# Draft decision

# Endeavour Energy distribution determination

# 2015–16 to 2018–19

# Attachment 6: Capital expenditure

November 2014

AUSTRALIAN ENERGY REGULATOR

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# Note

This attachment forms part of the AER's draft decision on Endeavour 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

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

# 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 Endeavour 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 Endeavour 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 Endeavour Energy's proposed total forecast capex

Appendix B - Overview of our assessment approaches

Appendix C - Demand

Appendix D - Operating and environmental factors

Appendix E - Predictive modelling approach and scenarios.

## 6.1 Draft decision

We are not satisfied that Endeavour Energy's proposed total forecast capex of $1,746 million ($2013–14) reasonably reflects the capex criteria. Our alternative estimate of Endeavour Energy's total forecast capex for the 2014–2019 period that we are satisfied reasonably reflects the capex criteria is $1,070 million ($2013–14).[2] Table 6-1 outlines our draft decision.

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

| | 2014–15 | 2015–16 | 2016–17 | 2017–18 | 2018–19 | Total |
|---|---|---|---|---|---|---|
| Endeavour Energy's proposal | 432.9 | 361.1 | 314.3 | 325.7 | 312.0 | **1,746** |
| AER draft decision | 285.1 | 223.1 | 184.1 | 194.4 | 183.7 | **1,070.4** |
| Difference | 147.8 | 138.0 | 130.2 | 131.3 | 128.3 | **675.6** |
| Percentage difference (%) | -34.1 | -38.2 | -41.4 | -40.3 | -41.1 | **-38.7** |

Source: Endeavour Energy Regulatory Proposal; AER analysis
Note: Numbers may not add up due to rounding.

A summary of our reasons and findings 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 Endeavour Energy's total forecast capex for the 2014–2018 period. We are not approving a particular category of capex or a particular

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

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 Endeavour 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 Endeavour 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:<br>▪ Endeavour 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 Endeavour Energy's forecasting methodology incorporates an overly conservative risk assessment which does not adequately justify the timing and priority of its proposed forecast capex.<br>▪ We have concerns with how Endeavour Energy has formulated and applied its key assumptions in relation to demand and customer forecasts and forecast labour escalation rates.<br>We also observe that Endeavour Energy's past capex performance is lower than that achieved by a number of other distribution networks. This suggests that efficient reductions in capex are achievable. This observation provides context for our analysis of specific capex drivers in Appendix A. |
| Augmentation capex | We have not accepted Endeavour Energy's proposed augex forecast of $426.1 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. Endeavour Energy's forecast is based on out-dated demand forecasts and take further 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. Endeavour Energy proposed augex forecast also did not take into account the most recent changes to the value of customer reliability (VCR).<br>We have instead included an amount of $351.8 million ($2013–14) of forecast augex in our alternative estimate that we are satisfied reasonably reflects the capex criteria. This amount is 17.4 per cent less than Endeavour Energy's proposal. To arrive at this reduction we:<br>▪ reduced Endeavour Energy's augex forecast by approximately 2.85 per cent to account for updated spatial demand forecasts<br>▪ applied a further 15 per cent reduction to account for the absence of Endeavour Energy applying more widely risk-based cost benefit analysis techniques.<br>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 reflect the change in VCR. We expect that Endeavour 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 have accepted Endeavour Energy's proposed connections forecast of $105.8 million ($2013/2014), excluding overheads, and have included it in our alternative estimate. We consider the trend of Endeavour Energy's connections capex forecast is consistent with the forecast drivers in construction activity in commercial and industrial, and multi-dwelling |

| | |
|---|---|
| | residential premises. We therefore consider this amount will allow Endeavour Energy to achieve the capex objectives.<br><br>We also have accepted Endeavour Energy's proposed capital contributions forecast of $356.9 million. Capital contributions are mostly driven by connection and augmentation works and this amount appears consistent with Endeavour Energy's proposed connections forecast. However, in its revised regulatory proposal, we expect Endeavour Energy to clearly explain how capital contributions are allocated to the capex associated with each capex driver. We have adopted Endeavour Energy's proposed capital contributions figure from the PTRM. |
| Asset replacement capex (repex) | We have not accepted Endeavour Energy's proposed forecast repex of $739.7 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:<br><br>▪ Endeavour Energy's proposal is around 55 per cent higher than Endeavour Energy's historical trend (inclusive of overheads) and compares unfavourably on a number of category level benchmarks which we have taken into account.<br><br>▪ Our consultant, EMCa has found a number of issues with Endeavour Energy's proposal which we accept. These issues include Endeavour Energy using overly conservative risk criteria that systematically overstate its costs and not adequately justifying the timing of its proposal at the project/program level.<br><br>▪ The network health indicators concerning the condition of Endeavour Energy's assets do not support a significant increase in the need for repex relative to the longer term trend of actual repex that Endeavour Energy has spent in past regulatory control periods.<br><br>We have instead included an amount of $661 million ($2013–14), excluding overheads in our alternative estimate for the 2014–2019 period. This amount will allow Endeavour Energy to achieve the capex objectives. In particular, our view of Endeavour Energy's long-term repex requirements as evidenced by its past expenditure and will provide Endeavour Energy with a reasonable opportunity to recover at least its efficient costs. |
| Reliability improvement capex | We have not accepted Endeavour Energy's proposed forecast reliability improvement capex of $65.3 million ($2013–14). Endeavour Energy submitted that its proposal is for ensuring compliance with reliability targets set out in the licence conditions and in particular for customers connected to worst performing parts of the network and to stabilise and maintain reliability performance at levels that will avoid incurring penalties under the STPIS. However, on the basis of the information before us, Endeavour Energy has not demonstrated how its proposal addresses any potential compliance issues regarding its Schedule 3 licence conditions (individual feeder performance obligations). We also do not consider it to be appropriate for the amount of reliability improvement capex to include expenditure to avoid penalties that may arise under the STPIS. The STPIS funds a service provider (by providing a reward) for reliability improvements where this is valued by customers and conversely the STPIS penalises a service provider for a deterioration in performance on the basis that customers do not value the higher level of reliability. Finally, it is not clear the extent to which this expenditure is allocated to capex associated with each capex driver. It is important for this to be made clear in order for us to ensure that Endeavour Energy has not otherwise been provided with expenditure to address compliance issues with the reliability targets set out in its licence conditions.<br><br>We expect Endeavour Energy to provide further information in its revised regulatory proposal regarding the portion of this forecast that is considered to be augex and repex and supporting information in relation to the amount required to meet its Schedule 3 licence obligations. We also expect Endeavour Energy to provide analysis that supports the additional expenditure that is not related to its Schedule 3 licence obligations. |
| Non-network capex | We have not accepted Endeavour Energy's proposed forecast capex of $176.4 million ($2013–14) for non-network capex. On the basis of the information before us, this amount is |

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|---|---|
| | overstated and exceeds the amount required to achieve the capex objectives.<br><br>We have instead included an amount of $163.3 million ($2013-14) of forecast non-network capex in our alternative estimate that we are satisfied reasonably reflects the capex criteria. In particular, this amount reflects:<br><br>▪ removal of the field service centre projects at Mulgrave and Guildford from the proposed buildings and property capex program. We consider the need for and scope of these projects is not supported as Endeavour Energy has not yet appropriately accounted for expected reductions in field service centre staff over the next 2-3 years.<br><br>▪ a reduction of 18 per cent to Endeavour Energy's proposed plant and equipment capex program to fully account for expected employee reductions in the 2014–2019 period. |
| Capitalised overheads | We have not accepted Endeavour Energy's proposed forecast capex of $308.5 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 13 per cent average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period.<br><br>We have instead included an amount of $145.3 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 Endeavour Energy spent in the 2009–2014 regulatory control period. |
| Labour cost escalators | We have also not accepted Endeavour 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 Endeavour 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 Endeavour Energy to provide this information in its revised regulatory proposal. |
| Adjustments and unaccounted for capex | Endeavour Energy proposed total gross capex of $2,103 million ($2013-14) for the 2014-19 period. This forecast included an amount of capex ($432 million) referred to in the RIN as a 'balancing item'. We understand that the balancing item includes capital contributions and proposed reliability and improvement capex.[3] We have removed the proposed reliability improvement capex from the balancing item given we have separately assessed this expenditure. We have included the proposed capital contributions from the PTRM ($356 million) in the balancing item (this differs from the amount of $302 million for capital contributions proposed in the RIN). We have then allocated this residual balancing item to augex, connections and repex by the proportion of each driver to total forecast capex. These adjustments have resulted in an increased amount for the proposed capex drivers as set out below.<br><br>▪ Augex proposed $315 million (amended to $426 million)<br><br>▪ Connections capex $76 million (amended to $106 million)<br><br>▪ Repex proposed $740 million (amended to $1021 million).<br><br>We note that there is a discrepancy between the amount of capital contributions proposed in the RIN ($302 million) and the amount proposed in the PTRM ($356 million). Further, we |

3 Endeavour Energy in its basis of preparation submitted as part of the RIN indicated that the balancing item includes capital contributions and reliability improvement expenditure.

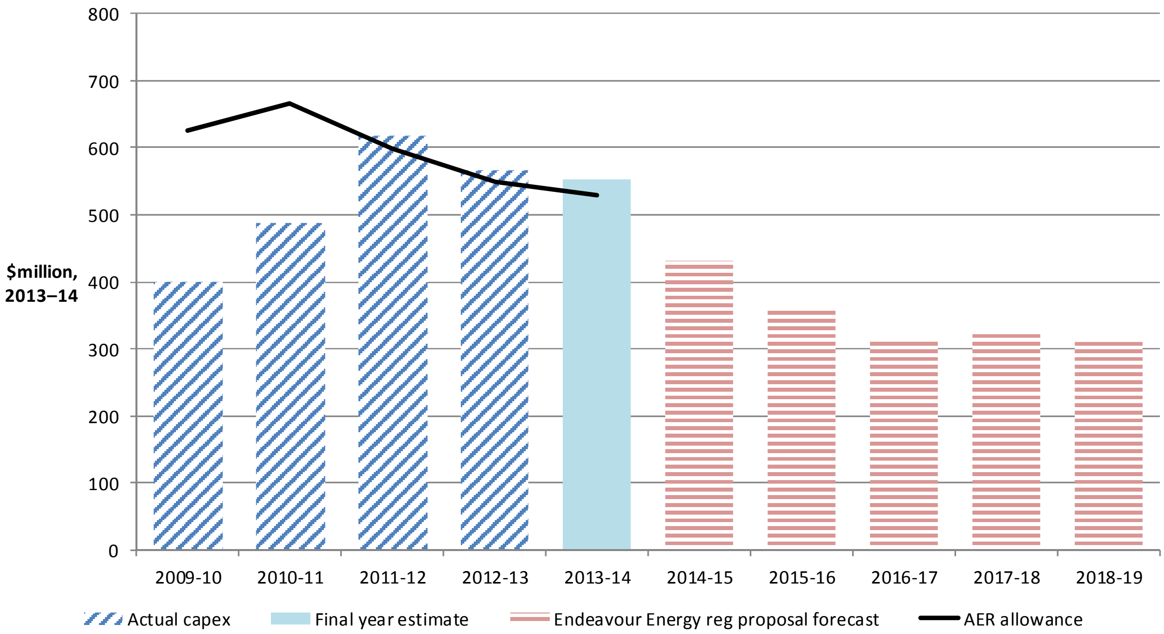
understand that Endeavour Energy has proposed total non-network capex for the 2014-19 period which is inclusive of overheads. We expect Endeavour Energy to clarify the proposed amount of capital contributions proposed for 2014-19, the amount of overhead that should be allocated to non-network capex and our approach of allocating the balancing item across the capex drivers in its revised regulatory proposal.

Source: AER analysis
Note: Our assessment of augex, connections and repex includes an allocation of Endeavour Energy's balancing item to each capex driver by the proportion of each driver to total capex.

## 6.2 Endeavour Energy's proposal

Endeavour Energy proposed total forecast capex of $1,746 million ($2013–14) for the 2014–2019 period. Figure 6-1 shows the decrease between Endeavour Energy's proposal for the 2014–2019 period and the actual capex that it spent during the 2009–2014 regulatory control period. This forecast 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 Endeavour Energy's total actual and forecast capex 2009–2019**




Source: AER analysis

## 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 Endeavour Energy's proposed total forecast capex if we are satisfied that it reasonably reflects the capex criteria.[4] If we are not satisfied, we substitute it with our alternative estimate of

[4] NER, clause 6.5.7(c).

Endeavour Energy's total forecast capex that we are satisfied reasonably reflects the capex criteria.[5] 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
- 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 '[these criteria broadly reflect the NEO [National Electricity Objective]'.[6] The capital expenditure objectives (capex objectives) referred to in the capex criteria, are to: [7]

- 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:[8]

> 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 Endeavour Energy's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.

The capex factors are:[9]

- the AER's most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient distribution network service provider (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

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5 NER, clause 6.5.7(d).

6 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).

7 NER, clause 6.5.7(a).

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

9 NER, clause 6.5.7(e).

- 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
- 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.[10]

In taking these factors into account, the AEMC has noted that:[11]

> …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.[12]

## 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 Endeavour 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.[13] The AEMC removed the focus on a business' 'individual circumstances' as it could be an impediment to the use of benchmarking by the AER.[14]

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:

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10 NER, clause 6.5.7(e)(12).
11 AEMC Economic Regulation Final Rule Determination, p. 115.
12 NEL, sections 7A and 16(2).
13 NER, clause 6.5.7(e)(4).
14 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 97.

> …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.[15]

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

## Building an alternative estimate of total forecast capex

Our starting point is the service provider's proposal.[16] 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[17]
- 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

15 AEMC, Final Rule Determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 No. 5, p. ii.

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

17 As part of the 2012 rule changes, the AEMC 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. The AEMC removed the focus on a business' 'individual circumstances' as it could be an impediment to the use of benchmarking by the AER: AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 97; NER, clauses 6.5.7(c) and 6.5.7(e)(4).

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.

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.[18]

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 distribution 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.[19]
- Past expenditure was sufficient for Endeavour Energy to manage and operate its network in that previous period, in a manner that achieved the capex objectives.[20]

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

## Comparing the service provider's proposal with our alternative estimate

Having established our alternative estimate of the total forecast capex, we can test the service provider's proposed total forecast capex. This includes comparing our alternative estimate 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.

18 AER Expenditure Forecast Electricity Distribution Guideline, p. 12.
19 AER Expenditure Forecast Electricity Distribution Guideline, pp. 8 and 9.
20 AER Expenditure Forecast Electricity Distribution Guideline, p. 9.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[21]

> 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, real cost escalators and contingent projects.

Where we approve a service provider's proposed total forecast capex or where we substitute our 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 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 Endeavour Energy's total forecast capex reasonably reflects the capex criteria. We compared Endeavour Energy's capex forecast to a capex forecast we constructed using the approach and techniques outlined above. Endeavour 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 TransGrid'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 | 117.8 | 73.6 | 46.4 | 58.8 | 55.2 | 351.8 |
| Connections | 18.2 | 21.1 | 22.0 | 21.9 | 22.6 | 105.8 |
| Replacement | 136.4 | 141.8 | 132.4 | 129.2 | 121.3 | 661.1 |

[21] AEMC Economic Regulation Final Rule Determination, p. 112.

| | | | | | | |
|---|---|---|---|---|---|---|
| Reliability improvement | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Non-Network | 48.7 | 27.2 | 28.6 | 28.6 | 30.1 | 163.2 |
| Capitalised overheads | 35.4 | 30.7 | 26.1 | 27.3 | 25.9 | 145.4 |
| **Gross Capex** | **356.5** | **294.5** | **255.5** | **265.8** | **255.1** | **1 427.4** |
| Capital contributions | 71.4 | 71.4 | 71.4 | 71.4 | 71.4 | 357.0 |
| **Net Capex** | **285.1** | **223.1** | **184.1** | **194.4** | **183.7** | **1 070.4** |

Source: AER analysis

Note: Endeavour Energy reported $432.6 million ($2013–14) in capex as a 'balancing item' in Table 2.1 of its RIN. We have allocated this balancing item to augex, connections and repex by the proportion of each driver to total capex. Our assessment of each capex driver in the appendices incorporates this balancing item allocation.
Numbers may not add up due to rounding.

Our assessment of Endeavour 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

Our assessment of capex drivers is in Appendix A. This sets out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. Our reasoning in the appendices forms the basis of our alternative estimate.

### 6.4.1 Forecasting methodology

Endeavour 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.[22] It is also required to include this information in its regulatory proposal.[23]

The main points of Endeavour Energy's forecasting methodology are:[24]

- There are four categories of system capex: growth (augmentation capex), replacement capex, reliability capex and demand and network operating management capex. There are four categories of non-system capex: land and buildings, fleet, plant and equipment and information and communications technology.
- The forecast capex is supported by a strategic asset management plan and individual asset management plans for each capex category.
- A bottom up assessment was applied to derive its forecast for all capex categories with the exception of information and communications technology, in which a combined top down and bottom up assessment was applied.

22 NER, clauses 6.8.1A and 11.56.4(o); Endeavour Energy, Expenditure Forecasting Methodology, November 2013.
23 NER, clause S6.1.1(2); Endeavour Energy, Regulatory Proposal, pp. 51–61 and Attachment 0.08.
24 Endeavour Energy, Regulatory Proposal, Attachment 0.08, pp. 10–15.

- Costings were based largely on historical costs. Historical unit-costs, current labour and contractor rates and materials and equipment costs were used to develop the bottom-up forecasts.

We have identified two aspects of Endeavour 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.

Firstly, Endeavour Energy's forecasting methodology applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for all its capex categories (except for information and communications technology). It does not combine this with the application of a top-down assessment to check or test whether these estimates are efficient. The drawback of deriving an estimate of capex solely by applying a bottom-up assessment is that of itself it does not provide any evidence that the estimate is efficient. Bottom up approaches have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. Whereas reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency. In certain very limited circumstances, a bottom up build may be a reasonable starting point to justifying expenditure. However, simply aggregating such 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:[25]

> 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 Assessment Guidelines, we intend to assess forecast capex proposals through a combination of top down and bottom up modelling.[26] Our top-down assessment of Endeavour Energy's proposed forecast is a material consideration in determining whether we are satisfied if it reasonably reflects the capex criteria. For example, trend analysis is a top-down assessment that can be applied in the context of a distribution network. This technique is able to test whether an estimate that results from a bottom-up assessment might be efficient. We have used this technique in this determination.

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.

Endeavour Energy's forecast methodology for the majority of its forecast capex does not demonstrate any of these points.

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25 National Generators Forum, Submission to the Revenue Determinations (2014–2019) of the NSW Distribution Network Service Providers, p. 9.

26 AER Expenditure Forecast Electricity Distribution Guideline, p. 17.

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 of as to whether the proposed total capex forecast reasonably reflects the capex criteria.

Secondly, Endeavour Energy's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is excessively conservative. This is evident in Endeavour Energy's failure to fully justify the timing and priority of its proposed forecast capex. Ultimately, this excessively conservative approach to risk means that Endeavour Energy is forecasting more capex in the 2014–2019 period that is necessary to achieve the capex objectives. In particular, Endeavour 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 excessively 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 Endeavour Energy's proposed repex.[27] [28]

### 6.4.2 Key assumptions

The NER require Endeavour 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.[29]

Endeavour Energy's key assumptions are:[30]

- 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 Endeavour Energy’s enterprise bargaining agreement
- its customer engagement in accordance with the stakeholder engagement process outlined in the NER.

We have addressed these key assumptions in Appendix A (the impact of the amendments to the reliability and planning conditions), Appendix C (demand) and in attachment 7 (opex rate of change appendix - forecast labour escalation rates).

In addition, we have some specific concerns about Endeavour Energy's key assumption about its legal and organisational structure. Endeavour 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

27 EMCa, Endeavour Energy, p. iii
28 EMCa, pp. ii, 12–16.
29 NER, clauses S6.1.1(2), (4) and (5).
30 Endeavour Energy, Regulatory Proposal, p 54; Endeavour Energy, Regulatory Proposal, Attachment 0.06.

current owner that a sale of the company will proceed in the 2014–19 period".[31] This appears to imply that a 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 Endeavour Energy's capex performance

We have looked at a number of historical metrics of Endeavour Energy's capex performance against that of other DNSPs in the NEM. We also compare Endeavour 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 Endeavour Energy's relative partial and multilateral total factor productivity (MTFP) performance, capex and RAB per customer and maximum demand, and Endeavour Energy's historic capex trend.

Together, these metrics suggest that there is the potential for efficiencies to be found in Endeavour Energy's proposed forecast capex for the 2014–2019 period. However, Endeavour Energy performs better than the other NSW DNSPs both in relation to its historical capex and its proposed capex for the 2014–2019 period.

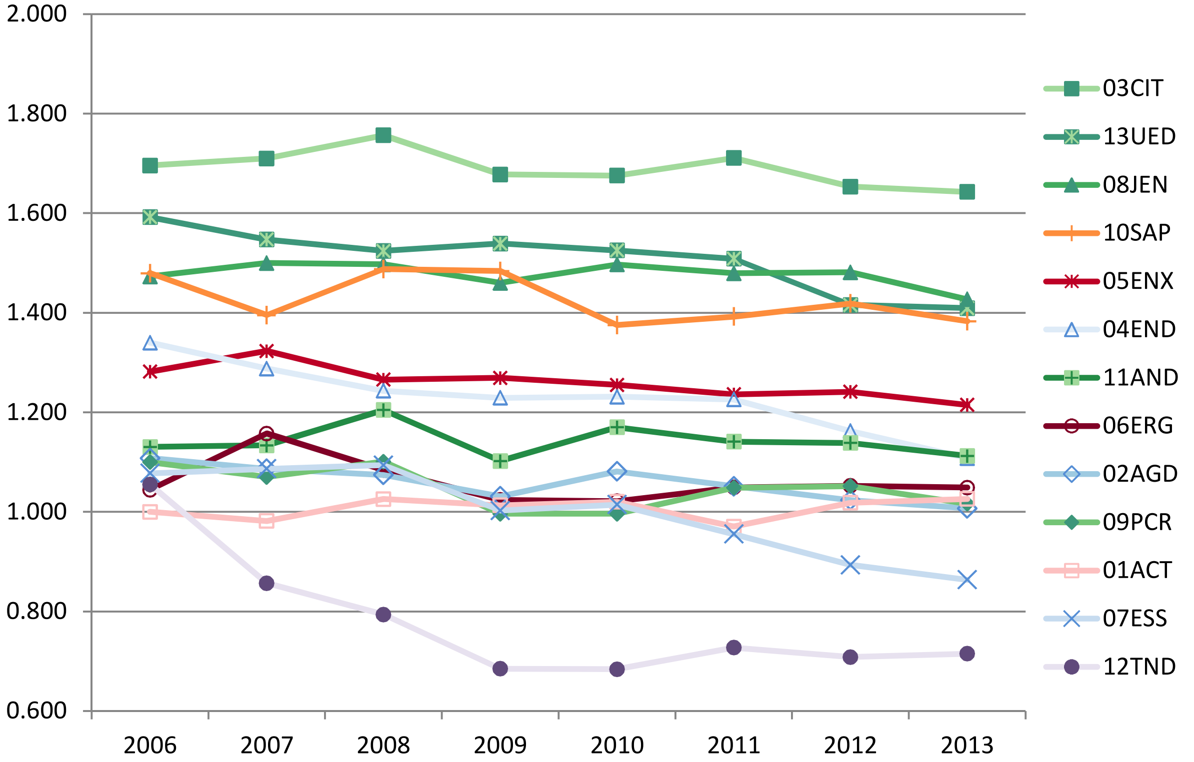
While these results are not a direct input into our alternative estimate of Endeavour Energy's capex forecast, they inform us of Endeavour Energy relative capital efficiency and whether efficient reductions to its capex forecast is achievable. We consider that it is reasonable to benchmark Endeavour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

#### 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. Endeavour Energy outperforms the NSW and ACT DNSPs, and a number of the Victorian DNSPs, but is significantly lower than the remaining Victorian and South Australian DNSPs.

[31] Endeavour Energy, Regulatory Proposal, Attachment 0.06, p 3.

