Draft Decision

Ausgrid 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 Ausgrid’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 mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection methodology

Attachment 19 – Pricing methodology

Contents

Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	aggregate service revenue requirement
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium

Shortened form	Extended form
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

6 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of standard control services.[1] The return on and of forecast capex are two of the building blocks that form part of Ausgrid's total revenue requirement.[2]

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 Ausgrid's proposed total forecast capex. Further detailed analysis is in the following appendices:

Appendix A Assessment of forecast capex drivers that underlie Ausgrid's proposed total forecast capex

Appendix B Demand

Appendix C Assessment approaches

Appendix D Real cost escalation

Appendix E Operating and environmental factors

Appendix F Predictive modelling approach and scenarios

6.1 Draft decision

We are not satisfied that Ausgrid's proposed total forecast capex of $4,421 million ($2013–14) for the 2014–2019 period reasonably reflects the capex criteria. Our alternative estimate of Ausgrid's total forecast capex for the 2014–2019 period that we are satisfied reasonably reflects the capex criteria is $2,546.4 million ($2013–14).[3] Table 6-1 outlines our draft decision.

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

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Ausgrid's proposal	1011.5	984.9	856.8	814.0	753.8	4,421.0
AER draft decision	591.0	544.1	481.0	473.3	457.0	2,546.4
Difference	-420.5	-440.8	-375.8	-340.7	-296.8	-1,874.6
Percentage difference (%)	-41.6	-44.8	-43.9	-41.9	-39.4	-42.4

Source: Ausgrid Regulatory Proposal; AER analysis.

[1] These capital expenses include expenditure for standard control services provided by a DNSP by means of, or in connection with, its dual function assets. A dual function asset is any part of a network that is owned, operated or controlled by a DNSP which operates between 66kV and 220 kV and which operates in parallel and provides support to a transmission network: see NER, cl. 6.24.

[2] NER, cl. 6.4.3(a).

[3] This amount is subject to removal of Ausgrid's labour cost adjustment based on real cost escalation and replacement with labour cost adjustment based on the historical average.'

Note: Numbers may not total 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 Ausgrid's total forecast capex for the 2014–2019 period. We are not approving a particular category of capex or a particular project, but rather an overall amount. However, as part of our assessment, we necessarily review the categories of expenditure and some particular projects in order to test whether Ausgrid'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 Ausgrid'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: ▪ Ausgrid'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 Ausgrid's forecasting methodology incorporates an overly conservative risk assessment which does not adequately justify the timing and priority of its proposed forecast capex and lacks a clear delivery strategy. ▪ We have concerns with how Ausgrid has formulated and applied its key assumptions in relation to demand and customer forecasts and forecast materials escalation rates and labour escalation rates. We also have concerns about the relevance of its key assumption about its legal and organisational structure. We also observe that Ausgrid's past capex performance reveals that its capital efficiency is significantly lower than that achieved by other distribution network service providers (DNSPs). This suggests that efficient reductions in capex are achievable. This observation provides context for our analysis of specific capex drivers in Appendix A. In determining our alternative estimate we have addressed the concerns we have with Ausgrid's forecasting methodology and key assumptions. Specifically, we have undertaken a top-down assessment by applying our assessment techniques of economic benchmarking, trend analysis and an engineering review. We have also addressed the deficiencies in Ausgrid's key assumptions about demand and customer forecast and forecast materials escalation rates and labour escalation rates.
Augmentation capex (augex)	We do not accept Ausgrid's proposed augex forecast of $509 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. Ausgrid's forecast is based on out-dated demand forecasts and did not take account of the savings that could be achieved through risk based cost benefit analysis assessment techniques in the context of the revisions to its licence conditions. The Ausgrid proposed augex forecast also did not take into account the most recent changes to the value of customer reliability (VCR). We have instead included an amount of $376.4 million ($2013–14) of forecast augex in our alternative estimate that we are satisfied reasonably reflects the capex criteria. This amount is 26 per cent less than Ausgrid's proposal. To arrive at this reduction we: ▪ reduced Ausgrid's augex forecast by approximately 12 per cent to account for updated spatial demand forecasts ▪ applied a further 15 per cent reduction to account for the absence of Ausgrid applying a

Issue	Reasons and findings
	risk-based cost benefit analysis techniques. 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 Ausgrid will assess and incorporate the changes to the VCR in its total forecast capex as part of submitting its revised regulatory proposal.
Customer connections capex	We are satisfied Ausgrid's proposed connections forecast of $171.1 million ($2013-14 4), excluding overheads, is consistent with the capex objectives. Hence, we will make an allowance for this in determining the total capex forecast for the 2014–2019 period. We consider the trend of Ausgrid'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 Ausgrid to achieve the capex objectives. We also accept Ausgrid's proposed capital contributions forecast of $522.29 million, as we consider it is consistent with Ausgrid's forecast level of connection works which we are also accepting. We consider that capital contributions are mostly driven by connection and augmentation works. We expect Ausgrid to explain how capital contributions should be allocated to each service in its revised regulatory proposal.
Asset replacement capex (repex)	We have not accepted Ausgrid's proposed forecast repex of $3,226 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: ▪ Ausgrid's proposal is around 40 per cent higher than Ausgrid's historical trend and compares unfavourably on a number of category level benchmarks which we have taken into account. ▪ Our consultant, EMCa has found a number of issues with Ausgrid's proposal which we accept. These issues include Ausgrid using overly conservative risk criteria and multiple contingency allowances that systematically overstate its costs, not adequately justifying the timing of its proposal at the project/program level, relying on network age and condition information that is at times inconsistent and contradictory. ▪ The network health indicators concerning the condition of Ausgrid's assets do not support a significant increase in repex relative to the longer term trend of actual repex that Ausgrid has spent in past regulatory control periods. ▪ Ausgrid faced significant capex deliverability challenges during the 2009–2014 regulatory control period. We have found no evidence to suggest that Ausgrid is better equipped to deal with or will not face these same challenges during the 2014–2019 period. We have instead included an amount of $1,769 million ($2013–14) in our alternative estimate for the 2014–2019 period. This amount will allow Ausgrid to achieve the capex objectives. In particular, this amount: ▪ Taking into account Ausgrid's past repex practices, is at the upper end of the range of reasonable forecast repex amounts (excluding overheads) between $1600 million ($2013–14) and $1,796 million ($2013–14) resulting from our predictive modelling. ▪ Is consistent with our view of Ausgrid's long-term repex requirements as evidenced by its past expenditure and will provide Ausgrid with a reasonable opportunity to recover at least its efficient costs.
Reliability improvement capex	We have not accepted Ausgrid's proposed forecast capex of $28.3 million ($2013–14) for its network reliability performance obligations in relation to individual feeder performance. This amount was determined by applying a top down assessment using historical individual feeder

Issue	Reasons and findings
	performance to estimate future individual feeder performance to determine this amount. While we consider this approach is sound, Ausgrid has not identified what part of this amount is augex or repex related. This information is necessary to ensure that the forecast network reliability capex that Ausgrid requires to achieve the capex objectives is not overstated, or otherwise already provided for by the forecast augex and repex amounts that we have included in our alternative estimate. It is also not clear to us the extent to which Ausgrid's proposal is related to its proposed improvement in SAIDI during the 2014–2019 period. To this end it also remains unclear whether this expenditure should form part of Ausgrid's total forecast capex, given any improvements that are valued by customers should be funded through the STPIS. We expect Ausgrid to provide further information in its revised regulatory proposal to identify what part of its proposed $28.3 million is augex or repex related. We also expect Ausgrid to provide further information in support of its proposed expenditure that is not related to its Schedule 3 licence obligations.
Non-network capex	We have not accepted Ausgrid's proposed forecast capex of $307.6 million ($2013–14) for non-network capex. On the basis of the information before us, this amount is overstated and exceeds the amount required to achieve the capex objectives. We have instead included an amount of $279.2 million ($2013-14) of forecast non-network capex in our alternative estimate that we are satisfied reasonably reflects the capex criteria. This amount will allow Ausgrid to achieve the capex objectives. This amount reflects a reduction of 20 per cent to Ausgrid's proposed buildings and property capex program in the 2014–2019 period. In our view, this reduction accounts for the identified delay in the schedule of major projects and the likelihood of future deferrals and refinements in project scope and cost for the building and property program. This is based on our assessment that Ausgrid's forecast buildings and property capex is front-loaded and overstated due to the likelihood of future changes in project timing, scope and cost.
Capitalised overheads	We have not accepted Ausgrid's proposed forecast capex of $729.2 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 20 per cent average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period. We have instead included an amount of $477.3 ($2013-14) million in our alternative estimate. This amount is consistent with the other amounts of capex that we have included in our alternative estimate and the amount of actual capitalised overheads that Ausgrid spent in the 2009–2014 regulatory control period.
Real cost escalation	We have not accepted Ausgrid's proposed real escalation of commodity prices. We also have not accepted Ausgrid's proposed real escalation of labour prices. Our reasons for this are: ▪ The degree of the potential inaccuracy of commodities forecasts due to: ▪ recent studies which show that forecasts for example of crude oil spot prices based on futures prices do not provide a significant improvement compared to a 'no-change' forecast for most forecast horizons, and sometimes perform worse ▪ evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than 'no change' forecasts; and ▪ the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $USD to $AUD). A review of the economic literature of exchange rate forecast models suggests a "no change" forecasting approach may

Issue	Reasons and findings
	be preferable to the forward exchange rate produced by these forecasting models. ▪ The limited evidence available to us neither supports or confirms how accurately Ausgrid's commodities escalation forecasts are likely to reasonably reflect changes in prices paid by Ausgrid for physical assets in the past. Therefore, it is not open to us to conclude that Ausgrid's forecasts are reliable and accurate. ▪ Ausgrid has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that may affect the commodities forecast. Our alternative estimate instead incorporates a real cost escalation of zero per cent which, on the basis of the information before us, we consider is likely to provide a more reliable estimation for the price of cost inputs used by Ausgrid to provide network services. We have also not accepted Ausgrid'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 Augrid'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 Ausgrid to provide this information in its revised regulatory proposal
Adjustments and unaccounted for capex	Ausgrid proposed total gross capex of $4,943 million ($2013-14) for the 2014-19 period. This forecast included an amount of capex referred to in the RIN as a 'negative balancing item'. We have allocated this balancing item to augex, connections and repex by the proportion of each driver to total capex. In addition, we have allocated the difference between non-network capex proposed in the RIN ($575 million) and non-network capex in the PTRM/supporting material of ($307 million) across each capex driver. Overall these adjustments have resulted in an increased amount for the proposed capex drivers as set out below: ▪ Augex proposed $489 million (amended to $508 million) ▪ Connections capex ($165 million) (amended to $171 million) ▪ Repex proposed $3,106 million (amended to $3,226). We expect Ausgrid to clarify the proposed amount of non-network capex in its revised regulatory proposal and our approach of allocating the balancing item across the capex drivers.

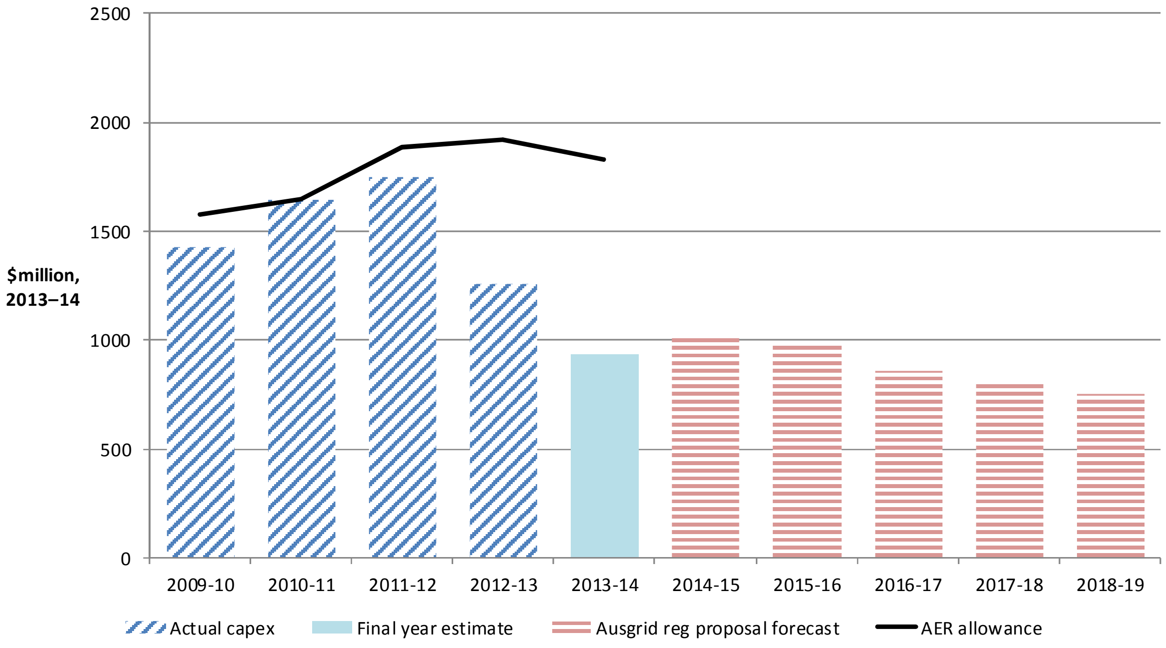
Source: AER analysis.

6.2 Ausgrid's proposal

Ausgrid proposed total forecast capex of $4,421 million ($2013–14) for the 2014–2019 period.

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

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



Source: Ausgrid, Regulatory Proposal; 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 Ausgrid'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 Ausgrid'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 '[t]hese 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

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4 NER, cl. 6.5.7(c).
5 NER, cl. 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, cl. 6.5.7(a).

- 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 Ausgrid'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 DNSP over the relevant regulatory control period
- the actual and expected capex of the DNSP during the preceding regulatory control periods
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers
- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure
- whether the capex forecast is consistent with any incentive scheme or schemes that apply to the DNSP
- the extent to which the capex forecast is referable to arrangements with a person other than the DNSP that, in the opinion of the AER, do not reflect arm's length terms
- whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project
- 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.

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8 AEMC, *Economic Regulation Final Rule Determination*, p. vii.
9 NER, cl. 6.5.7(e).
10 NER, cl. 6.5.7(e)(12).
11 AEMC, *Economic Regulation Final Rule Determination*, p. 115.

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 our 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 Ausgrid, 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:[15]

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

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

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:

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12 NEL, ss. 7A and 16(2).

13 NER, cl. 6.5.7(e)(4).

14 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p. 97.

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.

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

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

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.[17]

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

[17] AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 12.

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.[18]

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

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

Comparing the service provider's proposal with our alternative estimate

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

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[20]

> 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 alternative estimate of total forecast capex, it is important to recognise that the service provider is not precluded from undertaking unexpected capex works, if the need arises, and despite the fact that such works did not form part 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.

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[18] AER, *Expenditure Forecast Electricity Distribution Guideline*, pp. 8 and 9.
[19] AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 9.
[20] AEMC, *Economic Regulation Final Rule Determination*, p. 112.

6.4 Reasons for draft decision

We are not satisfied that Ausgrid's proposed total forecast capex reasonably reflects the capex criteria. We compared Ausgrid's proposal to our alternative estimate that we constructed using the approach and techniques outlined above. Ausgrid's proposal is materially higher than ours. For that reason and the reasons outlined below and in appendix A 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 Ausgrid'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
Augex	94.75	70.07	65.05	68.18	78.41	376.40
Connections	29.50	32.81	36.99	36.59	35.19	171.1
Repex	392.56	395.52	348.26	327.19	305.32	1768.85
Reliability	0.00	0.00	0.00	0.00	0.00	0.00
Non-network	55.6	49.8	57.0	60.1	56.7	279.2
Capitalised overheads	105.84	100.87	93.17	90.21	87.23	477.32
Materials escalation adjustment	-1.60	-1.08	- 1.07	-2.11	-1.62	--4.28
Gross capex	**679.82**	**647.98**	**599.38**	**580.17**	**561.27**	**3,068.62**
Customer contributions	**88.80**	**103.90**	**118.37**	**106.91**	**104.32**	**522.30**
Net capex	**591.02**	**544.08**	**481.01**	**473.26**	**456.96**	**2546.33**

Source: AER analysis.
Note: Ausgrid reported $145.74 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. In addition, we have allocated the difference between non-network capex proposed in the RIN ($575 million and non-network capex in the PTRM and supporting material of $307 million) across each capex driver.
Numbers may not add up due to rounding.

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

6.4.1 Forecasting methodology

Ausgrid is required to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[21] It is also required to include this information in its regulatory proposal.[22]

The main points of Ausgrid's forecasting methodology are:[23]

- There are eight capital plans. Four of these capital plans relate to network assets: area plans (major projects), replacement and duty of care plans, distribution capacity plans (including reinforcements and customer contributions requiring augmentation) and the reliability investment plan. The remaining four plans relate to non-network assets plans: technology, corporate property plan, fleet plan and other support plan.
- Each capital plan is based on meeting one or more its capex drivers (asset condition and safety, increased delivery capacity including new customer connections, reliability investment to comply with reliability performance targets in the NSW licence condition, supporting non-network assets).
- Ausgrid has used a bottom up build to derive its forecast capex for all of its capital plans except for its distribution capacity plan and reliability investment plan, in which it has used a top-down assessment.
- The key inputs into determining its forecast capex for each capital plan include demand forecasts, customer connection growth, cost escalation and costing of the works, which is primarily based on historical costs.
- Ausgrid has implemented a 'prioritisation process' that was centrally coordinated across all the NSW DNSPs, which identifies opportunities to defer or avoid capex on the basis of a risk assessment.
- Ausgrid has applied its approved cost allocation method so that all forecast capex is allocated to standard control services.

We have identified three aspects of Ausgrid'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, Ausgrid'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 involve applying a top-down assessment. In our view, applying a top-down assessment is a critical part of the process in deriving a forecast capex allowance. It indicates that some level of overall restraint that has been brought to bear. This is an important factor for us to consider in deciding whether we are satisfied that a proposed forecast capex allowance reasonably reflects the capex criteria. In particular, to derive an estimate of capex by solely applying a bottom-up assessment does not itself provide any evidence that the estimate is efficient. Bottom-up assessments have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level. Whereas reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency. Whilst in certain very limited

21 NER, cll. 6.8.1A and 11.56.4(o); Ausgrid, Expenditure Forecasting Methods, November 2013.
22 NER, cl. S6.1.1(2); Ausgrid, *Regulatory Proposal*, pp. 39–41
23 Ausgrid, *Expenditure Forecasting Methods*, November 2013, pp. 8–11; Ausgrid, *Regulatory Proposal*, pp. 39–41.

circumstances, a bottom up build may be a reasonable approach to justifying expenditure, this is not the case when looking at aggregated areas of expenditure or at the portfolio level. However, simply aggregating estimates is unlikely to result in a total forecast capex allowance that we are satisfied reasonably reflects the capex criteria. Our review reflects the submission made by the National Generators Forum:[24]

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

As we stated in our Forecast Expenditure Guidelines, we intend to assess forecast capex proposals through a combination of top down and bottom up modelling.[25] Our top-down assessment of Ausgrid'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 transmission 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.

Ausgrid's forecast methodology does not demonstrate any of these points.

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 forecast capex reasonably reflects the capex criteria.

Secondly, Ausgrid'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 Ausgrid not fully justifying the timing and priority of its proposed forecast capex. Ultimately, this overly conservative approach to risk means that Ausgrid is forecasting more capex in the 2014–2019 period that is necessary to achieve the capex objectives. In particular, Ausgrid 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 Ausgrid's proposed repex.[26]

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24 National Generators Forum, S*ubmission to the Revenue Determinations (2014–2019) of the NSW Distribution Network Service Providers*, p. 9.

25 AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 17.

26 EMCa, pp. ii, 12–16; TransGrid, pp. 5 and 8–24.

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

Ausgrid significantly underspent its forecast capex allowance by around 21 per cent in the 2009–2014 regulatory control period. Ausgrid submitted that the key reasons for the underspend include having more detailed information than was the case in 2007–08, a review of deferrals in light of the adverse impacts of large price increases, actual unit costs being higher than forecast and challenges and resource constraints in delivering a large capex program.[27] It is the last reason here concerns us.

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

The concerns that we outline below were material to forming the view that we are not satisfied that Ausgrid’s forecast capex reasonably reflects the capex criteria.

6.4.2 Key assumptions

The NER require Ausgrid 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.[28]

Ausgrid's key assumptions are:[29]

- 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
- its customer engagement in accordance with the stakeholder engagement process outlined in the NER
- the transitional services agreement between it and EnergyAustralia.

We have addressed these key assumptions in appendix A (the impact of the amendments to the reliability and planning conditions), Appendix B (demand) and Appendix D (forecast labour escalation rates).

In addition, we have some specific concerns about Ausgrid's key assumption about its legal and organisational structure and the pending expiry of its transitional services arrangement with EnergyAustralia. Ausgrid submitted that its “current ownership and legal structure [does] not

27 Ausgrid, *Regulatory Proposal*, pp. 33–34.
28 NER, cll. S6.1.1(2), (4) and (5).
29 Ausgrid, *Regulatory Proposal*, p. 41, Attachments 5.13 and 5.14.

incorporate any impacts associated with a potential change of ownership … [and] this is a reasonable assumption given that there has been no formal announcement by the current owner that a sale of the company will proceed in the 2014–2019 period".[30] 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 Ausgrid's capex performance

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

Together, these metrics suggest that Ausgrid's capex efficiency, compared to other DNSPs, is one of the lowest in the NEM. These strongly suggest that there is the potential for efficiencies to be found in Ausgrid's proposed forecast capex for the 2014–2019 period. In particular, these metrics suggest that capex reductions of up to 39 per cent for Ausgrid to bring it in line with the Victorian and South Australian DNSPs.

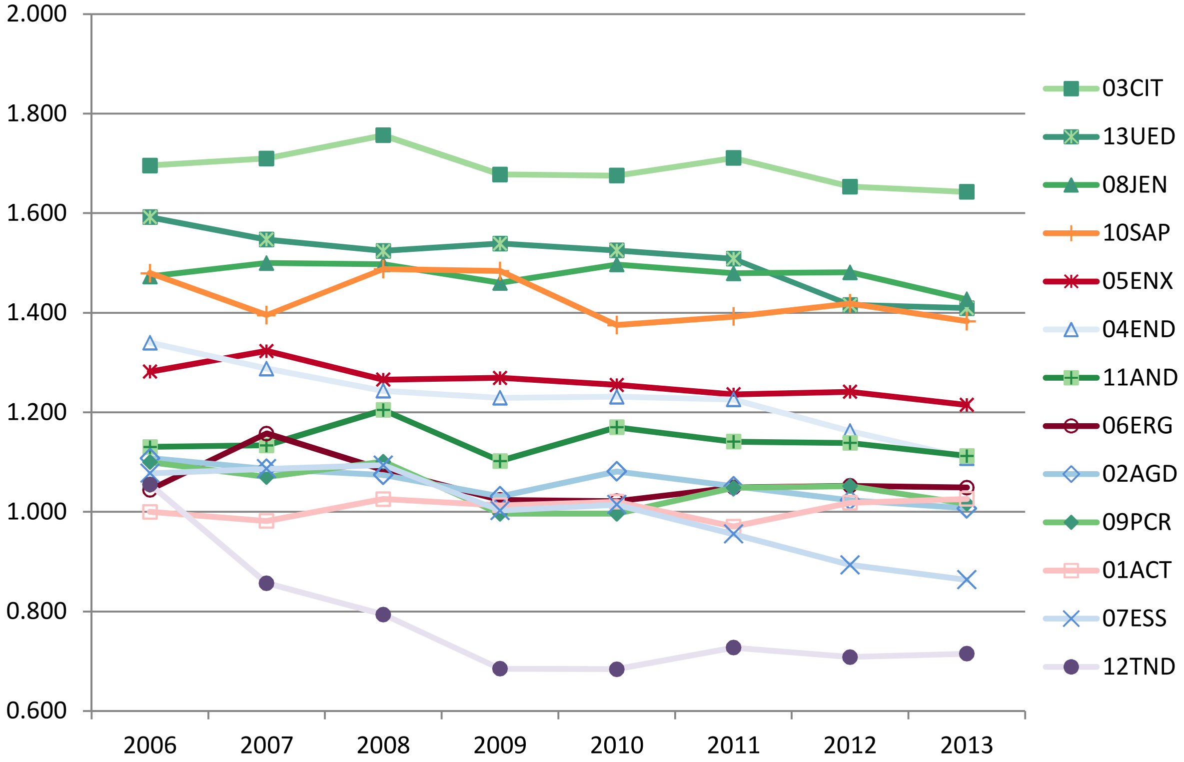
While these results are not a direct input into our alternative estimate of Ausgrid's capex forecast, they inform us of Ausgrid's relative capital efficiency and whether efficient reductions to its capex forecast is achievable. We consider that it is reasonable to benchmark Ausgrid's capex efficiency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

Partial factor productivity of capital and multilateral total factor productivity

Figure 6-2 shows a measure of partial factor productivity of capital taken from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. Ausgrid had the third lowest level of partial factor productivity of capital of the DNSPs in the NEM, and substantially lower than a number of the Victorian and South Australian DNSPs.

[30] Ausgrid, *Regulatory Proposal*, Attachment 5.13, p 3.

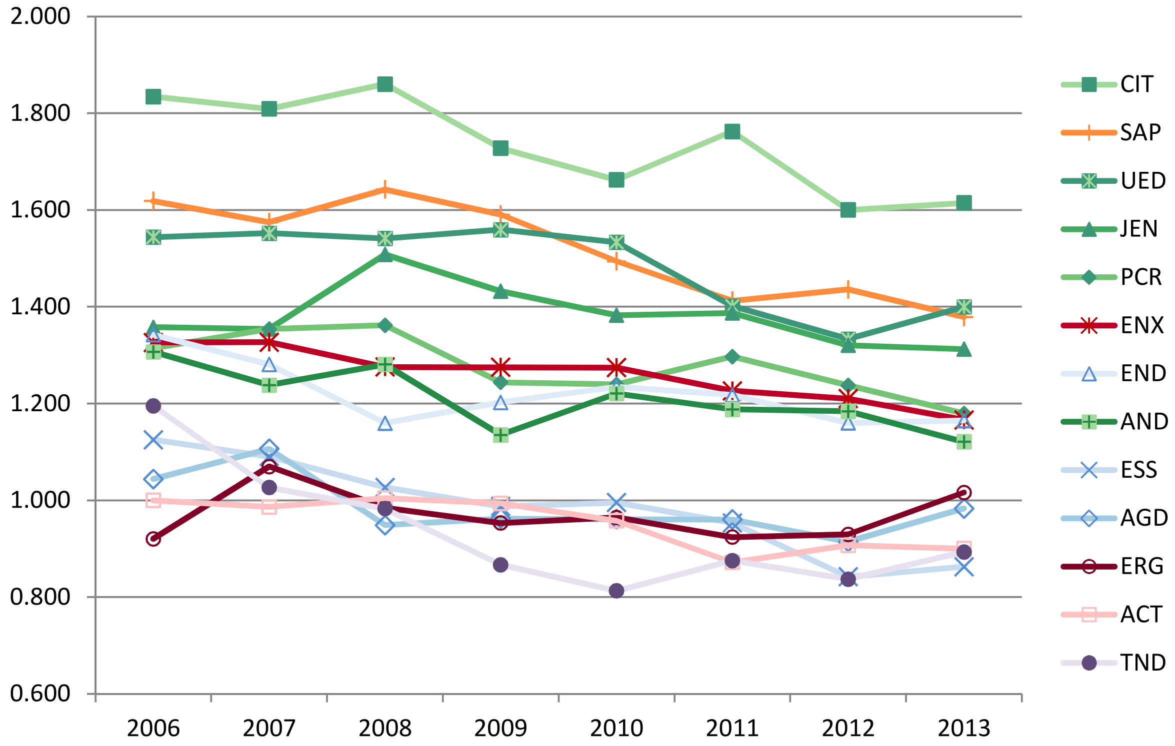
Figure 6-2 **Partial factor productivity of capital (transformers, overhead and underground lines)**



Source: AER annual benchmarking report.

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

Figure 6-3 Multilateral total factor productivity



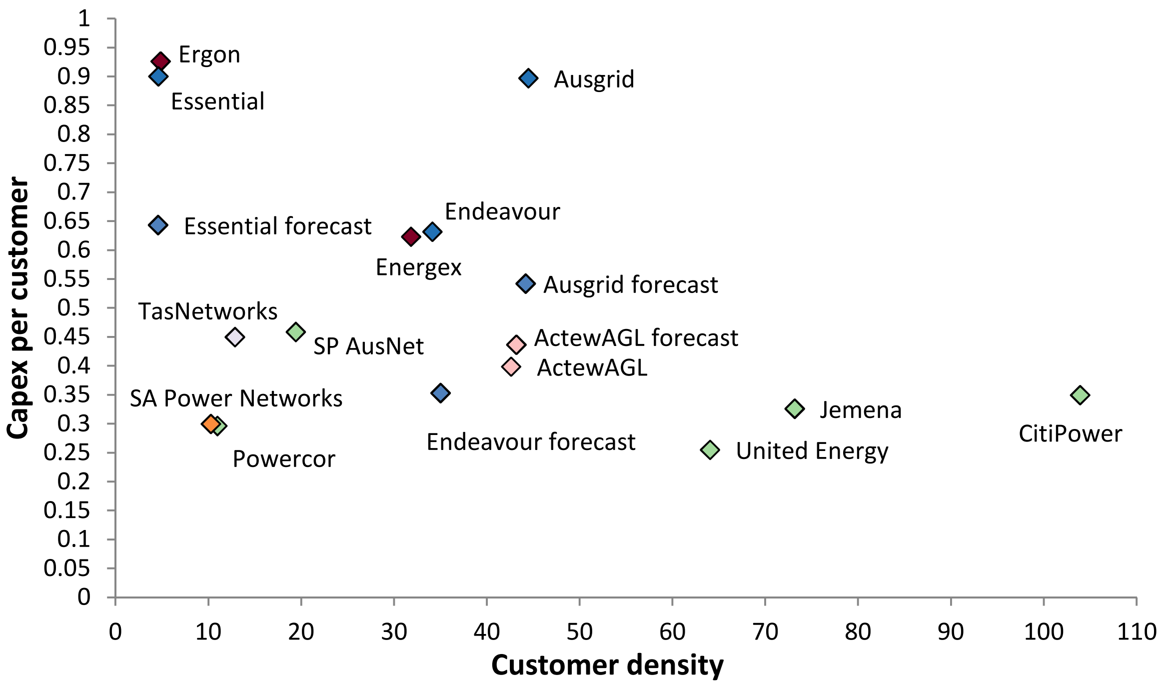
Source: AER annual benchmarking report.

Relative capex efficiency metrics

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

Figure 6-4 shows that Ausgrid had one of the highest levels of capex per customer in the NEM for the 2008-2012 period. Ausgrid's capex per customer will reduce for the 2014–2019 period based on their proposed forecast capex. However, Ausgrid's capex per customer is still high when compared with the Victorian and South Australian DNSPs. Ausgrid's proposed forecast capex for the 2014–2019 period would have to reduce by approximately 39 per cent in order for its capex per customer to be comparable to that the average $3,300 per customer achieved by the Victorian and South Australian DNSPs in 2008–2012.

