum resources reasonably practical to achieve the capex objectives and maintain the required or efficient service levels.

We have considered these factors as they relate directly to our assessment of whether the DNSP's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives:[130]

- If a capex forecast is reasonable and unbiased, the forecast should reflect the efficient costs required to meet the capex objectives. That is, there should be no systemic biases which result in a forecast that is greater than or less than the efficient forecast. Further, the forecast should be reasonable in that it reflects what a prudent operator would incur to achieve the capex objectives.
- If the Essential Energy's risk management is prudent and efficient, Essential Energy's forecast is likely to reflect the costs that a prudent operator would require to achieve the capex objectives. A prudent operator would consider both the probability of a risk eventuating and the impact of the risk (if it were to occur) in determining whether to undertake work to mitigate the risk.[131]

[130] NER, cl. 6.5.7(c) (version 58).
[131] This approach is supported by NERA Economic Consulting, see NERA, Economic Interpretation of cll. 6.5.6 and 6.5.7 of the NER, Supplementary Report, Ausgrid submission, 8 May 2014, p. 7.

- If Essential Energy's costs and work practices are prudent and efficient, Essential Energy will have the appropriate governance and asset management practices to ensure that Essential Energy has determined an efficient capex forecast that is based on a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

Accordingly, the engineering review was tasked with assessing whether there were any systemic issues arising from Essential Energy's governance and risk assessment framework and whether there is evidence that indicates that the forecasts are biased. The engineering reviews focused on Essential Energy's major replacement programs and adopted a sampling approach in considering the above factors. Where this revealed concerns about systemic issues, we asked the engineers to quantify the likely impact of these biases. This review covered an assessment of:

- the options the NSP investigated to address the economic requirement (for example, for repex projects the review included an assessment of the extent to which the NSP considered sub options for replacements)
- whether the timing of the project is efficient and prudent (including replacement strategies at a portfolio level)
- unit costs and volumes, including comparisons with past trends in expenditure
- longer term asset replacement strategies (including replacement strategies at a portfolio level rather than at a project level)
- the relative prices of operating and capital inputs and the substitution possibilities between operating and capital expenditure
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers. This is most relevant to core network expenditure (augex and repex) and may include the NSP's consideration of the value of customer reliability (VCR) standard or a similar appropriate standard.

In some cases we have also reviewed specific capex projects or programs of work to determine whether these meet the capex criteria. These reviews have been undertaken in respect of particular capex categories related to proposed asset replacement expenditure.

C Demand

This attachment sets out our observations of demand trends in Essential Energy's network for the 2014–2019 period.[132]

Demand forecasts are fundamental to a NSP's forecast capex and opex, and to the AER's assessment of that forecast expenditure.[133] Essential Energy must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. When Essential Energy invests in its network to meet demand and increases in electricity consumption, it incurs capex. In particular, the expected growth in demand is an important factor driving network augmentation expenditure and connections expenditure (growth capex).[134] Essential Energy uses demand forecasts in conjunction with network planning to determine the amount and timing of such expenditure. Essential also incurs opex in relation to the new assets it builds to meet demand growth.

System demand represents total demand in the Essential Energy distribution network. This attachment considers demand forecasts in Essential Energy's network at the system level. These observations give an indication of overall demand trends and for the first time include a comparison to AEMO's independent demand forecasts. System demand trends give a high level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased requirement for growth capex, and converse for forecasts of stagnant or falling system demand.[135] Accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network. For example, overly high demand forecasts may lead to inefficient expenditure as NSPs install unnecessary capacity in the network.

However, localised demand growth (spatial demand) drives the requirement for specific growth projects or programs. Spatial demand growth is not uniform across the entire network: for example, future demand trends would differ between established suburbs and new residential developments. Accordingly, there may also be a need to consider spatial demand forecasts as part of determining the requirement for growth capex for the 2014–2019 period. Section A.1 discusses this analysis in more detail.

C.1.1 AER position on system demand trends

We are satisfied the system demand forecasts in Essential Energy's regulatory proposal for the 2014–2019 period reasonably reflects a realistic expectation of demand.[136] The demand forecasts in Essential Energy's regulatory proposal for the 2014–2019 period are considerably lower than previous forecasts.[137] As we would expect, one result of this trend is the significant reduction in Essential Energy's augex forecast for the 2014–2019 period compared to the 2009–2014 regulatory control period (see section A.1).

However, we understand the NSPs are in the process of further updating their demand forecasts. We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we will consider updated demand forecasts and other information in the final decision to reflect the most up to date data. We would also expect Essential Energy's expenditure forecasts to

[132] In this attachment, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated.
[133] NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).
[134] Sections A.1 and A.2 discuss our consideration of Essential Energy's augex and connections expenditure.
[135] Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.
[136] NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).
[137] Essential Energy, *Regulatory proposal*, May 2014, p. 43; Essential Energy, *Regulatory proposal*, 2 June 2008, p. 95.

reflect updates to its demand forecasts. For example, we would expect a downward revision of Essential Energy's expenditure forecast with a downward revision in the demand forecast (noting spatial demand is the main driver for growth capex).

The Australian Energy Market Operator (AEMO) forecasted similar trends of low system demand growth for Essential Energy's network and for the NSW region more generally. We note AEMO downgraded its demand forecast for the NSW region in its most recent report.[138]

Submissions from stakeholders suggest there is evidence demand will continue to stagnate, or even fall, in Essential Energy's network for the 2014–2019 period. We note stakeholders generally provided qualitative evidence, and did not suggest specific demand figures.

Section C.1.3 discusses these observations in more detail.

C.1.2 AER approach

Our consideration of demand trends in Essential Energy's network relied primarily on comparing demand information from the following sources:

- Essential Energy's regulatory proposal
- forecasts from AEMO
- stakeholder submissions in response to Essential Energy's regulatory proposal (as well as submissions made in relation to the NSW/ACT distribution determinations more generally).

Essential Energy's proposal

Essential Energy's proposal described their demand forecasting methods, including approaches to:

- weather correction
- accounting for spot loads
- accounting for transfers
- accounting for embedded generation.[139]

Essential Energy obtained its system demand forecast by aggregating spatial demand forecasts.[140] It does not appear Essential Energy produced a separate demand forecast using a top-down approach.[141]

Essential Energy is in the process of transitioning from a relatively simplistic process to a more complex and repeatable process closely aligned with the AEMO connection point (CP) forecasting method. For example, Essential Energy stated its previous process included minimal weather correction and reconciliation between top-down and bottom-up forecasts. Essential anticipates it will

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[138] AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014, p. 4-4.
[139] Essential, *Regulatory proposal: Attachment 5.13: Draft: Guideline for electricity network demand forecasting*, 30 May 2014.
[140] Essential, *Regulatory proposal: Attachment 5.13: Draft: Guideline for electricity network demand forecasting*, 30 May 2014.
[141] Essential, *Basis of preparation: Response to reset RIN*, 29 May 2014, p. 174.

complete the transition by January 2015.[142] We note Essential Energy did not provide weather corrected demand (historical or forecast).[143]

AEMO forecasts

In July 2014, AEMO published the first edition of transmission connection point (CP) forecasts for New South Wales and Tasmania.[144] These forecasts are AEMO's independent electricity maximum demand forecasts at transmission connection point level, over a 10-year outlook period.[145] The Standing Council on Energy Resources (SCER) intended these demand forecasts to inform our regulatory determinations.[146] In addition, AEMO has published the National Electricity Forecasting Report (NEFR) since 2012, and published the latest edition in June 2014 (2014 NEFR).[147] The NEFR includes AEMO's summer and winter demand forecasts for all regions (states) in the National Electricity Market.

AEMO described the key steps to its CP forecasting methodology as:

- data preparation (including demand and weather data)
- weather normalisation
- determination of starting point
- determination of growth rate
- determination of baseline forecasts (application of growth rate to the starting point)
- adjust for rooftop photovoltaics and energy efficiency
- reconciliation of CP forecasts with the relevant state forecast from the 2014 NEFR.[148]

As part of our consideration of system demand forecasts, we compared Essential Energy's system demand forecast to the sum of AEMO's CP forecasts for Essential Energy's network. We undertook further investigation to understand Essential Energy's demand forecasts where they differed significantly from AEMO's CP forecasts. This included making enquiries of Essential Energy and AEMO to determine any differences in the composition of the datasets they each used and to ascertain the reasons for discrepancies.

Section C.1.3 sets out our comparisons of AEMO's CP forecasts with Essential Energy's demand forecasts and takes into account stakeholder submissions.

C.1.3 AER considerations on system demand trends

The demand forecasts in Essential Energy's regulatory proposal for the 2014–2019 period are considerably lower than previous forecasts. One result of this trend is the significant reduction in

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[142] Essential, *Regulatory proposal: Attachment 5.13: Draft: Guideline for electricity network demand forecasting*, 30 May 2014, p. 3.

[143] Essential, *Basis of preparation: Response to reset RIN*, 29 May 2014, pp. 28–36 and 176; Essential, *Essential Energy response to RIN (Public)*, 30 May 2014, p. 45.

[144] AEMO, *Transmission connection point forecasting report for New South Wales and Tasmania*, July 2014, p. 6.

[145] AEMO, Website: http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts, accessed 3 September 2014.

[146] AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 182.

[147] AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014.

[148] AEMO, *Transmission connection point forecasting report for New South Wales and Tasmania*, July 2014, pp. 7–8; AEMO, *Connection point forecasting: A nationally consistent methodology for forecasting maximum electricity demand*, 26 June 2014.

Essential Energy's augex forecast for the 2014–2019 period compared to the 2009–2014 regulatory control period (see section A.1). We note Essential Energy's forecast demand growth rates displayed a similar trend to AEMO's forecasts, although the absolute values of Essential Energy's demand forecasts are higher than AEMO's forecasts.

There is also some evidence which shows demand may stagnate, or even continue to fall in the 2014–2019 period. For example, several stakeholders raised concerns that Essential, as well as the other NSW/ACT DNSPs in general, are still using overly conservative demand forecasts as inputs to their regulatory proposals. We note stakeholders generally provided qualitative evidence, and did not suggest specific demand figures.

Figure C-1 shows our comparison between Essential Energy's system demand and AEMO's CP demand for the Essential Energy network.[149] It shows the growth trend for Essential Energy's system demand forecast is consistent with AEMO's CP forecasts for Essential Energy's network for the 2014–2019 period. This is despite having different datasets and forecasting approaches (see below). This gives us a level of confidence the trend in Essential Energy's forecasts are realistic.

Figure C-1 also indicates there are differences in Essential Energy's and AEMO's historical data. In addition, Essential Energy's forecasts are consistently higher than AEMO's forecasts at both 10 per cent and 50 per cent probability of exceedance (PoE) levels.

We liaised with Essential Energy and with AEMO to ascertain the reasons for the discrepancies.[150] We also asked Essential Energy whether they would adjust their demand forecast to match AEMO's CP forecasts, given the latter are the latest available forecasts.[151]

[149] We summed AEMO's coincident demand figures for each CP in Essential Energy's network for each year.
[150] We liaised with the other NSW/ACT DNSPs regarding similar issues.
[151] AER, *Email to Essential Energy: AER Essential 012 - maximum demand*, 12 August 2014.

Figure C-1 Essential Energy demand

Source: Essential Energy reset RIN; AEMO, *Dynamic interface for connection points in New South Wales and Tasmania*, 31 July 2014.

Essential Energy, and the other NSW/ACT DNSPs, noted several differences in the datasets it used to derive its forecasts and AEMO's datasets. These included:

- different treatment of major customers and embedded generation
- different timing: several NSPs stated they used financial years whereas AEMO used seasons to define their data. This affects the pattern of the time series.
- different levels of coincidence: Essential Energy noted AEMO's coincident demand figures are coincident to the NSW regional demand. On the other hand, each NSW/ACT DNSP's system demand was coincident to its own system demand.[152]

The NSPs also noted differences in forecasting methods as possible explanations in differences between their demand forecasts and AEMO's.[153]

More specifically, Essential Energy noted the reasons below for differences between its historical demand data series and AEMO's. These subsequently explain the differences between the demand forecasts.

152 ActewAGL, *Response to AER: Information request AER Essential 023*, 20 August 2014; Ausgrid, *Response to AER: Information request AER Ausgrid 021*, 1 September 2014; Endeavour Energy, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014; Essential Energy, *Response to AER: Information request AER Essential 012*, 21 August 2014.

153 ActewAGL, *Response to AER: Information request AER Essential 023*, 20 August 2014; Ausgrid, *Response to AER: Information request AER Ausgrid 021*, 1 September 2014; Endeavour Energy, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014; Essential Energy, *Response to AER: Information request AER Essential 012*, 21 August 2014.