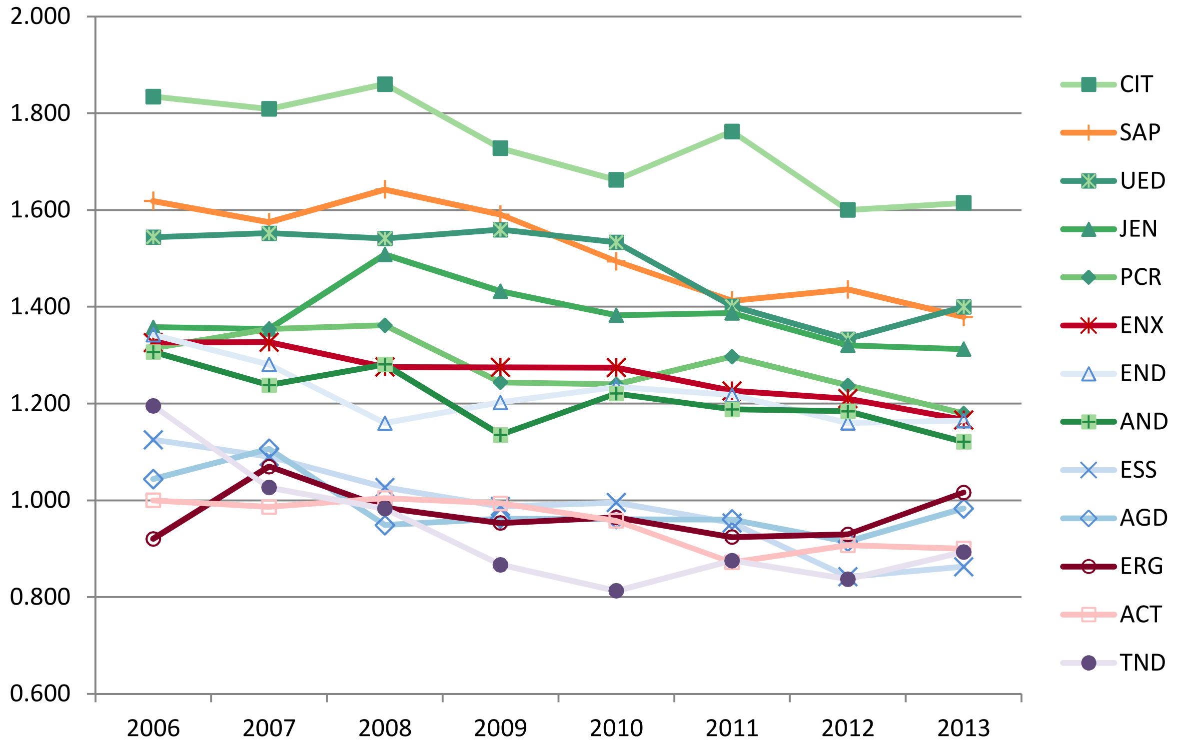
**Figure 6-2 Partial factor productivity of capital (transformers, overhead and underground lines)**




Source: AER annual benchmarking report

Figure 6-3 shows that Endeavour Energy performs similar on MTFP. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length). Across all of these measures, Endeavour Energy outperformed the NSW and ACT DNSPs; however the majority of the Victorian and South Australian DNSPs outperformed Endeavour Energy.

**Figure 6-3 Multilateral total factor productivity**



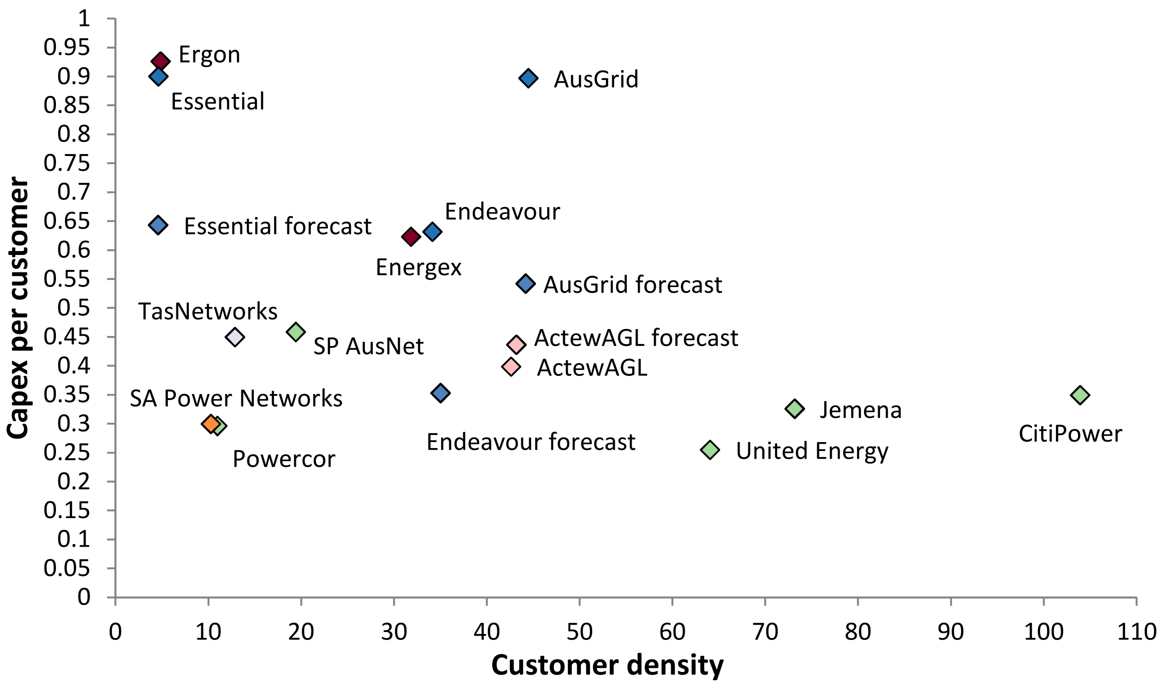

Source: AER annual benchmarking report

## Relative capex efficiency metrics

Figure 6-4 and Figure 6-5 show 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 Endeavour Energy had relatively high capex per customer for the 2008-2012 period. Endeavour Energy's capex per customer will reduce for the 2014–2019 period based on their proposed forecast capex. This reduction brings Endeavour Energy's capex per customer to a simlar level as the Victorian and South Australian DNSPs.

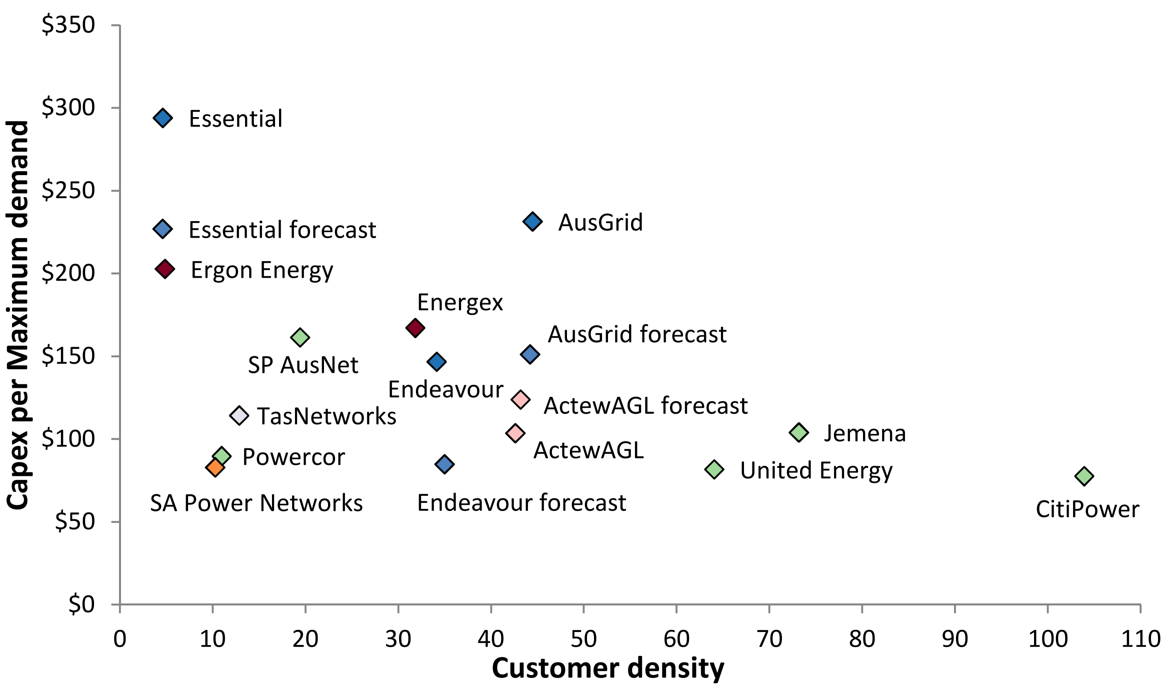
**Figure 6-4 Capex per customer (000s, $2013-14), against customer density**




Source: AER analysis

Figure 6-5 shows that Endeavour Energy's capex per maximum demand for the 2008-2012 period was relatively high, but significantly lower than the other NSW DNSPs. Capex per maximum demand is forecast to reduce for Endeavour Energy in the next period but is still among the highest levels in the NEM. This reduction brings Endeavour Energy's capex per customer to a similar level as the Victorian and South Australian DNSPs, and significantly below the other NSW DNSPs.

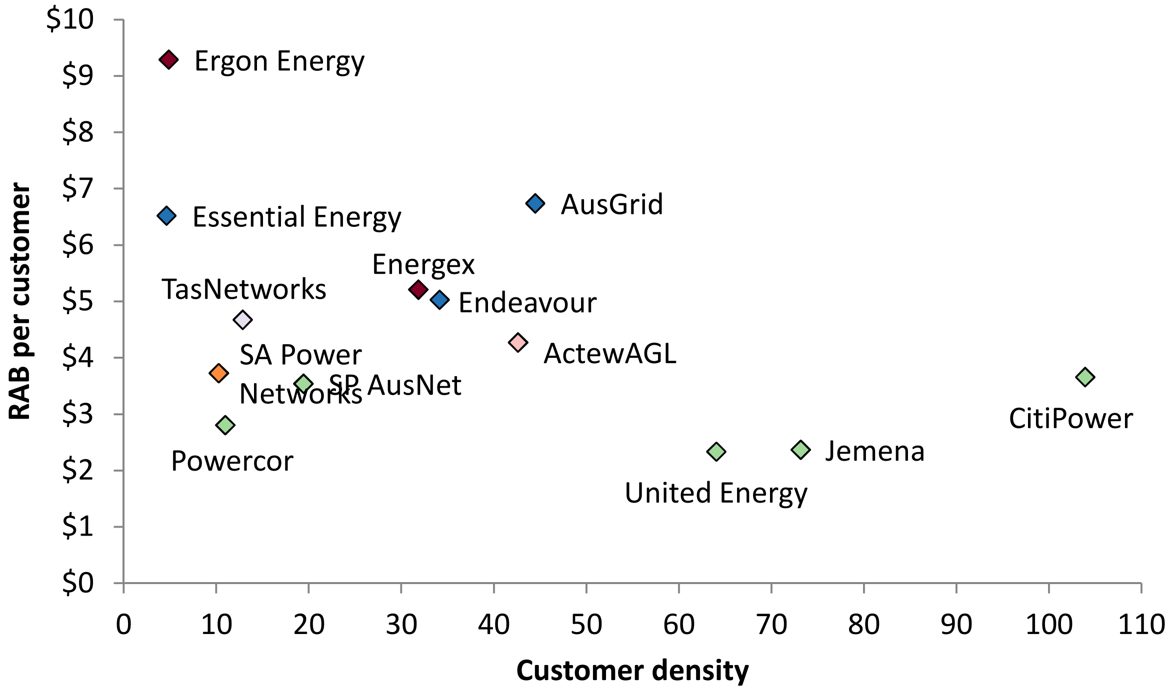
**Figure 6-5 Capex per maximum demand (000s, $2013-14), against customer density**




Source: AER analysis

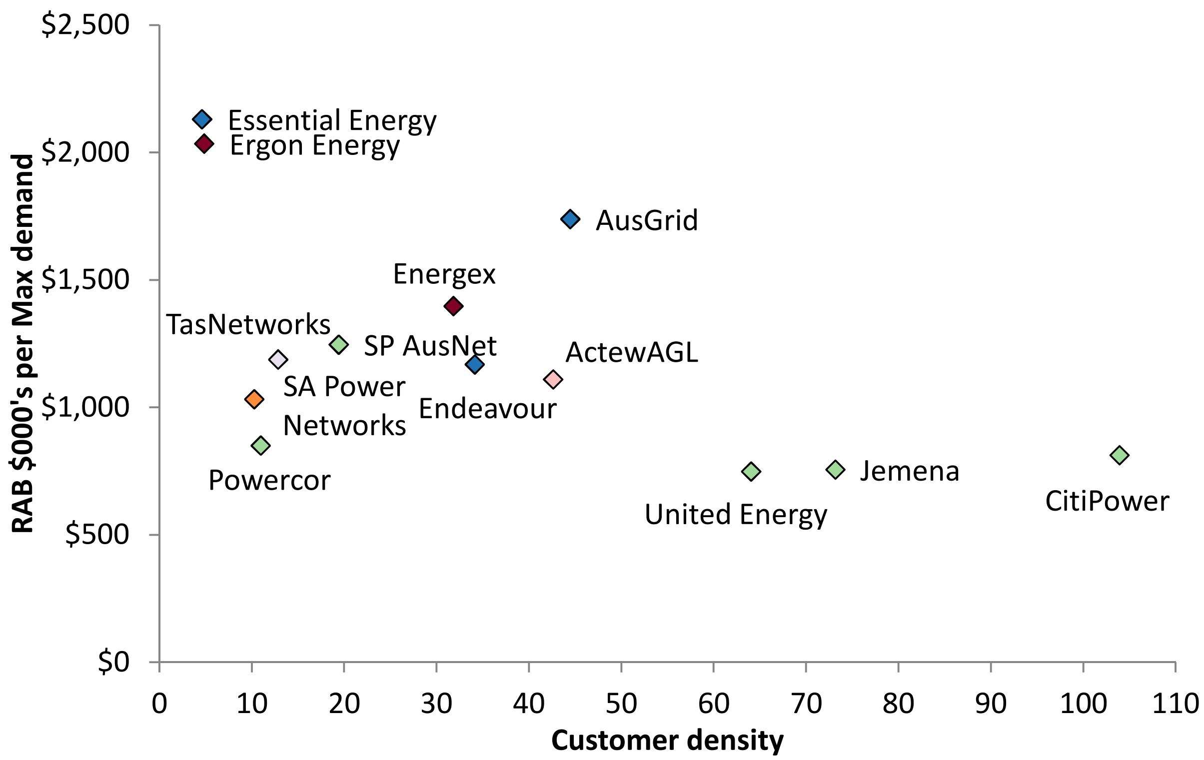
Figure 6-6 and Figure 6-7 show that the comparative ranking for the DNSPs is similar when the RAB is used instead of capex. Specifically, as at 2013, Endeavour Energy's RAB per customer and RAB per maximum demand was higher than the Victorian and South Australian DNSPs, but below the NSW DNSPs.

**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**



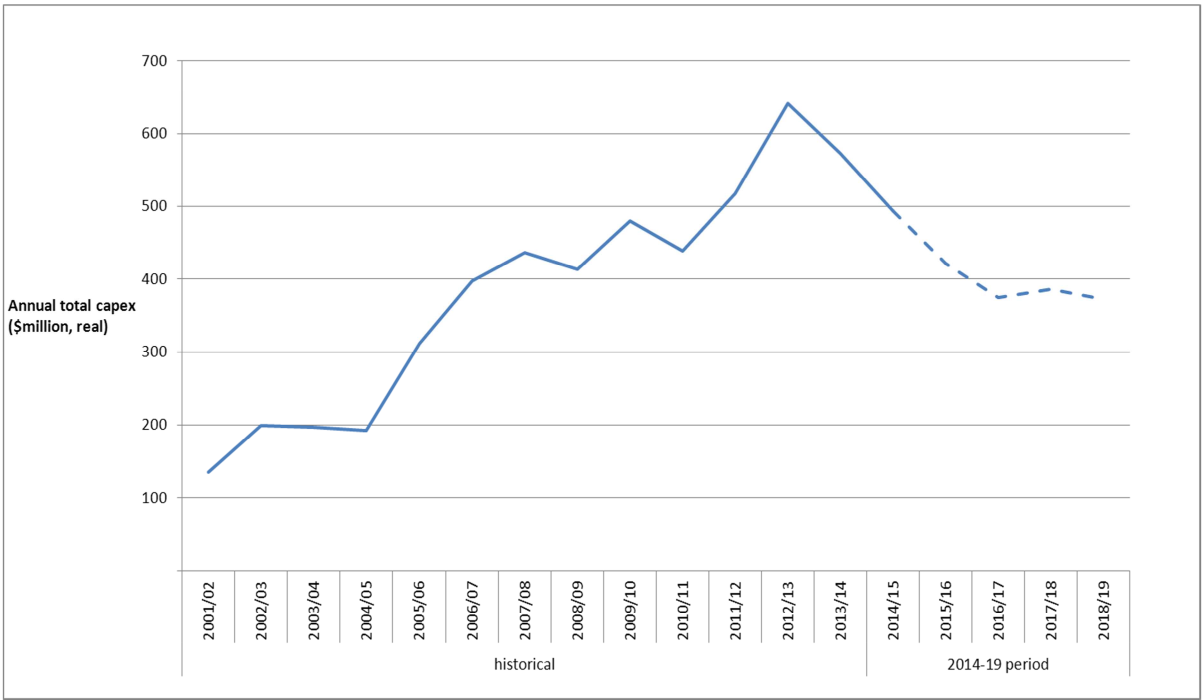

Source: AER analysis

## Endeavour Energy historic trend and licence conditions

We have also considered how Endeavour Energy's capex allowance should change to reflect given 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 Endeavour 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 Endeavour Energy's average proposed capex for the 2014–2019 period is relatively high when compared with the historical average.

**Figure 6-8 Endeavour 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: Endeavour Energy 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 2004-09 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 Endeavour Energy (then Energy Australia).[32]

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 2009-14 period were proposed. The licence conditions were subsequently amended in December 2007 to delay implementation of some of the requirements (thought the DNSPs had already received their pass throughs).[33]

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 requirements, NSW DNSPs can decide how to design 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.

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32 IPART, NSW Distribution Network Cost Pass Through Review - Statement of Reasons for decision, 5 May 2006.

33 See http://www.ipart.nsw.gov.au/files/9c9eef97-8a35-4b95-901a-a16900bdef9b/

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.[34]

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.[35]

Even without the change in standards, it could be expected that NSW DNSPs' capex would come down for the 2014–2019 period given the significant capex invested from 2005–06 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.[36]

Relevantly, the recent rule change to the expenditure objectives in the NER means that Endeavour 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.[37] 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.[38]

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 Endeavour Energy for the 2014–2019 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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34 AEMO, Submission to AEMC's Review of Distribution Reliability Outcomes and Standards, Draft Report - NSW Workstream, p. 1

35 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.

36 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.

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

38 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 Endeavour 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 Endeavour Energy's total forecast capex.

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

| Other component | Interrelationships with total forecast capex |
|---|---|
| Total forecast opex | There are elements of Endeavour Energy's total forecast opex that are related to its total forecast capex. These are:<br>▪ the labour cost escalators that we approved in (refer to the Opex rate of change Appendix)]<br>▪ the amount of maintenance opex that is reflected in Endeavour Energy's opex base year that we approved in (refer to Attachment 7<br>The labour cost escalators are interrelated because Endeavour 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 Endeavour Energy's total forecast opex, it is interrelated. This is because the amount of maintenance opex that is reflected in Endeavour Energy's opex base in part determines the extent to which Endeavour Energy needs to spend repex during the 2014–2019 period. |
| Forecast demand | Forecast demand is related to the amount of forecast growth driven capex that is included in Endeavour 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. |
| Capital Expenditure Sharing Scheme (CESS) | The CESS is related to Endeavour 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 Endeavour Energy's regulatory asset base. In particular, the CESS will ensure that Endeavour Energy bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Endeavour 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, Endeavour Energy risks having to bear the entire overspend. |
| Service Standards Performance Incentive Scheme (STPIS) | The STPIS is interrelated to Endeavour 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 Endeavour 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 Endeavour Energy's total forecast capex for the 2014–2019 period.<br>We did not identify any contingent projects for Endeavour Energy during the 2014–2019 period. |

Source: AER analysis

### 6.4.5 Capex factors

In applying our assessment techniques to determine whether we are satisfied that Endeavour 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 Endeavour 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 Endeavour Energy's capex performance. |
| The actual and expected capex of Endeavour Energy during any preceding regulatory control periods | We have had regard to Endeavour 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 Endeavour 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 Endeavour 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 Endeavour Energy in the course of its engagement with electricity consumers | We have had regard to the extent to which Endeavour Energy's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Endeavour Energy. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Endeavour 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 Endeavour Energy's proposed real cost escalation factors for materials. In particular, we have accepted Endeavour Energy's proposal to not apply real cost escalation for materials. |
| 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 Endeavour Energy's total forecast capex and total forecast opex in Table 6-4 above. |
| Whether the capex forecast is consistent with any incentive scheme or schemes that apply to Endeavour Energy | We have had regard to whether Endeavour Energy's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Endeavour 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 arrangements with a person other than the DNSP that do not reflect arm's length terms | We have had regard to whether any part of Endeavour Energy's proposed total forecast capex or our alternative estimate that is referable to arrangements with a person other than Endeavour Energy that do not reflect arm's length terms. We did not identify any parts of Endeavour 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 Endeavour 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 did not identify any such amounts that should more appropriate be included as a contingent project. |
| The extent to which Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives | We have had regard to the extent to which Endeavour 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 Endeavour Energy for us to have regard to. |
| Any other factor the AER considers relevant and which the AER has notified Endeavour Energy in writing, prior to the submission of its revised regulatory proposal, 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 Endeavour 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 Endeavour 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 Endeavour 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: reliability improvement capex

Section A.5: non-network capex

Section A.6: capitalised overheads

Section A.7: demand management

## A.1 AER findings and estimates 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

Endeavour Energy proposed a forecast of $426.12 million ($2013–14) for augex over the 2014–2019 period (excluding overheads). This is 61 per cent less than the actual augex that it spent during the 2009–2014 regulatory control period. We do not accept Endeavour Energy's proposal. We have instead included an amount of $351.83 million ($2013–14) for forecast augex in our alternative estimate, a reduction of 17.4 per cent.

This amount should provide Endeavour 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 Endeavour Energy to meet expected demand, and comply with relevant regulatory obligations[39]

[39] NER, clause 6.5.7(a)(3).

- an engineering review undertaken by WorleyParsons of Endeavour Energy's forecasting processes and methodology to assess whether Endeavour Energy's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives
- the augex model to generate trends in asset utilisation, to assess Endeavour Energy's need for network augmentation (as noted below, this was only used to a limited extent in this assessment).[40]

Based on this analysis, our reasons for not accepting Endeavour Energy's proposal and including $351.83 million ($2013–14) for forecast augex in our alternative estimate instead are as follows.

First, the trend in augex shows that Endeavour Energy has proposed significant reductions to their augex in comparison to the augex it spent during the 2009–2014 regulatory control period. This reduction is consistent with the fall in demand over the 2009–2014 regulatory control period and the excess capacity observed in Endeavour Energy's network. Nonetheless, Endeavour Energy undertook significant investment in its network in the 2009–2014 regulatory control period, resulting in a significant reduction in asset utilisation in its network. This suggests there is some excess capacity in the network that remains to be more efficiently utilised, ahead of additional augmentation investment.

Second, 30 per cent of Endeavour Energy's augex forecast was based on capacity requirements for their HV network. Endeavour Energy provided a draft of their 2014 demand forecasts that show a reduction in ratcheted demand of 12.8 per cent. We have used Endeavour Energy's draft 2014 spatial demand forecasts to reduce the expenditure required for its HV feeders by 12.8 per cent. This follows from analysis by WorleyParsons on Ausgrid which concluded a positive linear relationship exists between a change in forecast demand and expenditure requirements for HV feeders.

Third, based on WorleyParsons' findings, there is evidence that Endeavour Energy will be able to find further economies and make prudent changes to its augex projects during the 2014–2019 period, based on the application of risk-based assessments to new and ongoing programs of work. WorleyParsons suggests that it is reasonable to expect reductions of between 10 and 20 per cent. We consider that a 15 per cent reduction is reasonable. This takes into account that Endeavour Energy has already made significant reductions to its augex program compared to the previous period.

Fourth, Endeavour Energy's proposed expenditure to meet growing demand in new developments is likely to be overstated. This is because there is excess capacity in existing network adjacent to the new development areas, and there is some uncertainty about whether all of the new suburbs will be ready for development within the 2014–2019 period. We have not made an explicit adjustment to the augex forecast to account for the overstated pockets of growth proposal. However, we consider that it lends further support to our 15 per cent reduction to the augex forecast (as outlined above).

