



PRELIMINARY DECISION
Energex determination 2015–16
to 2019–20

Attachment 6 – Capital
expenditure

April 2015

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Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

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

Email: AERInquiry@aer.gov.au

Note

This attachment forms part of the AER's preliminary decision on Energex's 2015–20 distribution determination. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanism

Attachment 15 – Pass through events

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Shortened forms

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

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

6 Capital expenditure

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

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

- Appendix A - Assessment Techniques
- Appendix B - Assessment of capex drivers
- Appendix C - Demand
- Appendix D - Real material cost escalation
- Appendix E - Predictive modelling approach

6.1 Preliminary decision

We are not satisfied that Energex's proposed total forecast capex of \$3239.6 million (\$2014–15) reasonably reflects the capex criteria. We have substituted it with our estimate of Energex's total forecast capex for the 2015–20 period. We are satisfied that our substitute estimate of \$2361.5 million (\$2014–15) reasonably reflects the capex criteria. Table 6-1 outlines our preliminary decision.

Table 6-1 Our preliminary decision on Energex's total forecast capex (million \$2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Energex's proposal	670.3	688.5	629.0	613.3	638.4	3239.6
AER preliminary decision	498.5	513.6	465.5	446.2	437.8	2361.5
Difference	-171.9	-175.0	-163.5	-167.1	-200.6	-878.1
Percentage difference (%)	-26%	-25%	-26%	-27%	-31%	-27%

Source: Energex, *Regulatory Proposal*; AER analysis.

Note: Numbers may not add up due to rounding.

A summary of our reasons and findings that we present in this attachment and appendix B are set out in Table 6-2. These reasons include our responses to stakeholders' submissions on Energex's regulatory proposal. In the table we present our reasons largely by 'capex driver' such as augex and repex. This reflects the way in which we tested Energex's proposed total forecast capex. Our testing used techniques,

¹ NER, cl. 6.4.3(a).

tailored to the different capex drivers taking into account the best available evidence. The outcomes of some of our techniques revealed that some aspects of Energex’s proposal, such as customer connections and non-network capex, were consistent with the NER requirements in that they reasonably reflected the efficient costs of a prudent distributor as well as a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives. We found that other aspects of Energex’s proposal associated with some capex drivers, in particular augex and repex, revealed inefficiency inconsistent with the NER. Consequently, our findings on augex and repex largely explain why we were not satisfied with Energex's proposed total forecast capex.

Our findings on the capex associated with specific capex drivers are part of our broader analysis and are not intended to be considered in isolation. Our preliminary decision concerns Energex’s total forecast capex for the 2015–20 regulatory control period. We are not approving an amount of forecast expenditure for each capex driver. However, we do use our findings on the different capex drivers to arrive at a substitute estimate for total capex because as a total, this amount has been tested against the NER requirements. We are satisfied that our estimate represents the total forecast capex that as a whole reasonably reflects all aspects of the capex criteria.

Table 6-2 Summary of AER reasons and findings

Issue	Reasons and findings
Forecasting methodology, key assumptions and past capex performance	<p>Our concerns with Energex’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.</p> <p>We conclude that Energex's forecasting methodology predominately relies upon a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure and that the top-down constraints imposed by their governance process are insufficient for us to be able to conclude that the forecasts are prudent and efficient. Bottom up approaches have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. In the absence of a strong top-down challenge of the aggregated total of bottom-up projects, simply aggregating such estimates is unlikely to result in a total forecast capex allowance that we can be satisfied reasonably reflects the capex criteria.</p> <p>In determining our alternative estimate we have addressed the concerns we have with Energex’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 Energex’s key assumptions about demand and customer forecast and forecast materials escalation rates and labour escalation rates.</p>
Augmentation capex	<p>We do not accept Energex’s proposed augex allowance. Our substitute augex allowance is 19.8 per cent lower than Energex’s proposal. We have reduced Energex’s proposed augex to reinforce the sub-transmission and distribution segments of Energex’s network. This reduction reflects the removal of systemic bias present within Energex’s forecasting methodologies which overstate its proposed augex. These biases have been quantified through a detailed engineering review performed by our consultant, EMCa. Additionally, Energex has not sufficiently justified its reliability and power quality programs with a risk and cost/benefit analysis which establishes the benefit of the programs.</p>
Customer connections capex	<p>We do not accept Energex’s proposed customer connections capex and reduce Energex’s proposal by 18.3 per cent. We have not approved any expenditure for the QLD bus terminal and community amenity programs. This reflects the uncertainty about the QLD bus terminal project being undertaken, and the community amenity program which was incorrectly proposed to be recovered as standard control services.</p>

Issue	Reasons and findings
	<p>We accept Energex's proposed capital contributions as it is consistent with forecast construction activity in QLD.</p>
<p>Asset replacement capex (repeX)</p>	<p>We do not accept Energex's proposed repeX forecast of \$1249.5 million (\$2014-15), excluding overheads. We have instead included in our alternative estimate an amount of \$621.8 million (\$2014-15), excluding overheads. Our estimate is 50.2 per cent lower than Energex's proposal. This reduction reflects the outcomes of our predictive modelling and evidence that Energex has an overly conservative risk management approach, and a bias towards overestimation in its repeX forecast.</p> <p>We are satisfied our alternative estimate reasonably reflects the capex criteria. It includes:</p> <ol style="list-style-type: none"> \$472.7 million of expenditure for six modelled asset categories that is based on Energex's own 'business as usual' asset management practices, its current tolerance for risk and its proposed forecast unit costs; \$149.1 million for assets we consider that are not suitable for predictive modelling. This consists of \$42.4 million for the SCADA, \$67.9 million for pole top structures and \$38.8 million for repeX classified as 'other' by Energex.
<p>Non-network capex</p>	<p>We have accepted Energex's forecast non-network capex of \$244.1 million (\$2014-15), excluding overheads, and included it in our estimate of total capex.</p> <p>Energex's forecast non-network capex is 35 per cent lower than actual non-network capex during the 2010-2015 regulatory control period. The longer term trends in non-network capex suggest that Energex has forecast capex for this category at historically low levels. In our view, Energex's forecast reflects the key drivers of the non-network categories of capex.</p>
<p>Capitalised overheads</p>	<p>We do not accept Energex's proposed capitalised overheads. We have instead included in our alternative estimate of overall total capex an amount of \$823.5 million (\$2013-14) for capitalised overheads.</p> <p>Given that our assessment of Energex's proposed direct capex, demonstrates that a prudent and efficient DNSP would not undertake the full range of direct expenditure contained in Energex's proposal, it follows that we would expect some reduction in the size of Energex's capitalised overheads. We have adjusted Energex's overheads on the basis of information they provided to us.</p> <p>However, we also note that 35 per cent of Energex's proposed \$900.4 million (\$2014-15) total capitalised overheads is attributable to information, communications and technology (ICT) services. We have identified some issues regarding this expenditure which we expect Energex to address in its revised proposal.</p>
<p>Real cost escalators</p>	<p>In respect of real material cost escalators (leading to cost increases above CPI), we are not satisfied that Energex's proposed real material cost escalators 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 2015-20 regulatory control period. We consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria including that it is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2015-20 regulatory control period. Our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to Energex's forecast capex for standard control services.</p> <p>In respect of real labour cost escalators (leading to cost increases above CPI), we are not satisfied that Energex's proposed real labour cost escalators 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 2015-20 regulatory control period. We have used an average of Energex's consultant PricewaterhouseCoopers and our consultant Deloitte Access Economics (DAE's) labour forecasts of the utilities sector as detailed in attachment 7.</p>

Source: AER analysis

We consider that our overall capex allowance addresses the revenue and pricing principles. In particular, we consider that Energex has been provided a reasonable opportunity to recover at least the efficient costs it incurs in:²

- Providing direct control network services; and
- Complying with its regulatory obligations and requirements.

As set out in appendix B we are satisfied that our overall capex allowance is consistent with the NEO in that our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity. Further, in making our preliminary decision, we have specifically considered the impact our decision will have on the safety and reliability of Energex's network. We consider this capex forecast is sufficient for a prudent and efficient distributor in Energex's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

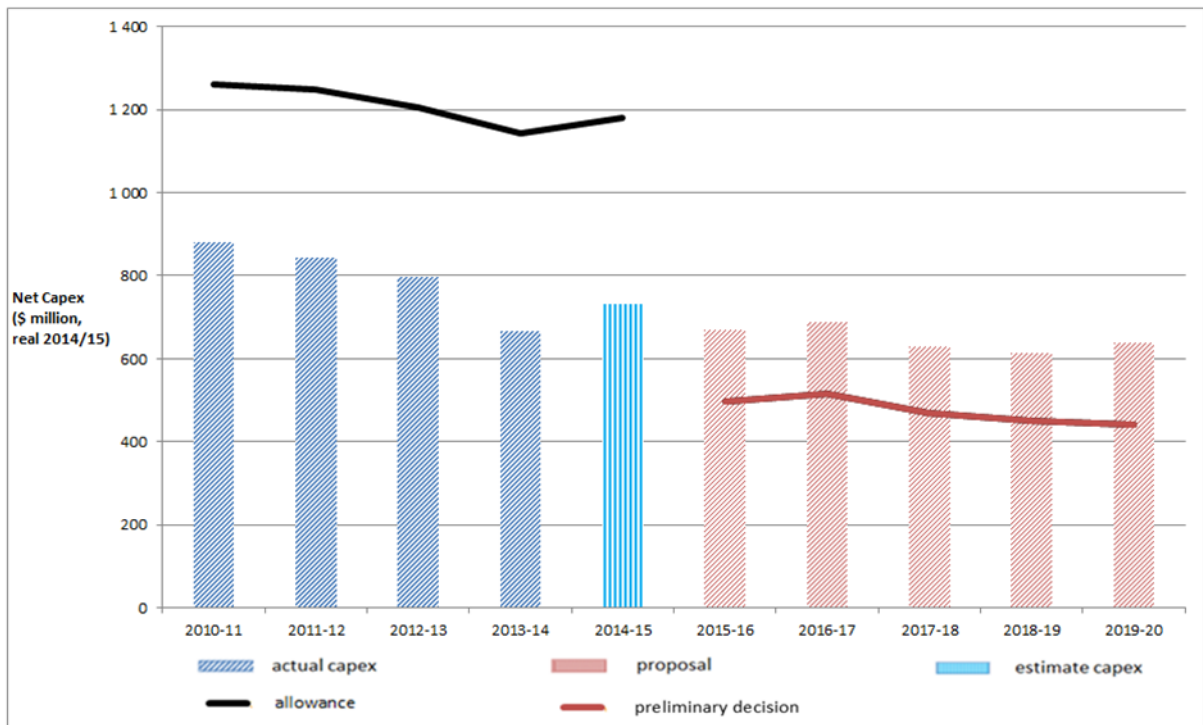
6.2 Energex's proposal

Energex proposed total forecast capex of \$3239.6 million (\$2014–15) for the 2015–20 regulatory control period. Figure 6-1 shows the decrease between Energex's proposal for the 2015–20 regulatory control period and the actual capex that it spent during the 2010–15 regulatory control period. It submits that the reduction in the capex forecast reflects subdued growth in peak demand and recent changes to Energex's Distribution Authority from 1 July 2014, in relation to security and reliability standards.³

² NEL, s. 7A.

³ Energex, *Regulatory Proposal*, October 2014, p. 95.

Figure 6-1 Energex's total actual and forecast capex 2010–2020



Source: AER analysis

6.3 AER's 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 distributor. Key to our assessment is the information provided by the distributor in its proposal. At the same time as Energex submitted its proposal, it also submitted its response to our RIN. We have also sought further clarification from Energex of some aspects of its proposal through information requests.

Our assessment approach involves two key steps:

- First, our starting point for building an alternative estimate is Energex's regulatory proposal.⁴ We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of Energex's proposal at the total level and at the capex driver level such as its proposed augmentation expenditure and replacement expenditure. This analysis not only informs our view on whether Energex's proposal reasonably reflects the capex criteria set out in the NER⁵ but it also provides us with an alternative forecast that does meet the criteria. In arriving

⁴ AER, *Expenditure Forecast Electricity Distribution Guideline*, November 2013, p. 9; see also AEMC, *Economic Regulation Final Rule Determination*, pp. 111 and 112.

⁵ NER, cl. 6.5.7(c).

at our alternative estimate, we have had to weight the various techniques used in our assessment.

- Second, having established our alternative estimate of the *total* forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate total with the distributor's proposal total. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied that the distributor's proposal reasonably reflects the capex criteria, we accept it. If we are not satisfied, the NER require us to put in place a substitute estimate which we are satisfied reasonably reflects the capex criteria. Where we have done this, our substitute estimate is based on our alternative estimate.

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 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
- 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 AEMC has described our role in these terms:⁸

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

⁶ AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Distributors) Rule 2012*, 29 November 2012, p. 113 (AEMC, *Economic Regulation Final Rule Determination*).

⁷ NER, cl. 6.5.7(a).

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

In deciding whether we are satisfied that Energex'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 benchmark capex that would be incurred by an efficient distributor over the relevant regulatory control period
- the actual and expected capex of the distributor 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 distributor 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 distributor
- the extent to which the capex forecast is referable to arrangements with a person other than the distributor 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 distributor has considered, and made provision for, efficient and prudent non-network alternatives.
- In addition, we may notify the distributor in writing, prior to the submission of its regulatory proposal, of any other factor we consider relevant.¹⁰ We have not had regard to any additional factors in this preliminary decision for Energex.

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

...this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

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

More broadly, we also note that in exercising our discretion, we take into account the revenue and pricing principles which are set out in the NEL.¹²

⁹ NER, cl. 6.5.7(e).

¹⁰ NER, cl. 6.5.7(e)(12).

¹¹ AEMC, *Economic Regulation Final Rule Determination*, p. 115.

Expenditure Forecast Assessment Guideline

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 (Expenditure Guideline).¹³ We undertook extensive consultation with stakeholders in the preparation of the Expenditure Guideline. The Expenditure Guideline sets out the AER's proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For Energex, our final framework and approach paper (published in April 2014) stated that we would apply the Expenditure Guideline, including the assessment techniques outlined in it.¹⁴ We may depart from our Expenditure Guideline approach and if we do so, we need to explain why. In this determination we have not departed from the approach set out in our Guideline.

We note that the RIN data forms part of a distributor's regulatory proposal.¹⁵ In our Expenditure Guideline we set out that we would "require all the data that facilitate the application of our assessment approach and assessment techniques" and the RIN we issued in advance of a distributor lodging its regulatory proposal would specify the exact information required.¹⁶ Accordingly, we consider that our intention to materially rely upon the RIN data was made clear as part of the Expenditure Guideline.

6.3.1 Building an alternative estimate of total forecast capex

Our starting point for building an alternative estimate is Energex's proposal.¹⁷ We then considered its performance in the previous regulatory control period to inform our alternative estimate. We also reviewed the proposed forecast methodology and the distributor's reliance on key assumptions that underlie its forecast.

We then applied our specific assessment techniques, to develop and estimate and assess the economic justifications that the distributor put forward. Many of our techniques encompass the capex factors that we are required to take into account. Further details on each of these techniques are included in appendices A and B.

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 distributor should or should not undertake. They are

¹² NEL, ss. 7A and 16(2).

¹³ AEMC, Economic Regulation Final Rule Determination, p. 114 and AER Expenditure Forecast Electricity Distribution Guideline.

¹⁴ AER, Framework and approach paper, p.88

¹⁵ NER, clause 6.8.2(c2) and (d).

¹⁶ AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 25.

¹⁷ AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 9; see also AEMC, *Economic Regulation Final Rule Determination*, pp. 111 and 112.

but one means of assessing the overall total forecast capex required by the distributor. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects but rather an overall revenue requirement that included total capex forecast.¹⁸ Once we approve total revenue, which will be determined by reference to our analysis of the proposed capex, the distributor is then able to prioritise its capex program given the prevailing circumstances at the time (such as demand and economic conditions that impact during the regulatory period). Some projects or programs of work that were not anticipated may be required. Equally likely, some of the projects or programs of work that the distributor has proposed for the regulatory control period may not ultimately be required in the regulatory period. We consider that a prudent and efficient distributor would 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.¹⁹

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, in the particular circumstances of each assessment. By relying on a number of techniques and weighting as relevant, we ensure we can take into consideration a wide variety of information and can take a holistic approach to assessing the proposed capex forecast.

Where our techniques involve the use of a consultant, to the extent that we accept our consultants' findings, we have set this out clearly in this preliminary decision and they form part of our reasons for arriving at our preliminary decision on overall capex. In all cases where we have relied on the findings of our consultants, we have done so only after carefully reviewing their analysis and conclusions, and evaluating these in the light of the outcomes from our other techniques and our examination of the distributor's proposal.

We also need to take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The

¹⁸ AEMC, Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, p. vii

¹⁹ AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 12.

other components that directly affect the total forecast capex are forecast opex, forecast demand, the service target performance incentive scheme, the capital expenditure sharing scheme, real cost escalation and contingent projects. We discuss how these components impact the total forecast capex in Table 6-4.

Underlying our approach are two general assumptions:

- The 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.²⁰
- Past expenditure was sufficient for Energex to manage and operate its network in that previous period, in a manner that achieved the capex objectives.²¹

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

6.3.2 Comparing the distributor's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the distributor's proposed total forecast capex. This includes comparing our alternative estimate of forecast total capex with the distributor's proposal. The distributor'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.²²

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.

²⁰ AER, *Expenditure Forecast Electricity Distribution Guideline*, pp. 8 and 9. The Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by United Energy Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA)

²¹ AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 9.

²² AEMC, *Economic Regulation Final Rule Determination*, p. 112.

We have not relied solely on any one technique to assist us in forming a view as to whether we are satisfied that a distributor's proposed forecast capex reasonably reflects the capex criteria. We have drawn on a range of techniques as well as our assessment of other elements that impact upon capex such as demand and real cost escalators.

Our decision concerns Energex's total forecast capex and we are not approving specific projects. It is important to recognise that the distributor 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. We consider that acting prudently and efficiently, the distributor will consider the changing environment throughout the regulatory period and make sound decisions taking into account their individual circumstances to address any unanticipated issues. Our provision of a total capex forecast does not constrain a distributor's actual spending – either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to expend particular capital expenditure differently or in excess of the total capex forecast set out in our this decision. Our decision does not constrain it from doing so.

The regulatory framework has a number of mechanisms to deal with unanticipated expenditure needs. Importantly, where unexpected events leads to an overspend of the approved capex forecast, a distributor does not bear the full cost, but rather bears 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 distributor to pass on such expenses to customers where appropriate.

This does not mean that we have set our alternative estimate below the level where Energex has a reasonable chance to recover its efficient costs. Rather, we note that Energex is able to respond to any unanticipated issues that arise during the 2015-20 regulatory control period and in the event that the approved total revenue underestimates the total capex required, Energex has significant flexibility to allow it to meet its safety and reliability obligations.

Conversely, if we overestimate the amount of capex required, the stronger incentives put in place by the AEMC in 2012 should lead to a distributor spending only what is efficient, with the benefits of the underspend being shared between the distributor and consumers.

6.4 Reasons for preliminary decision

We applied the assessment approach set out in section 6.3 to Energex. We are not satisfied that Energex's total forecast capex reasonably reflects the capex criteria. We compared Energex's capex forecast to our capex forecast we constructed using the approach and techniques outlined in appendix A and B. Energex's proposal is materially higher than our assessment. 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 Energex's total forecast capex for the 2015–20 regulatory control period.

Table 6-3 Our assessment of required capex by capex driver (\$ million 2014–15)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Augmentation	92.6	103.6	87.9	65.3	56.4	405.8
Connections	51.7	51.3	52.0	55.9	61.0	272.0
Replacement	126.5	131.2	121.3	124.1	118.7	621.8
Non-Network	54.5	56.0	44.1	43.1	46.5	244.1
Capitalised overheads	173.4	171.6	161.1	159.2	158.1	823.5
Materials escalation adjustment	-0.3	-0.2	-0.9	-1.4	-2.8	-5.6
Net Capex (excluding cap cons)	498.5	513.6	465.5	446.2	437.8	2361.5
Capital Contributions	30.0	33.2	34.7	36.8	37.6	172.3
Gross Capex (includes capital contributions)	528.4	546.8	500.2	483.0	475.4	2533.8

Source: AER analysis

Note: Numbers may not add up due to rounding.

Our assessment of Energex's forecasting methodology, key assumptions and past capex performance is discussed in the section below.

Our detailed assessment of capex drivers is in appendix B. This sets out the application of our assessment techniques to the capex drivers, and the weighting we gave to particular techniques. We used our reasoning in the appendices to form our alternative estimate.

6.4.1 Key assumptions

The NER require Energex 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.²³

²³ NER, cl. S6.1.1(2), (4) and (5).

Energex's key assumptions are as follows:²⁴

- Demand and energy – Energex used the base case network peak demand for forecast network augmentation expenditure.
- Customer numbers – Energex used the base case customer number forecast to forecast connections and customer-initiated works.
- Customer engagement – Energex used customer expectations obtained through a research and consultation program relating to network investment, reliability, price and other operating services.
- Cost escalators – Cost escalators are applied to reflect changes in labour, materials and contractors.
- Unit rates – Unit rates are used in the development of bottom up forecasts where appropriate.

We have assessed Energex's key assumptions in the appendices to this capex attachment.

6.4.2 Forecasting methodology

Energex is required to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.²⁵ It is also required to include this information in its regulatory proposal.²⁶

The main points of Energex's forecasting methodology are:²⁷

- Energex's capex forecasting methodology primarily takes a bottom up approach, developing a program on a project basis that meets the network requirements. The bottom up forecast is reconciled against corporate expenditure targets and an acceptable network risk profile.²⁸
- There are four categories of system capex: asset replacement, corporate initiated augmentation, customer initiated capital works and reliability/quality improvements. There are four categories of non-system capex: information and communications, tools and equipment, fleet and land and buildings.
- Energex's system capital expenditure program is developed through a network investment plan which is prepared in accordance with Energex's network planning and governance processes to ensure prudence and efficiency of the capital spend.

²⁴ Energex, *Regulatory proposal*, October 2014, p.108.

²⁵ NER, cl. 6.8.1A and 11.56.4(o); Energex, *Expenditure Forecasting Methodology*, November 2013.

²⁶ NER, cl. S6.1.1(2);

²⁷ Energex, *Regulatory proposal*, October 2014, p.106.

²⁸ Energex, *Regulatory proposal*, October 2014, p.106.

- A bottom up assessment was applied to derive its forecast for all capex categories except overheads, where a base, step and trend approach was used. The bottom-up forecasts are generally based on forecast quantities and unit costs.
- Costings were based largely on historical costs. Historical unit-costs, current labour and contractor rates and materials and equipment costs were used to develop the bottom-up forecasts.
- Energex performs an optimisation of the capital program to achieve target network performance outcomes including an evaluation of the risk profile and reconciliation with corporate expenditure targets
- Energex undertakes a review against top down capex targets
- As part of the final program, network risk is revisited, the material and resourcing requirements are identified and financials are finalised.

We have identified two aspects of Energex'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. These are:

- Energex's forecasting methodology generally applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for all its capex categories.
- Energex's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is excessively conservative.

Insufficient top-down restraint

Energex's forecasting methodology is primarily based upon a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for all its capex categories (except for overheads).²⁹ Energex stated that it applies a benchmarking approach at the program level as a top-down assessment of program efficiency. It also submitted that it has applied the AER's augex and repex models as a top-down assessment.³⁰

The drawback of deriving an estimate of capex by applying a bottom-up assessment is that of itself it does not provide sufficient evidence that the estimate is efficient. Bottom up approaches have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. In contrast, reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency. In certain very limited circumstances, a bottom up build may be a reasonable starting point to justifying expenditure.³¹

²⁹ Energex, *Regulatory proposal*, p. 106.

³⁰ Energex, *Regulatory proposal*, p. 106.

³¹ It is possible for a bottom-up approach to reasonably reflect the capex criteria and if our assessment demonstrated this to be the case, then we would accept a total capex forecast derived from the bottom-up assessment. However, due to potential overestimation in a bottom-up approach, a top down assessment is a vital aspect of testing the validity of the bottom-up forecast.

However, simply aggregating such estimates is unlikely to result in a total forecast capex allowance that we are satisfied reasonably reflects the capex criteria.

As we stated in our Expenditure Forecast Assessment Guideline, we intend to assess forecast capex proposals through a combination of top down and bottom up modelling.³² Our top-down assessment of Energex's proposed forecast is a material consideration in determining whether we are satisfied if it reasonably reflects the capex criteria. For example, trend analysis is a top-down assessment that can be applied in the context of a distribution network. This technique is able to test whether an estimate that results from a bottom-up assessment might be efficient. We have used this technique in this determination.

A top-down assessment should also clearly evidence a holistic and strategic consideration or assessment of the entire forecast capex program at a portfolio level. It should also demonstrate how the forecast capex proposal has been subject to governance and risk management arrangements. In turn, these arrangements should demonstrate how the timing and prioritisation of certain capital projects or programs has been determined over both the short and the long-term. It should also demonstrate that the capex drivers, such as asset health and risk levels, are well defined and justified. In particular, asset health and risk level metrics are key elements of capex drivers.

Energex's forecast methodology cites the application of a top-down forecasting approach. We have examined the top-down approach used by Energex and do not consider that it brings sufficient restraint to bear on the overall forecast. This is supported by our consultant Energy Market Consulting associates (EMCa) which concluded that:³³

It is our view that a robust top-down challenge process to the expenditure process may have identified opportunities to reduce forecast capex. We find that an effective challenge to that expenditure has not occurred. In regards to Energex's application of the repex modelling, we note that EMCa found that Energex presents alternative outcomes that are so wide as to be of little merit in helping to validate its proposed expenditure.³⁴ This suggests that the application of the model by Energex was not used to bring restraint to its forecasting approach.

In particular, we note that Energex has targeted no more than CPI increases in price over the 2015–20 regulatory control period.³⁵ However, this price constraint does not

³² AER, *Expenditure Forecast Electricity Distribution Guideline*, p. 17.

³³ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015 - 2020*, p. 20.

³⁴ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015 - 2020*, p. i.

³⁵ Energex, *Regulatory Proposal*, October 2014, p. 9.

address the prudence and efficiency requirement contained in the NER. We again agree with EMCA which stated that:³⁶

A forecasting process designed to constrain expenditure levels to maintain “network price increases below CPI” may result in a network capex forecast that is either too high or too low. We note, for example, that this constraint was not applied in the current RCP, when network prices increased considerably on the basis of what were then perceived to be high capex requirements. In either case, it would be only by coincidence that such a constraint would result in a prudent and efficient capital expenditure forecast. EMCA also found that:³⁷

In response to a more effective top-down challenge, we consider that the approval of lower risk and lower cost/benefit projects might have been rationalised or deferred. In the absence of clear evidence of such a challenge, we are unable to conclude that the proposed expenditure is prudent and efficient.

Whilst we appreciate that Energex has brought some top-down restraint to its forecasting approach, we are not convinced that it is appropriately robust. Accordingly, we have applied a range of assessment techniques available to us to perform our own 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 to each major sub-category of capex. The combination of our techniques informs our decision as to whether the proposed total capex forecast reasonably reflects the capex criteria.

6.4.3 Lack of cost benefit analysis

Secondly, Energex's cost-benefit evaluation, where it exists for each of its capital projects or programs, reveals that its underlying risk assessment is excessively conservative. EMCA found that for both augex and repex the expenditure has not been:³⁸

adequately supported by cost-benefit analysis and appropriately-applied risk assessment. As a result it appears that a high number of low risk rated projects included in the capital expenditure forecasts.

We do note that the 'As Low As Reasonably Practicable' (ALARP) principle allows for risks to be mitigated to the point where the cost is 'grossly disproportionate' to the benefits. However, we agree with EMCA's assessment that this is applicable to high or

³⁶ EMCA, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015 - 2020*, p. 16.

³⁷ EMCA, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015 - 2020*, p. 18.

³⁸ EMCA, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015 - 2020*, p. i and ii.

intolerable risks, leaving standard cost/benefit analysis the preferred tool for the majority of risk assessments.³⁹

The lack of a rigorous cost-benefit approach, combined with a top-down assessment designed to meet price rather than efficiency objectives, indicates to us that Energex's forecast methodology is likely to result in a capex forecast that does not reasonably reflect the capex criteria.

6.4.4 Interaction with the STPIS

We consider that our approved capital expenditure forecast is consistent with the setting of targets under the STPIS. In particular, we consider that the capex allowance should not be set such, that there is an expectation that it will lead to Energex systematically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient Energex to maintain performance at the targets set under the STPIS. As such, it is appropriate to apply the STPIS as set out in attachment 11.

In making our decision, we have specifically considered the impact our decision will have on the safety and reliability of Energex's network. We consider our substitute estimate is sufficient for Energex to maintain the safety, service quality and reliability of its network consistent with its obligations. In any event, our provision of a total capex forecast does not constrain a distributor's actual spending – either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to expend particular capital expenditure differently or in excess of the total capex forecast set out in our decision. Our decision does not constrain it from doing so. Under our analysis of specific capex drivers, we have explained how our analysis and certain assessment techniques factor in safety and reliability requirements.

6.4.5 Energex's capex performance

We have looked at a number of historical metrics of Energex's capex performance against that of other distributors in the NEM. We also compare Energex'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 distributors for the annual benchmarking report. This includes Energex's relative partial and multilateral total factor productivity (MTFP) performance, capex per customer and maximum demand, and Energex's historic capex trend.

We note that the NER sets out that we must have regard to our annual benchmarking report.⁴⁰ This section explains how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall

³⁹ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015 - 2020*, p. 35.