- AEMO's data would not include cross-border supplies from other distributors. Essential Energy estimated the combined demand of these missing points is at least 250MW
- Essential Energy used financial years whereas AEMO used a seasonal basis for recording demand. Hence, there are likely to be timing differences between the two datasets.
- AEMO's data is coincident to the NSW system demand, whereas Essential Energy's are coincident to its own system demand.[154]

Hence, there are differences in the starting points and growth rates of Essential Energy's and AEMO's forecasts. Essential Energy stated it would be reluctant to adopt AEMO's CP forecasts until it understands the discrepancies between its forecasts and AEMO's. Essential Energy stated it will continue to work with AEMO to reconcile these differences.[155]

AEMO acknowledged the factors the NSW/ACT DNSPs identified explain some of the differences between its dataset and those of the NSW/ACT DNSPs, including Essential. AEMO also noted the NSW/ACT DNSPs did not raise the treatment of rooftop photovoltaics, energy efficiency and large industrial customer activity in their responses. AEMO expected different handling of these issues would result in differences in the datasets and demand forecasts.[156]

We are satisfied Essential Energy's responses adequately explain at least some of the differences between its demand figures and those of AEMO.

We note AEMO reconciled the transmission CP forecasts with its NSW regional forecasts, and so those are not demand forecasts that are 'tailor made' for Essential Energy's network. Nevertheless, we consider they provide a useful reference point for assessing Essential Energy's demand forecasts.

We understand AEMO has begun consultation with some DNSPs in reconciling their datasets.[157] AEMO also indicated it would explore developing demand forecasts at the DNSP level in the future.[158] We anticipate these processes will result in more comparable datasets in future regulatory determinations.

While Essential Energy and AEMO forecasted slow, even stagnant, demand growth for the Essential Energy network, there is evidence demand growth may even be negative in the 2014–2019 period.

PIAC noted the growing disjunction between GDP and energy use, pointing to a decline in energy intensity.[159] PIAC considers the factors contributing to the decline in energy usage—such as high electricity prices, the growth of solar installations and energy efficiency initiatives—will continue.[160] To the extent this reduction is now ‘built in’ to NSW customers, coupled with the decline in energy intensive industry, PIAC considers it is unlikely there will be recovery in energy demand.[161] The

154 Essential, *Response to AER: Information request AER Essential 012*, 21 August 2014, pp. 1–2.
155 Essential, *Response to AER: Information request AER Essential 012*, 21 August 2014, p. 4.
156 AEMO, *AEMO review: AEMO/NSP transmission connection point forecast comparison: For New South Wales (incl. ACT)*, October 2014, p. 1.
157 AEMO, *AEMO review: AEMO/NSP transmission connection point forecast comparison: For New South Wales (incl. ACT)*, October 2014, pp. 6–8.
158 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 182.
159 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator’s NSW electricity distribution network price determination*, 8 August 2014, p. 40.
160 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator’s NSW electricity distribution network price determination*, 8 August 2014, pp. 40–41.
161 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator’s NSW electricity distribution network price determination*, 8 August 2014, p. 35.

Australia Institute also noted changes to behaviour and energy efficiency, and structural changes to the economy (such as the move from manufacturing to services, which are less energy-intensive).[162]

The Australia Institute noted the relationship between seasonal demand and weather appears to have changed much less (than the relationship between weather and electricity consumption). The Australia Institute expected demand to gradually increase with a growing population.[163] AEMO also forecast positive, albeit low, demand growth rates for the 2014–2019 period (see Figure C-1), with population growth and a positive economic outlook being the primary drivers.[164]

C.1.4 Other considerations on demand

Past forecasting inaccuracies

Cotton Australia noted Essential Energy's demand forecast for the 2009–2014 regulatory control period was inaccurate by 5 to 23 per cent. This led to over investment in Essential Energy's network and resulted in a higher than necessary regulated asset base.[165]

The Energy Market Reform Forum (EMRF) noted the electricity market experienced falling demand and consumption since the previous NSW distribution determination. Indeed, regular reviews of forecasts saw continual downward adjustments in demand and consumption.[166] Among other things, falling demand and consumption led to higher prices and revenue for the 2009–2014 regulatory control period, especially when compared with earlier periods.[167]

We acknowledge demand forecasting is not a precise science and will inevitably contain errors. However, consistent over-forecasting, as the submission above noted, may indicate a systemic bias in a NSP's demand forecasting approach.[168] Essential Energy stated it is improving its demand forecasting methods.[169] Our analysis in section C.1.3 indicates Essential Energy's demand forecasts exhibit growth patterns consistent with AEMO's. However, we will monitor the accuracy of Essential Energy's demand forecasts in future regulatory years to check for any indications of bias. This in turn would aid in monitoring potentially inefficient expenditure levels in the network.

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162 The Australia Institute, *Power Down: Why is electricity consumption decreasing?: Institute paper no. 14*, December 2013, pp. 59–66.

163 The Australia Institute, *Power Down: Why is electricity consumption decreasing?: Institute paper no. 14*, December 2013, p. 56.

164 AEMO, *Transmission connection point forecasting report for New South Wales and Tasmania*, July 2014, p. 1.

165 Cotton Australia, *Submission on DNSPs regulatory proposals*, 10 July 2014, p. 3.
Cotton Australia used the MD forecasts the AER considered met the requirements of the NER (from the final decision). Essential Energy's original MD forecasts were higher than the final decision forecasts. AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 83 and 114.

166 EMRF, *NSW electricity distribution revenue reset: Applications from Ausgrid, Endeavour Energy and Essential Energy: A response*, July 2014, pp. 8 and 11.

167 EMRF, *NSW electricity distribution revenue reset: Applications from Ausgrid, Endeavour Energy and Essential Energy: A response*, July 2014, pp. 8, 11–14.

168 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 176.

169 Essential Energy, *Regulatory proposal: Attachment 5.13: Draft: Guideline for electricity network demand forecasting*, May 2014, p. 3.

D Real material cost escalation

Real material cost escalation is a method for accounting for expected changes in the costs of key material inputs to forecast capex. The materials input cost model submitted by Essential Energy includes forecasts for changes in the prices of commodities such as copper, aluminium, steel and crude oil, rather than the prices of physical inputs themselves (e.g. poles, cables, transformers) which are the inputs directly sourced by Essential Energy in the provision of its network services. Essential Energy has also escalated construction costs in its cost of materials forecast.

D.1 Position

We are not satisfied that Essential Energy's proposed real material cost escalators (leading to cost increases above CPI) which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 period.[170] Instead we consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 period. We have arrived at this conclusion on the basis that:

- the degree of the potential inaccuracy of commodities forecasts is such that we consider that zero per cent real cost escalation is likely to provide a more reliable estimation for the price of input materials used by Essential Energy to provide network services
- there is little evidence to support how accurately Essential Energy's materials escalation model forecasts reasonably reflect changes in prices paid by Essential Energy for physical assets in the past and by which we can assess the reliability and accuracy of its forecast materials model. Without this supporting evidence, it is difficult to assess the accuracy and reliability of Essential Energy's material input cost escalators model as a predictor of the prices of the assets used by Essential Energy to provide network services, and
- Essential Energy has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that are not captured by the material input cost models used by Essential Energy.

Our approach to real materials cost escalation discussed above does not affect the proposed application of labour and construction cost escalators which apply to Essential Energy's standard control services capital expenditure. We consider that labour and construction cost escalation as proposed by Essential Energy is likely to more reasonably reflect a realistic expectation of the cost inputs required to achieve the capex criteria given these are direct inputs into the cost of providing network services.[171]

D.2 Essential Energy's proposal

Essential Energy applied material and labour cost escalators to various asset classes in forecasting its capex for the 2014–19 period.[172] Real cost escalation indices for the following material cost drivers were calculated for Essential Energy by Competition Economists Group (CEG):[173]

- aluminium

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170 NER, clause 6.5.7(a).
171 NER, clause 6.5.7(c)(3).
172 Essential Energy, *Revenue proposal*, p. 61.
173 CEG, *Escalation factors affecting expenditure forecasts*, December 2013.

- copper
- steel
- crude oil; and
- construction - both engineering and non-residential.

CEG sourced forward rates from Bloomberg up to 2023 to convert commodities traded on international markets priced in United States dollars to Australian dollars.[174]

Table D-1 outlines Essential Energy's real materials cost escalation forecasts.

Table D-1 Essential Energy's real materials cost escalation forecast—inputs (per cent)

	2014–15	2015–16	2016–17	2017–18	2018–19
Aluminium	4.2	5.8	5.0	4.2	3.6
Copper	-0.9	1.1	0.3	-0.3	-0.7
Steel	0.6	3.2	0.6	0.3	-0.1
Crude oil	-0.5	2.8	2.6	2.1	1.8
Construction	0.5	0.7	0.5	0.4	0.1
Land	4.1	4.1	4.1	4.1	4.1

Source: Essential Energy, *Revenue proposal, Attachment 5.6, CEG Escalation factors affecting expenditure forecasts*, December 2013, pp. 21, 24, 27, 30 and 31 and Attachment 5.7 - Cost escalation model.

On the basis of these individual material (and labour) cost escalators, Essential Energy apportioned an escalation weighting based on the input cost escalators contribution to the total price of each asset.[175]

D.3 Assessment approach

We assessed Essential Energy's proposed real material cost escalators for the purpose of assessing its proposed total capex forecast against the NER requirements. We must accept Essential Energy's capex forecast if we are satisfied it reasonably reflects the capex criteria.[176] Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.[177]

We have applied our approach as set out in our Expenditure Forecast Assessment Guideline (Expenditure Guideline) to assessing the input price modelling approach to forecast materials cost.[178] In the Expenditure Guideline we stated that we had seen limited evidence to demonstrate that the

174 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 9.
175 Essential Energy, *Regulatory proposal, Attachment 5.7*, May 2014.
176 NER, cl. 6.5.7(c).
177 NER, cl. 6.5.7(c)(3).
178 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline,* November 2013, pp. 50-51.

commodity input weightings used by service providers to generate a forecast of the cost of material inputs have produced unbiased forecasts of the costs the service providers paid for manufactured materials.[179] We considered it important that such evidence be provided because the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used.[180] As a result, the price of manufactured network materials may not be well correlated with raw material input costs. We expect service providers to demonstrate that their proposed approach to forecast manufactured material cost changes is likely to reasonably reflect changes in raw material input costs.

In our assessment of Essential Energy's proposed material cost escalation, we:

- reviewed the CEG report commissioned by Essential Energy[181]
- reviewed the materials input cost model used by Essential Energy; and
- reviewed the approach to forecasting manufactured material costs in the context of electricity service providers mitigating such costs and producing unbiased forecasts.

In forming our views, we also considered submissions by stakeholders. We received a submission from the Energy Markets Reform Forum (EMRF) which addressed materials escalation forecasts by Essential Energy.[182] In its submission, the EMRF made the following statements in respect of materials escalation forecasts:[183]

- CEG forecasts for materials costs increases for the 2014–2019 period appears at odds with a report by Bloomberg that shows that materials used in the electricity industry are likely to fall
- Essential Energy and CEG do not provide the weighting of each material element to its mix of materials and demonstrate that the weighting is reflective of the actual mix of the various elements that comprise the final adjustment to the cost of materials
- materials cost movements are based on assumptions that are inappropriate for the use they are applied. EMRF questioned how accurate and robust these forecasts have been in the past and whether there been any assessment to compare the forecasts with actual costs to identify the degree of accuracy implicit in the forecasts, and
- to overcome input cost forecasting inaccuracies, an escalation factor unique to the energy market could be used. The AER would generate this escalation factor annually for adjustments to allowed revenues rather than use the CPI. Using an industry specific escalation index would reduce the inaccuracies inherent in the current AER approach and should result in a more equitable outcome for both consumers and networks.

179 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.
180 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.
181 CEG, *Escalation factors affecting expenditure forecasts*, December 2013.
182 The Energy Markets Reform Forum, *NSW Electricity Distribution Revenue Reset - Applications from Ausgrid, Endeavour Energy and Essential Energy - A response*, July 2014.
183 The Energy Markets Reform Forum, NSW Electricity Distribution Revenue Reset - *Applications from Ausgrid, Endeavour Energy and Essential Energy - A response*, July 2014, pp. 26-30 and Appendix 1 - Five-year drop for commodities' prices.

We also received a submission from the Public Interest Advocacy Centre Limited which stated that it expects the AER to undertake further investigation into Essential Energy's materials costs forecasts.[184]

D.4 Reasons

We must be satisfied that a forecast is based on a sound and robust methodology in order to accept that Essential Energy's proposed total capex reasonably reflects the capex criteria.[185] This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[186] In making our assessment, we do recognise that predicting future materials costs for electricity service providers involves a degree of uncertainty. However, for the reasons set out below, we are not satisfied that the materials forecasts provided by Essential Energy satisfy the requirements of the NER. Accordingly, we have not accepted it as part of our alternative estimate in our draft decision on total forecast capex. We are satisfied that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and this has been taken into account into our alternative estimate.

Materials input cost model

Essential Energy's cost escalation model does not demonstrate how and to what extent material inputs have affected the cost of inputs such as cables and transformers. In particular, there is no supporting evidence to substantiate how accurately Essential Energy's materials escalation forecasts reasonably reflected changes in prices they paid for assets in the past to assess the reliability of forecast materials prices.