Finally, the recent VCR results published by AEMO (which have fallen compared to previous levels) suggest that the augex forecast is likely to be higher than Endeavour Energy's customers are willing to pay for. This suggests that some projects currently included in its proposal may not be required once a cost-benefit is undertaken incorporating the new VCR values.

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[40] 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.

We recognise that Endeavour 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 Endeavour 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 Endeavour 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 the revised augex forecast based on the estimated adjustment to HV feeders expenditure and a further 15 per cent reduction.

**Table A-1 AER's alternative estimate of augex ($2013–14, million)**

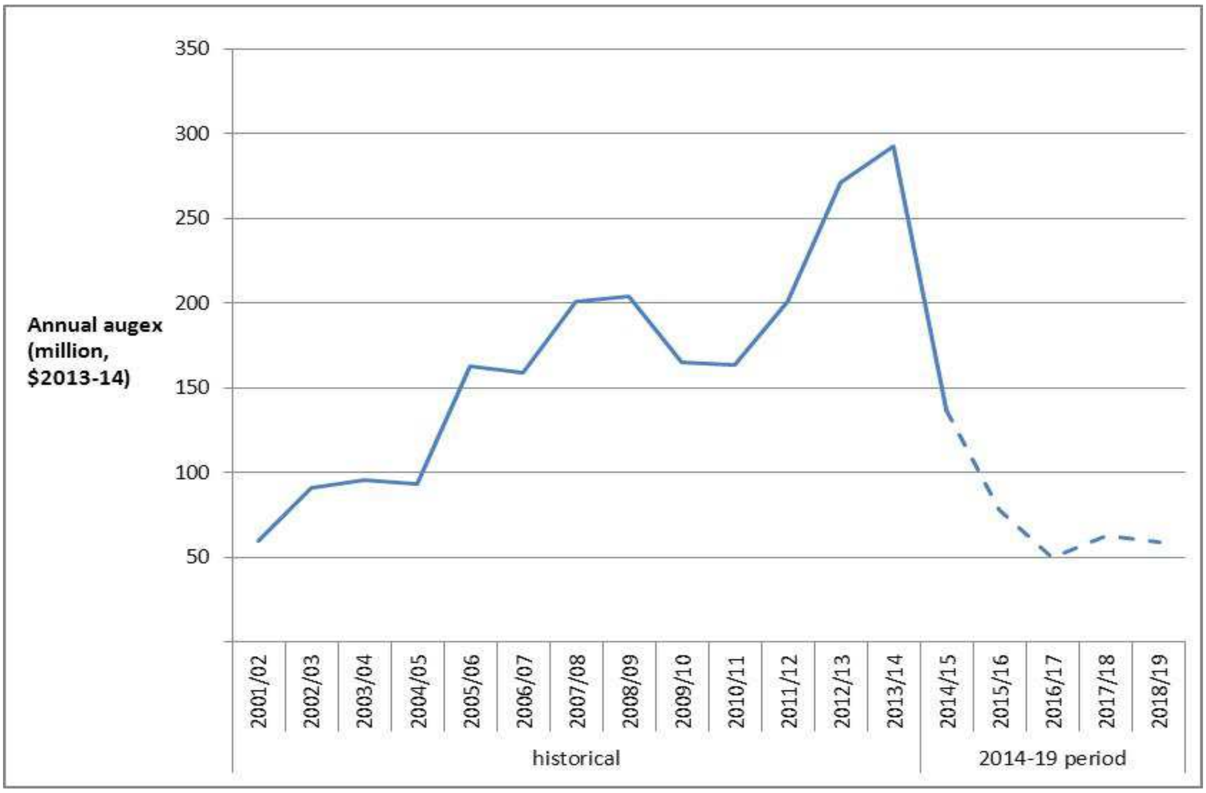
| Revised augex forecast | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | Total |
|---|---|---|---|---|---|---|
| **Augex forecast*** | 144.65 | 88.35 | 56.24 | 70.59 | 66.29 | 426.12 |
| Demand adjustment to HV network augex | -6.11 | -1.81 | -1.56 | -1.38 | -1.31 | -12.17 |
| **Augex forecast with demand adjustment** | 138.54 | 86.55 | 54.68 | 69.21 | 64.98 | 413.96 |
| Further 15% reduction | -20.78 | -12.98 | -8.20 | -10.38 | -9.75 | -62.09 |
| **AER revised augex forecast** | 117.77 | 73.57 | 46.44 | 58.81 | 55.24 | 351.87 |

Source: Endeavour Energy RIN, Endeavour Energy proposal, AER analysis
Notes: We have allocated the balancing item to Endeavour Energy's forecast augex allowance as a percentage of total capex.

## Trend analysis

Figure A-1 shows the trend in augex between 1999 and 2019 (as proposed). Endeavour Energy proposed similar levels of augex as it spent between 2001 and 2005.

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




Source: Endeavour Energy RIN, Endeavour Energy proposal, AER analysis.
Notes: These figures included an allocation of capitalised network and corporate overheads on the basis of augex as a proportion of total capex. These figures do not include an allocation of the balancing item.

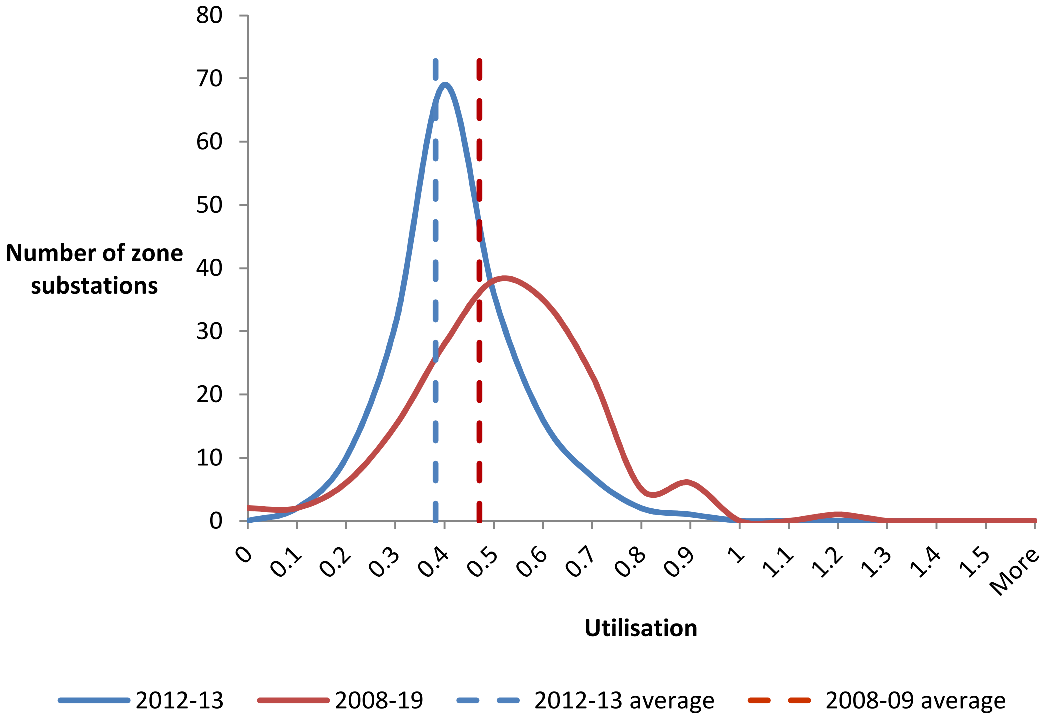
In our view, Endeavour Energy will require lower levels of augex during the 2014–2019 period given:

- Low demand growth — as discussed in appendix C, the available evidence points to slow demand growth (and a possible fall in demand) in Endeavour Energy'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 Endeavour Energy's capex from 2005 was the network design standards in its NSW licence condition. This increased the level of augmentation works on the network. The NSW Government removed these standards in July 2014 from Endeavour Energy's licence conditions.[41]
- Declining asset utilisation — increasing augex and declining demand over the 2009–2014 regulatory control period led to increased levels of excess capacity in the network (as is evident in Figure A-2 and Figure A-3 below).

41 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 Endeavour Energy 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 and Figure A-3 show decreasing utilisation levels at Endeavour 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.

**Figure A-2 Zone substation utilisation 2008–09 and 2012–13**

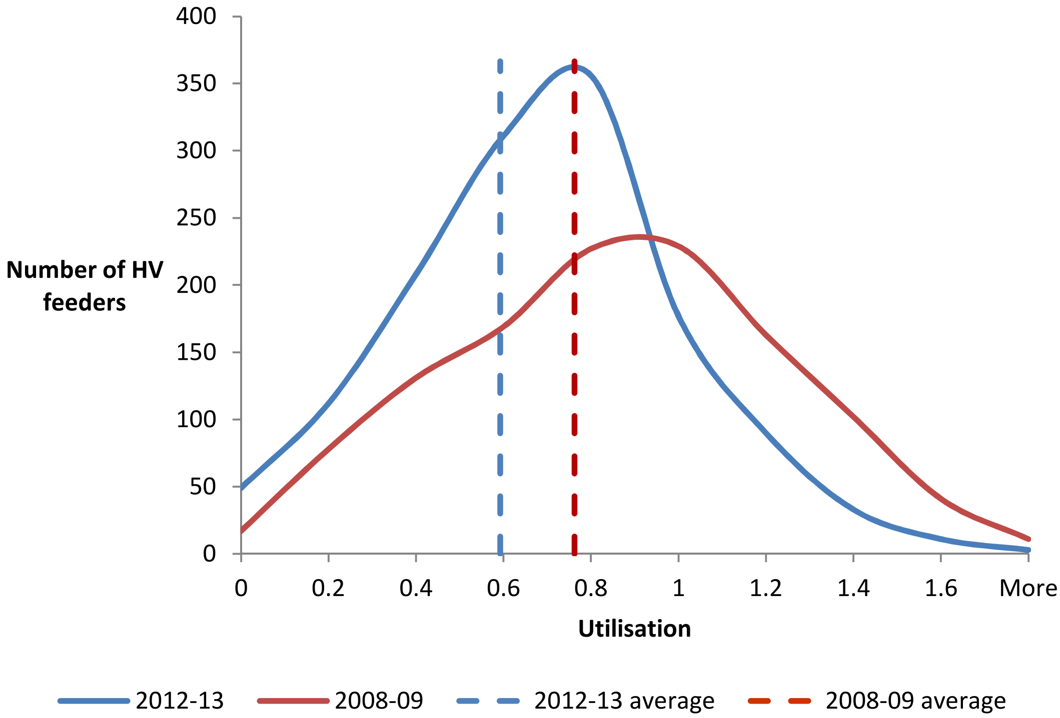



Source: AER analysis; augex model; Endeavour RIN

Note: Utilisation is the ratio of maximum demand and the capacity of each substation for the specified years.[42] Figure A-2 shows the number of Endeavour Energy's total zone substations at each utilisation band.

[42] Capacity is typically reported as the 'normal cyclic rating', which 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; Endeavour RIN

Note: Utilisation is the ratio of maximum demand and the thermal rating of each feeder for the specified years.[43] Figure A-3 shows the number of Endeavour Energy's total HV feeders at each utilisation band.

The AER's Consumer Challenge Panel (CCP1 Subpanel) also submitted that the general decline in asset utilisation between 2006 and 2013 provides an estimate of the significant excess capacity on Endeavour Energy's network.[44]

Endeavour Energy proposed that some level of augex is necessary to meet demand growth for new developments in North-West and South-West Sydney growth areas. Based on information published by the NSW Planning Authority, we are satisfied that the locations of suburbs scheduled for development during the 2014–2019 period are generally consistent with Endeavour Energy's proposed network augmentation.[45] However, there are a number of proposed estates that are yet to be released for planning.[46] Hence, we consider that Endeavour Energy's proposal may overstate the need for network augmentation in all proposed developments in the 2014–2019 period.

The EMRF submitted that Endeavour Energy's forecast augex for new developments is overstated due to significant past expenditure and low demand forecasts:

> Endeavour Energy makes the point that it expects there to be some growth arising out of investment in the NW and SW corridors of Sydney that will require an increase in supply capacity in those regions. If this occurs, there will be a need to extend the networks to these additional customers, and therefore some growth capex will be needed to support these new users.

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43 Thermal rating is the maximum rating assigned to a line or cable under normal operational conditions, that is, resulting in a normal life expectancy.

44 CCP submission (updated), pp. 22–23 and 25

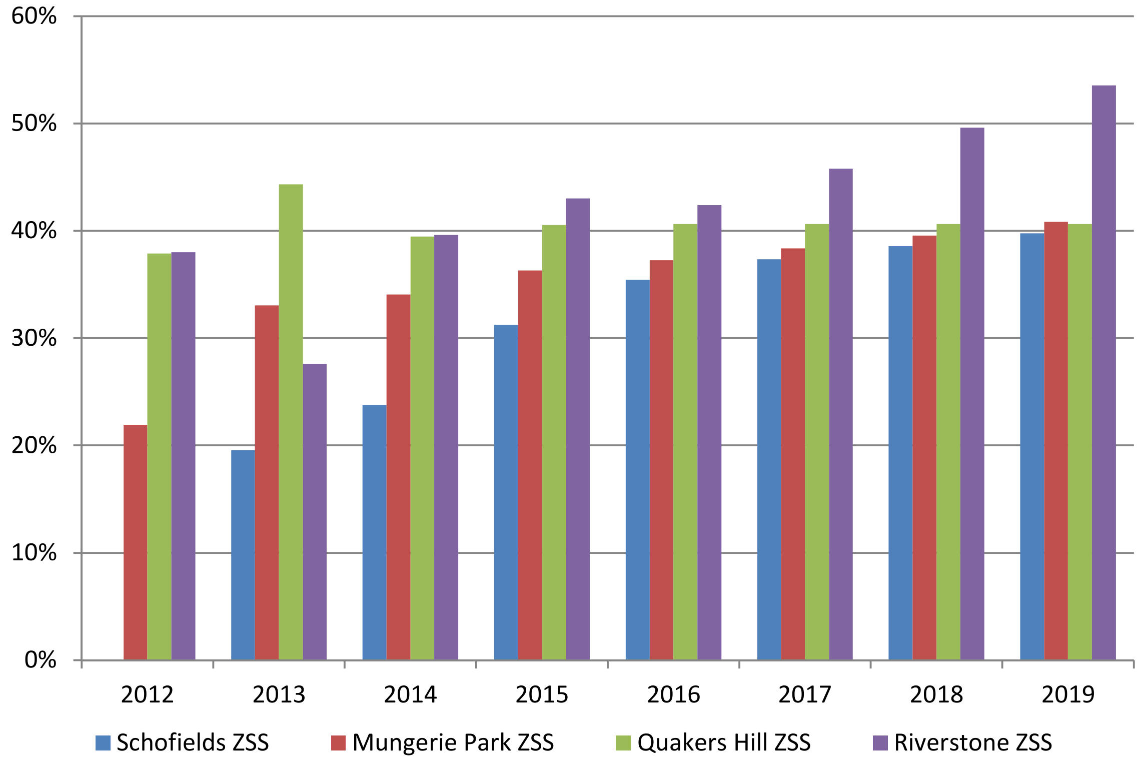
45 NSW Government, http://growthcentres.planning.nsw.gov.au/Infrastructure.aspx, accessed 17 November 2014.

46 NSW Government, http://growthcentres.planning.nsw.gov.au/TheGrowthCentres.aspx, accessed 17 November 2014.

> However, the EMRF is concerned that Endeavour Energy may be seeking to augment the existing network to provide this additional supply but provides no indication as to whether the existing network providing supply to these growth corridors is sized to carry the additional load that the new customers will impose on the network, particularly as Endeavour Energy did augment the network during [2009-14].
>
> …
>
> The conclusion that can be drawn from the data that is available, is that Endeavour Energy added considerably to the assets for growth during [2009-2014] despite falling demand. The clear implication is that Endeavour Energynow has a network oversized for its forecast demand in [2014-19], that Endeavour Energyover provided for growth in [2009-14] and that little capex for growth in [2014-19] is required.[47]

We have assessed the need for Endeavour Energy's proposed augex for these new developments by considering the utilisation across existing network infrastructure in areas proposed for development. Based on the supporting documents to Endeavour Energy's regulatory proposal, we consider that there is evidence that Endeavour Energy's proposed augex for these areas is based on the design standards in the previous NSW licence conditions (e.g. a N-1 design standard).[48] The utilisation profiles in Figure A-4 and Figure A-5 are revised to reflect installed capacity, based on AER analysis.

**Figure A-4 North-West growth areas zone substation (ZSS) utilisation**

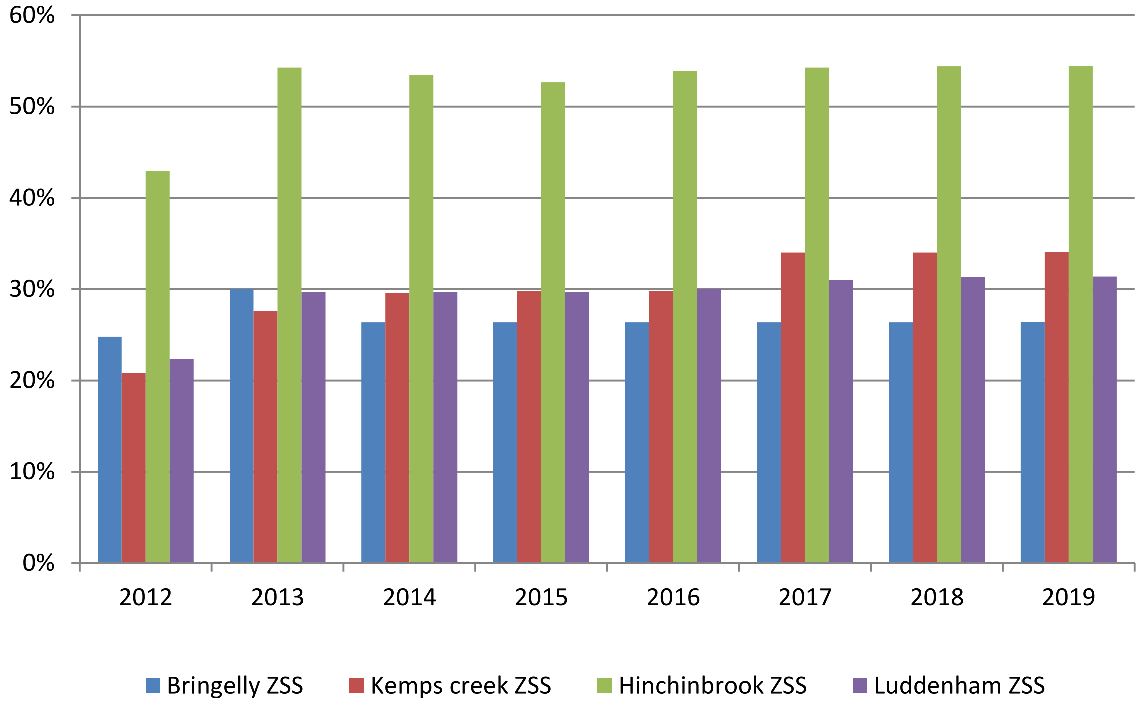



Source: AER analysis

[47] EMRF submission, pp. 75-76

[48] Endeavour Energy proposal, attachment 5.16 (Distribution Annual Planning report).

**Figure A-5 South-West growth areas zone substation (ZSS) utilisation**




Source: AER analysis

These figures show that the utilisation of existing assets that serve planned new developments is expected to be quite low, and remain low by the end of the period (with the exception of Hinchinbrook), based on the revised NSW licence conditions. We consider that this suggests that Endeavour Energy has not prudently considered the need for additional investment in light of the revised licence conditions. This is supported by the findings of engineering consultant WorleyParsons, as set out below.

In its regulatory proposal, Endeavour Energy provided for each major substation in its network the spatial demand forecast that it produced in 2013 (2013 forecasts). Endeavour Energy forecasted 108 substations would on average grow positively over the 2014–2019 period. During the determination process, Endeavour Energy 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 fell by 10 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 | 112 | 106 | 89 | 82 | 97 |
| 2013 forecasts | 122 | 116 | 102 | 90 | 108 |
| Per cent reduction (%) | 8.2 | 8.6 | 12.7 | 8.9 | 10 |

Source: Endeavour, Reply to AER Endeavour Energy - updated demand forecasts (Follow-up question), 22 October 2014.
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 drop in substations that expect positive demand growth provides additional evidence that Endeavour Energy's augex forecast should be lower than it proposed. This is because Endeavour Energy will not need to augment those substations it does not expect to grow and this lower demand forecast will furthermore reduce the network utilisation. While we understand Endeavour Energy has not yet finalised these updated demand figures, they indicate how Endeavour Energy's demand forecasts will likely change in its revised regulatory proposal.

We consider that Endeavour Energy's proposed augex forecast may be partially explained by the need to meet expected localised growth in demand (albeit not to the extent as proposed by Endeavour Energy). However, we consider there is some evidence that Endeavour Energy has proposed higher expenditure than is reasonably required to build its network to meet demand and reliability requirements.

## Engineering review of augex forecast and techniques

WorleyParsons has reviewed whether there are any systemic issues that may result in biases in Endeavour Energy's augex forecasts.[49]

We asked WorleyParsons to identify whether:

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

To conduct this review, WorleyParsons reviewed a sample of Endeavour Energy's projects or programs:

- High expenditure/carryover at start of period
- Projects deferred from the previous period and the basis for the revised timing and costing
- Distribution Works Program
- New Growth Programs
- Design planning criteria
- Work practices.

The sampling of the augex projects or programs focussed on assessing Endeavour Energy's forecast expenditure given the changes to the licence conditions for the new period and Endeavour Energy's transition from a deterministic planning methodology for assessing investments to a probabilistic or risk-based cost-benefit analysis methodology. Where possible, WorleyParsons quantified the likely impact of any issues on Endeavour Energy's augex forecast for the 2014–2019 period.

WorleyParsons found that Endeavour Energy's augex costs are likely to be higher than would be incurred by a prudent and efficient service provider.[50] The key findings to support this conclusion were:

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[49] WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014.

- Following the repeal of the NSW licence condition design standards, Endeavour Energy has begun utilising risk-based cost-benefit analysis to assessing proposed expenditure projects. These techniques were applied to some of the projects that make up the augex forecast. However, Endeavour Energy's proposed expenditure forecasts are likely to be biased given that more detailed reviews and cost-benefit analysis will be carried out over the 2014–2019 period and that savings that can be realised through these reviews are not reflected in the regulatory proposal for the 2014–2019 period.[51]

- Endeavour Energy has also begun applying an increasing level of business risk management to its business and it carries out prudent risk assessments as part of its approval processes for commitment to projects and programs. However, Endeavour Energy's proposed expenditure forecasts for the 2014–2019 period do not reflect the potential savings that could be realised in augex program through the use of these techniques.[52]

- The final Value of Customer Reliability (VCR) review report issued by AEMO in September 2014 has determined a lower VCR value for NSW than the value used by Endeavour Energy derived from the AER Service Target Performance Incentive Scheme (STPIS). This will result in a consequential lowering of customer benefits and further deferment of augex when it is applied. (See below for more detail about AEMO's VCR review).[53]

- Endeavour Energy recognises the need to further reduce costs and improve work practices and also that reductions and improvements have been made through the outsourcing of capex works in the previous regulatory control period.[54]

Based on its findings, WorleyParsons considered that reductions to Endeavour Energy's projected augex may be possible through the application of risk assessment techniques to all projected programs of work. They found that Endeavour Energy already achieved a reduction of 38% of projected expenditure for its Distribution Works Program through the application of prudent risk-assessment and cost-benefit analysis.[55] WorleyParsons considered that it would be reasonable to expect further reductions in the order of 10 to 20 per cent, given the nature of the projects involved and that they have already been subject to reductions through the Networks NSW Network Investment Prioritisation Program.[56]

We consider that Endeavour Energy could efficiently make a 15 per cent reduction to its augex projects by applying these factors. This estimate takes into account that Endeavour Energy has already made significant reductions to its augex program compared to the previous period, but also takes into account that we consider that it has overstated the need to meet pockets of growth. We have taken these findings into account when forming our conclusion on Endeavour Energy's proposed augex forecast.

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50 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, p. 7

51 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, pp. 6-8

52 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, p. 8

53 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, p. 6 and 8

54 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, p. 8

55 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, p. 6

56 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014–2019, 7 November 2014, p. 8

## Change in value customer place on electricity reliability

In October 2014, subsequent to the submission of Endeavour 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 lead 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 significantly lower than in previous Australian studies, with the lower VCRs driven primarily by commercial and agricultural customers.