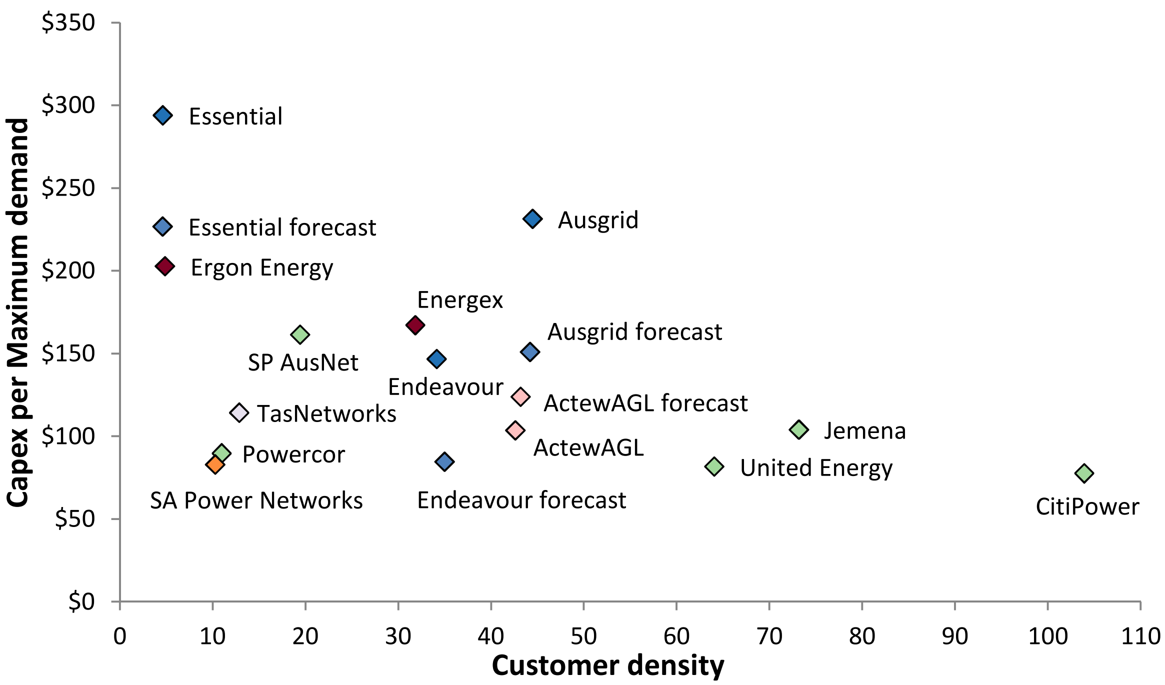
Figure 6-4 Capex per customer (000s, $2013-14), against customer density



Source: AER analysis.

Figure 6-5 shows that Ausgrid had the second highest level of capex per maximum demand for the 2008–2012 period. Capex per maximum demand is forecast to reduce for Ausgrid in the next period but is still among the highest levels in the NEM. Ausgrid's proposed forecast capex for the 2014–2019 period would have to reduce by approximately 34 per cent in order for its capex per maximum demand to be comparable to the average of $99,500 per maximum demand achieved by the Victorian and South Australian DNSPs in 2008–2012.

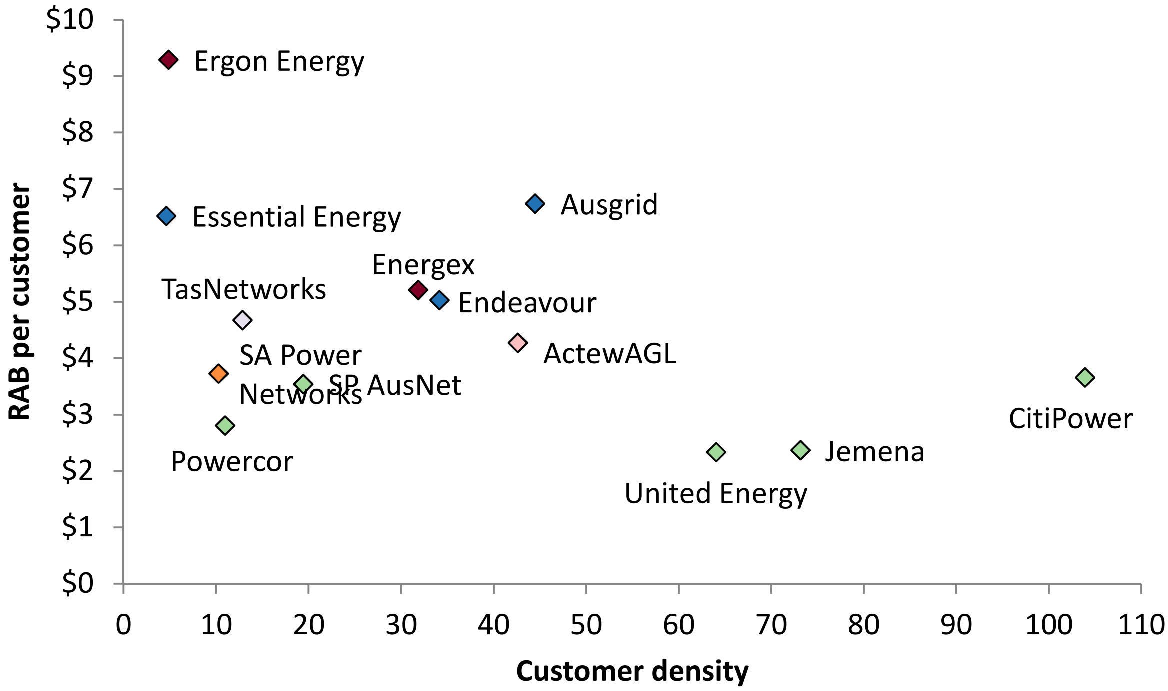
Figure 6-5 Capex per maximum demand (000s, $2013–14), against customer density



Source: AER analysis

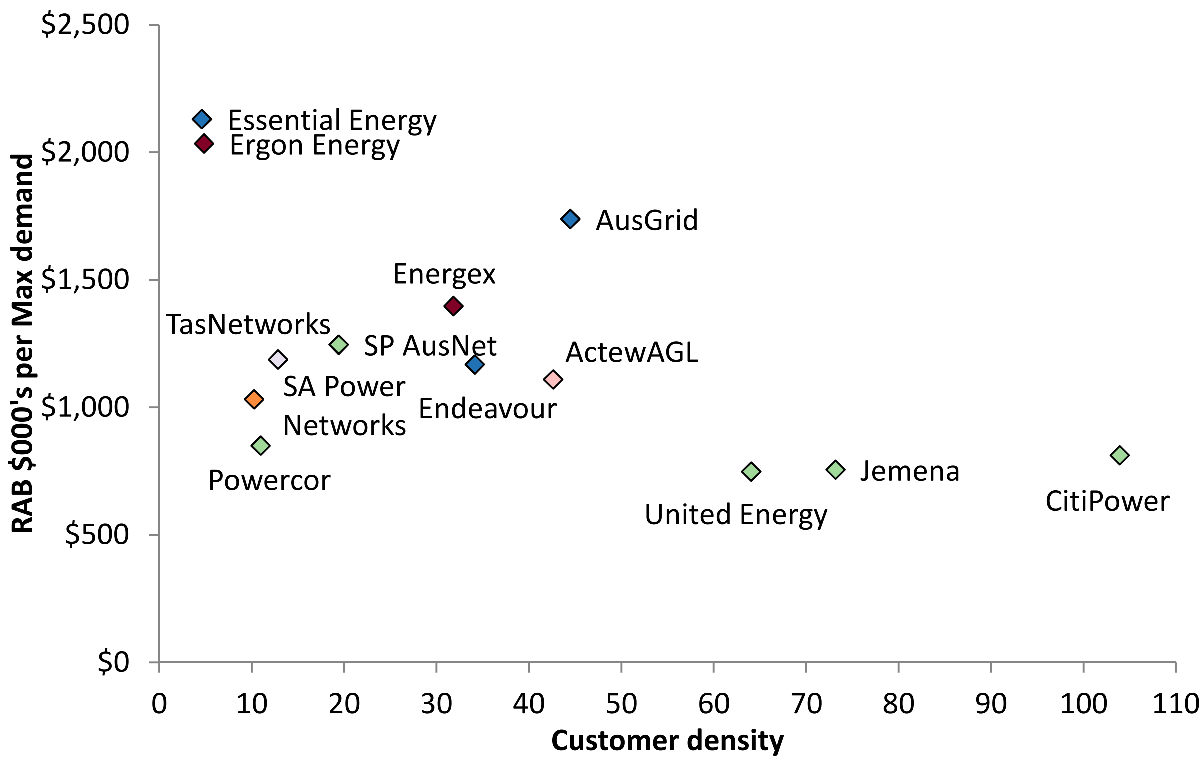
Figure 6-7 shows that the comparative ranking for the DNSPs is similar when the RAB is used instead of capex. Specifically, as at 2013, Ausgrid had one of the highest levels of RAB per customer and RAB per maximum demand in the NEM.

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



Source: AER analysis

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



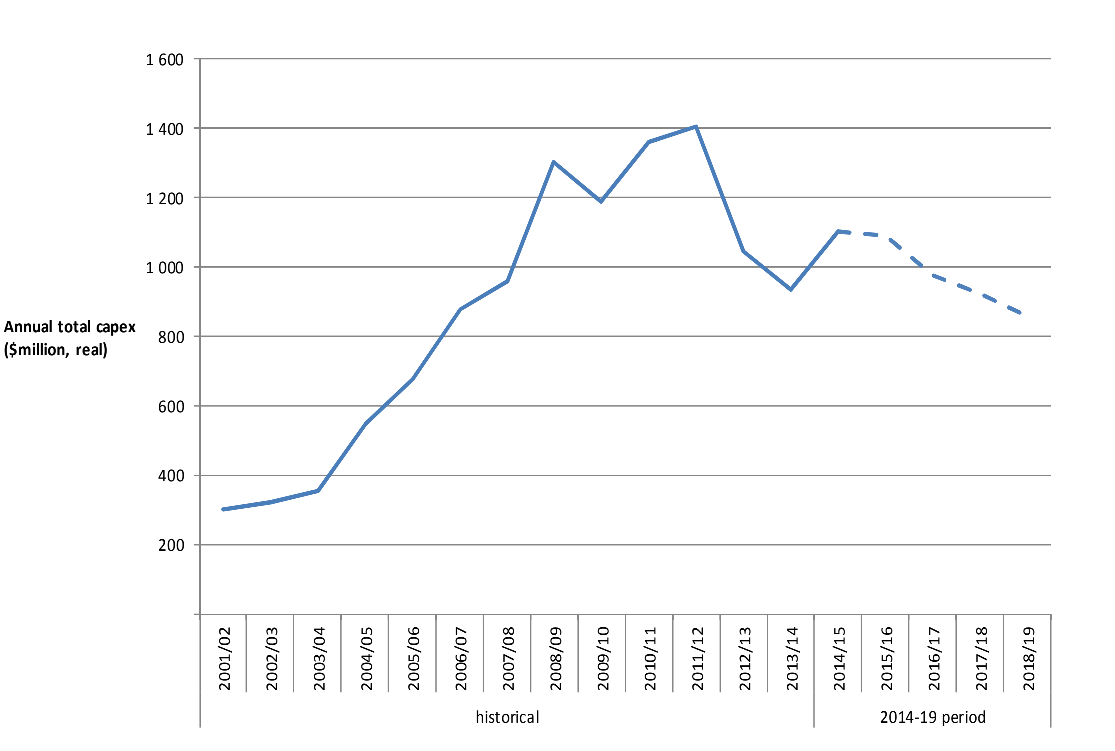
Source: AER analysis.

Ausgrid historic trend and licence conditions

We have also considered how Ausgrid'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 control period is likely to overstate capex levels. This means that it may be appropriate for us to compare Ausgrid's capex proposal for the 2014–2019 period against the long term historical trend in capex levels.

Figure6.8 shows actual historic capex and proposed capex between 2001–12 and 2018–19. This figure shows that Ausgrid's proposed capex for the 2014–2019 period is relatively high when compared with the historical average.

Figure6.8 Ausgrid total capex (including overheads)—historical and forecast for 2014–2019 period



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

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

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

These changes increased the capex requirements of the NSW DNSPs. As the 2004–2009 regulatory determination had already been made, the NSW DNSPs applied to the NSW Independent Pricing and Regulatory Tribunal (IPART) to have these costs passed through to customers. IPART approved a pass through of $624.2 million for Ausgrid (then Energy Australia).[31]

These cost pass throughs explain a significant proportion of the capex increases from 2005/06 to 2008-09, even before the even greater capex increases for the 2009–2014 regulatory control period were proposed. The licence conditions were subsequently amended in December 2007 to delay implementation of some of the requirements (though the DNSPs had already received their pass throughs).[32]

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

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

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.

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.[33]

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.[34]

Even without the change in standards, it could be expected that NSW DNSPs' capex would come down for the 2014–2019 regulatory control period given the significant capex invested from 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.[35]

Relevantly, the recent rule change to the expenditure objectives in the NER means that Ausgrid 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.[36] 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.[37]

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 Ausgrid for the 2014–2019 regulatory control period. However, it has not reduced to the levels that existed prior to the licence conditions being introduced. Given the recent changes in licence conditions, we consider the period prior to 2005 should be the benchmark for assessing the level of capex for the 2009–2014 regulatory control period.

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

34 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.

35 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.

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

37 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 Ausgrid'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 the total forecast capex.

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

Other component	Interrelationships
Total forecast opex	There are elements of Ausgrid's total forecast opex that are related to its total forecast capex. These are: ▪ the labour cost escalators that we approved in (refer to opex rate of change appendix) ▪ the amount of maintenance opex that is reflected in Ausgrid's opex base year that we approved in (refer to Attachment 7) The labour cost escalators are interrelated because Ausgrid'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 Ausgrid's total forecast opex, it is interrelated. This is because the amount of maintenance opex that is reflected in Ausgrid's opex base in part determines the extent to which Ausgrid 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 Ausgrid's total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
CESS	The CESS is related to Ausgrid'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 transmission 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 Ausgrid's regulatory asset base. In particular, the CESS will ensure that Ausgrid bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Ausgrid 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, Ausgrid risks having to bear the entire overspend.
STPIS	The STPIS is related to Ausgrid'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 related to Ausgrid'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 Ausgrid's total forecast capex for the 2014–2019 period. We have identified one contingent project for Ausgrid during the 2014–2019 period.

Source: AER analysis.

6.4.5 Consideration of the capex factors

In deciding whether or not we are satisfied Ausgrid's forecast reasonably reflects the capex criteria, we have had regard to the following capex factors when applying our assessment techniques to the total proposed capex forecast, and where relevant, to different sub-categories of proposed expenditure. 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 Ausgrid'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 Ausgrid's capex performance.
The actual and expected capex of the Ausgrid during any preceding regulatory control periods	We have had regard to Ausgrid'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 Ausgrid's capex performance. It can also be seen in our assessment of the forecast capex associated with each of the capex drivers that underlie Ausgrid'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 Ausgrid in the course of its engagement with electricity consumers	We have had regard to the extent to which Ausgrid's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Ausgrid. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Ausgrid'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 Ausgrid's proposed real cost escalation factors for materials. We discuss this in Appendix D.
The substitution possibilities between operating and capital expenditure	We have had regard to the substitution possibilities between opex and capex. We have considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between Ausgrid'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 Ausgrid	We have had regard to whether Ausgrid's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Ausgrid'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 Ausgrid's proposed total forecast capex or our alternative estimate that is referable to arrangements with a person other than Ausgrid that do not reflect arm's length terms. We did not identify any parts of Ausgrid'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	We have had regard to whether any amount of Ausgrid's proposed total forecast capex or our alternative estimate that relates to a

Capex factor	AER consideration
included as a contingent project	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 Ausgrid has considered and made provision for efficient and prudent non-network alternatives	We have had regard to the extent to which Ausgrid 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 Ausgrid for us to have regard to.
Any other factor the AER considers relevant and which the AER has notified Ausgrid in writing, prior to the submission of its revised regulatory proposal under 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

We present our detailed analysis of the sub-categories of Ausgrid's forecast capex for the 2014–2019 period in this Appendix. These sub-categories reflect the drivers of forecast capex over the 2014–2019 period. These drivers are augmentation capex (augex), customer connections capex, replacement capex (repex), reliability improvement capex, capitalised overheads and non-network capex.

As we discuss in the capex attachment, we are not satisfied that Ausgrid's proposed total forecast capex reasonably reflects the capex criteria. In this appendix we set out further analysis in support of this view. This further analysis also explains the basis for our alternative estimate of Ausgrid's total forecast capex that we are satisfied reasonably reflects the capex criteria. In coming to our views and our alternative estimate we have applied the assessment approach that we discuss in appendix C.

This appendix sets out our findings and views on each sub-category of capex. The structure of this appendix is:

- Section A.1: forecast augex
- Section A.2: forecast customer connections capex, including capital contributions
- Section A.3: forecast repex
- Section A.4: forecast reliability improvement capex
- Section A.5: forecast capitalised overheads
- Section A.6: non-network capex
- Section A.7: demand management.

In each section we present our views on the amount of capex for each sub-category that is included in our alternative estimate of Ausgrid's total forecast capex that we are satisfied reasonably reflects the capex criteria (alternative estimate).

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.

A.1.1 Position

Ausgrid proposed a forecast of $509 million for augex.[38] This is a 76 per cent decrease compared to actual augex incurred in the 2009–2014 regulatory control period. We do not accept Ausgrid's proposal. We have instead included an amount of $376.4 million ($2013–14) for forecast augex in our alternative estimate, a reduction of 26 per cent.

[38] In its reset RIN, Ausgrid's augex forecast for the 2014–2014 period amounted to $489.5 million. We derived the $509 million after allocation of the balancing item and other expenditures (see capex attachment).

This amount is sufficient to provide Ausgrid 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 to assess how Ausgrid's augex has changed over time and across businesses, taking into consideration changes in demand, network capacity and design and planning standards. This will inform us as to whether the forecast is within a reasonable range to allow Ausgrid to meet expected demand, and comply with relevant regulatory obligations.[39]
- an engineering review of Ausgrid's forecasting processes and methodology. This will directly inform our assessment of whether Ausgrid's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives.
- the augex model to generate trends in Ausgrid's asset utilisation, which will provide us with insights into the 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 Ausgrid's proposal and including $376.4 million ($2013–14) for forecast augex in our alternative estimate instead are as follows.

First, the trend in augex shows that Ausgrid has proposed significant reductions to their augex in comparison to the augex it spent during the 2009–2014 regulatory control period. This reduction is generally consistent with the fall in demand over 2009–2014 and the excess capacity observed in Ausrid's network. Nonetheless, Ausgrid 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, 40 per cent of Ausgrid's augex forecast was based on a cost estimation model for their 11kV network requirements that used a demand forecast from 2013. Ausgrid has provided a draft of their 2014 forecasts that show a reduction in ratcheted demand of 31.5 per cent compared to the 2013 forecasts. We have used Ausgrid's draft 2014 spatial demand forecasts to reduce the expenditure required for its 11kV network by 31.5 per cent. This follows from analysis by WorleyParsons which concluded a positive linear relationship exists between a change in forecast demand and expenditure requirements for the 11kV network.

Third, based on independent advice from WorleyParsons, it is evident that Ausgrid's augex forecast is biased because it has not sufficiently taken into account the impact of the changes to the NSW licence conditions design standards that took effect on 1 July 2014. WorleyParsons concluded that Ausgrid could achieve efficiency gains by applying a risk-based cost benefit analysis assessment techniques to new and ongoing programs of work. In light of this advice, and the observed trend in augex, we have applied a further 15 per cent reduction to account for the absence of Ausgrid applying

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

[40] Asset utilisation results from the augex model are presented at Figure A-2 and Figure A-3. The augex model has been developed to derive an estimate of required augex based on predicted augmentation requirements This is in turn based on forecast demand, 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.

a risk-based cost benefit analysis technique. In our view, this reduction will not put at risk Ausgrid's ability to recover at least its efficient costs.

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 Ausgrid'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.

We recognise that Ausgrid'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 Ausgrid's forecast and so our estimate for the purpose of this draft decision does not reflect the change in VCR. However, we expect that Ausgrid 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 a 26 per cent reduction to Ausgrid's augex forecast.

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

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Ausgrid augex forecast	**126.14**	**92.93**	**88.87**	**95.08**	**105.94**	**508.96**
Demand adjustment to 11kV augex	-13.89	-9.88	-11.5	-13.84	-12.87	-61.98
Licence change adjustment (15%)[41]	-17.5	-12.98	-12.32	-13.06	-14.66	-70.52
Revised augex forecast	**94.75**	**70.07**	**65.05**	**68.18**	**78.41**	**376.4**

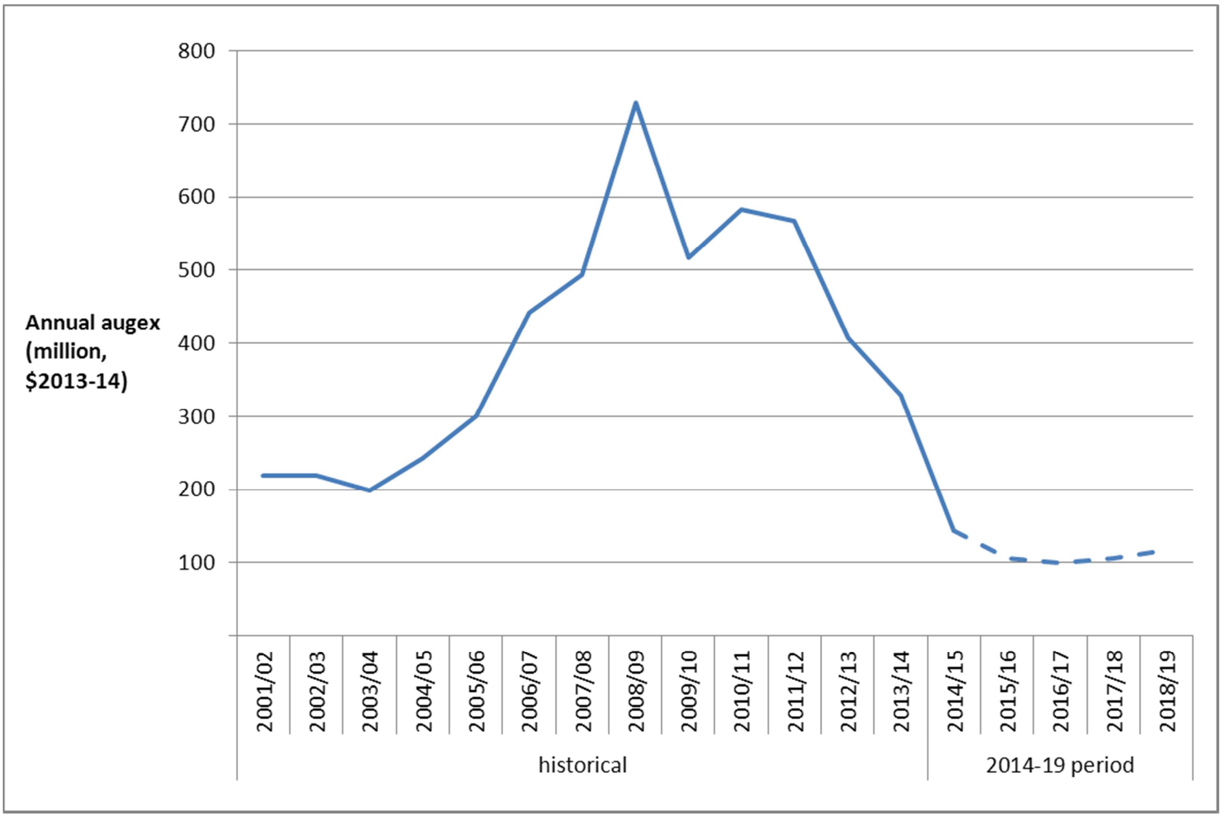
Source: AER analysis; Ausgrid RIN; WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014.

Trend Analysis

Figure A-1 shows the trend in augex between 1999 and 2019. Ausgrid proposes lower levels of augex than it spent in the 1999–2004 regulatory control period.

[41] We applied the 15 per cent licence change adjustment net of the balancing item adjustment.

Figure A-1 Trend in Augex ($2013–14)



Source: Ausgrid RIN, Ausgrid proposal, AER analysis.
Note: All figures up to 2013–14 denote actual expenditure. Figures from 2014–15 to 2018–19 are Ausgrid's forecasts. These figures included an allocation of capitalised network and corporate overheads on the basis of augex as proportion of total capex. These figures do not include an allocation of the balancing item.

We would expect Ausgrid to require low levels of augex for the 2014-19 regulatory control period given the combination of:

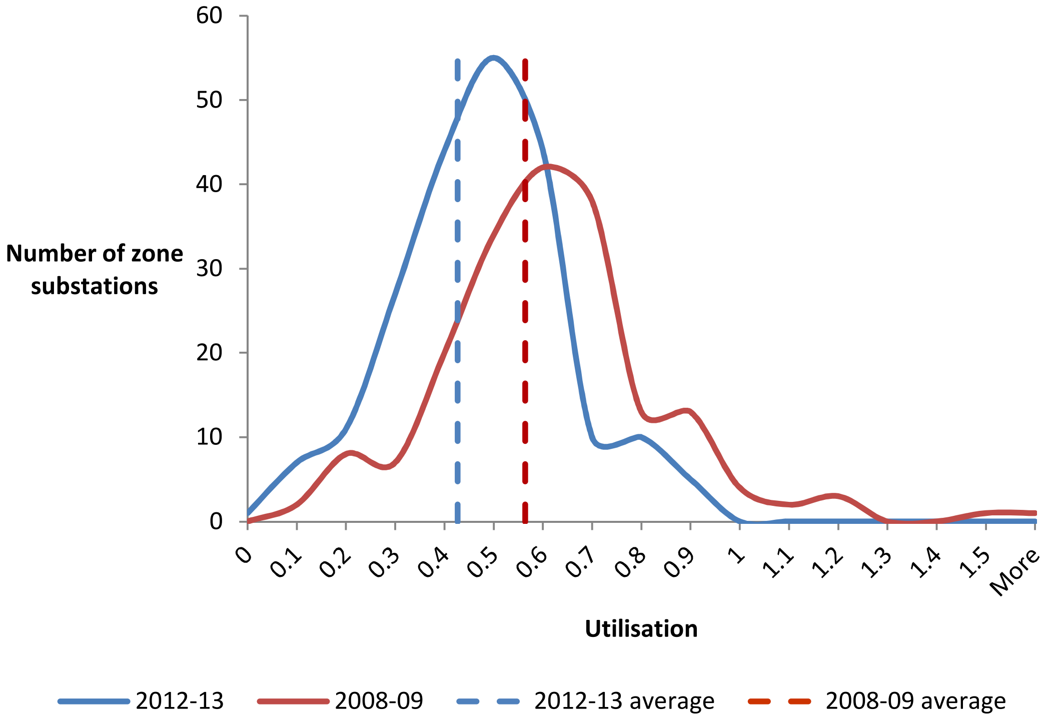
- low demand growth—as we discuss in Appendix B, available evidence points to slow demand growth (or possibly stagnant, even falling, demand) in Ausgrid's network over the 2014–2019 period. This forecast trend in demand is lower than in previous regulatory determinations. Furthermore, actual demand for the 2009–2014 regulatory control period was much lower than Ausgrid forecast in the previous distribution determination.
- the change in network design standards—as the capex attachment outlines, a key driver of Ausgrid's capex from 2005 was the network design standards in its NSW licence condition. These design requirements led to increased levels of network capacity. The NSW Government removed these standards in July 2014.[42]

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

- declining asset utilisation—the increase in augmentation works and the decrease in actual demand over 2009-2014 led to increased levels of excess capacity in the network (as evident in figures 2 and 3).

Figure A-2 shows a steady decrease in utilisation levels at Ausgrid's zone substations between 2008–09 and 2012–13. Similarly, Figure A-3 demonstrates utilisation levels for Ausgrid's HV feeders fell 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

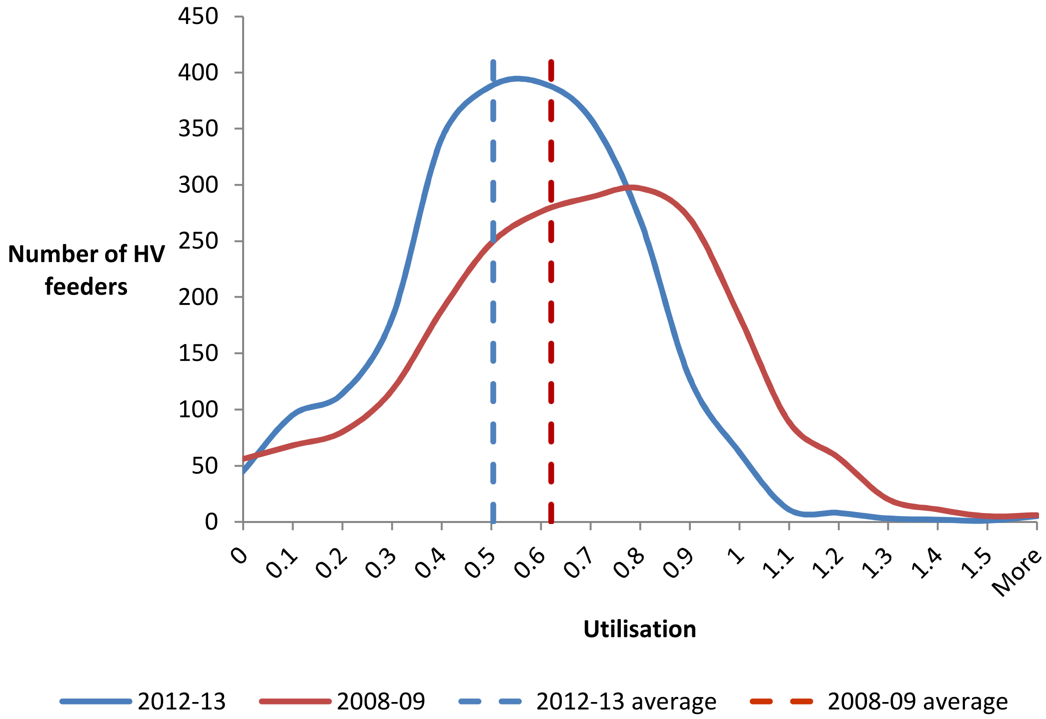


Source: AER analysis; augex model.

Note: Utilisation is the ratio of maximum demand and the capacity of each substation for the specified years.[43] Figure A-2 shows the number of Ausgrid's total zone substations at each utilisation band.

[43] Capacity is 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.

Note: Utilisation is the ratio of maximum demand and the thermal rating of each feeder for the specified years.[44] Figure A-3 shows the number of Ausgrid's total HV feeders at each utilisation band.

The AER's Consumer Challenge Panel (CCP Subpanel 1) noted the general decline in asset utilisation between 2006 and 2013 provides an indication of significant excess capacity on Ausgrid's network.[45] PIAC similarly noted the dramatic reduction in Ausgrid's network utilisation. PIAC submitted this indicates a need for significant constraint in future investment and detailed examination of local augmentation proposals.[46]

We note that Ausgrid has proposed proportionately similar reductions in augex as Endeavour Energy. This is appropriate given that Ausgrid and Endeavour face similar trend in demand and excess network capacity, and there is not anything materially different between the governance structures of Ausgrid and Endeavour Energy that would suggest that similar cost reductions were not achievable.

Having said that, Ausgrid stated it still needs to invest in capacity to meet pockets of demand (growth) in its network, particularly from new customers.[47] In particular, Ausgrid noted some augex projects arising from new residential developments such as those in the Sutherland area.[48] Ausgrid considers some of these projects are uncertain as a result of uncommitted land developments.[49] As we noted in appendix B, spatial demand is the main driver of specific growth-related projects. For example, Ausgrid noted 42 of its zone substations experienced growth rates greater than two per cent per

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

45 CCP1 Subpanel, *CCP1 submission to AER re NSW DNSPs: Jam tomorrow?*, August 2014, pp. 22-23 and 25

46 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, pp. 44–45.