In our Expenditure Guideline, we requested service providers should demonstrate that their proposed approach to forecast materials cost changes reasonably reflected the change in prices they paid for physical inputs in the past. Essential Energy's proposal does not include supporting data or information which demonstrates movements or interlink-ages between changes in the input prices of commodities and the prices Essential Energy paid for physical inputs. Essential Energy's material cost input model assumes a weighting of commodity inputs for each asset class but does not provide information which explains the basis for the weightings or that the weightings applied have produced unbiased forecasts of the costs of Essential Energy's assets. For these reasons, there is no basis on which we can conclude that the forecasts are reliable. In summary, Essential Energy has not demonstrated that their proposed approach to forecast materials cost changes reasonably reflects the change in prices they paid for assets in the past.

Materials input cost model forecasting

Essential Energy has used its consultants' report to estimate cost escalation factors in order to assist in forecasting future operating and capital expenditure. These cost escalation factors include commodity inputs in the case of capital expenditure. The consultant has adopted a high level approach hypothesising a relationship between these commodity inputs and the physical assets purchased by Essential Energy. Neither the consultants' report nor Essential Energy have successfully attempted to explain or quantify this relationship, particularly in respect to movements in the prices between the commodity inputs and the physical assets and the derivation of commodity input weightings for each asset class.

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184 Public Interest Advocacy Centre Limited, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, August 2014.

185 NER, cl. 6.5.7(c).

186 NER, cl. 6.5.7(c)(3).

We recognise that active trading or futures markets to forecast prices of assets such as transformers are not available and that in order to forecast the prices of these assets a proxy forecasting method needs to be adopted. Nonetheless, that forecasting method must be reasonably reliable to estimate the prices of inputs used by service providers to provide network services. Essential Energy has not provided any supporting information that indicates whether the forecasts have taken into account any material exogenous factors which may impact on the reliability of material input costs. Such factors may include changes in technologies which affect the weighting of commodity inputs, suppliers of the physical assets changing their sourcing for the commodity inputs, and the general volatility of exchange rates.

Materials input cost mitigation

We consider that there is potential for Essential Energy to mitigate the magnitude of any overall input cost increases. This could be achieved by:

- potential commodity input substitution by the electricity service provider and the supplier of the inputs. An increase in the price of one commodity input may result in input substitution to an appropriate level providing there are no technically fixed proportions between the inputs. Although there will likely be an increase in the cost of production for a given output level, the overall cost increase will be less than the weighted sum of the input cost increase using the initial input share weights due to substitution of the now relatively cheaper input for this relatively expensive input.

  We are aware of input substitution occurring in the electricity industry during the late 1960's when copper prices increased, potentially impacting significantly on the cost of copper cables. Electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. We do however recognise that the principle of input substitutability cannot be applied to all inputs, at least in the short term, because there are technologies with which some inputs are not substitutable. However, even in the short term there may be substitution possibilities between operating and capital expenditure, thereby potentially reducing the total expenditure requirements of an electricity service provider[187]

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.[188] For example, Essential Energy has not demonstrated whether there are any opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs

- the scale of any operation change to the electricity service provider's business that may impact on its capex requirements, including an increase in capex efficiency, and

- increases in productivity that have not been taken into account by Essential Energy in forecasting its capex requirements.

By discounting the possibility of commodity input substitution throughout the 2014–2019 period, we consider that there is potential for an upward bias in estimating material input cost escalation by maintaining the base year cost commodity share weights.

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187 NER, cl. 6.5.7(e)(7).
188 NER, cl. 6.5.7(e)(6).

Forecasting uncertainty

The NER requires that an electricity service provider's forecast capital expenditure reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[189] We consider that there is likely to be significant uncertainty in forecasting commodity input price movements. The following factors have assisted us in forming this view:

- recent studies which show that forecasts of crude oil spot prices based on futures prices do not provide a significant improvement compared to a 'no-change' forecast for most forecast horizons, and sometimes perform worse[190]
- evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than 'no change' forecasts;[191] and
- the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $US to $AUS). A review of the economic literature of exchange rate forecast models suggests a "no change" forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.[192]

Strategic contracts with suppliers

We consider that electricity service providers can mitigate the risks associated with changes in material input costs by including hedging strategies or price escalation provisions in their contracts with suppliers of inputs (e.g. by including fixed prices in long term contracts). We also consider there is the potential for double counting where contract prices reflect this allocation of risk from the electricity service provider to the supplier, where a real escalation is then factored into forecast capex. In considering the substitution possibilities between operating and capital expenditure,[193] we note that it is open to an electricity service provider to mitigate the potential impact of escalating contract prices by transferring this risk, where possible, to its operating expenditure.

Cost based price increases

Allowing individual material input costs that constitute cost escalation reflects more cost based price increases. We consider this cost based approach reduces the incentives for electricity service providers to manage their capex efficiently, and may instead incentivise electricity service providers to over forecast their capex. In taking into account the revenue and pricing principles, we note that this approach would be less likely to promote efficient investment.[194] It also would not result in a capex

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189 NER, cl. 6.5.7(c)(3).

190 R. Alquist, L. Kilian, R. Vigfusson, *Forecasting the Price of Oil*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1022, July 2011 (also published as Alquist, Ron, Lutz Kilian, and Robert J. Vigfusson, 2013, *Forecasting the Price of Oil*, in Handbook of Economic Forecasting, Vol. 2, ed. by Graham Elliott and Allan Timmermann (Amsterdam: North Holland), pp. 68-69 and pp. 427–508) and International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, pp. 25–31.

191 International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, p. 27, Chinn, Menzie D., and Olivier Coibion, *The Predictive Content of Commodity Futures*, Journal of Futures Markets, 2014, Volume 34, Issue 7, p. 19 and pp. 607-636 and T. Reeve, R. Vigfusson, *Evaluating the Forecasting Performance of Commodity Futures Prices*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1025, August 2011, pp. 1 and 10.

192 R. Meese, K. Rogoff, (1983), *Empirical exchange rate models of the seventies: do they fit out of sample?*, Journal of International Economics, 14, B. Rossi, (2013), *Exchange rate predictability*, Journal of Economic Literature, 51(4), E. Fama, (1984), *Forward and spot exchange rates*, Journal of Monetary Economics, 14, K. Froot and R. Thaler, (1990), Anomalies: Foreign exchange, the Journal of Economic Perspectives, Vol. 4, No. 3, CEG, *Escalation factors affecting expenditure forecasts*, December 2013, and BIS Shrapnel, *Real labour and material cost escalation forecasts to 2019/20, Australia and New South Wales*, Final report, April 2014.

193 NER, cl. 6.5.7(e)(7).

194 NEL, Part 1, section 7.

forecast that was consistent with the nature of the incentives applied under the CESS and the STPIS to Essential Energy as part of this decision.[195]

Selection of commodity inputs

The limited number of material inputs included in Essential Energy's cost escalation model may not be representative of the full set of inputs or input choices impacting on changes in the prices of assets purchased by Essential Energy. Essential Energy's cost escalation model may also be biased to the extent that it may include a selective subset of commodities that are forecast to increase in price during the 2014–2019 period.

Commodities boom

The relevance of material input cost escalation post the 2009 commodities boom experienced in Australia when material input cost escalators were included in determining the approved capex allowance for electricity service providers. We consider that the impact of the commodities boom has subsided and as a consequence the justification for incorporating material cost escalation in determining forecast capex has also diminished.

D.4.1 Review of independent expert's reports

We have reviewed the CEG report commissioned by Essential Energy. We consider that this review, along with our review of two other reports detailed below, provides further support for our position to not accept Essential Energy's proposed materials cost escalation.

CEG report

- CEG acknowledge that forecasts of general cost movements (e.g. consumer price index or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs (e.g. energy costs and equipment leases etc.).[196] This is consistent with the Post-tax Revenue Model (PTRM) which reflects at least in part movements in an electricity service provider's intermediary input costs.

- CEG acknowledge that futures prices will be very unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[197] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the price of assets that are not captured by the cost escalation model used by Essential Energy.

- CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets:[198]

  > While futures prices are not accurate predictors of future spot prices, they nevertheless reflect current beliefs of market participants about forthcoming price developments.

  This supports our view that there is a reasonable degree of uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of assets used by NSPs to provide network services. Whilst the IMF may conclude that commodity futures prices reflect market beliefs on future prices, there is no support from the IMF that futures prices provide an accurate predictor of future commodity prices.

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195 NER, cl. 6.5.7(e)(8).
196 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.
197 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.
198 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

- Figures 1 and 2 of CEG's report respectively show the variance between aluminium and copper prices predicted by the London Metals Exchange (LME) 3 month, 15 month and 27 month futures less actual prices between July 1993 and December 2013.[199] Analysis of this data shows that the longer the futures projection period, the less accurate are LME futures in predicting actual commodity prices. Given the next regulatory control period covers a time span of 60 months we consider it reasonable to question the degree of accuracy of forecast futures commodity prices towards the end of this period.

  Figures 1 and 2 also show that futures forecasts have a greater tendency towards over-estimating of actual aluminium and copper prices over the 20 year period (particularly for aluminium). The greatest forecast over-estimate variance was about 100 per cent for aluminium and 130 per cent for copper. In contrast, the greatest forecast under-estimate variance was about 44 per cent for aluminium and 70 per cent for copper.

- In respect of forecasting electricity service providers future costs, CEG stated that:[200]

  > There is always a high degree of uncertainty associated with predicting the future. Although we consider that we have obtained the best possible estimates of the NSPs' future costs at the present time, the actual magnitude of these costs at the time that they are incurred may well be considerably higher or lower than we have estimated in this report. This is a reflection of the fact that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.

  This statement again is consistent with our view about the degree of the precision and accuracy of futures prices in respect of predicting electricity service providers future input costs. CEG also highlights the (poor) predictive value of LME futures for actual aluminium prices.[201]

- CEG also acknowledge that its escalation of aluminium prices are not necessarily the prices paid for aluminium equipment by manufacturers. As an example, CEG referred to producers of electrical cable who purchase fabricated aluminium which has gone through further stages of production than the refined aluminium that is traded on the LME. CEG also stated that aluminium prices can be expected to be influenced by refined aluminium prices but these prices cannot be expected to move together in a 'one-for-one' relationship.[202]

  GEG provided similar views for copper and steel futures. For copper, CEG stated that the prices quoted for copper are prices traded on the LME that meet the specifications of the LME but that there is not necessarily a 'one-for-one' relationship between these prices and the price paid for copper equipment by manufacturers.[203] For steel futures, CEG stated that the steel used by electricity service providers has been fabricated, and as such, embodies labour, capital and other inputs (e.g. energy) and acknowledges that there is not necessarily a 'one-for one' relationship between the mill gate steel and the steel used by electricity service providers.[204]

  These statements by CEG support our view that the cost escalation model used by Essential Energy has not demonstrated how and to what extent material inputs have affected the cost of intermediate outputs. We note, as emphasised by CEG, there is likely to be significant value

199 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5–6.
200 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.
201 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.
202 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.
203 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.
204 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 23.

adding and processing of the raw material before the physical asset is purchased by Essential Energy.

- CEG has provided data on historical indexed aluminium, copper, steel and crude oil actual (real) prices from July 2005 to December 2013 as well as forecast real prices from January 2014 to January 2021 which were used to determine its forecast escalation factors.[205] For all four commodities, the CEG forecast indexed real prices showed a trend of higher prices compared to the historical trend. Aluminium and crude oil exhibited the greatest trend variance. Copper and steel prices were forecast to remain relatively stable whist aluminium and crude oil prices were forecast to rise significantly compared to the historical trend.

In addition to our review of the CEG Report, we have also received submissions from TransGrid and Jemena Gas Networks on other resets that are currently being undertaken from TransGrid and Jemena Gas Networks. We have considered the relevance of those submissions to the issues raised by Essential Energy in order to arrive at a position that takes into account all available information. Our views on these reports are set out below. Overall, both these reports lend further support to our position to not accept Essential Energy's proposed materials cost escalation.

SKM report

- SKM caution that there are a variety of factors that could cause business conditions and results to differ materially from what is contained in its forward looking statements.[206] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the cost of assets that are not captured by Essential Energy's cost escalation model.

- SKM stated it used the Australian CPI to account for those materials or cost items for equipment whose price trend cannot be rationally or conclusively explained by the movement of commodities prices.[207]

- In its modelling of the exchange rate, SKM has in part adopted the longer term historical average of $0.80 USD/AUD as the long term forecast going forward.[208] This is consistent with our view that longer term historical commodity prices should be considered when reviewing and forecasting future prices. In general, we consider that long term historical data has a greater number of observations and as a consequence is a more reliable predictor of future prices than a data time series of fewer observations.

- SKM stated that the future price position from the LME futures contracts for copper and aluminium are only available for three years out to December 2016 and that in order to estimate prices beyond this data point, it is necessary to revert to economic forecasts as the most robust source of future price expectations.[209] SKM also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.[210]

- SKM stated that in respect to the reliability of oil future contracts as a predictor of actual oil prices, futures markets solely are not a reliable predictor or robust foundation for future price forecasts. SKM also stated that future oil contracts tend to follow the current spot price up and down, with a curve upwards or downwards reflecting current (short term) market sentiment.[211] SKM selected

205 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, Figures 3, 4 and 5, pp. 23, 25 and 28.
206 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.
207 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.
208 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.
209 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.
210 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 16.
211 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.