**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[57]
Notes: 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. 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 Endeavour Energy's augex forecasts were made in advance of the changes to the VCR. We expect that Endeavour Energy will assess the changes to the VCR in the context of submitting a revised regulatory proposal.

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 B.3.

## HV feeders and revised demand forecasts

Endeavour Energy's forecast augex of $94.9 million ($2013–14) for HV feeders makes up 22 per cent of its total augex forecast. Table A-4 summarises the components of Endeavour Energy's HV feeder augex forecast.

57 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 Endeavour Energy augex forecast for HV feeders ($2013/14, million)**

| Project type | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2014/15 |
|---|---|---|---|---|---|
| Overhead HV feeder augmentations | 10.42 | 3.20 | 4.40 | 4.02 | 4.73 |
| Underground cables HV feeder augmentations | 37.25 | 10.89 | 7.75 | 6.78 | 5.47 |
| Total HV feeder augmentations | 47.68 | 14.09 | 12.16 | 10.80 | 10.20 |

Source: Endeavour Energy RIN.

As we noted previously, Endeavour Energy provided updated demand spatial forecasts for each of its major substations (2014 forecasts). While we understand Endeavour Energy has not yet finalised these figures, they indicate how Endeavour Energy's demand forecasts will likely change in its revised regulatory proposal.[58]

We consider that a reduction in forecast demand will lead to a proportionate reduction to Endeavour 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.[59] We consider an equivalent relationship exists between demand and HV feeder expenditure for Endeavour 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 DNSP networks.

We have estimated the impact of these changes in demand on Endeavour 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.7).[60] 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, Endeavour Energy expects a 40.2 MVA, or 12.81 per cent, reduction in ratcheted demand in the 2014 forecasts compared to the 2013 forecasts.[61] Consistent with this, for

59 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, November 2014, section 3.4.3.

60 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.

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

the purposes of this draft decision, we have used this 12.81 per cent reduction in the demand forecast as an input when reducing Endeavour Energy's proposed augex allowance.[62]

**Table A-5 Ratcheted demand (MVA)**

| | Difference between aggregated 2018/19 and 2014/15 forecasts |
|---|---|
| 2014 forecasts | 273.8 |
| 2013 forecasts | 314 |
| MVA reduction | 40.2 |
| Per cent reduction | 12.81 |

Source: Endeavour, Reply to AER Endeavour Energy 35 - updated demand forecasts (Follow-up question), 22 October 2014.

We applied a 12.81 per cent reduction to the HV feeders components of Endeavour Energy's forecast augex. Table A-6 shows that applying the 12.81 per cent demand adjustment reduces the expenditure forecast for HV feeder augmentations to $82.76 million ($2013–14). This is a reduction of $12.16 million ($2013–14) compared to Endeavour Energy's proposal of $94.92 million ($2013–14) for HV feeders.[63]

**Table A-6 Demand adjustment to Endeavour Energy's HV feeder augmentation program ($2013–14, million)**

| Project type | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|---|---|
| Overhead HV feeder augmentations | 9.1 | 2.8 | 3.8 | 3.5 | 4.1 |
| Underground cables HV feeder augmentations | 32.5 | 9.5 | 6.8 | 5.9 | 4.8 |
| Total HV feeder augmentations | 41.6 | 12.3 | 10.6 | 9.4 | 8.9 |

Source: Endeavour Energy RIN.

## 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. 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 Endeavour Energy's total forecast capex is driven by augmentation of the shared distribution network to accommodate commercial and industrial and residential customers connecting in greenfield and brownfield developments (as discussed in the previous section).[64]

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[62] As we noted earlier, we understand Ausgrid has not yet finalised the 2014 forecasts. For the final decision, we will consider the finalised version of the 2014 forecasts as inputs to our assessment of Ausgrid's augex forecast.

[63] We assume the linear relationship between demand and the 11kV model's output holds equally for larger values like 31.45 per cent as it does for smaller values (like 10 per cent, the figure Ausgrid used to suggest the linear relationship). We also consider this is consistent with the 11kV model which assumes demand for each feeder within a zone grows at the same rate as the zone substation demand forecasts. See Ausgrid, *11kV model: Method & outcomes of DND*, 29 May 2014, pp. 3, 6 and 10; Ausgrid, *Ausgrid's response to the AER's information request of 16 September 2014*, 24 September 2014, p. 2.

[64] Endeavour Energy, Regulatory proposal, pp. 62–63.

## A.2.1 Position

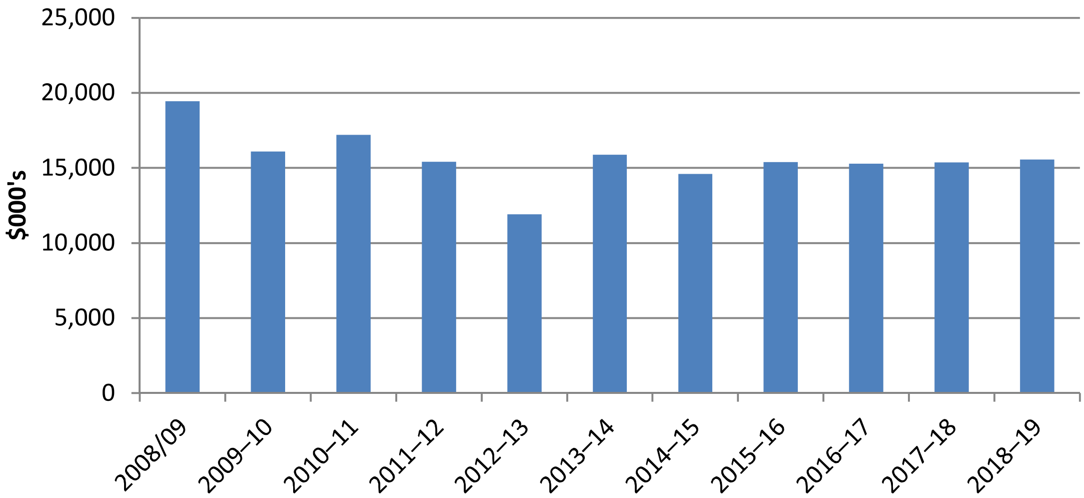
Endeavour Energy proposed $105.82 million ($2013–14) for customer connections capex for the 2014–2019 period (excluding overheads). This is approximately 3 per cent of Endeavour Energy's proposed total forecast capex and is 21 per cent less than the actual customer connections capex it spent during the 2009–2014 period. Figure A.6 depicts the historical and forecast capex profile over the 2009–2019 period. We accept Endeavour Energy's proposal and will include it in our alternative estimate.

**Table A-7 Proposed connections capex ($2013–14, million)**

| Customer-initiated service category | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | Total |
|---|---|---|---|---|---|---|
| Endeavour proposed* | 18.17 | 21.12 | 21.99 | 21.92 | 22.62 | 105.82 |
| AER approved | 18.17 | 21.12 | 21.99 | 21.92 | 22.62 | 105.82 |

Source: Endeavour Energy RIN.
Notes: We have allocated the balancing item to Endeavour Energy's forecast connections allowance as a percentage of total capex.

**Figure A.6 Endeavour Energy connections capex**



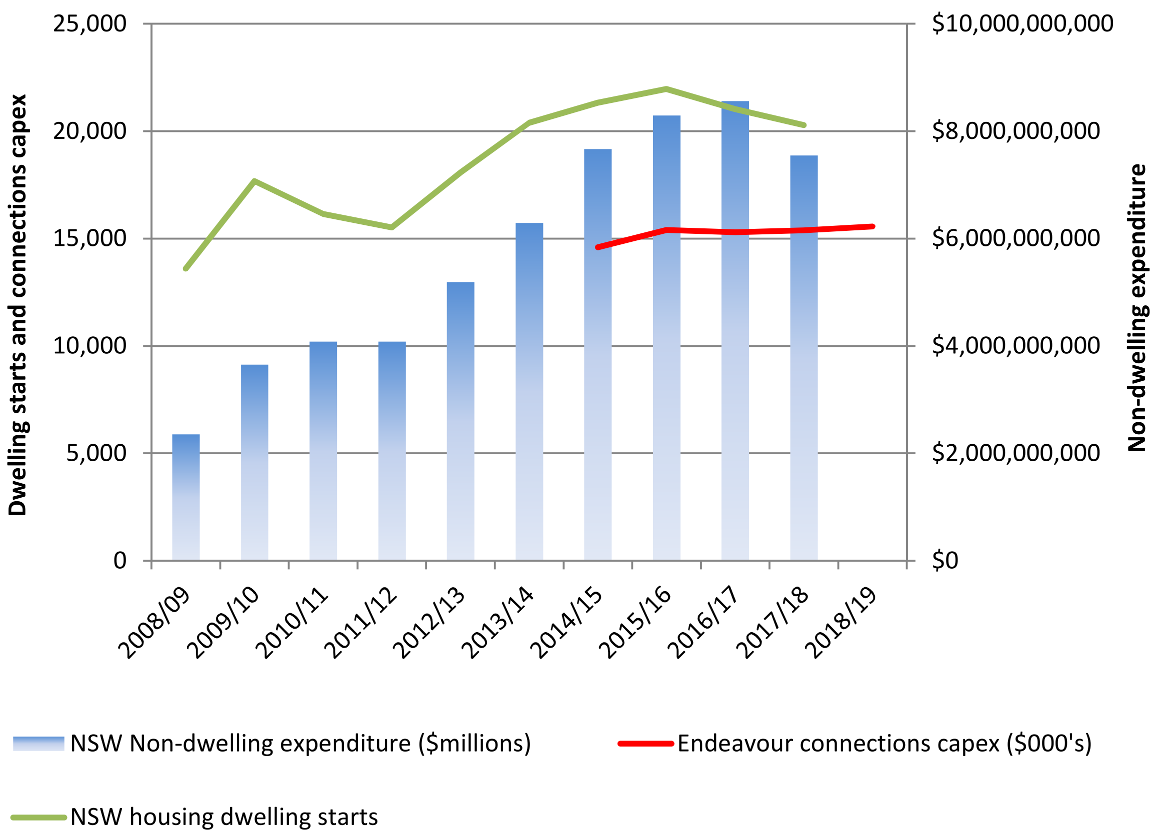

Source: Endeavour Energy RIN

Figure A-7 shows that the trend of Endeavour Energy's proposed connections capex is consistent 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 Endeavour 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.

65 PIAC, Submission to NSW revenue proposals, p. 39.

Figure A-7 Endeavour Energy connections capex and NSW construction activity




Source: BIS Shrapnel,[66] Endeavour 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 Endeavour Energy, and payments from customers who directly benefit from connection services which are not contestable. We have subtracted Endeavour Energy's proposed capital contributions from gross capex to calculate net capex.

We accept Endeavour Energy's proposed capital contributions forecast of $356.89 million, as we consider it is consistent with Endeavour 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 Endeavour Energy to clearly explain how capital contributions should be allocated to each service. Table A-8 outlines Endeavour Energy's proposed capital contributions allowance.

66 BIS Shrapnel, Building in Australia 2013–2028, table 5.1.
67 Endeavour Energy, RIN, June 2014, template 2.1.
68 Housing Industry Association, http://hia.com.au/en/businessinfo/economicinfo/housingforecasts.aspx, accessed 18 November 2014.

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

| | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | Total |
|---|---|---|---|---|---|---|
| Endeavour Energy proposed | 71.38 | 71.38 | 71.38 | 71.38 | 71.38 | 356.89 |
| AER approved | 71.38 | 71.38 | 71.38 | 71.38 | 71.38 | 356.89 |

Source: Endeavour Energy PTRM.
Notes: Capital contribution figures were sourced from Endeavour Energy's PTRM. We note these figures do not reconcile with Endeavour Energy's proposed RIN summary sheet 2.1. Given the differences in capital contribution figures across multiple sources of Endeavour Energy's proposal, we have adopted the proposed capital contribution amounts in the PTRM for modelling consistency with Endeavour's proposed maximum allowable revenue requirements.

# 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

Endeavour Energy proposed $739.7 million ($2013–14) of forecast repex (excluding capitalised overheads).

We do not accept Endeavour Energy's proposal. We have instead included an amount of $661.1 million ($2013–14) in our alternative estimate, a reduction of 10.6 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
- engineering reviews of repex proposals
- predictive modelling of repex requirements.

In summary, we find that:

- Endeavour Energy's proposed repex is around 55 per cent higher than its long term average.
- Controlling for network scale characteristics, Endeavour Energy's historical repex does not compare favourably to that of other service providers in the NEM.
- In relation to the likely condition of Endeavour Energy's assets, the substantial increase in network utilisation during the 2009–14 regulatory control period provides an operating environment that should reduce the rate of deterioration of Endeavour Energy's assets over the 2014–19 period.
- An engineering review carried out by EMCa found that there are systemic issues with Endeavour Energy's forecast that mean its proposal is likely to overstate the amount of repex

required to meet the capex objectives. Endeavour Energy is likely to be replacing many assets earlier than is necessary to meet the capex objectives.

- Our predictive modelling is consistent with Endeavour Energy's proposal for the six asset groups that were modelled. We are satisfied that repex of $519 million is a prudent and efficient amount required to meet the capex objectives for this modelled component.

- For categories that were not included in predictive modelling, we are satisfied that a total of $142 million is likely to be a prudent and efficient level of repex. When added this amount to the modelled component, which gives a total repex estimate of $661 million.

The amount of forecast repex that we have included in our alternative estimate is $661 (2013-14), excluding capitalised overheads. This is 10.6 per cent less than Endeavour Energy's proposal. This amount ensures that Endeavour Energy will be provided with a reasonable opportunity to recover at least its efficient costs. It will also minimise the potential for Endeavour 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

Endeavour 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 DNSPs in the NEM. Specifically, we have considered:

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

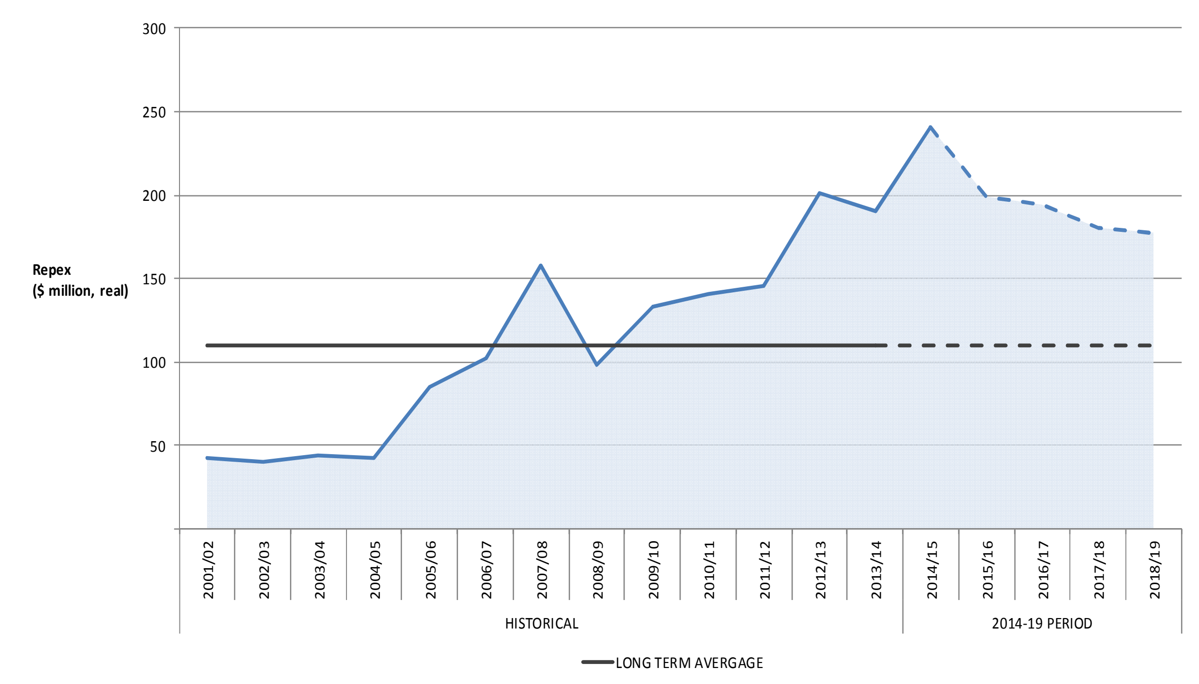
- Endeavour Energy's actual repex relative to other service providers in the NEM for selected performance metrics that may provide an indication of relative efficiency

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

### Historical trends

Figure A-8 shows the trend in Endeavour Energy's historical and proposed repex. It also shows Endeavour Energy's actual long term average across the same time period.

**Figure A-8 Endeavour Energy's repex including overheads historic actual and proposed for 2014–2019 period (real $ million June 2014)**




Source: Historical: IPART Regulatory Accounts (prior to 2010/11) and AER Annual RINs (2010/11 to 2013/14)
2014–2019 period: Endeavour 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 the capex attachment, during the 2009–2014 regulatory control period, Endeavour 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 Endeavour Energy's underlying repex requirements.

Figure A-8 shows that Endeavour Energy's proposed forecast repex of $992 million ($2013-2014) for the 2014–19 period significantly exceeds its long term average.[69] This is a 55 per cent increase above its long term average repex and a 22 per cent increase in the amount actually incurred in the most recent regulatory control period.[70]

### *Relationship between total repex and network scale*

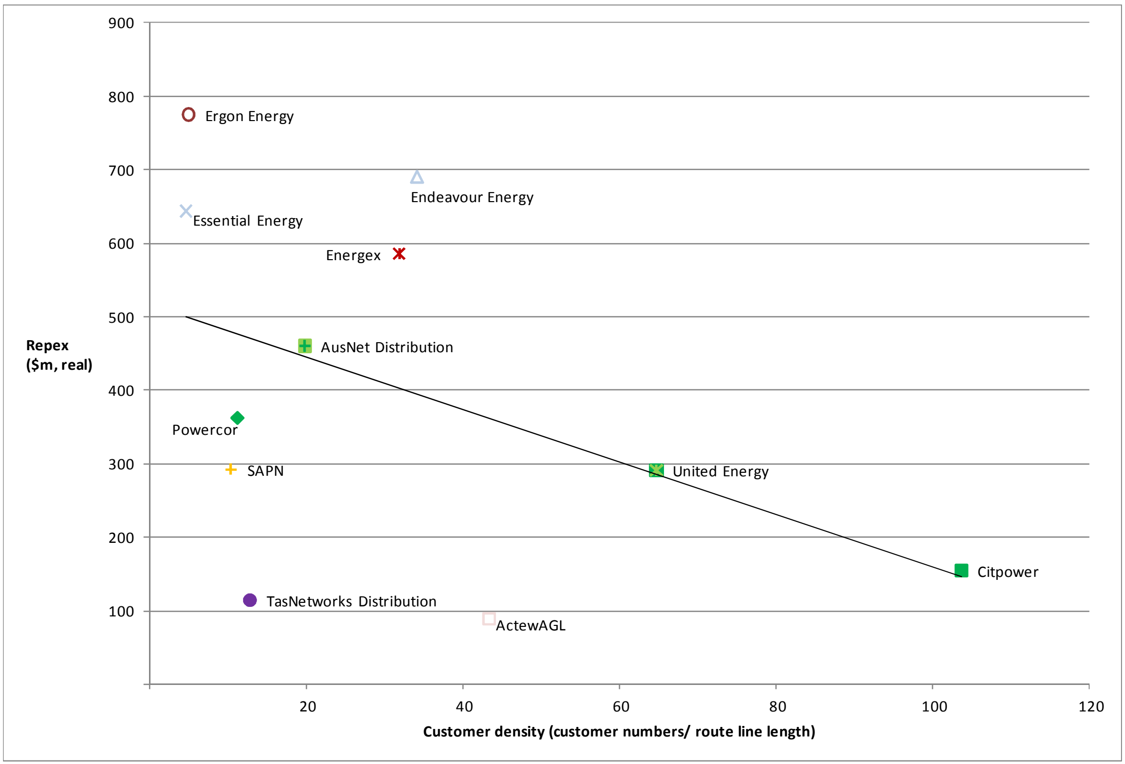
Network scale characteristics, such as the number of customers a service provider serves, its size, operating environment and asset mix, have a bearing on the amount of repex a service provider incurs. Endeavour Energy is a 'hybrid' network. With its asset base split between urban and rural feeders we expect that it will incur relatively average repex when compared with other service providers. For this reason, in assessing the relative efficiency of Endeavour 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.

69 Endeavour 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)

70 IPART Regulatory Accounts (2009/10) and AER Annual RINs (2010/11 to 2013/14)

In particular, we have used two measures of network density: customer density and capacity density. 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 providers across the 2008-13 period to assess the relationship between total repex and network scale. Figure 3 shows this for customer density across service providers.

**Figure A-9 Repex across the NEM normalised for customer density**

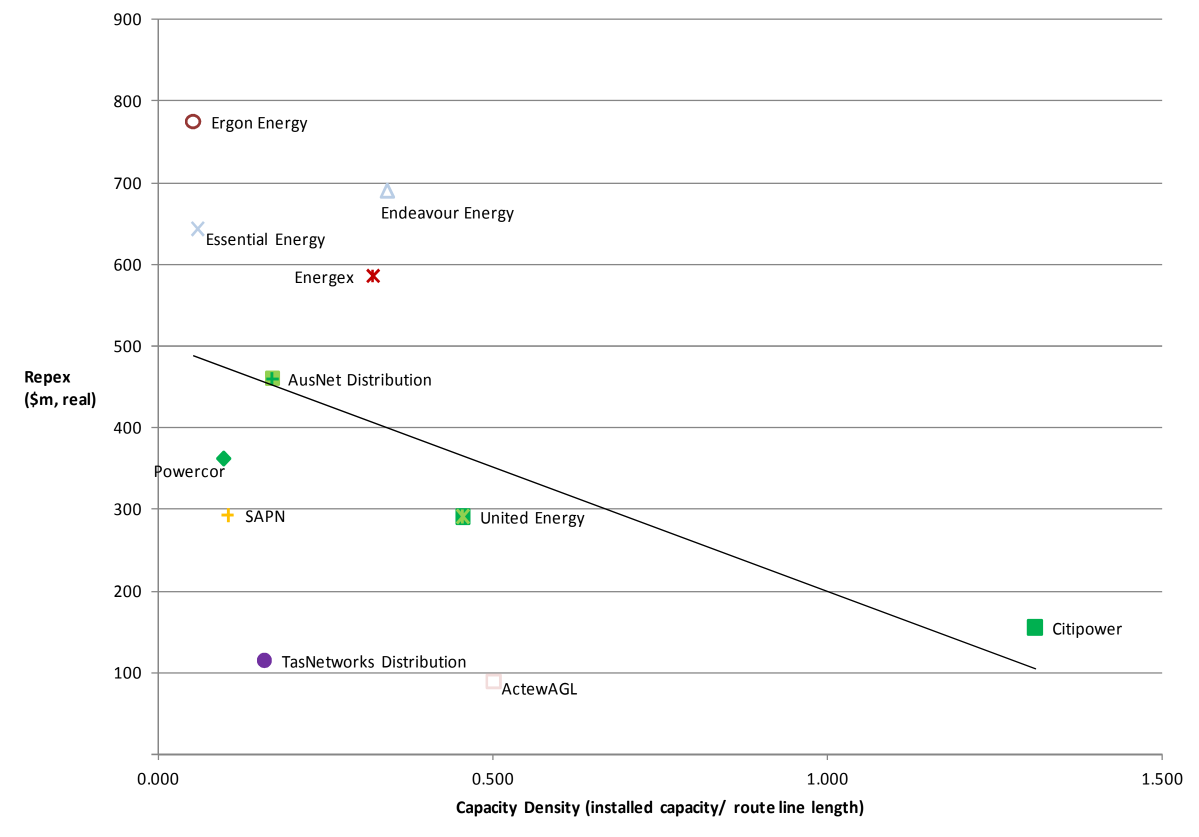



Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
Customer Numbers and Route Line Length: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence)
(Ausgrid excluded as it is a significant outlier)

In general, Figure A-9 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.

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. We understand capacity density to be the quotient of installed capacity and network length. Figure A-10 shows the relationship between repex and capacity density across the service providers.