47 Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 34.

48 Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, pp. 37–38.

49 Ausgrid, *ID94035: Area plan summary: Sutherland*, 30 May 2014 p. 4; Ausgrid, *ID94035: Area plan summary: Upper Central Coast*, 30 May 2014, p. 4.

annum between 2009–10 and 2013–14. This is despite generally declining demand through the rest of the network (see Figure B-2).[50]

AGL and PIAC stated that we should confirm that augmentation on existing capacity uses realistic demand forecasts. As discussed in appendix B, PIAC pointed to significant errors in Ausgrid's historical forecasts.[51]

Ausgrid stated it relied on spatial demand forecasts for zone substations and subtransmission substation (major substations) as it provides a more accurate basis for determining capacity needs.[52] In its regulatory proposal, Ausgrid provided the spatial demand forecast for each major substation in its network that it produced in 2013 (2013 forecasts). Ausgrid forecasted 76 substations would on average grow more than two per cent per annum over the 2014–2019 period.[53]

During the determination process, Ausgrid provided us with draft updated spatial demand forecasts (2014 forecasts). As Table A-2 shows, on average, the number of major substations with expected demand growth rates fell by 66.9 per cent between the 2013 and 2014 forecasts. In the 2014 forecasts, Ausgrid identified that 24 substations would on average grow more than two per cent per annum over the 2014–2019 period.[54]

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

	2015/16	2016/17	2017/18	2018/19	Average
2014 forecasts	36	32	26	84	
2013 forecasts	82	154	172	160	
Per cent reduction	56.1	79.2	84.9	47.5	66.9

Source: Ausgrid, *Reply to AER AUSGRID 039 - updated demand forecasts (Follow- up question)*, 2 October 2014.
Note: '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 significant drop in substations that expect positive demand growth suggests Ausgrid's augex forecast should be lower than it proposed. This is because Ausgrid will not need to augment those substations it does not expect to grow. While we understand Ausgrid has not yet finalised these updated demand figures, they indicate how Ausgrid's demand forecasts will likely change in its revised regulatory proposal. We have estimated the likely impact of this change in demand and taken this into account in forming our estimate of the total capex for the 2014–19 regulatory control period.

We also received the following comments in submissions:

- PIAC considered much of Ausgrid's growth will come from urban growth, the costs of which are largely recovered from the developers.[55] Similarly, TEC requested that we assess whether expenditure allocated to augex is reasonable given developers pay for much of 'growth capex'.[56]

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50 Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 37.
51 AGL, *NSW electricity distribution networks regulatory proposals: 2014- 19: AGL submission to the Australian Energy Regulator*, 8 August 2014, p. 12; PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p. 42.
52 Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 37.
53 Ausgrid, *Regulatory proposal: Attachment 5.03: Spatial demand forecast by zones and substations*, May 2014.
54 Ausgrid, *Reply to AER AUSGRID 039 - updated demand forecasts (Follow- up question)*, 2 October 2014.
55 PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p. 106.

- EMRF noted Ausgrid's proposed 'area plans' to increase the capacity of the subtransmission and transmission elements of the network.[57] EMRF stated there was significant 'pre-expansion' of the network in the current regulatory control period. EMRF noted Ausgrid reduced its area plans expenditure in the current regulatory control period due to lower than forecast demand. As we noted above, it appears Ausgrid is in the process of revising its demand forecasts downward compared to its regulatory proposal. EMRF stated Ausgrid identified that it did not require this work. Hence, area plan capex in the forthcoming regulatory control period to address augmentation is not necessary.[58]

We are satisfied the need to meet localised demand growth partly explains Ausgrid's augex forecast (noting we expect lower demand forecasts in Ausgrid's revised regulatory proposal). However, we consider there is some evidence that Ausgrid has proposed higher expenditure than is reasonably required to build its network to meet demand and reliability requirements. This is discussed below.

Engineering review of forecasting methodology

We engaged engineering consultant Worley-Parsons to review whether there are any systematic issues that may result in biases in Ausgrid's augex forecasts.

We asked Worley-Parsons to identify whether:

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

To conduct this review, Worley-Parsons reviewed a sample of Ausgrid's projects or programs:

- High expenditure/carryover at start of period
- Project deferrals from the previous period and the basis for the revised timing and costing
- HV feeders and the 11kV Model
- Design Planning Criteria.

Worley-Parsons then focussed on assessing the sample of Ausgrid’s augex forecast given the changes to the licence conditions (as discussed in section the capex attachment). This included assessing whether Ausgrid was transitioning from a deterministic planning methodology to a probabilistic or risk-based cost-benefit analysis methodology.[59] Where the assessment revealed concerns about systemic issues, they quantified the likely impact of these biases.

Based on its sample of projects or programs, Worley-Parsons observed Ausgrid developed its augex forecast primarily on the licence conditions applying in the 2009–2014 regulatory control period.

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56 TEC, *Submission to the Australian Energy Regulator issues paper on the NSW electricity distribution businesses’ regulatory proposals*, August 2014, p. 14.

57 Ausgrid stated area plans identify augmentations and large strategic replacements on its subtransmission network. Ausgrid stated approximately 85% of area plans capex forecast relates to replacement of large assets. See Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, pp. 43–44.

58 EMRF, *NSW electricity distribution revenue reset: Applications from Ausgrid, Endeavour Energy and Essential Energy: A response*, July 2014, p. 67.

59 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014, pp. 10–14.

Ausgrid only considered in limited detail the impact of the changes to the licence conditions. For example, Worley-Parsons investigated five projects Ausgrid deferred from the 2009–2014 regulatory control period to the 2014–2019 period. Despite the repeal of the NSW licence condition design standards, Worley-Parsons found no evidence Ausgrid used cost optimisation or risk-based techniques in its augex forecast.[60] Worley-Parsons considered this will bias upwards the forecasts forming the regulatory proposal.

Similarly, Worley-Parsons found Ausgrid did not incorporate the change in licence conditions in its 11kV modelling process, which forms a significant component of its augex forecast.[61] Based on its observations, Worley-Parsons concluded that Ausgrid could achieve efficiency gains by the application of risk based cost benefit analysis assessment techniques to projected programs of work. Because the application of these techniques is not reflected in Ausgrid's augex forecast, this suggests that the forecast is higher than would be incurred by a prudent and efficient service provider.

We consider that Ausgrid could efficiently make a 15 per cent reduction to its augex projects by applying risk based cost benefit analysis assessment techniques to projected programs of work over the 2014–19 period. This is reasonable in light of the advice of WorleyParsons in relation to Endeavour Energy. For Endeavour Energy, Worley-Parsons noted that the application of risk based cost benefit analysis assessment techniques had the potential to reduce expenditure by between 10 and 20 per cent. As noted previously, we do not consider that there is anything so materially different between the governance structures of Ausgrid and Endeavour Energy that would suggest that similar cost reductions were not achievable. We have formed a view that further 15 per cent reduction is necessary for the forecast to reasonably reflect the required expenditure.

This estimate also has regard to the existing level of network capacity and utilisation. Ausgrid made significant augmentation investments in the previous period and this is reflected in excess network capacity. We consider that Ausgrid should utilise this capacity ahead of additional augmentation investment, and additional augmentation investments may not reflect efficient use of the network.

HV feeders expenditure and revised demand forecasts

Ausgrid's augex forecast of $251.9 million ($2013–14) for HV feeders makes up 52.5 per cent of its total augex forecast. A significant proportion of this forecast comprises its 11kV capacity plan of $202.3 million ($2013–14).[62] This is 41.3 per cent of Ausgrid's total augex forecast for the 2014–2019 period.[63] Table A-3 summarises the components of this augex forecast.

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60 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014, p. 11.

61 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014, p. 12.

62 Ausgrid, *11kV model: Method & outcomes of DND*, 29 May 2014, p. 16.

63 Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 44; Ausgrid, *Regulatory proposal: Attachment 5.25: Overview of the distribution capacity plans 2014–19 regulatory period*, May 2014, p. 16; Ausgrid, *11kV model: Method & outcomes of DND*, 29 May 2014, p. 16.

Table A-3 Ausgrid augex forecast for 11kV network (million, $2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Total 11kV Capacity Plan	**45,813**	**31,795**	**38,157**	**44,554**	**42,014**	**202,334**
Capacity Augmentation	**4,331**	**24,672**	**29,337**	**36,287**	**33,241**	**127,869**
11kV DND Model Results	4,222	24,913	30,338	36,313	33,960	129,747
Major Projects Synergies	-854	-883	-1,569	-515	-1,261	-5,082
Project Specific DM	-84	-415	-502	-598	-560	-2,160
CBD Capacity	1,048	1,057	1,070	1,086	1,103	5,364
Other Works	**2,201**	**747**	**2,034**	**1,088**	**1,596**	**7,666**
Fault Level	1,100		1,124		579	2,803
Voltage Regulation	550	374	455	544	508	2,432
Substation Connections	550	373	455	544	509	2,432
Works in Progress	**32,478**		**26**			**32,503**
Support costs	**6,804**	**6,376**	**6,760**	**7,179**	**7,177**	**34,295**
Planning, Forecasting and Compliance	5,272	5,375	5,516	5,687	5,777	27,626
Switching and Control	294	191	237	288	271	1,280
GIS Data Capture	1,238	810	1,007	1,205	1,129	5,389

Source: Ausgrid, *11kV model: Method & outcomes of DND*, 29 May 2014, p. 16.

Table A-3 shows Ausgrid used its '11kV model' to forecast a significant component—$129.747 million ($2013–14)—of its HV feeder augex forecast.[64]

As we noted in Appendix B, Ausgrid had been progressively downgrading its demand forecasts during the 2009–14 regulatory control period. The trend towards falling demand growth reduced the requirements for future network augmentation works—Figure A-1 and Figure B-2 provide clear evidence of this. In addition, we note the stated focus of Networks NSW on reductions in capital and

64 This figure does not include HV feeder augex for the CBD, which Ausgrid forecasted separately. See Ausgrid, *11kV model: Method & outcomes of DND*, 29 May 2014, p. 16.

operating costs.[65] As a sensitivity check, we requested that Ausgrid demonstrate the impact of a 10 per cent reduction and a 10 per cent increase in load growth on the output of the 11kV model.[66] .

From analysis based on previous sensitivity tests, Ausgrid estimated a 10 per cent reduction (increase) in forecast demand would result in a 10 per cent reduction (increase) in expenditure requirements. Worley-Parsons concluded that this demonstrated a positive linear relationship between a change in forecast demand and a change in its expenditure requirements for HV feeders.[67]

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

We estimated the impact of these changes in demand on Ausgrid'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).[68] 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-4 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, Ausgrid expects a 463MVA, or 31.45 per cent, reduction in ratcheted demand in the 2014 forecasts. Consistent with this, for the purposes of this draft decision, we have used this 31.45 per cent reduction in the demand forecast as an input when updating the output of the 11kV model.[69]

Table A-4 Ratcheted demand (MVA)

	Difference between aggregated 2018/19 and 2014/15 forecasts
2014 forecasts	1010.8
2013 forecasts	1474.5
MVA reduction	463.7
Per cent reduction	31.45

Source: Ausgrid, *Reply to AER AUSGRID 039 - updated demand forecasts (Follow- up question)*, 2 October 2014.

65 Ausgrid, *Regulatory proposal: Attachment 1.01: Networks NSW: Delivering efficiencies for our customers*, May 2014.

66 AER, *AER email: FW: AER AUSGRID 038 - 11 KV model*, 16 September 2014.

67 WorleyParsons, *Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019*, 17 November 2014, p. 12.

68 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.

69 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.

We applied a 31.45 per cent reduction to most components of Ausgrid's augex forecast from its 11kV capacity plan (see Table A-5). We note Ausgrid's application of the linear adjustment to augex (from changes in demand) applied specifically to the results of the 11kV model results. However, we consider it is appropriate to apply this reduction to the majority of the 11kV capacity plan line items. We consider a change in demand is likely to affect most of these line items, not just the augmentation works from the 11kV model. We did not apply the 31.45 per cent reduction to the following line items:

- Fault level—while this is impacted by demand driven expenditure, other factors such as network rearrangement can also impact on this expenditure. We have therefore excluded this from our adjustments.[70]
- Voltage regulation—this is largely demand related expenditure which is driven by organic growth as well as connections. As connections can also impact on this expenditure we have excluded this from our adjustments.

We also note that the offset in expenditure due to demand management ($2.160 million) is likely significantly understated given the previous success of Ausgrid's demand management activities in deferring the requirement for capex. This is discussed in section A.7.

Table A-5 shows that applying the 31.45 per cent demand adjustment reduces the expenditure forecast on the 11kV capacity plan to $140.347 million ($2013–14). This is a reduction of $61.986 million ($2013–14) compared to Ausgrid's proposal of $202.334 million ($2013–14).[71]

Table A-5 Demand adjustment to Ausgrid's 11kV capacity plan (million, $2013–14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Total 11kV Capacity Plan	**31,924**	**21,913**	**26,653**	**30,713**	**29,143**	**140,347**
Capacity Augmentation	**2,970**	**16,913**	**20,111**	**24,874**	**22,787**	**87,654**
11kV DND Model Results	2,894	17,078	20,797	24,893	23,280	88,941
Major Projects Synergies	-585	-605	-1,076	-353	-864	-3,484
Project Specific DM	-58	-284	-344	-410	-384	-1,480
CBD Capacity	718	725	733	744	756	3,677
Other Works	**2,027**	**630**	**1,891**	**917**	**1,436**	**6,900**
Fault Level	1,100	0	1,124	0	579	2,803
Voltage	550	374	455	544	508	2,432

70 We also note that 'Support costs' more strictly relates to the volume of work to be undertaken (rather than to the demand forecast). However, these expenditure items will fall as a reduction in forecast demand reduces the work volume.

71 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.

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Regulation						
Substation Connections	377	256	312	373	349	1,666
Works in Progress	**22,264**	**0**	**18**	**0**	**0**	**22,281**
Support costs	**4,664**	**4,371**	**4,634**	**4,922**	**4,920**	**23,511**
Planning, Forecasting and Compliance	3,614	3,685	3,781	3,898	3,960	18,938
Switching and Control	202	131	162	197	186	878
GIS Data Capture	849	555	690	826	774	3,694

Source: AER analysis; Ausgrid, *11kV model: Method & outcomes of DND*, 29 May 2014, p. 16.

Change in value customer place on electricity reliability

In October 2014, subsequent to the submission of Ausgrid'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 lower 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-6, the results of AEMO's study reveals that VCRs are significantly lower than previous Australian studies, driven primarily by commercial and agricultural customers.

Table A-6 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, *Value of customer reliability review: Final report*, September 2014, pp. 2, 18 and 31; Oakley Greenwood, *Valuing reliability in the National Electricity Market*, March 2011, pp. 32–33.

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

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

A.2 AER findings and estimates for 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.[72] Given the competition between service providers, we do not regulate the majority of connection services in New South Wales.

Ausgrid proposed connections capex of $171.1 million ($2013/14) over the 2014–19 period, which represents less than five per cent of total capex and a 57 per cent reduction in the spend over the 2009–14 period. Ausgrid notes that the reduction in connections capex is due to the reclassification of some connections services to alternative control services. As such, service costs are recovered directly from connecting customers rather than as costs shared by the entire customer base.

Table A-7 Total customer connections capex ($2013–14, million)

Customer-initiated service category	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Ausgrid proposed*	29.50	32.81	36.99	36.59	35.19	171.07
AER approved	29.50	32.81	36.99	36.59	35.19	171.07

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

The connections allowance is driven by augmentation and extensions to the shared distribution network to connect new commercial and industrial sites, and multi-unit residential developments.[73]

We consider the trend of Ausgrid's proposed connections capex is consistent with the forecast drivers in construction activity in commercial and industrial, and multi-dwelling residential premises, as per Figure A-4. We consider a lag exists between dwelling starts and the time taken to connect to the distribution network which explains the delay between trends of the two series. We are satisfied that Ausgrid's proposed connections capex of $171.1 million ($2013/14) reasonably reflects the required expenditure and we will make an allowance for it in determining the total capex forecast for the 2014–2019 period.

PIAC urged us to investigate the funding requirements arising out of forecast connection works between high-density developments and urban or rural customers.[74] We reviewed Ausgrid's proposal and assessed that Ausgrid's mix of forecast connection works is consistent with its customer base,

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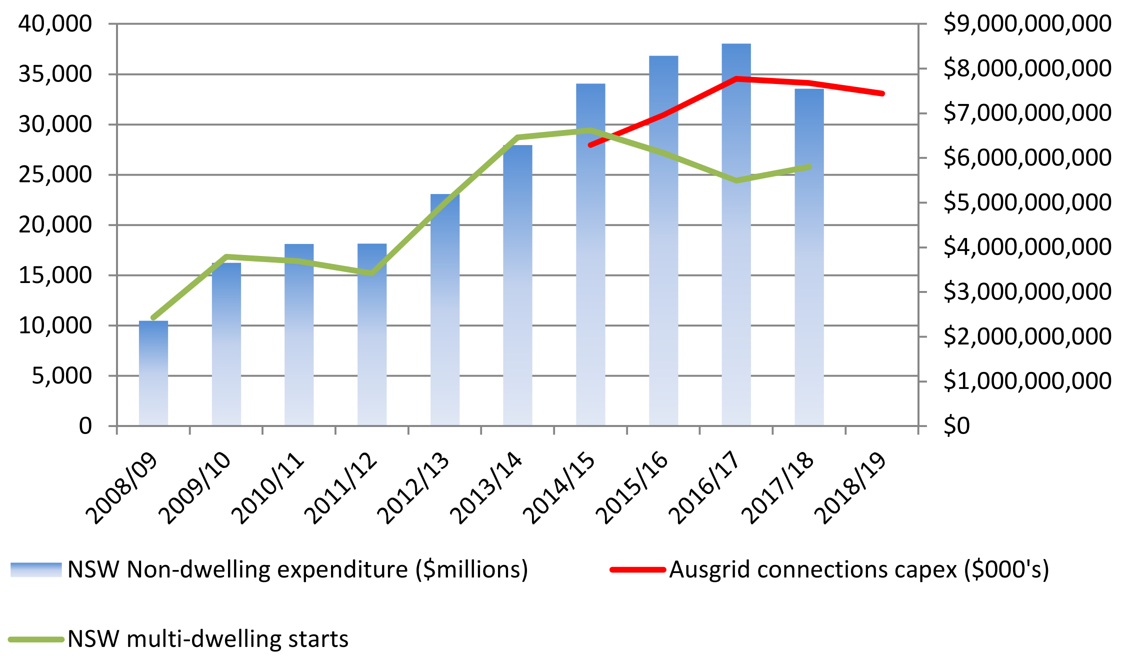
72 AER, *Stage 1 Framework and approach paper: Ausgrid, Endeavour Energy and Essential Energy: Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, p. 16.

73 Ausgrid, *Customer connections capex model: Method and outcomes (explanatory)*, May 2014, p. 5.

74 PIAC, *Moving to a new paradigm: Submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p. 39.

forecast construction activity, and not biased toward works whose costs are recovered across the whole customer base.

Figure A-4 Ausgrid connections capex and NSW construction activity



Source: Ausgrid RIN template 2.1; BIS Shrapnel, *Building in Australia 2013–2028*, table 5.1; Housing Industry Association, http://hia.com.au/en/businessinfo/economicinfo/housingforecasts.aspx, accessed 18 November 2014.

A.2.1 Assessment of capital contributions

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

We accept Ausgrid's proposed capital contributions forecast of $522.29 million, as we consider it is consistent with Ausgrid'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 Ausgrid to clearly explain how capital contributions should be allocated to each service. Table A-8 outlines Ausgrid's forecast of capital contributions for the 2014–2019 regulatory period.

Table A-8 Ausgrid proposed customer contributions ($2013/14, million)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Ausgrid proposed	88.80	103.90	118.37	106.91	104.32	522.29
AER approved	88.80	103.90	118.37	106.91	104.32	522.29

Source: Ausgrid RIN.

A.3 AER findings and estimates for replacement capital expenditure

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

A.3.1 Position

Ausgrid proposed $3,226 million ($2013–14) of forecast repex (excluding capitalised overheads).

We do not accept Ausgrid's proposal. We have instead included an amount of $1,769 million ($2013–14) in our alternative estimate, a reduction of 43 per cent.

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

- **benchmarking** at the expenditure category level and **trend analysis** of historical actual and expected repex
- **an engineering review** of repex proposals
- **predictive modelling** of repex requirements.
- In summary, we find that:
- Ausgrid's proposed repex is around 40 per cent higher than its long term average
- Controlling for network scale characteristics, Ausgrid's historical repex does not compare favourably to that of other service providers in the NEM and appears high.
- Measures of asset health suggest that Ausgrid has not demonstrated that the likely condition of its assets supports its proposed forecast repex.
- In relation to the likely condition of Ausgrid's assets, the substantial increase in spare network capacity during the 2009–14 regulatory control period provides an operating environment that should reduce the rate of deterioration of Ausgrid's assets over the 2014–19 period. Further, the remaining asset lives of Ausgrid's assets have been increasing (where asset age is a proxy for asset condition). This suggests that Ausgrid would require less repex to maintain its network now than it has in the past.
- An engineering review carried out by EMCa found that there are systemic issues with Ausgrid's forecast that mean Ausgrid's proposal is likely to significantly overstate the amount of repex required to meet the capex objectives. In particular, Ausgrid is likely to be replacing assets many assets too early than is necessary to meet the capex objectives.
- Our predictive modelling also suggests that Ausgrid's proposal is likely to be overstated. This demonstrates that Ausgrid's asset replacement requirements are likely to be materially lower. The range of reasonable outcomes based on our modelling is between $1.36 billion and $1.43 billion for the six modelled asset categories. This is a 43 to 48 per cent reduction in Ausgrid's proposal, excluding capitalised overheads.
- For categories that were not included in predictive modelling, we are satisfied that a total of $339 million is likely to be a prudent and efficient level of repex. When added this amount to the

modelled component, this gives a reasonable range for total repex of between approximately $1.694 billion and 1.769 billion.

- Finally, there is the real potential for Ausgrid to face deliverability constraints in the 2014–2019 period. This casts material doubt on whether Ausgrid's forecast repex forecast is a realistic expectation of the cost inputs required to achieve the capex objectives.
- The amount of forecast repex that we have included in our alternative estimate is $1,769 billion (2013-14), excluding capitalised overheads. This is 43 per cent less than Ausgrid's proposal. Our estimate for repex is at the upper end of our reasonable range. This amount ensures that Ausgrid will be provided with a reasonable opportunity to recover at least its efficient costs. It will also minimise the potential for Ausgrid 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

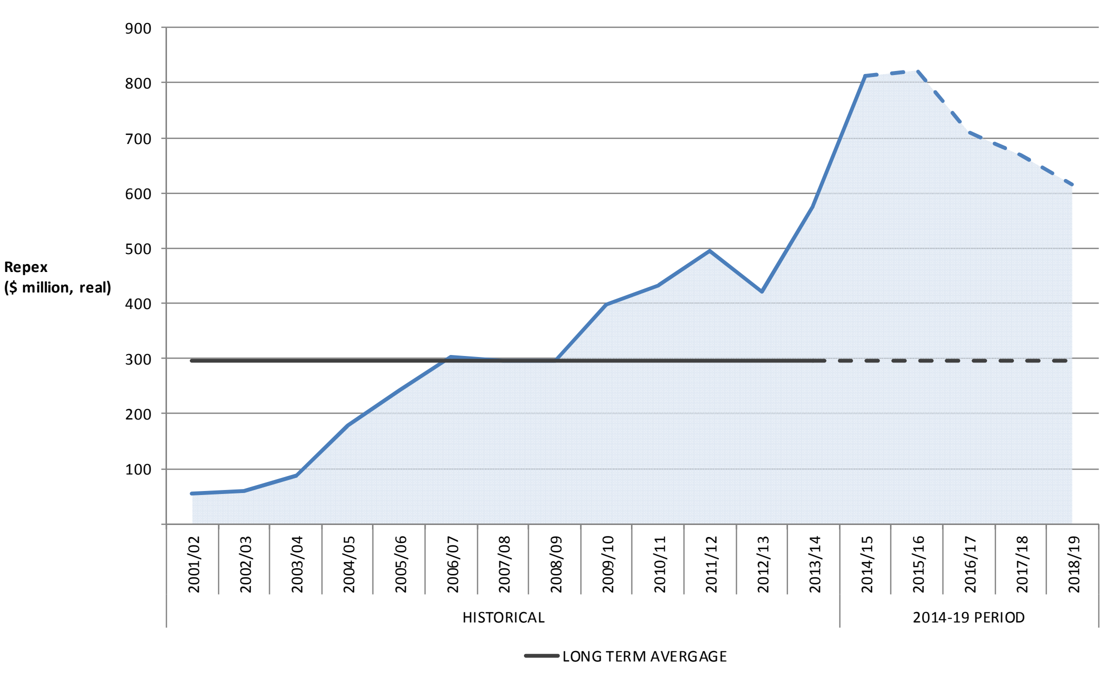
Ausgrid's proposed forecast repex for the 2014–19 period exceeds its historical trend (based on the time series data available). Notably, its historical repex is also relatively high in comparison to other DNSPs in the NEM. Specifically, we have considered:

- trends in Ausgrid's actual repex over time to allow comparison with actual repex in previous regulatory control periods
- Ausgrid's actual repex relative to other DNSPs 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 Ausgrid's network assets.

Historical trends

Figure A-5 shows the trend in Ausgrid's historical and proposed repex. It also shows Ausgrid's actual long term average across the same time period.

Figure A-5 Ausgrid's repex including overheads- historic actual and proposed for 2014-19 period (real $ million June 2014)



Source: Historical: IPART Regulatory Accounts (prior to 2010–11) and AER Annual RINs (2010–11 to 2013–14)
2014-19 period: Ausgrid'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 Ausgrid 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 Ausgrid's underlying repex requirements.

Figure A-5 shows that Ausgrid's proposed forecast repex of $3,629 million, including overheads (real June 2014) for the 2014–2019 period significantly exceeds its long term average.[75] This is a 41 per cent increase above its long term average repex[76] and a 56 per cent increase in the amount incurred in the most recent regulatory control period.[77]

Repex compared with forecast

In the capex attachment we compared the amount of actual capex Ausgrid incurred against its forecast in the 2009–2014 regulatory control period. Figure A-6 below shows this differential with respect to repex.

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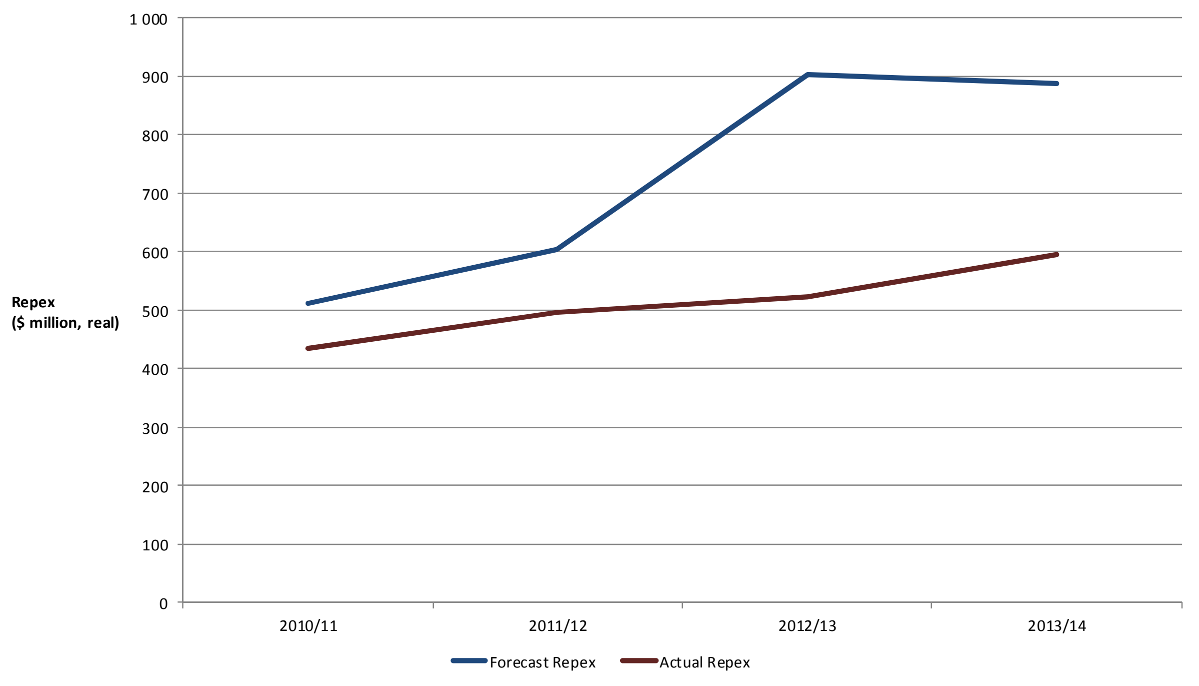
[75] Ausgrid's Reset RIN - Table 2.1.1 - Standard control services capex (after allocating capitalised network and corporate overheads on the basis of repex as proportion of total capex).

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

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

Figure A-6 Ausgrid's Repex allowance and actual in recent years



Source: AER analysis

The first year in the regulatory control period is unaccounted for in Figure A-6 due to data availability.[78] Although Figure A-6 is only a partial observation of Ausgrid's repex relative to its forecast, it clearly demonstrates that Ausgrid has systematically underspent its repex forecast. Ausgrid has indicated that this underspend is in part due to deliverability issues that it considers will not arise in the 2014–019 period.[79] However, Energy Market Consulting associates (EMCa) considers there is a significant risk regarding the deliverability of its proposed repex.[80]

Relationship between total repex and network scale

Network scale characteristics, such as the number of customers a DNSP serves, its size, operating environment and asset mix, have a bearing on the amount of repex a DNSP incurs. Given the size of Ausgrid's asset base and the number of customers its serves, we expect that it will incur relatively more repex than other DNSPs. For this reason, in assessing the relative efficiency of Ausgrid's historical repex against that of other DNSPs, we have applied a series of normalisation factors to account for the impact of Ausgrid's network size.

In particular, we have used two measures of network density: customer density and capacity density.[81] 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 DNSP across the regulatory years

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78 The AER's last determination for Ausgrid (Energy Australia) did not disaggregate the capex on the basis of purpose driven capex. We collected this data when the AER began issuing Annual RINs, 2010/11 was the first reporting period. Ausgrid applied a CPI adjustment to the purpose driven capex allowance it reported in the 2010/11 and 2011/12 annual RINs. The AER's 2009-14 determination for Ausgrid (Energy Australia) was made in $2008/09, these figures have been adjusted to a consistent basis applied for the 2014-19 period determination.