Consensus Economics forecasts as the best currently available outlook for oil prices throughout the duration of the next regulatory control period.[212] The decision by SKM to adopt an economic forecast for oil rather than using futures highlights the uncertainty surrounding the forecasting of commodity prices.

BIS Shrapnel report

- BIS Shrapnel has forecast prices of gas service provider related materials to increase, in part due to movements in the exchange rate. BIS Shrapnel are forecasting the Australian dollar to fall to US$0.77 from mid-2016 to mid-2018[213]. This is significantly lower than the exchange rate forecasts by SKM of between US$0.91 to US$0.85 from 2014-15 to 2018-19.[214] CEG did not publish its exchange rate forecasts in its report but state that for the purposes of the report it sourced forward rates from Bloomberg until 2023.[215] BIS Shrapnel stated that exchange rate forecasts are not authoritative over the long term.[216]

  We consider the forecasting of foreign exchange movements during the next regulatory control period to be another example of the potential inaccuracy of modelling for material input cost escalation.

- In its forecast for general materials such as stationary, office furniture, electricity, water, fuel and rent, BIS Shrapnel assumed that across the range of these items, the average price increase would be similar to consumer price inflation and that the appropriate cost escalator for general materials is the CPI.[217] This treatment of general business inputs supports our view that where we cannot be satisfied that a forecast of real cost escalation for a specific material input is robust, and cannot determine a robust alternative forecast, zero per cent real cost escalation is reasonably likely to reflect the capex criteria and under the PTRM the electricity service provider's broad range of inputs are escalated annually by the CPI.

Comparison of independent expert's cost escalation factors

To illustrate the potential uncertainty in forecasting real material input costs, we have compared the material cost escalation forecasts derived by the consultants as shown in Table D-2.

Table D-2 Real material input cost escalation forecasts ($ real 2012-13)

	2014–15 (%)	2015–16 (%)	2016–17 (%)	2017–18 (%)	2018–19 (%)
Aluminium					
CEG	4.2	5.8	5.0	4.2	3.6
SKM	4.69	4.88	3.09	4.42	2.97
BIS Shrapnel	1.4	5.6	3.9	11.0	-6.5
Range (low to					

212 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.
213 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 6.
214 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.
215 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.
216 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A-7.
217 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 48.

	2014–15 (%)	2015–16 (%)	2016–17 (%)	2017–18 (%)	2018–19 (%)
high)	1.4 to 4.69	4.88 to 5.8	3.09 to 5.0	4.2 to 11.0	-6.5 to 3.6
Copper					
CEG	-0.9	1.1	0.3	-0.3	-0.7
SKM	-0.17	0.17	-1.15	-0.16	-1.45
BIS Shrapnel	-0.9	-1.5	0.3	9.3	-8.7
Range (low to high)	-0.9 to 0.17	-1.5 to 1.1	-1.15 to 0.3	-0.3 to 9.3	-8.7 to -0.7
Steel					
CEG	0.6	3.2	0.6	0.3	-0.1
SKM	2.84	2.45	-0.35	0.38	-1.11
BIS Shrapnel[1]	5.1	1.0	-0.2	8.0	-8.9
Range (low to high)	0.6 to 5.1	1.0 to 3.2	-0.35 to 0.6	0.3 to 8.0	-0.1 to -8.9
Oil					
CEG	-0.5	2.8	2.6	2.1	1.8
SKM	-5.11	-0.79	0.74	1.85	0.51
BIS Shrapnel[2]	1.4	-1.1	-0.2	6.5	-6.2
Range (low to high)	-5.11 to 1.4	-1.1 to 2.8	-0.2 to 2.6	1.85 to 6.5	-6.2 to 1.8

Source: CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 21, 24 and 27, SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 2 and BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. iii.

1 Asian market price as BIS Shrapnel believes the Asia market is more appropriate.[218]

2 BIS Shrapnel have forecast plastics prices based on price changes in Nylon-11 and HDPE (Polyethylene). BIS Shrapnel state that Castor Oil is the key raw material of Nylon-11 and because it does not have any historical data on Castor Oil, it has approximated Nylon-11 by using HDPE growth rates. HDPE (Polyethylene) prices are proxied by BIS Shrapnel using Manufacturing Wages, General Materials, and Thermoplastic Resin prices. BIS Shrapnel state that Thermoplastic Resin is primarily driven by Crude Oil.[219]

As Table D-2 shows, there is considerable variation between the consultant's commodities escalation forecasts. The greatest margin of variation is 10.1 per cent for aluminium in 2018-19, where CEG has forecast a real price increase of 3.6 per cent and BIS Shrapnel a real price decrease of 6.5 per cent. BIS Shrapnel's forecasts exhibit the greatest margin of variation but there also considerable variation

218 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 40.

219 BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. iii.

between CEG and SKM's forecasts. These forecast divergences between consultants further demonstrate the uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of intermediate outputs used by service providers to provide network services. This supports our view that Essential Energy's forecast real material cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 regulatory control period.[220]

D.5 Conclusions on materials cost escalation

We are not satisfied that Essential Energy has demonstrated that the weightings applied to the intermediate inputs have produced unbiased forecasts of the movement in the prices it expects to pay for its physical assets. In particular, Essential Energy has not provided sufficient evidence to show that the changes in the prices of the assets they purchase are highly correlated to changes in raw material inputs.

CEG, in its report to Essential Energy, identified a number of factors which are consistent with our view that Essential Energy's input cost model has not demonstrated how and to what extent material inputs are likely to affect the cost of assets. CEG acknowledged that forecasts of general cost movements (e.g. CPI or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs.[221] CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[222] CEG also stated that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.[223]

Recent reviews of commodity price movements show mixed results for commodity price forecasts based on futures prices. Further, nominal exchange rates are in general extremely difficult to forecast and based on the economic literature of a review of exchange rate forecast models, a “no change” forecasting approach may be preferable.

It is our view that where we are not satisfied that a forecast of real cost escalation for materials is robust, and we cannot determine a robust alternative forecast, then real cost escalation should not be applied in determining a service provider's required capital expenditure. We accept that there is uncertainty in estimating real cost changes but we consider the degree of the potential inaccuracy of commodities forecasts is such that there should be no escalation for the price of input materials used by Essential Energy to provide network services.

In previous AER decisions, namely our Final Decisions for Envestra's Queensland and South Australian networks, we took a similar approach. This was on the basis that as all of Envestra's real costs are escalated annually by CPI under its tariff variation mechanism, CPI must inform the AER's underlying assumptions about Envestra's overall input costs. Consistent with this, we applied zero real cost escalation and by default Envestra's input costs were escalated by CPI in the absence of a viable and robust alternative. Likewise, for Essential Energy, we consider that in the absence of a well-founded materials cost escalation forecast, escalating real costs annually by the CPI is the better alternative that will contribute to a total forecast capex that reasonably reflects the capex criteria.

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220 NER, cl. 6.5.7(a).
221 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.
222 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.
223 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

The CPI can be used to account for the cost items for equipment whose price trend cannot be conclusively explained by the movement of commodities prices. This approach is consistent with the revenue and pricing principles of the NEL which provide that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services.[224]

D.5.1 Labour and construction escalators

Our approach to real materials cost escalation does not affect the application of labour and construction cost escalators, which will continue to apply to standard control services capital and operating expenditure.

We consider that labour and construction cost escalation more reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[225] We consider that real labour and construction cost escalators can be more reliably and robustly forecast than material input cost escalators, in part because these are not intermediate inputs and for labour escalators, productivity improvements have been factored into the analysis (refer to the opex attachment).

Construction costs can be forecast with greater precision because the drivers (construction and manufacturing wages, plant equipment and other fabricated metal products, and plant and equipment hire) are reasonably transparent and can be predicted with some degree of accuracy.

Further details on our consideration of labour cost escalators are discussed in appendix D.

[225] NER, cll. 6.5.6(c)(3) and.6.5.7(c)(3).

E Operating and environmental factors

Our draft decision for Essential Energy draws upon the annual benchmarking results and other capital expenditure comparisons between DNSPs. While these results are not a direct input into our alternative estimate of Essential Energy's capex forecast, they inform us of Essential Energy's relative capital efficiency and whether efficient reductions to its forecast is achievable.

This appendix considers the operating and environmental factors identified by DNSPs that will affect the applicability of using the benchmarking results. For the reasons outlined in this appendix, in our view, any differences in operating and environmental factors should not lead to material cost advantage or disadvantage between the DNSPs in the NEM. Hence, it is reasonable to compare Essential Energy's capital efficiency relative to the other DNSPs in the NEM.

The factors considered in this appendix are:

- Existing network design
- Network scale
- Physical and environmental factors
- Regulatory factors, including building requirements, environmental regulations, health regulations, network licence conditions, State/City development policies and traffic management requirements.

E.1 Existing network design

E.1.1 Proportion of 22kV and 11kV lines

The high-voltage 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. However, higher voltage assets are typically more expensive.

The NSW and ACT DNSPs operate a high-voltage distribution network that is predominantly 11kV (although 22kV forms a significant proportion of some NSW networks). The proportion of 22kV in NSW is 39 per cent and 19 per cent is 22kV.

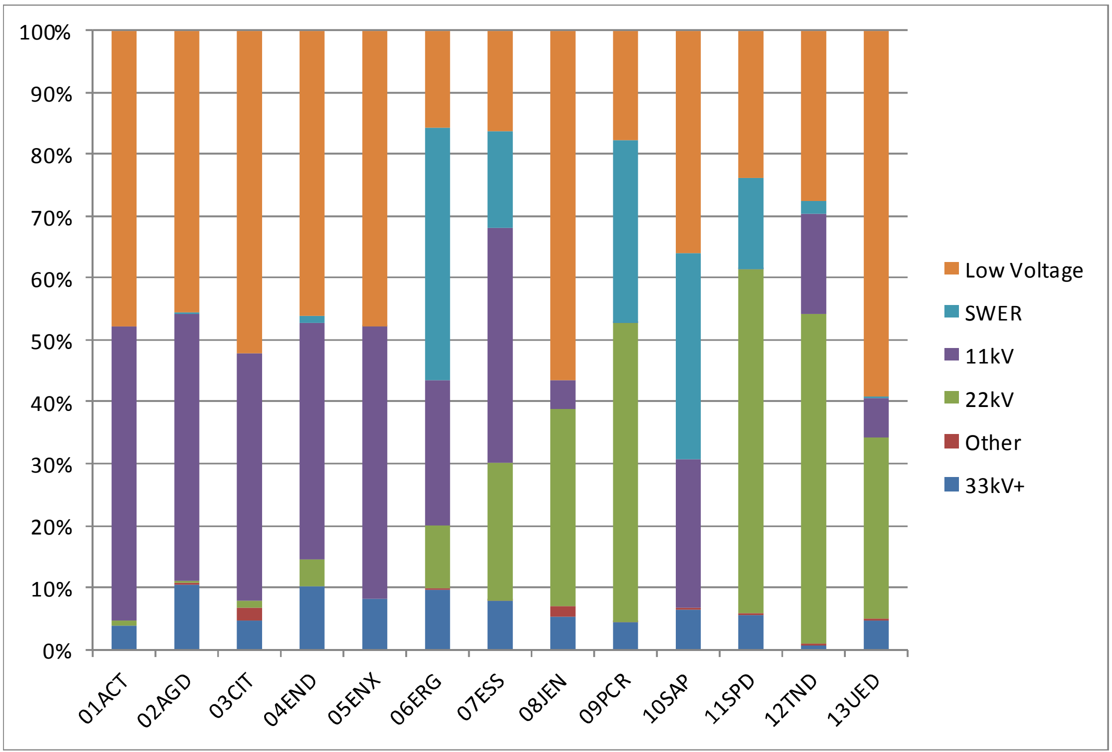
The Victorian DNSPs have mostly migrated their high-voltage networks to a 22kV model with the notable exception of CitiPower. CitiPower reported mostly 11kV high-voltage assets with a very small proportion of 22kV. The proportion of 22kV network in Victoria is 47 per cent of the total network length and just 2 per cent is 11kV.

In South Australia, SAPN reported a high-voltage network that was exclusively 11kV.[226] Queensland on average also had a higher proportion of 11kV to 22kV lines than NSW.

Figure E-1 shows the line voltages operated by the DNSPs as a proportion of total line length.

[226] Single Wire Earth Return (SWER) lines are considered separately.

Figure E-1 Line voltages by length



Source: AER analysis.

Ausgrid's consultants Evans and Peck have claimed that because Victoria operates a 22 kV high-voltage distribution system they have a cost advantage over DNSPs that operate 11kV distribution systems.[227] They claim that this represents a cost advantage and will manifest itself in lower operation, maintenance and repex costs. [228]

Table E-1 provides an overview of the costs and benefits of the differing high-voltage network types.

227 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 17.

228 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.