**Figure A-10 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)

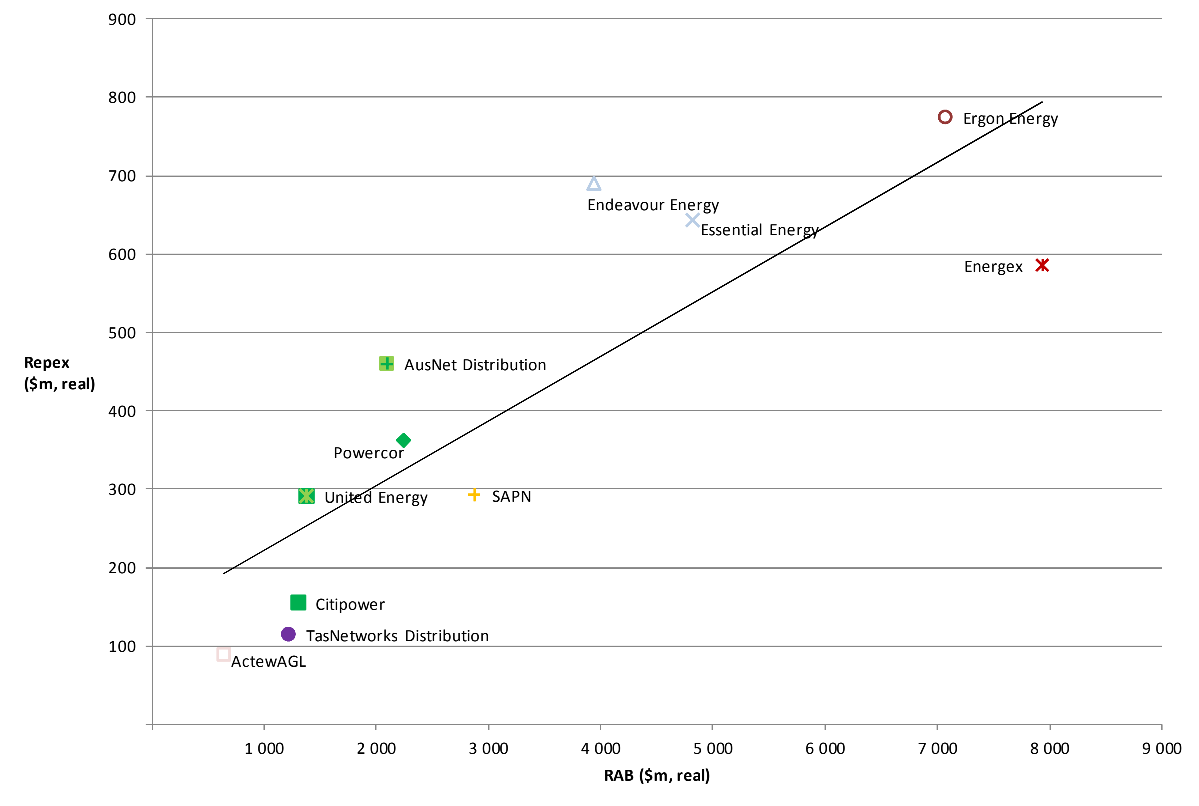
Comparing Figure A-9 with Figure A-10 shows that there are similar relationships when normalising total repex by customer density and capacity density.

Endeavour 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. The predominately rural networks have a high proportion of assets on long rural feeders. However, Endeavour Energy has only 0.5 per cent of its assets on rural long feeders (compared to around 50 per cent for the predominately rural networks).

### *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 eventually need to be replaced. Figure 6 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-11 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-11 shows there is a positive correlation between the size of a RAB and the repex 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. 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-11).[71]

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

## Asset Health Indicators

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

- the age of Endeavour Energy's network and

71 NSP Responses to AER category analysis circulated 15 August 2014

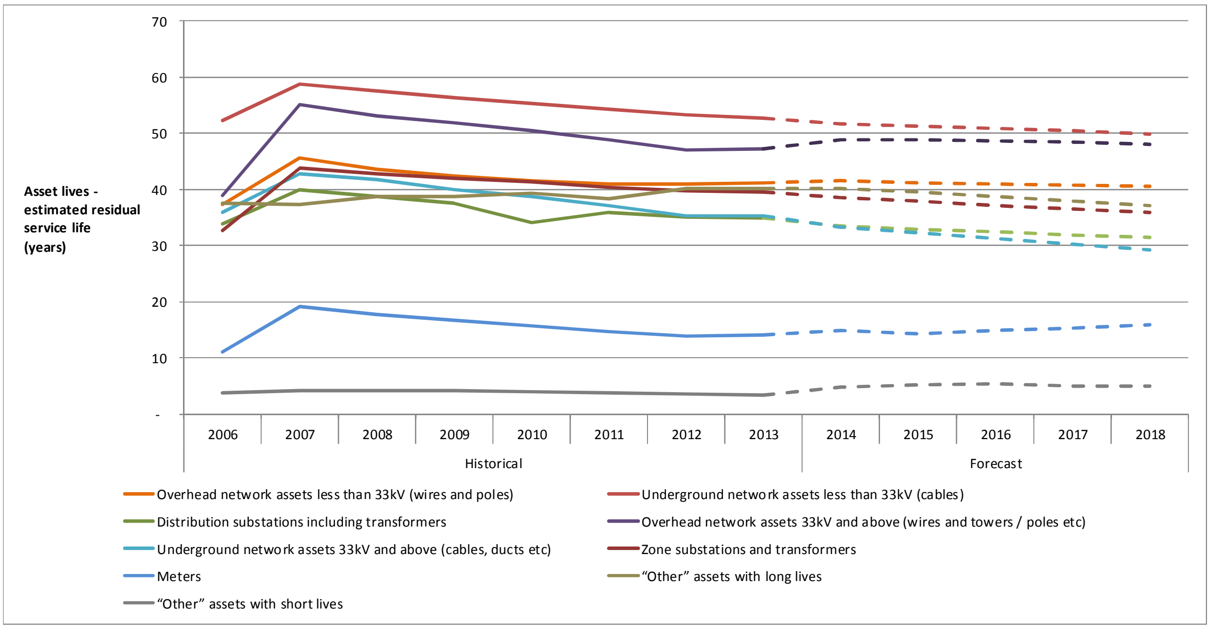
- utilisation of the network (where lower network utilisation should be positively correlated to asset condition).

## Asset age

Asset age is a reasonable proxy for asset condition which affects the repex requirements on the network. We note that Endeavour Energy and the service providers agree with this.[72]

Figure A.12 shows the asset age trends that Endeavour Energy submitted for the following categories of assets in support of its repex proposal.

**Figure A.12 Endeavour Energy Asset Lives – estimated residual service life**




Source: Endeavour Energy - EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services) for historical and Endeavour Energy Reset RIN - 2014-19 3.3 Assets (RAB) Table 3.3.4.2

However, Figure A.12 also shows that the trend in residual lives of Endeavour Energy's assets has been relatively stable over time. This suggests that the health of Endeavour Energy's asset base has not significantly declined or improved over the last eight years. That is, the majority of its assets are expected, in aggregate, to maintain their function for the same duration as they did in 2006 (noting there are some differences between asset classes). This suggests that Endeavour Energy would require a relatively similar level repex to maintain its network now than it has in the past.[73] These historical weighted average remaining life trends also reflect the impact of the Endeavour's Energy's historical repex which suggests that the long term repex trend is consistent with maintaining asset lives.

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72 Endeavour Energy, Regulatory Proposal p. 45
73 Endeavour Energy, Regulatory Proposal p. 63

**Figure A-13 Asset Age Profile**

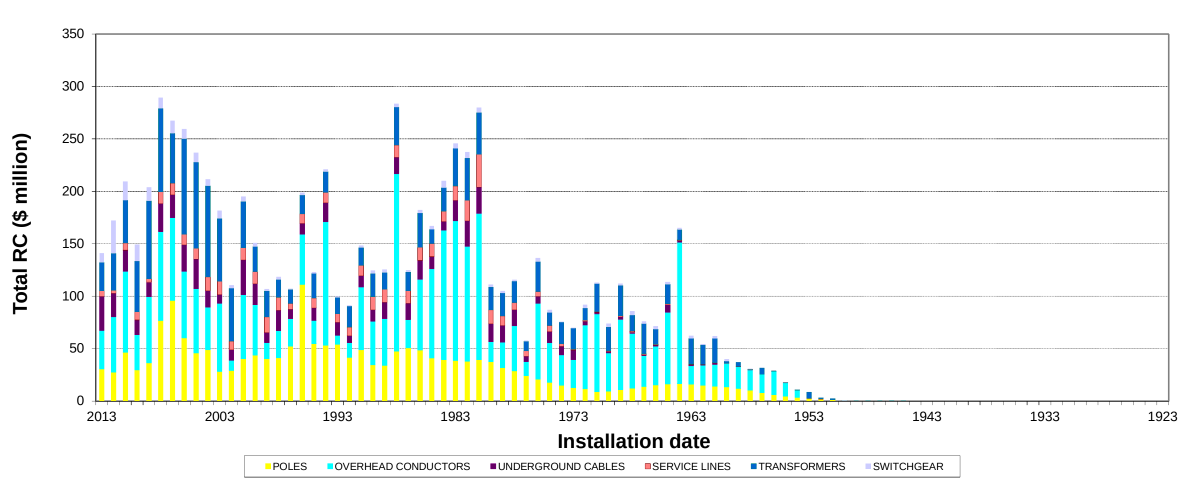
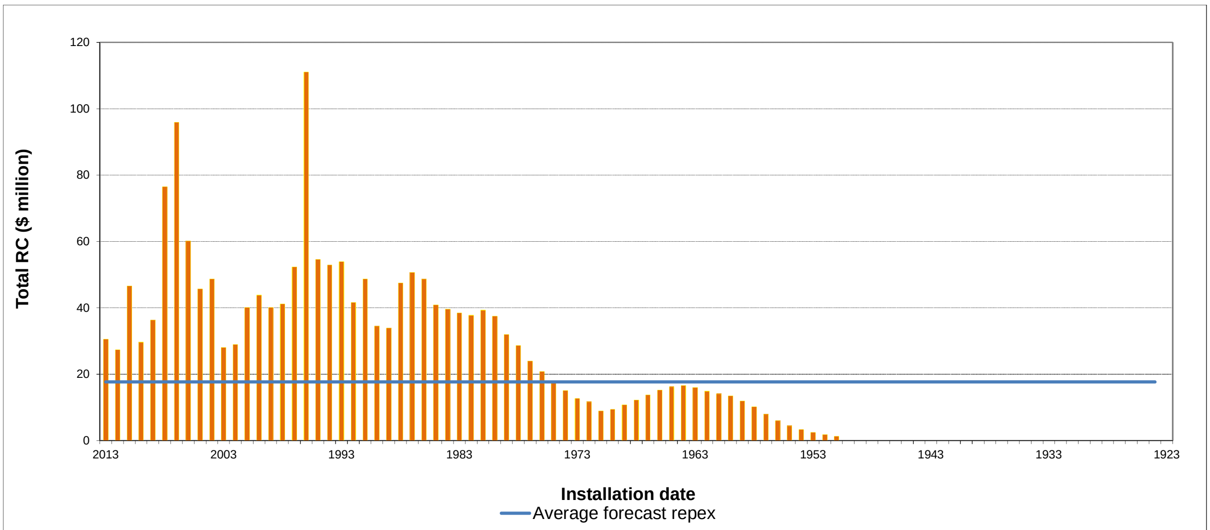


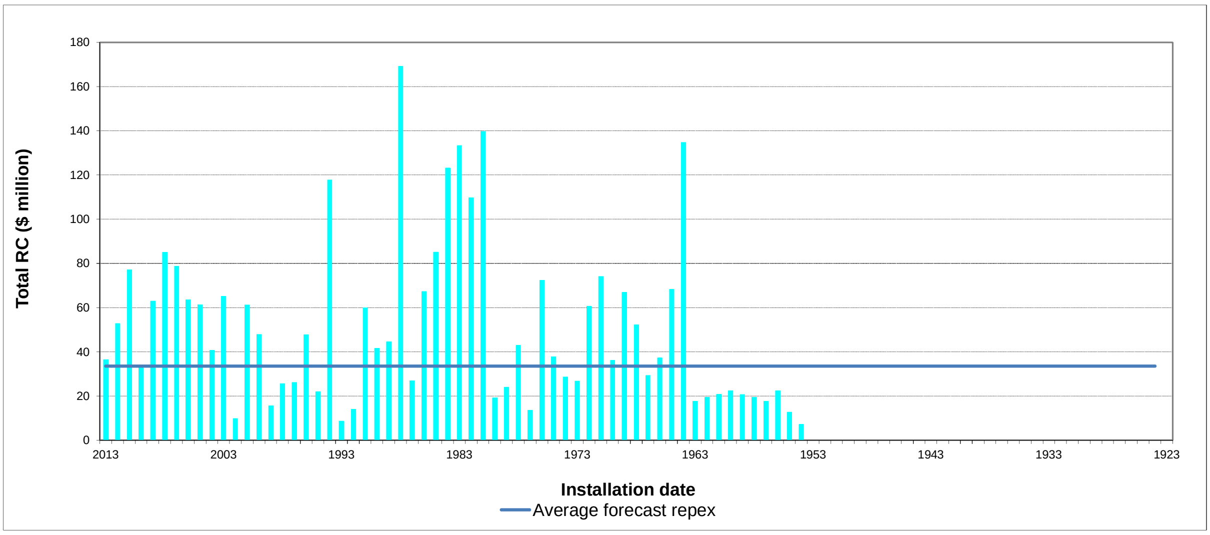

Figure A-13 shows the age of six of Endeavour Energy's asset groups, weighted by their replacement value. Endeavour Energy's asset base is weighted towards relatively new assets, which reflects its above-trend level of capex over the last ten years. Endeavour Energy also has a large stock of assets in commission from the 1960s.

The asset groups that comprise Figure A-13 are presented in Figure A.14 - Figure A-19 below. Endeavour Energy's average annual repex for the 2014–19 period is also presented as a line in these charts. For all asset groups other than switchgear, there are a number of years in the asset profile where the average forecast repex figure equals or exceeds the value of assets in commission for a given year. For Switchgear, the average annual forecast repex is well above the replacement value of the assets in commission (excluding recent years in the profile, which are not relevant for assessing repex).

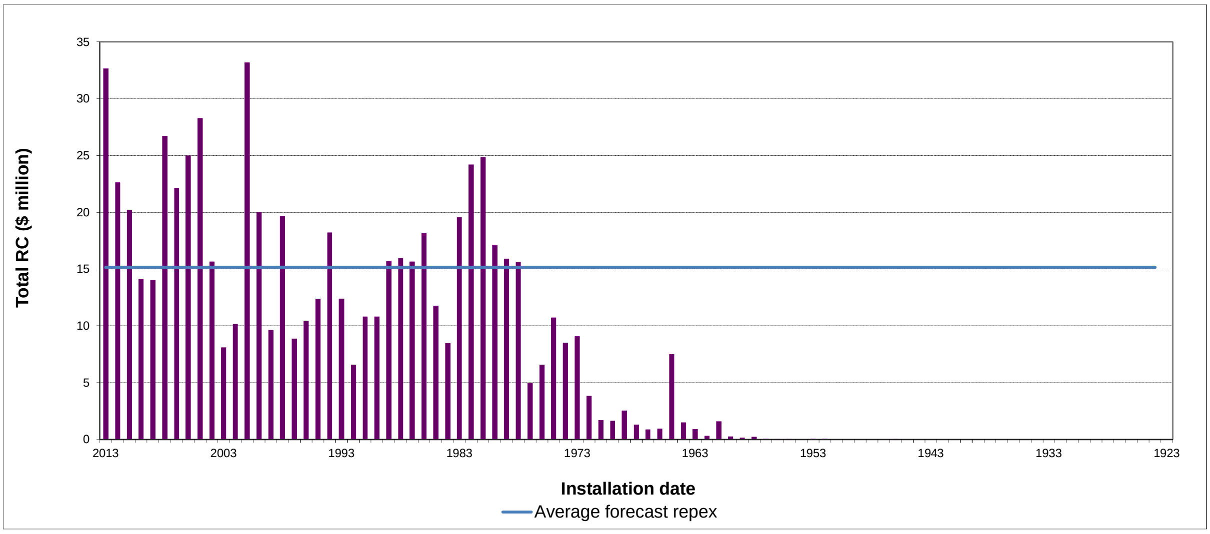
**Figure A.14 Asset age profile – Poles**



### Figure A-15 Asset age profile – Overhead conductor




### Figure A-16 Asset age profile – Underground cable




### Figure A-17 Asset age profile – Service lines

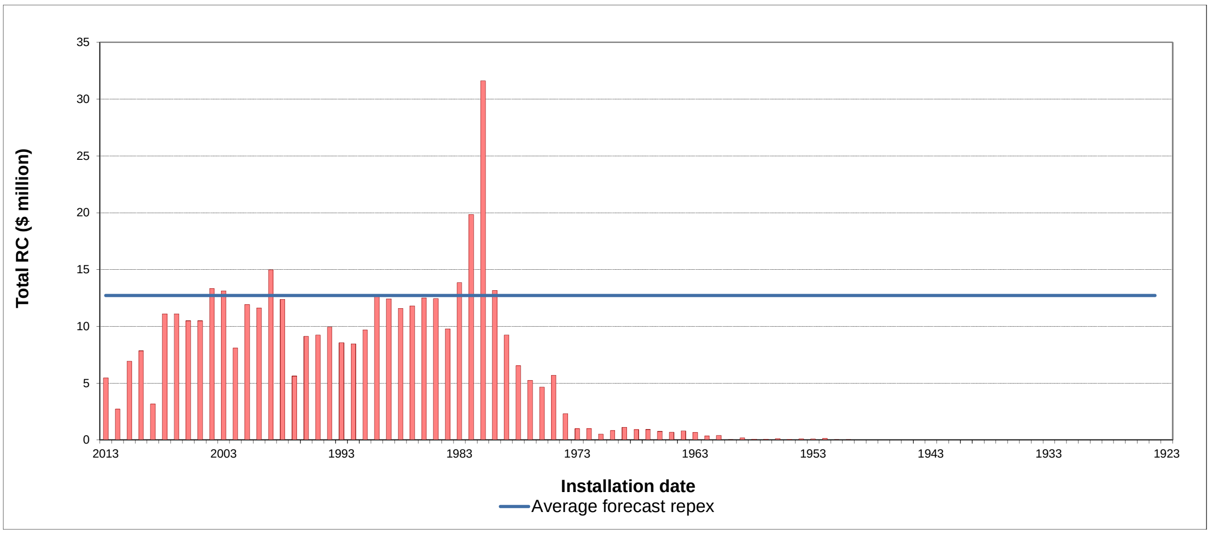


**Figure A-18 Asset age profile – Transformers**

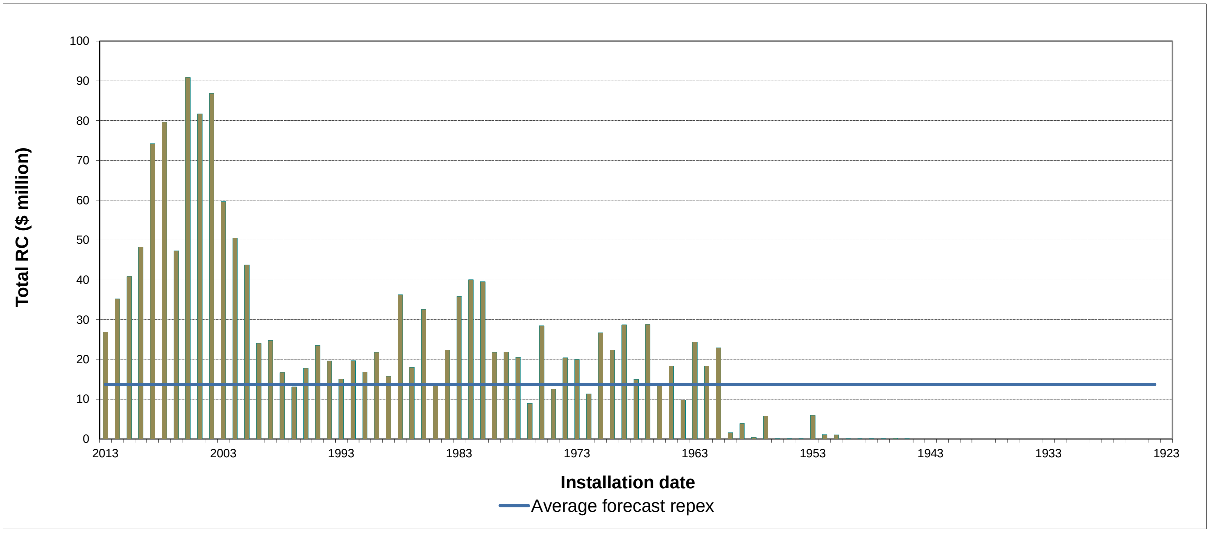
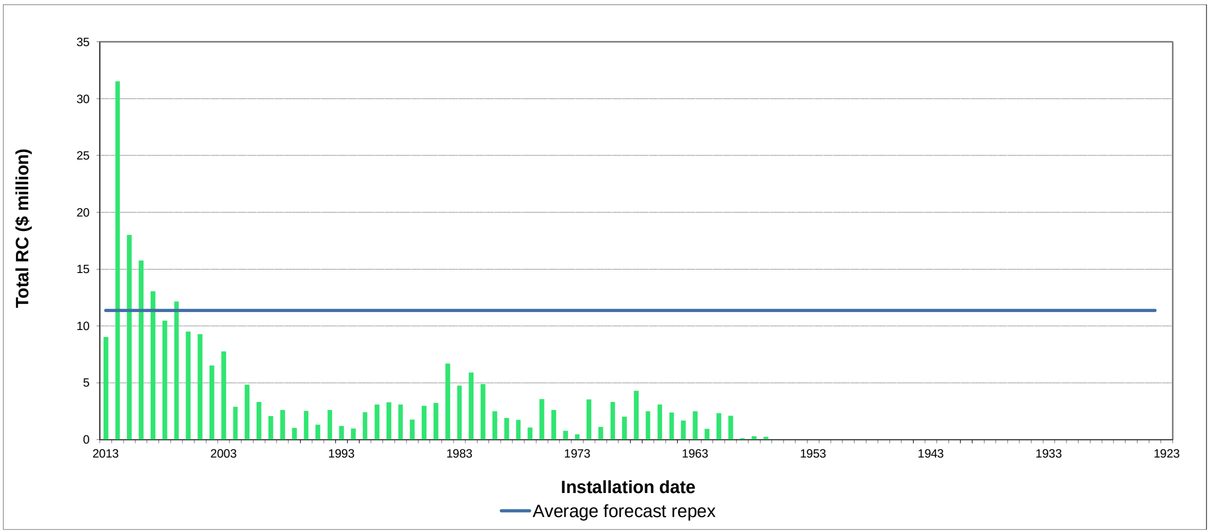



**Figure A-19 Asset age profile – Switchgear**




## Asset utilisation

Another indicator of asset health includes changes in the utilisation level of network assets. As we discuss in section A.1, Endeavour Energy has significant spare capacity in its network based on past investments to meet expected demand. In general, we expect that there is a positive correlation between asset condition and lower network utilisation. Given Endeavour 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. Similarly, the EMRF commented that:[74]

> A lightly loaded asset is likely to have a longer useful life than 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

74 EMRF submission, August 2014, p.20

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 Endeavour Energy's proposed repex forecast

This section sets out the findings of an engineering review undertaken by EMCa that we commissioned to test Endeavour Energy's repex forecast against the capex criteria. In particular, we engaged EMCa to test whether Endeavour 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 Endeavour Energy is a prudent and efficient operator in its costs, work practices, and expectations.[75] 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.[76] Another example is in relation to Endeavour 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).[77]

Given repex was a major component of Endeavour 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:[78]

- Systemic issues meant that Endeavour Energy's repex needs were significantly overstated and its repex forecast was likely to have overestimation bias.
- Endeavour Energy's asset management decisions are characterised by inadequate options analysis, and a lack of cost-benefit analysis to support the timing and volume of replacement activity. Further, there is inadequate evidence of efficient costs.
- Endeavour Energy's approach to risk is overly conservative.

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

### EMCa findings

EMCa finds that Endeavour Energy's repex forecasts have an overestimation bias:[79]

- Endeavour Energy has inadequately justified its selected activities. Its proposed expenditure is not subject to robust options analysis. That is, Endeavour Energy considers an inadequate number of options, cost-benefit analysis is rudimentary where used, and there is a lack of sensitivity analysis.

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75 NER, clause 6.5.7(c).
76 NER, clause 6.5.7(a).
77 NER, clause 6.5.7(e).
78 EMCa, Technical *review of regulatory proposals, Review of proposed replacement capex in Endeavour Energy's regulatory proposal 2014–2019*, October 2014, p, 1–3. (EMCa, *Review of Endeavour Energy's repex*, October 2014).
79 EMCa, *Review of Endeavour Energy's repex*, October 2014, pp. 17–21.