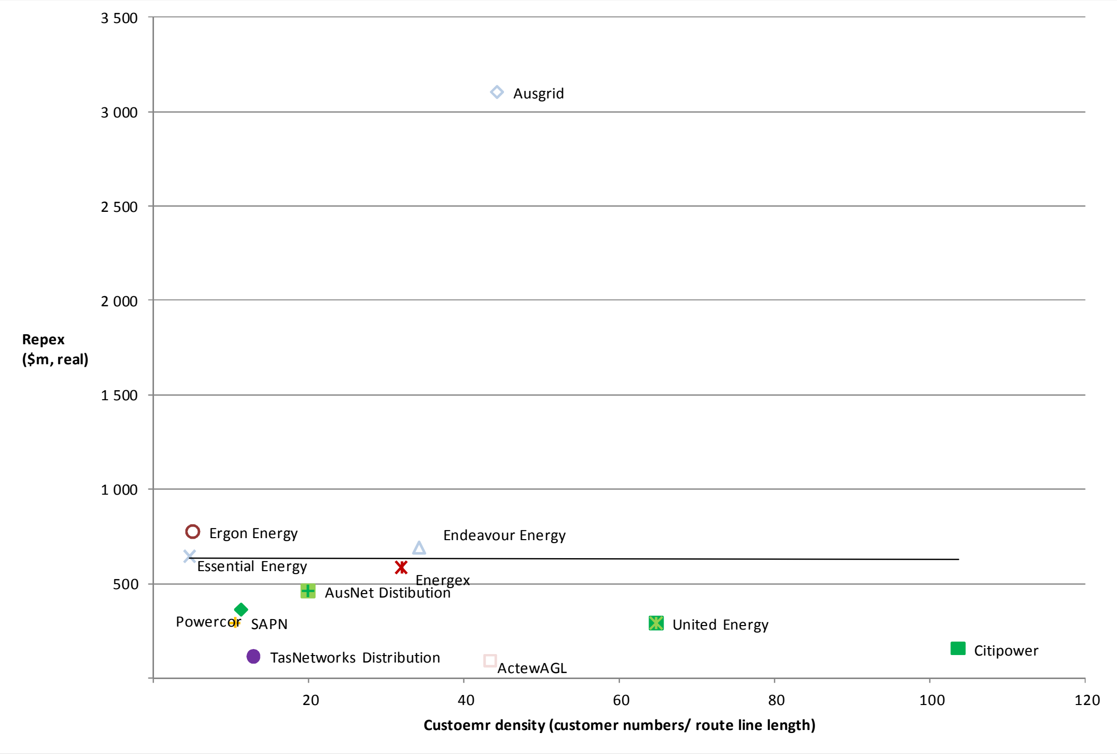
79 Ausgrid, *Regulatory Proposal* 30 May 2014, p. 33.

80 EMCa, *Technical review of regulatory proposals, Review of proposed replacement capex in Ausgrid's regulatory proposal 2014–2019*, October 2014, pp, 13–14. (EMCa, *Review of Ausgrid's repex*, October 2014).

81 Customer density is customer numbers divided by route line length.

2008–13 to assess the relationship between total repex and network scale. Figure A-7 shows this for customer density across the DNSPs.

Figure A-7 Repex across NEM normalised for customer density



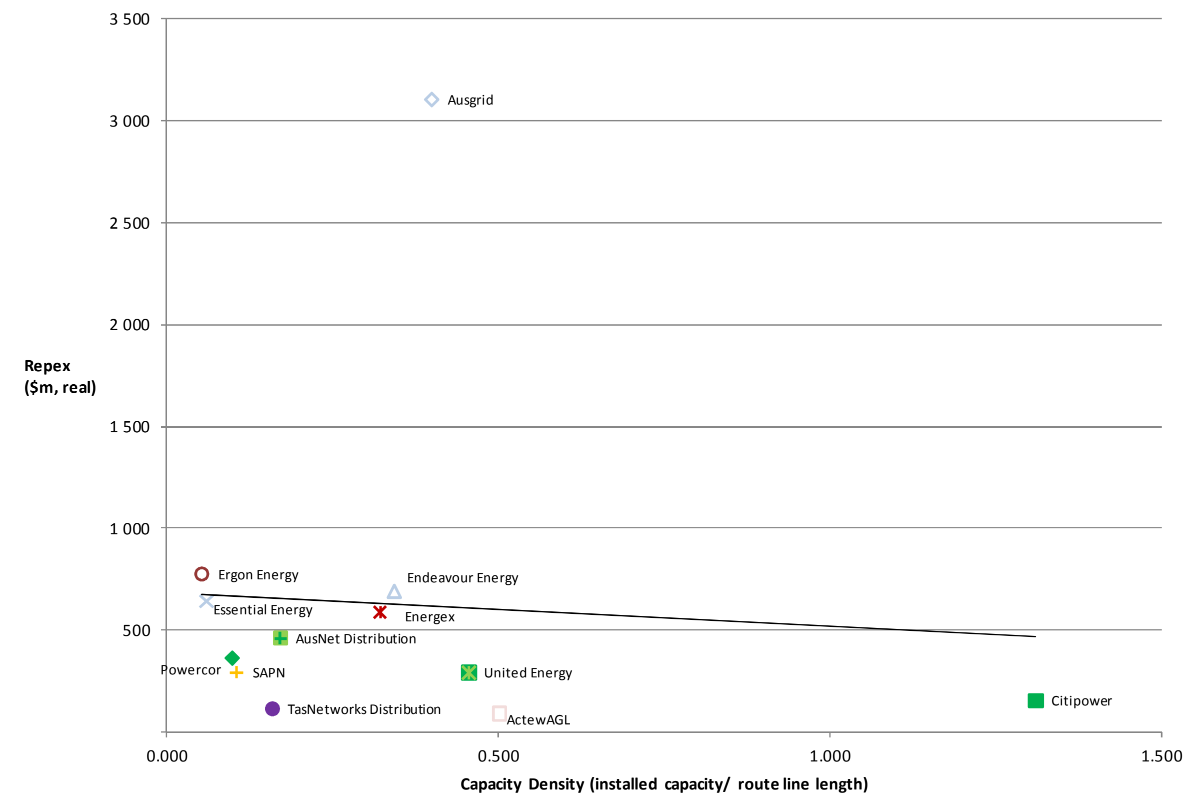
Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
Customer Numbers and Route Line Length: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence.

In general, Figure A-7 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 DNSPs. Notably, Ergon Energy and Essential Energy (predominantly rural networks) incur relatively less repex than Ausgrid after normalising for customer density across the NEM.

We received feedback from some DNSPs that normalising total repex for capacity density is important to understanding the impacts of network scale on total repex.[82] We understand capacity density to be the quotient of installed capacity and network length. Figure A-8 shows the relationship between repex and capacity density across the DNSPs.

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

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



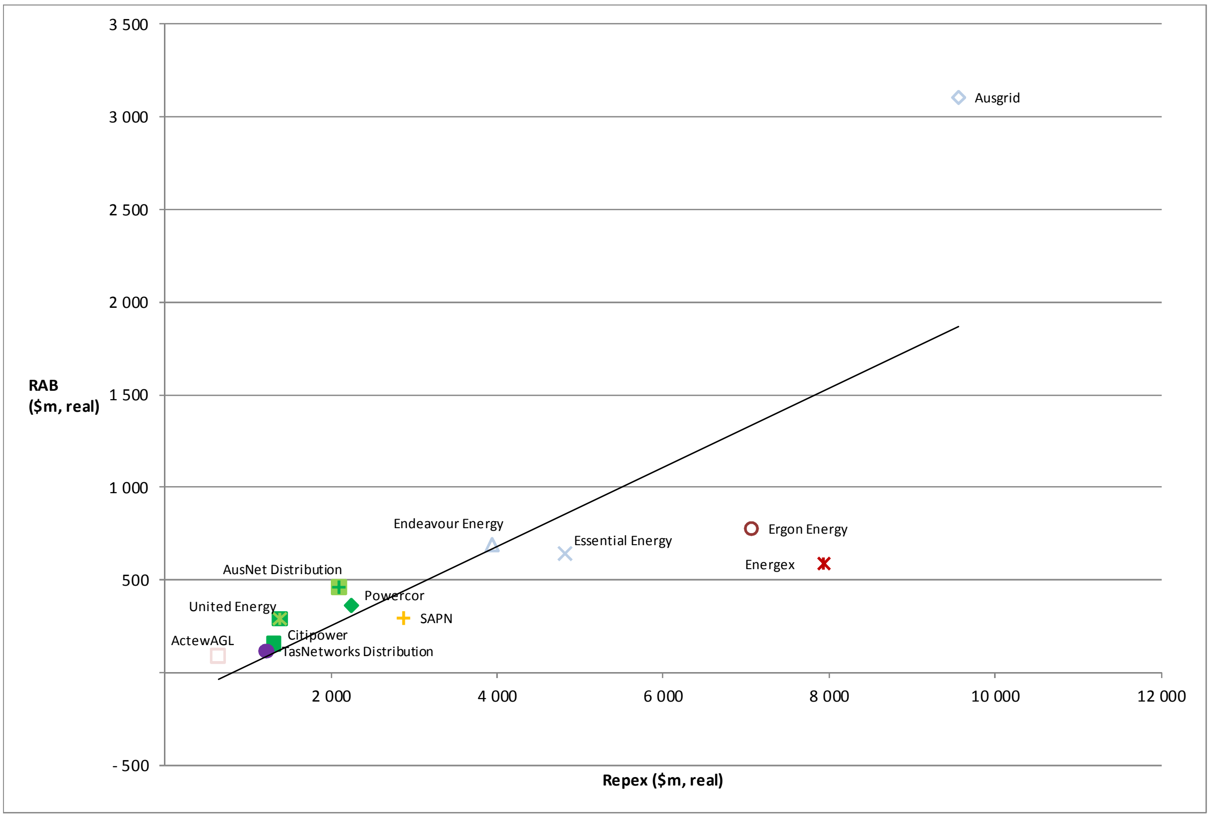
Source: Total Repex: Category analysis and Reset RINs - Table 2.1.1 - Standard control services capex
Installed capacity: EBT and Reset RINs - 3.4 Operational data
(Jemena excluded as information is commercial in confidence

Comparing Figure A-7 with Figure A-8 shows that there are similar relationships when normalising total repex by customer density and capacity density. Ausgrid 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 assets 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, Ausgrid has only 6.4 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 DNSP'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 A-9 compares the DNSPs on the basis of the cumulative repex incurred across the regulatory years 2008-13 as a proportion of their opening RABs, which we have used to proxy the number of assets that exist on a network.

Figure A-9 Proportion of asset base replaced in the 2008-13 period



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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.
(Jemena excluded as information is commercial confidence).
We have approximated each distributors asset base as its initial RAB as at 2008.

Figure A-9 shows there is a positive correlation between the size of a RAB and the repex a DNSP incurs.

The DNSPs have submitted that repex depends not only on the size of their RABs, but the characteristics of their RAB as well.[83] Some DNSPs also submitted that this measure fails to account for the age and condition of the RAB, any capex and opex trade-offs, whether a DNSP employs a deterministic or probabilistic replacement strategy and a DNSP's particular investment cycle (noting the limited number of years used to determine DNSPs propensity for replacement (repex being the aggregate of only five years of expenditure as shown in Figure A-9.

Whilst we acknowledge the limitations outlined above, this measure clearly indicates that Ausgrid has incurred a significantly higher proportion of repex relative to the size of its RAB.

Asset Health Indicators

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

- the age of Ausgrid's network and

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

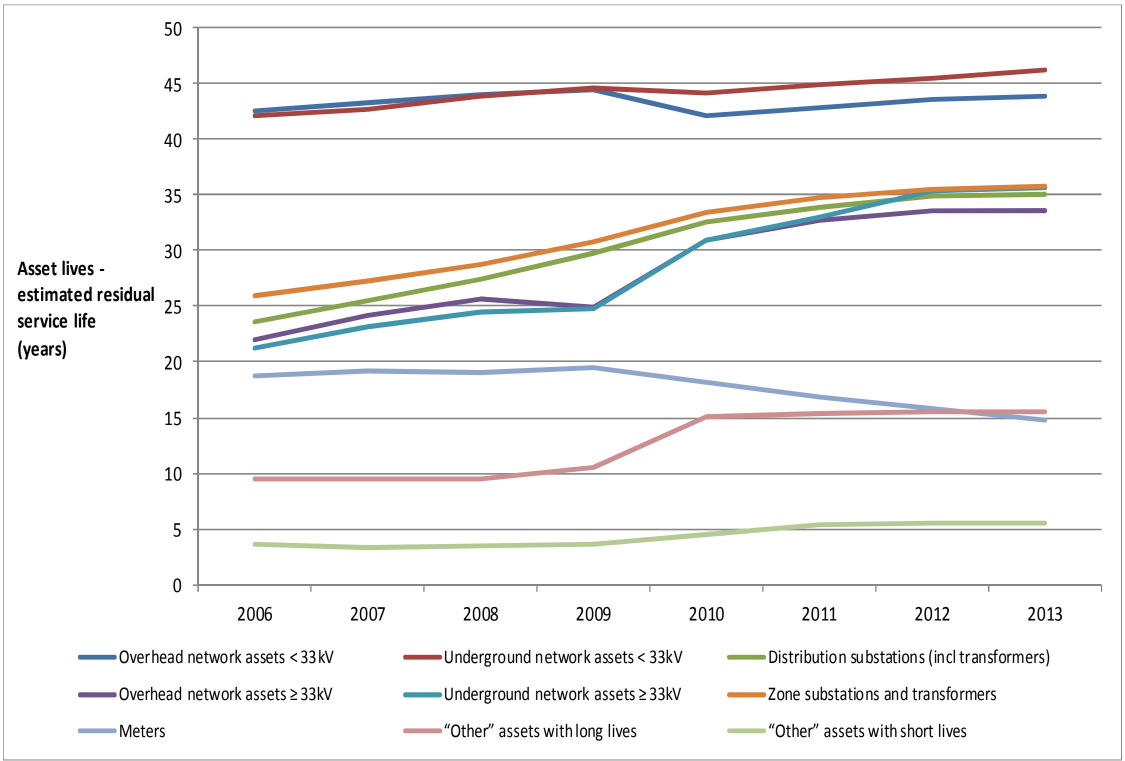
- utilisation of the network (where space capacity should be correlated to asset condition).

Asset age

Asset age is a reasonable proxy for asset condition which affects asset the repex requirements on the network. We note that Ausgrid and the DNSPs agree with this.[84]

In Figure A-10 we have derived the weight average remaining life of Ausgrid's RAB to reveal the trend in age of the Ausgrid network.

Figure A-10 Ausgrid Asset Lives – estimated residual service life



Source: Ausgrid - EBT RIN - 4. Assets (RAB) - Table 4.4.2 Asset Lives – estimated residual service life (Standard control services).

Figure A-10 shows that the residual lives of Ausgrid's assets have been increasing since 2006. This suggests that the health of Ausgrid's asset base has improved over the last eight years. Its assets are now expected, in aggregate, to maintain their function for a longer period than they did in 2006. This suggests that Ausgrid would require less repex to maintain its network now than it has in the previous regulatory control period. Similarly, the EMRF commented that:[85]

> Considering 85% of the area plan capex is for replacement, the EMRF finds it difficult to accept that the element of replacement capex should need to increase by over 40% when the average life expectancy of the network has increased throughout AA3 [the 2009-14 regulatory control period] as has service performance.

84 Ausgrid, *Regulatory Proposal*, p. 31
85 EMRF submission, August 2014, p.71

Figure A-11 Asset Age Profile

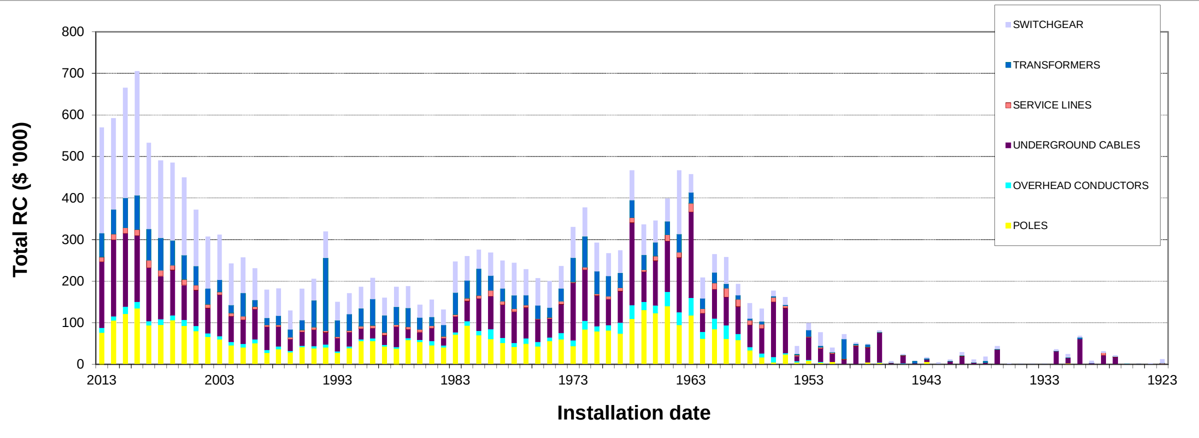


Figure A-11 shows the age of six of Ausgrid's asset groups, weighted by their replacement value. Ausgrid's asset base is heavily weighted towards new assets, which reflects its above-trend level of capex over the last ten years. Ausgrid also has a relatively large stock of assets from the 1960s and 1970s. Ausgrid's stock of older assets is low, with relatively few assets still in commission from the 1950s or earlier. Ausgrid's forecast repex for the 2014–2019 period, which averages more than $600 million a year, would effectively trend forward the peaks from the last five years, which sit well above the replacement value of assets in commission from earlier in the age profile.

The asset groups that comprise Figure A-11 are presented in Figure A-12 to Figure A-17 below. Ausgrid's average annual repex for the 2014–19 period is also presented as a line in these charts. For poles and service lines, 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 in a given year. For all other categories, the average annual forecast repex is, for the majority of years, well above the replacement value of the assets in commission (excluding recent years in the profile, which are not relevant for repex). This is particularly pronounced in the 'switchgear group', where Ausgrid has forecast most of its repex for the 2014–19 period. In switchgear, the average annual forecast repex exceeds the value of in commission assets in all years up until 2006. This suggests that Ausgrid's forecast significantly overestimates the stock of old assets in the network that need to be replaced.

Figure A-12 Asset age profile – Poles

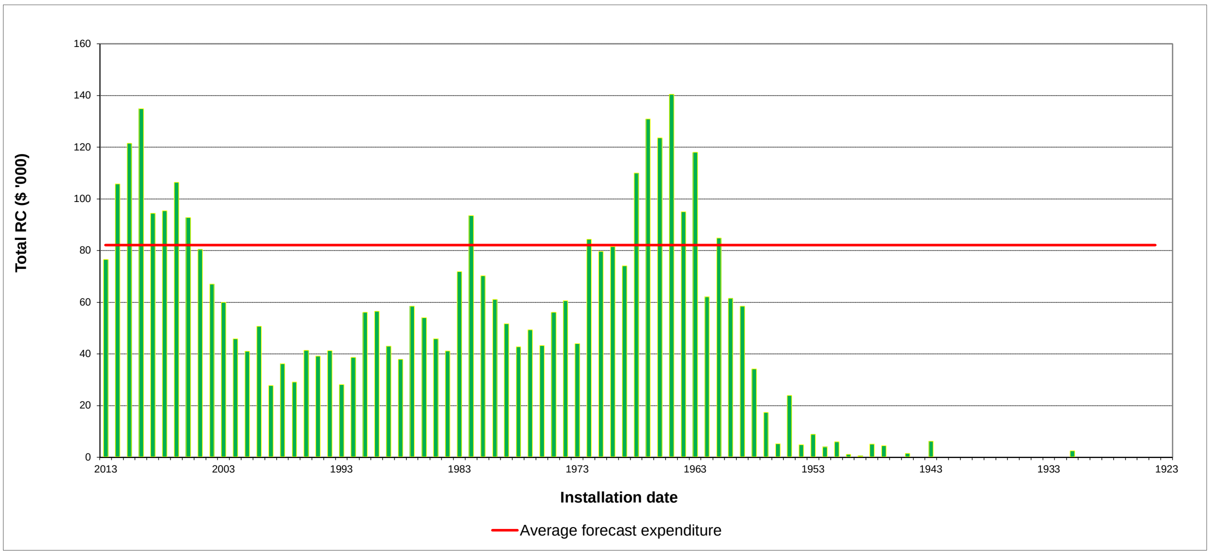


Figure A-13 Asset age profile – Overhead conductor

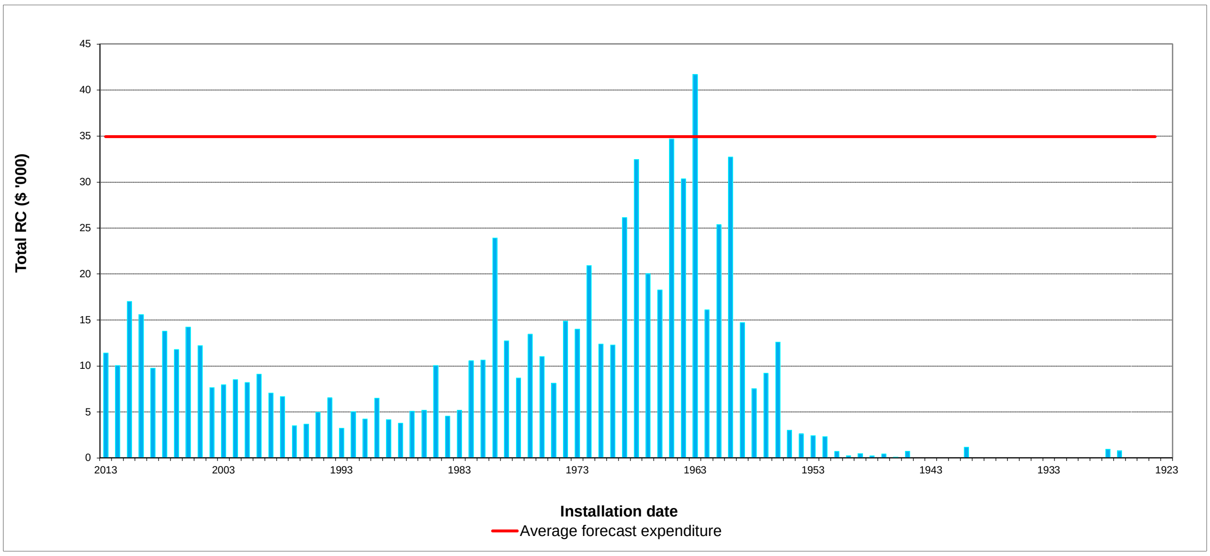


Figure A-14 Asset age profile – Underground cable

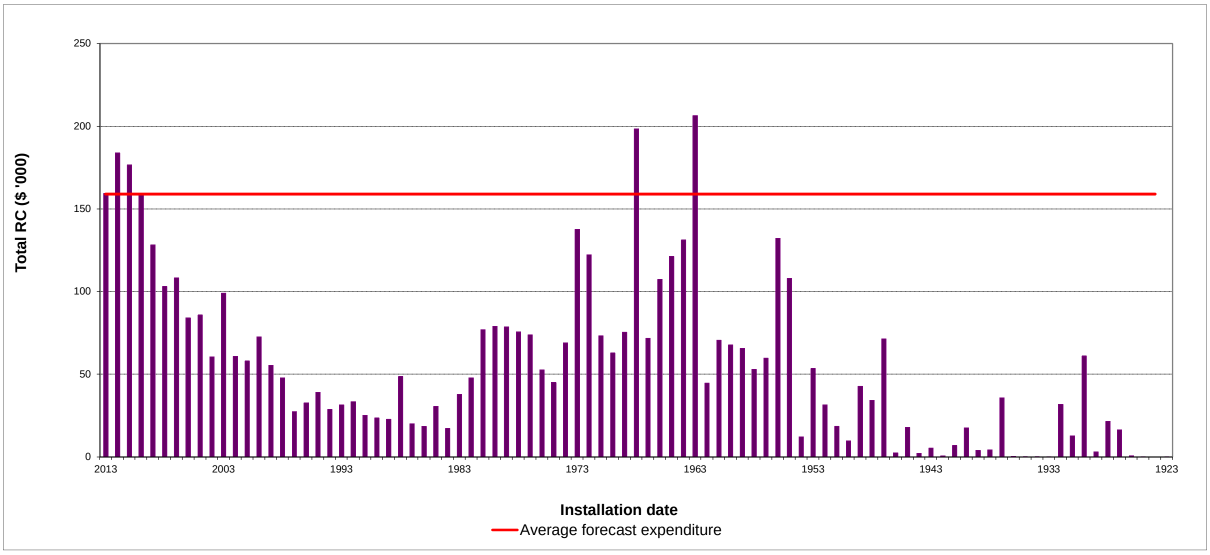


Figure A-15 Asset age profile – Service lines

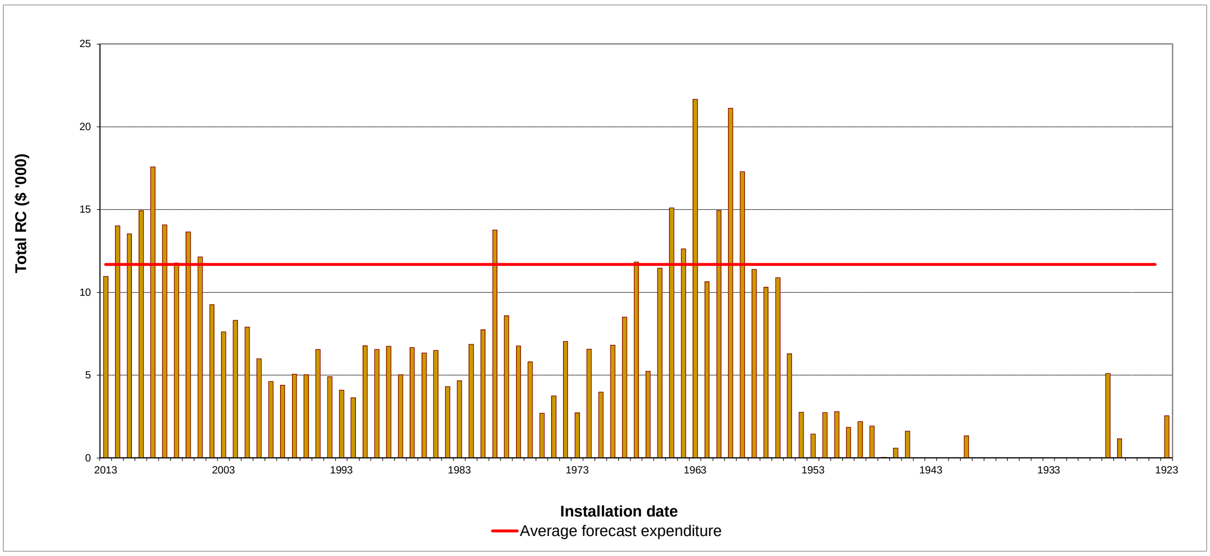


Figure A-16 Asset age profile – Transformers

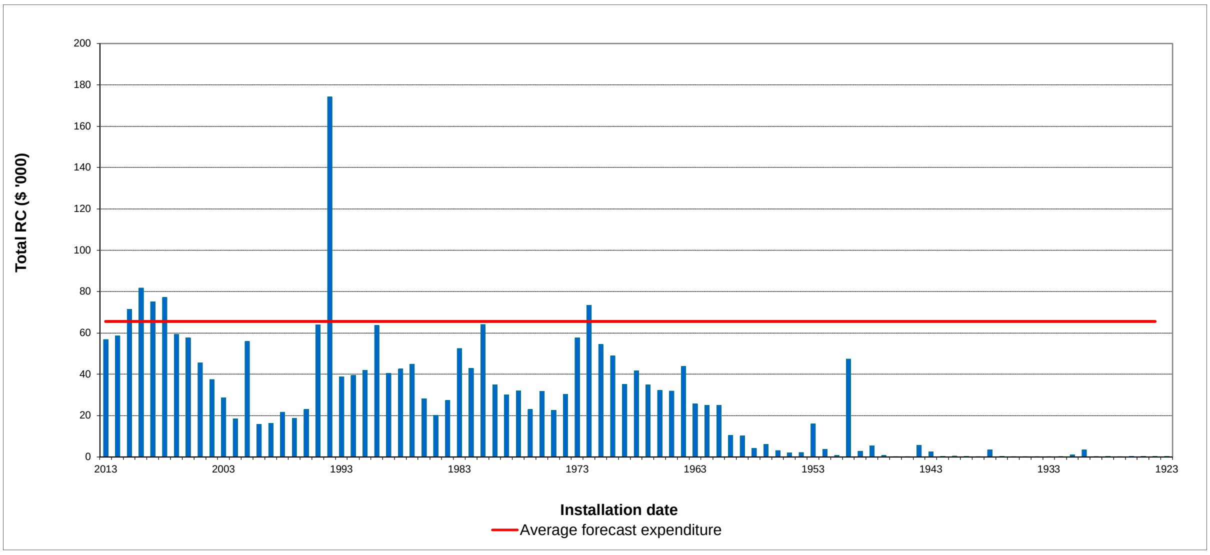
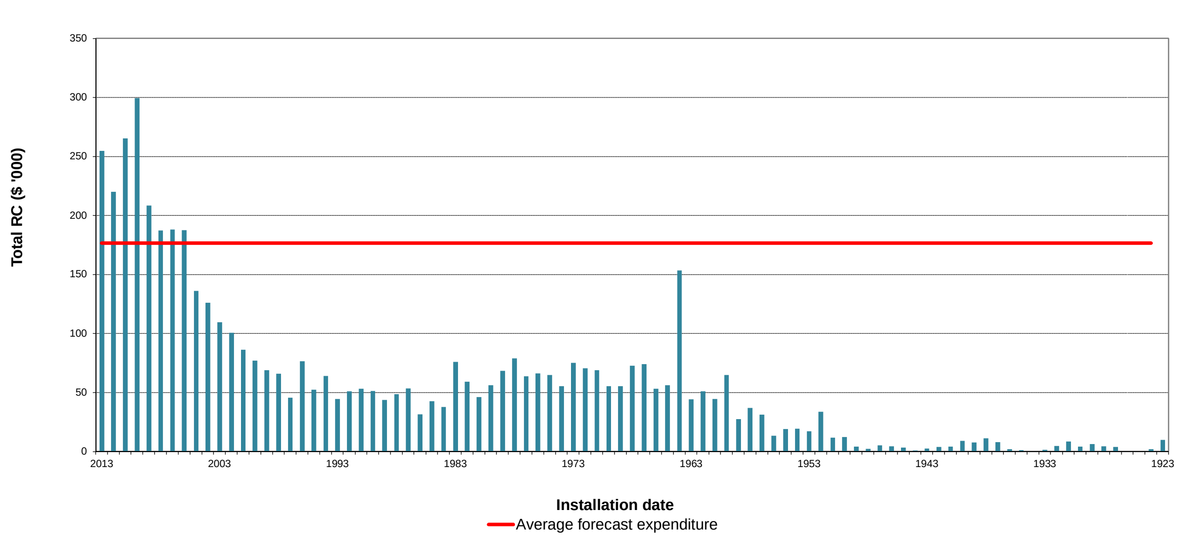


Figure A-17 Asset age profile – Switchgear



Asset utilisation

Another indicator of asset health is changes in the utilisation level of network assets.[86] As we discuss in our assessment of augex, Ausgrid has significant spare capacity in its network based on past investments to meet expected demand that did not eventuate. In general, we expect that there is a positive correlation between asset condition and lower network utilisation. Similarly, the EMRF commented that: [87]

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

Given Ausgrid is expected to have significantly increased spare capacity in its network during the 2014–2019 period, we consider that asset condition will also be positively impacted. This should result in reduced repex compared to the past.