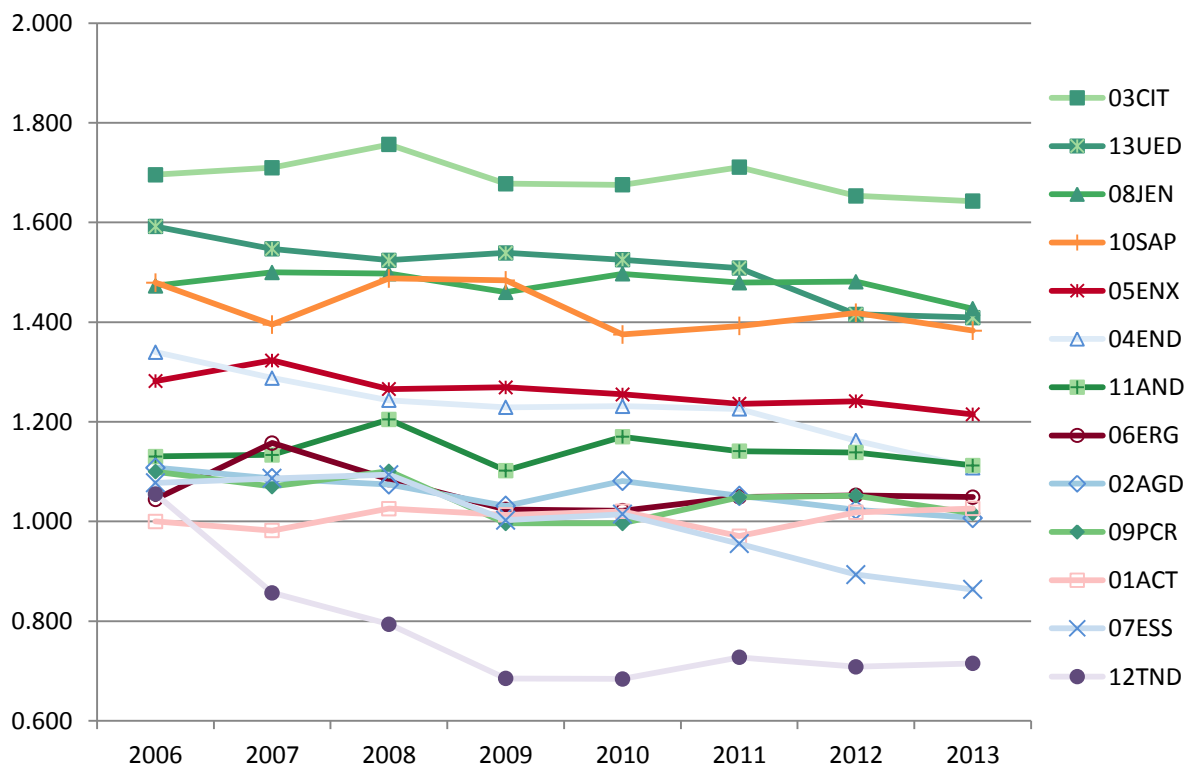
⁴⁰ NER, cl. 6.5.7(e).

understanding of Energex's proposal in a broader context. We have not relied on our high level benchmarking metrics other than to gain a high level insight into Energex's proposal. We have not used this analysis deterministically in our capex assessment, which differs from our approach in the opex assessment.

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. Energex falls in the middle of the range on this assessment, falling behind some of the Victorian and South Australian distributors.

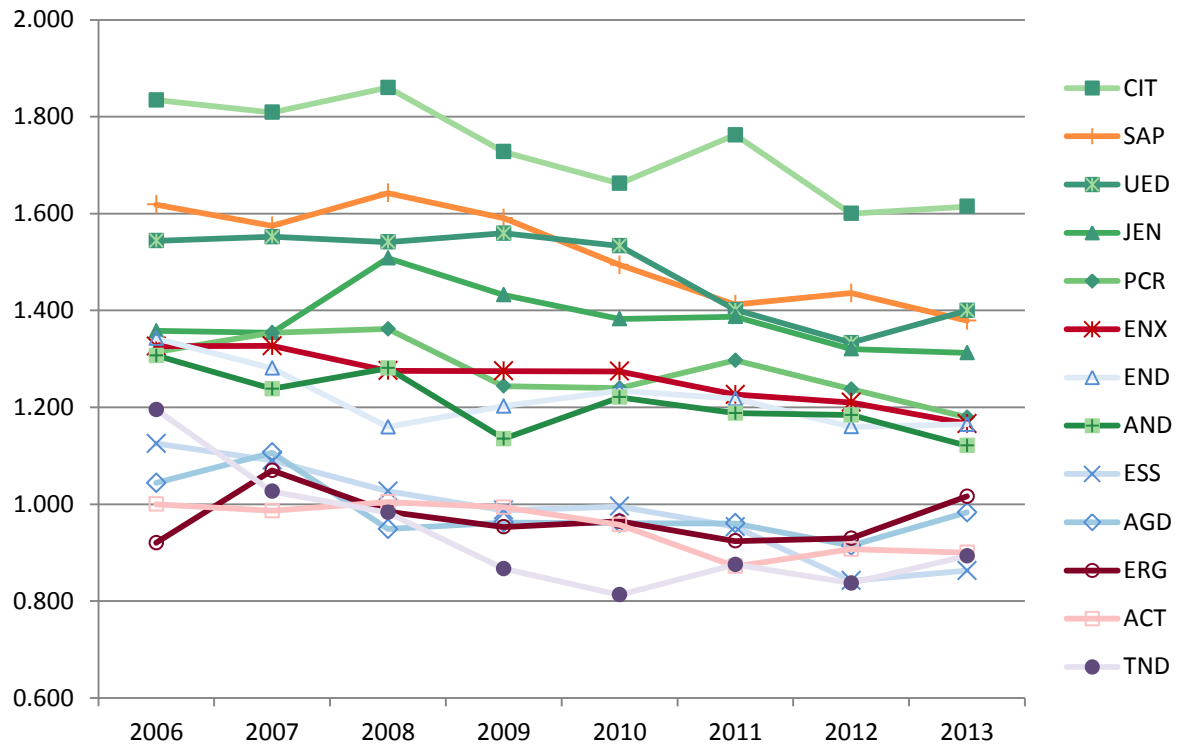
Figure 6-2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER annual benchmarking report.

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

Figure 6-3 Multilateral total factor productivity



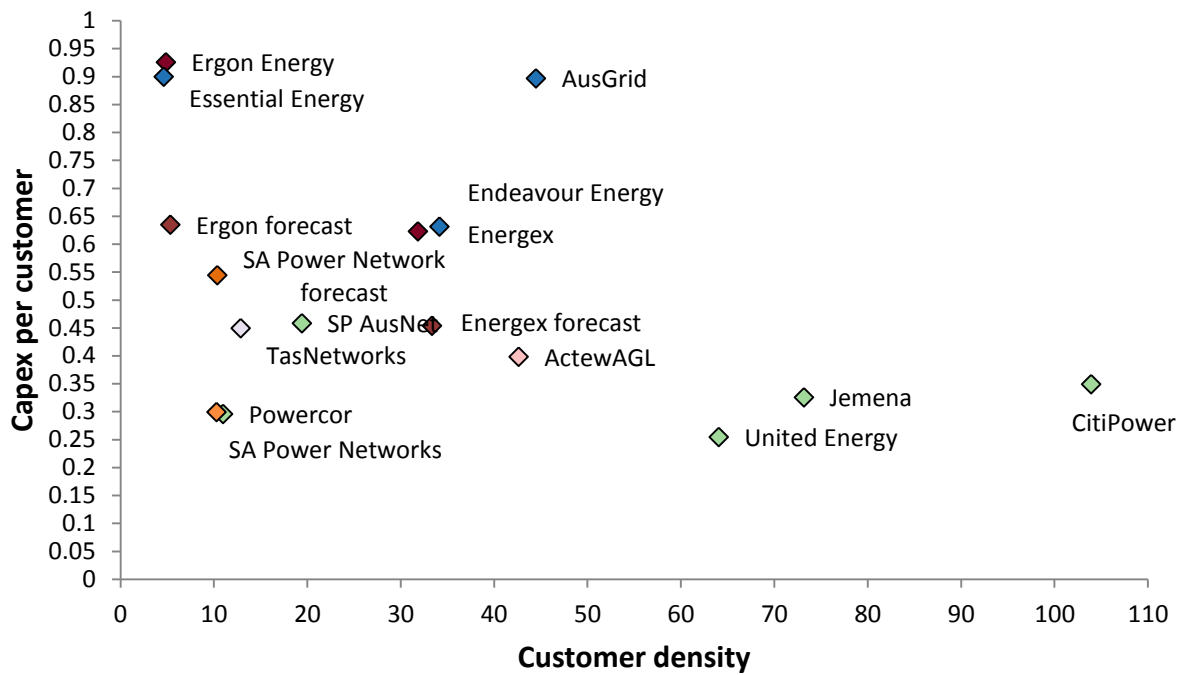
Source: AER annual benchmarking report.

Relative capex efficiency metrics

Figure 6-4 and Figure 6-5 show capex per customer and per maximum demand, against customer density. Capex is taken as a five year average for the years 2008–12. For the QLD and SA distributors, we have also included the businesses' proposed capex for the 2015–20 regulatory control period. We have considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6-4 shows that Energex had relatively high capex per customer for the 2008–2012 period. Energex's capex per customer will reduce for the 2015–20 regulatory control period based on their proposed forecast capex. This reduction brings Energex's capex per customer to a similar level as the Victorian and South Australian distributors.

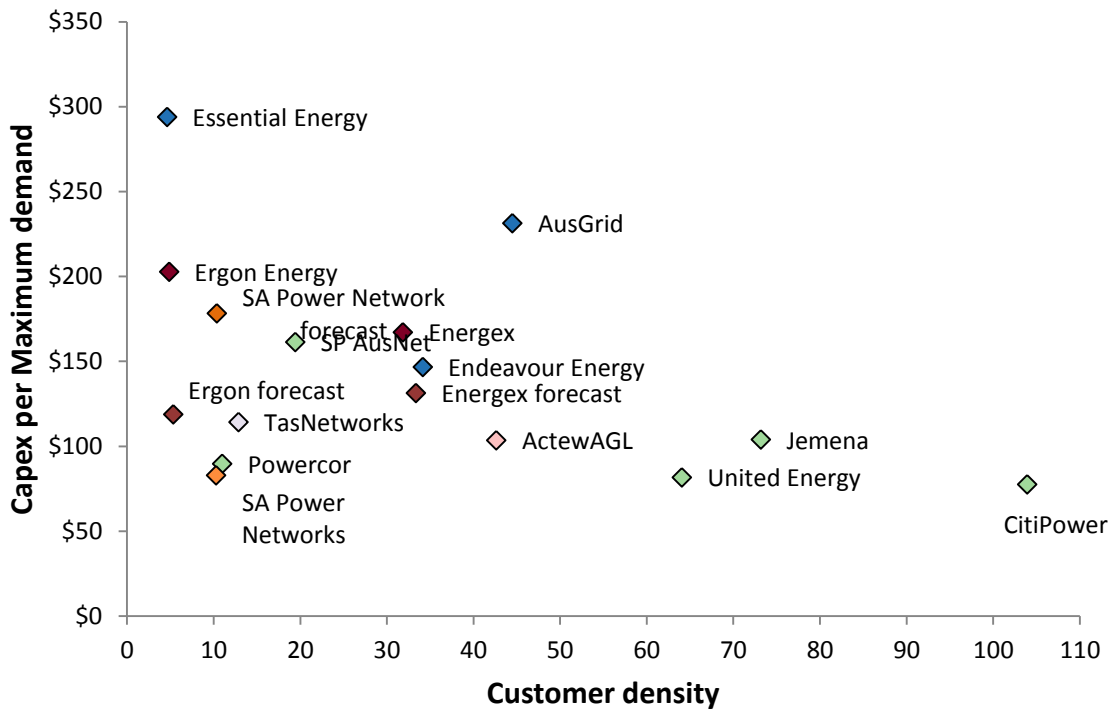
Figure 6-4 Capex per customer (000s, \$2013–14), against customer density



Source: AER analysis

Figure 6-5 shows that Energex's capex per maximum demand for the 2008–2012 period was relatively high, but significantly lower than some NSW distributors. Capex per maximum demand is forecast to reduce for Energex in the next period.

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



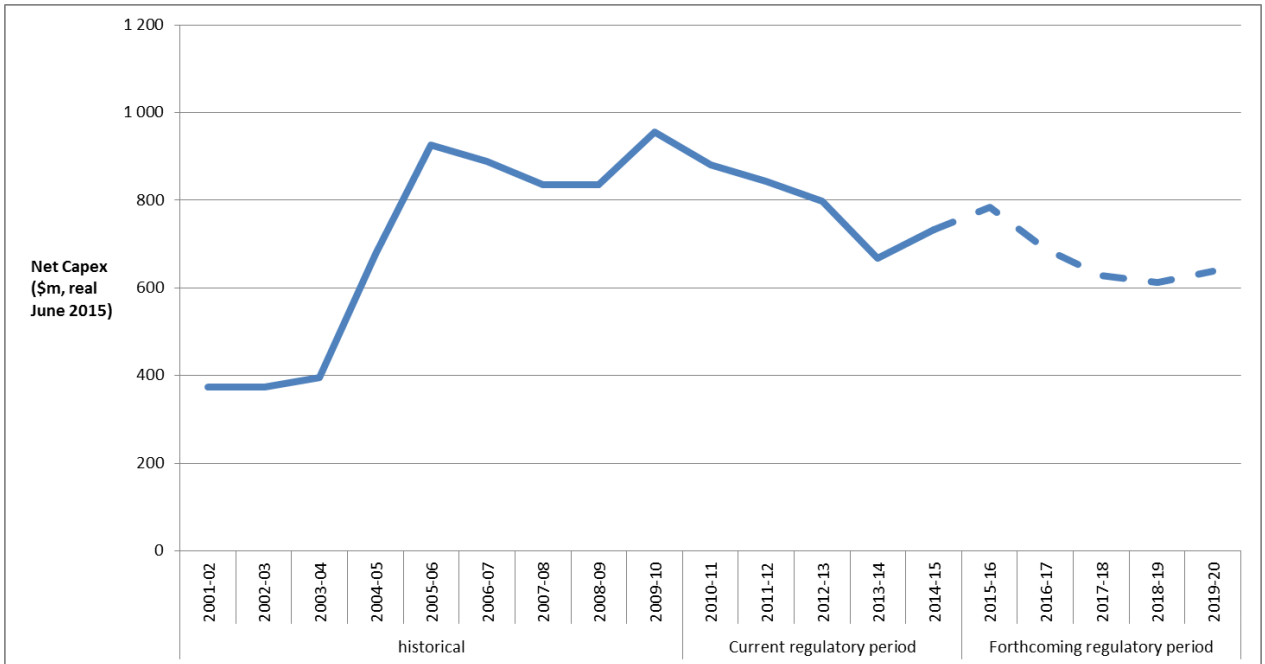
Source: AER analysis

6.4.6 Energex historic capex trends

We have compared Energex's capex proposal for the 2015–20 regulatory control period against the long term historical trend in capex levels.

Figure 6-6 shows actual historic capex and proposed capex between 2001–12 and 2018–19. This figure shows that while Energex's average proposed capex for the 2015–20 regulatory control period is lower than the previous regulatory period, it is still a substantial increase over the early 2000's.

Figure 6-6 Energex total capex (including overheads)—historical and forecast for 2015–2020 period



Source: AER analysis

6.4.7 Interrelationships

There are a number of interrelationships between Energex's total forecast capex for the 2015–20 regulatory control period and other components of its distribution determination that we have taken into account in coming to our preliminary decision. Table 6-4 summarises these other components and their interrelationships with Energex's total forecast capex.

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

Other component	Interrelationships with total forecast capex
Total forecast opex	<p>There are elements of Energex's total forecast opex that are related to its total forecast capex. These are:</p> <ul style="list-style-type: none"> the labour cost escalators that we approved in Attachment 7 the amount of maintenance opex that is reflected in Energex's opex base year that we approved in Attachment 7 <p>The labour cost escalators are interrelated with capex because Energex's total forecast capex includes expenditure for capitalised labour. Maintenance opex is also related to capex, although we did not approve a specific amount of maintenance opex as part of assessing Energex's total forecast opex. This is because the amount of maintenance opex that is reflected in Energex's opex base in part determines the extent to which Energex needs to spend repex during the 2015–2020 period.</p>
Forecast demand	Forecast demand is related to Energex'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

Other component	Interrelationships with total forecast capex
	security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme (CESS)	The CESS is related to Energex's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it reasonably reflects the capex criteria. As we noted in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudence of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from Energex's regulatory asset base. In particular, the CESS will ensure that Energex bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Energex 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, Energex risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	<p>The STPIS is interrelated to Energex'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 2015–2020 period. This is because such expenditure should be offset by rewards provided through the application of the STPIS.</p> <p>Further, the forecast capex should be sufficient to allow Energex to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to Energex systematically under or over performing against its targets.</p>
Contingent project	<p>A contingent project is interrelated to Energex'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 Energex's total forecast capex for the 2015–2020 period.</p> <p>We did not identify any contingent projects for Energex during the 2015–2020 period.</p>

Source: AER analysis

6.4.8 Capex factors

In deciding whether or not we are satisfied Energex'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 distributor over the relevant regulatory control period	We have had regard to our most recent benchmarking report in assessing Energex's proposed total forecast capex and in determining our alternative estimate for the 2015–2020 period. This can be seen in the metrics we used in our assessment of Energex's capex performance.
The actual and expected capex of Energex during any preceding regulatory control periods	We have had regard to Energex's actual and expected capex during the 2010–2015 and preceding regulatory control periods in assessing its proposed total forecast capex. This can be seen in our assessment of Energex's capex performance. It can also be seen in our assessment of the forecast capex associated with each of the capex drivers that underlie Energex's total forecast capex. In these cases, we have applied trend analysis which is

Capex factor	AER consideration
<p>The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by Energex in the course of its engagement with electricity consumers</p>	<p>reasonably likely to be recurrent in nature (e.g. non-network related capex)</p> <p>We have had regard to the extent to which Energex's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Energex. Energex has undertaken engagement with its customers and presented high level findings regarding its customer preferences. These findings suggest that consumers value lower prices and reliable networks.</p> <p>On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Energex's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.</p>
<p>The relative prices of operating and capital inputs</p>	<p>We have had regard to the relative prices of operating and capital inputs in assessing Energex's proposed real cost escalation factors for materials. In particular, we have not accepted Energex's proposal to apply real cost escalation for materials.</p>
<p>The substitution possibilities between operating and capital expenditure</p>	<p>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 Energex's total forecast capex and total forecast opex in Table 6-4 above.</p>
<p>Whether the capex forecast is consistent with any incentive scheme or schemes that apply to Energex</p>	<p>We have had regard to whether Energex's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Energex's total forecast capex and the application of the CESS and the STPIS in Table 6-4 above.</p>
<p>The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms</p>	<p>We have had regard to whether any part of Energex's proposed total forecast capex or our alternative estimate that is referable to arrangements with a person other than Energex that do not reflect arm's length terms. We have considered the arrangements between Energex and its related party SPARQ regarding the provision of ICT services and do not have evidence to indicate that this does not reflect arm's length terms.</p>
<p>Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project</p>	<p>We have had regard to whether any amount of Energex's proposed total forecast capex or our alternative estimate that relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriate be included as a contingent project.</p>
<p>The extent to which Energex has considered and made provision for efficient and prudent non-network alternatives</p>	<p>We have had regard to the extent to which Energex 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 B.</p>
<p>Any other factor the AER considers relevant and which the AER has notified Energex in writing, prior to the submission of its regulatory proposal, is a capex factor</p>	<p>We did not identify any other capex factor that we consider relevant.</p>

Source: AER analysis

6.5 Allocation of balancing item

Energex's RIN contained a balancing item of $-\$85.4$ million ($\$2014-15$). Energex advised that the balancing item relates to Fleet oncosts and Material oncosts captured as part of direct capex and a community amenity allowance.

We have allocated this balancing item to driver categories for the purpose of our assessment. Table 6-6 sets out our allocation of Energex's balancing item.

Table 6-6 Allocation of balancing item to driver

\$ million (\$2013/14)	Initial Proposal	Initial Proposal (after allocating balancing item)	Preliminary Decision
Augmentation	512.7	512.7	405.8
Connections	311.9	332.9	272.0
Replacement	1,249.5	1,249.5	621.8
Reliability improvement	0.0	0.0	0.0
Other system assets	0.0	0.0	0.0
Non-Network	244.1	244.1	244.1
Capitalised overheads	985.8	900.4	823.5
Other expenditure - (community amenity)	21.0	0.0	0.0
Materials escalation adjustment	0.0	0.0	-5.6
Balancing item	-85.4	0.0	0.0
TOTAL NET CAPEX	3,239.6	3,239.6	2,361.6
Capcons	172.3	172.3	172.3
TOTAL GROSS CAPEX	3,411.9	3,411.9	2,533.9

Source: AER analysis

A Assessment Techniques

This appendix describes the assessment approaches we have applied in assessing Energex's proposed forecast capex. We use a variety of techniques to determine whether the proposed capex reasonably reflects the capex criteria. The extent to which we rely on each of the assessment techniques is set out in appendix B.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure being assessed. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our expenditure assessment guideline, where we stated:⁴¹

Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across distributors) when forming a view on forecast unit costs.

Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

The assessment techniques that we have used to assess Energex's capex are set out below.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. We are required to consider economic benchmarking as it is one of the capex factors under the NER.⁴² Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.⁴³ It allows us to compare the performance of a distributor against its own past performance, and the performance of other distributors. Economic benchmarking helps us to assess whether a distributor's capex forecast represents efficient costs.⁴⁴ As stated by the AEMC, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.⁴⁵

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

⁴¹ AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013, p. 8.

⁴² NER, cl. 6.5.7(e)(4).

⁴³ AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013.

⁴⁴ NER, cl. 6.5.7(c).

⁴⁵ AEMC, *Economic Regulation Final Rule Determination*, p. 25.

overall capex efficiency. In general, these measures calculate a distributor's efficiency with consideration given to its inputs, outputs and its operating environment. We have considered each distributor's operating environment in so far as there are factors that are outside of a distributor's control but which affect a distributor's ability to convert inputs into outputs.⁴⁶ Once such exogenous factors are taken into account, we expect distributors 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.⁴⁷

In addition to the measures in the annual benchmarking report, we have considered how distributors have performed on a number of overall capex metrics, including capex per customer, and capex per maximum demand. We have calculated these economic benchmarks based on actual data from the previous regulatory control period.

The results from the economic benchmarking give an indication of the relative efficiency of each of the distributors, and how this has changed over time.

A.2 Trend analysis

We have considered past trends in actual and forecast capex. This is one of the capex factors to which we are required to have regard.⁴⁸

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 distributors in their proposals, as well as changes in the circumstances of the distributor.

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.⁴⁹ 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 distributor.

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

⁴⁶ AEMC, *Economic Regulation Final Rule Determination*, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

⁴⁷ AER, *Annual Benchmarking Report*, 2014.

⁴⁸ NER, cl. 6.5.7(e)(5).

⁴⁹ NER, cl. 6.5.7(a)(3).

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.

A.3 Category analysis

Expenditure category level analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex:

- 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.

Using standardised reporting templates, we have collected data on augex, repex, connections, non-network capex, overheads and demand forecasts for all distributors in the NEM. The use of standardised category data allows us to make direct comparisons across distributors. 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 distributors, and how these factors may change over time.

A.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 (only used in a qualitative sense)

The use of the repex and augex models is directly relevant to assessing whether a distributor's capex forecast reasonably reflects the capex criteria.⁵⁰ The models draw

⁵⁰ NER, cl. 6.5.7(c).

on actual capex incurred by a distributor during the preceding regulatory control period. This past capex is a factor that we must take into account.⁵¹

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. In instances where we consider a distributor'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 is used to forecast the amount of augmentation driven by increases in maximum demand. IT augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.⁵² The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the distributor over a given period.⁵³ In this way, the augex model accounts for the main internal drivers of augex that may differ between distributors, namely peak demand growth and its impact on asset utilisation. We can use the augex model to identify general trends in asset utilisation over time as well as to identify outliers in a distributor's augex forecast.⁵⁴ However, we have not relied heavily on the augex model for this reset. This is because Energex experienced negative demand growth and positive growth in augex in some network segments during the 2010–15 period. This 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.

A.5 Engineering review

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

In particular, in respect of augex and repex, our engineering consultants considered whether the distributor's:

- Forecast is reasonable and unbiased, by assessing whether the distributor'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.

⁵¹ NER, cl. 6.5.7(e)(5).

⁵² Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

⁵³ For more information, see: AER, *Guidance document: AER augmentation model handbook*,

⁵⁴ 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.

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

These factors relate directly to our assessment of whether the distributor's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives:⁵⁵

- 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 distributor's risk management is prudent and efficient, the distributor'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.⁵⁶
- If the distributor's costs and work practices are prudent and efficient, the distributor will have the appropriate governance and asset management practices to ensure that the distributor 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 engineering consultants 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 distributor investigated to address the economic requirement (for example, for augmentation projects the review should have included an assessment of the extent to which the distributor considered and provided for efficient and prudent non-network alternatives⁵⁷)
- whether the timing of the project is efficient
- unit costs and volumes, including comparisons with relevant benchmarks

⁵⁵ NER, cl. 6.5.7(c).

⁵⁶ This approach is supported by NERA Economic Consulting, see NERA, Economic Interpretation of cl. 6.5.6 and 6.5.7 of the National Electricity Rules, Supplementary Report.

⁵⁷ NER, cl. 6.5.7(c)(10).

- whether the project should more appropriately be included as a contingent project⁵⁸
- 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 expenditure⁵⁹
- the extent to which the capex forecast is referable to arrangements with a person other than the distributor that, in the opinion of the AER, do not reflect arm's length terms⁶⁰, where relevant
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the distributor in the course of its engagement with electricity consumers.⁶¹ This is most relevant to core network expenditure (augex and repex) and may include the distributor's consideration of the value of customer reliability (VCR) standard or a similar appropriate standard.

⁵⁸ This principally relates to augex. See NER, cl. 6.5.7(e)(9A).

⁵⁹ This principally relates to augex. See NER, cl. 6.5.7(e)(6) and (e)(9A).

⁶⁰ NER, cl. 6.5.7(e)(9).

⁶¹ NER, cl. 6.5.7(e)(5A).

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of Energex's forecast capex for the 2015–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2015–20 regulatory control 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 Energex'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 Energex'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 section 6.3.

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

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

In each of sections B.1 to B.7 we examine seven sub-categories of capex which we include in our alternative estimate. For each such sub-category, we explain why we are satisfied the amount of capex that we include in our alternative estimate reasonably reflects the capex criteria.

B.1 Alternative estimate

Having examined Energex's proposal, we formed a view that our alternative estimate of the capex reasonably reflects the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix B. Our weighting of each of these techniques is set out under the capex drivers below.

We are satisfied that our alternative estimate reasonably reflects the capex criteria

B.2 AER findings and estimates for augmentation expenditure

Augmentation capex (augex) 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. Typically, the largest driver of augex is maximum demand and its effect on network utilisation and reliability.

Energex proposes a forecast of \$512.7 million (\$2014–15) for augex, excluding overheads. This is a 64 per cent decrease compared to actual augex incurred in the 2010–15 regulatory control period. As set out in Table B-1, Energex's proposed augex forecast is comprised of capex for demand (within its distribution, low voltage and sub-transmission networks), reliability, power quality, land and easements, and additional 'on-costs'.

Table B-1 Energex's proposed augex (\$2014–15, million, excluding overheads)

Category	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Sub-transmission	31.5	41.4	22.7	13.3	4.2	113.1
Distribution	18	19.6	20.7	19.8	18.9	97
Low voltage programs	38.9	39.1	39.1	17.3	17.4	151.8
Demand management	1	1.2	1.2	1.2	1	5.6
Reliability	14.6	11	11	11.1	11.2	58.9
Power quality	5.8	4.9	4.9	11.4	11.5	38.4
Sub-total	109.6	117.2	99.6	74.2	64	464.7
Land and easements	3.3	5.4	5.5	7.7	7.8	29.6
Additional on-costs	4.6	4.1	4.1	2.9	2.6	18.4
Total augex proposal	117.5	126.7	109.2	84.8	74.4	512.7

Source: Energex reset RIN; EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 41; Energex response to AER Energex 010 and 030.

Note: Numbers may not add up due to rounding.

We do not accept Energex's augex forecast. We have instead included an amount of \$405.5 million (\$2014–15) in our alternative estimate, a reduction of 20.9 per cent.

We have formed this view after reviewing all of the material submitted by Energex in its regulatory proposal as well as its supporting documentation. Our review was undertaken in three parts. First, we considered the proposed forecast in the context of past expenditure, demand trends and forecast network utilisation.⁶² This is set out in

⁶² The augex model has been developed to derive an estimate of required augex based on predicted augmentation requirements (based on demand and asset utilisation) and unit costs. However, we have not relied heavily on the augex model for this reset. This is because Energex experienced negative demand growth and positive growth in augex in some network segments during the 2010-15 period. This 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

section B.2.1 and takes into account changes in demand, network capacity, design standards and reliability obligations.

Second, we examined the forecasting methodologies that underpinned Energex's forecast. As set out in section B.2.2, our examination of Energex's processes was assisted by a technical review undertaken by our independent consultants, Energy Market Consulting Associates (EMCa). We asked EMCa to undertake a review to test three hypotheses:

- The business's forecast is reasonable and unbiased: the business's proposed expenditures are a reasonable forecast of the unbiased efficient cost of maintaining performance at the required or efficient service levels. There are no in-built systemic biases which result in the forecast being higher or lower than is efficient.
- The business's costs and work practices are prudent and efficient: the business uses the minimum resources reasonably practical to achieve the capex objectives and maintain the required or efficient service levels.
- The business's risk management is prudent and efficient: 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.