Table E-1 high-voltage network voltage assessment

11kV networks		22kV networks	
Costs	Benefits	Costs	Benefits
Larger number of feeders	Lower cost feeders, particularly underground	Higher cost feeders, particularly underground	Smaller number of feeders
	Lower cost distribution substations	Higher cost distribution substations	
Larger number of zone substations	Lower cost substations	Higher cost zone substations	Fewer zone substations
Greater number of civil and protection assets	Improved reliability from shorter feeders	Reduced reliability from greater feeder exposure (or greater costs in sectionalising)	Lower costs for fewer civil and protection assets
Increased maintenance (subtransmission lines, # circuit breakers, etc.)	Decreased maintenance (11kV lines, smaller capacity Z/S transformers, circuit breakers, etc.)	Increased maintenance (22kV lines, larger capacity Z/S transformers, circuit breakers, etc.)	Decreased maintenance (subtransmission lines, #circuit breakers, etc.)

Source: AER analysis.

From the above it is evident that there are both advantages and disadvantages associated with the higher capacity high-voltage networks. It would appear that 22kV networks may have a higher capital and reliability cost, and a lower maintenance cost.

It is not inherently obvious whether the overall life-cycle costs of a 22kV network are greater or less than a similar 11kV network. We note that the South Australian and Victorian DNSPs represent the two extremes in terms of 11kV and 22kV networks respectively – Powercor and SP AusNet are predominantly 22kV systems and SAPN has a predominantly 11kV system. If this factor were material to the costs of the DNSPs we would expect this to be most apparent when comparing these two jurisdictions. The benchmarking data indicates that SAPN, Powercor and SP AusNet have very similar levels of expenditure and performance suggesting that this factor is not material to overall performance.

Within Victoria, CitiPower has a predominantly 11kV high-voltage network while SP AusNet and Powercor have predominantly 22kV networks. Were 11kV networks inherently more expensive to operate and maintain we would expect to see a material difference in performance between these Victorian DNSPs. In the majority of the benchmark analysis, CitiPower expenditures are consistent or better than those of Powercor and SP AusNet. Noting that the customer density of these businesses is very different, this again raises questions as to whether 11kV networks have a material or detrimental impact on performance.

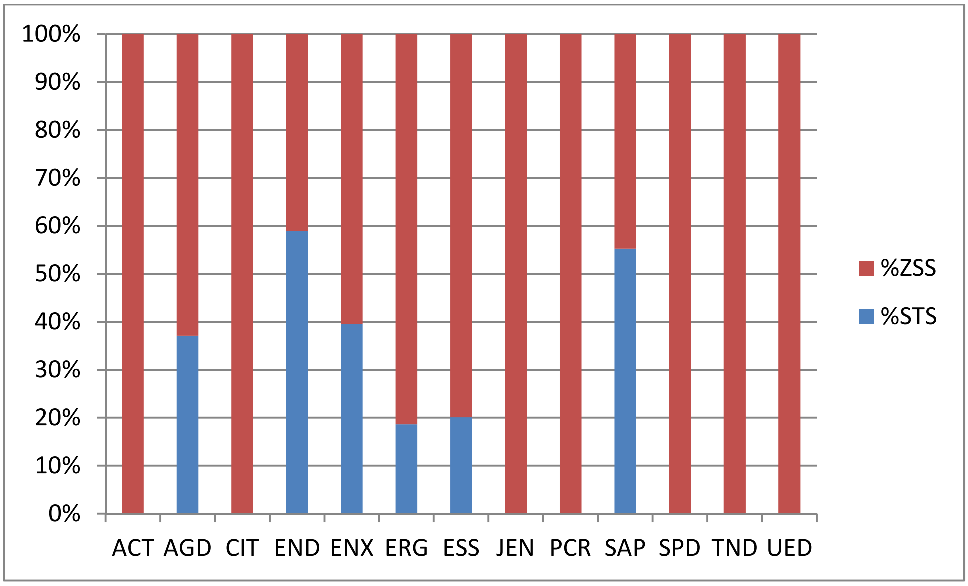
We also note that new major network extensions in all DNSPs continue to be undertaken at the existing voltage levels. If there were a distinct cost advantage from 11kV or from 22kV networks we would expect to see networks adopting plans and longer terms strategies to move to the more efficient voltage levels. We may also expect to see major network extensions or additions to be reflecting the more efficient voltage levels. The absence of any such changes is suggestive that the cost difference between the two voltages is not sufficient to warrant the incremental cost of the change.

E.1.2 Subtransmission variations

Ausgrid, Endeavour, and Essential have all raised subtransmission network configuration as an operating environment factor that will affect benchmarking results with other DNSPs.[229] [230] [231]

The transition point between transmission and distribution varies across jurisdictions and also within DNSPs. All DNSPs take supply from transmission Grid Exit Points (GXPs) across a range of voltages. Figure E-2 identifies the proportion of subtransmission capacity on the DNSP networks that is operating at higher transformation levels. The blue shaded bars indicate the higher voltage transformation capacity.

Figure E-2 Subtransmission capacity



Source: AER analysis.

Ausgrid has said that because it has a higher proportion of subtransmission assets their cost structures are inherently higher for providing services to their customers.

Ausgrid's consultants Evans and Peck have said that Victoria and Tasmania have a natural cost advantage because they have a shorter total length of installed subtransmission cables.[232] They have also said that Victoria has a natural cost advantage over all other states because it has less subtransmission transformer capacity installed.[233] Evans and Peck have also said that because there is only one transformation step in Victorian subtransmission networks the Victorian DNSPs will have a cost advantage over all other DNSPs.[234] As a result, Evans and Peck conclude that this factor has a

229 Ausgrid, *Regulatory proposal: Attachment 5.33*, May 2014, p. 5.
230 Endeavour Energy, *Regulatory proposal: Attachment 0.12*, May 2014, p. 5.
231 Essential Energy, *Regulatory proposal Attachment 5.*4, May 2014p. 5.
232 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 14.
233 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 18.
234 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 21.

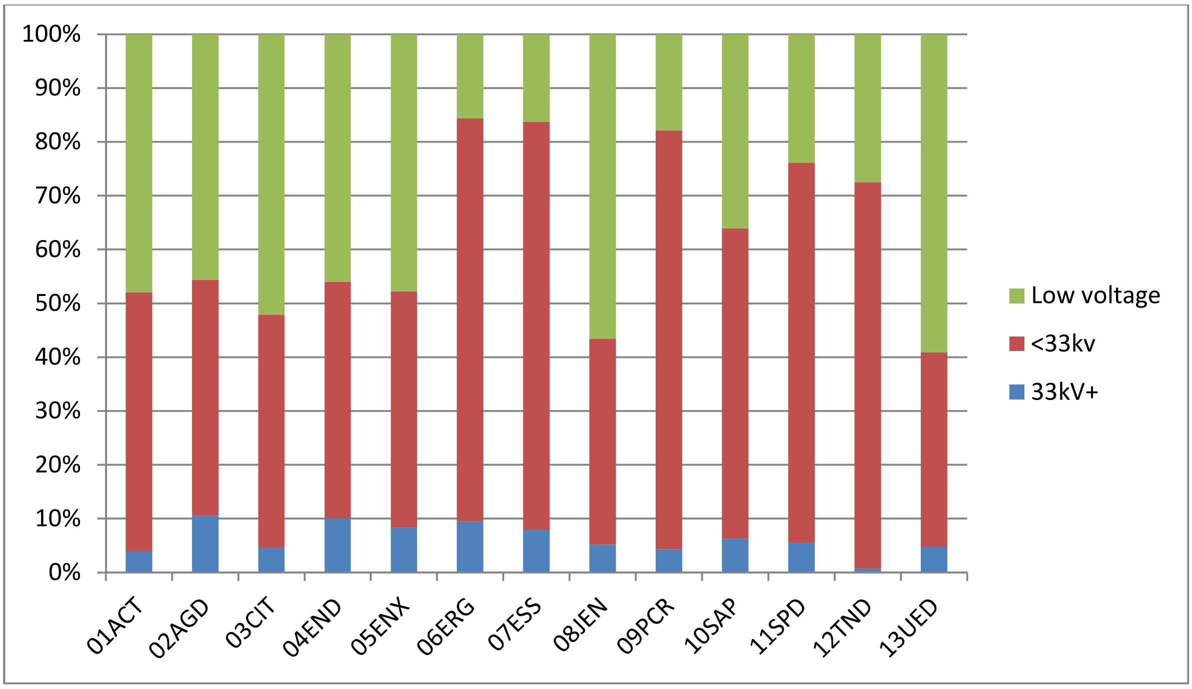
positive impact on Victorian benchmarks, particularly in terms of the existing asset base on a per customer base.

We agree with the above observations that the NSW DNSPs 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 DNSPs 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. One consideration is that the use of the higher transformation substations (STS) is driven by lower load density and size. In more densely populated areas, 132/11kV zone substations are used and there is little need for the intermediate 66kv and 33kVA subtransmission. As load density is already accounted for in the customer density normalisation, there may be a risk of double-counting the STS assets.

Figure E-3 provides the overall line lengths for each of the major voltage levels across each DNSP.

Figure E-3 Voltage line lengths



Source: AER analysis.

The above figure shows that sub-transmission lines represent a small proportion of total network line length. Ausgrid has the greatest proportion of sub-transmission lines - representing 10.6 per cent of the network. Endeavour Energy reported a value of 10.1 per cent and Essential Energy 7.9 per cent. The average proportion of Victorian and South Australian sub-transmission lines was 5.4 per cent.

This suggests that relative to the comparison firms, ActewAGL has a cost advantage. However, ActewAGL's size and the voltage of its subtransmission system may offset this. Being a relatively small service provider, ActewAGL may not be able to achieve the same economies of scale that the larger comparison firms may be able to in their subtransmission networks. Additionally, ActewAGL's subtransmission network is exclusively 132kV, while in general the subtransmission networks of the comparison firms are 66kV. These things in combination may offset the advantage of having less subtransmission, relative to the comparison firms.

E.1.3 Backyard reticulation

Backyard reticulation is a description for the ACT practice of running overhead lines along the rear property boundaries in urban residential areas. This practice was halted in favour of undergrounding a number of decades ago, but there remains a legacy of backyard reticulation lines many ACT suburbs. Backyard reticulation is only applicable to low voltage overhead lines in the ACT.

Typically the pole line is run in parallel with the adjoining property boundaries of the residential properties. This keeps the overhead lines from being viewed from the street and was considered to increase the visual amenity of the suburb.

ActewAGL has identified backyard reticulation as an operating environment factor that is likely to affect their benchmarking results.[235] ActewAGL considers that backyard reticulation increases their replacement capex.

ActewAGL has reported a total network length of 5,088km. Table E-2 shows the proportion of backyard reticulation of this network.

Table E-2 Proportion of backyard reticulation

Network component (circuit length)	(km)	Proportion (%)
ActewAGL Total network	5,088	
ActewAGL overhead network	2,394	47%
ActewAGL low-voltage overhead network	1,184	23%
ActewAGL backyard reticulation network	755	15%

Source: AER analysis.

The primary implications for electricity distribution of backyard reticulation are in terms of access to the line. In most Australian DNSPs, local electricity reticulation is via the road easement; typically the nature strip or adjacent to the centre roadway. The road easement is typically public land, whereas the backyard reticulation is typically run in privately owned land. The nature strip provides a useful location for access to overhead assets as it is usually relatively flat and directly easily accessible from the roadway. This allows for the ready access for personnel and vehicles to the assets.

Backyard reticulation places an uncertain set of barriers between the assets and ready access. These can include gates, fences, gardens, pools and animals. Not all backyard reticulation will have access issues, but it is more likely than not.

We agree with ActewAGL that backyard reticulation will have impacts on the costs associated with asset replacement. We consider that backyard reticulation will add costs to the replacement of poles and that there are also savings associated with pole replacement in backyards.

[235] ActewAGL, *Regulatory proposal*, July 2014, p. 243.

Over the current regulatory control period, overall asset replacement represents 21 per cent of total annual capital expenditure and pole replacement represents approximately 50 per cent of this. As discussed above, ActewAGL reported that less than one-third of their overhead network is located in backyards.

On this basis, the issue of backyard reticulation is a matter that relates to approximately 3.5 per cent of capital expenditure. Backyard reticulation poles are exclusively low-voltage poles and will therefore not incur the additional costs associated with replacement of high-voltage or sub-transmission poles.

The potential additional costs for backyard reticulation pole replacement would include negotiations with landowners, access, specialised materials and remediation. As backyard reticulation pole replacement takes place off the street, there would be a related reduction in costs associated with traffic management.

Typical pole replacement works would utilise heavy machinery. Backyard reticulation areas would limit the use of heavy machinery. Without heavy plant to dig hole and lift the poles and conductors etc., the work would be more labour intensive and slower. This would result in some saving in plant costs, but would result in labour costs that would be higher.

Overall we consider that there may be additional overall costs associated with pole replacement in backyard reticulation areas. However, we consider that the overall impact of these costs will be partially mitigated by reduced traffic management and that the resultant impact on overall capex costs will be very small.