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

Engineering review of Ausgrid's proposed repex forecast

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

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

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

87 EMRF submission, August 2014, p. 20.

We consider that EMCa's assessment reflects the capex criteria by seeking to assess whether Ausgrid is a prudent and efficient operator in its costs, work practices, and expectations.[88] 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.[89] Another example is in relation to Ausgrid's actual and expected repex in the previous regulatory control period, and the substitution possibilities between repex and opex (whether to replace or maintain).[90]

Given repex was a major component of Ausgrid's proposed total forecast capex, we engaged EMCa to provide expert advice on the issues identified above. Broadly, on these aspects EMCa found that:[91]

- Several systemic issues meant that Ausgrid's repex needs were overstated and its repex forecast was likely to have overestimation bias.
- Ausgrid's asset management decisions are characterised by a lack of robust options being considered, or cost-benefit analysis supporting the timing and volume of replacement activity. Ausgrid's repex program is also likely to have material deliverability risk.
- Ausgrid's approach to risk is overly conservative.

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

EMCa findings

EMCa notes that Ausgrid spent considerably less on repex than its approved forecast in the previous regulatory control period. It considers this evidences systemic overestimating bias in Ausgrid's cost forecasting methodology. While Ausgrid claims to have recognised and addressed the shortcomings EMCa remain unconvinced that Ausgrid's forecasting approach is sufficiently robust.[92]

EMCa finds that Ausgrid's repex forecasts have an overestimation bias:[93]

- Ausgrid tends to use overly conservative risk criteria, and its investment decision making relies heavily on risk-based justification.
- Ausgrid's forecasting approach is based on good industry practice, but at the project/program level it has inadequate justification of timing, explanation of the step-changes in some expenditures, and delivery risk management. Ausgrid justifies increases in proposed repex in the 2014–2019 regulatory control period with information on the age and condition of the network. However, EMCa finds this justification is undermined by several inconsistencies and contradictions in Ausgrid's rationale.
- Ausgrid's cost estimates are likely to be biased towards overestimating. Ausgrid applies contingency allowances to specific project estimates and as across portfolios. EMCa considers it is overly conservative to apply a contingency allowance at multiple levels.

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88 NER, cl. 6.5.7(c).
89 NER, cl. 6.5.7(a).
90 NER, cl. 6.5.7(e).
91 EMCa, *Review of Ausgrid's repex*, October 2014, p, i–iii.
92 EMCa, *Review of Ausgrid's repex*, October 2014, p. 12.
93 EMCa, *Review of Ausgrid's repex*, October 2014, pp. 15–20.

EMCa notes the Networks NSW Board reduced the overall expenditure forecast originally developed within Ausgrid by 24 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 processes used within Ausgrid were inadequate, either in terms of the prudency of the repex work proposed (volume and timing) or the cost of the work. Further, that the methodology used is a useful decision support tool, but on its own will not necessarily lead to an optimal portfolio.[94]

EMCa assessed the governance and management framework that Ausgrid uses to plan and approve its repex projects and programs. Although Ausgrid's governance approach has the most typical elements found in good industry practice, EMCa found material issues with Ausgrid's implementation.[95] EMCa considers the prudency of Ausgrid's repex is undermined as:[96]

- Ausgrid overstates the risk its assets pose as it uses a conservative operational risk framework, and applies likelihood and consequence findings conservatively.
- Ausgrid has insufficient quality data in some categories to make an optimal assessment of particular strategies and justify the volume and timing of repex.
- Ausgrid did not provide comprehensive cost benefit analysis to support some of its key asset strategies.

EMCa considered that Ausgrid is biased towards assessing risks as extreme or high, which makes it difficult for managers to discriminate between the numerous projects/programs, and will exaggerate the repex required (for both the level of repex needed and the urgency). Although Ausgrid is developing other methods and tools for more robust and quantitative portfolio management, it is yet to apply this to all cases or beyond project level analysis.[97]

EMCa also expects Ausgrid will experience deliverability issues that will lead to inefficiencies in delivering its planned repex program, particularly early in the 2014–2019 regulatory control period. EMCa cites, for example, that Ausgrid only recently established a project management office and has not yet developed a delivery strategy or plan for its proposed portfolio of replacement work. EMCa notes that Ausgrid's proposed forecast repex is based on future programs significantly different from historical work—higher volumes of smaller projects. It considers the resulting need for differing skill-sets will create deliverability challenges and may lead to inefficiencies, compounding delivery issues observed in the previous regulatory period. EMCa found no evidence that Ausgrid considered these issues adequately or that this is reflected in Ausgrid's proposed forecast repex.[98]

EMCa reviewed Ausgrid's proposed repex programs for each of the high level asset categories. Its findings at the repex program level supported the issues identified with Ausgrid's governance and management framework and forecasting methods. EMCa found that for the majority of work programs prudency and cost efficiency were undermined by:[99]

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94 EMCa, *Review of Ausgrid's repex*, October 2014, pp. i, 12–13; 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.

95 EMCa, *Review of Ausgrid's repex*, October 2014, p. 10.

96 EMCa, *Review of Ausgrid's repex*, October 2014, p. 9.

97 EMCa, *Review of Ausgrid's repex*, October 2014, pp. 13, 17.

98 EMCa, *Review of Ausgrid's repex*, October 2014, pp. iii, 13–14.

99 EMCa, *Review of Ausgrid's repex*, October 2014, pp. 17–18, 21–22.

- A lack of robust options, risk and cost-benefit analysis supporting the timing and volume of replacement activity. The identification and evaluation of multiple investment options (including the cost-benefit of deferral options) is not universally adopted.
- A lack of reliable asset condition and failure data.
- A variety of risk assessment approaches with a bias towards conservatism.
- Inadequate consideration of delivery management.
- Inadequate evidence to show Ausgrid addressed cost estimation errors from the previous regulatory period.
- A lack of business cases for the proposed work.

Predictive modelling

This section sets out our assessment of the findings from the predictive modelling of repex (the repex model).[100] 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 many factors that drive individual asset replacement.[101] Our approach to developing outputs from the repex model is detailed in appendix F.

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

We have also adopted a robust approach to scrutinising the outcomes of the model. By examining whether both inputs and outcomes are robust, we have narrowed the range within which expenditure is likely to reasonably reflect the capex criteria. This range, in conjunction with our other analytical techniques, informs our alternative estimate.[102]

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. Pole top structures and SCADA were not modelled, along with specialised categories of capex defined by Ausgrid that were not classified under the six groups above. In total, the assets modelled represent $2.6 billion or 84 per cent of Ausgrid's proposed repex.

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

Analysis of the reasonable estimation range

As outlined in appendix F, 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

[100] 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 F for details on our consultation).

[101] AER, Electricity network service providers, Replacement expenditure model handbook, November 2013, p. 10.

[102] AER Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013.

assessment techniques. These include our benchmarking results for total capex and repex, analysis of Ausgrid'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 Ausgrid (the base case model);
- replacement life information derived by using Ausgrid’s replacement volumes from the last five years (referred to as “calibrated lives”); and
- unit costs and replacement lives derived by comparing information from all service providers across the NEM (benchmarked replacement lives and unit costs).

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

The base case model

The base case model uses replacement life information inputs provided by Ausgrid 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 Ausgrid’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 $6.3bn and $3.8bn, respectively. These estimates are higher than Ausgrid’s forecast of $2.6bn for the six modelled asset groups.

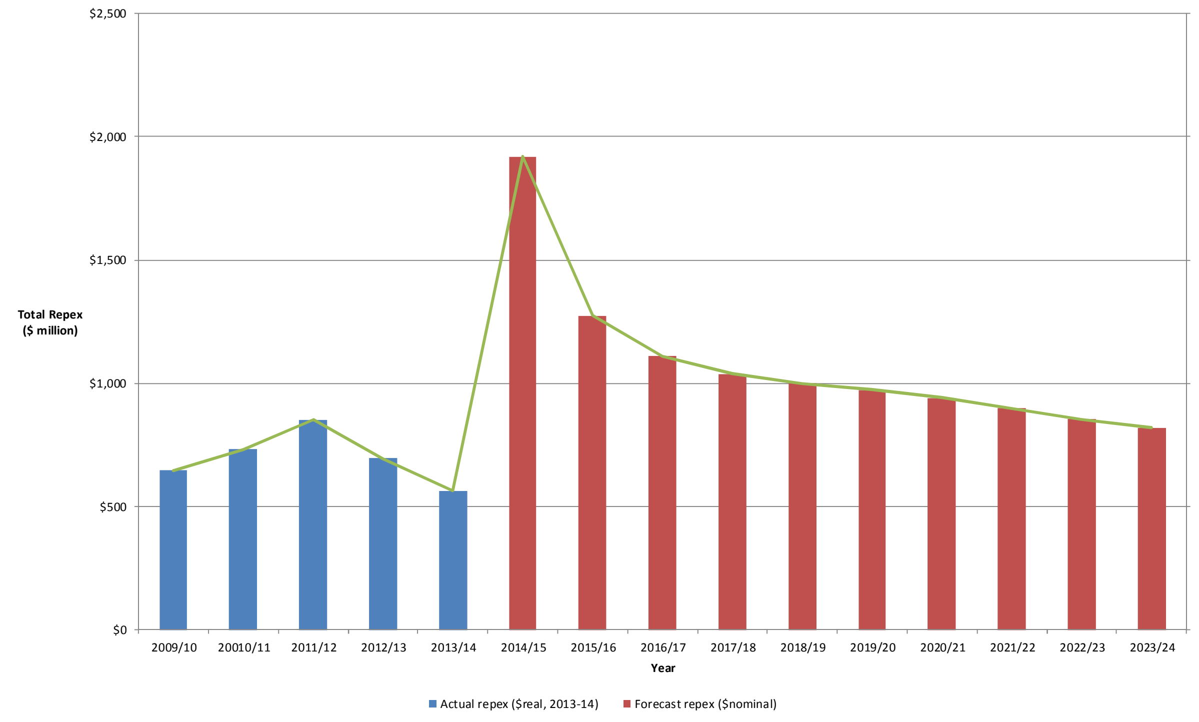
Table A-9 Base case model outcomes

Unit cost	Model outcome
Historical	$6,341.8
Forecast	$3,733.8

Source: AER analysis

The replacement profile predicted by the repex model under the base case scenario features a sharp step-up in expenditure in the first year of the forecast, which then declines over the remainder of the period (see Figure A-18). This replacement profile indicates that a significant portion of the asset population currently in commission has survived to an older age than would be expected using the base case replacement life figures submitted by Ausgrid. Using Ausgrid’s base case replacement lives causes the model to immediately predict the replacement of this stock of assets. This, in turn, results in a large stock of predicted asset replacements in the first year of the forecast, which then declines over time.

Figure A-18 Ausgrid's replacement expenditure from 2009-14 and expenditure predicted by the base case model



Source: Ausgrid, AER analysis.

In scrutinising the discrepancy between Ausgrid's forecast of $2.6bn and our base case outcomes, we consider that the base case outcomes are not credible or reliable for the reasons outlined below.

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

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

The 'step-up/trend down' replacement profile observed from the base case model suggests that a significant proportion of the asset population has survived longer than would be expected using Ausgrid's data. The 'survivor' assets have a material effect on the observed outcome. This outcome suggests that the base case replacement lives are shorter than those achieved in practice. We have undertaken further analysis to determine replacement life information that matches Ausgrid's actual replacement practices.[103] This work is outlined in appendix F.

Second, our detailed assessment of Ausgrid's forecasting process and assessment of asset risks identified a strong bias towards early replacement of assets, and the likelihood of systemic overestimation of repex. Furthermore, our assessment of Ausgrid's repex trends over the past

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

13 years showed its forecast repex to be significantly above its long-term trend. Based on these assessments, our expectation is that the prudent and efficient level of repex is likely to be well below the outcomes in the base case modelling and materially lower than Ausgrid's forecast.

Third, further analysis of the base case model results reveals the replacement life inputs are the main drivers of the base case outcome. If the base replacement life information is substituted with calibrated lives (and unit costs are held constant) the model outputs are $2.5 billion for historical unit cost and $1.4 billion for forecast unit cost (the calibrated model is discussed in the next section). Taken together with the information from our other analytical techniques and our concerns that the base case lives do not reflect Ausgrid's actual replacement practices, we consider that the base case replacement life information provided by Ausgrid will not result in a reasonable range for repex.

The selection of unit costs also leads to materially different estimates. Inputting historical unit costs results in an estimate that is $2.6 billion higher than inputting forecast unit costs. To assess the suitability of both as inputs, we compared both to a benchmark average of unit costs for all service providers. In doing so, we note that both forecasts, historical unit and forecast unit, include total costs[104] whereas all other NSPs reported on a direct cost basis to allow comparability when benchmarking unit costs. Despite this, the forecast unit costs do not give significantly higher model outputs than those provided by using a benchmark average of unit costs from all service providers (the benchmarked model is discussed below). Conversely, historical unit costs provide a much higher estimation of repex when assessed against the benchmark average. Given this observation, we consider that the forecast unit costs are more likely to result in an estimate that reasonably reflects prudent and efficient costs than if our estimate were to use historical costs. For these reasons we have excluded observations based on historical unit costs from the output range. However, we have used forecast unit costs as an input when testing the outcomes from the calibrated and benchmarked models.

The calibrated model

The calibrated model uses replacement lives and standard deviations based on Ausgrid'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. However, as noted above, we do not consider historical unit costs are appropriate for the purpose of arriving at a reasonable range of outputs. The benchmarked unit costs are discussed in the benchmark model section below.

Table A-10 Calibrated model outcomes

Unit cost	Model outcome
Historical	$2,468.2
Forecast	$1,429.8
Benchmark average	$1,355.5
Benchmark first quartile	$979.1
Benchmark lowest	$681.8

Source: AER analysis.

104 Ausgrid was advised of this issue but did not provide updated information.

Using calibrated replacement lives and Ausgrid's forecast unit costs gives an output of $1.4 billion. The calibrated replacement life estimate provides a substantially lower predicted volume and expenditure forecast than Ausgrid's forecast, despite essentially trending forward Ausgrid's observed replacement practices from the last period. It may be expected that trending forward average replacement lives from the 2009-14 regulatory control period will lead to a similar outcome to the last period – which would in turn be similar to Ausgrid's forecast. However, the historically high volume of asset replacement work that Ausgrid has carried out over the last five years is likely to have changed its asset age profile from five years ago. That is, by spending a large amount on repex in the last regulatory control period, Ausgrid is expected to have replaced a significant number of its older assets. This in turn may be expected to reduce the overall age of its network. If the average replacement life and standard deviation stays the same, but the network's overall age is reduced, fewer assets will need to be replaced in the next period.

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

> In previous determinations, the AER has used 'calibration' functions when the base case suggests that a far higher level of expenditure is warranted. In these cases, the AER has used most recent historical data or substituted benchmarking data to 'refit' the model to derive alternative outcomes. When the AER has re-calibrated the models they have found that DNSP's proposed forecasts exceed the predicted values of the model.
>
> In our view this raises significant concerns with the validity of the model given that the 'base case' could produce results that the AER considered were invalid. In these cases, it would be incorrect to use a flawed model with different input data (either benchmark of past expenditure) to derive a conclusion that the AER considered was not anomalous. In our view, this is a type of backsolve to validate the use of the model.[105]

In our Explanatory Statement to the Expenditure Forecast Assessment Guideline, we addressed concerns with the model and updated the Replacement expenditure model handbook to address specific issues.[106] This concern as raised by Networks NSW in this determination was not submitted at the time we consulted on our Guideline but we acknowledge that with any modelling there is always room for disagreement. In our Explanatory Statement to our Guideline we expressly recognised that we will attempt to resolve issues with the repex model as they arise.

After considering the concerns raised by NSW Networks, our view is that these concerns are unfounded. The model is based on well-established principles of probability and normal distribution. It has been used by the AER previously and has similar characteristics to the model used by OFGEM.[107] We do not accept that the model is flawed because we use different input data. In our view, it is good practice to scrutinise the inputs having regard to the outcomes and when viewed against the regulatory proposal which is the subject of our determination. We consider this good practice.

We further note, as foreshadowed in the Explanatory Statement to our Guideline that we will use the repex model as a first pass model, in combination with other techniques.[108] It is not used in isolation, but one of a number of analytical tools.

In this instance, for Ausgrid, the base case outcomes may be "invalid" as Networks NSW might describe our findings, but nonetheless the discrepancy they reveal has provided further focus for our

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

enquiry. Due to that discrepancy, it is correct that we assess the robustness of the inputs used in order to explain the reliability, or not, of the outcomes. This assists us in narrowing the range of what is reasonable.

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

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

> The model may also be calibrated to compare actual levels of expenditure undertaken in the current period. We consider that this assumption may not necessarily provide a reflection of the level of expenditure needed to maintain the safety and reliability of the network. This is for 3 reasons:
>
> - A DNSP may change in planning standards or risk assessments, driving a change in replacement levels compared to the past. Indeed this was the experience encountered by NSW DNSPs in the mid 2000s when comprehensive reviews identified a need to increase levels of replacement due to under-investment in the past.
> - New standards might be imposed in terms of safety, environmental or worker safety that necessitates an increase in replacement needs.
> - A DNSP may detect a change in failure rates or risks for an asset class prompting the need to develop a proactive replacement program.[109]

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

Further, our draft decision is being made on the information available to us at present. Ausgrid's failure rates or risk may change in the future, irrespective of whether a repex model is used. This is not a valid reason to exclude the calibrated lives.

It is important also to take into account the following. Our assessment earlier in this attachment indicates that Ausgrid takes a very risk averse approach to its projects and in the application of contingencies.[110] We consider using calibrated lives will trend forward this risk aversion, which would lead to the outcomes potentially overstating the efficient volume of replacement.

We are satisfied that the use of recent historical behaviour to derive a replacement life is a reasonable approach to finding an input for the purposes of establishing a reasonable range of repex for the 2014–19 regulatory control period. Compared to the base case lives supplied by Ausgrid, the calibrated lives estimate a lower volume of replacement, which is more in line with the results from our other assessment techniques. However, we also consider it appropriate to test the outcomes of the calibrated model against benchmarked inputs derived from other service providers.

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109 Networks NSW, *Report - REPEX Model Review*, May 2014. p. 11.
110 EMCa, *Review of Ausgrid's repex*, p. 20.

The benchmarked model

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

Benchmark of uncalibrated service provider submitted replacement lives

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

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

Unit cost	Model outcome
Historical	$6,741.9
Forecast	$4,175.2
Benchmark average	$3,649.8
Benchmark first quartile	$2,485.7
Benchmark lowest	$1,562.1

Source: AER analysis.

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

Unit cost	Model outcome
Historical	$5,405,248.3
Forecast	$3,278,746.9
Benchmark average	$2,785,504.3
Benchmark first quartile	$1,932,843.9
Benchmark lowest	$1,239,573.8

Source: AER analysis.

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

Unit cost	Model outcome
Historical	$5,163.7
Forecast	$3,495.0
Benchmark average	$2,673.9
Benchmark first quartile	$1,941.5
Benchmark lowest	$1,357.5

Source: AER analysis.

Benchmark of calibrated replacement lives

We also calculated calibrated replacement life information for each service provider and derived benchmarks from these observations. Using the benchmarked calibrated replacement life information from all service providers in the NEM in the repex model results in a repex estimate of $1.4 billion using forecast unit costs. Using replacement lives one quartile above the mean gives an estimate of $1.2 billion, while using the longest observed replacement life in the NEM gives an estimate of $0.99 billion.

The average benchmarked calibrated replacement life observation is lower than Ausgrid's own calibrated model outcomes. The first quartile observation is substantially lower than the average, while the longest observed replacement life gives a very low estimate of repex.

While the calibrated benchmark replacement lives provide a useful set of results for analytical purposes, we have decided not to include them in the reasonable range. The calibrated benchmark replacement lives will reflect to some extent the circumstances of a service provider (such as their age profile) and so we have only used this information as a useful check on Ausgrid's calibrated model outcomes, and we will consider using this benchmarked data in future regulatory decisions.

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

Unit cost	Model outcome
Historical	$2,736.8
Forecast	$1,427.9
Benchmark average	$1,017.4
Benchmark first quartile	$796.2
Benchmark lowest	$654.1

Source: AER analysis.

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

Unit cost	Model outcome
Historical	$2,393.5
Forecast	$1,159.9
Benchmark average	$809.9

Benchmark first quartile	$657.7
Benchmark lowest	$566.9

Source: AER analysis.

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

Unit cost	Model outcome
Historical	$2,138.7
Forecast	$993.2
Benchmark average	$677.1
Benchmark first quartile	$573.2
Benchmark lowest	$495.7

Source: AER analysis.

Unit cost

Using a replacement unit cost based on an average benchmark results in an estimate of $1.38bn for the six modelled asset groups (using forecast unit cost).[111] This is lower than the outcome achieved using Ausgrid's forecast unit costs. We consider that the benchmarked average unit cost is a useful comparison with the cost of other service providers in the NEM and have included these values it in the reasonable range. We have decided to exclude the outcomes of both the first quartile and the lowest unit cost unit price benchmarking. Using the lowest observed unit cost or a unit cost one quartile below the mean results in a much lower estimate of repex for Ausgrid. At the lowest unit cost, or the frontier, we are relying on a single observation, whereas the average benchmark is based on all observations from the NEM (after controlling for outliers, as discussed in appendix F). We consider the average benchmark, which is based on multiple observations, is more reliable of the average cost of replacement in the NEM.

Table A-17 Benchmarked model outcome – Unit costs

Replacement life	Unit cost	Model outcome
Calibrated	Forecast	$1,429.8
Calibrated	Benchmark average	$1,355.5
Calibrated	Benchmark first quartile	$979.1
Calibrated	Benchmark lowest	$681.8
NSP benchmark average (calibrated)	Forecast	$1,427.9
NSP benchmark average (calibrated)	Benchmark average	$1,017.4

111 The benchmarked unit costs are input into the calibrated model, and replace the forecast unit costs.

Replacement life	Unit cost	Model outcome
NSP benchmark average (calibrated)	Benchmark first quartile	$796.2
NSP benchmark average (calibrated)	Benchmark lowest	$654.1

Source: AER analysis.

The reasonable range

The discussion above established the inputs that we consider provide a reasonable estimate of repex for Ausgrid. Based on our predictive modelling, we are of the view that Ausgrid's efficient repex for those categories that have been modelled is between $1.36bn and $1.43bn. The final estimate of efficient repex will involve the weighing up of all information, indicators and techniques.

Unmodelled repex

Repex categorised as: supervisory control and data acquisition (SCADA), network control and protection (collectively referred to hereafter as SCADA); Pole top structures; and "Other" in Ausgrid's RIN response was not included in the repex model. As noted in Appendix F, 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 $459 million of Ausgrid's 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 Ausgrid's forecasting method. Our analysis of these is included below.

SCADA, network control and protection

Ausgrid has proposed repex of $252 million for SCADA, network control and protection (referred to as SCADA). This represents a 58 per cent increase over the 2009–14 regulatory control period, or $92 million.

Ausgrid's expenditure on SCADA declined over the 2009–14 regulatory control period. Ausgrid's proposal for the next period provides for:

- a step increase in repex over the first two years of the 2014–19 period; and
- a decline over the remaining three years, which nonetheless remains above the repex incurred in any year of the 2014–2019 period.

We would expect that a step-change of this magnitude, which is not only large, but goes against the observed trend from the last period, would be justified by evidence of replacement need and supporting information.

EMCa reviewed Ausgrid's SCADA as part of its advice. EMCa considered there was inadequate condition based support for the proposed increased expenditure. EMCa considered that the forecasts put forward by Ausgrid do not provide analysis of credible replacement alternatives, and did not provide sufficient evidence that the costs incurred in undertaking the works are efficient. EMCa concluded that Ausgrid's supporting documents did not present an appropriate level of analysis and justification to support an expenditure program of above $100 million. 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.[112]

In reaching our view on Ausgrid's SCADA, we have not only considered EMCa's specific views on SCADA, abut also its overall views on systemic issues with Ausgrid's forecasting approach and assessment of risk. We have also indirectly taken account of the repex modelling results, which indicates Ausgrid has, in aggregate, forecast a higher than necessary volume of repex for the 2014–19 period.

Ausgrid submitted an updated RIN on 12 September 2014, where it reallocated categories of capex previously not included in one of the defined asset groups into the SCADA group. This resulted in its repex forecast for SCADA being $138 million higher than in its original proposal. While the scale of Ausgrid's SCADA is changed by these additions, the systemic issues identified by EMCa and the lack of supporting evidence to justify the step change, remain.

Taking all of this into account, we see no justification for the step change proposed by Ausgrid. We are satisfied that Ausgrid's SCADA repex from last period of $160 million is sufficient to meet the capex criteria.

Pole top structures

Ausgrid has forecast $68 million of expenditure on pole top structures over the 2014–19 period. Ausgrid has not provided historical expenditure on pole top structures from the 2009–14 period. As we do not have a historical expenditure to compare the forecast against, we have used our findings and observations from our other assessment techniques to aid our analysis.

First, EMCa's review of Ausgrid's pole replacement program indicated that it had reservations around the escalation in pole replacement expenditure towards the end of the 2014–19 period, the deliverability of the program and the unit cost of pole replacement. However, EMCa did consider that Ausgrid had provided analysis supporting its strategy.[113] Predictive modelling provides a range of outcomes, the highest of which, using Ausgrid's own costs and calibrated replacement lives, is closer to Ausgrid's proposal, while the lower figure, based on benchmarked inputs, is lower.

We consider that EMCa's findings on pole replacements accords with the higher observation from predictive modelling. We have used this to infer that Ausgrid's forecast expenditure on pole top structures is likely to be reasonable.

Other repex

Ausgrid categorised a number of assets under an "Other" asset group in its RIN response. Ausgrid forecast $138 million of repex for these assets for the 2014–19 period. The assets include:

- Distribution voltage regulation
- Buildings
- STS Reactors and Capacitors
- Sub-Transmission Main OH Easement

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[112] Ausgrid submitted an updated RIN on 12 September 2014, where it moved categories of capex previously not included in one of the defined asset groups into the SCADA group. This resulted in its repex forecast for SCADA being $138 million higher than in its original proposal.

[113] EMCa, *Review of Ausgrid's repex*, p. 32.

- STS Building
- STS DC Systems
- Zone Reactors and Capacitors.

Ausgrid's "Buildings" asset subcategory is the largest of these, with $111 million forecast for the 2014–19 period. This is $53 million, or 32 per cent lower than its expenditure on "Buildings" in the 2009–14 period. In total, Ausgrid's expenditure on repex for assets in the "other" asset group is, $59 million, or 30 per cent lower than it was in the 2009–14 period. Given the significant downward trend, we have not undertaken a review of this category. We also consider that this trend accords better with our observations from predictive modelling, and the long term trend in total repex. We are therefore satisfied that the total of $111 million in the "other" asset group is likely to be a prudent and efficient level of repex.

A.4 AER findings and estimates for reliability improvement capex

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

Ausgrid proposed $28.3 million ($2013–14) of forecast capex related to its network reliability performance obligations. Ausgrid has proposed $23 million ($2013–14) for individual feeder performance, where a feeder is expected to exceed the thresholds in Schedule 3 of its licence obligations. The remaining $4 million ($2013–14) is proposed to address poor reliability on feeder segments where this is considered to be technically and economically feasible[114]. Ausgrid submitted that this expenditure is not covered by its proposed augmentation and repex.[115]

We also recognise that Ausgrid has undertaken a top down assessment to forecast capex for this category of expenditure based on historical expenditure. Given historical individual feeder performance is likely to be a guide to future individual feeder performance we consider that Ausgrid's proposed methodology is sound. However, we have not accepted this amount for the purpose of the draft decision on the basis that Ausgrid has not identified what component of this proposed capex is augex and repex related. This information is necessary to ensure we do not double count this expenditure (e.g. if this expenditure is mainly repex related we have already taken this into account in our alternative estimate of repex. It is also not clear to us the extent to which Ausgrid's proposal is related to its proposed improvement in SAIDI during the 2014–2019 period. To this end it also remains unclear whether this expenditure should form part of Ausgrid's total forecast capex, given any improvements that are valued by customers should be funded through the STPIS.

Accordingly, we expect Ausgrid to provide further information in its revised regulatory proposal regarding the portion of this forecast that is considered to be augex and repex. We also expect Ausgrid 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.

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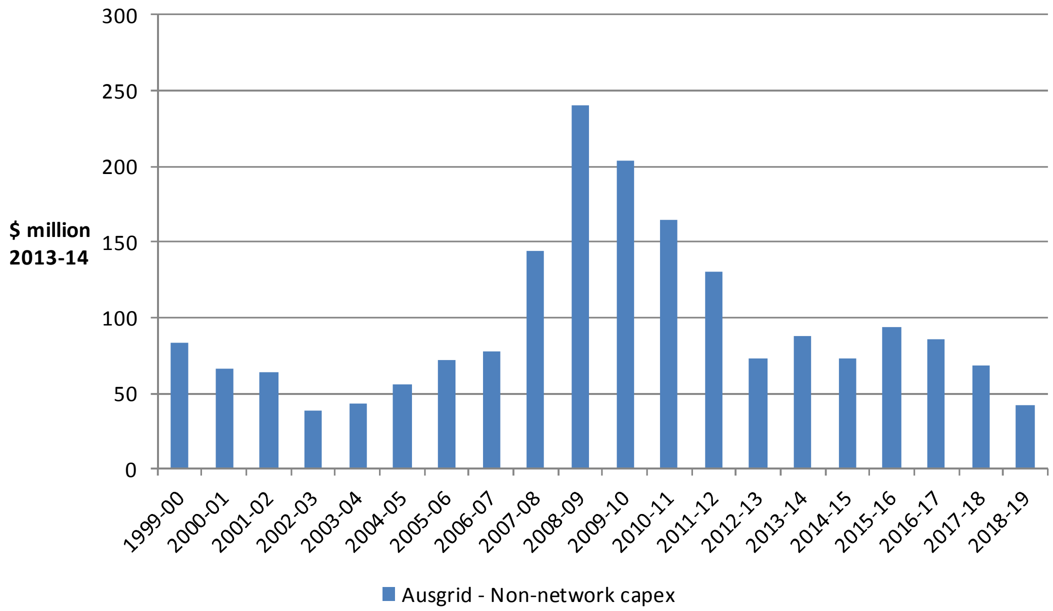
114 Ausgrid, *Attachment 5.26 - Overview of the reliability investment plan for 2014-19*, May 2014, p. 21.
115 Ausgrid, *Attachment 5.26 - Overview of the reliability investment plan for 2014-19*, May 2014, p. 19.

A.5.1 Position

Ausgrid proposed $307.6 million ($2013–14) of forecast non-network capex.[116] We do not accept Ausgrid's proposal. We have instead included an amount of $279.2 million ($2013–14) in our alternative estimate. This is nine per cent less than Ausgrid's proposal. In coming to this view, we applied our assessment approach that we discuss in appendix C.

Figure A-19 shows Ausgrid's historical non-network capex for the regulatory periods from 1999–00 to 2013–14, and forecast capex for the 2014–19 period.

Figure A-19 Ausgrid's non-network capex 1999–00 to 2018–19 ($million, 2013–14)



Source: Ausgrid, *Regulatory information notice*, template 2.6; Ausgrid, *Attachment 5.21 - Capex by asset class for previous, current and forecast period*, 31 May 2014; EnergyAustralia, *RIN response for 2009-14 regulatory control period, template 2.2.1*; AER analysis.