The third part of our review involved seeking to quantify the impact of forecasting biases we and EMCa identified. To do this, we have had regard to the technical review of a sample of projects undertaken by EMCa. EMCa estimated the impact of the overestimation bias at the cost category level as set out in section B.2.3. As set out in section B.2.3, we accept EMCa's findings because EMCa satisfied the scope of work we assigned them, and demonstrated that it has applied independent engineering expertise to Energex's own planning documentation and supporting evidence.

Our preliminary decision to include \$405.2 million (\$2014–15, excluding overheads) for augex in our alternative estimate is based on adopting the mid-point of the range of overestimated capex for sub-transmission, distribution, reliability and power quality established through the EMCa technical review. In the absence of evidence pointing towards to the top or bottom of the range, we consider that adopting the mid-point reflects a reasonable estimate. Based on the reasons set out in section B.2.3, we consider this amount should provide Energex with a reasonable opportunity to recover at least the efficient costs to augment its network to meet forecast demand, reliability and network quality requirements.

As set out in section B.2.3, we have also removed the \$18.4 million (\$2014–15) in capex that Energex categorises as 'on-costs'. This capex was not reviewed by EMCa.

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.

Table B-2 sets out our preliminary decision for each year of the 2015–20 regulatory control period. Our detailed findings are set out in sections B.2.1, B.2.2 and B.2.3.

Table B-2 AER's alternative estimate of augex (\$2014–15, million, excluding overheads)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Energex proposal	117.5	126.7	109.2	84.8	74.4	512.7
Adjustment to account for over-estimation	-20.5	-19.0	-17.2	-16.5	-15.6	-88.7
Removal of additional on-costs	-4.6	-4.1	-4.1	-2.9	-2.6	-18.4
AER alternative estimate	92.6	103.6	87.9	65.3	56.4	405.5
Difference	-21.2%	-18.2%	-19.5%	-23.0%	-24.3%	-20.9%

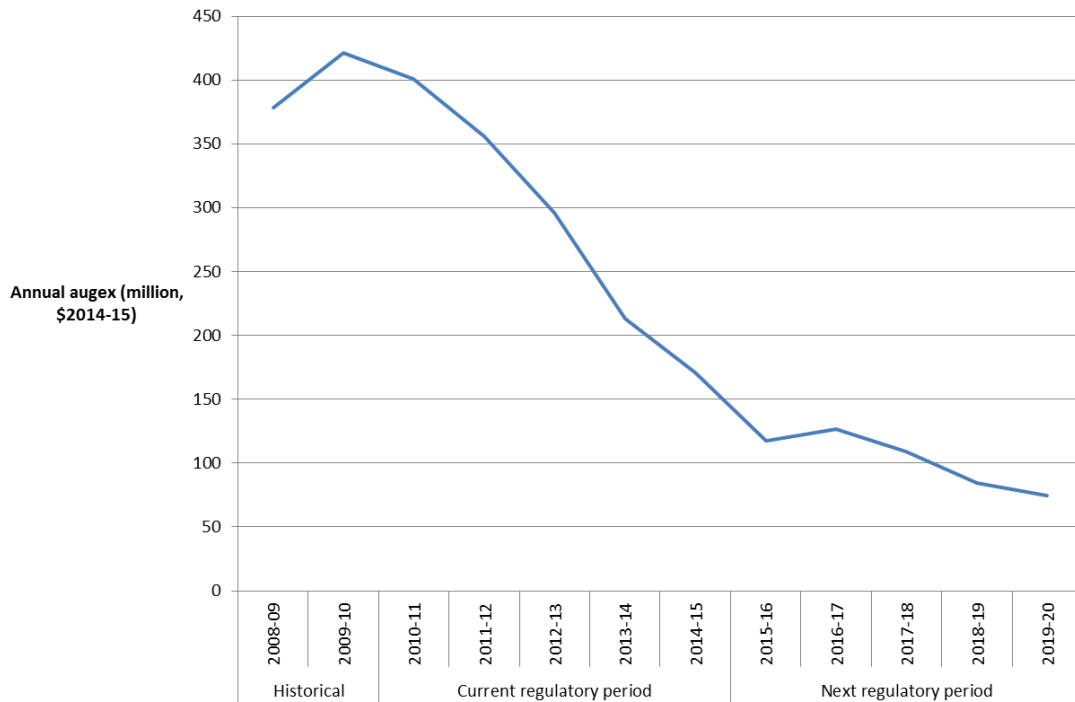
Source: AER analysis

Note: Numbers may not add up due to rounding.

B.2.1 Trend analysis

Figure B-1 shows the trend in augex between 2008–09 and 2019–20 (as proposed by Energex). As noted, this is a 64 per cent decrease compared to actual augex incurred in the 2010–15 regulatory control period.

Figure B-1 Energex's augex historic actual and proposed for 2015–2020 period (\$2014–15, million, excluding overheads)



Source: Energex regulatory proposal, Energex reset RIN, AER analysis

The largest component of Energex's augex forecast is \$367.3 million (\$2014–15) in demand-related augex (excluding overheads).⁶³ This is 69 per cent less than the actual demand-related augex it spent during the 2010–15 period. The major drivers of Energex's demand-driven augex proposal are a small number of large projects to address localised increases in peak demand in the sub-transmission and distribution networks.

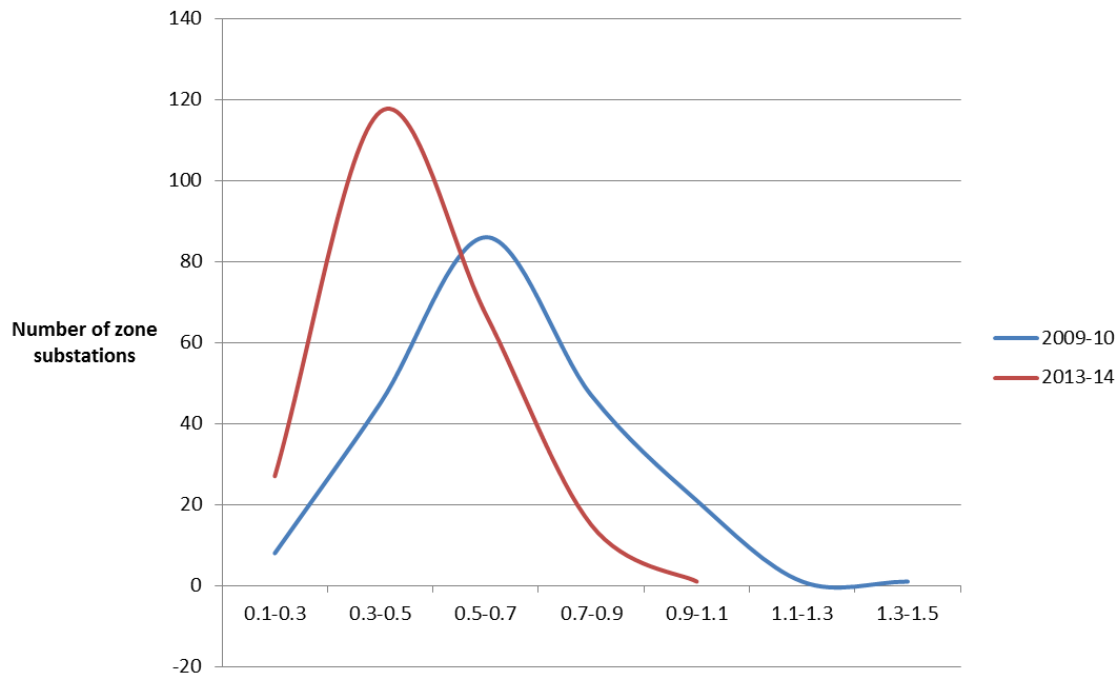
We have reviewed the trends in maximum demand and network utilisation as these are the key drivers of augmentation. This provides an initial sense of whether Energex's augex forecast is reasonably required to meet forecast demand and alleviate forecast capacity constraints.

As outlined in appendix C, the available evidence points to low demand growth over the 2015–20 regulatory control period. This forecast for low demand growth follows declining demand in the previous period. Consistent with this fall in demand, Figure B-2 below highlights a significant decline in Energex's network utilisation between 2009–10 and 2013–14. Network utilisation is a measure of the installed network

⁶³ Energex refers to this expenditure as 'growth and compliance' in its regulatory proposal. See Energex, Regulatory proposal: July 2015 to June 2020, 31 October 2014, p. 112.

capacity that is in use (or is forecast to be). Where utilisation rates are shown to be declining over time, it is expected that total augex requirements would similarly fall.

Figure B-2 Zone substation utilisation 2009–10 and 2013–14



Source: AER analysis; augex model, Energex reset RIN

Note: Utilisation is the ratio of maximum demand and the normal cyclic rating of each substation for the specified years.⁶⁴ Figure B-2 shows the number of Energex's total zone substations at each utilisation band.

This decrease in utilisation is also consistent with the changes to Energex's network planning design standards. Since 2004, Energex had invested significantly in duplicating network assets to increase network security (and hence decrease network utilisation) following a Government-initiated review of QLD electricity distribution and service delivery.⁶⁵ A subsequent review of Energex's capex programs (the Electricity Network Capital Program Review 2011) recommended a relaxation of these design standards and recommended a move to more probabilistic-based network planning approaches.⁶⁶ Energex submits that the overall drop in growth-related capex is consistent with these changes in design standards and the drop in demand.⁶⁷

⁶⁴ Normal cyclic rating is the maximum peak loading based on a given daily load cycle that a substation can supply each day of its life under normal conditions resulting in a normal rate of wear.

⁶⁵ *Electricity Network Capital Program Review 2011: Detailed report of the independent panel*, December 2011, p. 7.

⁶⁶ *Electricity Network Capital Program Review 2011: Detailed report of the independent panel*, December 2011, p. 10.

⁶⁷ Energex identified \$870 million worth of capex savings in the 2010-14 period (compared to the AER's capex allowance). This included \$255 million savings based on the recommended changes to network design standards, and \$550 million in augex and connections savings from reduced demand. See Electricity Network Capital

A number of parties have made submissions noting that the AER should closely review that Energex's augex forecasts are based on realistic demand forecasts and network capacity. In particular:

- AGL encouraged the AER to confirm that any augmentation of existing capacity is founded on realistic maximum demand forecasts as the network's forecast of peak demand appear aggressive.⁶⁸
- The Energy Users Association of Australia (EUAA) submits that Energex's augex appears high considering the Queensland jurisdiction has relaxed its security and reliability standards following the ENCAP review.⁶⁹
- The CCP submitted that Energex's augex proposal has not taken into account significant levels of excess capacity and declines in network utilisation. It stated that the AER needs to ensure that Energex's excess capacity is more efficiently utilised ahead of any additional augmentation investment.⁷⁰

While growth in system-wide demand is forecast to be low over the 2015–20 regulatory control period and there is existing network capacity, Energex proposes augmentation of a small number of zone substations due to forecast localised demand growth.⁷¹ We have examined forecast zone substation utilisation for the 2015–20 regulatory control period based on forecast demand at each substation and existing levels of capacity from our augex model. This gives us a high-level indication of whether localised augmentation may be required.

Figure B-3 shows that the majority of Energex's substations are forecast to be utilised between 20 and 50 per cent, with only a low amount of highly utilised substations. This is consistent with existing levels of utilisation in the network. A small number of substations are forecast to increase in utilisation to between 70 and 90 per cent, suggesting that some augmentation may be required. However, it is not clear that this in itself supports the overall level of augex Energex is proposing.

Program Review 2011: Detailed report of the independent panel, December 2011, p. 73) and Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 112.

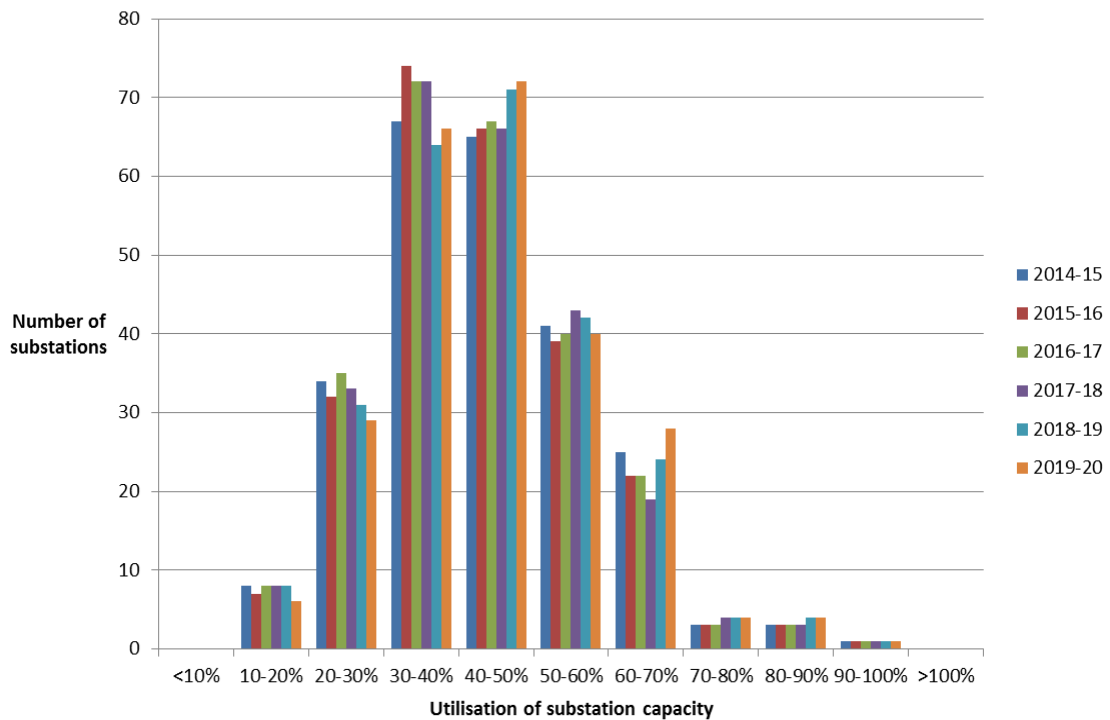
⁶⁸ AGL, Submission on Energex's regulatory proposal, p. 12.

⁶⁹ EUAA, Submission on Energex's regulatory proposal, p. 19.

⁷⁰ CCP, Submission on Energex's regulatory proposal, p. 14.

⁷¹ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 112.

Figure B-3 Zone substation forecast utilisation 2014–15 to 2019–20



Source: AER analysis; augex model, Energex reset RIN

Notes: Utilisation is the ratio of maximum demand and the thermal rating of each feeder for the specified years. Forecast utilisation in this figure is based on forecast weather corrected 50% POE maximum demand at each substation and existing capacity without additional augmentation over 2015-20

B.2.2 Forecasting methodology

The forecasting methodology adopted by Energex is important in determining whether the augex forecast is prudent and efficient. As a starting point in our detailed analysis of Energex's augex forecast, we have reviewed the forecasting methodology.

For growth related augex, Energex employs a bottom-up forecasting methodology to determine its expenditure requirements. The key input into this process is the spatial demand forecast, which is then compared against the capacity of the existing network at various levels, together with a consideration of its planning and reliability requirements.⁷² Where constraints are found to emerge, a project is then developed and is subjected to a risk assessment process against a counterfactual that the project does not proceed as planned.⁷³

Our assessment of Energex's forecasting methodology is informed by the findings and recommendations from engineering consultants EMCa. These findings suggest that

⁷² Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Appendix 19, p. 27.

⁷³ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Appendix 19, p. 28.

the framework and methodology applied by Energex is consistent with industry standards.⁷⁴ However, EMCa also found that the sensitivity of some of the augex forecast to demand and its risk assessment approach mean that the augex forecast is likely overstated.⁷⁵

Our review of Energex's forecasting methodology has focussed on:

- how the spatial demand forecasts have been used and how they reconcile with top-down system-wide forecasts
- how the estimation process is undertaken to forecast the cost of augex projects
- the governance process for augex forecasting, and evidence of a top-down check on bottom-up builds, and
- evidence of consideration of options other than augex.

Demand forecasting

Demand forecasting is a key input into determining network augmentation requirements. Augmentation decisions are made based on forecast demand at the localised zone substation level. These localised forecasts are referred to as spatial demand forecasts.

Appendix C contains our assessment of the top-down system wide forecast prepared by Energex. Energex uses a combination of bottom up spatial forecasting for each individual zone substation, combined with an adjustment process to take into account the top-down system wide demand forecast. The individual substation forecasts are made up of Energex's assessment of future large demand connections (block loads) entering or exiting the network, together with growth in the communities supplied from each zone substation.

The zone substation growth forecasts are summed to a system total demand. A reconciliation process is then used to adjust the top-down whole of system demand forecast and the bottom-up zone-substation forecast. EMCa notes that, at an onsite meeting, Energex advised that this reconciliation process resulted in decreased zone-substation forecasts of around 10 per cent.⁷⁶

As set out in appendix C, EMCa has found evidence that Energex incorporated changes in the demand forecasting methodology recommended by the AER during the regulatory determination process for the 2010–2015 period. Nevertheless, EMCa have

⁷⁴ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 26.

⁷⁵ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 50 and 64.

⁷⁶ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 42.

concerns with the size of the discrepancy between the top-down assessment and the bottom-up zone-substation total.⁷⁷

We note the concerns of EMCa and agree that further explanation of the discrepancy is necessary. As we set out in appendix C, our final decision will take account AEMO's connection points demand forecasts for Queensland that are due by July 2015. We expect that Energex's proposal on the revocation and substitution of this determination will take account of these revised forecasts and provide further information on the reconciliation of these forecasts with their own zone-substation forecasts.

However, we also recognise that significant reductions have been imposed on the spatial demand forecasts to take account of the top-down system-wide forecast. As such, pending AEMO's demand forecasts that are due in July 2015, we are satisfied that on the basis of evidence presently available, the augex forecast is based on a realistic expectation of demand, as set out further in section C.1.

Both the EUAA and the CCP submit that previous poor forecasting of demand has had a negative impact on customers through increased capex.⁷⁸ Furthermore, these submissions encouraged us to interrogate the forecasts of demand to ensure that they reflect declines in maximum demand.⁷⁹ We have taken into account Energex's demand forecast when assessing Energex's augmentation program, considered in section B.2.3 and appendix C below.

Cost estimation

EMCa reviewed the project cost estimation process that Energex used to develop its forecasts for augex projects and found that it is reasonable and without evidence of systemic bias.⁸⁰ As such, our project sampling review discussed in section B.2.3 focusses on the process that Energex use to define the need for projects and accepts the costings of those projects.

That said, as discussed in in section B.2.3, there is evidence of the scope of works for some projects leading to overestimation in total project costings. So while the cost estimation methodology employed by Energex is sound, there is evidence of the scope and design of some projects leading to a total forecast that is higher than is necessary for a prudent and efficient distributor.

⁷⁷ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 45.

⁷⁸ EUAA, *Submission on Energex's regulatory proposal*, p. 19; CCP, *Submission on Energex's regulatory proposal*, p. 13.

⁷⁹ CCP, *Submission on Energex's regulatory proposal*, p. 13; EUAA, *Submission on Energex's regulatory proposal*, p. 19.

⁸⁰ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 38 to 40.

Governance and top-down constraints

As set out above, projects in Energex's forecast program of works are subjected to a risk assessment process by Energex. The risk assessment process requires that projects be given a score calculated by reference to its likelihood of occurring, and its impact if it did occur.⁸¹ Projects are then ranked in order of risk score and compared against a budget constraint.

However, as EMCa notes, the program of work proposed by Energex includes a large number of low and very low risk projects (making up around 50 per cent of the number of projects).⁸² EMCa concludes that this suggests there may be a significant component of Energex's proposed augex that could be deferred into the next regulatory period.⁸³

Energex has also structured its proposal to limit network price growth to no more than CPI.⁸⁴ This is a form of top-down constraint on Energex's capex forecast by setting a limit on capex so that prices do not increase by more than CPI. While we recognise Energex's objectives in limiting capex over the 2015-20 period, it does not immediately follow that the resultant capex will be prudent and efficient. This is because this top-down constraint may result in Energex not sufficiently reviewing projects that are low risk and may not be necessary, but which can be undertaken within this price objective. EMCa supports this view, noting that Energex has not provide clear evidence of a robust top-down challenge beyond that imposed by the CPI price objective.⁸⁵

B.2.3 Driver and project analysis

Energex's overall augex forecast is comprised of different cost drivers. Figure B-4 shows these cost drivers and their contribution to the overall augex forecast.

Figure B-4 Energex proposed augex forecast (\$2014–15, million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Sub-transmission	31.5	41.4	22.7	13.3	4.2	113.1
Distribution	18	19.6	20.7	19.8	18.9	97
LV program	38.9	39.1	39.1	17.3	17.4	151.8

⁸¹ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, pp. 30-31

⁸² EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 35

⁸³ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, pp. 35-36 and 64

⁸⁴ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 9 and 298

⁸⁵ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 22

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Demand management	1	1.2	1.2	1.2	1	5.6
Reliability	14.6	11	11	11.1	11.2	58.9
Power quality	5.8	4.9	4.9	11.4	11.5	38.4
Land and easements	3.3	5.4	5.5	7.7	7.8	29.6
Additional on-costs	4.6	4.1	4.1	2.9	2.6	18.4
Total augex proposal	117.5	126.7	109.2	84.8	74.4	512.7

Source: Energex reset RIN; EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020, 20 April 2015, p. 41; Energex response to AER EGX 010 and 030

To quantify the impact of forecasting biases we identified in B.2.2, we have had regard to the technical review of a sample of projects undertaken by EMCa.⁸⁶ The purpose of the engineering review is to determine whether there is evidence of systemic forecasting bias resulting from either governance processes or cost estimates, by identifying incidence of forecasting bias in bottom-up project estimates.

As shown in section B.2.1, Energex proposed a significant reduction in augex for the 2015-20 period. However, while the reduction in growth-related augex is supported by revised (lower) demand forecasts, EMCa identified systemic issues of overestimation across the sample of projects which they reviewed.⁸⁷ Collectively, the results of these analyses lead to the finding that Energex's total forecast augex for 2015–20 is overestimated. In particular, EMCa found that:⁸⁸

- the augex has not been adequately linked to a prudent needs-driven analysis, including consideration of net deferrals, softening of demand growth and efficient timing of expenditure
- the augex is not adequately supported by cost-benefit analysis and appropriately applied risk assessment, and
- the augex has not been subjected to an adequate top-down challenge process to determine the optimal expenditure program.

Based on these findings and its sample of projects, EMCa estimated the impact of the overestimation bias at each of the cost category levels.⁸⁹

⁸⁶ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, section 6.

⁸⁷ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 62-63.

⁸⁸ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 62-63.

⁸⁹ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 63.

- Growth and compliance augex (distribution and sub-transmission) — 5 to 15 per cent overestimation
- Power quality augex — 25 to 50 per cent overestimation
- Reliability augex — 50 to 80 per cent overestimation.

EMCa concludes that if Energex's augex forecast is reduced by these levels of overestimation, the resulting forecast could be said to be broadly representative of a prudent and efficient expenditure level.⁹⁰ We agree with EMCa's findings because EMCa has satisfied the scope of work we assigned them, and has demonstrated that it has applied independent engineering expertise to Energex's own planning documentation and supporting evidence. These reasons are demonstrated within the following sections.

We have adopted the mid-point of EMCa's recommended ranges for each cost category it reviewed — sub-transmission, distribution, power quality and reliability. In the absence of evidence pointing towards to the top or bottom of the range, we consider that adopting the mid-point reflects a reasonable estimate of the level of augex Energex requires to prudently and efficiently meet the capital expenditure objectives.

EMCa did not review land and easements, or the additional capex categorised as 'on-costs'. As set out further below, our preliminary decision on these components is:

- We accept Energex's proposed augex for land and easements because it likely reflects a realistic expectation of demand in the 2020–25 period. However, our final decision will take into account AEMO's connection points forecasts for 2020–25 (to be published by July 2015) and other information so that it reflects the most up to date information.
- We do not accept the additional on-costs because it is not clear based on the information provided by Energex whether the underlying driver of the capex is augmentation, or how it has been calculated.

Table B-3 below sets out our alternative estimate of Energex's augex forecast based on our findings for each cost-driver of Energex's proposal.

⁹⁰ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 63

Table B-3 AER adjusted augex forecast (\$2014–15, million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Sub-transmission	28.4	37.3	20.4	12.0	3.8	101.8
Distribution	16.2	17.6	18.6	17.8	17.0	87.3
LV program	35.0	35.2	35.2	15.6	15.7	136.6
Demand management	1.0	1.2	1.2	1.2	1.0	5.6
Reliability	5.1	3.9	3.9	3.9	3.9	20.6
Power quality	3.6	3.1	3.1	7.1	7.2	24.0
Land and easements	3.3	5.4	5.5	7.7	7.8	29.6
Additional on-costs	0.0	0.0	0.0	0.0	0.0	0.0
Total direct augmentation	92.6	103.6	87.9	65.3	56.4	405.5
Difference to Energex proposal	-24.9	-23.1	-21.3	-19.5	-18.0	-107.2

Source: AER Analysis.

The following sections set out Energex’s proposed capex for each cost driver, EMCa’s assessment and findings, and our conclusions.

Sub-transmission augex

Energex proposed \$113.1 million (\$2014–15) to augment its sub-transmission network.⁹¹ The augmentation program consists of 90 projects to:⁹²

- service customer growth
- comply with security standards (e.g. voltage and fault limits, flood mitigation), and
- joint planning projects to complement Powerlink’s transmission network upgrades.

Fifty-four per cent of Energex’s proposed sub-transmission augex allowance is driven by two sub-transmission projects. These are a new 132kV Feeder from Palmwoods to West Maroochydore and a third 110/11kV transformer at West End zone substation.⁹³ The remainder of sub-transmission proposal is comprised of many smaller projects.

EMCa conducted a detailed engineering review of the sub-transmission forecast that focused on these two projects. EMCa reviewed the business case for each project, considering the status of the project in terms of its stage of development, and the

⁹¹ Energex, response to AER EGX010, p. 2.

⁹² Energex, response to AER EGX010, p. 2, 24–27.

⁹³ Energex, response to AER EGX010, pp. 29–31.

materiality of its cost compared to overall capex. EMCa's findings for these two projects are:

- 132kV Feeder from Palmwoods to West Maroochydore — This project is justified based on forecast demand growth in the Sunshine Coast. EMCa found that this project is sufficiently justified, but that this justification is dependent on forecast demand eventuating. Energex has deferred and revised this project as the situation changed which EMCa states is aligned with their stated asset management strategy and practices.⁹⁴
- Third 110/11kV transformer at West End — This project is justified based on meeting projected additional demand in the Brisbane CBD (including as a result of the Brisbane Bus and Train Tunnel by 2020). While the case for this project is reasonably justified, it is sensitive to large new loads eventuating by 2020, in particular the Brisbane Bus and Train Tunnel. Any delay or deferral of these loads may allow the capex to be deferred into the 2020-25 regulatory period.⁹⁵

The sub-transmission augex proposal is heavily front-loaded with 85 per cent occurring in the first three years of the 2015–20 regulatory control period.⁹⁶ Based on this expenditure profile, EMCa observed that the deferral of the need for one or both of these two largest projects will have a significant impact on Energex's augex program requirements.⁹⁷ In particular, any deferral will increase the probability that some work later in the program will be deferred to the 2020–25 period.⁹⁸

EMCa concluded that Energex's forecast growth and compliance augex requirements (of which sub-transmission is a component) are overestimated in the order of 5 to 15 per cent.⁹⁹ This was supported by EMCa's findings that the timing of individual sub-transmission projects is likely to change, including a level of deferral beyond the 2015–20 regulatory control period.

We consider that this assessment is supported by the uncertainty surrounding the timing of the proposed Brisbane Bus and Tunnel Train project. While the Brisbane Bus and Train Tunnel project is projected to be constructed by 2021 (with capex incurred throughout the 2015–20 regulatory control period), this project is still pending a

⁹⁴ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 49.

⁹⁵ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 49-50.

⁹⁶ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 48.

⁹⁷ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 51.

⁹⁸ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 52-53.

⁹⁹ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 64.

Government decision to proceed.¹⁰⁰ As noted in section B.3, Energex's connections forecast includes capex to reinforce the Brisbane CBD 110kV network to support this project. Our substitute connections forecast does not include any allowance for this connection project, partially due to the uncertainty about whether the project is still likely to be required during the 2015–20 regulatory control period.

In light of these findings (and the associated findings for distribution augex below), we have applied a 10 per cent reduction to the total growth and compliance augex forecast (which is the mid-point of EMCa's recommended range). As set out previously, we consider that the mid-point is reasonable in the absence of evidence pointing towards the top or bottom of the range.

Distribution and low voltage augex

Energex propose \$248.8 million (\$2014–15) to augment its distribution network.¹⁰¹ This consists of:

- \$97 million (\$2014–15) to augment Energex's 11kV network to service customer and demand growth
- \$151.8 million (\$2014–15) to augment Energex's low voltage network due to growth, bushfire and flood mitigation programs.

These programs generally consist of high-volume, low cost projects across Energex's LV and 11kV networks. EMCa's detailed engineering review of the distribution forecast focused on assessing the business case for the programs, while also taking into account the justification for any step changes observed in the volumes of activity.¹⁰²

For the \$97 million (\$2014–15) 11kV augmentation program, EMCa reviewed the two largest projects for which Energex have provided project assessment reports. EMCa's findings for these two projects are:

- 11kV Overhead Thermal Fault Limitations — This project addresses the potential failure of segments of several 11kV feeders due to thermal rating limitations. EMCa observed that this project is largely driven by safety considerations. EMCa concluded that this project could be delayed based on Energex's assessment that the risk associated with delaying the project completion is low.¹⁰³
- Deception Bay Project — This project establishes new 11kV feeder ties to the Mango Hill Substation to address projected residential and commercial demand

¹⁰⁰ The project is at the "Revised Reference Design and Revised Reference Design Assessment Report" stage and that this was originally to be completed during 2014. See <http://www.qld.gov.au/transport/projects/bat/about/timeframes/index.html>.