- Further, Endeavour Energy appears to have insufficient asset information and asset knowledge for most asset classes, leading to questionable proposed asset activity levels and an over-reliance on high level analysis. It was not always clear how Endeavour Energy derived its forecast volumes of replacement work. Endeavour Energy's lack of apparent understanding of defects and failures makes it unlikely that its proposed expenditure represents a prudent forecast of what is required.

- Endeavour Energy has not followed its internal governance process rigorously enough in developing its expenditure forecasts. This has also resulted in more forecast replacement volumes and/or scopes of work than is justified.

- Endeavour Energy's repex programs are at an early stage of estimation in its planning process. EMCa note it is not until later approval stages that it must estimate projects with accuracy of plus or minus ten per cent. Endeavour Energy also typically applies contingency amounts of between five and ten per cent to its base estimates. EMCa considers these project-level contingencies are inherent in the portfolio forecast Endeavour Energy has proposed, and will result in an upwardly biased forecast.

EMCa notes the Networks NSW Board reduced the overall expenditure forecast originally developed within Endeavour Energy by 15 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 Endeavour Energy was inadequate, either in terms of the prudency of the repex work proposed (volume and timing) or the cost of the work. Further, EMCa is of the view that the methodology used is a useful decision support tool, but on its own will not necessarily lead to an optimal portfolio.[80]

EMCa notes that Endeavour Energy did not provide information comparing its actual repex with forecast repex in the previous regulatory control period. EMCa considers this raises concerns with Endeavour Energy's ability to forecast prudent and efficient expenditure for the next regulatory period. Further, EMCa commented that this evidences a lack of planning continuity and internal assessment of forecasting performance.[81]

EMCa assessed the governance and management framework that Endeavour Energy uses to plan and approve its repex projects and programs. While Endeavour Energy's asset management approach correctly identifies where it should focus its repex, EMCa finds its application of the approach is biased towards overstating network risk and therefore overstates the amount of work required.[82] EMCa found material issues with Endeavour Energy's implementation of portfolio management, asset management and project governance.[83] EMCa considers the prudency of Endeavour Energy's repex is undermined as:[84]

- Endeavour Energy has inadequate data quality to optimally assess particular asset strategies and to justify the volume and timing of replacement activity.

80 EMCa, *Review of Endeavour Energy's repex*, October 2014, pp. 1, 14–16; 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.

81 EMCa, *Review of Endeavour Energy's repex*, October 2014, p. 11–12.

82 EMCa, *Review of Endeavour Energy's repex*, October 2014, p. 2.

83 EMCa, *Review of Endeavour Energy's repex*, October 2014, p. 13.

84 EMCa, *Review of Endeavour Energy's repex*, October 2014, p. 12–16.

- Endeavour Energy uses an industry standard risk management framework to assess bottom-up risk, but applies the risk assessment criteria conservatively. This results in it overstating the risk posed by its assets at an aggregate level.

- Endeavour Energy failed to provide comprehensive justification for its activities with a lack of options considered and inadequate cost-benefit analysis.

- Endeavour Energy uses a number of tools to manage its portfolio of replacement work. EMCa views these as useful lead indicators or 'sense-checkers' but considers they are decision support tools and not a substitute for rigorous project governance.

While Endeavour Energy's corporate risk matrix is consistent with the Networks NSW equivalent, EMCa finds Endeavour Energy's approach to risk assessment is based on limited fault information and a lack of detailed analysis. The variable quality of Endeavour Energy's defect information and analysis is the potential cause of its apparently conservative approach to risk assessment. Endeavour Energy's tendency to overstate asset failure risks leads to higher volumes of repex than is prudently required.[85]

EMCa reviewed Endeavour Energy's proposed repex programs for each of the high level asset categories. Its findings at the repex program level supported the issues identified with Endeavour Energy's governance and management framework and forecasting methods. EMCa found that for the majority of work programs there is:[86]

- inadequate options analysis, including a lack of cost-benefit analysis, and lack of justification for the timing of resolving condition-based issues identified

- inadequate explanation of the degree of step-change evident in proposed expenditure

- inadequate evidence of efficient costs

- lack of robust delivery management.

### A.3.3 Predictive modelling

This section sets out our assessment of the findings from the predictive modelling of repex (the repex model).[87] 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.[88] Our approach to developing outputs from the repex model is detailed in Appendix E.

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

85 EMCa, *Review of Endeavour Energy's repex*, October 2014, pp. 118–19.
86 EMCa, *Review of Endeavour Energy's repex*, October 2014, pp. 22–31.
87 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 E for details on our consultation).
88 AER, Electricity network service providers, Replacement expenditure model handbook, November 2013, p. 10.

is likely to reasonably reflect the capex criteria. This range, in conjunction with our other analytical techniques, informs our alternative estimate.[89]

### 3.4.1 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 appendix E. In total, the assets modelled represent $515 million or 70 per cent of Endeavour Energy's proposed repex.

Pole top structures and SCADA, along with specialised categories of capex defined by Endeavour Energy that were not classified under the six groups above, were not modelled. These represent the remaining 30% of Endeavour Energy's proposed repex, and are separately assessed in the SCADA section of A.3.4.

### 3.4.2 Analysis of the reasonable estimation range

As outlined in Appendix E, 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 Endeavour 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 Endeavour Energy (the base case model);
- replacement life information derived by using Endeavour 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 detailed in Appendix E.

#### The base case model

The base case model uses replacement life information inputs provided by Endeavour 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 Endeavour 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 $642 million and $562 million, respectively. These estimates are higher than Endeavour Energy's forecast of $514 million for the six modelled asset groups. However, they do not exceed Endeavour Energy's proposal by as great a margin as either Ausgrid or Essential Energy when the same base case assumptions were applied to those service providers.

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89 AER Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013.

**Table A-9 Base case model outcomes**

| Unit cost | Model outcome |
|---|---|
| Historical | $659.3 |
| Forecast | $575.1 |

Source: AER analysis

We understand that Endeavour Energy has utilised a similar predictive model to the AER in estimating its repex requirements. . Despite the similarities in final outcomes, the base case still gives a higher forecast of repex requirements than Endeavour Energy's forecast.

EMCa's assessment of Endeavour Energy's forecasting process and assessment of asset risks identified a bias towards early replacement of assets, and the likelihood of systemic overestimation of repex Furthermore, our assessment of Endeavour Energy's repex trends over the past 13 years showed its forecast repex to be above its long-term trend. Based on these considerations, we are of the view that the base case outcomes are less likely to reflect Endeavour Energy's prudent and efficient repex.

### The calibrated model

The calibrated model uses replacement lives and standard deviations based on Endeavour 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 | $584.5 |
| Forecast | $519.1 |
| Benchmark average | $950.6 |
| Benchmark first quartile | $612.4 |
| Benchmark lowest | $377.6 |

Source: AER analysis

Using calibrated replacement lives and Endeavour Energy's forecast unit costs gives an output of $519 million, which is a similar estimate of repex to Endeavour Energy's forecast. Using historical unit costs gives an output of $584 million, similar to the base case results.

We have excluded the historical unit costs from the reasonable range estimate. As with the base case analysis, the outcomes using historical unit costs are above Endeavour Energy's forecast. Given our findings in relation to long-term repex trends, and EMCa's conclusions, we do not consider historical unit costs provide a reliable outcome for inclusion in a reasonable range.

By comparison, the outcomes using the forecast unit costs align with both our other assessment techniques. We consider that forecast unit costs do not give rise to the same concerns that attach to the use of historical unit costs and consequently are more likely to result in a reasonable estimate. We therefore consider that the outcome of using forecasts unit costs is more likely to result in a reasonable estimate.

### The benchmarked model

As noted above, the outcome when using forecast unit costs in the calibrated model is relatively close to Endeavour Energy's proposal. We have also run the repex model under a variety of benchmarked input assumptions (which we refer to as "the benchmarked model"). The benchmarked model uses unit costs and replacement life information based on observations from all distribution service providers in the NEM. The derivation of these inputs is discussed in Appendix E.

Ultimately, we are satisfied that both the outcome of the calibrated model using forecast unit costs and Endeavour Energy's forecast for the six modelled asset groups compare favourably with the outcomes of the benchmarked model. Given this, we have not considered it necessary to include the benchmarked observations in the reasonable range.

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

| Unit cost | Model outcome |
|---|---|
| Historical | $793.4 |
| Forecast | $699.3 |
| Benchmark average | $889.3 |
| Benchmark first quartile | $630.3 |
| Benchmark lowest | $407.6 |

Source: AER analysis

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

| Unit cost | Model outcome |
|---|---|
| Historical | $662,594.6 |
| Forecast | $583,349.8 |
| Benchmark average | $701,493.8 |
| Benchmark first quartile | $526,160.8 |
| Benchmark lowest | $367,051.0 |

Source: AER analysis

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

| Unit cost | Model outcome |
|---|---|
| Historical | $595.0 |
| Forecast | $525.9 |
| Benchmark average | $612.2 |
| Benchmark first quartile | $483.0 |
| Benchmark lowest | $361.5 |

Source: AER analysis

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

| Unit cost | Model outcome |
|---|---|
| Historical | $420.4 |
| Forecast | $365.3 |
| Benchmark average | $366.2 |
| Benchmark first quartile | $341.2 |
| Benchmark lowest | $319.1 |

Source: AER analysis

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

| Unit cost | Model outcome |
|---|---|
| Historical | $394.2 |
| Forecast | $341.1 |
| Benchmark average | $341.5 |
| Benchmark first quartile | $323.9 |
| Benchmark lowest | $307.5 |

Source: AER analysis

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

| Unit cost | Model outcome |
|---|---|
| Historical | $377.2 |
| Forecast | $325.5 |
| Benchmark average | $323.0 |
| Benchmark first quartile | $311.6 |
| Benchmark lowest | $300.5 |

Source: AER analysis

**Table A-17 Benchmarked model – Unit costs**

| Replacement life | Unit cost | Model outcome |
|---|---|---|
| Calibrated | Forecast | $519.1 |
| Calibrated | Benchmark average | $950.6 |
| Calibrated | Benchmark first quartile | $612.4 |
| Calibrated | Benchmark lowest | $377.6 |

| | | |
|---|---|---|
| NSP benchmark average (calibrated) | Forecast | $365.3 |
| NSP benchmark average (calibrated) | Benchmark average | $366.2 |
| NSP benchmark average (calibrated) | Benchmark first quartile | $341.2 |
| NSP benchmark average (calibrated) | Benchmark lowest | $319.1 |

Source: AER analysis

## A.3.4 The reasonable range

Following our modelling, we have concluded that the calibrated model using forecast unit costs leads to an estimate which we consider is the point around which a reasonable range exists. Consequently, we are satisfied that an amount of $519 million of repex is a reasonable estimate of the prudent and efficient capex for the six modelled categories.

### Unmodelled repex

Repex categorised as supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA) and "Other" in Endeavour Energy's RIN response was not included in the repex model. As noted in Appendix E, 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 $225 million (or 30 per cent) of Endeavour Energy's proposed repex.

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

#### *SCADA, network control and protection*

Endeavour Energy has proposed repex of $108 million for SCADA, network control and protection (referred to as SCADA). This represents a 55 per cent increase over the 2009-14 regulatory control period, or $59 million.

Endeavour Energy's expenditure on SCADA was constant at around $5 million for the first four years of the 2009–14 regulatory control period, and increased to around $29 million in 2013–14. Endeavour Energy's proposal for the next period:

- maintains the step-increase for 2014–15, declining slightly to $24 million, with a further increase in 2015–16; and
- declines to a lower level for the final three years of the 2014–19 period, which nonetheless is significantly above the repex from the first four years of the 2009–14 regulatory control period.

We would expect that a step-increase of this magnitude, which is, on average, four times above historic repex from the first four years of the 2009–14 regulatory control period, would be justified by evidence of replacement need and supporting information.

EMCa considered that Endeavour Energy did not strongly support its increase in SCADA (including pilot cables).[90] It also noted that EMCa's own assessment that its SCADA assets were in good condition did not support the proposed increase.

Based on the lack of supporting information we agree with EMCa's view that a step change in expenditure from historical levels has not been adequately justified. In reaching our view on Endeavour Energy's SCADA, we have taken into account EMCa's specific view that the increase in SCADA has not been justified; and EMCa's overall findings on systemic issues.

On this basis, we consider that Endeavour Energy's forecasts do not reasonably reflect the capex criteria. We are satisfied that Endeavour Energy's average SCADA from the 2009–14 regulatory control period, which equates to $25 million ($2013–14), reasonably reflects the capex criteria.

### *Other repex*

Endeavour Energy categorised a number of assets under an "Other" asset group in its RIN response. Ausgrid forecast $117 million of repex for these assets for the 2014–2019 period. The assets include:

- Substation Miscellaneous Total Expenditure
- Substation Major Projects Total Expenditure
- 11kv - Chamber type (with LV CB) 1 Transformer Substation
- 11kv - Chamber type (with LV CB) 2 Transformer Substation
- 11kv - Chamber type (with LV CB) 4 Transformer Substation
- 11/22kv - 1 phase All sizes Substation
- 11/22kv - 3 phase <64kVA Substation
- 11/22kv - 3 phase >=64kVA Substation
- 11/22kv - kiosk and pad mount <=500kVA Substation
- 11/22kv - kiosk and pad mount >500kVA Substation
- 11/22kv Switching Station
- 12.7kv SWER All sizes Substation.

The first two subcategories relate to expenditure on zone and substation transmission assets. Endeavour Energy's forecast repex for these subcategories is $99 million, which is $233 million lower than its repex in the 2009–14 regulatory control period. In total, Endeavour Energy's expenditure on repex for assets in the "other" asset group is $230 million lower than it was in the 2009–14 period. Given this is a significant downward trend which accords with our findings from our other assessment techniques in particular our trend analysis, we are satisfied that the total of $117 million in the "other" asset group is likely to be a prudent and efficient level of repex for these assets.

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90 EMCa, *Review of Endeavour Energy's repex*, p. 25–26.

## A.4 AER findings and estimates for reliability improvement capex

Reliability improvement capex includes capex to meet network reliability performance obligations set out in Endeavour Energy's licence conditions.

Endeavour Energy proposed $65.3 million ($2013-14) of forecast capex related to its network reliability performance obligations. In particular, Endeavour Energy has proposed expenditure to:[91]

- Ensure compliance with reliability targets set out in the licence conditions and in particular for customers connected to worst performing parts of the network; and
- To stabilise and maintain reliability performance at levels that will avoid incurring penalties under our STPIS.

We do not accept Endeavour Energy's amount on the basis that:

- A review of Endeavour Energy's supporting information does not indicate the amount and the basis for this amount that has been proposed to address any compliance issues related to the Schedule 3 licence conditions (i.e. individual feeders performance obligations
- It appears that the proposed amount includes expenditure to avoid penalties under the STPIS; and
- The amount proposed has not been allocated in such a way that enables us to identify whether this amount already forms part of our analysis of other capex driver categories (e.g. we may have taken into account compliance related repex as part of our consideration of repex)

We recognise that Endeavour Energy is required to comply with its licence obligations, including in relation to individual feeder performance. However, we do not consider it appropriate that expenditure be proposed to avoid STPIS penalties. The STPIS funds a service provider (by providing a reward) for reliability improvements where this is valued by customers and conversely the STPIS penalises a service provider for a deterioration in performance on the basis that customers do not value the higher level of reliability.

We expect Endeavour Energy to provide further information in its revised regulatory proposal regarding the portion of this forecast that is considered to be augex and repex and supporting information in relation to the amount required to meet its Schedule 3 licence obligations. We also expect Endeavour Energy to provide analysis that supports the additional expenditure that is not related to its Schedule 3 licence obligations.

## A.5 AER findings and estimates for non-network capex

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

### A.5.1 Position

Endeavour Energy forecast total non-network capex of $176.4 million ($2013–14) for the 2014–2019 period.[92] We do not accept Endeavour Energy's proposal. We have instead included an amount of

[91] Endeavour Energy, Regulatory Proposal, p.63
[92] Endeavour Energy, *Regulatory proposal*, 31 May 2014, p. 62.

$163.3 million ($2013–14) for forecast non-network capex in our alternative estimate which we consider reasonably reflects the capex criteria.

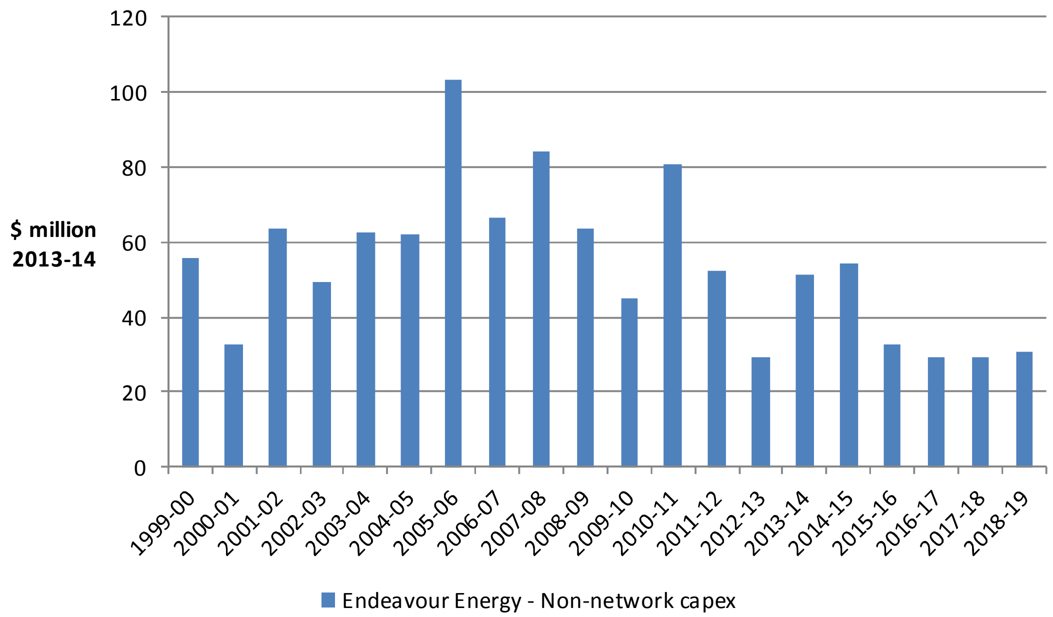
In coming to this view, we have found:

- Endeavour Energy's forecast capex for major field service centre projects at Mulgrave and Guildford does not reasonably reflect the efficient costs that a prudent operator would require to meet the capex criteria.[93] The need for and scope of the proposed projects is not supported given Endeavour Energy has not yet appropriately accounted for the expected reductions in field service centre populations over the next 2-3 years.

- Endeavour Energy's forecast plant and equipment capex also does not fully reflect forecast reductions in staff numbers. We consider that forecast capex of $16.1 million ($2013–14) reasonably reflects the required expenditure. This represents a reduction of 25 per cent from Endeavour Energy's actual capex in the 2009–2014 regulatory control period, in line with the forecast reduction in employee numbers.

Figure A-20 shows Endeavour Energy's historical non-network capex for the period from 1999-00 to 2013-14, and forecast capex for the 2014–2019 period.

**Figure A-20 Endeavour Energy's non-network capex 1999-00 to 2018-19 ($million, 2013-14)**




Source: Endeavour Energy , *Regulatory information notice*, template 2.6; Endeavour Energy , *Attachment 5.17 - Capital expenditure for previous, current and forecast period*, 31 May 2014; Integral Energy, *RIN response for 2009-14 regulatory control period, template 2.2.1*; AER analysis.

Endeavour Energy's forecast non-network capex for the 2014–2019 period is 32 per cent lower than actual and expected capex in the 2009–2014 regulatory control period. The forecast reduction in non-network capex is less than Endeavour Energy's forecast reduction in total capex of 37 per cent.[94] This is consistent with Origin Energy's observation that where there is a material reduction in network

[93] NER, cl. 6.5.7(c)(1) and cl. 6.5.7(c)(2).

[94] Endeavour Energy, *Attachment 5.17 - Capital expenditure for previous, current and forecast period*, 31 May 2014; AER analysis.

capex costs there should also be a significant and observable reduction in support costs such as fleet, property and ICT.[95]

Our analysis of longer term trends in non-network capex suggests that Endeavour Energy has forecast capex for this category at historically low levels, with the exception of the 2014-15 year.[96] Non-network capex in 2014-15 is forecast to be higher than each of the three preceding years, and at least 40 per cent higher than any other year of the 2014–2019 period. We therefore consider that Endeavour Energy's forecast non-network capex program warrants further review to confirm the need and timing for the proposed expenditure, with particular focus on the 2014-15 year.

We have 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.[97] Figure A-21 shows Endeavour Energy's actual and forecast non-network capex by sub-category for the period from 2004-05 to 2018-19.

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


Source: Endeavour Energy , *Attachment 5.17 - Capital expenditure for previous, current and forecast period*, 31 May 2014; AER analysis.

Endeavour Energy has forecast capex reductions for all categories of non-network capex in the 2014–2019 period. Significant reductions are forecast for both motor vehicles and buildings and property capex, while ICT and plant and equipment capex are forecast to decline slightly in the 2014–2019 period. This follows reductions in average annual expenditure achieved in all categories in the 2009–2014 regulatory control period when compared to the 2004–2009 regulatory control period.[98] Overall,

95 Origin Energy, *Submission to the AER*, 8 August 2014, p. 27.

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

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

98 Endeavour Energy, *Attachment 5.17 - Capital expenditure for previous, current and forecast period*, 31 May 2014; AER analysis.

Endeavour Energy's non-network capex forecast continues a long term trend of declining real expenditure since the peak experienced in 2005-06.

Forecast capex for each category is relatively smooth across the 2014–2019 period, with the exception of buildings and property capex. The significant spike in buildings and property capex in 2014-15 is driving the high level of non-network capex forecast for that year compared to all other years of the 2014–2019 period, as noted above. We therefore sought further information from Endeavour Energy in relation to its forecast buildings and property capex, as well as the related plant and equipment category, to confirm the need and timing of the forecast capex.[99] Our conclusions on each of these categories of non-network capex are summarised below.

### Buildings and property capex

Endeavour Energy forecast capex of $48.2 million ($2013–14) for non-network buildings and property projects in the 2014–2019 period. This included expenditure on major field service centre (FSC) projects at Springhill, Guildford and Mulgrave, as well as security related expenditure and capex for general upgrades at other office and FSC sites.[100]

We sought information from Endeavour Energy to support the need, timing and costs of the proposed buildings and property projects.[101] Endeavour Energy advised that it does not have a single integrated property plan, but rather specific business cases for major components of the property plan.[102] The primary document identified by Endeavour Energy in support of its proposed buildings and property capex was the update to its FSC strategy prepared in May 2014.[103] This FSC strategy update states that:[104]

> Following the recent development of the 5 year work program for the 2014/19 AER submission … there is potential for the FSC populations to reduce considerably over the next 2-3 years. Planned projects driven by FSC population will require review once the final determination is made by the AER. Our forecast reflects our current plans and information available at the time of preparing the 2014-19 submission. We prudently review projects prior to their implementation and any known changes to drivers prior to the AER's final determination will be included in our revised proposal to the AER in January 2015.

Further, in relation to the specific project proposed at Mulgrave the FSC strategy update states that:[105]

> Based on the revised workforce plan forecasts the key drivers of the decision for the new larger facility at Mulgrave are now diminished.

In relation to the proposed Guildford FSC project, the FSC strategy update states that:[106]

> With the development of the Rapid response crews within System Control and the potential for expansion of Rapid Response and EMSO activities … the drivers for Guildford FSC (response times from Hoxton Park FSC) are also under review as the Guildford area is a part of the Rapid Response coverage area.

In summary, the FSC strategy update identifies that Endeavour Energy's key priorities for 2014-15 will be to complete the Springhill FSC project and to "review the drivers for Mulgrave FSC, Shellharbour Pole Yard and Guildford FSC by March 2015 based on revised FSC population forecasts".[107]

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99 AER, *Information request ENDEAVOUR 024*, 1 September 2014 and AER, *Information request ENDEAVOUR 024 - follow up*, 22 September 2014.

100 Endeavour Energy, *Regulatory proposal*, 31 May 2014, p. 66; Endeavour Energy , *Land and Buildings Capex Program Breakdown*, 13 June 2014.

101 AER, *Information request ENDEAVOUR 024*, 1 September 2014.

102 Endeavour Energy, *Response to Information request ENDEAVOUR 024*, 8 September 2014, p. 2.

103 Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014.

104 Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014, p. 2.

105 Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014, p. 5.