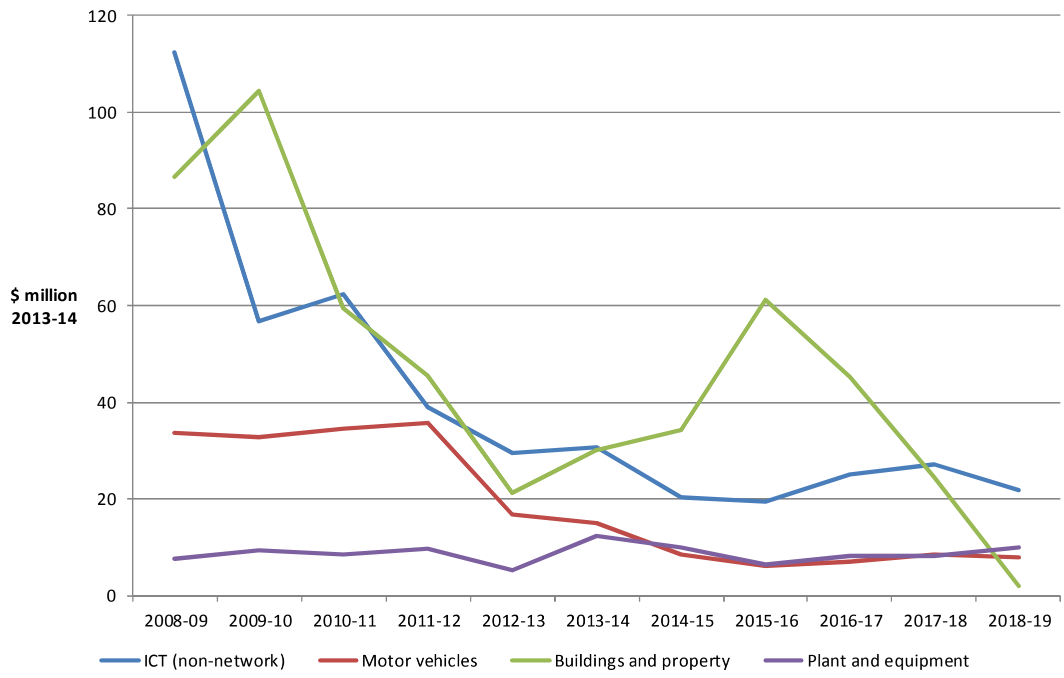
Ausgrid's forecast non-network capex for the 2014–19 period is approximately 45 per cent lower than actual and expected capex in the 2009–14 regulatory control period. This is greater than Ausgrid's forecast reduction in total capex of 37 per cent.[117] Our analysis of longer term trends in non-network capex suggests that Ausgrid has forecast capex for this category returning to historically low levels, with the exception of the 2015–16 and 201–17 years.[118] Non-network capex in 2015–16 is forecast to be higher than each of the three preceding years. Ausgrid's forecast non-network capex in both 2015–16 and 2016–17 is higher than actual capex in any year prior to 2007–08 for which comparable data is available. We therefore consider that Ausgrid's forecast non-network capex program warrants further review to confirm the need and timing for the proposed expenditure, with particular focus on the 2015–16 and 2016–17 years.

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

116 Ausgrid, *Attachment 5.20 - Total capex forecast for 2014-19*, May 2014; AER analysis. Excludes capitalised overheads.
117 Ausgrid, *Regulatory proposal*, 31 May 2014, p. 30.
118 NER, cl. 6.5.7(e)(5).

warrant further review.[119] Figure A-20 shows Ausgrid's actual and forecast non-network capex by sub-category for the period from 2004–05 to 2018–19.

Figure A-20 Ausgrid's non-network capex by category ($million, 2013-14)



Source: Ausgrid, *Regulatory information notice*, template 2.6; Ausgrid, *Attachment 5.21 - Capex by asset class for previous, current and forecast period*, 31 May 2014; AER analysis.

Ausgrid has forecast capex reductions for all categories of non-network capex in the 2014–19 period. Significant reductions are forecast for ICT, motor vehicles and buildings and property capex, while plant and equipment capex is forecast to decline slightly in the 2014–19 period. This follows historically high levels of expenditure in the 2009–14 regulatory control period, with the exception of the plant and equipment category.[120]

Forecast capex for each category is relatively smooth and at historically low levels across the 2014–19 period, with the exception of buildings and property capex. The significant spike in buildings and property capex in 2015–16 and 2016–17 is driving the high level of non-network capex forecast for those years compared to all other years of the 2014–19 period, as noted above. We therefore sought further information from Ausgrid in relation to its buildings and property program to confirm the need and timing of the forecast capex.[121]

Buildings and property capex

$142.2 million ($2013–14) of Ausgrid's proposed forecast of non-network capex is for its buildings and property program in the 2014–19 period.[122] The majority of this expenditure relates to the replacement or refurbishment of ageing depot buildings. Ausgrid also forecast expenditure to enable the consolidation of its CBD office accommodation following a reduction in staffing levels and the NSW Government's sale of Ausgrid's George Street head office building. Three major depot replacement or

[119] NER, cl. 6.5.7(e)(5).
[120] Ausgrid, *Attachment 5.21 - Capex by asset class for previous, current and forecast period*, 31 May 2014; AER analysis.
[121] AER, *Information request AUSGRID 031*, 1 September 2014.
[122] Excludes capitalised overheads.

refurbishment projects, at Chatswood, Homebush and Alexandria, account for the majority of the forecast depot expenditure.[123]

Having reviewed the business cases and other documentation submitted by Ausgrid in support of its forecast buildings and property capex, we sought further information to support the need, timing and costs of the proposed program, focussing on the major depot projects at Chatswood, Homebush and Alexandria.[124] Our conclusions in relation to the timing and quantum of Ausgrid's forecast capex are summarised below.

Timing of ***buildings and property capex***

Ausgrid's forecast buildings and property capex is substantially front-loaded, with approximately 85 per cent of forecast capex scheduled in the first three years of the 2014–19 period. Ausgrid submitted that the scheduling of projects was based on a number of factors, including the need to accommodate staff or inventory at other locations with fixed term lease agreements, and coordination with state infrastructure projects or neighbouring redevelopment.[125] However, Ausgrid also acknowledged that it had scheduled projects earlier in the regulatory period to assist in managing the delivery risks associated with the planning consent process. Ausgrid stated that:[126]

> past experience has proven that … the timing of expenditure will flex with either delays or expedited planning consents, design development, latent conditions within the ground and inclement weather related to construction.

We consider this represents evidence that Ausgrid's schedule of expenditure is intentionally front-loaded and is unlikely to be achieved in practice. The delivery risks identified by Ausgrid are highly likely to result in project deferrals rather than any expedition of the projects. We agree with Ausgrid that past experience suggests the timing of expenditure will vary from that proposed, particularly when expenditure is front-loaded. Ausgrid's buildings and property capex in the 2009–14 regulatory control period was also front-loaded, with approximately 43 per cent of forecast capex for the period scheduled in the first year, 2009–10. Actual expenditure in 2009–10 was 14 per cent less than forecast.[127]

Having considered the information provided by Ausgrid, and had regard to actual expenditure in the 2009–14 regulatory control period,[128] we consider that Ausgrid's proposed front loading of non-network buildings and property capex is not justified and reflects a schedule which is unlikely to be delivered in practice. We consider that forecast non-network property capex should be more equally distributed over the five years of the 2014–19 period to reflect a realistic expectation of capex delivery.

Quantum of ***buildings and property capex***

Ausgrid submitted that, having experienced significant structural change in the 2009–14 regulatory control period, and reassessed its property strategy and the scope of proposed projects, it can now confidently confirm its forecasts for the 2014–19 period.[129] However, for the reasons set out below, we consider that Ausgrid's non-network buildings and property capex is likely to be overstated, and does

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123 Ausgrid, *Attachment 5.28 - Overview of non-system property capex*, May 2014, pp. 17–18.
124 AER, *Information request AUSGRID 031*, 1 September 2014.
125 Ausgrid, *Response to AER information request AUSGRID 031*, 9 September 2014, p. 1.
126 Ausgrid, *Response to AER information request AUSGRID 031*, 9 September 2014, p. 1.
127 Ausgrid, *Attachment 5.28 - Overview of non-system property capex*, May 2014, p. 10.
128 NER, cl. 6.5.7(e)(5).
129 Ausgrid, *Response to AER information request AUSGRID 031*, 9 September 2014, p. 2.

not reasonably reflect the efficient costs a prudent operator would require to meet the capex criteria.[130]

Ausgrid's property plan states that a number of projects planned for the 2005–09 regulatory control period were completed in the 2009-14 regulatory control period, for example the Thornton Pole Store and Silverwater Learning Centre.[131] Similarly, the property plan lists 10 projects or programs commenced in the 2009–14 regulatory control period but not yet completed.[132] This includes the Ourimbah depot project, for which Ausgrid forecasts further capex of $8 million in the 2014–19 period. Major projects at Alexandria and Chatswood were planned for the 2009–14 regulatory control period, but were deferred and have been re-scoped and proposed again for the 2014–19 period.[133] Based on this observed historical pattern, and despite the re-scoping that has already occurred in relation to Alexandria and Chatswood, we consider it likely that a proportion of projects proposed by Ausgrid for the 2014–19 period will again be re-scoped, deferred or not completed within the period.

Ausgrid's actual non-network buildings and property capex in the 2009–14 regulatory period was only $9 million below forecast capex for that period.[134] This indicates that projects deferred in the 2009–14 regulatory control period, such as the $85 million proposed for the Alexandria depot, were largely replaced with new projects arising from increases in staff numbers and the volume of system works.[135] These factors are not relevant to the 2014-19 period, and instead, the reverse is likely to apply. Ausgrid's staffing numbers and system work volumes are forecast to decline across the 2014–19 period, and we have made further reductions to other elements of Ausgrid’s capex program in this draft decision. We therefore consider that any deferrals or scope adjustments within the 2014–19 period due to project specific factors are unlikely to be offset by new projects.

In regard to the timing and cost of the three major depot projects at Chatswood, Homebush and Alexandria, we queried whether these projects had been approved by Ausgrid's Board in accordance with the project schedule set out in the business case for each project.[136] Ausgrid advised that Board approval is, in each case, now expected to occur 12-15 months later than the date scheduled in the business case.[137] Further, we are not satisfied that the cost information presented in Ausgrid's business cases reflects a reasonable estimate of the efficient cost of the projects. For example, the business case for the Chatswood depot project states that:

> as the project is at a feasibility stage, the capital commitment costs were derived generally in accordance with the master plan opinion of probable cost.

Ausgrid's property plan states that the accuracy of master plan order of cost estimates is typically plus or minus 40 per cent.[138] On this basis, we are not satisfied that the schedule and cost information presented in Ausgrid's business cases fully supports the forecast capex for non-network buildings and property projects.

Conclusion

The amount of forecast buildings and property capex and forecast other non-network capex that we have included in our alternative estimate is $279.2 million ($2013–14). This reflects a reduction from

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130 NER, cl. 6.5.7(c)(1).
131 Ausgrid, *ID29045 Property plan - capital requirements FY 14/15 to FY18/19*, March 2014, p. 7.
132 Ausgrid, *ID29045 Property plan - capital requirements FY 14/15 to FY18/19*, March 2014, pp. 6–7.
133 Ausgrid, *ID29045 Property plan - capital requirements FY 14/15 to FY18/19*, March 2014, p. 7.
134 Ausgrid, *Attachment 5.28 - Overview of non-system property capex*, May 2014, p. 10.
135 Ausgrid, *Attachment 5.28 - Overview of non-system property capex*, May 2014, p. 11.
136 AER, *Information request AUSGRID 031*, 1 September 2014.
137 Ausgrid, *Response to AER information request AUSGRID 031*, 9 September 2014, pp. 6,8 and 9.
138 Ausgrid, *ID29045 Property plan - capital requirements FY 14/15 to FY18/19*, March 2014, p. 31.

Ausgrid's proposed forecast of $142.2 million ($2013–14) to $113.8 million ($2013–14) for its buildings and property program in the 2014–19 period. This is 20 per cent less than Ausgrid's proposal. It is also equivalent to a 12 month deferral of Ausgrid's smoothed total capex forecast for this category.

In our view, this accounts for the identified delay in the schedule of major projects and the likelihood of future refinements in project scope and cost.

This is based on applying our assessment approach and our finding that Ausgrid's forecast buildings and property capex is front-loaded and overstated due to the likelihood of future changes in project timing, scope and cost.

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 Ausgrid's capitalisation policy. They are generally costs shared across different assets and cost centres. The amount of capitalised overheads incurred is a function of the amount of capital works that is undertaken.

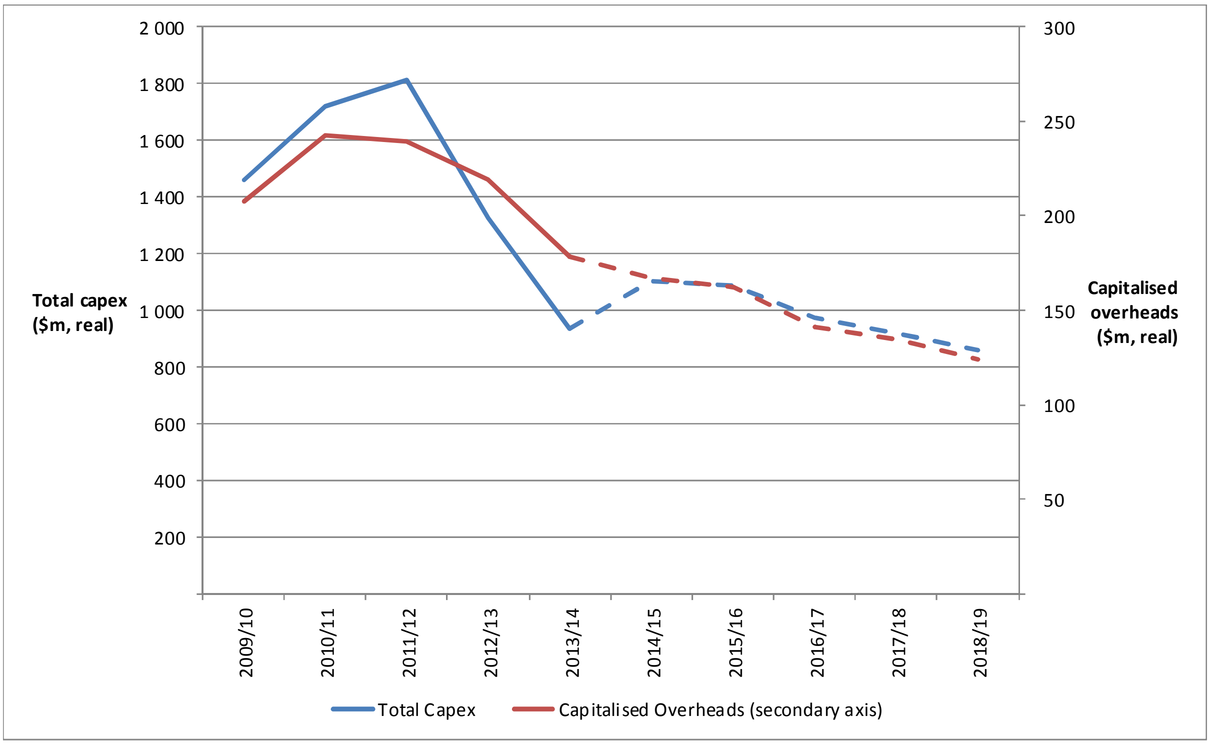
A.6.1 Position

Ausgrid proposed $729.2 million ($2013–14) of forecast capitalised overheads. We do not accept Ausgrid's proposal. We have instead included an amount of $477.3 million ($2013–14) in our alternative estimate. This is 48 per cent less than Ausgrid's proposal. In coming to this view, we applied trend analysis to assess Ausgrid's proposal by reference to the actual capitalised overheads it incurred during the 2009–2014 regulatory control period.

Trend analysis

Ausgrid proposed $729.2 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-21 shows, the reduction itself is consistent with the reduction Ausgrid's proposed total forecast capex compared to the actual (and estimated) capex that it spend during the 2009–2014 regulatory control period.

Figure A-21 Ausgrid - total capex and capitalised overheads ($ million - real June 2014)



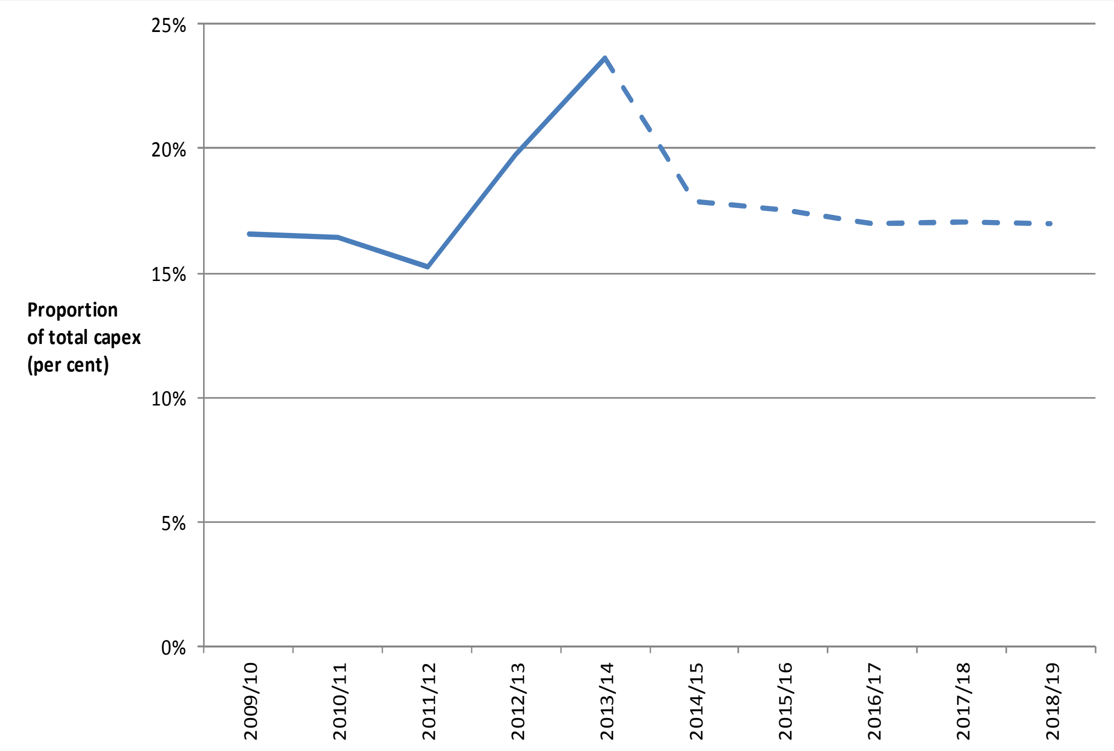
Source: Ausgrid - Reset RIN - 2.1 Expenditure Summary - Table 2.1.1 - Standard control services capex and Table 2.1.5 Dual function assets capex (capitalised overheads aggregate corporate and network capitalised overheads)

Figure A-22 shows that the average proportion of actual capitalised overheads to total capex in the 2009–2014 regulatory control period of around 15 per cent. Origin submitted that:[139]

> Ausgrid's overhead ratio should reflect efficient levels and, in the absence of an efficient benchmark, should be reduced to rates that it has achieved previously in 2011–12.

[139] Origin, Submission, p. 26.

Figure A-22 Ausgrid - 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 Ausgrid's proposal of $729.2 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 Ausgrid's base opex (see attachment 7) 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 is confirmed by Ausgrid's regulatory proposal.[140]

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).

Our consideration of Ausgrid's proposed opex step change for a broad-based demand management program is discussed in attachment 7. This program is primarily directed towards new initiatives that are focused on longer term capex deferral benefits, whereas this section considers potential deferral benefits of demand management in the 2014–19 period.

A.7.2 Our assessment

Ausgrid's proposal included an increase of $22.1 million additional opex and $1.3 million additional capex over the 2014–19 period for broad-based demand management initiatives. Ausgrid states the direct capex offset is $16 million for the 2014–19 period, as reflected in a reduction in the 11kV Capital Works Plan.

Comparison with demand management activities during 2009–14

We consider that Ausgrid is understating the capex offset that could be achieved through efficient demand management activities. Our 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[141]. 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 resulting 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").[142] As such, we consider that the Ausgrid experience in demand management in 2009–14 might represent a reasonable benchmark to assess the capex that may be deferred in the 2014–2019 period.

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140 Ausgrid Regulatory proposal Attachment 6.12, p. 29.

141 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.

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

Value of demand management in low demand growth environment

As discussed in appendix B, 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 is confirmed by Ausgrid:

> 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 of 9.2 per cent, or approximately $197 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 Demand

This attachment sets out our observations of demand trends in Ausgrid's network for the 2014–2019 period.[143]

Demand forecasts are fundamental to a NSP's forecast capex and opex, and to the AER's assessment of that forecast expenditure.[144] Ausgrid must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. When Ausgrid 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).[145] Ausgrid uses demand forecasts in conjunction with network planning to determine the amount and timing of such expenditure. Ausgrid also incurs opex in relation to the new assets it builds to meet demand.

System demand represents total demand in the Ausgrid distribution network. This attachment considers demand forecasts in Ausgrid'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.[146] 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.

B.1 Position on system demand trends

We are satisfied the system demand forecasts in Ausgrid's regulatory proposal for the 2014–2019 period reasonably reflects a realistic expectation of demand.[147] The demand forecasts in Ausgrid's regulatory proposal for the 2014–2019 period are considerably lower than previous forecasts. Indeed, Ausgrid has progressively downgraded its demand forecasts since its regulatory proposal for the 2009–2014 regulatory control period.[148] As we would expect, one result of this trend is the significant reduction in Ausgrid's augex forecast for the 2014–2019 period compared to the 2009–2014 regulatory control period (see section A.1).

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

[143] In this attachment, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated.
[144] NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).
[145] Sections A.1 and A.2 discuss our consideration of Ausgrid's augex and connections expenditure.
[146] Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.
[147] NER, cll. 6.5.6(c)(3) and 6.5.7(c)(3).
[148] Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 37.

For example, Ausgrid provided updated non-coincident demand forecasts for each zone substation and subtransmission substation in its network.[149] Compared to the forecasts it used in its regulatory proposal, Ausgrid forecasted lower demand for the majority of substations in the updated forecasts (see section A.1 for a more detailed discussion).[150] All else being equal, this suggests Ausgrid's updated system demand forecast would also be lower.[151] Hence, there is evidence a lower system demand forecast (compared to Ausgrid's proposal) may also reflect a realistic expectation of demand.[152] We would expect a downward revision of Ausgrid'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 Ausgrid'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.[153]

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

Section B.3 discusses these observations in more detail.

B.2 AER approach

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

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

B.2.1 Ausgrid's proposal

Ausgrid provided historical and forecast demand figures in their proposal and in the reset RINs.[154] Ausgrid's proposal also described their demand forecasting methods, including approaches to:

- weather correction
- accounting for spot loads
- accounting for transfers
- accounting for embedded generation.[155]

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149 We understand Ausgrid has not finalised these figures. AER, *Email to Ausgrid: AER Ausgrid 039 - updated demand forecasts*, 17 September 2014.

150 AER analysis; Ausgrid, *Ausgrid's response to the AER's information request of 26 September 2014: Attachment: P50 2013 2014 Development forecast all zones.xlsx*, 2 October 2014.

151 System demand forecast may remain the same (or even increase) if areas with increased demand forecasts at least offset areas with lower forecasts.

152 NER, clauses 6.5.6(c)(3) and 6.5.7(c)(3).

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

154 Ausgrid reset RIN; Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 37; Ausgrid, *Attachment 5.03: Spatial demand forecast by zones and substations*, May 2014.

Ausgrid obtained its system demand forecast by aggregating spatial demand forecasts.[156] It does not appear Ausgrid produced a separate demand forecast using a top-down approach.[157]

B.2.2 AEMO forecasts

In July 2014, AEMO published the first edition of transmission connection point (CP) forecasts for New South Wales and Tasmania.[158] These forecasts are AEMO's independent electricity maximum demand forecasts at transmission connection point level, over a 10-year outlook period.[159] The Standing Council on Energy Resources (SCER) intended these demand forecasts to inform our regulatory determinations.[160] In addition, AEMO has published the National Electricity Forecasting Report (NEFR) since 2012, and published the latest edition in June 2014 (2014 NEFR).[161] 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.[162]

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

Section B.3 sets out our comparisons of AEMO's CP forecasts with Ausgrid's demand forecasts and takes into account stakeholder submissions.

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155 Ausgrid, *Regulatory proposal: Attachment 5.04: (INV-STD-10022) Planning standard - Demand forecast and related documents*, May 2014.

156 Ausgrid, *Basis of preparation: Response to reset regulatory information notice*, 30 May 2014, p. 177; Ausgrid, *Regulatory proposal: Attachment 5.04: (INV-STD-10022) Planning standard - Demand forecast and related documents*, May 2014, p. 3.

157 Ausgrid, *Ausgrid response to AER reset regulatory information notice: Response to reset regulatory information notice issued by AER on 7 March 2014 (amended 21 March)*, 30 May 2014, pp. 81–82.

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

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

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

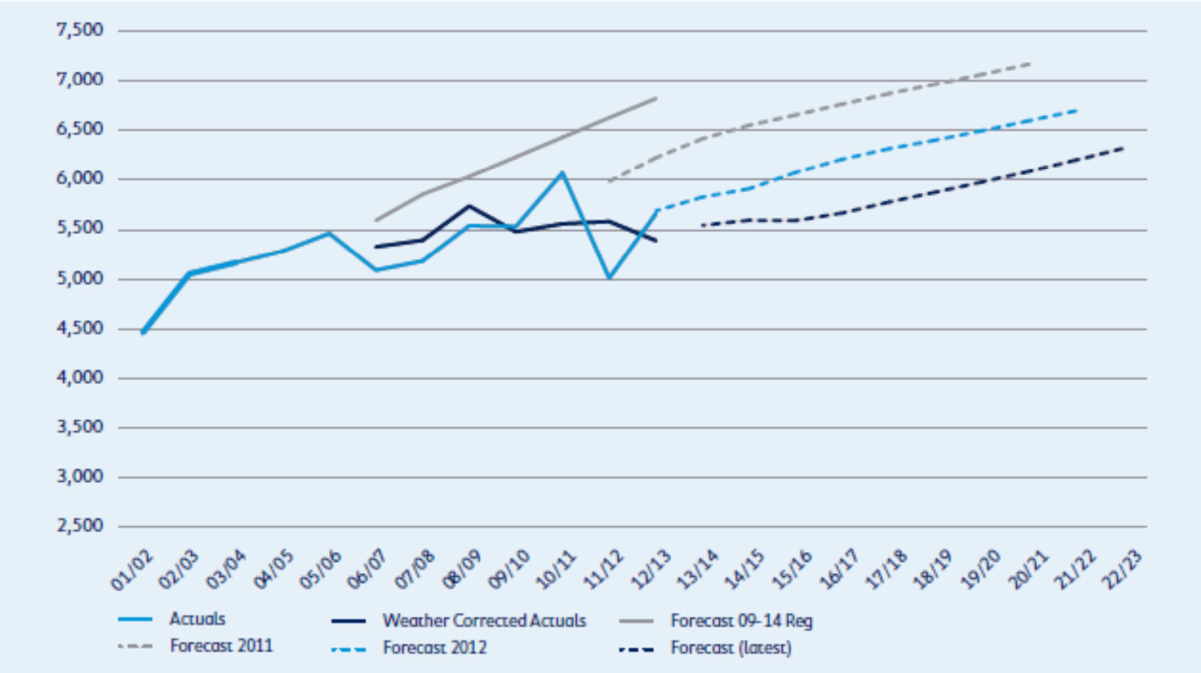
161 AEMO, *National electricity forecasting report for the National Electricity Market*, June 2014.

162 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.

B.3 AER considerations on system demand trends

The demand forecasts in Ausgrid's regulatory proposal for the 2014–2019 period are considerably lower than previous forecasts. Indeed, Figure B-1 shows Ausgrid progressively downgraded its demand forecasts since its regulatory proposal for the 2009–2014 regulatory control period.[163] We note Ausgrid 's forecast demand growth rates displayed a similar trend to AEMO's forecasts, although the absolute values of Ausgrid's demand forecasts are higher than AEMO's forecasts.

Figure B-1 Ausgrid summer demand (MW)



Source: Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 37.

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

Figure B-2 shows our comparison between Ausgrid's system demand and AEMO's CP demand for the Ausgrid network.[164] It shows the growth trend for Ausgrid's system demand forecast is consistent with AEMO's CP forecasts for Ausgrid'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 Ausgrid's forecasts are realistic.

Figure B-2 also indicates there are differences in Ausgrid's and AEMO's historical data, particularly for 2008–09 and 2013–14. In addition, Ausgrid's forecasts are consistently higher than AEMO's forecasts. Indeed, Ausgrid's forecast at 50 per cent probability of exceedance (PoE) is consistently above AEMO's 10 per cent PoE forecasts.

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[163] Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, p. 37.

[164] We summed AEMO's coincident demand figures for each CP in Ausgrid's network for each year.

We liaised with Ausgrid and with AEMO to ascertain the reasons for the discrepancies.[165] We also asked Ausgrid whether they would adjust their demand forecast to match AEMO's CP forecasts given the latter are the latest available forecasts.[166]

Figure B-2 Comparison of Ausgrid demand and AEMO CP demand

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

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

- Different treatment of major customers and embedded generation
- Different timing: several NSPs stated they used financial years whereas AEMO used seasons to define their data. This affects the pattern of the time series.
- Different levels of coincidence: the NSW/ACT DNSPs stated 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.[167]

The NSW/ACT DNSPs also noted differences in forecasting methods as possible explanations in differences between their demand forecasts and AEMO's.[168]

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165 We liaised with the other NSW/ACT DNSPs regarding similar issues.

166 AER, *Email to Ausgrid: AER Ausgrid 021 - maximum demand*, 12 August 2014.

167 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.

More specifically, Ausgrid noted some of the differences between its demand data and AEMO's is due to differing treatment of HV customers and embedded generation. Ausgrid also stated AEMO's data series requires more thorough validation and AEMO's 2008–09 demand figure appears to be a significant underestimation. Ausgrid cautioned against making direct comparisons between the two data series.[169] Ausgrid 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 Ausgrid. 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.[170]

We are satisfied Ausgrid'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 Ausgrid's network. Nevertheless, we consider they provide a useful reference point for assessing Ausgrid's demand forecasts.

We understand AEMO has begun consultation with some DNSPs in reconciling their datasets.[171] AEMO also indicated it would explore developing demand forecasts at the DNSP level in the future.[172] We anticipate these processes will result in more comparable datasets in future regulatory determinations.

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

On 2 October 2014, Ausgrid provided draft updated spatial demand forecasts for the 2014–2019 period (summer and winter). For most substations, these forecasts are lower than the forecasts it used in its regulatory proposal. Ausgrid stated improvements in its forecasting process, not just lower economic growth forecasts, explain the lower demand forecasts.[173]

Several stakeholders raised concerns that Ausgrid, as well as the other NSW/ACT DNSPs, are still using overly conservative demand forecasts as inputs to their regulatory proposals. AGL and the Public Interest Advocacy Centre (PIAC) compared Ausgrid's peak demand forecasts against the NEFR 2014 low and medium forecasts for both summer and winter periods. Their analysis indicated Ausgrid's summer peak demand forecasts are still overly high.[174] AGL noted Ausgrid is forecasting aggregate growth in summer peak demand of almost 4 per cent from 2013 to 2019. This is well above

168 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.

169 Ausgrid, *Response to AER: Information request AER Ausgrid 021*, 1 September 2014, p. 2.

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

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

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

173 Ausgrid, *Ausgrid's response to the AER's information request of 26 September 2014*, 2 October 2014, p. 1; Ausgrid, *P50 2013 2014: Development forecast all zones*, 2 October 2014; AER analysis.