¹⁰¹ Energex, response to AER EGX010, p. 2.

¹⁰² EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 53.

¹⁰³ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 53-54.

growth. EMCa found that Energex's project documentation justifies the early completion of this project. However, EMCa found that Energex's risk assessment for this project is likely overstated.¹⁰⁴

Based on this sample, EMCa concluded that some of Energex's proposed augex for its 11kV network could be prudently deferred by Energex given that there are a disproportionately high number of projects with a low risk assessment.¹⁰⁵

EMCa also reviewed Energex's evidence submitted in support of the \$151 million (\$2014-15) LV augmentation program. Based on its review, EMCa observed that the programs have not been subject to appropriate risk assessment, or been subject to adequate governance and top-down challenge to establish the optimal level of risk (beyond the top-down challenge to limit price increases to CPI, as discussed in section B.2.2).¹⁰⁶ EMCa also observed that the proposed \$70.3 million program to retrofit transformers with LV protection (the single largest program within LV augmentation) is the continuation of a program from the 2010–15 period; however the proposed capex is higher than Energex incurred for this program in the 2010–15 period, and this step-up is not adequately explained.¹⁰⁷

Overall, EMCa states that it is unable to conclude that the proposed distribution augex forecast is efficient and prudent given the project documentation provided by Energex to support this expenditure.¹⁰⁸ EMCa considered that Energex's case for the prudence and efficiency of this proposal is not justified given a lack of robust options and cost-benefit analysis, and that the risk assessment undertaken by Energex that has been undertaken being at too high a level to assist meaningful decision making.¹⁰⁹

EMCa concluded that the need for growth and compliance augex (of which distribution augex is a component) forecast by Energex is overestimated in the order of 5 to 15 per cent.¹¹⁰

In light of these findings (and the associated findings for sub-transmission augex above), we have applied a 10 per cent reduction to the total growth and compliance augex forecast (which is the mid-point of EMCa's recommended range). As set out

¹⁰⁴ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 54.

¹⁰⁵ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 64.

¹⁰⁶ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 55.

¹⁰⁷ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 55.

¹⁰⁸ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 55.

¹⁰⁹ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 55.

¹¹⁰ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 64.

previously, we consider that the mid-point is reasonable in the absence of evidence pointing towards to the top or bottom of the range.

Power quality augex

Energex proposes \$36.8 million (\$2014–15) to monitor and manage power quality issues resulting from the penetration of solar panels connections within the network.¹¹¹

Energex proposes to continue insulating monitoring devices on its network in 2015–20 due to a projected increase in solar panel connections by 70 per cent compared to 2013–14 levels.¹¹² EMCa observe that Energex proposes to significantly increase the number of monitors installed across its network, with an objective to complete the rollout of monitors by the end the 2020–25 period.¹¹³

EMCa notes that the inclusion of some form of monitoring to validate and improve network data for Energex is likely to provide benefits.¹¹⁴ However, it finds that Energex's proposed level of network monitoring is above the level of power quality monitoring present at most network operators, and an appropriate cost benefit analysis has not been provided to support the proposed increases in the number of monitors forecast to be installed.¹¹⁵

EMCa also considers that the projected increase in solar panel connections is not supported by any evidence that Energex relied upon (e.g. forecast models for growth in solar connections).¹¹⁶ EMCa considers that the projected increase in solar connections is likely overstated because it does not account for the expected softening of solar growth.¹¹⁷

Finally, EMCa notes that it saw no evidence of risk assessments undertaken by Energex that relate directly to these programs.¹¹⁸

Based on these findings, EMCa concludes that the size of the power quality augex program forecast to be required is overestimated by 25 to 50 per cent.¹¹⁹ The upper

¹¹¹ Energex, response to AER EGX010, p. 1 and Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

¹¹² Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Appendix 29, p. 17.

¹¹³ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 58.

¹¹⁴ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 59.

¹¹⁵ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 59-60.

¹¹⁶ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 58.

¹¹⁷ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 58 and 60.

¹¹⁸ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 60.

bound of 50 per cent represents the over-estimation from Energex conducting the networking monitoring program over two regulatory periods, which EMCa considered was not justified.¹²⁰

We note that AEMO's 2014 National Electricity Forecasting Report forecasts strong growth in rooftop solar connections in the near future, by up to 24 per cent annually.¹²¹ However, a recent update to this report by AEMO suggested that solar generation was less than forecast between October and December 2014.¹²² AEMO is currently preparing its National Electricity Forecasting Report for 2015, which includes the most up to date information about projected solar generation. We expect that Energex will take AEMO's latest forecast into account when preparing its revised proposal.

Based on EMCa's findings, and the uncertainty about the projected increases in solar connections over 2015–20, we apply a 37.5 per cent reduction to Energex's power quality forecast (which is the mid-point of EMCa's recommended range). As set out previously, we consider that the mid-point is reasonable in the absence of evidence pointing towards to the top or bottom of the range.

Reliability augex

Energex proposed \$58.9 million (\$2014–15) in capex (excluding overheads) to meet the reliability obligations set out in its Distribution Authority.¹²³ This is a 55 per cent reduction over the actual 2010–15 expenditure for reliability.

Energex's Distribution Authority sets out the network performance targets and planning criteria Energex must meet. Energex's relevant reliability obligations under its Distribution Authority include meeting the jurisdictional Minimum Service Standard¹²⁴ and implementing a program for improving the worst performing distribution feeders.¹²⁵ Energex submitted that the proposed \$58.9 million (\$2014–15) capex will enable it to meet these reliability obligations.¹²⁶

The worst performing feeder improvement program requires Energex to improve 11 kV feeders where their performance is:

- ranked the worst 10 per cent of 11 kV feeders, based on a three year average and

¹¹⁹ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 64-65.

¹²⁰ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 65.

¹²¹ AEMO, *National Electricity Forecasting Report*, June 2014, p. 4.

¹²² AEMO, *National Electricity Forecasting Report Update*, December 2014, p. 3.

¹²³ Energex, response to AER EGX010, p. 1 and Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

¹²⁴ The minimum service standard targets are expressed as the minimum duration and frequency of outages experienced by the average customer in a year. These are expressed as the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

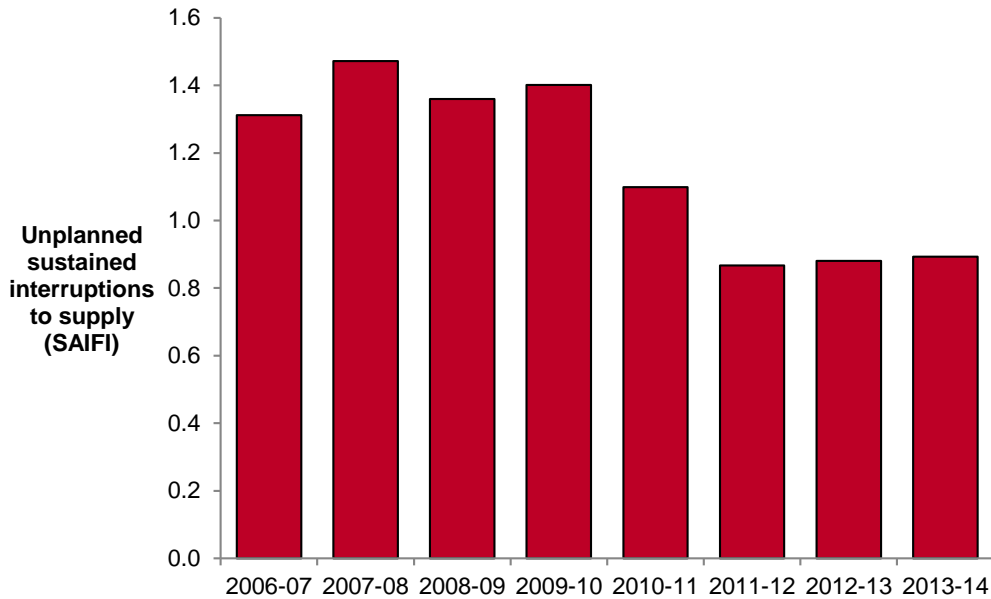
¹²⁵ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, pp.59–60, 79.

¹²⁶ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

- greater than 150 per cent of the performance target for the feeder category.¹²⁷

Energex's network reliability has been steadily improving over the current regulatory period. Figure B-5 and Figure B-6 show that the number of unplanned sustained interruptions to supply on Energex's network and duration of the events has reduced between 2007–08 and 2012–13. Energex's network performance against its minimum service standard over the current regulatory period has also improved.

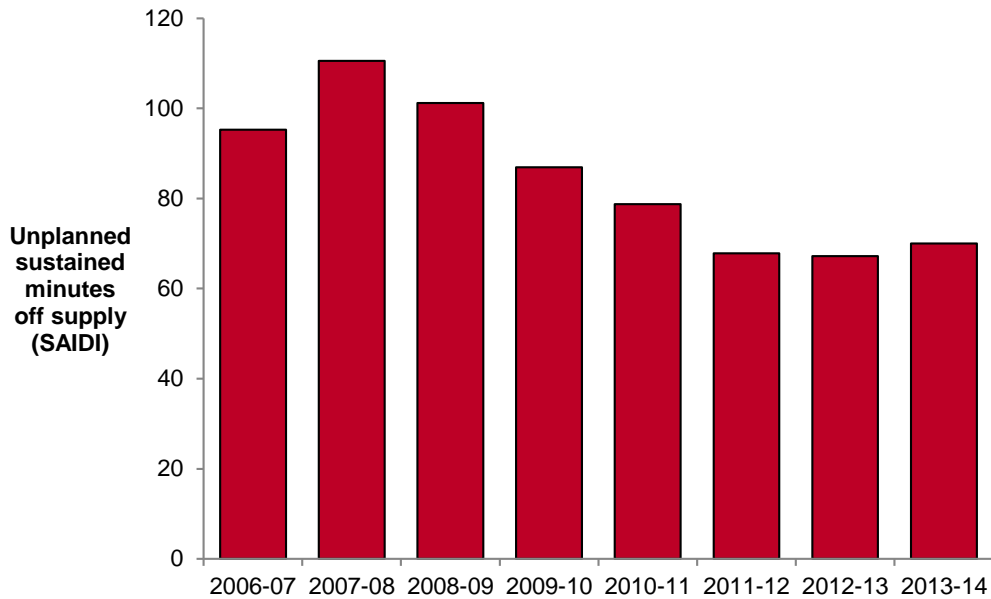
Figure B-5 Energex's reliability performance (SAIFI) 2006–2014



Source: AER analysis

¹²⁷ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 79.

Figure B-6 Energex's reliability performance (SAIDI) 2006–2014



Source: AER analysis

The improved reliability performance over the 2010–15 period appears to have resulted in Energex proposing a lower reliability capex for 2015–20. Of the \$58.9 million (\$2014–15) proposed, \$54.8 million (\$2014–15) will be for the worst performing feeder improvement program and \$4.1 million (\$2014–15) for projects carried over from 2010–15 that aim to improve the minimum service standard.¹²⁸

For the worst performing feeder improvement program, Energex proposed 22 reliability projects per annum based on its review of the worst performing feeders. This includes 18 rural worst performing feeders and 4 urban worst performing feeders. Energex submitted that the annual allowance proposed for worst performing feeders is based on the historical number of worst performing feeders. This forecast assumes similar worst performing feeder improvements will be required over the 2015–20 period.¹²⁹

We received the following stakeholder submissions on the proposed reliability capex:

- AGL and the Chamber of Commerce and Industry Queensland questioned the size of the proposed augex, noting that Energex has already been outperforming reliability targets.¹³⁰

¹²⁸ Energex, response to AER EGX051, p. 3.

¹²⁹ Energex, response to AER EGX051, pp. 1-2.

¹³⁰ AGL, *submission to the AER, Energex Regulatory Proposal 2015–20*, 30 January 2015, p.11; Chamber of commerce and industry Queensland, *Submission to the AER, Energex's regulatory proposal for 2015–20*, 30 January 2015, p. 11.

- COTA Queensland questioned the customer engagement research program Energex used to arrive at its reliability capex forecast.¹³¹
- The Queensland Farmers' Federation and Cane Growers noted that the proposed augex should be reviewed due to declining demand trends and recently reduced reliability standards.¹³²
- The Queensland Council of Social Service and Total Environment Care note that the reduced reliability standard in Queensland should expect strong reduction in capital spending in the next regulatory control period.¹³³

We have carefully reviewed Energex's reliability capex proposal in light of Energex's historical and current reliability performance, and its reliability obligations to address the worst performing feeders in its network.

We undertook a high-level review of historical performance of worst performing feeders to assess whether or not they all qualify as worst performing feeders. We analysed the historical data (2010–15) Energex provided on the actual SAIDI and SAIFI performance of each worst performing feeder. We compared the actual three-year (2011–14) average performance of each worst performing feeder against the minimum service standard (SAIDI and SAIFI) targets.

We found that most of the identified worst performing feeders that Energex proposes to improve performed worse than the minimum service standard targets on average over 2011–14. However, a small number of feeders appeared to perform better than the minimum service standard on average. This suggests that improving the reliability of these small number of feeders is not necessary to comply with Energex's Distribution Authority.

EMCa also conducted a technical review of whether the proposed reliability capex is reasonable, prudent and efficient. EMCa focused in its assessment on the worst performing feeders forecast. EMCa observed that Energex is forecasting similar quantities of worst performing feeders for each year of the regulatory period based on the 2013/14 worst performing feeders. While we consider that historical capex can be a good indicator of future capex requirements under similar circumstances, EMCa found that this likely overstates the scope of the required capex because Energex's overall network reliability has been improving.

EMCa also made the following findings which supported this conclusion:¹³⁴

¹³¹ COTA, *Submission to the AER, Energex's regulatory proposal for 2015–20*, 30 January 2015, p. 2.

¹³² Cane Growers Submission to the AER, *Ergon Energy and Energex –Network Distribution Resets 2015–20*, 30 January 2015, p. 5; Queensland Farmers' Federation, *Submission to the AER on Queensland Distribution Networks' 2015–20 revenue proposal*, 30 January 2015, p. 6.

¹³³ Queensland Council of Social Service, *Understanding the long term interests of electricity consumers, Submission to AER's Queensland electricity distribution determination 2015–20*, 30 January 2015, p. 51; Total Environment Centre, *Submission to the AER on Queensland Distribution Networks' 2015–20 revenue proposal*, February 2015, pp. 14–15.

- In identifying the proposed worst performing feeders, Energex did not remove isolated trends or events from the calculation of average three year SAIDI.
- Energex has not provided a cost benefit analysis for the proposed expenditure. For this reason, EMCa considers the case for reliability improvement to be unproven.
- EMCa reviewed the unit cost approach Energex used to forecast the improvement program costs. EMCa considered the unit costs are forecasted to be higher than required to manage these programs.
- The level of expenditure is significantly higher than that proposed by Energex, which is subject to a similar worst performing feeder program under the same jurisdictional requirements.
- There is scope for reducing the reliability improvement programs on the basis of current reliability performance being achieved at Energex and Energex's own customer research.
- Some proposed projects could be deferred or be adjusted for greater risk tolerance and timing.

EMCa concludes that Energex has overestimated the required capex by 50 to 80 per cent.¹³⁵ Our high-level analysis of Energex's worst performing feeder performance confirms that the proposed capex is likely overstated.

Based on these findings, we have reduced the reliability capex forecast by 65 per cent (which is the mid-point of EMCa's suggested range). This amounts to \$20.6 million (\$2014-15) which will allow Energex to implement its reliability program and meet the capex criteria.

Land and easements

Energex proposes \$29.6 million (\$2014–15) to purchase land and easements to build new substations and overhead lines in advance of the need to build the infrastructure.¹³⁶ This capex was not reviewed by our consultants EMCa.

In support of this proposal, Energex submits that:

Energex undertakes 30 year scenario planning to identify long term network development requirements. Areas such as the Ripley Valley, Caloundra and Yarrabilba have been identified as areas where infrastructure is likely to be

¹³⁴ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, pp. 61–62, 65.

¹³⁵ EMCa, *Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex's Regulatory Proposal 2015-2020*, 20 April 2015, p. 66.

¹³⁶ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

required during the 2020–25 regulatory control period. The cost of purchasing land in these areas has been included in the 2015-20 expenditure forecast.¹³⁷

Based on Energex's submission, these property acquisitions appear to be driven by forecast demand in the Ripley Valley, Caloundra and Yarrabilba areas in the 2020–25 period, rather than in the 2015–20 regulatory control period. To assess this capex, we would therefore need to be satisfied that Energex's forecast demand growth in these areas reflects a realistic expectation of demand.

Energex has not provided any documentation to support demand growth projections in the Ripley Valley, Caloundra and Yarrabilba areas, and the subsequent need to build new substations and overhead feeders. However, as set out in appendix C, we are satisfied that Energex's system-wide demand forecasts for 2015-20 reflect a realistic expectation of demand for this period. Given that Energex is forecasting some growth in demand over the period, it is not unreasonable to expect that this growth would continue through the 2020–25 period.

As we note in section C.4, the Australian Energy Market Operator (AEMO) is scheduled to release its Transmission Connection Point Forecasting Report for Queensland by July 2015. This report is expected to provide demand 10 year demand forecasts (i.e. 2015–25) for each connection point in Queensland, including those that service the Ripley Valley, Caloundra and Yarrabilba areas.

Our final decision will take these connection points forecasts and other information so that it reflects the most up to date data. We expect that Energex's revocation and substitution of our preliminary decision will take account of these forecasts and provide further information on the justification for its proposed land and easements purchases.

Additional on-costs capex

As noted, Energex's total proposed augex forecast is \$512.7 million (\$2014–15). Based on our review of Energex's proposal and supporting documentation, we can account for \$494.3 million (\$2014–15) through the forecasts for growth and compliance, reliability and power quality, and land and easements (as set out in Table B-1).

Energex classifies the remaining \$18.4 million (\$2014–15) as 'on-costs' which are 'expenditure items that are not directly attributable to a service but arise as a direct consequence of incurring direct costs'.¹³⁸ Energex submits that both on-costs and overheads have been applied in accordance with Energex's approved CAM and allocated to regulated services (capex and opex) based on total direct spend.¹³⁹

¹³⁷ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 113.

¹³⁸ Energex, response to AER EGX010, p. 1.

¹³⁹ Energex, response to AER EGX010, p. 2.

Given that this \$18.4 million (\$2014–15) in on-costs has been calculated in accordance with Energex's CAM, it is not clear to us why it has been included as a direct cost within Energex's augex proposal. Rather, it appears that it is more accurately described as capitalised overheads. At the same time Energex submits that it is a cost that it incurred as a direct consequence of incurring direct costs, which is not typically something that would be categorised as overheads.

We are not satisfied that this additional \$18.4 million (\$2014–15) is prudent and efficient because it is not clear based on the information provided by Energex whether the underlying driver of the capex is augmentation, or how it has been calculated. On this basis, we have not included it in our alternative estimate.

In Energex's submission on the revocation and substitution of our preliminary decision, we encourage Energex to provide further information to account for this additional capex and why it is prudent and efficient. We will have regard to this information in our final decision.

B.3 AER findings and estimates for connections

Connections capex is incurred by Energex to connect new small customers to its network and augment the shared network in order to connect customers.

Capital contributions are made up of the value of assets constructed by third parties which are operated by Energex, and cash provided by customers to fund connection works which specifically benefit them. These contributions are subtracted from total gross capex and as such decrease the revenue that is recovered from all consumers.

Energex proposed an allowance of \$160.6 million (\$2014–15) to fund forecast connection works for the 2015–20 period, net of customer contributions. Table B-4 presents Energex's proposed allowance for connections expenditure.

Table B-4 Energex proposed connections capex (\$2014–15, million, excluding overheads)

Category	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Connections capex	55.6	55.2	56.5	62.1	103.4	332.8
Capital contributions	30.0	33.2	34.7	36.8	37.6	172.3
Total	25.7	22.0	21.8	25.3	65.8	160.6

Source: Energex, Response to AER information request AER Energex 004.

We do not accept Energex's connections forecast. We have instead included an amount of \$99.7 million (\$2014–15) in our alternative estimate. We accept Energex's capital contributions forecast.

To reach our alternative estimate of Energex's connections forecast, we considered:

- the trend in connections capex compared to forecast construction activity in Queensland

- the significant connections capex associated with the Brisbane CBD bus and train tunnel project, and
- the community amenity program which was incorrectly proposed to be recovered as standard control services.

Our alternative estimate is shown in Table B-5.

Table B-5 AER adjusted connections capex (\$2014–15, million, excluding overheads)

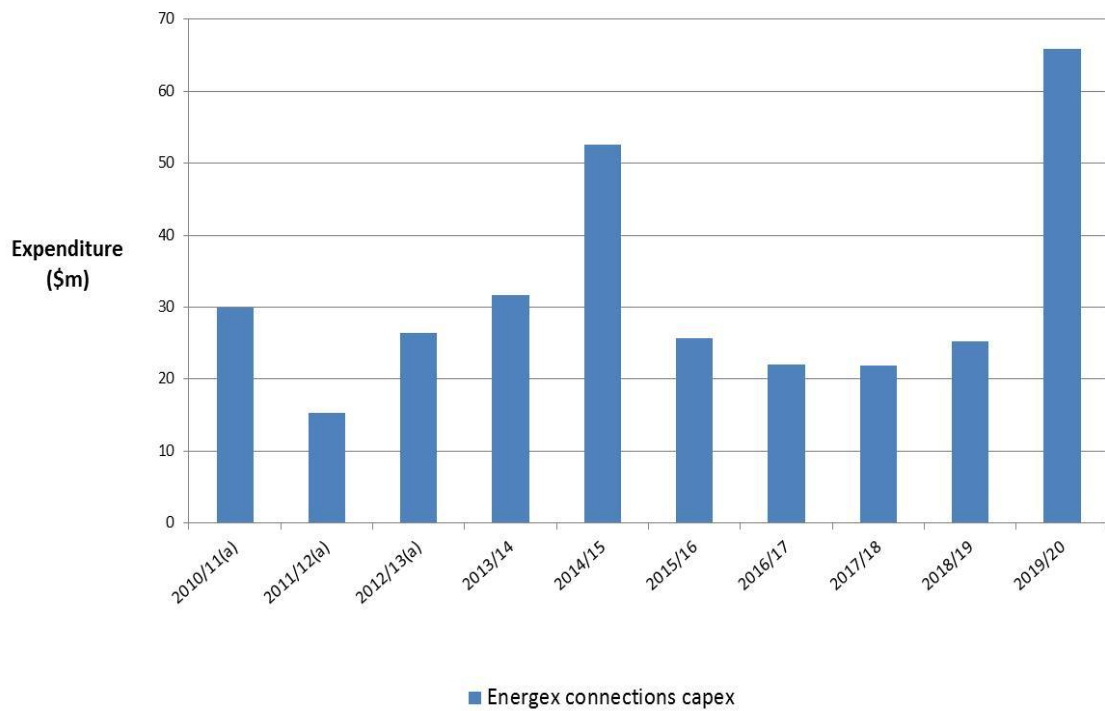
Category	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Connections capex	51.7	51.3	52.0	55.9	61.0	271.9
Capital contribution	30.0	33.2	34.7	36.8	37.6	172.3
Total	21.7	18.1	17.3	19.1	23.4	99.7

Source: AER analysis

B.3.1 Trend analysis

Energex developed its forecast for connections capex based upon forecast customer numbers, regional development plans and known development applications. As shown in Figure B-8, Energex's proposed forecast for connections expenditure generally follows a decreasing trend from the 2010–14 period, except for a large increase in expenditure during 2019–20. Energex estimates the capex incurred to be \$40.5 million in 2019–20 to provide electricity connections associated with the construction of the Brisbane CBD bus terminal project.

Figure B-7 Connections capex historic actual and proposed for 2010–2020 period (\$2014–15, million)

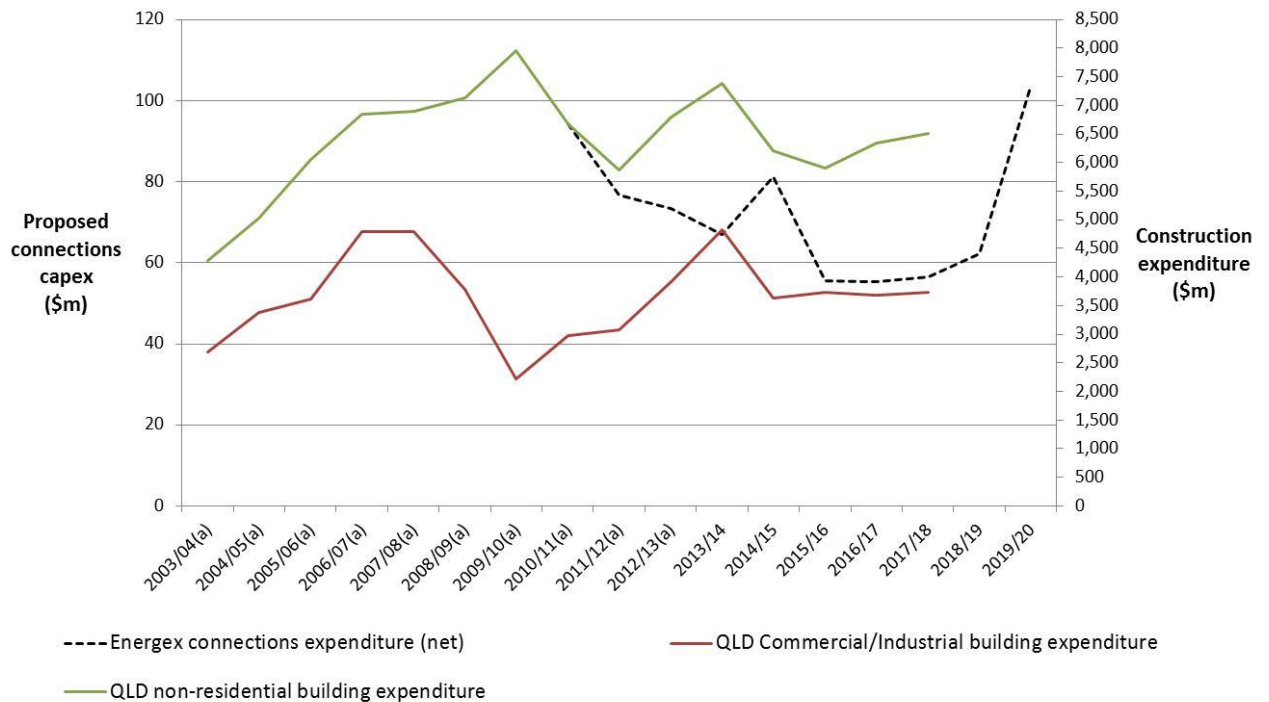


Source: Energex regulatory proposal

Note: Connections capex is shown net of customer capital contributions.

We consider that forecast dwelling growth and construction expenditure are reasonable proxies for forecast growth in connections services for residential and commercial customers. Generally, we consider that the trend of Energex's forecast of connections expenditure and capital contributions is not inconsistent with the trends in forecast construction activity in Queensland as shown in. This is particularly evident over the 2015/16 to 2017/18 period. On this basis, Energex's proposed forecast for connections expenditure and customer contributions appears reasonable. However, this does not apply to the final year of the 2015–20 regulatory control period which reflects a large portion of expenditure associated with the large Queensland bus and train tunnel connection project. We consider there is insufficient evidence for us to include Energex's proposed capex allowance for the large bus and train tunnel connection project in our alternative estimate. This is considered further below.

Figure B-8 Connections capex and non-residential construction activity



Source: BIS Shrapnel, Energex regulatory proposal.

Note: Connections capex is shown inclusive of customer capital contributions. The difference between the trends in connections capex between Figure B-7 and Figure B-8 is due to the size of capital contributions.

AGL Energy submitted that we should investigate whether the unit cost of new connections are efficient when compared to other networks.¹⁴⁰ We agree that comparing the proposed unit costs for Energex’s new connections with those of other distributors will help us be satisfied that the connections forecast is prudent and efficient. To be able to make meaningful comparisons, unit costs of network connections would need to be consistently calculated for different types of connections across the NEM, for example simple and complex and under and above ground. For this preliminary decision, we do not have the required data to effectively undertake this comparison. On this basis, we have relied more primarily on trend analysis of forecast construction activity in Queensland. However, we intend to work with distributors to ensure that data is collected that would enable meaningful unit cost comparisons to be undertaken for future decisions.

The EUAA suggests that the AER should scrutinise the basis of estimating increases in customer-initiated capital works expenditure before allocations across standard and alternative control services and capital contributions.¹⁴¹ We note that the funding and

¹⁴⁰ AGL Energy, *AGL submission to the Australian Energy Regulator*, 30 January 2015, p. 12.

¹⁴¹ Energy Users Association of Australia, *Submission to Energex revenue proposal 2015/16 to 2019/20*, 30 January 2015, p. 22.

charges across the entire customer base for connection services is made on a net basis. That is, after subtracting capital contributions and allocating expenditure to alternative control services, for which individual customers entirely bear the cost for those connection services that they solely benefit. We have therefore assessed the proposed capex allowance for connection services on a net basis when deciding how connection costs should be recovered across the entire customer base.

B.3.2 Brisbane CBD bus and train tunnel

Energex's proposed connections forecast includes \$40.5 million (\$2014–15) for a single connections project to reinforce the 110 kV network around the Brisbane CBD area to supply the new Brisbane Bus and Train tunnel (BAT).¹⁴² This project drives the significant increase in forecast connections capex in 2019/20.