E.2 Scale factors

E.2.1 Customer density

Customer density is a useful proxy for identifying the distance between customers. As each DNSP 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. There are factors that are proportional to customer density that are the underlying cost drivers including:

- Asset spacing - The need to service customers that are spaced further apart will require additional length of lines or cables to provide the same level of service.
- Asset exposure - A shorter line will have be less exposed to degradation from the elements and damage from third parties.
- 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, and design.

- Proportion of overhead and underground - Increased urban density can result in greater obligations or constraints on the DNSPs in relation to the 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, etc., will typically result in less habitable areas and increased costs associated with access to these areas.

Each of the above factors will impact network costs differently. It is obvious that some will have more of an adverse effect on rural services, while others will have a more adverse impact on urban services. Table E-3 summarises our assessment of whether the factors are likely to benefit or adversely impact networks depending on their respective customer density.

Table E-3 customer density factor impacts

Factor	Capex benchmark benefit
Asset spacing	Urban networks
Asset exposure	Urban networks
Travel times	Urban networks
Traffic management	Rural networks
Asset complexity	Rural networks
Proximity to third-party assets	Rural networks
Proportion of overhead and underground	Rural networks
Topographical conditions	Rural networks

Source: AER analysis.

It is not evident from the above chart whether the overall impact of the above measures would favour urban networks or rural networks. For example, comparing the asset cost per customer between 2009 and 2013 (figure 16 of our annual benchmarking report), there is relatively little cost difference between the Victorian rural and urban distribution networks.

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 a customers per square kilometre of service territory

The use of service territory has proven problematic and is not recommended for use. This is due to the difficulty in accurately measuring service territory items such as lakes, national parks, unpopulated areas, etc. As the networks do not incur costs for areas that are un-serviced, this is not considered as a useful measure for expenditure or service comparisons.

A number of benchmarking studies and reviews have considered the relative merits of the different remaining density measures identified above (customer, energy and demand).[236] [237] [238] As the ratios of energy and demand are relatively similar on a per customer basis, it is not clear whether there is any greater intrinsic benefit from any one of these density measures.

As customer density per kilometre is a relatively easy concept to understand, we have adopted this as our standard approach.

E.2.2 Load shape

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. The higher the peak demand, the more assets will be required to accommodate those peaks.

Evan's and Peck say that the load factor and duration for SA and Victoria give DNSPs in those states a natural cost advantage.[239] Because DNSPs in SA and Victoria have lower load factors it means that probabilistic planning is more applicable to those businesses.

Figure E-4 shows the ratio of network demand to average energy[240] for each of the NEM DNSPs. This figure shows that South Australian customers have the most peaky electricity demand, while Queensland has the lowest. This means that SAPN is required to provide more assets to meet the peak demand on its network when compared to the average electricity delivered. This would impact the expenditure required to build and replace assets as well as the ongoing operations and maintenance associated with those assets. However, as we have seen, SAPN appears as relatively efficient in overall benchmarks as well as in both capex and opex benchmarking indicators.

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236 Benchmarking Opex and Capex in Energy Networks, Working Paper no.6, May 2012, p18

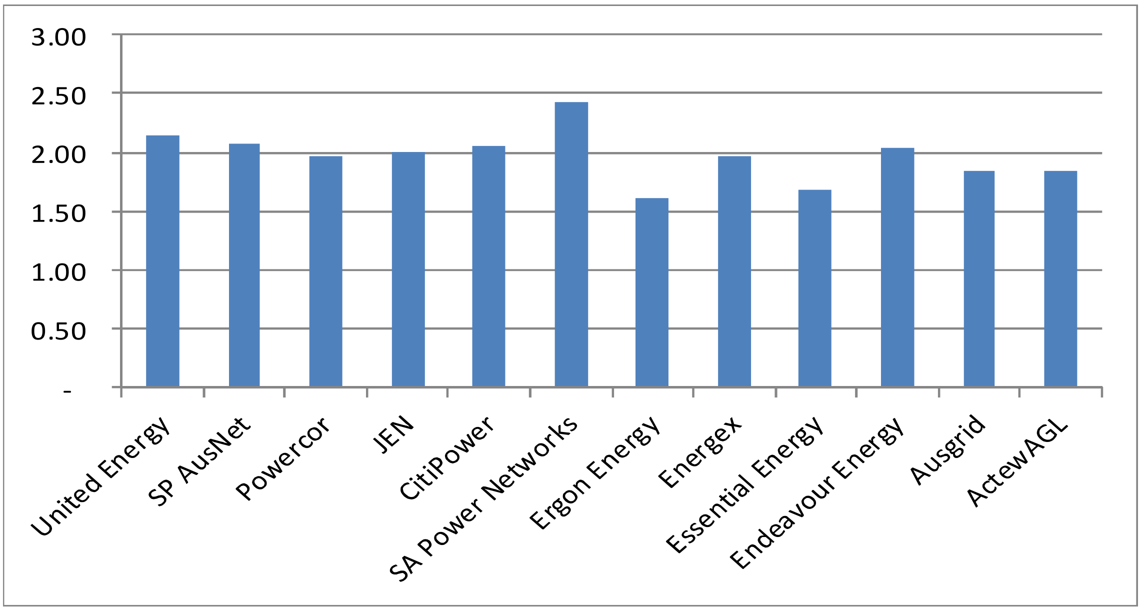
237 Western Power: Transmission & Distribution Network cost analysis & Efficiency benchmarks Volume II, Theoretical framework June 2005, Benchmark Economics

238 Aurora Energy, A comparative analysis: Aurora Energy's Network cost structure, Benchmark Economics

239 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, pp. 26–27.

240 Five year average.

Figure E-4 Network load factor



Source: AER analysis.

We disagree with the Evan's and Peck statement in relation to probabilistic planning. We consider that probabilistic planning is the efficient approach for all network businesses, irrespective of their energy or load factors. Deterministic planning does not consider the cost and benefits of individual projects and will therefore result a less cost effective outcome in the longer term.

On this basis, we consider that peakier network loads such as those on South Australia and Victoria should result in higher costs to the networks operating within them in relation to energy throughput, but not in relation to maximum demands.

E.2.3 Economies of scale

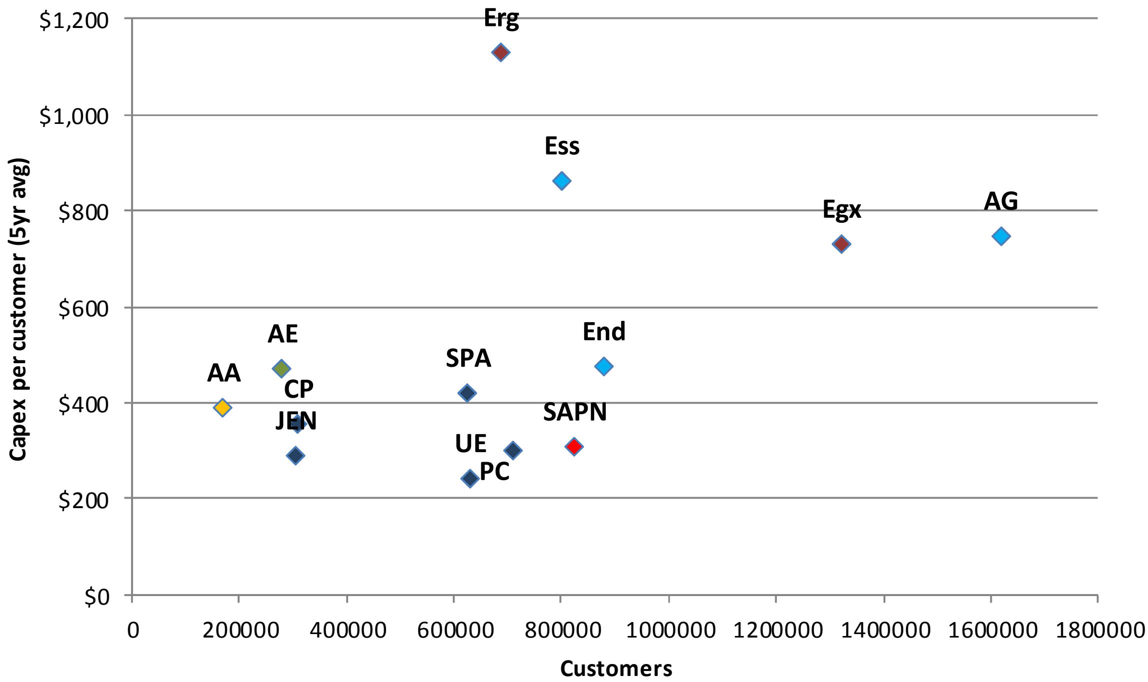
There is a wealth of literature highlighting the potential for economies of scale across all industries. Economies of scale do exist and may well have a material impact. Many of the DNSP submissions refer to the existence of economies of scale.

ActewAGL has claimed that because it is the smallest DNSP it does not have access to the same economies of scale as other DNSPs. As a result their costs will appear to be higher than for all other DNSPs that have access to greater economies of scale.[241]

Figure E-5 show that the larger DNSPs tend to be more expensive than the smaller ones when using customer numbers as a proxy for scale.

[241] ActewAGL, *Regulatory proposal*, May 2014, p. 243.

Figure E-5 Capital expenditure per customer



Source: AER analysis.

The above charts are not fully representative of the scale opportunities that are present for each company. For example:

- ActewAGL has the potential for scale opportunities through the relationship with its retail, gas and water operations.
- The NSW DNSPs are seeking to drive additional scale opportunities through the Network NSW merger.
- Powercor, CitiPower and SAPN share ownership and some management structures.
- Tasmanian Networks has been formed in part to drive efficiencies through shared services
- AusNet Services operates transmission and distribution networks under a single management structure.

On the basis of the above information, we consider the economies of scale do exist, but are difficult to accurately assess and are at present significantly less material than many other factors impacting DNSP performance.

E.3 Physical environment factors

E.3.1 Bushfires

Evans and Peck state that on the basis of a Fire Danger Index published by the Australasian Fire and Emergency Service Authorities that NSW, the ACT, and Victoria have an equal risk of Fire Danger. Evans and Peck then conclude that DNSPs in NSW, the ACT, and Victoria have natural cost disadvantages due to the risk of bushfires.

We agree with Evans and Peck that "the impact and underlying tragedy of (the 2009 Victorian bushfires) are not to be understated or overlooked in any way". Bushfire risk is a very serious concern for all Australians and represents a significant risk for all DNSPs.

However, it is unclear if ActewAGL will face greater bushfire risk than the comparison service providers. Some of the information available suggests that bushfire risk is higher in the ACT than in Victoria and South Australia, while some suggests that Victoria and South Australia are higher risk. Although some of our comparison service providers are not likely to face high bushfire risks, such as CitiPower, we have weighted ActewAGL's efficiency target according to the number of customers that the comparison service providers have. This means that the efficiency target is weighted towards predominantly rural service providers with higher bushfire risk.

Forecasts from Deloitte Access Economics of the total economic costs of bushfires for 2014, in Table E-4 below, suggests that the forecast economic cost of bushfires is higher for the ACT than for Victoria and South Australia. We have normalised the forecast 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 E-4 Forecast economic cost of bushfires 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	43	0.0	44	40	172
% of GSP	0.16%	0.01%	0.00%	0.05%	0.17%	0.05%

Source: Deloitte Access Economics[242] and ABS.[243] [244]

However, major bushfires have tended to occur more frequently in South Australia and Victoria than the ACT. Table E-5 below, which shows the location, and impacts, of major Australian bushfires of the 1900 to 2008 period, demonstrates this.

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242 DEA, Scoping study of a cost benefit analysis of bushfire mitigation: Australian Forest Products Association, May 2014, p. 12.

243 ABS, 5220.0 - Australian National Accounts: State Accounts, 2012-13.

244 ABS, 6401.0 - Consumer Price Index.

Table E-5 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.[245]

Also when normalised by population, South Australia and Victoria experienced more deaths as a result of bushfire than the ACT. We have normalised by population rather than area because bushfires in unpopulated areas will not cause any deaths and are unlikely to damage property. This is shown in Table E-6 below.

Table E-6 Deaths as a result of bushfires per 100,000 people by state 1900 to 2008

	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
Deaths	5	105	17	44	67	296
Average population 1900-2008[246]	122 524	3 804 434	1 688 122	911 524	324 896	2 818 053
Deaths per 100,000 residents	4.1	2.8	1.0	4.8	20.6	5.1

Source: Haynes et al[247] and ABS.[248]

On balance, we consider that it is uncertain whether the ActewAGL's network faces greater or lesser risk of bushfire than the comparison service providers, which are located in South Australia and Victoria. Because of this uncertainty, we consider that there is not enough evidence at this stage to suggest that ActewAGL or the comparison service providers have a relative cost advantage or disadvantage due to bushfire risk.

E.3.2 Climate

Evans and Peck say that climate can affect asset failure rates and line design requirements. They do not explain, how or which DNSPs would be affected. [249]

245 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.

246 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.

247 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.