174 AGL, *NSW electricity distribution networks regulatory proposals: 2014- 19: AGL submission to the Australian Energy Regulator*, 8 August 2014, pp. 5–6; PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p. 39.

the –5 and –10 per cent growth in the 2014 NEFR Medium and Low scenarios respectively.[175] Our analysis indicates Ausgrid forecasted average annual demand growth of 1.17 per cent between 2014–15 and 2018–19, with the 2014 NEFR forecasting 1.68 per cent.[176] We note the 2014 NEFR forecasts demand for the NSW region as a whole, rather than for Ausgrid's network specifically and so are not directly comparable.

PIAC stated Ausgrid appears to explain its forecast demand growth by reference to improved consumer confidence and economic growth. Ausgrid also referred to higher customer and demand growth in specific areas of the network.[177] PIAC considers these factors do not explain increases that are greater than the NEFR's forecasts for the NSW region. PIAC noted the growing disjunction between GDP and energy use, pointing to a decline in energy intensity.[178] 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.[179] 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.[180] 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).[181]

The Total Environment Centre (TEC) noted Ausgrid forecasted increases in demand in the 2014–2019 period. This, despite Ausgrid's weather corrected demand remaining flat. TEC therefore suggested the AER scrutinise these forecasts.[182]

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.[183] AEMO also forecast positive, albeit low, demand growth rates for the 2014–2019 period (see Figure B-2), with population growth and a positive economic outlook being the primary drivers.[184]

B.4 Other considerations on demand

B.4.1 Past forecasting inaccuracies

PIAC stated the AER should thoroughly examine Ausgrid's demand forecasts to ensure they provide a sound base for capex proposals. PIAC's analysis found many instances of significant disparity between Ausgrid's spatial demand forecasts and actual spatial demand in the 2009–2014 regulatory

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175 AGL, *NSW electricity distribution networks regulatory proposals: 2014- 19: AGL submission to the Australian Energy Regulator*, 8 August 2014, pp. 5–6.

176 AER analysis; Ausgrid RIN table 5.3.1; AEMO, *2014 NEFR - NSW*, 16 June 2014; AEMO, *National electricity forecasting report for the national electricity market*, June 2014, p. 4-4.

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

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

179 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.

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

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

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

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

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

control period.[185] We considered the effects of spatial demand forecasts on expenditure in section A.1.

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.[186] Among other things, falling demand and consumption led to higher prices and revenue for the 2009–2014 period, especially when compared with earlier periods.[187]

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.[188] Ausgrid stated it is improving its demand forecasting methods.[189] Our analysis in section B.3 indicates Ausgrid's demand forecasts exhibit growth patterns consistent with AEMO's, although differences in the underlying datasets inhibit direct comparisons. We will monitor the accuracy of Ausgrid'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.

185 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.

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

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

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

189 Ausgrid, *Regulatory proposal: 1 July 2014 to 30 June 2019*, 30 May 2014, pp. 31, 34.

C Assessment approaches

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

C.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. This is one of the capex factors that we are required to have regard to.[190] Economic benchmarking applies economic theory to measure the efficiency of a DNSP's use of inputs to produce outputs, having regard to environmental factors.[191] It allows us to compare the performance of a DNSP against its own past performance, and the performance of other DNSPs. Economic benchmarking helps us to assess whether a DNSP's capex forecast represents efficient costs.[192] As stated by the AEMC, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[193]

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 NSP's efficiency with consideration given to its inputs, outputs and its operating environment. We have considered each DNSP's operating environment in so far as there are factors that are outside of a NSP's control but which affect a NSP's ability to convert inputs into outputs.[194] Once such exogenous factors are taken into account, we expect DNSPs 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.[195]

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 2014–2019 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

190 NER, cl. 6.5.7(e)(4).
191 AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013.
192 NER, cl. 6.5.7(c).
193 AEMC, *Economic Regulation Final Rule Determination*, p. 25.
194 AEMC, *Economic Regulation Final Rule Determination*, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.
195 AER, *Annual Benchmarking Report*, 2014.

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.

Customer numbers and maximum demand are used as proxies for output.[196] 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.[197] It is generally positively related to efficiency: a DNSP with lower customer density is likely to require more network assets to service the same number of customers, for example, than does a higher density DNSP. Since the lower density DNSP will require more inputs to produce the same level of outputs, it will appear less efficient than the higher density DNSP.

The results from the economic benchmarking give an indication of the relative efficiency of each of the DNSPs, and how this has changed over time. It indicates the likely range of forecast capex that would be required by an efficient and prudent DNSP taking into account. However, we accept that it is difficult to fully account for exogenous factors particular to each DNSP. To the extent that we are unable to adequately account for exogenous factors, we have factored this into the weighting that we have given our benchmarking, as applied to each DNSP.[198] 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, an alternative estimate.

C.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.[199]

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.[200] 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

196 For more on these measures, see the AER's annual Benchmarking Report.
197 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.
198 AEMC Economic Regulation Final Rule Determination, November 2012, p. 113.
199 NER, cl. 6.5.7(e)(5).
200 NER, cl. 6.5.7(a)(3).

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 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.

C.3 Category analysis

Expenditure category level analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex. This is directly relevant to assessing whether a DNSP's capex forecast reasonably reflects the capex criteria.[201]

Using standardised reporting templates, we have collected data on augex, repex, connections, non-network capex, overheads and demand forecasts for all DNSPs in the NEM. The use of standardised category data allows us to make direct comparisons across DNSPs and use this to form a view on whether the total forecast capex reasonably reflects the capex criteria. Standardised category data also allows us to identify and scrutinise different operating and environmental factors that affect the amount and cost of works performed by DNSPs, and how these factors may change over time.

We have used category analysis to allow us to compare across time and between DNSPs across:

- overall costs within each category of capex
- unit costs, across a range of activities
- volumes, across a range of activities
- asset lives, across a range of asset classes which we have used in assessing repex.

Category analysis has been used to identify areas of a DNSPs' capex proposal that may require further examination. For example, where a DNSP's unit costs are consistently higher than other similar DNSPs we have sought to understand the drivers of this. In addition, we have used category analysis as an input to determining a alternative estimate where we are not satisfied that the DNSP's proposal meets the NER requirements. In doing so we have considered the operating environment of the DNSP so as to ensure that any benchmark applied to the DNSP reflects a prudent and efficient benchmark for a DNSP operating in a similar operating environment.

[201] NER, cl. 6.5.7(c).

C.4 Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works. We have two predictive models:

- the repex model
- the augex model.

The use of the repex and augex models is directly relevant to assessing whether a DNSP's capex forecast reasonably reflects the capex criteria.[202] The models draw on actual capex incurred by a DNSP during the preceding regulatory control period. This past capex is a factor that we must take into account.[203]

The repex model is a high-level probability based model that forecasts asset replacement capex (repex) for various asset categories based on their condition (using age as a proxy), and unit costs. We use the repex model to assess DNSPs' asset life and unit cost trends over time, as well as comparing them to DNSP benchmarks. In instances where we consider this shows a DNSP's proposed repex does not conform to the capex criteria, we have used this (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[204] The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the NSP over a given period.[205] In this way, the augex model accounts for the main internal drivers of augex that may differ between DNSPs, namely peak demand growth and its impact on asset utilisation.

We use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a DNSP's augex forecast.[206] The augex model is only one of several techniques we have used to assess augex forecasts and, where relevant, to reach a alternative estimate.

As a general point, we acknowledge that modelling will generally be a simplification of reality and as such may have limitations. We have factored these limitations into the weighting we have given the results of our modelling.

C.5 Engineering review

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

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

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202 NER, cl. 6.5.7(c).

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

204 Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

205 For more information, see: AER, *Guidance document: AER augmentation model handbook*, November 2013.

206 AER, 'Meeting summary – DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 1.

- Forecast is reasonable and unbiased, by assessing whether the DNSP's proposed capex is a reasonable forecast of the unbiased efficient cost of maintaining performance at the required or efficient service levels.

- Risk management is prudent and efficient, by assessing whether the business manages risk such that the cost to the customer of achieving the capex objectives at the required or efficient service levels is commensurate with the customer value provided by those service levels.

- Costs and work practices are prudent and efficient, by assessing whether the DNSP uses the minimum resources reasonably practical to achieve the capex objectives and maintain the required or efficient service levels.

We have considered these factors as they relate directly to our assessment of whether the DNSP's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives:[207]

- 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 DNSP's risk management is prudent and efficient, the DNSP's forecast is likely to reflect the costs that a prudent operator would require to achieve the capex objectives. A prudent operator would consider both the probability of a risk eventuating and the impact of the risk (if it were to occur) in determining whether to undertake work to mitigate the risk.[208]

- If the DNSP's costs and work practices are prudent and efficient, the DNSP will have the appropriate governance and asset management practices to ensure that the DNSP 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.

The engineers applied a sampling approach in considering the above factors. Where this revealed concerns about systemic issues, we asked the engineers to take a broader sample and to quantify the likely impact of these biases.

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 including for non-network capex and have included the assessment of:

- the options the NSP investigated to address the economic requirement (for example, for augmentation projects the review should have included an assessment of the extent to which the NSP considered and provided for efficient and prudent non-network alternatives[209])

- whether the timing of the project is efficient

- unit costs and volumes, including comparisons with relevant benchmarks

- whether the project should more appropriately be included as a contingent project[210]

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[207] NER, cl. 6.5.7(c).

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

[209] NER, cl. 6.5.7(c)(10).

- deliverability of the project, given other capex and opex works
- the relative prices of operating and capital inputs and the substitution possibilities between operating and capital expenditure[211]
- 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[212], where relevant

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.[213] 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.

210 This principally relates to augex. See NER, cl. 6.5.7(e)(9A).
211 This principally relates to augex. See NER, cll. 6.5.7(e)(6) and (e)(9A).
212 NER, cl. 6.5.7(e)(9).
213 NER, cl. 6.5.7(e)(5A).

D Real cost escalation

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

D.1 Position

We are not satisfied that Ausgrid's proposed real material cost escalators (leading to cost increases above CPI) which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 period.[214] Instead we consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 period. We have arrived at this conclusion on the basis that:

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

Our approach to real materials cost escalation discussed above does not affect the proposed application of labour and construction cost escalators which apply to Ausgrid's standard control services capital expenditure. We consider that labour and construction cost escalation is likely to more reasonably reflect a realistic expectation of the cost inputs required to achieve the capex criteria given these are direct inputs into the cost of providing network services.[215]

D.2 Ausgrid's proposal

Ausgrid applied material and labour cost escalators to various asset classes in forecasting its capex for the 2014–19 period.[216] Real cost escalation indices for the following material cost drivers were calculated for Ausgrid by Competition Economists Group (CEG):[217]

- aluminium

214 NER, cl. 6.5.7(a).
215 NER, cl. 6.5.7(c)(3).
216 Ausgrid, *Regulatory proposal*, p. 40.
217 CEG, *Escalation factors affecting expenditure forecasts*, December 2013.

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

CEG sourced forward rates from Bloomberg up to 2023 to convert commodities traded on international markets priced in United States dollars to Australian dollars.[218]

Ausgrid also escalated the cost of land on which its assets are located.[219] Ausgrid used BIS Shrapnel to forecast land prices.[220]

Table D-1 outlines Ausgrid's real input materials escalation forecasts.

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

	2014–15	2015–16	2016–17	2017–18	2018–19
Aluminium	4.2	5.8	5.0	4.2	3.6
Copper	-0.9	1.1	0.3	-0.3	-0.7
Steel	0.6	3.2	0.6	0.3	-0.1
Crude oil	-0.5	2.8	2.6	2.1	1.8
Land (commercial)	6.3	18.3	4.0	-1.8	-16.8
Land (industrial)	4.1	5.2	3.5	-1.6	-9.8

Source: Ausgrid, Revenue proposal, Attachment 5.19 - CEG, Escalation factors affecting expenditure forecasts, December 2013, pp. 21, 24, 27, 30 and 31 and BIS Shrapnel, Sydney commercial property prospects update 2011–2021, Sydney suburban centres and office parks update 2011-2021 and Sydney industrial property: market forecasts and strategies 2011–2021.

Ausgrid's approach to forecasting escalation followed the following process[221]:

- identify the inputs that comprise the physical asset
- use the CEG forecasts to escalate the commodity inputs and the BIS Shrapnel forecasts to escalate land
- apply the input escalation forecasts above to each physical asset based on contracts Ausgrid has with its equipment suppliers. Ausgrid state that these contracts include a price adjustment formulae which indicate how much of a commodity input is included in each physical asset

218 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 9.
219 Ausgrid, *Regulatory proposal*, *Attachment 5.16 - Overview of the cost escalation methodology*, p. 3.
220 Ausgrid, *Regulatory proposal*, *Attachment 5.16 - Overview of the cost escalation methodology*, p. 4.
221 Ausgrid, *Regulatory proposal*, *Attachment 5.16 - Overview of the cost escalation methodology*, p. 9.

- each physical asset is then mapped to asset classes such as distribution substations, and
- finally a weighted index is assigned to each asset class which is then applied to the forecast costs of that asset class in constant dollar terms.

Ausgrid's cost escalators for land are applied at an asset category level (rural, suburban, industrial and CBD) while materials escalation is applied at an asset type level.

Table D-2 outlines Ausgrid's real cost escalation indices by asset class.

Table D-2 Ausgrid real materials cost escalation forecast (per cent change)

	2014–15	2015–16	2016–17	2017–18	2018–19
Asset classes					
Sub-Transmission & Zone Sub-Stations	-1.0	2.0	-0.2	-0.3	-0.3
Distribution Substations	-1.5	4.0	-0.1	-0.3	-0.4
Sub-Transmission Overhead	-0.3	0.7	0.1	0.3	0.2
Sub-Transmission Underground	-1.3	1.0	-0.4	-0.3	-0.4
11kV Overhead	-0.9	2.3	0.1	0.2	0.1
11kV Underground	-0.73	1.52	0.24	0.61	0.51
Land - Rural	4.2	4.1	5.2	3.5	-1.6
Land – Suburban & Industrial	4.2	4.1	5.2	3.5	-1.6
Land CBD	12.0	6.3	18.3	4.0	-1.8
Communication Cable	-	-	-	-	-
Communication Equip	-	-	-	-	-
Metering	-	-	-	-	-
Street Lighting	-	-	-	-	-
Other	-	-	-	-	-
Non-System: IT Software	1.7	1.7	1.7	1.7	1.7
Non-System: IT Hardware	-0.5	-0.5	-0.5	-0.5	-0.5

	2014–15	2015–16	2016–17	2017–18	2018–19
Non-System: IT Facilities Management	0.6	0.6	0.6	0.6	0.6

Source: Ausgrid, Revenue proposal, Attachment 5.16 - Overview of the cost escalation methodology, p. 9.11.

Ausgrid estimated real materials cost increases to increase its capex costs by $4.3 million ($ June 2014).[222]

D.3 Assessment approach

We assessed Ausgrid's proposed real material cost escalators for the purpose of assessing its proposed total capex forecast against the National Electricity Rules (NER) requirements. We must accept Ausgrid's capex forecast if we are satisfied it reasonably reflects the capex criteria.[223] Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.[224]

We have applied our approach as set out in our Expenditure Forecast Assessment Guideline (Expenditure Guideline) to assessing the input price modelling approach to forecast materials cost.[225] In the Expenditure Guideline we stated that we had seen limited evidence to demonstrate that the commodity input weightings used by service providers to generate a forecast of the cost of material inputs have produced unbiased forecasts of the costs the service providers paid for manufactured materials.[226] We considered it important that such evidence be provided because the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used.[227] As a result, the price of manufactured network materials may not be well correlated with raw material input costs. We expect service providers to demonstrate that their proposed approach to forecast manufactured material cost changes is likely to reasonably reflect changes in raw material input costs.

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

- reviewed the CEG report commissioned by Ausgrid[228]
- reviewed the cost escalation model used by Ausgrid; and
- reviewed the approach to forecasting manufactured material costs in the context of electricity service providers mitigating such costs and producing unbiased forecasts.

In forming our views, we also considered submissions by stakeholders. We received a submission from the Energy Markets Reform Forum (EMRF) which addressed materials escalation forecasts by

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222 Ausgrid, *Regulatory proposal*, *Attachment 5.16 - Overview of the cost escalation methodology*, p. 8.
223 NER, cl. 6.5.7(c).
224 NER, cl. 6.5.7(c)(3).
225 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline,* November 2013, pp. 50-51.
226 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.
227 AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.
228 CEG, *Escalation factors affecting expenditure forecasts*, December 2013.

Ausgrid.[229] In its submission, the EMRF made the following statements in respect of materials escalation forecasts:[230]

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

D.4 Reasons

We must be satisfied that a forecast is based on a sound and robust methodology in order to accept that Ausgrid's proposed total capex reasonably reflects the capex criteria.[231] This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[232] In making our assessment, we do recognise that predicting future materials costs for electricity service providers involves a degree of uncertainty. However, for the reasons set out below, we are not satisfied that the materials forecasts provided by Ausgrid satisfy the requirements of the NER. Accordingly, we have not accepted it as part of our alternative estimate in our draft decision on total forecast capex. We are satisfied that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and this has been taken into account into our alternative estimate.

Materials input cost model

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

In our Expenditure Guideline, we requested service providers should demonstrate that their proposed approach to forecast materials cost changes reasonably reflected the change in prices they paid for physical inputs in the past. Ausgrid's proposal does not include supporting data or information which demonstrates movements or interlink-ages between changes in the input prices of commodities and the prices Ausgrid paid for physical inputs. Ausgrid's cost escalation model assumes a weighting of

229 The Energy Markets Reform Forum, *NSW Electricity Distribution Revenue Reset - Applications from Ausgrid, Endeavour Energy and Essential Energy - A response*, July 2014.

230 The Energy Markets Reform Forum, NSW Electricity Distribution Revenue Reset - *Applications from Ausgrid, Endeavour Energy and Essential Energy - A response*, July 2014, pp. 26-30 and Appendix 1 - Five-year drop for commodities' prices.

231 NER, cl. 6.5.7(c).

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

commodity inputs for each asset class but does not provide information which explains the basis for the weightings or that the weightings applied have produced unbiased forecasts of the costs of Ausgrid's assets. For these reasons, there is no basis on which we can conclude that the forecasts are reliable. In summary, Ausgrid has not demonstrated that their proposed approach to forecast materials cost changes reasonably reflects the change in prices they paid for assets in the past.

Materials input cost model forecasting

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

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

Materials input cost mitigation

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

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

  We are aware of input substitution occurring in the electricity industry during the late 1960's when copper prices increased, potentially impacting significantly on the cost of copper cables. Electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. We do however recognise that the principle of input substitutability cannot be applied to all inputs, at least in the short term, because there are technologies with which some inputs are not substitutable. However, even in the short term there may be substitution possibilities between operating and capital expenditure, thereby potentially reducing the total expenditure requirements of an electricity service provider[233]

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.[234] For example, Ausgrid has not demonstrated whether there are any

[233] NER, cl. 6.5.7(e)(7).
[234] NER, cl. 6.5.7(e)(6).

opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs

- the scale of any operation change to the electricity service provider's business that may impact on its capex requirements, including an increase in capex efficiency, and
- increases in productivity that have not been taken into account by Ausgrid in forecasting its capex requirements.

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

Forecasting uncertainty

The NER requires that an electricity service provider's forecast capital expenditure reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[235] We consider that there is likely to be significant uncertainty in forecasting commodity input price movements. The following factors have assisted us in forming this view:

- recent studies which show that forecasts of crude oil spot prices based on futures prices do not provide a significant improvement compared to a ‘no-change’ forecast for most forecast horizons, and sometimes perform worse[236]
- evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is somewhat mixed. Only for some commodities and for some forecast horizons do futures prices perform better than ‘no change’ forecasts;[237] and
- the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in $US to $AUS). A review of the economic literature of exchange rate forecast models suggests a “no change” forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.[238]

Strategic contracts with suppliers

We consider that electricity service providers can mitigate the risks associated with changes in material input costs by including hedging strategies or price escalation provisions in their contracts with suppliers of inputs (e.g. by including fixed prices in long term contracts). We also consider there is the potential for double counting where contract prices reflect this allocation of risk from the electricity service provider to the supplier, where a real escalation is then factored into forecast capex.

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

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

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

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

In considering the substitution possibilities between operating and capital expenditure,[239] we note that it is open to an electricity service provider to mitigate the potential impact of escalating contract prices by transferring this risk, where possible, to its operating expenditure.

Cost based price increases

Allowing individual material input costs that constitute cost escalation reflects more cost based price increases. We consider this cost based approach reduces the incentives for electricity service providers to manage their capex efficiently, and may instead incentivise electricity service providers to over forecast their capex. In taking into account the revenue and pricing principles, we note that this approach would be less likely to promote efficient investment.[240] It also would not result in a capex forecast that was consistent with the nature of the incentives applied under the CESS and the STPIS to Ausgrid as part of this decision.[241]

Selection of commodity inputs

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

Commodities boom

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

D.4.1 Review of independent expert's reports

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

CEG report

- CEG acknowledge that forecasts of general cost movements (e.g. consumer price index or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs (e.g. energy costs and equipment leases etc.).[242] This is consistent with the Post-tax Revenue Model (PTRM) which reflects at least in part movements in an electricity service provider's intermediary input costs.

- CEG acknowledge that futures prices will be very unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[243] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the price of assets that are not captured by the cost escalation models used by Ausgrid.

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239 NER, cl. 6.5.7(e)(7).
240 NEL, Part 1, s. 7.
241 NER, cl. 6.5.7(e)(8).
242 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.
243 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

- CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets:[244]

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

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

- Figures 1 and 2 of CEG's report respectively show the variance between aluminium and copper prices predicted by the London Metals Exchange (LME) 3 month, 15 month and 27 month futures less actual prices between July 1993 and December 2013.[245] Analysis of this data shows that the longer the futures projection period, the less accurate are LME futures in predicting actual commodity prices. Given the next regulatory control period covers a time span of 60 months we consider it reasonable to question the degree of accuracy of forecast futures commodity prices towards the end of this period.

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

- In respect of forecasting electricity service providers future costs, CEG stated that:[246]

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

  This statement again is consistent with our view about the degree of the precision and accuracy of futures prices in respect of predicting electricity service providers future input costs. CEG also highlights the (poor) predictive value of LME futures for actual aluminium prices.[247]

- CEG also acknowledge that its escalation of aluminium prices are not necessarily the prices paid for aluminium equipment by manufacturers. As an example, CEG referred to producers of electrical cable who purchase fabricated aluminium which has gone through further stages of production than the refined aluminium that is traded on the LME. CEG also stated that aluminium prices can be expected to be influenced by refined aluminium prices but these prices cannot be expected to move together in a 'one-for-one' relationship.[248]

  GEG provided similar views for copper and steel futures. For copper, CEG stated that the prices quoted for copper are prices traded on the LME that meet the specifications of the LME but that

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[244] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.
[245] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5–6.
[246] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.
[247] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.
[248] CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.

there is not necessarily a 'one-for-one' relationship between these prices and the price paid for copper equipment by manufacturers.[249] For steel futures, CEG stated that the steel used by electricity service providers has been fabricated, and as such, embodies labour, capital and other inputs (e.g. energy) and acknowledges that there is not necessarily a 'one-for one' relationship between the mill gate steel and the steel used by electricity service providers.[250]

These statements by CEG support our view that the cost escalation models used by Ausgrid has not demonstrated how and to what extent material inputs have affected the cost of intermediate outputs. We note, as emphasised by CEG, there is likely to be significant value adding and processing of the raw material before the physical asset is purchased by Ausgrid.

- CEG has provided data on historical indexed aluminium, copper, steel and crude oil actual (real) prices from July 2005 to December 2013 as well as forecast real prices from January 2014 to January 2021 which were used to determine its forecast escalation factors.[251] For all four commodities, the CEG forecast indexed real prices showed a trend of higher prices compared to the historical trend. Aluminium and crude oil exhibited the greatest trend variance. Copper and steel prices were forecast to remain relatively stable whist aluminium and crude oil prices were forecast to rise significantly compared to the historical trend.

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

SKM report

- SKM caution that there are a variety of factors that could cause business conditions and results to differ materially from what is contained in its forward looking statements.[252] This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the cost of assets that are not captured by Ausgrid's material input cost models.

- SKM stated it used the Australian CPI to account for those materials or cost items for equipment whose price trend cannot be rationally or conclusively explained by the movement of commodities prices.[253]

- In its modelling of the exchange rate, SKM has in part adopted the longer term historical average of $0.80 USD/AUD as the long term forecast going forward.[254] This is consistent with our view that longer term historical commodity prices should be considered when reviewing and forecasting future prices. In general, we consider that long term historical data has a greater number of observations and as a consequence is a more reliable predictor of future prices than a data time series of fewer observations.

- SKM stated that the future price position from the LME futures contracts for copper and aluminium are only available for three years out to December 2016 and that in order to estimate prices

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249 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.
250 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 23.
251 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, Figures 3, 4 and 5, pp. 23, 25 and 28.
252 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.
253 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.
254 SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.

beyond this data point, it is necessary to revert to economic forecasts as the most robust source of future price expectations.[255] SKM also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.[256]

- SKM stated that in respect to the reliability of oil future contracts as a predictor of actual oil prices, futures markets solely are not a reliable predictor or robust foundation for future price forecasts. SKM also stated that future oil contracts tend to follow the current spot price up and down, with a curve upwards or downwards reflecting current (short term) market sentiment.[257] SKM selected Consensus Economics forecasts as the best currently available outlook for oil prices throughout the duration of the next regulatory control period.[258] The decision by SKM to adopt an economic forecast for oil rather than using futures highlights the uncertainty surrounding the forecasting of commodity prices.

BIS Shrapnel report

- BIS Shrapnel has forecast prices of gas service provider related materials to increase, in part due to movements in the exchange rate. BIS Shrapnel are forecasting the Australian dollar to fall to US$0.77 from mid-2016 to mid-2018[259]. This is significantly lower than the exchange rate forecasts by SKM of between US$0.91 to US$0.85 from 2014-15 to 2018-19.[260] CEG did not publish its exchange rate forecasts in its report but state that for the purposes of the report it sourced forward rates from Bloomberg until 2023.[261] BIS Shrapnel stated that exchange rate forecasts are not authoritative over the long term.[262]

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

- In its forecast for general materials such as stationary, office furniture, electricity, water, fuel and rent, BIS Shrapnel assumed that across the range of these items, the average price increase would be similar to consumer price inflation and that the appropriate cost escalator for general materials is the CPI.[263] This treatment of general business inputs supports our view that where we cannot be satisfied that a forecast of real cost escalation for a specific material input is robust, and cannot determine a robust alternative forecast, zero per cent real cost escalation is reasonably likely to reflect the capex criteria and under the PTRM the electricity service provider's broad range of inputs are escalated annually by the CPI.

Comparison of independent expert's cost escalation factors

To illustrate the potential uncertainty in forecasting real material input costs, we have compared the material cost escalation forecasts derived by the consultants as shown in Table D-3.

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[255] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.
[256] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p.16.
[257] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.
[258] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.
[259] BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 6.
[260] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.
[261] SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.
[262] BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A-7.
[263] BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 48.

Table D-3 Real material input cost escalation forecasts ($ real 2012-13)

	2014–15 (%)	2015–16 (%)	2016–17 (%)	2017–18 (%)	2018–19 (%)
Aluminium					
CEG	4.2	5.8	5.0	4.2	3.6
SKM	4.69	4.88	3.09	4.42	2.97
BIS Shrapnel	1.4	5.6	3.9	11.0	-6.5
Range (low to high)	1.4 to 4.69	4.88 to 5.8	3.09 to 5.0	4.2 to 11.0	-6.5 to 3.6
Copper					
CEG	-0.9	1.1	0.3	-0.3	-0.7
SKM	-0.17	0.17	-1.15	-0.16	-1.45
BIS Shrapnel	-0.9	-1.5	0.3	9.3	-8.7
Range (low to high)	-0.9 to 0.17	-1.5 to 1.1	-1.15 to 0.3	-0.3 to 9.3	-8.7 to -0.7
Steel					
CEG	0.6	3.2	0.6	0.3	-0.1
SKM	2.84	2.45	-0.35	0.38	-1.11
BIS Shrapnel[1]	5.1	1.0	-0.2	8.0	-8.9
Range (low to high)	0.6 to 5.1	1.0 to 3.2	-0.35 to 0.6	0.3 to 8.0	-0.1 to -8.9
Oil					
CEG	-0.5	2.8	2.6	2.1	1.8
SKM	-5.11	-0.79	0.74	1.85	0.51
BIS Shrapnel[2]	1.4	-1.1	-0.2	6.5	-6.2
Range (low to high)	-5.11 to 1.4	-1.1 to 2.8	-0.2 to 2.6	1.85 to 6.5	-6.2 to 1.8

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

[1] Asian market price as BIS Shrapnel believes the Asia market is more appropriate.[264]

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

[2] BIS Shrapnel have forecast plastics prices based on price changes in Nylon-11 and HDPE (Polyethylene). BIS Shrapnel state that Castor Oil is the key raw material of Nylon-11 and because it does not have any historical data on Castor Oil, it has approximated Nylon-11 by using HDPE growth rates. HDPE (Polyethylene) prices are proxied by BIS Shrapnel using Manufacturing Wages, General Materials, and Thermoplastic Resin prices. BIS Shrapnel state that Thermoplastic Resin is primarily driven by Crude Oil.[265]

As Table D-3 shows, there is considerable variation between the consultant's commodities escalation forecasts. The greatest margin of variation is 10.1 per cent for aluminium in 2018–19, where CEG has forecast a real price increase of 3.6 per cent and BIS Shrapnel a real price decrease of 6.5 per cent. BIS Shrapnel's forecasts exhibit the greatest margin of variation but there also considerable variation between CEG and SKM's forecasts. These forecast divergences between consultants further demonstrate the uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of intermediate outputs used by service providers to provide network services. This supports our view that Ausgrid's forecast real material cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2014–19 regulatory control period.[266]

D.5 Conclusions on materials cost escalation

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

CEG, in its report to Ausgrid, identified a number of factors which are consistent with our view that Ausgrid's input cost model has not demonstrated how and to what extent material inputs are likely to affect the cost of assets. CEG acknowledged that forecasts of general cost movements (e.g. CPI or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs.[267] CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.[268] CEG also stated that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.[269]

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

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

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

266 NER, cl. 6.5.7(a).

267 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.

268 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

269 CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

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

The CPI can be used to account for the cost items for equipment whose price trend cannot be conclusively explained by the movement of commodities prices. This approach is consistent with the revenue and pricing principles of the NEL which provide that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services.[270]

D.5.1 Labour and construction escalators

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

We consider that labour and construction cost escalation more reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[271] We consider that real labour and construction cost escalators can be more reliably and robustly forecast than material input cost escalators, in part because these are not intermediate inputs and for labour escalators, productivity improvements have been factored into the analysis (refer to the opex attachment).

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

Further details on our consideration of labour cost escalators are discussed in attachment 7 of this decision.

[271] NER, cl. 6.5.6(c)(3) and.6.5.7(c)(3).

E Operating and environmental factors

Our draft decision for Ausgrid draws upon the annual benchmarking results and other capital expenditure comparisons between DNSPs. While these results are not a direct input into our alternative estimate of Ausgrid's capex forecast, they inform us of Ausgrid'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 Ausgrid's capital efficiency relative to the other DNSPs in the NEM.

The factors considered in this appendix are:

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

E.1 Existing network design

E.1.1 Proportion of 22kV and 11kV lines

The high-voltage networks are the key means for the distribution of electricity over middle distances such as between suburbs and across small regional areas. Simplistically, a doubling of the voltage will provide a doubling of the capacity of the line. In the case of high-voltage lines, a 22kV line will potentially have twice the capacity of an 11kV line. However, higher voltage assets are typically more expensive.