The BAT is a new combined bus and train tunnel from Dutton Park to Roma Street, with two new stations at Woolloongabba and the Brisbane CBD.¹⁴³ Energex submits that it is required to provide connection services to supply the train, station and tunnel electrical loads. Table B-6 sets out Energex's proposed expenditure that relates to the BAT in the connections forecast.¹⁴⁴

Table B-6 Energex bus terminal project capex forecast (\$2014–15, million, excluding overheads)

Expenditure category	2015-16	2016-17	2017-18	2018-19	2019-20	Total
BAT substation	0.0	0.0	0.1	1.4	9.4	10.9
Dutton Park feeder	0.0	0.0	0.4	0.6	28.6	29.6
Total	0.0	0.0	0.5	2.0	38.0	40.5

Source: Energex regulatory proposal, Response to information request AER Energex 010, p. 3.

We sought further information from Energex on the BAT expenditure.¹⁴⁵ In their response to our information request, Energex notes that at the time of putting together the proposal, the BAT scope of works included provision for a 110kv connection. This is included in the “H16-QR Dutton Park Est DCCT 110kV UG Feeder” project shown above. However, Energex now advise that as a result of further investigations, including joint planning with Powerlink, it is likely that the scope of works will be revised down to include a 33kv solution from Victoria Park and Tennyson substations. The details and associated costs for this revised scope of work will be included in Energex’s revised proposal.

¹⁴² Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 114.

¹⁴³ Energex, response to AER EGX010, p. 3.

¹⁴⁴ Energex, response to AER EGX010, p. 4.

¹⁴⁵ Energex, response to AER EGX010.

We welcome the early notice from Energex that the revised proposal will contain a revised scope of works for this project. At this stage, we have not received an indication of the likely revised costs of the project. Therefore, our alternative estimate of Energex's connections forecast does not include any allowance for the project pending receipt of the revised proposal. However, we also understand that the project is at the "Revised Reference Design and Revised Reference Design Assessment Report" stage and that this was originally to be completed during 2014.¹⁴⁶ We would expect that the revised proposal would also take into account not just the revised costs reflecting the new scope of works, but also whether the project is still likely to be required during the 2015–20 period.

B.3.3 Community amenity capex

Energex also proposes \$20.08 million (\$2014–15) for a "community amenity" program aimed at undergrounding overhead networks for local or state authority-initiated projects.¹⁴⁷ This program covers all work incurred in replacing overhead reticulation with underground cables, typically upon request of the property owner or developer.¹⁴⁸

Since lodging its revenue proposal, Energex has advised us that the capex proposed for the community amenity program should be recovered through alternative control services.¹⁴⁹ This reflects the fact that the service is initiated by a local Authority or Government and should be borne solely by the customers requesting the service. On this basis, our alternative estimate of Energex's proposed capex allowance does not include the \$20.08 million for community amenity.;

B.4 AER findings and estimates for replacement expenditure

Repex is driven by a distributor's need to replace its assets. In the long run, a distributor's assets will no longer meet the requirements of the network and need to be replaced, refurbished or removed.¹⁵⁰ Replacement may occur when an asset fails, or a condition assessment may find it is likely to fail soon and replacement is the most economic option. It may also occur because jurisdictional safety regulations mean it can no longer be safely operated on the network, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network.

In general, the majority of network assets will remain in efficient use for far longer than a single five year regulatory period. As a consequence, a distributor will only need to replace a portion of its network assets in each regulatory control period. The majority of

¹⁴⁶ <http://www.qld.gov.au/transport/projects/bat/about/timeframes/index.html>, accessed 12/03/15.

¹⁴⁷ Energex, Response to AER EGX010, Q2, Spreadsheet: Customer Initiated work.

¹⁴⁸ Energex, Network asset management program – Customer initiated 2015–2020, p. 13.

¹⁴⁹ Energex, Email response "RE: Community Amenity", sent Friday 13 March 2015.

¹⁵⁰ Assets may also be replaced due to network augmentation. In these cases the primary reason for the asset expenditure is not the replacement of an asset that has reached the end of its economic life, but the need to deploy new assets to augment the network, predominantly in response to changing demand.

its assets will remain in commission beyond the end of the regulatory control period, and be replaced in subsequent regulatory periods.

Our assessment of repex seeks to establish the portion of Energex's assets that will likely require replacement over the 2015–20 regulatory control period and the associated expenditure.

B.4.1 Position

We do not accept Energex's proposed repex of \$1.25 billion. We have instead included in our alternative estimate of overall total capex, an amount of \$622 million (\$2014–15) for repex, excluding overheads, 50 per cent lower than Energex's proposal. We are satisfied that this amount reasonably reflects the capex criteria.

B.4.2 Energex's proposal

Energex's initial proposal for repex is \$1250 million (excluding overheads). Energex submitted that this expenditure is required to comply with its asset management strategies to meet its safety and Distribution Authority targets for reliability and security of supply.¹⁵¹

This expenditure covers replacement programs across the distribution, sub-transmission and SCADA and network communications components of the network. Energex submitted for each that:

- The distribution asset replacement programs are driven by safety, ageing asset profiles, asset condition and failure rates.¹⁵²
- Sub-transmission assets are generally low volume, high value assets, such as large power transformers. They are generally assessed on an individual basis.¹⁵³
- The SCADA and network communications replacement program is driven by the obsolescence of the ageing communications network and SCADA system components. This includes the replacement of ageing hardware and software to ensure the ongoing sustainability and ability of these systems to support the power network.¹⁵⁴

B.4.3 AER approach

We have applied several assessment techniques to assess Energex's forecast of repex against the capex criteria. These techniques are:

- analysis of Energex's long term repex trends predictive modelling of Energex's assets in commission

¹⁵¹ Energex, *Regulatory Proposal, October 2014*, p. 109-10.

¹⁵² Energex, *Regulatory Proposal, October 2014*, p. 110.

¹⁵³ Energex, *Regulatory Proposal, October 2014* p. 111.

¹⁵⁴ Energex, *Regulatory Proposal, October 2014* p. 111.

- predictive modelling of Energex's assets in commission
- technical review of Energex's approach to forecasting, costs, work practices and risk management
- consideration of various asset health indicators.

We primarily use our predictive modelling to assess approximately 61 per cent of Energex's proposed repex in combination with the findings of EMCa's technical review. For the remaining categories of expenditure, we do not use our predictive modelling but rely instead on the analysis of historical expenditure for those categories as supported by the findings of EMCa's technical review. We note that the other two assessment techniques were considered, but were not ultimately used to reject Energex's forecast of repex or develop our alternative estimate, though our findings from those other assessment techniques are consistent with our overall conclusion.

Trend analysis

We recognise the limitations of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a distributor may have a lumpy asset age profile or legislative obligations may change over time). In recognising these limitations, we have drawn general observations from the historic trend analysis and benchmarking in relation to repex, but we have not used trend analysis to reject Energex's forecast of repex or develop our alternative estimate

Predictive modelling

We use a predictive model known as the repex model to predict likely asset replacement volumes and expenditure based on the number and age of assets in commission, the assumed age of replacement of these assets and their corresponding unit costs.¹⁵⁵ The model uses age as a proxy for many factors that drive individual asset replacement.¹⁵⁶ The technical underpinnings of the repex model are discussed in detail in the replacement expenditure model handbook.¹⁵⁷ 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. More detail on the repex model and input data is at Appendix E.

¹⁵⁵ We first used the predictive model to inform our assessment of the Victorian distributors' repex proposals in 2010. We undertook extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline. We have since used the repex model to inform our assessment of repex proposals for Tasmanian, NSW, ACT and QLD distributors.

¹⁵⁶ AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013, p. 10.

¹⁵⁷ AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

The repex model can predict the reasonable amount of repex Energex would require if it maintains its current risk profile for replacement into the next regulatory control period. Using what we refer to as calibrated replacement lives in the repex model gives an estimate that reflects 'business as usual' asset management practices consistent with the capex objectives. We explain the calibrated replacement life scenario, along with other input scenarios, further at section E.5.

Any material difference from the calibrated (business as usual) estimate could be explained by evidence of a non-age related increase in asset risk in the network (such as a change in jurisdictional safety or environmental legislation) or evidence of significant asset degradation that could not be explained by asset age. We use our qualitative techniques, particularly EMCa's technical review, to assess whether there is any such evidence.

We recognise that our predictive modelling cannot perfectly predict Energex's necessary replacement volumes and expenditure over the next regulatory control period, in the same way that no prediction of future needs will be absolutely precise. However, we consider the repex model is suitable for providing a reasonable statistical estimate of replacement volumes and expenditure for certain types of assets, where we are satisfied we have the necessary data. We explain our reasons for this in appendix E.

We also recognise that there are reasons why some assets may be better assessed outside of the model. Where we considered this was justified, we have separately assessed those assets by using techniques other than predictive modelling.

Technical review

Energex's proposed repex was subject to a technical review by Energy Market Consulting Associates (EMCa). EMCa assessed Energex's approach to forecasting including whether it has had regard to cost-benefit analysis that was robust and appropriate. It also assessed Energex's costs, work practices and risk management approach. This was to identify whether Energex systematically overestimated risk and, in turn, whether its approach to repex and repex forecasts was in accordance with its risk profile in the next regulatory control period.

As set out above, we have had regard to EMCa's findings to assess whether Energex's risk profile is different in the next regulatory control period, such that it requires repex above the business as usual prediction of our repex model. We have also relied on it, in combination with analysis of historical repex at the category level, to inform our assessment of repex programs to which we did not apply our predictive modelling.

Asset health indicators

We have used a number of asset health indicators with a view to observing asset health. Asset utilisation is one such indicator. We have relied on changes in asset utilisation to provide an indication as to whether Energex's assets are likely to deteriorate more or less than would be expected given the age of its assets. Utilisation

in particular is a useful check on the outcomes of our predictive modelling in that unlike the other indicators, and the predictive modelling itself, it is not age based.

The remaining indicators we have used are aged based. We acknowledge that these are less useful for providing a check on the outcomes of our predictive modelling because the model also assumes age is a reasonable proxy for asset condition. Similar to measures of asset unitisation we have not relied on the age-based aspects of our asset health indicators to any extent to inform our alternative estimate, they have however provided context for our decision.

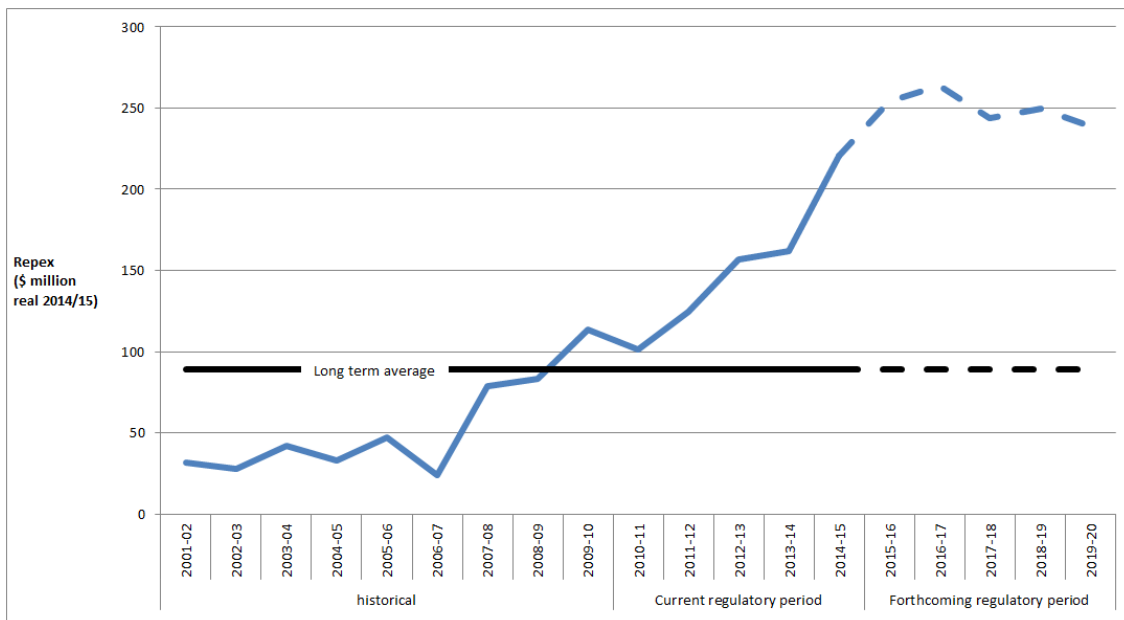
B.4.4 AER repex findings

Trends in historical and forecast repex

We have conducted a trend analysis of repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.¹⁵⁸

Our use of trend analysis is to gauge how Energex's historical repex compares to its expected repex for the 2015–20 regulatory control period. Figure B-9 below indicates that Energex's repex proposal for the 2015–20 regulatory control period is well above that it incurred in the previous regulatory control period and the early 2000s.

Figure B-9 Energex's repex - historic actual and proposed for 2015–20 regulatory control period (real \$ million June 2015)



¹⁵⁸ NER, cl. 6.5.7(e)(5).

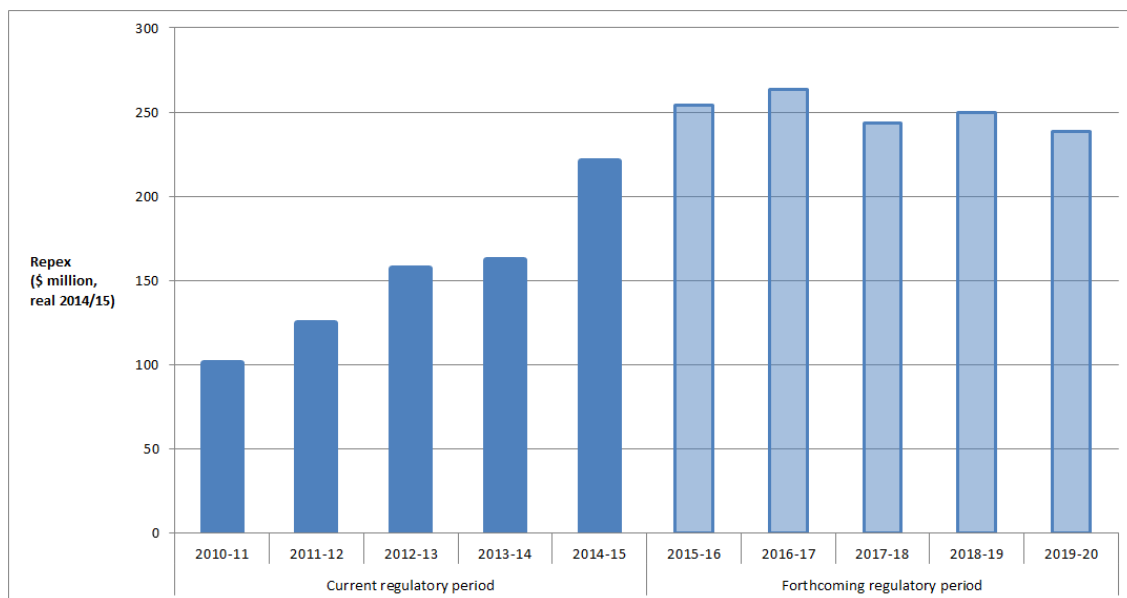
Source: Historical years: *Energex 2010-15 Revised Regulatory Proposal - RIN response - Table 2 - Capital expenditure by purpose*. Current and forthcoming regulatory periods: *Energex - Regulatory Proposal 2015-20 - Reset RIN - Table 2.1.1 - Standard Control Services Capex*

When considering the above trend we acknowledge there are limitations in long term year on year comparisons of replacement expenditure. In particular, we are mindful that:

- Energex's regulatory reporting has been subject to varied definitions of replacement expenditure across time.¹⁵⁹
- There are natural variations in a distributor's replacement needs over time. Such variations can be a result of lumpy asset age profiles or changes in relevant regulatory obligations.¹⁶⁰

Figure B-10 compares actual and expected repex in the current and forthcoming regulatory control period.

Figure B-10 Actual and expected repex (\$ million real June 2015)



Source: Energex - Regulatory Proposal 2015-20 - Reset RIN - Table 2.1.1 - Standard Control Services Capex

Figure B-10 indicates the proposed repex for the 2015–20 regulatory control period is substantial increase from the current regulatory control period. In the context of this substantial increase we have applied our other assessment techniques to assess the

¹⁵⁹ In the Reset RIN we defined replacement expenditure to be: *Repex: The non-demand driven capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life. Capex has a primary driver of replacement expenditure if the factor determining the expenditure is the existing asset's inability to efficiently maintain its service performance requirement.*

¹⁶⁰ NER 6.5.7 (a).

basis for the proposed increase and to ascertain the efficient and prudent amount of total proposed repex.

Predictive modelling

We use predictive modelling to estimate how much repex Energex is expected to need in future, given how old its current assets are, and based on when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different distributors, 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 Energex that were not classified under the groups above. In total, the assets modelled represent 61 per cent of Energex's proposed repex. Our predictive modelling calculation process is described at appendix E of this preliminary decision.

We consider the best estimate of business as usual repex for Energex is provided by using calibrated asset replacement lives and unit costs derived from Energex's recent forecast expenditure. We have assessed this finding in the context of our technical review before forming a view as to the appropriate repex component of capex for Energex. We set out below our views on the modelling input scenarios, and our views on their suitability for use in our assessment.

In total for all six modelled categories we have included an amount of \$473 million (\$2014–15) in our alternative estimate of total forecast capex, compared to Energex's forecast of \$753 million. We have had regard to the outcome and the findings of the technical review in considering whether it is appropriate to forecast repex on the basis of a business as usual estimate, or whether Energex has provided sufficient evidence to suggest that its replacement needs are higher in the next period,

Submissions on Energex's proposal also considered that Energex's proposed repex for the 2015–20 period was higher than necessary:

- AGL noted that Energex submitted that maintaining levels of reliability, service levels improvements and age of network assets requires a substantial increase in repex. However, AGL queried the veracity of Energex's claims on the essential nature of this spending.¹⁶¹
- The Chamber of Commerce and Industry Queensland (CCIQ) considered the proposed levels of repex are significantly above Energex's underlying needs and questioned Energex's classification of 'supposed ageing assets'. Further, that the proposed repex appears very high, in light of the substantial repex programs performed during the previous regulatory periods as well as the asset age and asset utilisation trends CCIQ considers are notably declining. CCIQ would expect

¹⁶¹ AGL, *Submission on Energex's regulatory proposal 2015-20*, 30 January 2015 p.12

to see reductions in repex of around 40 per cent similar to those of our other determinations.¹⁶²

- COTA noted Energex's proposed increase of 66 per cent for repex. Given Energex's substantial asset replacement program in the 2010–15 period COTA questioned whether this proposed level of repex is necessary for the next regulatory period. Further, that Energex has claimed repex requirements are substantially influenced by the need to maintain high levels of network reliability and to replace ageing assets. COTA was of the view that analysis of asset age trends since 2006 appears to suggest that the network's average asset age is decreasing rather than increasing, suggesting less need to invest in replacement of ageing assets.¹⁶³
- The Queensland Council of Social Services (QCOSS) submitted it was difficult to understand the justification for Energex's large repex proposal as it considered there had been a decline in the average asset age for Energex. QCOSS considered Energex's proposal needed further scrutiny as replacements should be able to be deferred through corrective maintenance, acceptance of risk of failure, or the fact that assets may not be needed given weak or declining demand and peak forecasts. QCOSS also considered Energex is now proposing a significant pole replacement program while at the same time operating far in excess of jurisdictional safety requirements.¹⁶⁴

Model scenario inputs

The repex model uses the following inputs:

- The asset age profile input is the number of assets in commission and when each one was installed.
- The replacement life input is a mean replacement life and standard deviation (i.e. on average, how old assets are when they are replaced).
- The unit cost input is the unit cost of replacement (i.e. on average, how much each asset costs to replace).

In Appendix E, we describe using the repex model to create three scenarios. In each of the three modelling scenarios (base case scenario, calibrated scenario and benchmark scenario) we combined different data assumptions for the final two inputs.

Under all scenarios, the first input is Energex's asset age profile (how old Energex's existing assets are). This is fixed and does not change.

The second and third inputs can be varied by using different input assumptions about:

¹⁶² Chamber of Commerce and Industry Queensland (CCIQ), *Submission on Energex's regulatory proposal 2015-20* - 30 January 2015 p.8

¹⁶³ COTA - *Submission on Energex's regulatory proposal 2015-20* - 30 January 2015 p.2

¹⁶⁴ Queensland Council of Social Service (QCOSS) - *Submission on Qld Service Providers' regulatory proposals 2015-20* - 30 January 2015, p.55–56

- how long we expect an asset to last before it needs replacing; and
- how much it costs to replace it.

The repex model takes the replacement life input for each asset category and applies it to the actual age of the assets in each asset category, on an asset category basis. In doing this it calculates when and how many assets in the asset category will need replacement in the near future.¹⁶⁵ The model then applies the unit cost input to calculate how much expenditure is needed for that amount of replacement in each asset category. This is aggregated to a total repex forecast for each of the next 20 years.

In the remaining part of this section, we outline the replacement lives and unit cost inputs we tested in the repex model to assess Energex's proposed repex. As part of our assessment, we compared the outcomes of using Energex's estimated replacement lives and its unit costs, both forecast and historical, with the replacement lives and unit costs achieved by other NEM distributors. We also used the repex model to determine calibrated replacement lives that are based on Energex's past five years of actual replacement data. These reflect Energex's immediate past approach to replacement.¹⁶⁶

We calculated historic unit costs by dividing historic expenditure by historic volumes and forecast unit costs by dividing forecast expenditure by forecast volumes.

Detail on how we prepared the model inputs is at Appendix E of this preliminary decision.¹⁶⁷

Finding 'business as usual' repex

The calibrated asset life scenario gives an estimate based on Energex's current risk profile, as evidenced by its own replacement practices. Our estimate trends forward Energex's current approach to asset risk management, weighted by the actual age of its assets. Calibrated replacement lives use Energex's recent asset replacement practices to estimate a replacement life for each asset type. These replacement lives are calculated by using Energex's past five years of replacement volumes, and its current asset age profile (which reveals how many, and how old, Energex's assets are), to find the age at which, on average, Energex replaces its assets. The calibrated replacement life represents this age.

The calibrated asset life scenario has been our preferred modelling scenario in recent reviews of other distributors.¹⁶⁸ This is because we considered the calibrated

¹⁶⁵ The repex model predicts replacement volumes for the next 20 years.

¹⁶⁶ For discussion on how we prepared each of the inputs see AER, *Preliminary decision, Energex distribution determination Attachment 6: Capital expenditure, Appendix E: Predictive modelling approach and scenarios*, May 2015

¹⁶⁷ AER, *Preliminary decision, Energex distribution determination, Attachment 6: Capital expenditure, appendix E*, May 2015.

replacement lives formed the basis of a business as usual estimate of repex, as they are derived from the distributor's actual replacement practice observed over the past five years.

The distributor decides to replace each asset at a certain time by taking into account the age and condition of its assets, its operating environment, and its regulatory obligations. If the distributor is currently meeting its network reliability, quality and safety requirements by replacing assets when they reach a certain age, then by adopting the same approach to replacement in future they are likely to continue to meet its obligations.

However, if underlying circumstances are different in the next regulatory control period, then this approach to replacement may no longer allow a distributor to meet its obligations. We consider a change in underlying circumstances to be a genuine change in the underlying risk of operating an asset, genuine evidence that there has been a change in the expected non-age related condition of assets from the last regulatory control period, or a change in relevant regulatory obligations (e.g. obligations governing safety and reliability).

If we are satisfied that there is evidence of a change in a distributor's underlying circumstances, we will accept that future asset replacement should not be based on a business as usual approach. This means that where there is evidence that a distributor's risk profile has changed then it may be necessary to provide a forecast of repex that differs from the business as usual estimate. This forecast would be required in order to satisfy us that the amount reasonably reflects the capex criteria.

Calibrated scenario

We have modelled the calibrated lives using two unit cost assumptions, being:

- Energex's own historical unit costs from the current regulatory control period. These reflect the unit costs Energex has incurred over the last five years.
- Energex's own forecast unit costs for the next control regulatory period. These reflect the unit costs Energex expects to incur over the next five years.

The calibrated scenario gives an output of \$473 million using Energex's historical unit costs and \$571 million using Energex's forecast unit costs. Both of these outcomes are below Energex's forecast of \$753 million for the six modelled asset categories. This suggests that Energex's proposal is likely to be above a business as usual estimate of repex.

¹⁶⁸ AER, *Ausgrid final decision - Attachment 6 – Capital expenditure May 2015*; AER, *ActewAGL final decision - Attachment 6 – Capital expenditure May 2015*; AER, *Essential Energy final decision - Attachment 6 – Capital expenditure May 2015*; AER, *Endeavour Energy final decision - Attachment 6 – Capital expenditure May 2015*

There is a significant difference between the calibrated scenario outcomes when using Energex's historical or forecast unit costs. Energex's forecast unit costs for the next five years are, on average, higher than its unit costs over the last five years. However, in the absence of a reasonable explanation, we would not expect forecast unit costs to be higher than historical unit costs given the incentive framework encourages a distributor to become more cost efficient over time.

We compared Energex's historical unit costs to benchmark unit costs. This suggested Energex's historical unit costs are more likely to reflect a realistic expectation of future input costs than its forecast unit costs. Accordingly, we adopted Energex's historical unit costs for the purpose of calculating a business as usual repex estimate. Consequently, we consider \$473 million is the most reasonable "business as usual" estimation of repex. As noted above, we will rely on this outcome and the findings of the technical review in considering whether it is appropriate to forecast repex on the basis of a business as usual estimate, or whether Energex has provided sufficient evidence to suggest that its replacement needs are higher in the next regulatory control period, such that its forecast of \$753 million is appropriate.

Testing other model inputs

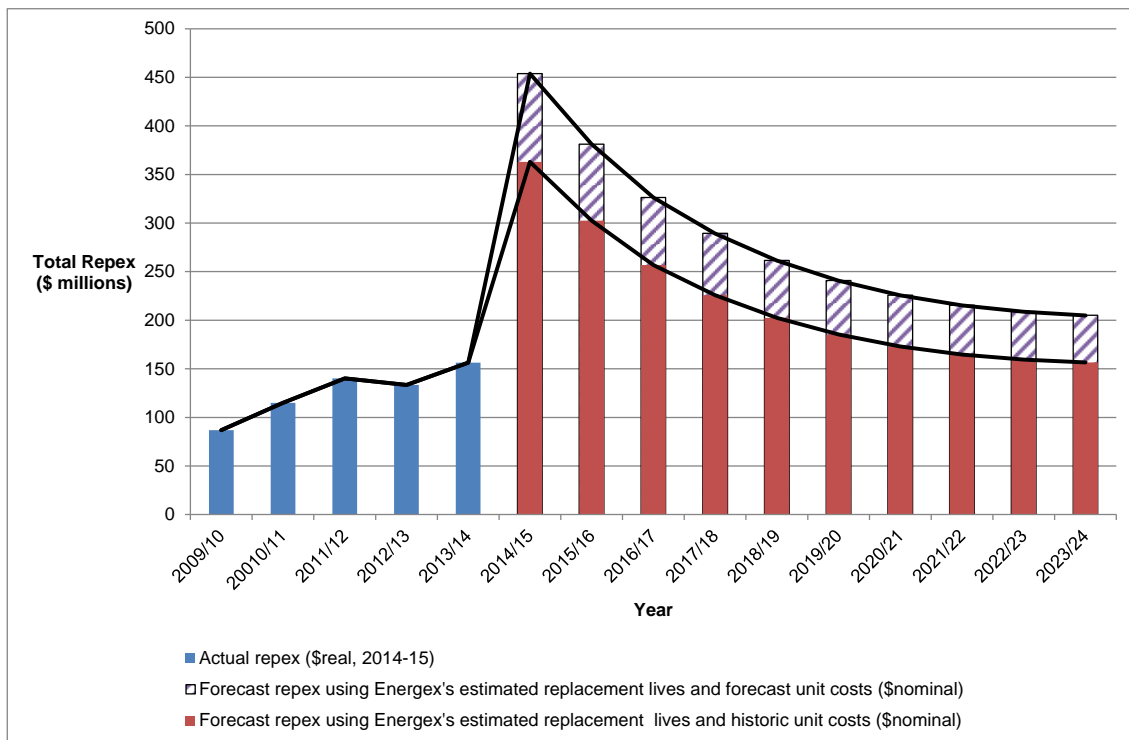
As outlined earlier (and in appendix E) we used the repex model to create other scenarios combining different input data. In this section we explain how the outcomes of these other scenarios support our conclusion to use the calibrated scenario.

Base case scenario outcomes

Energex provided its own estimate of asset replacement lives in its RIN response. To test these inputs we include them in a predictive modelling scenario that is referred to as the base case. The base case scenario gives repex estimates of \$1.31 billion (historical unit cost) and \$1.66 billion (forecast unit cost). These forecasts are higher than Energex's forecast of \$753 million for the six modelled asset groups.

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 B-11). This replacement profile indicates that a significant portion of the asset population currently in commission is much older than would be expected using Energex's estimated replacement lives. Using this input 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 B-11 Base case scenario outcome



Source: Energex, AER analysis.

Based on our analysis of the base case scenario outcomes we consider that Energex's estimated replacement lives are not credible or reliable for the following reasons.

First, if Energex's actual replacement lives were consistent with their estimated replacement lives, we would not expect to see the observed asset replacement profile. If Energex's actual asset replacement profile followed its estimated replacement lives, the older assets would have:

- already reached the end of their economic (replacement) lives and 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 predictive modelling.

The 'step-up/trend down' replacement profile observed from the base case scenario suggests that a significant proportion of the asset population has survived longer than would be expected using Energex's estimated replacement lives. These 'survivor' assets have a material effect on the observed outcome. This outcome suggests that Energex's estimated replacement lives are shorter than those it achieves in practice.

Second, further analysis of the base case scenario reveals the replacement life inputs are the main drivers of the base case scenario outcome. Under the calibrated scenario where Energex's estimated replacement lives are substituted with calibrated replacement lives, the model outputs are \$473 million for historical unit costs and \$571 million for forecast unit costs (the calibrated model is discussed in the next

section). Taken together with the information from our other analytical techniques and our concerns that Energex's base case lives do not reflect Energex's actual replacement practices, we consider that the estimated replacement life information provided by Energex will not result in a reasonable forecast of business as usual repex.