248 3105.0.65.001 - Australian Historical Population Statistics, 2014

249 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

We agree that the DNSPs are required to consider the regional climate in designing, constructing and maintaining their assets. As an example, DNSPs that service alpine areas will need to consider the local climate in their design standards to ensure that the lines and poles can bear the expected weight of snow and ice. In addition, the lower temperatures in these areas will allow for higher ratings of lines and substations.

With the exception of cyclones and bushfires, we are not aware of any Australian climatic conditions that are extensive enough such that they would require such a material change in design, construction or maintenance as to represent a material impact on overall expenditures.

E.3.3 Corrosive environments

Evans and Peck raise the issue of corrosion as an operating environment factor. They say that the presence of corrosive atmospheres containing things such as salts (in coastal environments) and acid sulphates (in soils) impact on maintenance costs and replacement decisions.[250]

While assets in coastal areas more exposed to corrosive materials, assets in inland areas are more exposed to dusts. These differences may lead to differences in design and operational considerations. However there is not sufficient evidence to conclude that this leads to material differences in costs.

E.3.4 Grounding conditions

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.[251] 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.

Evans and Peck say that rocky terrain and high resistivity soils make the installation of earth grid, to provide effective protection, more complex.[252] Evans and Peck provide no further information on how this will affect service providers differently.

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 more challenging grounding conditions than others do. It is likely that there is a greater degree of difference in grounding conditions within networks than between networks. Although there may be differences in grounding costs between networks, there is not sufficient evidence to conclude that these differences are material.

Earthing and grounding assets represent a very small proportion of overall network asset costs. On this basis, and the lack of any clear distinctions between the DNSP areas we do not consider that soil resistivity represents a material expenditure consideration.

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250 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.
251 Single Wire Earth Return (SWER).
252 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

E.3.5 Shape factors

Evans and Peck say that natural boundaries, such as water and national park, surrounding electricity networks impose costs on DNSPs.[253] These costs manifest themselves through imposing constraints on network planning.

Electricity networks are designed to provide electrical services to customers. Over time the networks have grown to match the expansion of the population and industry. This expansion was often along waterways and then later along the roads and highways. Natural boundaries limit the expansion of the population and as a result the networks also naturally terminate at these boundaries.

While these natural boundaries might represent a cost implication for transmission networks who are required to span them, this is not the case for distribution networks. Small waterways, channels, rail lines, and easements are a cost implication for all distribution networks. Large national parks, lakes and deserts are typically unpopulated and do not require electricity distribution.

Our position is that shape factors are unlikely to have any material effect on the benchmarking results. This is because all DNSPs have boundaries and obstacles in their operating areas. Larger obstacles create a natural barrier to population and industrial growth and do not require servicing from the distribution networks.

E.3.6 Topographical conditions

Ausgrid, Endeavour, and Essential have all raised topographic conditions as an operating environment factor that will affect the benchmarking results.[254] [255] [256]

Evans and Peck, in the report commissioned by Ausgrid, state that DNSPs in NSW and Victoria have a natural cost advantage due to the topography of those regions.[257] They do not explain why they consider this to be the case.

We consider that topographical conditions will not materially affect costs at a total network level. This is because the effect of adverse topography on costs can be reduced or eliminated through prudent network planning. Further the majority of population centres in Australia are located on relatively flat terrain. While DNSPs may have assets across more topographically difficult areas, they are immaterial in volume compared to the size of their networks. Therefore the majority of distribution assets are located in areas with similar topography.

E.4 Regulatory factors

E.4.1 Building requirements

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.[258]

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253 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.

254 Ausgrid, *Regulatory proposal: Attachment 5.33*, May 2014, p. 5.

255 Endeavour Energy, *Regulatory proposal: Attachment 0.12*, May 2014, p. 5.

256 Essential Energy, *Revenue proposal: Attachment 5*.4, May 2014, p. 5.

257 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 44.

258 ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

Ausgrid's consultant Evans and Peck identified differences in building regulations as an operating environment factor that may affect benchmarking results.[259] Evans and Peck 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.[260] 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.[261]

Evans and Peck say that building code requirements can affect comparisons across networks. They do not explain, how or which DNSPs would be affected. [262]

While there are differences between the building codes, these building codes generally conform to and maintain a sufficient level consistency with national guidelines. We consider there will not be material differences in costs between service providers in different jurisdictions due to building regulations. This is because the BCA applies in all states of Australia

E.4.2 Environmental regulations

Ausgrid's consultant Evans and Peck identified differences in environmental regulations as an operating environment factor that may affect benchmarking results.[263] Evans and Peck did not provide any explanation as to how this may impede like for like comparisons.

We investigated how environmental regulations may lead to material differences for the costs 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.[264] 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 will be material.

E.4.3 Occupational health and safety regulations

Ausgrid's consultant Evans and Peck identified differences in OH&S regulations as an operating environment factor that may affect benchmarking results.[265] Evans and Peck did not provide any explanation as to how this may impede like for like comparisons. ActewAGL noted that in 2011 the implementation of the Work Health and Safety Act 2011(ACT) imposed additional costs on it that had

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[259] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 5.

[260] ABCB, About the Australian Building Codes Board, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

[261] ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

[262] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.

[263] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 38.

[264] Productivity Commission, *Performance Benchmarking of Australian Business Regulation: Local Government as Regulator*, July 2012, p. 386-390.

[265] Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 38.

not existed previously.[266] It also notes that NSW and Victoria already had many of these more stringent requirements before the implementation of the harmonised OH&S legislation.

In the NEM, all jurisdictions, except Victoria, have enacted the Work Health and Safety Act and Work Health and Safety Regulations.[267] 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 ActewAGL.

E.4.4 State/City development policy

Evans and Peck say that state and city development policy can affect comparisons across networks.[268] They say that in Sydney costs are higher due to council requirements.[269] Specifically, they say that requirements for laying and relaying of concrete pavements are more onerous in Sydney than other parts of Australia. They say that the concrete in Sydney is thicker and therefore more costly. They also say that councils in NSW do not allow businesses to reseal roads themselves after works. Instead councils reseal the roads themselves and charge businesses a fee.

We are not aware of any evidence that concrete is thicker in Sydney. Even if this was the case and there was an overall average difference in concrete depths, this would not represent a material difference in overall projects costs let alone at the overall capex level.

The practice of certain councils requiring road and pavement reinstatement to be undertaken by the council and not the DNSP is relatively common across most urbanised municipalities. All major capital cities include streetscape environments that they seek to maintain to their specific standards. As discussed above, these additional costs do not represent a material component of overall capex. The customer density normalisation on the PPI benchmarks will include any potential impacts of the urban reinstatement process.

Reinstatement is a very small component of overall operating expenditures and most urban municipalities maintain specific streetscape requirements. On this basis we consider that this area will have no material impact on the overall or category benchmarks.

E.4.5 Traffic management requirements

Evans and Peck say that traffic management regulations can affect comparison of opex and capex across networks. They do not explain, how or who would be affected. [270]

Traffic management is a factor that is generally related to the volume of traffic in the vicinity of the worksite. We consider that traffic management will have a greater impact on expenditure in higher

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266 ActewAGL, *Capital and-operating expenditure 'site visit' clarifications*, 3 October 2014, pp. 38.

267 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]

268 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 5.

269 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 39-40.

270 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 38.

density areas than in lower density areas. We consider that the potential impacts of traffic management are recognised in the customer density normaliser that is used in the PPI benchmarking.

We recognise that each Australian state and territory has different standards for the development and implementation of traffic control plans at road work 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 road work sites requirements on AS1742 Part 3: Guide to traffic control devices for works on roads.[271]

Overall we consider that differences in traffic management regulations and traffic management needs are unlikely to materially affect costs at the total cost level. Differences in traffic management regulations are likely to represent a small portion of the total difference between traffic management costs. Traffic management costs are only a portion of project costs. Not all projects incur traffic management costs.

271 National Approach to Traffic Control at Work Sites, Publication no: AP-R337/09, Austroads 2009, p.1.

F Predictive modelling approach and scenarios

This section provides a guide to our repex modelling process. It sets out:

- the background to the repex modelling techniques
- discussion of the data required to apply the repex model
- detail on how this data was specified
- description of how this data was collected and refined for inclusion in the repex model
- the outcomes of the repex model under various input scenarios

This supports the detailed and multifaceted reasoning outlined in appendix A.

F.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and Gas Rules.[272] In light of these rule changes the AER undertook a "Better Regulation" work program, which included publishing a series of guidelines setting out our approach to regulation under the new rules.[273]

The Expenditure Forecast Assessment Guideline (EFAG) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[274] It lists predictive modelling as one of the assessment techniques the AER may employ when assessing a distributor's repex. We first developed and used our repex model in our 2009 review of the Victorian electricity DNSPs' 2011–15 regulatory proposals and have also used it subsequently.[275]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[276] At a basic level, the model predicts the volume of a distributor's assets that may need to be replaced over each of the next 20 years. This prediction is made by looking at the age of assets already in commission, and the time at which, on average, these assets would be expected to be replaced. The unit cost of replacing the assets is used to provide an estimate of replacement expenditure. The data used in the model is derived from the distributor's regulatory information notice (RIN) responses and from the outcomes of the unit cost and replacement life benchmarking across all distribution businesses in the NEM. These processes are described below.

F.2 Data specification process

Our repex model requires the following input data on a distributor's network assets:

- the age profile of network assets currently in commission
- expenditure and replacement volume data of network assets
- the mean and standard deviation of each asset's replacement life (replacement life).

272 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

273 See AER *Better regulation reform program* web page at http://www.aer.gov.au/Better-regulation-reform-program.

274 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013; AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, November 2013.

275 AER Determinations for 2011–15 for CitiPower, Jemena, Powercor, SP AusNet, and United Energy.

276 AER, Electricity network service providers, Replacement expenditure model handbook, November 2013.

Given our intention to apply unit cost and replacement life benchmarking techniques, we defined the model's input data around a series of prescribed network asset categories. We collected this information by issuing, in March 2014, two types of RINs:

1. "Reset RINs" which we issued to distributors requiring them to submit this information with their upcoming regulatory proposal

2. "Category analysis RINs" which we issued to all/other distributors in the NEM.

The two types of RIN request the same historical asset data for use in our repex modelling. The Reset RIN also collects data corresponding to the distributors proposed forecast repex over the 2014–19 period. In both RINs, the templates relevant to repex are sheets 2.2 and 5.2.

For background, we note that in past determinations, our RINs did not specify standardised network asset subcategories for distributors to report against. Instead, we required the distributors to provide us data that adhered to broad network asset groups (e.g. poles, overhead conductors etc.). This allowed the distributor discretion as to how its assets were subcategorised within these groups. The limited prescription over asset types meant that drawing meaningful comparisons of unit costs and replacement lives across distributors was difficult.[277]

Our changed approach of adopting a standardised approach to network asset categories provides us with a dataset suitable for comparative analysis, and better equips us to assess the relative prices of capital inputs as required by the capex criteria.[278]

When we were formulating the standardised network assets, we aimed to differentiate the asset categorisations where material differences in unit cost and replacement life existed. Development of these asset subcategories involved extensive consultation with stakeholders, including a series of workshops, bilateral meetings and submissions on data templates and draft RINs.[279]

F.3 Data collection and refinement

The new RINs represent a shift in the data reporting obligations on distributors. Given this is the first period in which the distributors have had to respond to the new RINs, we undertook regular consultation with the distributors. This consultation involved collaborative and iterative efforts to refine the datasets to better align the data with what the AER requires to deploy our assessment techniques. Networks NSW questioned whether the data collected by the AER was of sufficient quality to use in the repex model or for benchmarking purposes.[280] We consider that the data refinement and consultation undertaken after the RINs were received, along with the extensive consultation carried out during the Better Regulation process provide us with reasonable assurance of the data's quality for use in this part of our analysis.

To aid distributors, an extensive list of detailed definitions was included as an appendix to the RINs. Where possible, these definitions included examples to assist distributors in deciding whether costs or activities should be included or excluded from particular categories. We acknowledge that, regardless of how extensive and exhaustive these definitions are, they cannot cater for all possible circumstances. To some extent, distributors needed to apply discretion in providing data. In these

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277 The repex model has been applied in the Victorian 2011–15 and Aurora Energy 2012–17 distribution determinations; AER, *Electricity network service providers Replacement expenditure model handbook*, November 2013.

278 NER, cl. 6.5.7(e)(6).

279 See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at http://www.aer.gov.au/node/21843.

280 Networks NSW, *Report - REPEX Model Review*, May 2014.

instances, distributors were required to clearly document their interpretations and assumptions in a "basis of preparation" statement accompanying the RIN submission.

Following the initial submissions, we assessed the basis of preparation statements that accompanied the RINs to determine whether the data submitted complied with the RINs. We took into account the shift in data reporting obligations under the new RINs when assessing the submissions. Overall, we considered that the repex data provided by all distributors was compliant. We did find a number of instances where the distributors' interpretations did not accord with the requirements of the RIN but for the purpose of proceeding with our assessment of the proposals, these inconsistencies were not substantial enough for a finding of non-compliance with the NEL or NER requirements.[281]

Nonetheless, in order that our data was the most up to date and accurate, we did inform distributors, in detailed documentation, where the data they had provided was not entirely consistent with the RINs, and invited them to provide updated data. Refining the repex data was an iterative process, where distributors returned amended consolidated RIN templates until such time that the data submitted was fit for purpose.