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

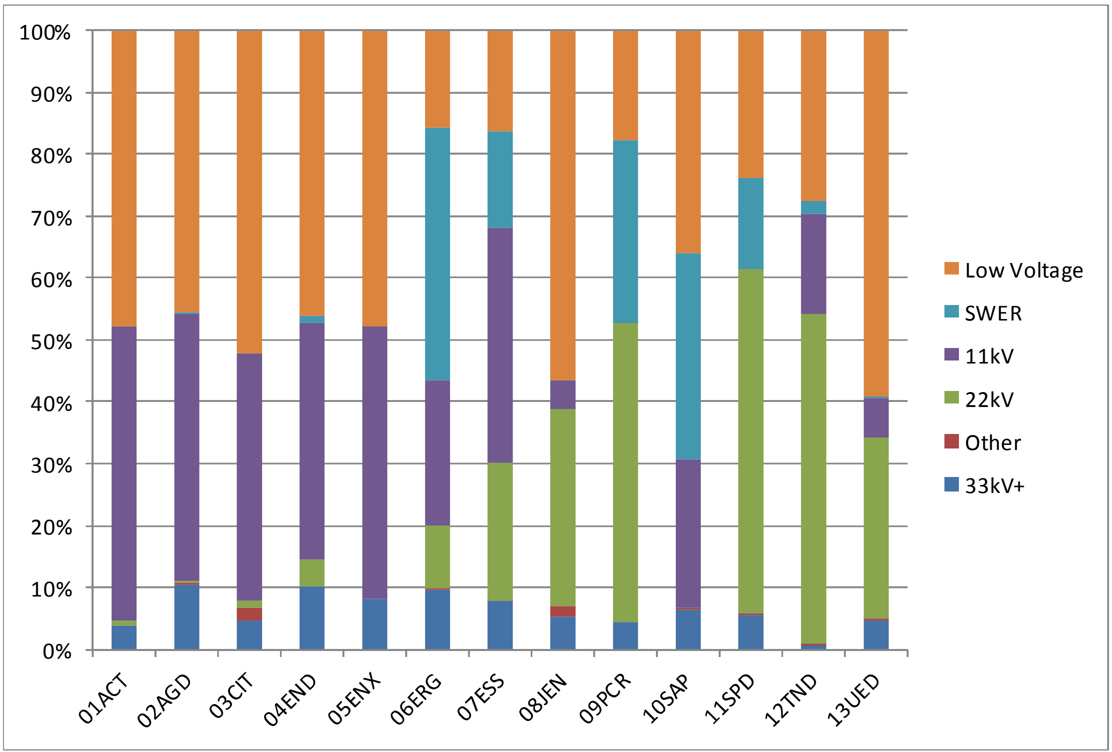
The Victorian DNSPs have mostly migrated their high-voltage networks to a 22kV model with the notable exception of CitiPower. CitiPower reported mostly 11kV high-voltage assets with a very small proportion of 22kV. The proportion of 22kV network in Victoria is 47 per cent of the total network length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

In South Australia, SAPN reported a high-voltage network that was exclusively 11kV[272]. Queensland on average also had a higher proportion of 11kV to 22kV lines than NSW.

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

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

Figure E-1 Line voltages by length



Source: AER analysis

Ausgrid's consultants Evans and Peck have claimed that because Victoria operates a 22 kV high-voltage distribution system they have a cost advantage over DNSPs that operate 11kV distribution systems.[273] They claim that this represents a cost advantage and will manifest itself in lower operation, maintenance and repex costs.[274]

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

Table E-1 high-voltage network voltage assessment

11kV networks		22kV networks	
Costs	Benefits	Costs	Benefits
Larger number of feeders	Lower cost feeders, particularly underground	Higher cost feeders, particularly underground	Smaller number of feeders
	Lower cost distribution substations	Higher cost distribution substations	
Larger number of zone substations	Lower cost substations	Higher cost zone substations	Fewer zone substations

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

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

11kV networks		22kV networks	
Greater number of civil and protection assets	Improved reliability from shorter feeders	Reduced reliability from greater feeder exposure (or greater costs in sectionalising)	Lower costs for fewer civil and protection assets
Increased maintenance (subtransmission lines, # circuit breakers, etc)	Decreased maintenance (11kV lines, smaller capacity Z/S transformers, circuit breakers, etc)	Increased maintenance (22kV lines, larger capacity Z/S transformers, circuit breakers, etc)	Decreased maintenance (subtransmission lines, #circuit breakers, etc)

Source: AER analysis.

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

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

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

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

E.1.2 Subtransmission variations

Ausgrid, Endeavour Energy, and Essential Energy have all raised subtransmission network configuration as an operating environment factor that will affect benchmarking results with other DNSPs.[275] [276] [277]

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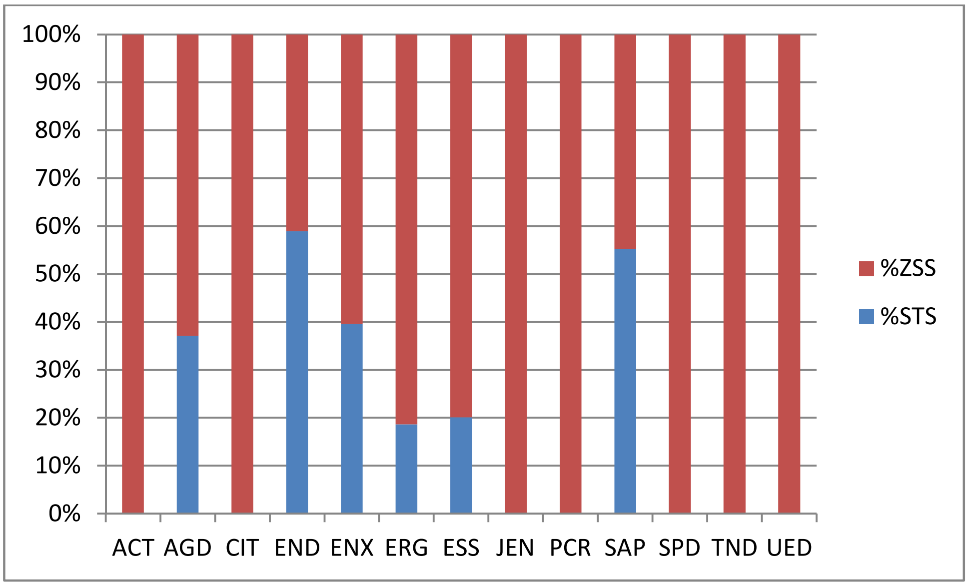
[275] Ausgrid, *Attachment 5.33* to *Regulatory proposal*, p. 5.
[276] Endeavour Energy, *Attachment 0.12* to *Regulatory proposal*, p. 5.

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

Figure E-2 Subtransmission capacity



Source: AER analysis.

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

Ausgrid's consultants Evans and Peck have said that Victoria and Tasmania have a natural cost advantage because they have a shorter total length of installed subtransmission cables.[278] They have also said that Victoria has a natural cost advantage over all other states because it has less subtransmission transformer capacity installed.[279] 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.[280] 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

277 Essential Energy, *Attachment 5.4* to *Regulatory proposal*, p. 5.

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

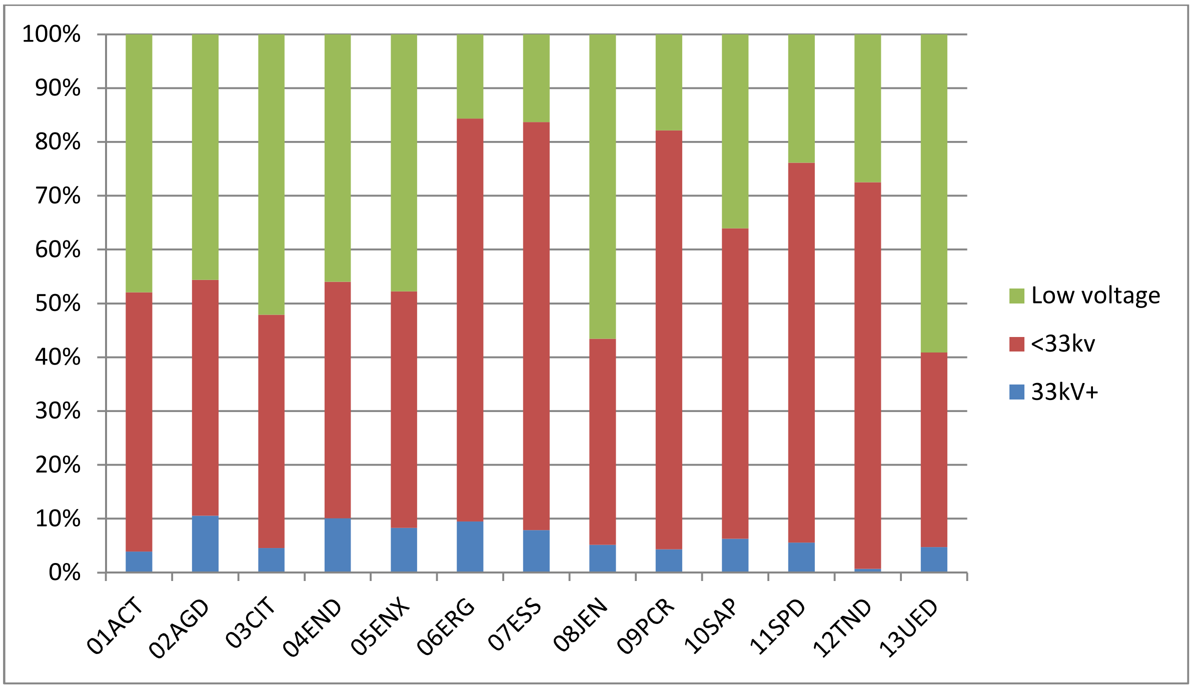
279 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australia DNSPs*, November 2012, p. 18.

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

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

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

Figure E-3 Voltage line lengths



Source: AER analysis.

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

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

E.1.3 Backyard reticulation

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

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

ActewAGL has identified backyard reticulation as an operating environment factor that is likely to affect their benchmarking results.[281] ActewAGL considers that backyard reticulation increases their replacement capex.

ActewAGL has reported a total network length of 5,088km.[282] Table E-2 shows the proportion of backyard reticulation of this network.

Table E-2 Proportion of backyard reticulation

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

Source: AER analysis.

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

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

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

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.[283] 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.

[281] ActewAGL, *Regulatory proposal*, p. 243.
[282] ActewAGL RIN.
[283] ActewAGL RIN.

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

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

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

E.2 Scale factors

E.2.1 Customer density

Customer density is a useful proxy for identifying the distance between customers. As each DNSP has an obligation to serve existing customers, we assume that this is therefore an exogenous factor.

Customer density, in and of itself, does not drive costs. There are factors that are proportional to customer density that are the underlying cost drivers including:

- Asset spacing - The need to service customers that are spaced further apart will require additional length of lines or cables to provide the same level of service.
- Asset exposure - A shorter line will have be less exposed to degradation from the elements and damage from third parties.
- Travel times - the time taken to travel between customers or assets increases as those assets or customer are spaced further apart.
- Traffic management - traffic management requirements typically increase proportionally to the volumes of traffic on, or adjacent, to the worksite.
- Asset complexity - The complexity of assets in a given location - for example; multiple circuits on a pole, or circuits in a substation.
- Proximity to third party assets - Increased urban density results in more third-party overhead and underground asset being in proximity to electrical assets. This proximity requires increased co-ordination, planning, and design.
- Proportion of overhead and underground - Increased urban density can result in greater obligations or constraints on the DNSPs in relation to the augmentation or construction of underground/overhead assets. Maintenance of underground assets is typically reduced compared with overhead.
- Topographical conditions - Adverse topographical conditions such as swamps, mountainous terrain, etc, will typically result in less habitable areas and increased costs associated with access to these areas.

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

Table E-3 customer density factor impacts

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

Source: AER analysis.

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

We have considered a number of measures for aggregating the impacts from the above factors. Historically, industry benchmarks have used a number of representative measures including:

- Customer density measured as customers per (circuit) km of line (cust/km)
- Energy density measured as energy delivered per (circuit) km of line (kWh/km)
- Demand density measured as demand per (circuit) km of line (MVA/km)
- Customer density measured a customers per square kilometre of service territory

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

A number of benchmarking studies and reviews have considered the relative merits of the different remaining density measures identified above (customer, energy and demand).[284] [285] [286] As the ratios of energy and demand are relatively similar on a per customer basis, it is not clear whether there is any greater intrinsic benefit from any one of these density measures.

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

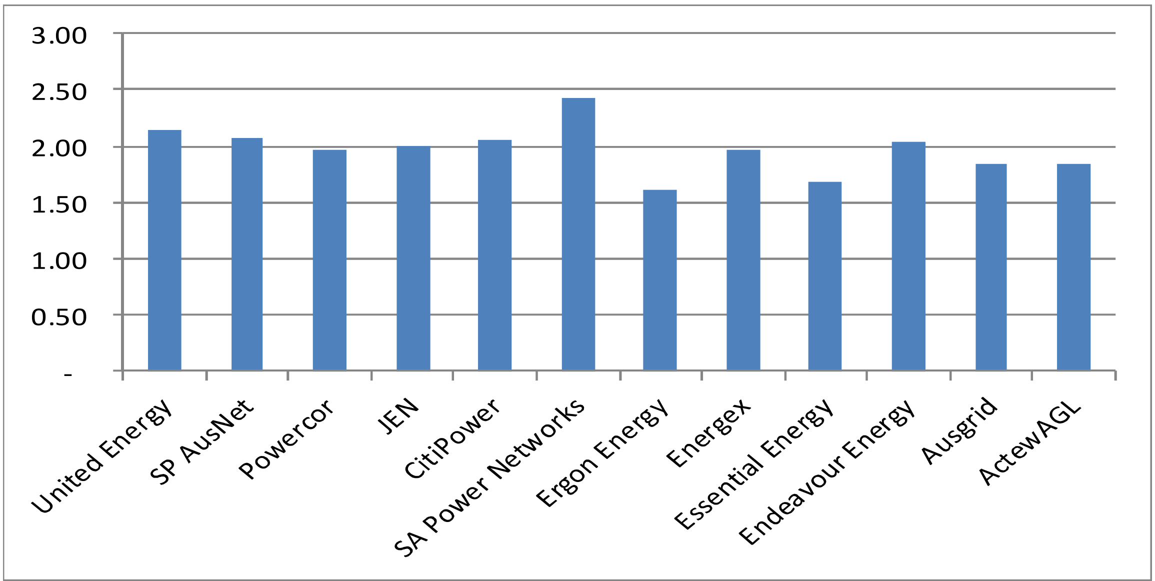
E.2.2 Load shape

Service providers design electricity networks to taking into account the expected peak demand for electricity services. While the actual energy usage on a network is important from a billing perspective, energy is not the driver for capital expenditure. The higher 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.[287] Because DNSPs in SA and Victoria have lower load factors it means that probabilistic planning is more applicable to those businesses.

Figure E-4 shows the ratio of network demand to average energy (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 E-4 Network load factor



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

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

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

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

Source: AER analysis.

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

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

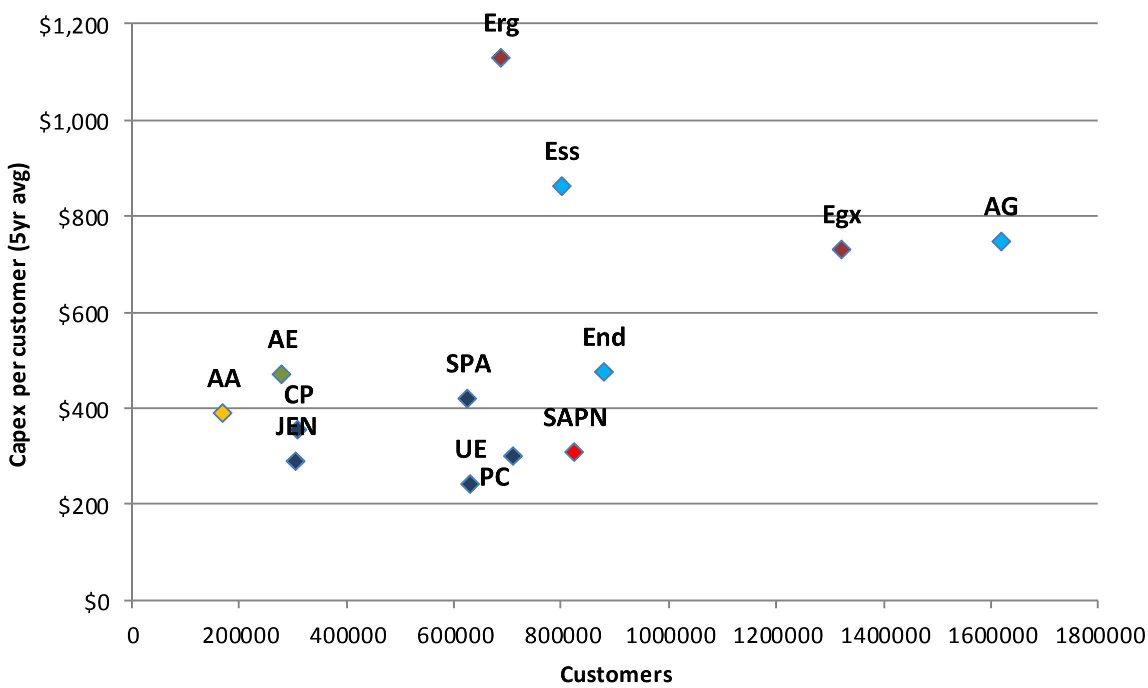
E.2.3 Economies of scale

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

ActewAGL has claimed that because it is the smallest DNSP it does not have access to the same economies of scale as other DNSPs. As a result their costs will appear to be higher than for all other DNSPs that have access to greater economies of scale.[288]

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

Figure E-5 Capital expenditure per customer



Source: AER analysis.

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

[288] ActewAGL, *Regulatory proposal*, p. 243.

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

On 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.

E.3 Physical environment factors

E.3.1 Bushfires

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

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

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

Forecasts from Deloitte Access Economics of the total economic costs of bushfires for 2014, in Table E-4 below, suggests that the forecast economic cost of bushfires is higher for the ACT than for Victoria and South Australia. We have normalised the forecast cost of bushfires by Gross State Product. This is to prevent population and physical size from interfering with comparisons. While not a perfect measure, we are satisfied that it is preferable to normalising by area or population.

Table E-4 Forecast economic cost of bushfires 2014

	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
GSP ($m 2013)	35 088	476 434	290 158	95 123	24 360	337 493
Forecast cost of bushfires 2014 ($m 2013)	55	43	0.0	44	40	172
% of GSP	0.16%	0.01%	0.00%	0.05%	0.17%	0.05%

Source: Deloitte Access Economics[289] and ABS.[290 291]

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

Table E-5 Significant bushfires and bushfire seasons in Australia 1900-2008

Date	States	Homes destroyed	Deaths
February 14, 1926	Victoria	550	39
January 8-13, 1939	Victoria and NSW	650	79
Summer 1943-44	Victoria	885	46
February 7, 1967	Tasmania	1557	64
January 8, 1969	Victoria	230	21
February 16, 1983	Victoria and SA	2253	60
February 18, 2003	ACT	530	4
January 11, 2005	South Australia	93	9

Source: Haynes et al.[292]

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 E-6 below.

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

	ACT	New South Wales	Queensland	South Australia	Tasmania	Victoria
Deaths	5	105	17	44	67	296
Average population 1900-2008[293]	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[294] and ABS.[295]

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

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

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

291 ABS, 6401.0 - Consumer Price Index.

292 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.

293 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.

294 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.

295 3105.0.65.001 - Australian Historical Population Statistics, 2014.

suggest that ActewAGL or the comparison service providers have a relative cost advantage or disadvantage due to bushfire risk.

E.3.2 Climate

Evans and Peck say that climate can affect asset failure rates and line design requirements. They do not explain, how or which DNSPs would be affected. [296]

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.

E.3.3 Corrosive environments

Evans and Peck raise the issue of corrosion as an operating environment factor. They say that the presence of corrosive atmospheres containing things such as salts (in coastal environments) and acid sulphates (in soils) impact on maintenance costs and replacement decisions. [297]

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.

E.3.4 Grounding conditions

Electricity distribution requires the use of earthing or grounding connection to aid in the protection and monitoring of the network. In rural areas, service providers use the earth as the return path for some forms of electricity distribution[298]. 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.[299] 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

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

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

[298] Single Wire Earth Return (SWER)

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

grounding costs between networks, there is not sufficient evidence to conclude that these differences are material.

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

E.3.5 Shape factors

Evans and Peck say that natural boundaries, such as water and national park, surrounding electricity networks impose costs on DNSPs.[300] These costs manifest themselves through imposing constraints on network planning.

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

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

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

E.3.6 Topographical conditions

Ausgrid, Endeavour, and Essential have all raised topographic conditions as an operating environment factor that will affect the benchmarking results.[301] [302] [303]

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.[304] 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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300 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.

301 Ausgrid, *Attachment 5.33* to *Regulatory proposal*, p. 5.

302 Endeavour, *Attachment 0.12* to *Regulatory proposal*, p. 5.

303 Essential *Attachment 5.*4 to *Regulatory proposal*, p. 5.

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

E.4 Regulatory factors

E.4.1 Building requirements

The Building Code of Australia (BCA) provides a set of nationally consistent, minimum necessary standards of relevant safety (including structural safety and safety from fire), health, amenity and sustainability objectives for buildings and construction.[305]

Ausgrid's consultant Evans and Peck identified differences in building regulations as an operating environment factor that may affect benchmarking results.[306] 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.[307] 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.[308]

Evans and Peck say that building code requirements can affect comparisons across networks. They do not explain, how or which DNSPs would be affected. [309]

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

E.4.2 Environmental regulations

Ausgrid's consultant Evans and Peck identified differences in environmental regulations as an operating environment factor that may affect benchmarking results.[310] 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.[311] 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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305 ABCB, The Building Code of Australia, available at; http://www.abcb.gov.au/about-the-australian-building-codes-board . [last accessed 4 September 2014].

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

307 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].

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

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

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

311 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.

E.4.3 Occupational health and safety regulations

Ausgrid's consultant Evans and Peck identified differences in OH&S regulations as an operating environment factor that may affect benchmarking results.[312] 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.[313] 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.[314] While enforcement activities may vary slightly across jurisdictions the main cost driver of OH&S costs will be the regulations and law with which businesses must comply. In this respect, we are satisfied that there will not be material cost differences between jurisdictions that have enacted the model laws. However, there is likely to be a cost differential between service providers in Victoria and those in other jurisdictions. Because the comparison firms are predominantly Victorian, this is likely to likely to lead to cost differentials between the comparison firms and ActewAGL.

E.4.4 State/City development policy

Evans and Peck say that state and city development policy can affect comparisons across networks.[315] They say that in Sydney costs are higher due to council requirements.[316] 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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312 Evans and Peck, *Review of factors contributing to variations in operating and capital costs structures of Australian service providers*, November 2012, p. 38.

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

314 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]

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

316 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.

E.4.5 Traffic management requirements

Evans and Peck say that traffic management regulations can affect comparison of opex and capex across networks. They do not explain, how or who would be affected. [317]

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.[318]

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.

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

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

F Predictive modelling approach and scenarios

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

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

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

F.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and Gas Rules.[319] 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.[320]

The Expenditure Forecast Assessment Guideline (EFAG) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.[321] 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.[322]

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.[323] At a basic level, the model predicts the volume of a distributor's assets that may need to be replaced over each of the next 20 years. This prediction is made by looking at the age of assets already in commission, and the time at which, on average, these assets would be expected to be replaced. The unit cost of replacing the assets is used to provide an estimate of replacement expenditure. The data used in the model is derived from the distributor's regulatory information notice (RIN) responses and from the outcomes of the unit cost and replacement life benchmarking across all distribution businesses in the NEM. These processes are described below.

F.2 Data specification process

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

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

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

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

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

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

323 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.[324]

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.[325]

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.[326]

F.3 Data collection and refinement

The new RINs represent a shift in the data reporting obligations on distributors. Given this is the first period in which the distributors have had to respond to the new RINs, we undertook regular consultation with the distributors. This consultation involved collaborative and iterative efforts to refine the datasets to better align the data with what the AER requires to deploy our assessment techniques. Networks NSW questioned whether the data collected by the AER was of sufficient quality to use in the repex model or for benchmarking purposes.[327] 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

[324] 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.

[325] NER, clause 6.5.7(e)(6).

[326] See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at http://www.aer.gov.au/node/21843.

[327] 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.[328]

Nonetheless, in order that our data was the most up to date and accurate, we did inform distributors, in detailed documentation, where the data they had provided was not entirely consistent with the RINs, and invited them to provide updated data. Refining the repex data was an iterative process, where distributors returned amended consolidated RIN templates until such time that the data submitted was fit for purpose.

F.4 Benchmarking repex asset data

As outlined above, we required the following data on distributors' assets for our repex modelling:

- age profile of network assets currently in commission
- expenditure, replacement volumes and failure data of network assets
- the mean and standard deviation of each asset's replacement life.

All NEM distributors provided this data in the Reset RINs and Category analysis RINs under standardised network asset categories.

To inform our expenditure assessment for the distributors currently undergoing revenue determinations,[329] we compared their data to the data from all NEM distributors. We did this by using the reported expenditure and replacement volume data to derive benchmark unit costs for the standardised network asset categories. We also derived benchmark replacement lives (the mean and standard deviation of each asset's replacement life) for the standardised network asset categories.

In this section we explain the data sets we constructed using all NEM distributors' data, and the benchmark unit costs and replacement lives we derived for the standardised network asset categories.

F.4.1 Benchmark data for each asset category

For each standardised network asset category where distributors provided data we constructed three sets of data from which we derived the following three sets of benchmarks:[330]

- benchmark unit costs

328 NER, cl. 6.9.1.
329 NSW and ACT distribution network service providers—Ausgrid, Endeavour Energy, Essential Energy, and ActewAGL.
330 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.[331] 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:[332]

- calculating the average of all values for an asset category
- determining the standard deviation of all values for an asset category
- excluding values that were outside plus or minus one standard deviation from the average.

Using the data set excluding outliers we then determined the:

- Average value:

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331 We took into account whether the distributor reported on calendar or financial year basis.

332 For the calibrated mean replacement lives we performed two additional steps on the data prior to this. We excluded any means where the distributor did not report corresponding replacement expenditure. This was because zero volumes lead to the repex model deriving a large calibrated mean which may not reflect industry practice and may distort the benchmark observation. We also excluded any calibrated mean lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years in the asset age profile.

- benchmark average unit cost
  - benchmark average mean and standard deviation replacement life
  - benchmark average calibrated mean and standard deviation replacement life.
- One quartile better than the average value:
  - benchmark first quartile unit cost
  - benchmark first quartile mean replacement life
  - benchmark first quartile calibrated mean replacement life.
- 'Best' value:
  - benchmark best (lowest) unit cost
  - benchmark best (longest) mean replacement life
  - benchmark best (highest) calibrated mean replacement life.[333]

F.5 Repex model scenarios

As noted above, our repex model uses an asset age profile, expected replacement life information and the unit cost of replacing assets to develop an estimate of replacement volume and expenditure over a 20 year period.

The asset age profile data provided by the distributors is a fixed piece of data. That is, it is set, and not open to interpretation or subject to scenario testing.[334] 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.[335] They are:

(1) The Base model – the base model uses inputs provided by the distributor in their RIN response. Each distributor provided average expected life data as part of this response. As the businesses did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years in the base model.

(2) The Calibrated model – the process of "calibrating" the expected replacement lives in the repex model is described in the AER's replacement expenditure handbook.[336] The calibration involves

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333 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.

334 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.

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

determining a replacement life and standard deviation that matches the distributor's recent historical level of replacement (in this case, the five years from 2009–10 to 2014–15). The calibrated model benchmarks the business to its own observed historical replacement practices.

(3) The Benchmarked model – the benchmarked model uses unit cost and replacement life inputs from the category analysis benchmarks. These represent the observed costs and replacement behaviour from distributors across the NEM. As noted above, we have made observations for an “average”, “first quartile” and “best performer” for each repex category, so there is no single "benchmarked" model, but a series of models giving a range of different outputs.

It is also possible to combine life and unit cost inputs between the three broad scenarios to further expand the range of scenarios under which the model is run (e.g. replacement lives from the calibrated model with unit costs from the benchmarked model). The model also takes account of different wooden pole staking rate assumptions (see section A.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.

F.6 The treatment of staked wooden poles

The staking of a wooden pole is the practice of attaching a metal support structure (a stake or bracket) to reinforce an aged wooden pole. The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like for

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

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.

F.6.1 Like-for-like repex modelling

Replacement expenditure is normally considered to be on a like-for-like basis. When an asset is identified for replacement, it is assumed that the asset will be replaced with its modern equivalent, and not a different asset. For example, conductor rated to carry low voltage will be replaced with conductor of the same rating, not conductor rated for high voltage purposes.

The repex model predicts the volume of old assets that need to be replaced, not the volume of new assets that need to be installed. This is simple to deal with when an asset is replaced on a like-for-like basis – the old asset is simply replaced by a new asset of the same kind. It follows that the volume of assets that needs to be replaced where like-for-like replacement is appropriate match the volume of new assets to be installed. The cost of replacing the volume of retired assets is the unit cost of the new asset multiplied by the volume of assets that need to be replaced.

F.6.2 Non-like-for-like replacement

Where old assets are commonly replaced with a different asset, we cannot simply assume the cost of the new asset will match the cost of the old asset's modern equivalent. As the repex model predicts the number of old assets that need to be replaced, it is necessary to make allowances for the cost of a different asset in determining the replacement cost. In running the repex model, the only category where this was significant was wooden poles.

Staked and unstaked wooden poles

The life of a wooden pole may be extended by installing a metal stake to reinforce its base. Staked wooden poles are treated as a different asset in the repex model to unstaked poles. This is because staked and unstaked poles have different expected lives and different costs of replacement.

When a wooden pole needs to be replaced, it will either be staked or replaced with a new pole. The decision on which replacement type will be carried out is made by determining whether the stake will be effective in extending the pole's life, and is usually based on the condition of the pole base. If the wood at the base has deteriorated too far, staking will not be effective, and the pole will need to be replaced. If there is enough sound wood to hold the stake, the life of the pole can be extended, and a stake can be installed. Consequently, there are two possible asset replacements (and two associated unit costs) that may be made by the distributor – a new pole to replace the old one or nailing a stake the old pole.

The other non-like-for-like scenario related to staking is where an in-commission staked pole needs to be replaced. Staking is a one-off process. When a staked pole needs to be replaced, a new pole must be installed in its place. The cost of replacing an in-commission staked pole is the cost of a new pole.

Unit cost blending

We use a process of unit cost blending to account for the non-like-for-like asset categories.

For unstaked wooden poles that need to be replaced, there are two appropriate unit costs: the cost of a new pole; and the cost of staking an old pole. We have used a weighted average between the unit cost of staking and the unit cost of pole replacement to arrive at a blended unit cost.[337] 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.[338] The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of pole types replaced. Where historical data was not available, we used the asset age data to determine what proportion of the network each pole category represented, and used this information to weight the unit costs.

F.7 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when finding replacement lives. This is because historical volumes of replacements are used in calibration. The RIN responses provide us with information on the volume of new assets installed over the last five years. However, the model predicts the volume of old assets being replaced - so an adjustment needs to be made for the calibration process to function correctly. We sought this information directly from the distributors. ActewAGL, Essential and Ausgrid provided the information on the number of old assets being replaced, which allowed us to calibrate the model. Endeavour did not provide us the information.[339] 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.340 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.

337 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.

338 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.

339 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.

340 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.