Benchmarked scenario outcomes

Benchmarked uncalibrated replacement lives

We developed a series of benchmark replacement lives using the data collected from all NEM distributors in the category analysis RINs. For model inputs we used the average, third quartile (above average), and longest replacement lives of all NEM distributors for each category. We discuss how we prepared this data in appendix E.

As with Energex's estimated replacement lives, we found using these benchmark replacement lives produced sharp 'step-up/trend down' forecast repex, indicating the replacement lives used are likely to be too short for modelling purposes as they predict a large unrealistic 'backlog' of replacement. When used in the model these also produced outcomes higher than Energex's own forecasts.

Benchmarked calibrated replacement lives

We developed benchmark calibrated lives by first using the repex model to calculate calibrated lives based on the replacement data from all NEM distributors. For model inputs we again used the average, third quartile (above average), and longest of the calibrated lives of all NEM distributors for each category. We discuss how we prepared this data in Appendix E.

When applied to the model for Energex, these replacement lives produced outcomes lower than when we used the calibrated replacement lives based on Energex's data. The calibrated benchmark replacement lives may reflect to some extent the particular circumstances of a distributor and this may not be applicable to the business under review. However, this input provided us with a check that Energex's calibrated replacement lives were reasonable against its peer distributors in the NEM.

Benchmarked unit costs

We developed industry benchmark unit costs using the data collected from all NEM distributors in the category analysis RINs. For model inputs we used the average, first quartile (below average), and lowest unit costs of all NEM distributors for each asset category. We discuss how we prepared this data in appendix E.

Applying average benchmark unit costs (in combination with the calibrated lives) in the repex model for Energex gave an outcome that was higher than Energex's proposal. The outcome when using the first quartile was similar to the historical unit cost/calibrated life scenario, and lowest unit cost benchmark numbers were below this figure. This indicates that Energex's direct historical unit costs are largely in line with the first quartile of distributors in the NEM.

Technical review

This section sets out the findings of the technical review undertaken by EMCa that we commissioned to help us to assess whether Energex's repex forecast reasonably reflects the capex criteria. In particular, we engaged EMCa to test whether Energex's:

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

We consider that EMCa's assessment assists in determining whether Energex's forecasting approach, costs and work practices are prudent and efficient. EMCa's report also assists us in assessing 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. Another example relates to Energex's actual and expected repex in the current regulatory control period, and the substitution possibilities between repex and opex (whether to replace or maintain).

By assessing Energex's approach to repex forecasting and risk management, the technical review assists us in forming a view as to whether Energex's underlying circumstances (particularly its asset risk) in the 2015-20 regulatory control period have changed from the last regulatory period. This allows us to form a view on whether Energex would require more or less repex than the business as usual estimate of repex in the 2015–20 regulatory control period.

We engaged EMCa to provide expert advice on the issues identified above. Broadly, EMCa found that:¹⁶⁹

- a CPI price outcome objective in the governance of Energex's expenditure forecast is not a meaningful discipline that will ensure the forecast is optimised.
- Energex's proposed forecast is not reasonable and exhibits a degree of upwards bias.
- Energex's costs and work practices are reasonably prudent and efficient.
- Energex's risk management framework has elements that reflect a bias towards over-estimation of risk and which contribute to an exaggeration of its forecast for required repex activity.

Energex did not test positively on two of the three broad issues above. We discuss EMCa's findings in more detail below.

¹⁶⁹ EMCa review of Energex's Augex and Repex Regulatory Proposal, p. iv.

EMCa findings

EMCa found that Energex has not provided convincing justification for the extent to which it proposed to increase repex in the 2015–20 regulatory control period. This is because¹⁷⁰:

- Energex has conducted insufficient project and program analysis to support the timing and volume of activity. Further, its replacement targets appear to coincide with regulatory period end points;
- risk assessment has been undertaken at too high a level to assist meaningful decision-making both within and across the program;
- aggregate repex modelling prepared by Energex presents alternative outcomes that are so wide as to be of little merit for use in a top-down challenge to validate the proposed expenditure levels; and
- there is inadequate justification of the significant proposed step increases in expenditure.

Forecasting approach

EMCa observed that the objective of Energex is to cap network price increases to CPI (or less). EMCa raise the following issue in relation to this approach:¹⁷¹

A forecasting process designed to constrain expenditure levels to maintain “network price increases below CPI” may result in a network capex forecast that is either too high or too low. We note, for example, that this constraint was not applied in the current RCP, when network prices increased considerably on the basis of what were then perceived to be high capex requirements. In either case, it would be only by coincidence that such a constraint would result in a prudent and efficient capital expenditure forecast. Moreover, we consider that specific factors in this instance provide significant headroom and which may allow Energex to meet this objective without necessarily allowing only for prudent and efficient capital expenditure. These factors include a low WACC, transfer of services from SCS to ACS (in regards to repex) and considerably reduced augex requirements relative to the allowance in the current RCP, due to rapid and recent declines in electricity demand growth.

EMCa considered that a CPI price cap objective on the overall business does not provide a meaningful discipline that would lead Energex to a prudent and efficient capex level.

¹⁷⁰ EMCa review of Energex’s Augex and Repex Regulatory Proposal p. 87.

¹⁷¹ EMCa review of Energex’s Augex and Repex Regulatory Proposal p. 15.

Application of risk assessment in forecasting

EMCa considered that Energex's application of its risk assessment framework to its proposed repex programs did not provide sufficient justification of risk-based prioritisation. EMCa observed that Energex's forecast contained an inappropriately high number of projects with 'Low' and 'Very low' risk ratings in Energex's capital expenditure forecasts. EMCa considered this arose from an inadequate top-down challenge, coupled with Energex's application of the CPI price outcome objective as a primary constraint. EMCa considered the overall capex program was not optimised in relation to risk and economic outcomes and Energex's capital expenditure forecast was above that which would reasonably be considered to be prudent and efficient.¹⁷²

EMCa noted that Energex has presented cost based risk management (CBRM) as its preferred forecasting methodology. EMCa noted that Energex had not provided details of any post-implementation review that assessed whether the benefits expected from use of CBRM at the time of its approval had been realised.¹⁷³

Further, EMCa found that the evidence provided by Energex indicated that most of Energex's forecasting was based on the use of expenditure trending, not CBRM. EMCa also noted that it was not clear at a detailed level how expenditure trending had been applied. EMCa noted the proposed significant step increase in repex appeared to be inconsistent with the application of its historical expenditure trending to the majority of expenditure categories. EMCa concluded that Energex had not presented drivers that would adequately justify this step increase in proposed expenditure.¹⁷⁴

EMCa observed that the application of risk assessment for repex programs did not provide sufficient evidence of risk-based prioritisation. As noted above, it referenced the inclusion of a high number of low risk rated projects in the capital expenditure forecasts to support this view. EMCa observed that Energex's repex modelling did not appear to have had any meaningful role in constraining its proposed program. Energex did not provide evidence of an effective top-down challenge being applied as part of its repex forecasting process - only of overall expenditure modelling that sought to achieve a price outcome.¹⁷⁵

A summary of EMCa's findings on specific programs is presented in Table B-7 below. We consider EMCa's findings support the outcomes of our overall assessment which is that a lower amount of repex than Energex's proposed amount is more likely to contribute to a prudent and efficient amount of total forecast capex for the 2015–20 regulatory control period.

¹⁷² EMCa review of Energex's Augex and Repex Regulatory Proposal, p. i.

¹⁷³ EMCa review of Energex's Augex and Repex Regulatory Proposal, p. 68.

¹⁷⁴ EMCa review of Energex's Augex and Repex Regulatory Proposal, p. 40.

¹⁷⁵ EMCa review of Energex's Augex and Repex Regulatory Proposal, p. 40.

Table B-7 EMCa review of asset replacement programs

Asset category	EMCa's consideration
"Other" asset category	EMCa observed an increase in expenditure for the "other" asset category from expenditure in the 2010-15 regulatory control period. Based on its review of the information provided in support of the larger programs, EMCa considered that the proposed step increases were without sufficient justification. Specifically, it noted that the category did not appear to be adequately supported by analysis of the drivers, options and risk. ¹⁷⁶
Transformers	EMCa was not satisfied that Energex's forecast for the transformer asset category had been developed based on CBRM analysis. EMCa noted the absence of some supporting information, but did not identify any systemic issues with the forecast.
Overhead conductors	EMCa considered Energex had not sufficiently justified the proposed volume of replacement in this asset category. EMCa was concerned that there was an absence of a clear forecasting methodology applied to this expenditure category, and that the qualitative nature of Energex's risk assessment may have led to an over-estimate of the expenditure forecast. EMCa also found inconsistencies in the information provided by Energex that caused it to further doubt the prudence of the forecast expenditure for overhead conductors.
Service lines	EMCa did not find sufficient analysis to support the proposed forecast for this asset category. It considers that the justification for the forecast expenditure is insufficient to support the proposed expenditure.
Poles	EMCa considered that the assumptions applied by Energex in this asset category reflected an overly conservative risk management approach to pole failure and were likely to have resulted in an inflated forecast of expenditure. ¹⁷⁷
SCADA, network control and protection system	EMCa did not consider that Energex had justified its proposed programs under this asset category. Energex has inferred benefits including deferred capital expenditure and reductions in maintenance cost for SCADA and for communications. However, these benefits do not appear to have been factored into the analysis provided or the expenditure forecasts.
Switchgear	EMCa did not identify any systemic issues with Energex's forecast of switchgear repex.
Pole top structures	EMCa considered that Energex had not provided sufficient analysis of the condition, forecast failure rate or risk to demonstrate the prudent level of expenditure

¹⁷⁶ EMCa review of Energex's Augex and Repex Regulatory Proposal, p. 72.

¹⁷⁷ EMCa review of Energex's Augex and Repex Regulatory Proposal, p. 81.

Asset category	EMCa's consideration
	proposed. It did not consider that Energex had justified its proposed expenditure for this asset category. ¹⁷⁸
Underground cables	EMCa did not identify any systemic issues with Energex's forecast of underground cable repex.

Source EMCa

Un-modelled repex

As noted in Appendix E, 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 Energex's RIN response was not included in the repex model.

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 39 per cent of Energex's proposed repex.

Because we are not in a position to use predictive modelling for these asset categories, we have placed more weight on analysis of historical repex and EMCa's findings in relation to these categories. Our analysis of these categories of proposed repex is set out below.

Other repex

Energex categorised a number of assets under an "Other" asset group in its RIN response. Energex forecast \$281 million of repex for these assets for the 2015–20 period. This represents almost a seven fold increase over the 2010–15 regulatory control period, or \$242 million. The assets are detailed in Energex's reset RIN. They include, among other things, assets relating to protection systems, SCADA development, cable terminations, condition monitoring schemes and reactive works.

EMCa considered the step increases in this category were not sufficiently justified. It was not satisfied that Energex had adequately supported its proposal through analysis of drivers, options and risk.

EMCa found that programs that appear to align with the timing of the revenue reset cycles were without adequate forecasting rigour, and, if subject to a robust top-down review process, would be likely to result in a reduction to the forecast expenditure.¹⁷⁹

¹⁷⁸ EMCa, Review of Energex's Augex and Repex Regulatory Proposal, p. 86.

¹⁷⁹ EMCa, Review of Energex's Augex and Repex Regulatory Proposal, p. 72.

EMCa did not find sufficient consideration of risk within this expenditure category to support the proposed level of expenditure. We consider Energex's proposed step increase in forecast expenditure has not been shown to reasonably reflect the capex criteria. As Energex has not established the need for a step increase for these assets, we consider its historical expenditure from the 2010-15 regulatory control period of \$39 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

SCADA, network control and protection

Energex has proposed repex of \$124 million for SCADA, network control and protection. This represents a 193 per cent increase over the 2010–15 regulatory control period, or \$82 million.

Energex's expenditure on this asset category increased significantly over the final two years of the 2010–15 regulatory control period. Energex's proposal for the next period includes a step increase in repex at the commencement of the 2015–20 regulatory control period, which declines in the final year of the period.

Energex identified a need for repex to address the obsolescence of system components. EMCa did not consider that Energex had justified its proposed programs under this asset category. It noted that Energex has inferred benefits including deferred capital expenditure and reductions in maintenance cost for SCADA and for communications. However, these benefits do not appear to have been factored into the analysis provided or the expenditure forecasts.

EMCa noted that Energex had not provided options analysis for relay replacement, and provided little analysis of the recommended options for its SCADA and communications programs.¹⁸⁰

In reaching our view on this asset category, we have considered EMCa's specific views on SCADA, network control and protection, and EMCa's overall views on systemic issues with Energex's forecasting approach and assessment of risk. Taking all of this into account, we see no justification for the step change proposed by Energex. We consider Energex's SCADA, network control and protection repex from last period of \$42 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

Pole top structures

Energex has forecast \$80 million of repex on pole top structures over the 2015–20 period. This represents a 19 per cent increase over the 2010–15 regulatory control period, or \$13 million.

¹⁸⁰ EMCa, Review of Energex's Augex and Repex Regulatory Proposal, pp. 82-84.

EMCa considered that Energex had not provided sufficient analysis of the condition, forecast failure rate or risk to demonstrate the prudent level of expenditure proposed. It did not consider that Energex had justification its proposed expenditure for this asset category.

In reaching our view on Energex's pole top structures, we have considered EMCa's specific views on pole top structures, and EMCa's overall views on systemic issues with Energex's forecasting approach and assessment of risk. Taking all of this into account, we do not consider there is sufficient justification to support the significant step change proposed by Energex. We consider Energex's pole top repex from last period of \$68 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

Network health indicators

We consider a major determinant of variations in repex levels over time is the condition of network assets. We expect distributors will have regard to the condition of its network assets when forecasting the capex it requires to maintain the quality, reliability and security of supply.¹⁸¹

Our trend analysis indicates that Energex is forecasting an increase to its recent repex requirements for the 2015–20 regulatory control period. We would expect that this increase would be reflective of a deterioration in the condition of its network assets in recent years, and/or Energex's age profile, which would support a need for substantial increases in asset replacement expenditure.

To inform our understanding of the condition of Energex's network assets, we have considered the following high level indicators of network health:

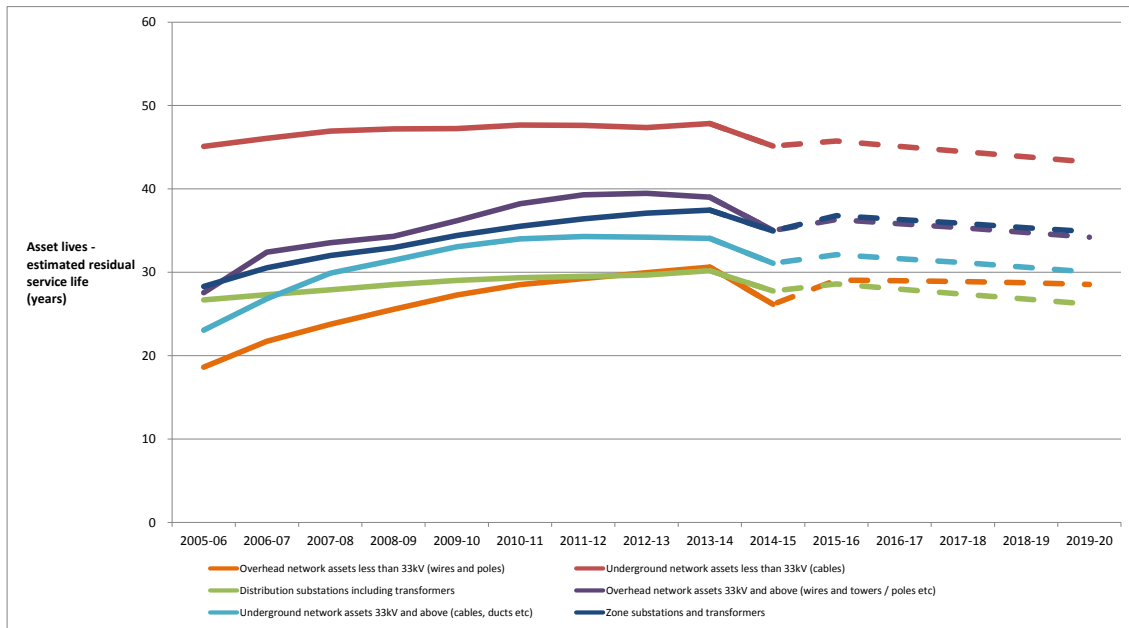
- trends in the remaining service life of Energex's network assets
- trends in the utilisation of network assets (with lower(higher) asset utilisation in certain asset classes correlating to lower(higher) rates of asset deterioration).

Trends in the remaining service life of network assets

Figure B-12 plots the estimated residual service life of Energex's network assets across time.

¹⁸¹ NER 6.5.7(c) & (a)

Figure B-12 Energex estimated residual service life by asset class



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

Figure B-12 shows that Energex's residual asset lives have improved since 2006 (with the exception of the estimate year) and is forecast to remain relatively stable, albeit with slight downward trend through the 2015–20 regulatory control period.

We acknowledge limitations exist when using estimated residual service life to indicate the trend in the underlying condition of network assets. In particular, we are mindful that increases in growth-related capex relative to repex can distort this measure's effectiveness as a proxy of the trend in the existing network assets' condition. That is, if additions to the asset base are of a higher value than those being replaced, the residual service life will improve without necessarily addressing any underlying asset condition deterioration. However, the historical increasing trend in residual lives (where age is a proxy for asset condition) does not suggest that there are asset health issues that require the step up in repex that Energex has proposed.

Asset utilisation

Another indicator of asset health we consider can impact asset condition is the degree of utilisation of certain types of network assets. As we discuss in the Augex appendix above, Energex has significant spare capacity in its network based on past investments to meet expected demand that did not eventuate and due to the higher security standards required under the Distribution Authority. All else being equal we expect a positive correlation between asset condition and lower network utilisation exists for certain asset classes.

This relationship is evidenced in the design standards for all distributors. However, we recognise that:

- The relationship between asset utilisation and condition is not uniform between asset types. For example; poles and fuses.
- The relationship is not necessarily linear (e.g. condition may not be materially impacted until a threshold point is reached).
- The condition of the asset may be difficult to determine (e.g. overhead conductor). As such, early-life asset failures may be due to utilisation or, more commonly, a combination of factors (e.g. utilisation and vibration).

Table B-8 below describes our view regarding the general relationship between an asset type's utilisation and its condition and major asset classes.

Table B-8 Utilisation and asset deterioration by asset type

Asset type	Generalised observation
Poles and pole-top structures	Generally not impacted by electrical utilisation.
Overhead conductors	Impacted by high levels of electrical utilisation. Low and moderate utilisation will have a minimal impact on condition, while increasing utilisation above design standards will have a compounding impact on condition. Conductors that have been historically overloaded may exhibit reduced tensile strength and increased brittleness and therefore be more prone to conductor failure.
Underground Cables	Impacted by high levels of electrical utilisation. Low and moderate utilisation will have a minimal impact on condition, while increasing utilisation above design standards will have a compounding impact on condition. Underground cables that have been historically overloaded may exhibit overheating and therefore be more prone to conductor failure through joint failure or insulation failure.
Transformers	Impacted by high levels of electrical utilisation. Low and moderate utilisation will have a minimal impact on condition, while increasing utilisation above design standards will have a compounding impact on condition. High levels of utilisation can result in failure of the insulating materials and a short-circuit.
Switchgear	Impacted by electrical load and by duty cycle. All utilisation can impact condition (where utilisation is measured as both the number of operations and the load made or broken when operated). Typically operation of the unit will result in degradation of the contact surfaces. Both the duty cycle and the electrical current that is connected/interrupted will impact condition.
Non-network assets	Generally not impacted by electrical utilisation.

Source: AER analysis

We do note that high levels of utilisation can occur through many practices. Even for assets that are generally lightly loaded, emergency and switching conditions can introduce short term levels of utilisation that may impact the condition of the asset. In general, a lightly loaded network will also be less subject to overload conditions from emergency and switching conditions.

Consistent with the trend in residual service life we consider utilisation on Energex's network should not have a material impact on the deterioration of network assets in recent years.

These observations are of a general nature. They support our view that there is a need for a more detailed review using our other assessment techniques to ascertain the efficient and prudent amount of total proposed repex.

B.5 AER findings and estimates for capitalised overheads

Capitalised overheads are costs associated with capital works that have been capitalised in accordance with Energex's capitalisation policy. They are generally costs shared across different assets and cost centres.

B.5.1 Position

We do not accept do not accept Energex's proposed capitalised overheads. We have instead included in our alternative estimate of overall total capex and amount of \$823.5 million (\$2013–14) for capitalised overheads. This is 9 per cent lower than Energex's proposal of \$900.4 million (\$2013–14). We are satisfied that this amount reasonably reflects the capex criteria.

B.5.2 Our assessment

As a logical proposition we consider that reductions in Energex's forecast expenditure should see some reduction in the size of Energex's total overheads. Given that our assessment of Energex's proposed direct capex, demonstrates that a prudent and efficient DNSP would not undertake the full range of direct expenditure contained in Energex's regulatory proposal. It follows that we would expect some reduction in the size of Energex's capitalised overheads. We do accept that some of these costs are relatively fixed in the short term and so are not correlated to the size of the expenditure program. However, we maintain that a portion of the overheads should vary in relation to the size of the expenditure.

We have engaged with Energex regarding its overheads.¹⁸² We sought to understand how overheads vary with the size of Energex's expenditure program and in particular to quantify the proportion of overheads that are fixed and varied. Energex submitted that:¹⁸³

Energex considers for the 2015-20 regulatory control period approximately 80% of the reported capitalised overhead would have little or no correlation with changes in direct spend (i.e. they would be fixed).

Further Energex submitted that:¹⁸⁴

¹⁸² AER, Information request Energex 050.

¹⁸³ Energex, response to information request EGX 050.

¹⁸⁴ Energex, response to information request EGX 050.

Based on the values included in Energex's Regulatory Proposal (below), for each 1% change in direct CAPEX, total capitalised overheads would vary by up to 0.20% (e.g. \$985.8M x 0.2% = \$1.99M). Alternately for every \$1M change in direct CAPEX, overheads would change by up to \$0.096M.

We have considered the relationship between opex and capex, specifically whether it is necessary to account for the way the CAM allocates overheads between capex and opex in making this decision. We considered that this was not necessary in order to satisfy the capex criteria. This is because:

Our opex assessment sets the efficient level of opex inclusive of overheads and so has accounted for the efficient level of overheads required to deliver the opex program by applying techniques which utilise the best available data and information for opex.

The starting point of our capitalised overheads assessment is Energex's proposal, which is based on their CAM. As such, Energex's forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of Energex's approved capex based on assessment techniques best suited to each of the capex drivers. In doing so we have accounted for there being a fixed proportion of capitalised overheads.

We have formed our alternative estimate on the basis of the information provided by Energex. On this basis we consider that a \$1.0 million reduction in Energex's forecast capex should result in a \$0.096 million reduction in Energex's capitalised overheads. As a result of a \$801.2 million (\$2014–15) reduction in Energex's direct capex that attract overheads we consider a reduction of \$76.9 million (\$2014–15) reasonably reflect the capex criteria.

B.6 AER findings and estimates for non-network capex

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

B.6.1 Position

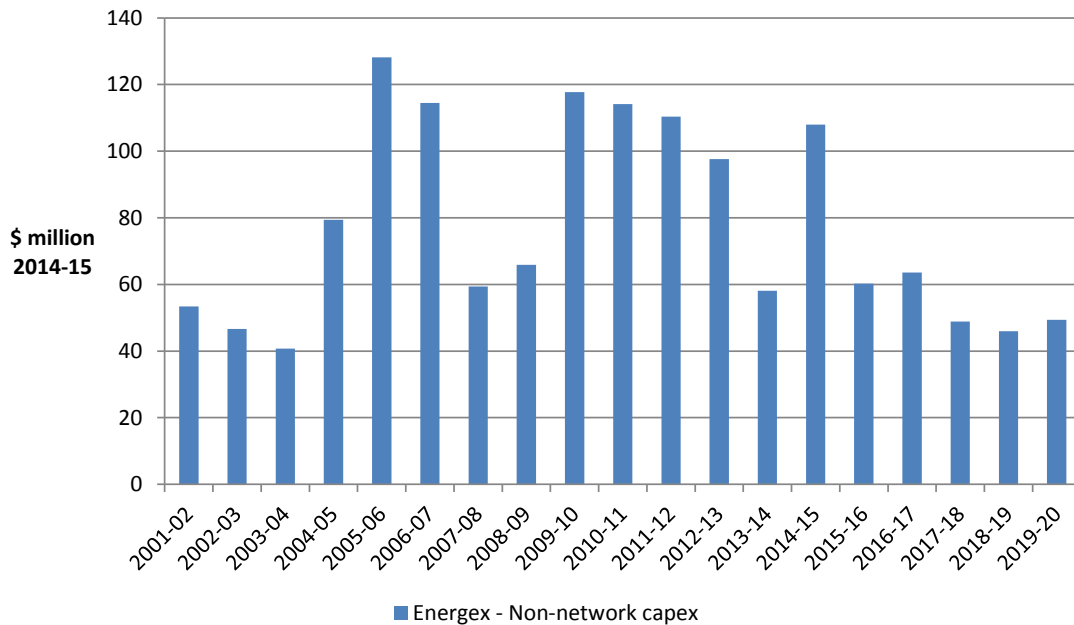
Energex forecast total non-network capex of \$244.1 million for the 2015–20 regulatory control period.¹⁸⁵ As part of our estimate of the total capex required for the 2015–20 regulatory control period, we accept that Energex's forecast of non-network capex reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.¹⁸⁶ We have included it in our estimate of total capex for the 2015–20 regulatory control period.

¹⁸⁵ Energex, *Regulatory information notice*, table 2.1.1; AER analysis. Excludes overheads.

¹⁸⁶ NER, cl. 6.5.7(c).

Figure B-13 shows Energex's actual and expected non-network capex for the period from 2001–02 to 2014–15, and forecast capex for the 2015–20 regulatory control period.

Figure B-13 Energex's non-network capex 2001–02 to 2019–20 (\$million, 2014–15)



Source: Energex, *Regulatory information notice*, template 2.6; Energex, *RIN response for 2010-2015 regulatory control period*, template 2.1.1; AER analysis. Includes capitalised overheads.

Energex's forecast non-network capex for the 2015–20 regulatory control period is 35 per cent lower than actual and expected capex in the 2010–15 regulatory control period.¹⁸⁷

Our analysis of longer term trends in non-network capex suggests that Energex has forecast capex for this category at historically low levels. Non-network capex in the 2015–20 regulatory control period is forecast to return to levels consistent with the period prior to 2004–05. This suggests that Energex's forecast of non-network capex requirements in the 2015–20 regulatory control period is at historically low levels and likely to be reasonable having regard to past expenditure.¹⁸⁸

We have also assessed forecast expenditure in each category of non-network capex. Analysis at this level has been used to inform our view of whether forecast capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts which may warrant further review.¹⁸⁹ Figure

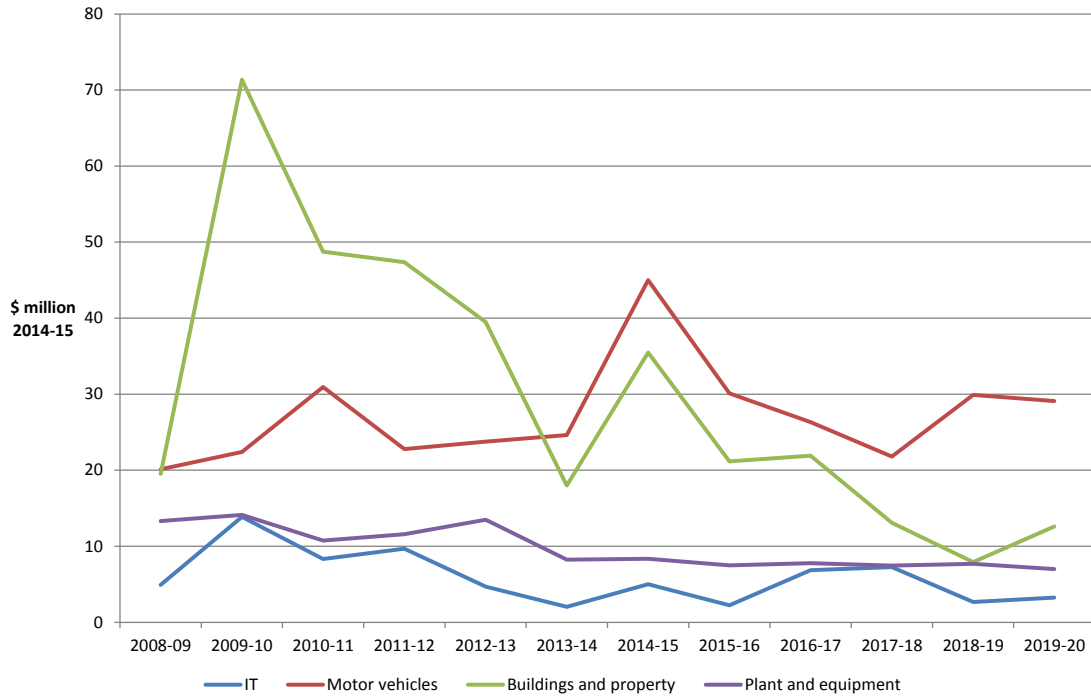
¹⁸⁷ Energex, *Regulatory information notice*, template 2.6; AER analysis.

¹⁸⁸ NER, cl. 6.5.7(e)(5).

¹⁸⁹ NER, cl. 6.5.7(e)(5).

B-14 shows Energex's actual and forecast non-network capex by sub-category for the period from 2008–09 to 2019–20.