F.4 Benchmarking repex asset data

As outlined above, we required the following data on distributors' assets for our repex modelling:

- age profile of network assets currently in commission
- expenditure, replacement volumes and failure data of network assets
- the mean and standard deviation of each asset's replacement life.

All NEM distributors provided this data in the Reset RINs and Category analysis RINs under standardised network asset categories.

To inform our expenditure assessment for the distributors currently undergoing revenue determinations,[282] we compared their data to the data from all NEM distributors. We did this by using the reported expenditure and replacement volume data to derive benchmark unit costs for the standardised network asset categories. We also derived benchmark replacement lives (the mean and standard deviation of each asset's replacement life) for the standardised network asset categories.

In this section we explain the data sets we constructed using all NEM distributors' data, and the benchmark unit costs and replacement lives we derived for the standardised network asset categories.

F.4.1 Benchmark data for each asset category

For each standardised network asset category where distributors provided data we constructed three sets of data from which we derived the following three sets of benchmarks:[283]

- benchmark unit costs

281 NER, cl. 6.9.1.
282 NSW and ACT distribution network service providers—Ausgrid, Endeavour Energy, Essential Energy, and ActewAGL.
283 We did not derive benchmark data for some standardised asset categories where no values were reported by any distributors, or for categories distributors created outside the standardised asset categories.

- benchmark means and standard deviations of each asset's replacement life (referred to as "uncalibrated replacement lives" to distinguish these from the next category)

- benchmark calibrated means and standard deviations of each asset's replacement life.

Our process for arriving at each of the benchmarks was as follows. We calculated a unit cost for each NEM distributor in each asset category in which it reported replacement expenditure and replacement volumes. To do this:

- We determined a unit cost for each distributor, in each year, for each category it reported under. To do this we divided the reported replacement expenditure by the reported replacement volume.

- Then we determined a single unit cost for each distributor for each category it reported under. We first inflated the unit costs in each year to June $2014 using the CPI index.284 We then calculated a single June $2014 unit cost. We did this by first weighting the June $2014 unit cost from each year by the replacement volume in that year. We then divided the total of these expenditures by the total replacement volume number.

We formulated two sets of replacement life data for each NEM distributor:

- The replacement life data all NEM distributors reported in their RINs.

- The replacement life data we derived using the repex model for each NEM distributor. These are also called calibrated replacement lives. The repex model derives the replacement lives that are implied by the observed replacement practices of a distributor. That is, based on the data a distributor reported in the RIN on its replacement expenditure and volumes over the most recent five years, and the age profile of its network assets currently in commission. The calibrated lives the repex model derives can differ from the replacement lives a distributor reports.

We derived the benchmarks for an asset category using each of the three data sets above. That is, we derived a set of benchmark unit costs, benchmark replacement lives, and benchmark calibrated replacement lives for an asset category. We applied the method outlined below to each of the three data sets.

We first excluded Ausgrid's data, since it reported replacement expenditure values as direct costs and overheads. Therefore these expenditures were not comparable to all other NEM distributors which reported replacement expenditure as direct costs only. We then excluded outliers by:[285]

- calculating the average of all values for an asset category

- determining the standard deviation of all values for an asset category

- excluding values that were outside plus or minus one standard deviation from the average.

Using the data set excluding outliers we then determined the:

- Average value:

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284 We took into account whether the distributor reported on calendar or financial year basis.

285 For the calibrated mean replacement lives we performed two additional steps on the data prior to this. We excluded any means where the distributor did not report corresponding replacement expenditure. This was because zero volumes lead to the repex model deriving a large calibrated mean which may not reflect industry practice and may distort the benchmark observation. We also excluded any calibrated mean lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years in the asset age profile.

    - benchmark average unit cost
    - benchmark average mean and standard deviation replacement life
    - benchmark average calibrated mean and standard deviation replacement life.
- One quartile better than the average value:
    - benchmark first quartile unit cost
    - benchmark first quartile mean replacement life
    - benchmark first quartile calibrated mean replacement life.
- 'Best' value:
    - benchmark best (lowest) unit cost
    - benchmark best (longest) mean replacement life
    - benchmark best (highest) calibrated mean replacement life.[286]

F.5 Repex model scenarios

As noted above, our repex model uses an asset age profile, expected replacement life information and the unit cost of replacing assets to develop an estimate of replacement volume and expenditure over a 20 year period.

The asset age profile data provided by the distributors is a fixed piece of data. That is, it is set, and not open to interpretation or subject to scenario testing.[287] However, we have multiple data sources for replacement lives and unit costs, being the data provided by the distributors, data that can be derived from their performance over the last five years, and benchmark data from all distributors across the NEM. The range of different inputs allows us to run the model under a number of different scenarios, and develop a range of outcomes to assist in our decision making.

We have categorised three broad input scenarios under which the repex model may be run. These are explained in greater detail within our Replacement expenditure model handbook.[288] They are:

(1) The Base model – the base model uses inputs provided by the distributor in their RIN response. Each distributor provided average expected life data as part of this response. As the businesses did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years in the base model.

(2) The Calibrated model – the process of “calibrating” the expected replacement lives in the repex model is described in the AER’s replacement expenditure handbook.289 The calibration involves

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[286] We did not determine quartile or best values for the standard deviation and calibrated standard deviation replacement lives. This is because we used the benchmark average replacement lives (mean and standard derivation) for comparative analysis between the distributors. However, the benchmark quartile and best replacement life data was for use in the repex model sensitivity analysis. The repex model only requires the mean component of an asset's replacement life as an input. The repex model then assumes the standard deviation replacement life of an asset is the square root of the mean replacement life. The use of a square root for the standard deviation is explained in more detail in our Replacement expenditure model handbook; AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

[287] It has been necessary for some service providers to make assumptions on the asset age profile to remove double counting. This is detailed at the end of this appendix.

[288] AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

determining a replacement life and standard deviation that matches the distributor's recent historical level of replacement (in this case, the five years from 2009–10 to 2014–15). The calibrated model benchmarks the business to its own observed historical replacement practices.

(3) The Benchmarked model – the benchmarked model uses unit cost and replacement life inputs from the category analysis benchmarks. These represent the observed costs and replacement behaviour from distributors across the NEM. As noted above, we have made observations for an "average", "first quartile" and "best performer" for each repex category, so there is no single "benchmarked" model, but a series of models giving a range of different outputs.

It is also possible to combine life and unit cost inputs between the three broad scenarios to further expand the range of scenarios under which the model is run (e.g. replacement lives from the calibrated model with unit costs from the benchmarked model). The model also takes account of different wooden pole staking rate assumptions.

Data assumptions

Certain data points were not available for use in the model. For unit costs, this arose either because the service provider did incur any expenditure on an asset category in the 2009–14 regulatory control period (used to derive historical unit costs) or had not proposed any expenditure in the 2014–19 period (used to derive forecast unit costs). If both these inputs were not available, we used the benchmarked average unit cost as a substitute input.

In addition, we did not use a calibrated asset replacement life where the service provider did not replace any assets during the 2009–14 regulatory control period. This is because the calibration process relies on replacement volumes over the five year period to derive a mean and standard deviation, and using a value of zero may not be appropriate for this purpose. In the first instance, we substituted these values with the average benchmark of calibrated replacement lives across service providers. Where this was not available, we used the base case observation from the service provider.

Unmodelled repex

As detailed in the AER's repex handbook, the repex model is most suitable for asset categories and groups with a moderate to large asset population of relatively homogenous assets. It is less suitable for assets with small populations or those that are relatively heterogeneous. For this reason, we chose to exclude certain data from the modelling process, and did not use predictive modelling to directly assess these categories. We decided to exclude SCADA repex from the model for this reason. Expenditure on pole top structures was also excluded, as we do not have asset age profile data to assess this expenditure against. Other excluded categories are detailed in appendix A.3 of this draft decision.

F.6 The treatment of staked wooden poles

The staking of a wooden pole is the practice of attaching a metal support structure (a stake or bracket) to reinforce an aged wooden pole. The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like for like basis. To understand why this requires special treatment, we have described the normal like-for-

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[289] AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013, pp. 20–21.

like assumption used in the repex model, why staked poles do not fit well within this assumption, and how we adapt the model inputs to take account of this.

F.6.1 Like-for-like repex modelling

Replacement expenditure is normally considered to be on a like-for-like basis. When an asset is identified for replacement, it is assumed that the asset will be replaced with its modern equivalent, and not a different asset. For example, conductor rated to carry low voltage will be replaced with conductor of the same rating, not conductor rated for high voltage purposes.

The repex model predicts the volume of old assets that need to be replaced, not the volume of new assets that need to be installed. This is simple to deal with when an asset is replaced on a like-for-like basis – the old asset is simply replaced by a new asset of the same kind. It follows that the volume of assets that needs to be replaced where like-for-like replacement is appropriate match the volume of new assets to be installed. The cost of replacing the volume of retired assets is the unit cost of the new asset multiplied by the volume of assets that need to be replaced.

F.6.2 Non-like-for-like replacement

Where old assets are commonly replaced with a different asset, we cannot simply assume the cost of the new asset will match the cost of the old asset's modern equivalent. As the repex model predicts the number of old assets that need to be replaced, it is necessary to make allowances for the cost of a different asset in determining the replacement cost. In running the repex model, the only category where this was significant was wooden poles.

Staked and unstaked wooden poles

The life of a wooden pole may be extended by installing a metal stake to reinforce its base. Staked wooden poles are treated as a different asset in the repex model to unstaked poles. This is because staked and unstaked poles have different expected lives and different costs of replacement.

When a wooden pole needs to be replaced, it will either be staked or replaced with a new pole. The decision on which replacement type will be carried out is made by determining whether the stake will be effective in extending the pole's life, and is usually based on the condition of the pole base. If the wood at the base has deteriorated too far, staking will not be effective, and the pole will need to be replaced. If there is enough sound wood to hold the stake, the life of the pole can be extended, and a stake can be installed. Consequently, there are two possible asset replacements (and two associated unit costs) that may be made by the distributor – a new pole to replace the old one or nailing a stake the old pole.

The other non-like-for-like scenario related to staking is where an in-commission staked pole needs to be replaced. Staking is a one-off process. When a staked pole needs to be replaced, a new pole must be installed in its place. The cost of replacing an in-commission staked pole is the cost of a new pole.

Unit cost blending

We use a process of unit cost blending to account for the non-like-for-like asset categories.

For unstaked wooden poles that need to be replaced, there are two appropriate unit costs: the cost of a new pole; and the cost of staking an old pole. We have used a weighted average between the unit cost of staking and the unit cost of pole replacement to arrive at a blended unit cost.[290] We ran the model under a variety of different weightings - including the observed staking rate of the business and observed best practice from the distributors in the NEM. We also tested the sensitivity of the model to a small change in the staking rate, which is presented in the sensitivity testing section of this appendix.

For staked wooden poles being replaced, in the first instance, we used historical data from the distributors on the proportion of different voltage staked wooden poles being replaced to approximate the volume of each new asset going forward.[291] The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of pole types replaced. Where historical data was not available, we used the asset age data to determine what proportion of the network each pole category represented, and used this information to weight the unit costs.

F.7 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when finding replacement lives. This is because historical volumes of replacements are used in calibration. The RIN responses provide us with information on the volume of new assets installed over the last five years. However, the model predicts the volume of old assets being replaced - so an adjustment needs to be made for the calibration process to function correctly. We sought this information directly from the distributors. ActewAGL, Essential and Ausgrid provided the information on the number of old assets being replaced, which allowed us to calibrate the model. Endeavour did not provide us the information.[292] In the absence of this information, it was necessary to make assumptions to allow us to calibrate the repex model. We considered Ausgrid's data would act as a good proxy for Endeavour's, given the similarities in location of the networks and similarities in the overall size of their wooden pole population.[293] We determined the proportion of Ausgrid's old staked poles replaced in the last period, and applied the observation to Endeavour's population of staked poles to give an estimate of the number of disposals over the last five years. It should be noted that staking of wooden poles is a relatively recent activity, and we have not observed a large number of historical replacements of these assets by the distributors.

290 For example, if a distributor replaces a pole with a new pole 50% of the time, and stakes the pole the other 50% of the time, the blended unit cost would be a straight average of the two unit costs. If the mix was 60:40, the unit cost would be weighted accordingly.

291 Poles with different maximum voltages have different unit costs. An assumption needs to be made to determine, for example, how many new ">1kv poles" and how many new "1kv-11kv" need to be installed to replace the staked wooden poles.

292 Endeavour has classified its staking as Opex, and did not provide the requested data for this reason; Endeavour Energy, Response to AER information request 021, 18 November 2014.

293 The use of Ausgrid's data to weight Endeavour's wooden pole replacements may give a different outcome than what we would see if we had been able to use Endeavour's actual data. If Endeavour provides this data in its revised proposal, we will re-run the model using its actual figures.