106 Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014, p. 5.

Endeavour Energy also provided the original FSC strategy and related documents prepared in 2010 as further support for the need and timing of the proposed FSC projects.[108] These documents provide context and background on the drivers of the projects identified at that time, and how the projects relate to Endeavour Energy's broader FSC strategy.

On reviewing these documents, we do not consider that Endeavour Energy's 2010 FSC strategy supports the need, timing or costs of the proposed projects given the significant changes in Endeavour Energy's operating environment since that time as set out in the May 2014 update.

Specifically, based on the information submitted, we are not satisfied that Endeavour Energy's forecast capex for major FSC projects at Mulgrave and Guildford reasonably reflects the efficient costs that a prudent operator would require to meet the capex criteria.[109] The need for and scope of the proposed projects is not supported given Endeavour Energy has not yet appropriately accounted for the expected reductions in FSC populations over the next 2-3 years. Endeavour Energy acknowledges that planned projects driven by FSC population require review, yet proposes to conduct this review after we make our final determination on the forecast capex for these projects. Therefore, we have excluded Endeavour Energy's forecast capex for the Mulgrave and Guildford projects from our estimate of total capex for the 2014-18 period.

Endeavour Energy has also forecast capex for completion of the Springhill FSC redevelopment in 2014-15, an FSC security program to replace locks and keys and improve CCTV coverage, and a general maintenance program for FSCs and office accommodation. The Springhill project is nearing completion, and is driven by a need to relocate the southern area control room and address safety and compliance issues at the site.[110] Similarly, the other buildings and property programs are driven by asset condition, safety and compliance issues.[111] We note that Endeavour Energy's proposed buildings and property capex excluding the major FSC projects is low compared to historical levels of expenditure. Therefore, on the basis of the information presently available to us, we consider that Endeavour Energy's forecast of $38.6 million ($2013–14) for buildings and property capex excluding the Mulgrave and Guildford FSC projects is likely to reflect efficient and prudent expenditure. However, in preparing its revised regulatory proposal, Endeavour Energy should address whether the expected reductions in FSC populations over the next two to three years will also affect this element of its buildings and property capex forecast. While the information available to us clearly indicates that expected reductions in FSC populations will directly impact upon the major FSC projects, it is less clear whether it will impact upon the forecast FSC and office maintenance and upgrade expenditure.

### Plant and equipment capex

Endeavour Energy forecast capex of $19.6 million ($2013–14) for plant and equipment, including furniture and fittings, in the 2014–2019 period. This includes tools of trade used in both capital and maintenance processes, as well as furniture and fittings and other tools and equipment purchases. Endeavour Energy's forecast capex for this category is based on historical expenditure.[112]

Endeavour Energy has forecast a reduction of 9 per cent in total plant and tools capex for the 2014–2019 period, with expenditure flat across each year.[113] However, the forecast level of plant and tools capex in every year of the 2014–2019 period, approximately $3.9 million ($2013–14), is higher than

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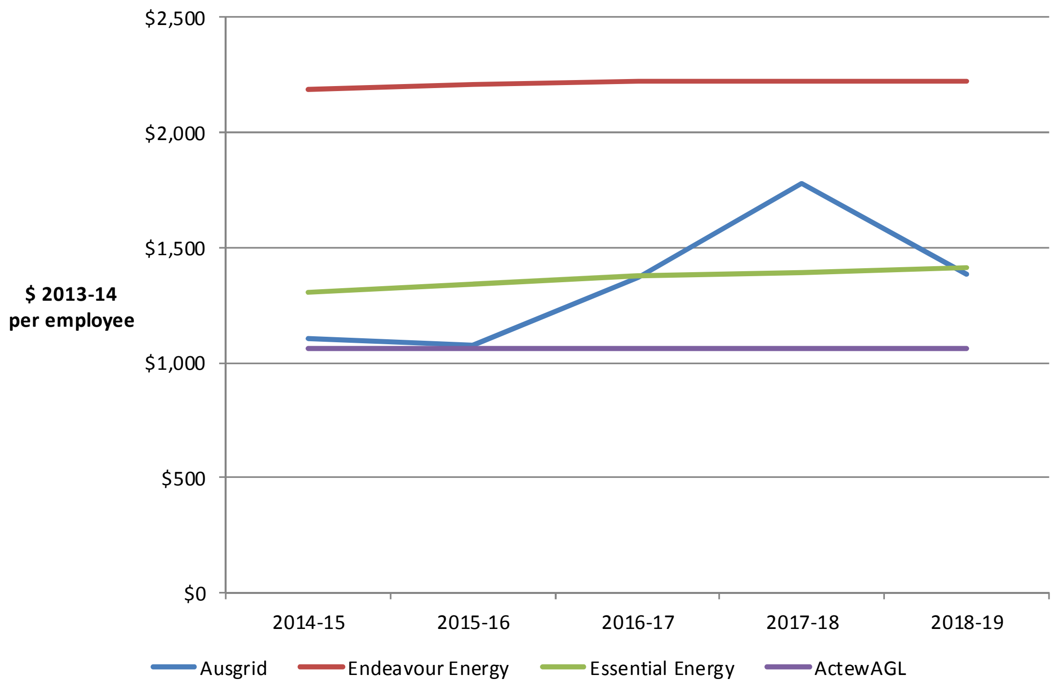
[107] Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014, p. 5.
[108] Endeavour Energy, *Response to AER information request ENDEAVOUR 024 - follow up*, 29 September 2014.
[109] NER, cl. 6.5.7(c)(1) and cl. 6.5.7(c)(2).
[110] Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014, p. 4.
[111] Endeavour Energy, *Land and Buildings Capex Program Breakdown*, 13 June 2014.
[112] Endeavour Energy, *Response to Information request ENDEAVOUR 024*, 8 September 2014, p. 6.
[113] Endeavour Energy, *Attachment 5.17 - Capital expenditure for previous, current and forecast period*, 31 May 2014.

Endeavour Energy's actual expenditure in three years of the 2009-14 regulatory control period.[114] We therefore sought further information from Endeavour Energy to justify the proposed level of plant and equipment capex.[115]

Endeavour Energy acknowledged that changes in its workforce plan forecasts, reflected in reducing FSC populations, had driven the 9 per cent reduction in total plant and equipment capex.[116] We agree that staff numbers, and particularly field service staff, are likely to be a driver of expenditure in this category. Endeavour Energy anticipates that its FSC populations are likely to 'reduce considerably' in the next two to three years.[117] It has also forecast a reduction in total employee numbers of approximately 25 per cent in the 2014–2019 period compared to the 2013-14 year.[118] In light of this, we are not satisfied that Endeavour Energy's forecast 9 per cent reduction in plant and equipment expenditure fully reflects forecast reductions in staff numbers. This is consistent with our conclusion above that Endeavour Energy had not appropriately accounted for expected staffing reductions in its forecast buildings and property capex.

Given the relationship between workforce forecasts and plant and equipment capex requirements, we examined how Endeavour Energy's forecast capex for plant and equipment per employee compared to other service providers in NSW/ACT. This analysis is shown in Figure A-22 below.

**Figure A-22 Plant and equipment capex per employee ($2013–14)**




Source: Endeavour Energy , *Regulatory information notice*, template 2.6; Essential Energy, *Regulatory information notice*, template 2.6; Ausgrid, *Regulatory information notice*, template 2.6; and ActewAGL, *Regulatory information notice*, template 2.6.

Figure A-22 indicates that Endeavour Energy's forecast plant and equipment capex is, on a per employee basis, higher than the other service providers in NSW and the ACT. We have not placed

114 NER, cl. 6.5.7(e)(5).
115 AER, *Information request ENDEAVOUR 024*, 1 September 2014.
116 Endeavour Energy, *Response to Information request ENDEAVOUR 024*, 8 September 2014, pp. 5-6.
117 Endeavour Energy, *Attachment 5.33 - Field Service Strategy Update (Public)*, 27 May 2014, p. 2.
118 Endeavour Energy, *Regulatory information notice*, template 2.6; AER analysis.

significant weight on this analysis, recognising the difficulty in comparing metrics of forecast expenditure in a specific category across different service providers. Nevertheless, we consider it is consistent with our view, based on the other evidence discussed above, that Endeavour Energy's forecast plant and tools expenditure is likely to be overstated.

In summary, we are not satisfied that Endeavour Energy's forecast plant and equipment capex reasonably reflects the efficient costs that a prudent operator would require to meet the capex criteria.[119] We consider that forecast capex of $16.1 million ($2013–14) reasonably reflects the required expenditure. This represents a reduction of 25 per cent from Endeavour Energy's actual capex in the 2009–2014 regulatory control period and is in line with the forecast reduction in employee numbers. We will make an allowance for it in our estimate of total capex for the 2014–2019 period.

119 NER, cl. 6.5.7(c)(1).

## A.6 AER findings and estimates for capitalised overheads

Capitalised overheads are costs associated with capital works that have been appropriately capitalised in accordance with Endeavour 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 and the amount of capital works that is undertaken.

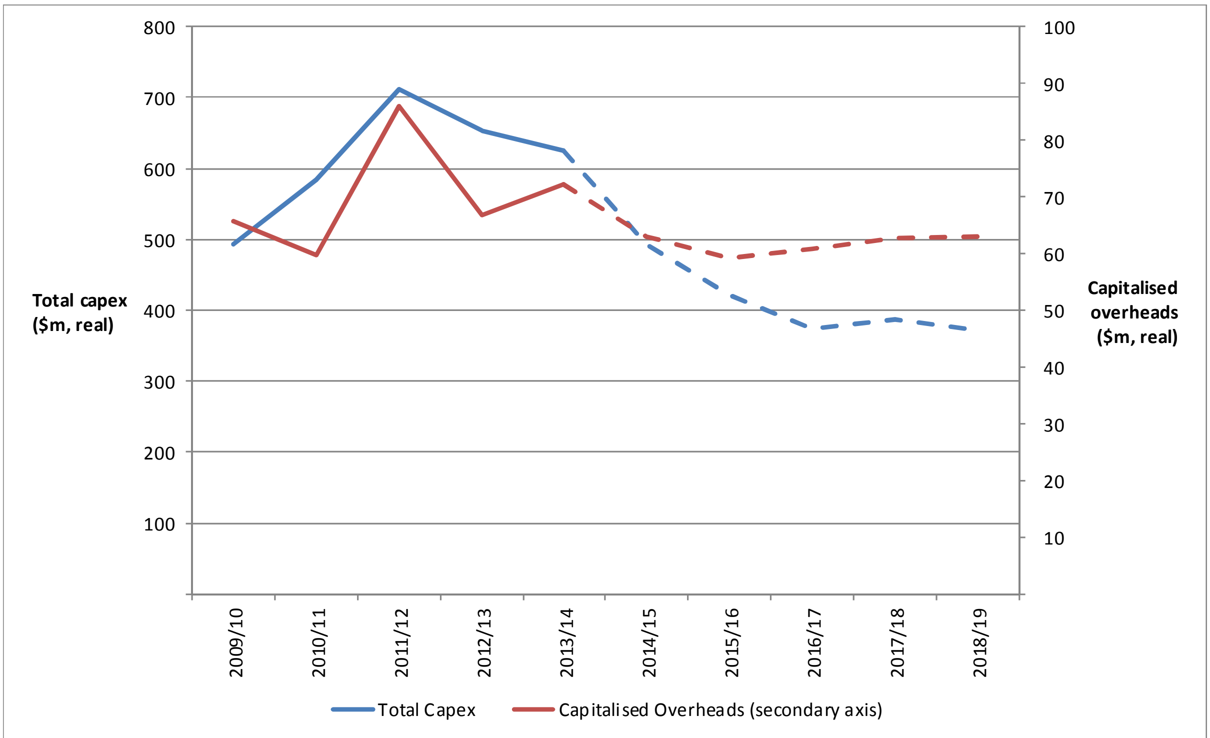
### A.6.1 AER Position

Endeavour Energy proposed $308.5 million ($2013-14) of forecast capitalised overheads. We do not accept Endeavour Energy's proposal. We have instead included an amount of $145.3 million ($2013-14) in our alternative estimate. This is 53 per cent less than Endeavour Energy's proposal. In coming to this view, we applied trend analysis to assess Endeavour Energy's proposal by reference to the actual capitalised overheads it incurred during the 2009–2014 regulatory control period

#### Trend analysis

Endeavour Energy proposed $308.5 million ($2013-14) of forecast capitalised overheads is a reduction from the actual capitalised overheads that it spent during the 2009–2014 regulatory control period. As Figure A-23 shows, the reduction itself is consistent with the reduction Endeavour Energy's proposed total forecast capex compared to the actual (and estimated) capex that it spend during the 2009–2014 regulatory control period.

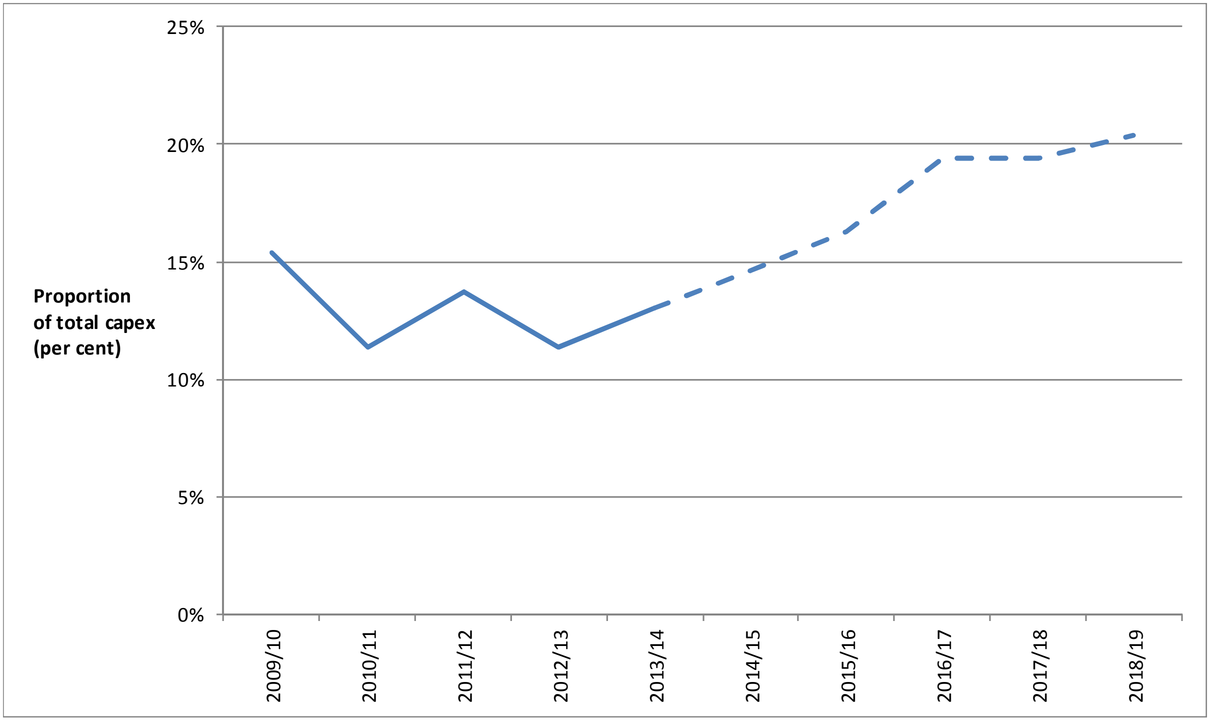
**Figure A-23 Endeavour Energy - total capex and capitalised overheads ($ million - real June 2014)**




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

Figure A-24 shows that the average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period of around 13 per cent.

**Figure A-24 Endeavour Energy - capitalised overheads as a proportion of total capex (per cent)**




Source: Ausgrid - Reset RIN - 2.1 Expenditure Summary - Table 2.1.1 - Standard control services capex and Table 2.1.5 Dual function assets capex (capitalised overheads aggregate corporate and network capitalised overheads)

However, whilst Endeavour Energy's proposal of $308.5 million for capitalised overheads is consistent with its proposed total forecast capex, it is not consistent with our alternative estimate. Further, our alternative estimate is consistent with the reduction in Endeavour Energy's base opex which requires less overhead to be capitalised.

## A.7 AER findings and estimates on 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.[120]

## A.7.1 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.7.2 Our assessment

### *Comparison with demand management activities of peers during 2009–14*

Our analysis suggests that the Endeavour Energy's estimate of $34 million significantly understates the amount of capex that could be deferred. 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[121]. 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").[122]

As such, we consider that the Ausgrid experience in demand management in 2009-14 may represent a reasonable benchmark to assess the capex that may be deferred by Endeavour 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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120 Ausgrid 2014-19 revenue proposal Attachment 6.12, p. 29.

121 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.

122 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.7.3 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 Endeavour of 9.2%, or approximately $93 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 TransGrid'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.[123] Economic benchmarking applies economic theory to measure the efficiency of a DNSP's use of inputs to produce outputs, having regard to environmental factors.[124] 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 TNSP's capex forecast represents efficient costs.[125] As stated by the AEMC, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[126]

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.[127] 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.[128]

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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123 NER, clause 6.5.7(e)(4)
124 AER, Explanatory Statement: Expenditure Forecasting Assessment Guidelines, November 2013.
125 NER, clause. 6.5.7(c)
126 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 25.
127 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.
128 AER, Annual Benchmarking Report, 2014.

Customer numbers and maximum demand are used as proxies for output.[129] 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.[130] 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 TNSPs, 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.[131] 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 alternative 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.[132]

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.[133] 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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129 For more on these measures, see the AER's annual Benchmarking Report.
130 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.
131 AEMC, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, November 2012, p. 113.
132 NER, clause 6.5.7(e)(5).
133 NER, clause 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 Endeavour Energy's capex proposals. This has involved reviewing Endeavour 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 Endeavour Energy's :

- Forecast is reasonable and unbiased, by assessing whether the TNSP’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:[134]

- 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 Endeavour Energy's risk management is prudent and efficient, Endeavour 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

[134] NER, s. 6.5.7(c) (version 58).

and the impact of the risk (if it were to occur) in determining whether to undertake work to mitigate the risk.[135]

- If Endeavour Energy's costs and work practices are prudent and efficient, Endeavour Energy will have the appropriate governance and asset management practices to ensure that Endeavour 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 Endeavour Energy's governance and risk assessment framework and whether there is evidence that indicates that the forecasts are biased. The engineering reviews focused on Endeavour 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.

[135] This approach is supported by NERA Economic Consulting, see NERA, Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules, Supplementary Report, Ausgrid submission, 8 May 2014, p. 7.

# C Demand

This attachment sets out our observations of demand trends in Endeavour Energy's network for the 2014–2019 period.[136]

Demand forecasts are fundamental to a NSP's forecast capex and opex, and to the AER's assessment of that forecast expenditure.[137] Endeavour Energy must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. When Endeavour 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).[138] Endeavour Energy uses demand forecasts in conjunction with network planning to determine the amount and timing of such expenditure. Endeavour Energy also incurs opex in relation to the new assets it builds to meet demand.

System demand represents total demand in the Endeavour Energy distribution network. This attachment considers demand forecasts in Endeavour 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.[139] 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 AER position on system demand trends

We are satisfied the system demand forecasts in Endeavour Energy's regulatory proposal for the 2014–2019 period reasonably reflects a realistic expectation of demand.[140] The demand forecasts in Endeavour Energy's regulatory proposal for the 2014–2019 period are considerably lower than previous forecasts.[141] As we would expect, one result of this trend is the significant reduction in Endeavour 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

[136] In this appendix, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated.
[137] NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
[138] Sections A.1 and A.2 discusses our consideration of Endeavour Energy's augex and connections expenditure.
[139] Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.
[140] NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).
[141] Endeavour, *Regulatory proposal to the Australian Energy Regulatory: Delivering better value: 1 July 2015 - 30 June 2019*, May 2014, p. 55; Endeavour, *Regulatory proposal to the Australian Energy Regulator 2009 to 2014: Delivering efficient and sustainable network services*, 2 June 2008, p. 61.

to reflect the most up to date data. We would also expect Endeavour Energy's expenditure forecasts to reflect updates to its demand forecasts. For example, we would expect a downward revision of Endeavour 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 Endeavour 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.[142]

Submissions from stakeholders suggest there is evidence demand will continue to stagnate, or even fall, in Endeavour Energy's network for the 2014–2019 period.

Section C.2.1 discusses these observations in more detail. We note stakeholders generally provided qualitative evidence, and did not suggest specific demand figures.

## C.2 AER approach

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

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

### Endeavour Energy's proposal

Endeavour Energy provided historical and forecast demand figures in their proposal and in the reset RINs.[143] Endeavour Energy's proposal described their demand forecasting methods, including approaches to:

- weather correction
- accounting for spot loads
- accounting for transfers
- accounting for embedded generation.[144]

Endeavour Energy obtained its system demand forecast by aggregating spatial demand forecasts.[145] It does not appear Endeavour Energy produced a separate demand forecast using a top-down approach.[146]

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142 AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014, p. 4-4.

143 Endeavour Energy reset RIN; Endeavour, *Regulatory proposal to the Australian Energy Regulatory: Delivering better value: 1 July 2015 - 30 June 2019*, May 2014, p. 55; Endeavour, *NFB 0010 Network demand forecasting - Summer and winter peak demand forecast process*, 2 November 2012.

144 Endeavour, *NFB 0010 Network demand forecasting - Summer and winter peak demand forecast process*, 2 November 2012.

145 Endeavour, *NFB 0010 Network demand forecasting - Summer and winter peak demand forecast process*, 2 November 2012, p. 5.

146 Endeavour, *Regulatory Information Notice (RIN) issued under division 4 of part 3 of National Electricity (New South Wales) Law: Endeavour Energy response to schedule 1 of the RIN (version 15 May)*, 30 May 2014, p. 47.

## AEMO forecasts

In July 2014, AEMO published the first edition of transmission connection point (CP) forecasts for New South Wales and Tasmania.[147] These forecasts are AEMO's independent electricity maximum demand forecasts at transmission connection point level, over a 10-year outlook period.[148] The Standing Council on Energy Resources (SCER) intended these demand forecasts to inform our regulatory determinations.[149] In addition, AEMO has published the National Electricity Forecasting Report (NEFR) since 2012, and published the latest edition in June 2014 (2014 NEFR).[150] 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.[151]

As part of our consideration of system demand forecasts, we compared Endeavour Energy's system demand forecast to the sum of AEMO's CP forecasts for Endeavour Energy's network. We undertook further investigation to understand Endeavour Energy's demand forecasts where they differed significantly from AEMO's CP forecasts. This included making enquiries of Endeavour 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.2.1 sets out our comparisons of AEMO's CP forecasts with Endeavour Energy's demand forecasts and takes into account stakeholder submissions.

## C.2.1 AER considerations on system demand trends

The demand forecasts in Endeavour Energy's regulatory proposal for the 2014–2019 period are considerably lower than previous forecasts. We note Endeavour Energy's forecast demand growth rates displayed a similar trend to AEMO's forecasts, although the absolute values of Endeavour 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 Endeavour, as well as the

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

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

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

150 AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014.

151 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.

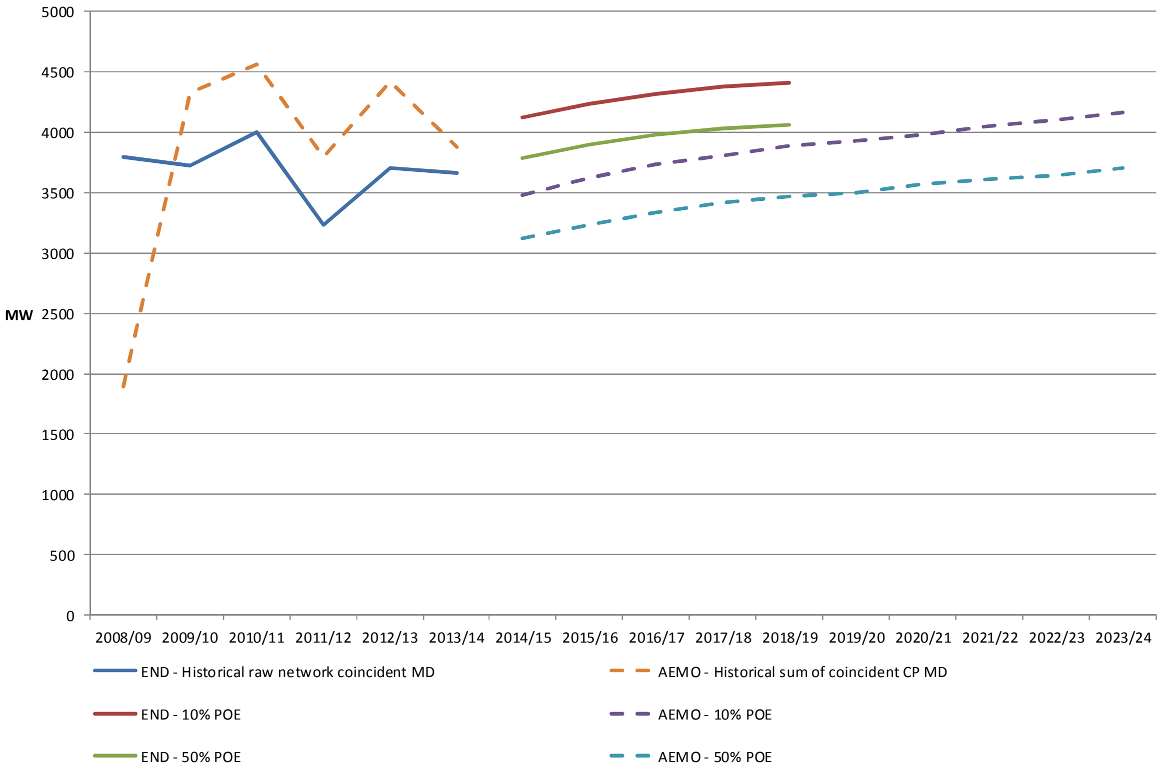
other NSW/ACT DNSPs in general, are still using overly conservative demand forecasts as inputs to their regulatory proposals. We note stakeholders generally provided qualitative evidence, and did not suggest specific demand figures.