Figure B-14 Energex's non-network capex by category (\$million, 2014–15)



Source: Energex, *Regulatory information notice*, template 2.6; AER analysis.

Energex has forecast reductions in capex for all categories of non-network capex in the 2015–20 regulatory control period. The forecast reductions in expenditure for the various categories of non-network capex range from 7 per cent for motor vehicles up to 59 per cent for buildings and property.¹⁹⁰ We are satisfied that these reductions reflect the high level drivers of expenditure in these categories and as such reasonably reflect efficient costs. For example, the significant decline in buildings and property capex reflects the focus of Energex's strategic property plan to maintain the existing property portfolio, pursue efficiency initiatives and progress opportunities to reduce costs.¹⁹¹ Based on our category level review of Energex's forecast non-network capex, we have not identified any areas for further specific review at the project or program level. We are satisfied that the forecast level of expenditure reasonably reflects the capex criteria.¹⁹²

We have also considered whether Energex's forecast reduction in non-network capex reflects the substitution possibilities between opex and capex for this category of expenditure, for example undertaking building or motor vehicle maintenance versus

¹⁹⁰ Energex, *Regulatory information notice*, template 2.6; AER analysis.

¹⁹¹ Energex, *Appendix 31 - Property Strategic Plan*, October 2014, p. 4.

¹⁹² NER, cl. 6.5.7(c)(1).

replacement.¹⁹³ Despite the significant reductions in forecast capex, we note that Energex also forecast non-network opex in the 2015–20 regulatory control period to reduce by 6 per cent compared to the 2010–15 regulatory control period.¹⁹⁴ Taking this into account, we are satisfied that Energex's forecast reduction in non-network capex does not simply reflect a reallocation of expenditure from capex to opex.

In summary, having considered Energex's regulatory proposal and had regard to the capex factors,¹⁹⁵ we are satisfied that total capex which reasonably reflects the capex criteria should include a forecast of \$244.1 million¹⁹⁶ for non-network capex. Our estimate of total capex for the 2015–20 regulatory control period reflects this conclusion.

SPARQ ICT expenditure included within overheads

In this preliminary decision, we have included in our alternative estimate the forecast expenditure for ICT overheads as proposed by Energex, adjusted to reflect the lower direct costs. At this stage we have no firm evidence that this expenditure is not prudent or efficient given a realistic expectation of demand and cost inputs.

However, our assessment of Energex's proposed ICT expenditure has revealed some areas of concern.

These concerns include that Energex:

- proposed using 2012-13 as the base year for forecasting 'operational support' and the 'telecommunications pass through' costs does not capture the efficiencies identified by the Independent Review Panel on Network Costs (the Panel) and ITNewcom (SPARQ's consultant);
- is over-recovering the financing costs which SPARQ charges to Energex, via the asset services fee. The over-recovery is due to Energex proposing to apply a significantly higher return on capital (WACC) than we have forecast in our preliminary decision. There is also potential for over- and under-recovery in the future as the WACC is not constant through the regulatory period with annual updating of the cost of debt;
- is relying on SPARQ ICT costs, the majority of which have not been market tested and there is evidence to suggest that there is further scope for efficiencies through reforms to the arrangements between Energex and SPARQ.
- is not transparently reporting its ICT costs. We consider that Energex' ICT should be reported within 'overheads' rather than in 'non-network IT'. We also consider that the off-balance sheet arrangement with SPARQ lacks transparency which

¹⁹³ NER, cl. 6.5.7(e)(7).

¹⁹⁴ Energex, *Regulatory information notice*, template 2.6; AER analysis.

¹⁹⁵ Relevantly, cl. 6.5.7(e)(5) and 6.5.7(e)(7).

¹⁹⁶ Excludes capitalised overheads.

hinders our ability to assess and track Energex' ICT expenditure across regulatory periods.

These issues are material given the amount of expenditure proposed by Energex for ICT costs. As noted, we expect Energex to address each of these issues in its revised proposal.

2012-13 base year

We note that Energex applied a 'base-step-trend approach' to forecasting 'operational support' and the 'telecommunications pass through' costs. It used 2012-13 as the base year. The baseline forecast holds expenditure constant in nominal terms. That is, it proposes a small downward expenditure trend for the period in real terms.¹⁹⁷ However the proposed step change for the increased operational support for the 2014-15 program of work alone more than offsets the base decline over the 2015-20 regulatory control period.¹⁹⁸ We consider that the savings measures that have been suggested by SPARQ's consultants, as well as those recommended by the Panel, could be expected to have a greater cost decrease than is proposed by Energex in providing a discount equivalent to inflation on the 2012-13 base year level of expenditure.

At this stage, we have not been able to confirm this to our satisfaction or quantify any possible efficiencies but we note that such efficiencies, if achievable, would be broadly consistent with KPMG's NEM-wide findings. We expect that Energex will evaluate the possibility of achieving efficiencies in preparing its revised proposal. We will be further reviewing this expenditure as part of our final decision.

Over-recovery of financing costs

We also note that Energex may wish to reconsider its reporting approach as it may have implications for the over- or under- recovery of expenditure relating to the asset services fee. Energex proposed applying a significantly higher WACC than our forecast for calculating the finance costs for the assets held by SPARQ for the 2015-20 regulatory control period (and these costs are passed through to Energex as part of the asset services fee).¹⁹⁹ This will result in a material over recovery in 2015-16 and is likely to be increasingly material over the rest of the regulatory period. We will give further consideration to the implications of Energex reporting approach and consequently, the possible inclusion of the SPARQ assets in the RAB.

In turn, this may impact upon our consideration of Energex' revised proposal, as explained below.

We note that 35 per cent of Energex's proposed \$900.4 million (\$2014-15) total capitalised overheads, is attributable to information, communications and technology

¹⁹⁷ Energex, Regulatory proposal, Appendix 32, ICT Strategic Plan, pp.3,14.

¹⁹⁸ Energex, Regulatory proposal, Appendix 32, ICT Strategic Plan, p.14.

¹⁹⁹ Energex, Response to information request AER Energex55, received 17April 2015, p.1.

(ICT) services.²⁰⁰ Energex and Ergon Energy have a 50 per cent shareholding each in SPARQ Solutions Pty Ltd (SPARQ). SPARQ provides ICT services to Energex and Ergon Energy. The total ICT service cost is allocated between alternate control services and standard control services overheads (and then between opex and capex overheads) in proportion to the relative direct expenditure.²⁰¹

SPARQ's forecast of ICT total expenditure for Energex consists of:²⁰²

- Asset service fees (\$242.8 million) - this fee consists of SPARQ's finance and depreciation charge for Energex' consumption of the ICT assets held by SPARQ.
- Service level agreement (\$230.3 million) - for SPARQ's costs associated with the on-going operation, support and maintenance of ICT services.
- Telecommunications (\$37.0 million)- for the costs of carrier, mobile, data, voice and device management services
- Non-capital project expenditure (\$22.3 million) - for non-recurrent opex reflecting the ICT specific expenses which cannot be capitalised.

Fifty nine per cent, or \$316.0 million, of SPARQ's total ICT expenditure for Energex is capitalised.

We note KPMG surveyed 10 DNSPs, including Energex and Ergon Energy, across four states in Australia, benchmarking the DNSP's ICT expenditure and activities.²⁰³ KPMG found that for 2012-13 on average the surveyed businesses spent:²⁰⁴

- 7 per cent of total opex and capex on non-network ICT²⁰⁵
- 4.48 per cent of total capex on non-network ICT²⁰⁶

Applying the benchmark of 4.48 per cent to the AER's substitute capex forecast yields an ICT capex forecast of \$117.5 million for Energex. This is 65 per cent below Energex' forecast ICT capex of \$334.9 million.²⁰⁷

²⁰⁰ Energex, 2015-20 regulatory proposal, November 2014, Att. 1. QLD - RESET RIN 2015-20 - Consolidated Final CONFID.xlsx, tab'2.10 Overheads'.

²⁰¹ This is as per Energex' Cost Allocation Methodology.

²⁰² Energex, 2015-20 regulatory proposal, November 2014, Appendix 37 ICT services expenditure.pdf, p.2.

²⁰³ SAPN, Regulatory proposal, Attachment 20.31 KPMG Independent Prudence and Efficiency Review, p.68,

²⁰⁴ SAPN, Regulatory proposal, Attachment 20.31 KPMG Independent Prudence and Efficiency Review, p.70.

²⁰⁵ SAPN, Regulatory proposal, Attachment 20.31 KPMG Independent Prudence and Efficiency Review, pp.22,70.

²⁰⁶ Energex, Response to AER information request AER EGX 006, received 23 December 2014: KPMG, 2013 Utilities ICT Benchmarking, Final Report Energex, 14 March 2014. KPMG defines non-network ICT capex as 'Actual capital expenditure of non-network (non-system) IT and communications directly attributable to the replacement, installation and maintenance of IT and communication systems for Standard Control Services (excluding SCADA and network control systems)' [SAPN, Response to AER SAPN 023 IT - Q2 - KPMG Non-Network IT and Communications Benchmarking.pdf, p.6] The AER RIN definition is documented below.

²⁰⁷ The \$334.9 million consists of the \$316.0 million SPARQ ICT cost included in overheads and the \$18.9 million included in non-network IT for client devices.

In addition to this benchmarking observation, we have the following concerns regarding Energex' proposed expenditure:

- SPARQ is a related party and its costs are not market tested; and
- Energex's reporting approach to its ICT expenditure lacks complete transparency and leads to over- and under- cost recovery.

We consider each of these points below.

SPARQ's costs are not market tested

We are concerned that the SPARQ ICT costs have not been market tested. We have no evidence that this arrangement does not reflect arm's length terms but the following information does provide a starting point for further consideration at the time of our final decision. Deloitte, in reviewing the SPARQ arrangement for the AER, noted that:²⁰⁸

... ICT costs are a material source of inefficiency within Energex's and Ergon's opex ... and we estimate that so far only 4 per cent of SPARQ's costs which were passed through to Energex and Ergon in 2013-14 have been market-tested). There appear to be material savings to be made from further reforms to the relationship between the DNSPs and SPARQ, and improvements to the DNSPs' ICT systems, processes and use of the market.

The Independent Review Panel on Network Costs (the Panel) was established by the Queensland Government to develop options to address the impact of network costs on electricity prices in Queensland.²⁰⁹ The Panel assessed Energex and Ergon Energy's essential capabilities, processes and outcomes against industry benchmarks.²¹⁰

In relation to overheads more generally, the Panel found that:²¹¹

[t]he overhead expense ... of Ergon Energy and Energex is more than \$1 billion annually [and] ... has grown rapidly in recent years and places the Queensland DNSPs among the least efficient in the NEM.

The three NSPs have all commenced programs to improve the efficiency of their operations and reduce both indirect and direct costs. The Panel acknowledges that these programs will yield results but believes that additional impetus is needed to produce the level of savings required to restore affordability for customers.

²⁰⁸ Deloitte Access Economics, Queensland Distribution Network Service Providers - Opex Performance Analysis, March 2015, p. xii; Ergon Energy, Email 'RE: TRIM: AER Ergon 24 - follow up to SPARQ discussion [SEC=UNCLASSIFIED]', received 24 April 2015: AER Ergon024 Confidential SPARQ Followup Response to AER 006.pdf, question 1, p.1.

²⁰⁹ Independent Review Panel on Network Costs, Electricity Network Costs Review, Final Report, p. 107.

²¹⁰ Independent Review Panel on Network Costs, Electricity Network Costs Review, Final Report p. 107.

²¹¹ Independent Review Panel on Network Costs, Electricity Network Costs Review, Final Report p. vii.

Five of the Panel's 45 recommendations (Recommendations 12 to 16) relate to Energex and Ergon Energy's ICT:²¹²

- Return the role of the Office of the Chief Information Officer to each of the DNSPs and SPARQ Solutions focus on its role as a distributor to the DNSPs. [Recommendation 12]
- Each of the DNSPs reassess its Information Communication and Technology capital expenditure priorities and focus on the prudent capital expenditure required to maintain its core distribution business activities (including regulatory compliance and safety obligations). [Recommendation 13]
- In addition to the cost savings already identified by SPARQ Solutions, further efficiencies should be achieved through actions such as:
 - Streamlining the testing process through the adoption of an automated testing tool;
 - Developing a common set of automated financial and management reports for the DNSPs; and
 - Reviewing existing system contracts to reduce user licence costs in line with future staffing levels within SPARQ Solutions and the DNSPs. [Recommendation 14]
- Alternative service delivery models for Information and Communication Technology services currently delivered by SPARQ Solutions should be tested as follows:
 - issue market tenders for the delivery of capital projects; and
 - issue market tenders for the delivery of the relevant operational Information Communication and Technology services. [Recommendation 15]
- Implement an integrated operating model that consolidates the Planning and Partnering positions within DNSPs to minimise the number of touch points between SPARQ Solutions and the DNSPs. [Recommendation 16]

The Panel stated that one of the objectives in forming SPARQ was to realise cost savings through the joint delivery of projects to Energex and Ergon Energy.²¹³ However, the Panel submitted that there 'has been very limited delivery of joint projects to date'.²¹⁴ It also noted that there is '[i]ncongruent ICT strategic planning between Ergon Energy and Energex' and that there were 'few instances where the DNSPs have chosen to work together to minimise ICT capital costs'.²¹⁵ In relation to this the Panel recommend changes to governance.²¹⁶ The Panel stated that it 'considers that the services currently provided by SPARQ may be delivered more efficiently by external

²¹² Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report* pp. x-xi.

²¹³ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 54.

²¹⁴ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 54.

²¹⁵ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 54.

²¹⁶ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 54.

distributors'.²¹⁷ It recommended that Energex and Ergon Energy test the provision of these services by competitive tender.²¹⁸

We note that there have been some changes implemented since the Panel's final report. This includes the formation of an ICT Panel which is managed by SPARQ. However, we consider that the reforms undertaken to date do not fully reflect the IRP recommendations and have not yet significantly increased competitive pressures on SPARQ. We note that the ICT panel established by SPARQ is for tendering capital works projects, not ICT commodity services.²¹⁹ We therefore consider that SPARQ's service provision is not actually market-test, as was recommended by the Panel.

ITNewcom, engaged by SPARQ in 2013, partially identified the magnitude of savings that could be realised through outsourcing. For the costs it examined, it found that there was potential to realise significantly greater cost reductions by outsourcing.²²⁰ We note that ITNewcom only made recommendations in relation to application and infrastructure services.²²¹ No recommendations relating to telecommunications, Data centre and Service Desk costs were made.

Energex's reporting approach

Energex should consider increasing the transparency by adopting the approach outlined below or otherwise provide us with information as to the trend in actual ICT capex as incurred by SPARQ as part of its revised proposal for the reasons set out below.

We consider that Energex has not correctly captured the SPARQ costs in reporting its ICT costs as overheads expenditure. We consider that the SPARQ costs would most accurately and transparently be captured as 'Non-Network—IT & Communications Expenditure'. By definition this is 'all non-network expenditure directly attributable to IT and communications assets including replacement, installation, operation, maintenance, licensing, and leasing costs but excluding all costs associated with SCADA and Network Control Expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices'.²²² Capturing the ICT costs as non-network costs would provide for consistent comparison against other businesses and for comparison of the business' own-trend expenditure.

²¹⁷ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 54.

²¹⁸ Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 54.

²¹⁹ Ergon Energy, Email 'RE: TRIM: AER Ergon 24 - follow up to SPARQ discussion [SEC=UNCLASSIFIED]', received 24 April 2015: AER_Ergon024_Confidential_SPARQ_Followup_Response_to_AER_006.pdf, question 1, p.2; AER_Ergon024_SPARQ_Confidential Attachment.pdf, pp.6, 10

²²⁰ Ergon Energy, Email 'RE: TRIM: AER Ergon 24 - follow up to SPARQ discussion [SEC=UNCLASSIFIED]', received 24 April 2015: AER_Ergon024_Confidential_SPARQ_Followup_Response_to_AER_006.pdf, p. 2; AER_Ergon024_SPARQ_Confidential Attachment, p.9.

²²¹ Ergon Energy, Email 'RE: TRIM: AER Ergon 24 - follow up to SPARQ discussion [SEC=UNCLASSIFIED]', received 24 April 2015: AER_Ergon024_Confidential_SPARQ_Followup_Response_to_AER_006.pdf, p. 2; AER_Ergon024_SPARQ_Confidential Attachment, pp.7-8.

²²² AER, Regulatory Information Notice, issued 25 August 2014, p. 105.

In addition, we note that the off balance sheet treatment of ICT expenditure by Energex and Ergon Energy means that it is difficult to assess the trend in actual ICT capex, as incurred by SPARQ. We are presented with an asset services fee, which reflects a combination of depreciation from ICT capex incurred in past regulatory periods, depreciation from ICT capex proposed for the 2015-18 regulatory period, plus finance costs for the residual ICT asset value from past and proposed expenditure.

By contrast, if these respective ICT assets were reflected in Energex and Ergon Energy's regulatory asset balance (RAB), this would lead to greater transparency. We consider that this would be possible because SPARQ is a joint operation of Energex and Ergon Energy. We understand that Energex and Ergon Energy have rights to the assets of SPARQ and obligations for the liabilities. In particular, Energex and Ergon have rights to substantially all of the economic benefits of SPARQ as they are its only customers. SPARQ also relies upon Energex and Ergon Energy for the settling of its liabilities, and the funding required for working capital as well as asset loans.¹ Hence, this arrangement should be directly translated to Energex and Ergon Energy's respective RAB for regulatory assessment purposes.

The other reason that Energex may wish to reconsider its reporting approach is that this arrangement has implications for the over- or under- recovery of expenditure. This may impact upon our consideration of its revised proposal, as explained below.

Energex proposed applying a significantly higher WACC than that in our preliminary decision for calculating the finance costs for the assets held by SPARQ for the 2015-20 regulatory control period (where these costs are passed through to Energex as part of the asset services fee).²²³

However, this is likely to result in over- or under- recovery of the return on the SPARQ ICT assets. A mismatch is created between the rate of return that would have applied if the asset was recognised directly in the Energex RAB and that which is applied under the SPARQ ICT asset loan agreement. That is, the finance 'cost pass through' to Energex by SPARQ as part of the asset services fee. The mismatch is created because:

- the WACC will update annually under the application of our cost of debt approach (see attachment 3). That is, it will not be static across the regulatory control period.
- we have proposed a different WACC to that proposed by Energex. We have calculated an initial WACC of 5.85 per cent - significantly lower than the WACC Energex proposed to be applied by SPARQ.

Given the magnitude of the ICT costs, the over- and under- recovery is material in 2015-16 and likely to be increasingly material as the regulatory period progresses.

A further mismatch is presented where there is a difference between the depreciation rate assumed by SPARQ and that assumed by Energex.

²²³ Energex, Response to information request AER Energex 55, received 17 April 2015, p.1.

There is no reason to suggest that the over- and under- recoveries will be symmetrical over time.

B.7 Demand management

Demand management refers to non-network strategies 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).

The current incentive frameworks and obligations in the NER are designed to encourage distributors to make efficient investment and expenditure decisions. However, the NER recognises that the planning and investment framework and the incentive regulation structure may not be sufficient by themselves to remove any bias towards network capital investment over non-network responses.

As such, the NER set out that distributors should examine non-network alternatives when developing network investments through the regulatory investment test for distribution (RIT-D) process. The RIT-D requires distribution network businesses to consult with stakeholders on the need for new capex projects and consider all credible network and non-network options as part of their planning processes. Its aim is to create a level playing field for the assessment of non-network options, such as demand-side management, against network options.

The NER also require us to consider the extent to which a business has considered efficient and prudent non-network alternatives in our assessment of capex proposals.²²⁴ In addition, the NER require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to network solutions. As set out in our demand management incentive scheme attachment (attachment 12), we are continuing Energex's demand management innovation allowance.

B.7.1 Position

Our preliminary decision is that it is most appropriate to rely on the incentive framework, together with the requirements in the RIT-D and the distribution Annual Planning Report, to drive the efficient use of demand management. The benefits of

²²⁴ NER, clause 6.5.7(3)(10)

capex deferral would be shared with consumers through the Capital Expenditure Sharing Scheme (CESS).

Accordingly, our alternative estimate of required capex does not include a generic reduction to overall system capex for potential for deferred capital needs through the use of demand management initiatives.

Our preliminary decision not to include a generic capex offset for possible future demand management activities does not impact on our consideration of the business cases for specific demand management proposals, or the consideration of non-network alternatives within the RIT-D process. Where a specific capex/opex trade-off can be shown to meet the capex and opex criteria we will include the amounts in the forecasts. This approach is consistent with the capital expenditure factor that requires us to have regard to the extent to which the distributor has considered, and made provision for, efficient and prudent non-network alternatives.²²⁵ Indeed, as set out in the opex attachment (Attachment 7), we consider Energex's Bromelton project which provides an annual deferral benefit of \$2.7 million per annum at a cost of \$5.8 million (\$2013–14) over the 2015–20 regulatory control period is an efficient capex/opex trade-off.²²⁶

B.7.2 Energex's proposal on demand management

Energex proposed \$95.3 million (\$2014–15) in opex for its 2015–20 demand management programs. Our consideration of Energex's opex proposals for broad-based and other specific demand management programs is included in the opex attachment (Attachment 7).

B.7.3 Reasons for preliminary decision

Distributors are required to transparently consider non-network alternatives through the RIT-D process. Through the RIT-D process and other initiatives developed as part of the demand management innovation allowance, it is expected that some amount of system capex currently in the forecast will be efficiently deferred. We are therefore considering whether it is appropriate to estimate the amount of capex that may be efficiently deferred through the use of demand management initiatives and explicitly reduce the capex forecast by this amount.

If we were to include an additional generic reduction to system capex to take account of the potential for capex deferrals, we would also need to assess the efficient opex required to support this capex offset. Given that we do not currently have actual expenditure data from which to accurately calculate a capex/opex trade-off, our preliminary decision is to not include an explicit reference in the capex or opex forecasts for broad based demand management activities.

²²⁵ NER, cl. 6.5.7(e)(10).

²²⁶ Energex, Response to AER information request EGX 010, p. 12.

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.

C Demand

This attachment sets out our observations of demand trends in Energex's network for the 2015–20 regulatory control period.²²⁷

Demand forecasts are fundamental to estimating an NSP's capex and opex, and to the AER's assessment of that forecast expenditure.²²⁸ Energex must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. The expected growth in demand is an important factor driving network augmentation expenditure and connections expenditure (growth capex). Energex uses demand forecasts in conjunction with network planning to determine the amount and timing of such expenditure. Energex also incurs opex in relation to the new assets it builds to meet demand.

This attachment considers demand forecasts in Energex's network at the system level. 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. Conversely, forecasts of stagnant or falling system demand generally signal a decreased requirement for growth capex.²²⁹ Accurate and 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 2015–20 regulatory control period.

Appendix B discussed this analysis in more detail.

C.1 AER position on system demand trends

We are satisfied the system demand forecasts in Energex's regulatory proposal for the 2015–20 regulatory control period reasonably reflects a realistic expectation of demand.²³⁰ However, in our final decision will take into account the updated forecasts from the Australian Energy Market Operator (AEMO) that are scheduled to be published by July 2015.

²²⁷ In this attachment, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated.

²²⁸ NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

²²⁹ Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.

²³⁰ NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

We consider the forecasts in our decisions should reflect the most current expectations of the forecast period. Hence, we will consider updated demand forecasts and other information in the final decision to reflect the most up to date data. We expect Energex's proposal for our final decision will provide revised forecasts as well as further information on the reconciliation of these forecasts with their own zone-substation forecasts

The demand forecasts in Energex's regulatory proposal for the 2015–20 period are considerably lower than previous forecasts. Energex has progressively downgraded its demand forecasts since its regulatory proposal for the 2010–15 regulatory control period.²³¹ As we would expect, one result of this trend is the significant reduction in Energex's augex forecast for the 2015–20 period compared to the 2010–15 regulatory control period (see appendix A).

As we set out below, in our final decision we will take account of the updated AEMO forecasts that are due by July 2015. We expect that Energex's proposal for our final decision will take account of these revised forecasts and provide further information on the reconciliation of these forecasts with their own zone-substation forecasts.

However, we also recognise that significant reductions have been imposed on the spatial demand forecasts to take account of the top-down system-wide forecast. As such, pending the AEMO's updated demand forecasts that are due in July 2015, we are satisfied that on current forecasts, system demand forecasts in Energex's regulatory proposal for the 2015–20 regulatory control period reasonably reflect a realistic expectation of demand.

Several stakeholders raised concerns that Energex is still using overly conservative demand forecasts as inputs to their regulatory proposals. AGL believes Energex's maximum demand forecasts are aggressive and is more comparable with AEMO's 10 per cent PoE forecast.²³² We note however that stakeholders generally provided qualitative evidence, and did not suggest specific demand figures.

C.2 AER approach

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

- Energex's regulatory proposal
- Regional forecasts from AEMO where available
- stakeholder submissions in response to Energex's regulatory proposal (as well as submissions made in relation to the Queensland distribution determinations more generally).

²³¹ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 89.

²³² AGL, submission to the Australian Energy Regulator 30 January 2015.

C.3 Energex's proposal

Energex provided historical and forecast demand figures in its proposal and in the reset RINs.²³³ Energex has forecast an average annual growth in peak demand of around 0.2 per cent in the 2015–20 regulatory control period. This is broadly consistent with its growth in peak demand at the end of the 2010-15 period (Figure C-1). This contrasts with its experience from 2010–11 to 2014–15, when Energex experienced a decline in peak demand of approximately 1.1 per cent per annum due to suppressed economic conditions, milder weather and changes in customer behaviour.

Figure C-1 Energex maximum demand (summer)

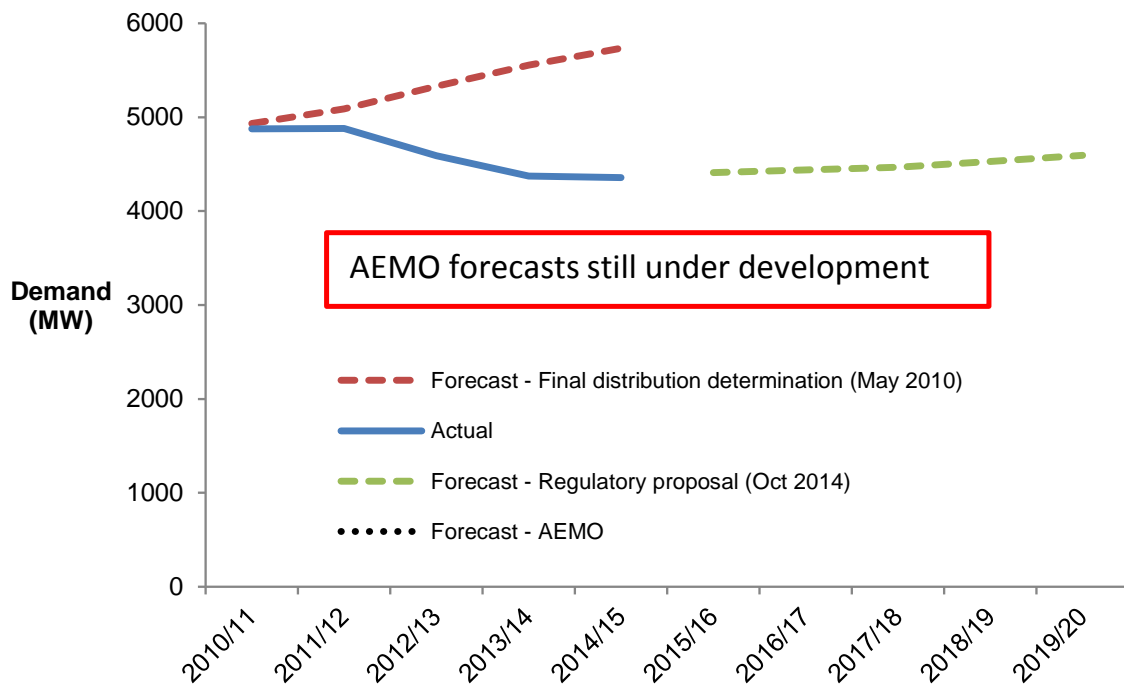


Table C-1 Maximum system demand (summer) - Weather corrected (50% PoE) (MW)

	2015-16	2016-17	2017-18	2018-19	2019-20	Average annual growth (2015-20)
Regulatory proposal (October 2014)	4 411	4 437	4 465	4 527	4 593	0.21%

Source: Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 89.

Energex's substation maximum demand forecasts incorporate:

²³³ Energex, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, p. 89.

- weather-corrected starting demand
- growth rates
- block loads
- load transfers, and
- demand management reductions.
- Energex’s forecast system maximum demand for the 2015-20 regulatory control period is based on the latest available data following the 2013 winter and 2013-14 summer season.

Energex uses a bottom-up forecast for each individual zone substation (i.e. spatial forecasts) based on its knowledge and understanding of its customer base and its assessments of future growth in the communities supplied from each zone substation. Energex’s forecasts are then aggregated to a system total, and reconciled to a system maximum demand forecast.²³⁴

Energex adjusts the aggregated zone substation (spatial) forecasts to reconcile to the system maximum demand forecast. At an onsite meeting conducted by the EMCa, Energex advised that it decreased its spatial forecasts (except to the extent of maintaining future demand from “block” loads) by around 10 per cent, prior to submitting its system demand forecasts as part of the regulatory proposal.

We acknowledge that Energex has incorporated some of the changes in the demand forecasting methodology recommended by the AER during the regulatory determination process for the 2010–2015 period. The framework used by Energex was recommended by ACIL Tasman consultants.

Energex provided an independent review of its peak demand model by Frontier Economics. Frontier Economics concluded that Energex’s peak system demand forecasting model meets AER’s criteria for good forecasting methodology. Frontier Economics recommended the use of additional test parameters in future versions of Energex’s Forecast Guidelines.