Figure C-1 shows our comparison between Endeavour Energy's system demand and AEMO's CP demand for the Endeavour Energy network.[152] It shows the growth trend for Endeavour Energy's system demand forecast is consistent with AEMO's CP forecasts for Endeavour 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 Endeavour Energy's forecasts are realistic.

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

We liaised with Endeavour Energy and with AEMO to ascertain the reasons for the discrepancies.[153] We also asked Endeavour Energy whether they would adjust their demand forecast to match AEMO's CP forecasts, given the latter are the latest available forecasts.[154]

**Figure C-1 Comparison of Endeavour Energy demand and AEMO CP demand**




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

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

[152] We summed AEMO's coincident demand figures for each CP in Endeavour Energy's network for each year.
[153] We liaised with the other NSW/ACT DNSPs regarding similar issues.
[154] AER, *Email to Endeavour Energy : AER Endeavour Energy016 - maximum demand*, 12 August 2014.

- 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: Endeavour 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.[155]

The NSW/ACT DNSPs also noted differences in forecasting methods as possible explanations in differences between their demand forecasts and AEMO's.[156]

More specifically, Endeavour Energy noted two major differences in the historical demands in Figure C-1. First, the Endeavour Energy historical demand included a mix of winter and summer peak demand, whereas AEMO is for historical summer demand only. Second, AEMO's historical dataset excludes some HV customers and embedded generation and so should be lower than Endeavour Energy's historical dataset.[157] AEMO's starting point would be lower than Endeavour Energy's starting point by at least 100MW.[158]

Endeavour Energy noted AEMO's forecast demand has a higher growth rate than Endeavour Energy's (2.4 per cent per annum, compared to 1.8 per cent per annum, respectively). The difference is likely due to differing forecasting methods.[159] Endeavour Energy stated preliminary analysis indicated growth rates should be lower than those it submitted in its regulatory proposal, and AEMO's growth rates are unrealistic in the current economic conditions. Endeavour Energy also raised concerns regarding AEMO's temperature correction method.[160]

Endeavour Energy did not propose to adopt AEMO's CP demand forecast as an input to its regulatory proposal due to these differences.

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 Endeavour. 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.[161]

We are satisfied Endeavour 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 Endeavour Energy's network. Nevertheless,

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

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

157 Endeavour, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014, pp. 1–2.

158 Endeavour, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014, p. 4.

159 Endeavour, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014, p. 2.

160 Endeavour, *Response to AER: Information request AER Endeavour Energy 016*, 20 August 2014, p. 4.

161 AEMO, *AEMO review: AEMO/NSP transmission connection point forecast comparison: For New South Wales (incl. ACT)*, October 2014, p. 1.

we consider they provide a useful reference point for assessing Endeavour Energy's demand forecasts.

We understand AEMO has begun consultation with some DNSPs in reconciling their datasets.[162] AEMO also indicated it would explore developing demand forecasts at the DNSP level in the future.[163] We anticipate these processes will result in more comparable datasets in future regulatory determinations.

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

Several stakeholders raised concerns that Endeavour, as well as the other NSW/ACT DNSPs, are still using overly conservative demand forecasts as inputs to their regulatory proposals. AGL stated Endeavour Energy did not provide sufficient justification for their demand forecast in its regulatory proposal.[164] The Total Environment Centre (TEC) noted Endeavour Energy forecast increases in demand in the 2014–2019 period. This, despite Endeavour Energy's demand falling in the 2009–2014 regulatory control period.[165]

PIAC noted the growing disjunction between GDP and energy use, pointing to a decline in energy intensity.[166] 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.[167] 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.[168] The 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).[169]

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.[170] 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.[171]

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162 AEMO, *AEMO review: AEMO/NSP transmission connection point forecast comparison: For New South Wales (incl. ACT)*, October 2014, pp. 6–8.

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

164 AGL, *NSW electricity distribution networks regulatory proposals: 2014- 19: AGL submission to the Australian Energy Regulator*, 8 August 2014, p. 5.

165 TEC, *Submission to the Australian Energy Regulator issues paper on the NSW electricity distribution businesses' regulatory proposals*, August 2014, pp. 12–13.

166 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p. 40.

167 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.

168 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p. 35.

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

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

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

## Past forecasting inaccuracies

PIAC stated the AER should thoroughly examine Endeavour Energy's demand forecasts to ensure they provide a sound base for capex proposals.[172]

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.[173] Among other things, falling demand and consumption led to higher prices and revenue for the 2009–2014 period, especially when compared with earlier periods.[174]

We acknowledge demand forecasting is not a precise science and will inevitably contain errors. Consistent over-forecasting, as the submission above noted, may indicate a systemic bias in a NSP's demand forecasting approach.[175] As we discussed above, our analysis indicates Endeavour Energy's demand forecasts exhibit growth patterns consistent with AEMO's. However, we will monitor the accuracy of Endeavour 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.

172 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, pp. 41–42, 106.

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

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

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

# D Operating and environmental factors

Our draft decision for Endeavour Energy draws upon the annual benchmarking results and other capital expenditure comparisons between DNSPs. While these results are not an input into our alternative estimate of Endeavour Energy's capex forecast, they inform us of Endeavour 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 Endeavour 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.

## D.1 Existing network design

### D.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% and 19% 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% of the total network length and just 2% is 11kV.

In South Australia, SAPN reported a high-voltage network that was exclusively 11kV[176]. Queensland on average also had a higher proportion of 11kV to 22kV lines than NSW.

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

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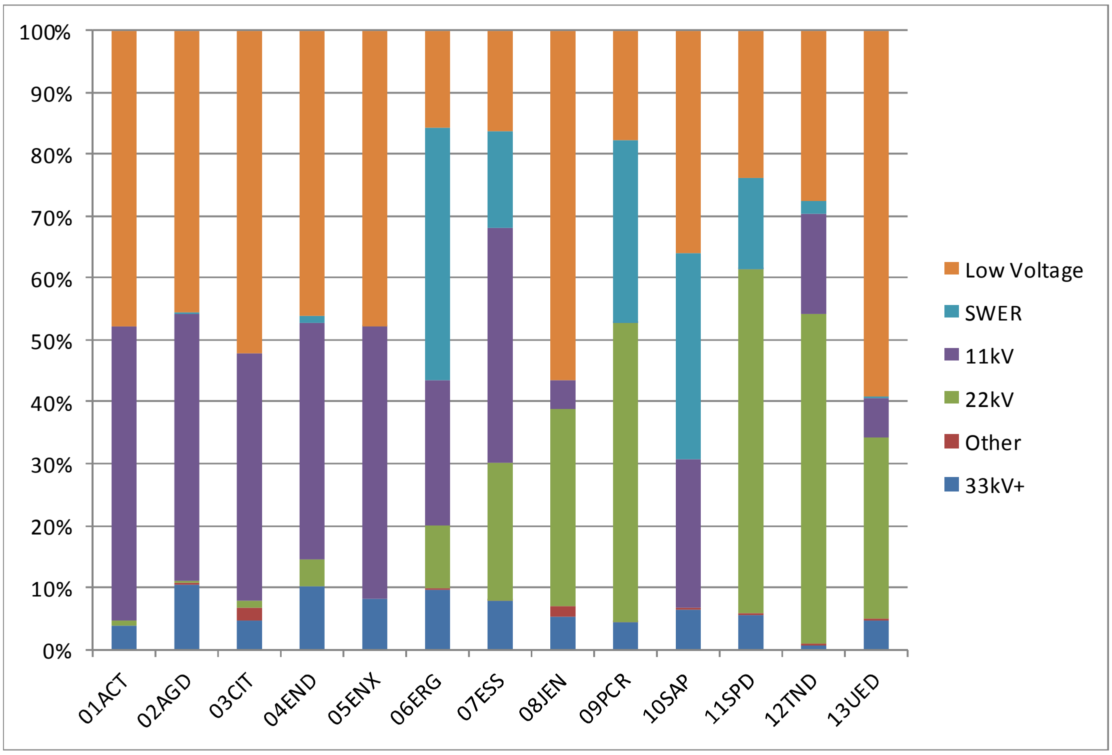
[176] Single Wire Earth Return (SWER) lines are considered separately.

**Figure D-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.[177] They claim that this represents a cost advantage and will manifest itself in lower operation, maintenance and repex costs. [178]

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

**Table D-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 | Lower costs for fewer civil and protection assets |

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

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

| | | | |
|---|---|---|---|
| | | sectionalising) | |
| 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.

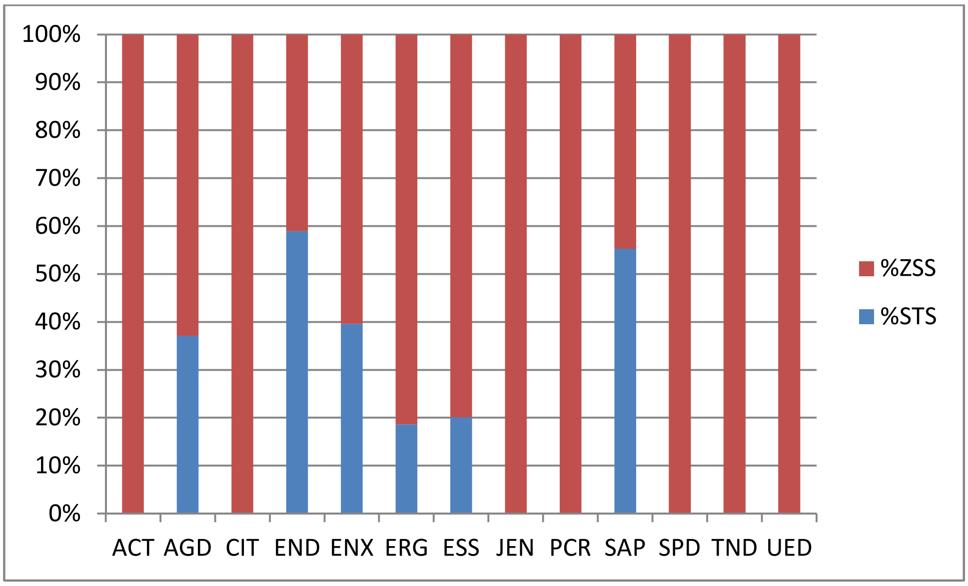
### D.1.2 Subtransmission variations

Ausgrid, Endeavour, and Essential have all raised subtransmission network configuration as an operating environment factor that will affect benchmarking results with other DNSPs.[179] [180] [181]

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 D-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.

[179] Ausgrid, *Attachment 5.33* to *Revenue proposal*, p. 5.
[180] Endeavour, *Attachment 0.12* to *Revenue proposal*, p. 5.
[181] Essential *Attachment 5.4* to *Revenue proposal*, p. 5.

**Figure D-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.[182] They have also said that Victoria has a natural cost advantage over all other states because it has less subtransmission transformer capacity installed.[183] 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.[184] As a result, Evans and Peck conclude that this factor has a 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 D-3 provides the overall line lengths for each of the major voltage levels across each DNSP.

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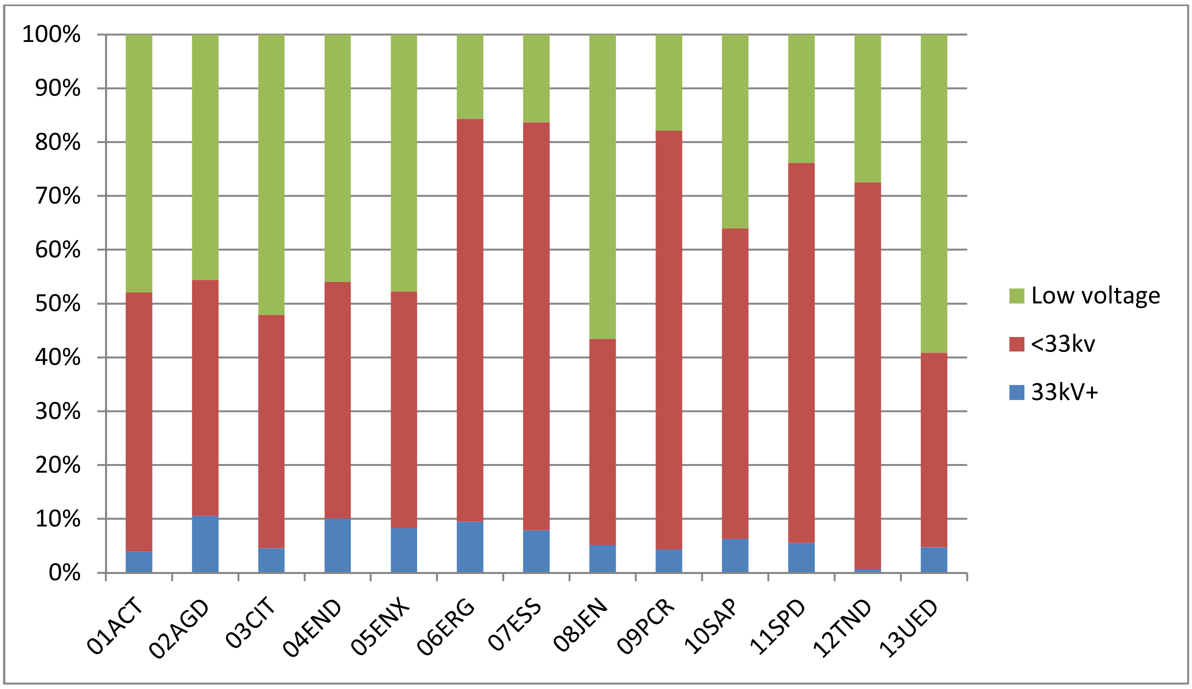
182 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 14.

183 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 18.

184 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 21.

**Figure D-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% of the network. Endeavour Energy reported a value of 10.1% and Essential Energy 7.9%. The average proportion of Victorian and South Australian sub-transmission lines was 5.4%.

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.

### D.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.[185] ActewAGL considers that backyard reticulation increases their replacement capex.

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

**Table D-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.

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.

185 ActewAGL, *Revenue proposal*, p. 243.

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.

## D.2 Scale factors

### D.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 D-3 summarises our assessment of whether the factors are likely to benefit or adversely impact networks depending on their respective customer density.

**Table D-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).[186][187][188] 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.

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

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

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

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

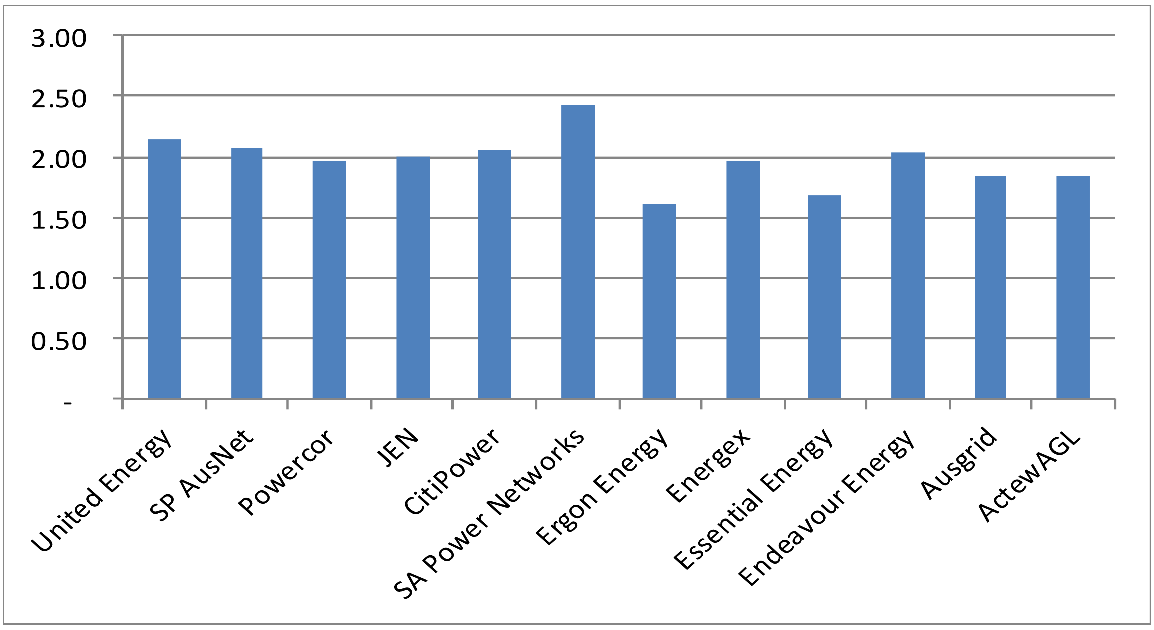
### D.2.2 Load shape

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 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.[189] Because DNSPs in SA and Victoria have lower load factors it means that probabilistic planning is more applicable to those businesses.

Figure D-4 shows the ratio of network demand to average energy (five year average) 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 a 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.

**Figure D-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.

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

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.

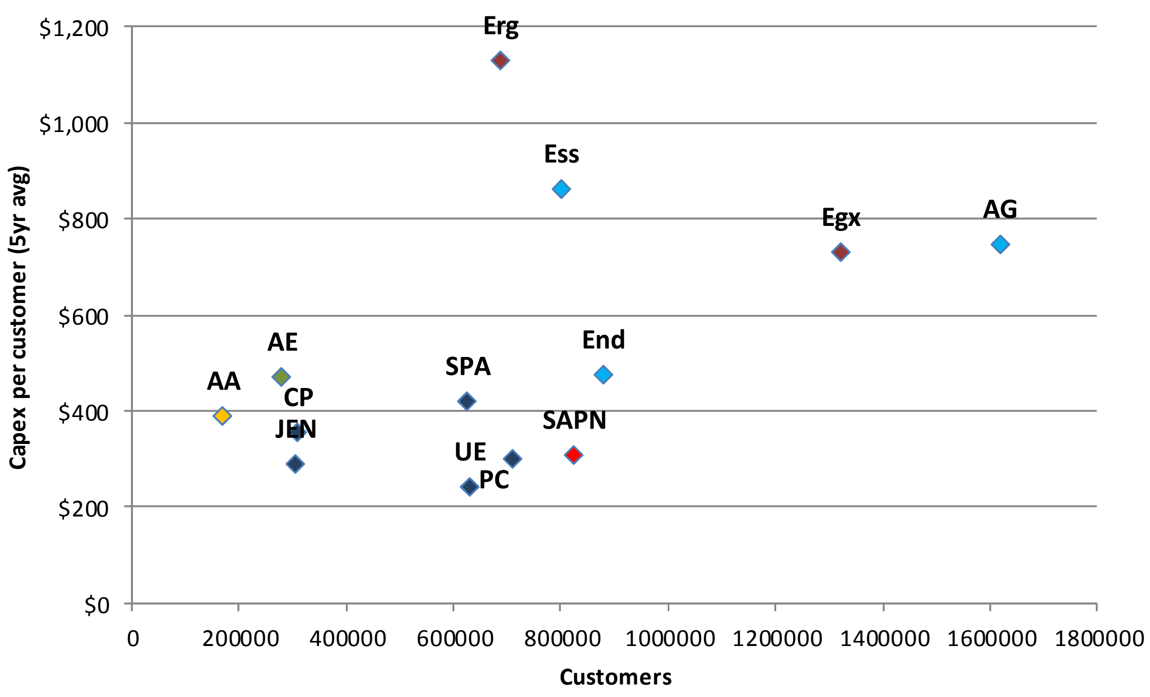
### D.2.3 Economies of scale

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.[190]

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

**Figure D.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

190 ActewAGL, *Revenue proposal*, p. 243.

- 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 this 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.

## D.3 Physical environment factors

### D.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 D-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 D-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[191] and ABS[192] [193]

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

[192] ABS, 5220.0 - Australian National Accounts: State Accounts, 2012-13

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

**Table D-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.[194]

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 to property. This is shown in Table D-6 below.

**Table D-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[195] | 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[196] and ABS[197]

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.

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193 ABS, 6401.0 - Consumer Price Index
194 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.
195 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.
196 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.
197 ABS, 3105.0.65.001 - Australian Historical Population Statistics, 2014

## D.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. [198]

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 snows 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.

## D.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. [199]

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 lead to material differences in costs.

## D.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.[200] 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.[201] 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.

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

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

200 Single Wire Earth Return (SWER)

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

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.

### D.3.5 Shape factors

Evans and Peck say that natural boundaries, such as water and national park, surrounding electricity networks impose costs on DNSPs.[202] 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.

### D.3.6 Topographical conditions

Ausgrid, Endeavour, and Essential have all raised topographic conditions as an operating environment factor that will affect the benchmarking results.[203] [204] [205]

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.[206] 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 asset 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.

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202 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.

203 Ausgrid, *Attachment 5.33* to *Revenue proposal*, p. 5.

204 Endeavour, *Attachment 0.12* to *Revenue proposal*, p. 5.

205 Essential *Attachment 5.*4 to *Revenue proposal*, p. 5.

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

## D.4 Regulatory factors

### D.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.[207]

Ausgrid's consultant Evans and Peck identified differences in building regulations as an operating environment factor that may affect benchmarking results.[208] 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.[209] 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.[210]

Evans and Peck say that building code requirements can affect comparisons across networks. They do not explain, how or which DNSPs would be affected. [211]

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

### D.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.[212] 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.[213] 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

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

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

[209] 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].

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

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

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

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

service providers will lead to differences in costs, but we do not have any evidence to suggest that these differences will be material.

### D.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.[214] 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 not existed previously.[215] 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.[216] 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.

### D.4.4 State/City development policy

Evans and Peck say that state and city development policy can affect comparisons across networks.[217] They say that in Sydney costs are higher due to council requirements.[218] 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.

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

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

216 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]

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

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

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.

### D.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. [219]

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 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.[220]

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.

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

220 National Approach to Traffic Control at Work Sites, Publication no: AP-R337/09, Austroads 2009, p1

# E 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.

## E.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and Gas Rules.[221] 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.[222]

The Expenditure Forecast Assessment Guideline (EFAG) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[223] 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.[224]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[225] 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.

## E.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)

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

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

[223] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013; AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, November 2013.

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

[225] 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 (eg. 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.[226]

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.[227]

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.[228]

## E.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.[229] 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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226 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.
227 NER, clause 6.5.7(e)(6).
228 See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at http://www.aer.gov.au/node/21843.
229 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.[230]

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.

## E.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,[231] 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.

### E.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:[232]

- benchmark unit costs

[230] NER, clause 6.9.1.
[231] NSW and ACT distribution network service providers—Ausgrid, Endeavour Energy, Essential Energy, and ActewAGL.
[232] 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.[233] 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:[234]

- 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:

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[233] We took into account whether the distributor reported on calendar or financial year basis.

[234] 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.

- Average value:
  - 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.[235]

## E.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.[236] 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.[237] 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.

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235 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.

236 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.

237 AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

(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.238 The calibration involves 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 (see Section A.3.3 for more information on this process). A full list of the scenarios modelled is provided in the next section.

### 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.

## E.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-

[238] AER, Electricity network service providers, Replacement expenditure model handbook, November 2013, pp. 20–21.

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-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.

### E.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.

### E.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.[239] 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.[240] 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.

## E.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.241 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.242 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.

239 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.

240 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.

241 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.

242 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.