Both the EUAA and the CCP submit that previous poor forecasting of demand has had a negative impact on customers.²³⁵ Furthermore, these submissions encouraged us to interrogate the forecasts of demand to ensure that they reflect declines in maximum demand arising from:

- reduced energy use in response to higher electricity prices
- increased uptake of solar photo-voltaic systems

²³⁴ EMCa, Review of Proposed Network Augmentation and Replacement Capital Expenditure in Energex’s Regulatory Proposal 2015-2020, 20 April 2015, pg. 44

²³⁵ EUAA, Submission on Energex’s regulatory proposal, p. 19; CCP, Submission on Energex’s regulatory proposal, p. 13.

- subdued economic growth and weaker electricity demand from the manufacturing sector.²³⁶

The submissions call for us to adopt demand forecasts which reflects AEMO's flat demand outlook where it is expected that the record peak demand experienced in 2009 will not be reached again until after 2020.²³⁷ As noted previously, our final decision will take account of the most recent AEMO forecasts that are due by July 2015.

C.4 AEMO forecasts

AEMO is scheduled to release a Transmission Connection Point (CP) Forecasting Report for Queensland by July 2015. Our final decision will take these updated CP forecasts into account. We expect that Energex's revocation and substitution of our preliminary decision will take account of these revised forecasts and provide further information on the reconciliation of these forecasts with their own zone-substation forecasts.

²³⁶ CCP, Submission on Energex's 's regulatory proposal, p. 13.

²³⁷ CCP, Submission on Energex's regulatory proposal, p. 13; EUAA, Submission on Energex's regulatory proposal, p. 19.

D Real material cost escalation

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

D.1 Position

We are not satisfied that Energex'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 2015–20 regulatory period.²³⁸ We consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria including that it is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2015–20 regulatory 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 Energex provide network services
- there is little evidence to support how accurately Energex's materials escalation model forecasts reasonably reflect changes in prices paid by Energex for physical assets in the past and by which we can assess the reliability and accuracy of its forecast materials model. Without this supporting evidence, it is difficult to assess the accuracy and reliability of Energex's material input cost escalators model as a predictor of the prices of the assets used by Energex to provide network services, and
- Energex 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 Energex.

Our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to Energex's standard control services capital expenditure. We consider that labour and construction cost escalation as proposed by Energex is likely to more reasonably reflect a realistic expectation of

²³⁸ NER, cl. 6.5.7(a).

the cost inputs required to achieve the capex criteria given these are direct inputs into the cost of providing network services.²³⁹

D.2 Energex's proposal

Energex applied cost escalators to reflect changes in labour, materials and contractors.²⁴⁰ Energex engaged consultants Jacobs SKM to provide advice and recommendations regarding appropriate escalation rates.²⁴¹ Real cost escalation indices for the following material cost drivers were calculated for Energex by Jacobs SKM:²⁴²

- aluminium
- copper
- steel,
- oil
- wood and
- construction costs.

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

Table D-1 Energex's real materials cost escalation forecast—inputs (real indices)

	2015–16	2016–17	2017–18	2018–19	2019–20
Aluminium	1.041	1.023	1.019	1.019	1.023
Copper	0.990	0.991	0.999	1.001	1.006
Steel	1.009	0.982	0.996	1.003	1.010
Oil	0.920	0.995	0.982	0.990	1.012
Wood	1.000	1.000	1.000	1.000	1.000
Construction Cost Index ¹	1.022	1.022	1.021	1.021	1.021
Trade weighted Index	1.000	1.000	1.000	1.000	1.000

Source: Energex, *2015-20 regulatory proposal, Appendix 20 Material cost escalation factors Jacobs SKM*, p. 31, November 2014.

²³⁹ NER, clause 6.5.7(c)(3).

²⁴⁰ Energex, *2015-20 regulatory proposal*, November 2014, p. 108.

²⁴¹ Energex, *2015-20 regulatory proposal*, November 2014, p. 108 and *Appendix 20 Material cost escalation factors Jacobs SKM and Appendix 35 Cost escalation rates and application*.

²⁴² Energex, *2015-20 regulatory proposal, Appendix 20 Material cost escalation factors Jacobs SKM*, p. 31, November 2014.

¹ Nominal cost escalation.

Jacobs SKM stated that in order to aggregate the input cost drivers for Energex's network asset categories, it assigned appropriate weightings for the relative contribution of each of the input cost drivers and economic indicator to each asset category.²⁴³ Table D-2 shows the real annual material cost escalation indices based on the movements in underlying cost drivers and economic indicators derived by Jacobs SKM, aggregated at the common standard asset class level used by Energex.

Table D-2 Real annual cost escalation of Energex's asset categories

	2015–16	2016–17	2017–18	2018–19	2019–20
Cost driver					
Overhead Subtransmission Lines	1.014	1.005	1.008	1.010	1.014
Underground Subtransmission Cables	0.993	1.000	1.002	1.003	1.007
Overhead Distribution Lines	1.000	0.998	1.000	1.003	1.008
Underground Distribution Cables	1.000	1.006	1.004	1.005	1.009
Distribution Equipment	0.995	0.998	0.999	1.000	1.004
Substation Bays	1.001	1.004	1.004	1.005	1.008
Substation Establishment	1.022	1.022	1.021	1.021	1.021
Distribution Substation Switchgear	0.995	0.998	0.999	1.000	1.004
Zone Transformers	0.997	0.996	0.999	1.002	1.007
Distribution Transformers	1.000	1.000	1.002	1.004	1.008
Low Voltage Services	1.021	1.010	1.009	1.010	1.013
Metering	0.992	0.999	0.998	0.999	1.002
Communications - Pilot Wires	1.000	1.000	1.000	1.000	1.000
Street Lighting	0.998	0.998	0.999	1.000	1.001
Control Centre - SCADA	1.000	1.000	1.000	1.000	1.000
System Buildings	1.022	1.022	1.021	1.021	1.021

Source: Energex, 2015-20 regulatory proposal, Appendix 20 Material cost escalation factors Jacobs SKM, p. 2, November 2014.

²⁴³ Energex, 2015-20 regulatory proposal, Appendix 20 Material cost escalation factors Jacobs SKM, p. 1, November 2014.

D.3 Assessment approach

We assessed Energex's proposed real material cost escalators for the purpose of assessing its proposed total capex forecast against the NER requirements. We must accept Energex's capex forecast if we are satisfied it reasonably reflects the capex criteria.²⁴⁴ Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.²⁴⁵

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.²⁴⁶ In the Expenditure Guideline Explanatory Statement we stated that we had seen limited evidence to demonstrate that the commodity input weightings used by distributors to generate a forecast of the cost of material inputs have produced unbiased forecasts of the costs the distributors paid for manufactured materials.²⁴⁷ 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.²⁴⁸ As a result, the price of manufactured network materials may not be well correlated with raw material input costs. We expect distributors 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 Energex's proposed material cost escalation, we:

- reviewed the Jacobs SKM report commissioned by Energex²⁴⁹
- reviewed the materials input cost approach used by Energex; and
- reviewed the approach to forecasting manufactured material costs in the context of electricity distributors mitigating such costs and producing unbiased forecasts.
- considered submissions on this issue.

D.4 Reasons

We are not satisfied that Energex's forecast is based on a sound and robust methodology for the reasons outlined below. We therefore consider that it does not reasonably reflect the capex criteria.²⁵⁰ This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the

²⁴⁴ NER, cl. 6.5.7(c).

²⁴⁵ NER, cl. 6.5.7(c)(3).

²⁴⁶ AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, pp. 50-51.

²⁴⁷ AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

²⁴⁸ AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

²⁴⁹ Energex, *2015-20 regulatory proposal*, November 2014, *Appendix 20 Material cost escalation factors Jacobs SKM*.

²⁵⁰ NER, cl. 6.5.7(c).

capex objectives.²⁵¹ Accordingly, we have not accepted it as part of our alternative estimate in our preliminary 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 costs

Energex's materials input cost proposal does not demonstrate how and to what extent material inputs have affected the cost of inputs such as cables and transformers. In particular, it has provided no supporting evidence to substantiate how accurately Energex'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 that distributors demonstrate that their proposed approach to forecast materials cost changes reasonably reflected the change in prices they paid for physical inputs in the past. Energex's proposal does not include supporting data or information which demonstrates movements or interlinkages between changes in the input prices of commodities and the prices Energex paid for physical inputs. Energex's material cost input proposal assumes a weighting of commodity inputs for each asset class but does not provide information which explains the basis for the weightings or that the weightings applied have produced unbiased forecasts of the costs of Energex's assets. For these reasons, there is no basis on which we can conclude that the forecasts are reliable.

Materials input cost forecasting

Energex 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 related to capital expenditure. The consultants have adopted a high level approach hypothesising a relationship between these commodity inputs and the physical assets purchased by Energex. Neither the consultants' reports nor Energex have adequately explained or quantified 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 distributors to provide network services. Energex 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,

²⁵¹ NER, cl. 6.5.7(c)(3).

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 Energex to mitigate the magnitude of any overall input cost increases. This could be achieved by:

- potential commodity input substitution by the electricity distributor 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 distributor's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. We do 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 distributor²⁵²

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.²⁵³ For example, Energex has not demonstrated whether there are any opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs
- the scale of any operation change to the electricity distributor'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 Energex in forecasting its capex requirements.

By discounting the possibility of commodity input substitution throughout the 2015-2020 regulatory 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.

²⁵² NER, cl. 6.5.7(e)(7).

²⁵³ NER, cl. 6.5.7(e)(6).

Forecasting uncertainty

The NER requires that an electricity distributor's forecast capital expenditure reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.²⁵⁴ 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 worse²⁵⁵
- 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;²⁵⁶ 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.²⁵⁷

Strategic contracts with suppliers

We consider that electricity distributors 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 distributor to the supplier, where a real escalation is then factored into forecast capex. In considering the substitution

²⁵⁴ NER, cl. 6.5.7(c)(3).

²⁵⁵ 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.

²⁵⁶ 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.

²⁵⁷ 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.

possibilities between operating and capital expenditure,²⁵⁸ we note that it is open to an electricity distributor 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 distributors to manage their capex efficiently, and may instead incentivise electricity distributors 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.²⁵⁹ 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 Energex as part of this decision.²⁶⁰

Selection of commodity inputs

The limited number of material inputs included in Energex's material input escalation may not be representative of the full set of inputs or input choices impacting on changes in the prices of assets purchased by Energex. Energex's materials input costs may also be biased to the extent that they may include a selective subset of commodities that are forecast to increase in price during the 2015-2020 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 distributors. 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.5 Review of consultant's reports

A number of businesses we are currently undertaking an assessment of their revenue requirements have included reports on material cost escalation in their submission. A number of these businesses²⁶¹ have commissioned reports by Competition Economists Group (CEG).²⁶² We have also received submissions from TransGrid and Jemena Gas Networks that included consultant's reports on materials escalation from SKM and BIS Shrapnel respectively. We have considered the relevance of these submissions to the

²⁵⁸ NER, cl. 6.5.7(e)(7).

²⁵⁹ NEL, s. 7.

²⁶⁰ NER, cl. 6.5.7(e)(8).

²⁶¹ Including ActewAGL, Ausgrid, Essential Energy, SAPN and TasNetworks.

²⁶² CEG, *Escalation factors affecting expenditure forecasts*, December 2013 and CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014.

issues relevant for Energex in order to arrive at a position that takes into account all available information. Our views on these reports are set out below. Overall, these reports lend further support to our position to not accept Energex's proposed materials cost escalation.

CEG report commissioned by SAPN

- CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets.²⁶³

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.

- In respect of forecasting electricity distributors future costs, CEG stated that.²⁶⁴

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 distributors future input costs.

- 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.²⁶⁵

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

²⁶³ CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014, pp. 5-6.

²⁶⁴ CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014, p.11.

²⁶⁵ CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014, p. 13.

specifications of the LME but that there is not necessarily a 'one-for-one' relationship between these prices and the price paid for copper equipment by manufacturers.²⁶⁶ For steel futures, CEG stated that the steel used by electricity distributors 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 distributors.²⁶⁷

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.

- 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.²⁶⁸ 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 whilst aluminium and crude oil prices were forecast to rise significantly compared to the historical trend.

CEG report commissioned by ActewAGL, Ausgrid, Endeavour Energy, Essential Energy and TasNetworks

CEG was commissioned by Ausgrid, Endeavour Energy, Essential Energy, ActewAGL and TasNetworks to estimate cost escalation factors.²⁶⁹ In its report to these distributors, CEG has provided further information to support our position to not accept Energex's proposed materials cost escalation.

- 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 distributors or their suppliers separate from material inputs (e.g. energy costs and equipment leases etc.).²⁷⁰ This is consistent with the Post-tax Revenue Model (PTRM) which reflects at least in part movements in an electricity distributor'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.²⁷¹ 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 material input cost assessment used by Energex.

²⁶⁶ CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014, p. 13.

²⁶⁷ CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014, p. 16.

²⁶⁸ CEG *Materials cost escalation factors: a report for SA Power Networks*, August 2014, pp. 15, 17 and 20.

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

²⁷⁰ CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.

²⁷¹ CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4-5.

- Figures 1 and 2 of CEG's report respectively show the variance between aluminium and copper prices predicted by the London Metals Exchange (LME) 3 month, 15 month and 27 month futures less actual prices between July 1993 and December 2013.²⁷² 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.

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.²⁷³ 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 Energex's material input costs.
- 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.²⁷⁴
- 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.²⁷⁵ This is consistent with our view that longer term historical commodity prices should be considered when reviewing and forecasting future prices. In general, we consider that long term historical data has a greater number of observations and as a consequence is a more reliable predictor of future prices than a data time series of fewer observations.
- SKM stated that the future price position from the LME futures contracts for copper and aluminium are only available for three years out to December 2016 and that in order to estimate prices beyond this data point, it is necessary to revert to economic forecasts as the most robust source of future price expectations.²⁷⁶ SKM

²⁷² CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5-6.

²⁷³ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.

²⁷⁴ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.

²⁷⁵ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.

²⁷⁶ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.

also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.²⁷⁷

- 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.²⁷⁸ SKM selected Consensus Economics forecasts as the best currently available outlook for oil prices throughout the duration of the next regulatory control period.²⁷⁹ 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 distributor 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-2018²⁸⁰. This is significantly lower than the exchange rate forecasts by SKM of between US\$0.91 to US\$0.85 from 2014-15 to 2018-19.²⁸¹ 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 2023.²⁸² BIS Shrapnel stated that exchange rate forecasts are not authoritative over the long term.²⁸³

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.²⁸⁴ 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 distributor's broad range of inputs are escalated annually by the CPI.

²⁷⁷ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p.16.

²⁷⁸ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.

²⁷⁹ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.

²⁸⁰ BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 6.

²⁸¹ SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.

²⁸² SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 9.

²⁸³ BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A-7.

²⁸⁴ BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 48.

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.

Table D-3 Real material input cost escalation forecasts (per cent)

	2015–16 (%)	2016–17 (%)	2017–18 (%)	2018–19 (%)	2019–20 (%)
Aluminium					
CEG	2.9	2.1	1.7	1.5	1.5
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 5.6	3.09 to 3.9	1.5 to 11.0	-6.5 to 1.5
Copper					
CEG	-0.9	-1.0	-0.2	-0.3	-0.2
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 0.17	-1.15 to 0.3	-0.3 to 9.3	-8.7 to -0.2
Steel					
CEG	3.1	0.5	0.1	0.0	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)	2.84 to 5.1	1.0 to 2.45	-0.35 to 0.1	0.3 to 8.0	0.1 to -8.9
Oil					
CEG	1.6	1.3	1.1	1.0	1.1
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 1.6	-1.1 to 1.3	-0.2 to 1.1	1.85 to 6.5	-6.2 to 1.1

Source: SAPN, Revenue proposal, Attachment 20.3, CEG Materials cost escalation factors: a report for SA Power Networks, August 2014, pp. 15, 17, and 19, 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.²⁸⁵

²⁸⁵ 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.²⁸⁶

As Table D-3 shows, there is considerable variation between the consultant's commodities escalation forecasts. The greatest margin of variation is 9.6 per cent for copper in 2018-19, where CEG has forecast a real price decrease of 0.3 per cent and BIS Shrapnel a real price increase of 9.3 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 distributors to provide network services. This supports our view that Energex'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 2015–20 regulatory control period.²⁸⁷

D.6 Conclusions on materials cost escalation

We are not satisfied that Energex 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, Energex 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 reports to electricity distributors, identified a number of factors which are consistent with our view that Energex's input costs proposal has not demonstrated how and to what extent material inputs are likely to affect the cost of assets. CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.²⁸⁸ 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.²⁸⁹

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.

²⁸⁶ BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. iii.

²⁸⁷ NER, clause 6.5.7(a).

²⁸⁸ CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

²⁸⁹ CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

We are not satisfied that a forecast of real cost escalation for materials is robust. We consider that in the absence of a robust alternative forecast, then real cost escalation should not be applied in determining a distributor'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 Energex to provide network services.

In previous AER decisions, namely our Final Decisions for Envestra's Queensland and South Australian networks, we took a similar approach. This was on the basis that as all of Envestra's real costs are escalated annually by CPI under its tariff variation mechanism, CPI must inform the AER's underlying assumptions about Envestra's overall input costs. Consistent with this, we applied zero real cost escalation and by default Envestra's input costs were escalated by CPI in the absence of a viable and robust alternative. Likewise, for Energex 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 distributor should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services.²⁹⁰

D.7 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.²⁹¹ We consider that real labour and construction cost escalators can be more reliably and robustly forecast than material input cost escalators, in part because these are not intermediate inputs and for labour escalators, productivity improvements have been factored into the analysis (refer to the opex attachment).

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

²⁹⁰ NEL, s. 7(2).

²⁹¹ NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

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

E Predictive modelling approach and scenarios

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

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

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

E.1 Predictive modelling techniques

In late 2012 the AEMC published changes to the National Electricity and National Gas Rules.²⁹² 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.²⁹³

The expenditure forecast assessment Guideline (Guideline) describes our approach, assessment techniques and information requirements for setting efficient expenditure allowances for distributors.²⁹⁴ 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.²⁹⁵

The technical underpinnings of the repex model are discussed in detail in the Replacement expenditure model handbook.²⁹⁶ 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

²⁹² AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

²⁹³ See AER *Better regulation reform program* web page at <http://www.aer.gov.au/Better-regulation-reform-program>.

²⁹⁴ AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013; AER, *Expenditure Forecast Assessment Guideline for Electricity Transmission*, November 2013.

²⁹⁵ AER Determinations for 2011–15 for CitiPower, Jemena, Powercor, SP AusNet, and United Energy.

²⁹⁶ AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

replacement life benchmarking across all distribution businesses in the NEM. These processes are described below.

E.2 Data specification process

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

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

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 requested the same historical asset data for use in our repex modelling. The Reset RIN also collected data corresponding to the distributors proposed forecast repex over the 2015–20 regulatory control period. In both RINs, the templates relevant to repex are sheets 2.2 and 5.2.

For background, we note that in past determinations, our RINs did not specify standardised network asset subcategories for distributors to report against. Instead, we required the distributors to provide us data that adhered to broad network asset groups (e.g. poles, overhead conductors etc.). This allowed the distributor discretion as to how its assets were subcategorised within these groups. The limited prescription over asset types meant that drawing meaningful comparisons of unit costs and replacement lives across distributors was difficult.²⁹⁷

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.²⁹⁸

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

²⁹⁷ 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.

²⁹⁸ NER, cl. 6.5.7(e)(6).

with stakeholders, including a series of workshops, bilateral meetings and submissions on data templates and draft RINs.²⁹⁹

E.3 Data collection and refinement

The new RINs represent a shift in the data reporting obligations on distributors. Given this is the first period in which the distributors have had to respond to the new RINs, we undertook regular consultation with the distributors. This consultation involved collaborative and iterative efforts to refine the datasets to better align the data with what the AER requires to deploy our assessment techniques. 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 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.³⁰⁰

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

E.4 Benchmarking repex asset data

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

²⁹⁹ See AER *Expenditure forecast assessment guideline—Regulatory information notices for category analysis* webpage at <http://www.aer.gov.au/node/21843>.

³⁰⁰ NER, cl. 6.9.1.

- 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,³⁰¹ we compared their data to the data from all NEM distributors. We did this by using the reported expenditure and replacement volume data to derive benchmark unit costs for the standardised network asset categories. We also derived benchmark replacement lives (the mean and standard deviation of each asset's replacement life) for the standardised network asset categories.

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

E.4.1 Benchmark data for each asset category

For each standardised network asset category where distributors provided data we constructed three sets of data from which we derived the following three sets of benchmarks:³⁰²

- benchmark unit costs
- 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 using the CPI index.³⁰³

³⁰¹ NSW, ACT, SA and QLD distribution network service providers—Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, SA Power Networks, Energex and Ergon Energy.

³⁰² 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.

³⁰³ We took into account whether the distributor reported on calendar or financial year basis.

We then calculated a single unit cost. We did this by first weighting the 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. To differentiate the two sets of benchmarked replacement lives, we refer to the benchmarks based on the calibration process as 'benchmark calibrated replacement lives' and the those based on replacement lives reported by the NEM distributors as 'benchmark uncalibrated replacement lives'. 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:³⁰⁴

- 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:
 - benchmark average unit cost

³⁰⁴ For the benchmarked calibrated 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 led 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 replacement lives above 90 years. Although the repex model can generate these large lives, observations of more than 90 years exceed the number of years reportable in the asset age profile.

- 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 (below the mean)
 - benchmark third quartile uncalibrated mean replacement life (above the mean)
 - benchmark third quartile calibrated mean replacement life (above the mean).
- 'Best' value:
 - benchmark best (lowest) unit cost
 - benchmark best (highest) uncalibrated mean replacement life
 - benchmark best (highest) calibrated mean replacement life.³⁰⁵

E.5 Repex model scenarios

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

The asset age profile data provided by the distributors is a fixed piece of data. That is, it is set, and not open to interpretation or subject to scenario testing.³⁰⁶ 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.³⁰⁷ They are:

³⁰⁵ 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.

³⁰⁶ It has been necessary for some distributors to make assumptions on the asset age profile to remove double counting. This is detailed at the end of this appendix.

³⁰⁷ AER, *Electricity network service providers, Replacement expenditure model handbook*, November 2013.

- (1) The Base scenario – the base scenario uses inputs provided by the distributor in their RIN response. Each distributor provided average replacement life data as part of this response. As the distributors did not explicitly provide an estimate of their unit cost, we have used the observed historical unit cost from the last five years and the forecast unit cost from the upcoming regulatory control period in the base scenario.
- (2) The Calibrated scenario – the process of “calibrating” the expected replacement lives in the repex model is described in the AER’s replacement expenditure handbook.³⁰⁸ The calibration involves determining a replacement life and standard deviation that matches the distributor's recent historical level of replacement (in this case, the five years from 2010–11 to 2014–15). The calibrated scenario benchmarks the business to its own observed historical replacement practices.
- (3) The Benchmarked scenarios – the benchmarked scenarios use 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 or third quartile” and “best performer” for each repex category, so there is no single "benchmark" scenario, but a series of scenarios giving a range of different outputs.

The model also takes account of different wooden pole staking/stobie pole plating rate assumptions (see section E.3 for more information on this process). A full list of the scenario outcomes is provided in Figure E-1 and Figure E-2 below.

Figure E-1 Repex model outputs – replacement lives

Replacement lives	
Base case (RIN)	\$1,314,013.23
Calibrated lives	\$472,650.38
Benchmarked uncalibrated average	\$1,248,174.44
Benchmarked uncalibrated third quartile	\$971,642.19
Benchmarked uncalibrated best	\$830,919.34
Benchmarked calibrated average	\$358,336.92
Benchmarked calibrated third quartile	\$272,558.73
Benchmarked calibrated best	\$208,061.41

Source: AER analysis, using historic unit cost

³⁰⁸ AER, Electricity network service providers, Replacement expenditure model handbook, November 2013, pp. 20–21.

Figure E-2 Repex model outputs – unit costs

Unit cost	
Benchmarked average	\$694,081.55
Benchmarked first quartile	\$473,586.15
Benchmarked best	\$327,274.08

Source: AER analysis, using calibrated replacement lives.

Data assumptions

Certain data points were not available for use in the model. For unit costs, this arose either because the distributor did incur any expenditure on an asset category in the 2010–15 regulatory control period (used to derive historical unit costs) or had not proposed any expenditure in the 2015–20 regulatory control 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 distributor did not replace any assets during the 2010–15 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 calibrated replacement life of the broad asset group to which the asset subcategory belonged. Where this was not available, we used the benchmarked calibrated replacement life or the base case replacement life from the distributor.

Un-modelled 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 it is related to expenditure on overall pole replacement and modelling may result in double counting of replacement volumes. Other excluded categories are detailed in appendix A.3 of this preliminary decision.

E.6 The treatment of staked wooden poles and plated stobie 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.³⁰⁹ The practice has been adopted by distributors as a low-cost option to extend the life of a wooden pole. These assets require special consideration in the repex model because, unlike most other asset types, they are not installed or replaced on a like for like basis. To understand why this requires special treatment, we have described below the normal like-for-like assumption used in the repex model, why staked poles do not fit well within this assumption, and how we adapt the model inputs to take account of this.

E.6.1 Like-for-like repex modelling

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

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

E.6.2 Non-like-for-like replacement

Where old assets are commonly replaced with a different asset, we cannot simply assume the cost of the new asset will match the cost of the old asset's modern equivalent. As the repex model predicts the number of old assets that need to be replaced, it is necessary to make allowances for the cost of a different asset in determining the replacement cost. In running the repex model, the only category where this was significant was wooden poles (or stobie poles for SA Power Networks).

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

³⁰⁹ The equivalent practice for stobie poles is known as "plating", which similarly provides a low cost life extension. SA Power Networks carries out this process. We applied the same process for modelling SA Power Networks' stobie pole plating data as we have for staked wooden poles. However, for simplicity, this section only refers to the staking process.

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.³¹⁰ 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.

For SA Power Networks (stobie plating) and Ergon Energy, we adopted their own observed plating/staking ratio, respectively. Energex, however, exhibited a staking ratio of 24 per cent. This is lower than peer urban networks such as Ausgrid and ActewAGL, and, indeed, lower than Ergon Energy's staking rate of 46 per cent on its predominantly rural network. Energex does not appear to achieve significantly longer lives on its poles than these three distributors (the weighted calibrated replacement life of its pole assets group is 56 years, while the figure for Ausgrid is 59 years). By contrast, Essential Energy, which also has a low staking rate, achieves longer lives than the other distributors (the weighted calibrated replacement life of its pole assets group is 66 years). As such, it appears that Energex predominantly chooses to replace its wooden poles earlier than other distributors, and does not utilise staking to the same extent. We consider that Energex's staking rate is lower than would be expected, given the age at which its assets reach replacement age and the practices of its peers.

³¹⁰ For example, if a distributor replaces a pole with a new pole 50 per cent of the time, and stakes the pole the other 50 per cent 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.

Consequently, we have applied in our modelling a benchmarked rate equivalent to Ausgrid's staking rate of 47 per cent.

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.³¹¹ The unit cost of replacing a staked wooden pole is a weighted average based on the historical proportion of pole types replaced. Where historical data was not available, we used the asset age data to determine what proportion of the network each pole category represented, and used this information to weight the unit costs.

E.7 Calibrating staked wooden poles

Special consideration also has to be given to staked wooden poles when finding replacement lives. This is because historical volumes of replacements are used in calibration. The RIN responses provide us with information on the volume of new assets installed over the last five years. However, the model predicts the volume of old assets being replaced - so an adjustment needs to be made for the calibration process to function correctly. We sought this information directly from the distributors. 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.

For SA Power Networks' stobie pole plating, we did not apply the calibration process. This is because SA Power Networks has only carried out the plating process for the past ten years. SA Power Networks submits that the average replacement life of a plated stobie pole is around 20 years. Given it has no assets in commission that have reached this age, this asset is not suitable for calibration. We have utilised the base case replacement life submitted by SA Power Networks in all iterations of the model.

E.8 Wooden pole asset adjustment (Ergon Energy)

Ergon Energy reported its staked wooden poles twice in its asset age profile: once as "staking of a wooden pole" and a second time under one of the six wooden pole categories. This resulted in the double counting of its wooden poles. Using the data "as is" in the repex model would result in the double counting of these assets.

Consequently, we made an adjustment to Ergon Energy's wooden pole data to net out the double counted assets.

The adjustment required involves subtracting the total number of staked poles from the total number of wooden poles in commission. We decided to do carry out this adjustment proportionally across the wooden pole asset base. We also assumed that no new pole installed after 1985 would have required staking (or the number would be negligible) so the adjustment would be applied to the pre-1985 asset base.

³¹¹ 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.

To make this adjustment, the total number of wooden poles in commission (with an installation date of 1985 or before) was calculated. Then we found the proportion of the total that each category of wooden poles made up in each year. The total number of staked poles was multiplied by these proportions to give an adjustment figure. This figure was then subtracted from the asset age profile.

Our approach allocates the adjustment across each year of the age profile, rather than attempting to make targeted adjustments at particular years, or bias the adjustment in favour of older poles. Given the expected lives of wooden poles (50+ years), it is likely that a greater number of the stakings were carried out on the older poles in the asset base than newer poles (that is, a pole that is over 50 years old is more likely to be staked than a pole that is under 50). Assuming this is correct, applying a constant allocation of the staking to all pre-1985 poles may result in a greater number of newer poles being netted out and fewer old poles being netted out than we would expect in practice. Under this circumstance, we would expect the repex model to calculate a greater volume of replacements than it would if the adjustments were distributed with an asymmetric bias towards older poles. Consequently, the approach does not disadvantage Ergon Energy, as it is not likely to result in an underestimation of their replacement requirements, and is more likely to skew in favour of replacement.

F Capitalised overheads: Confidential appendix