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

Attachment 6 − Capital expenditure

October 2015

AUSTRALIAN ENERGY REGULATOR

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Note

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

The final 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

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Attachment 12 – Demand management incentive scheme

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
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 investment made in the network to provide standard control services. This investment mostly relates to assets with long lives (30–50 years is typical) and these costs are recovered over several regulatory periods. On an annual basis, however, the financing cost and depreciation associated with these assets is recovered (return of and on capital) as part of the building blocks that form Ergon Energy's total revenue requirement.[1]

This attachment sets out our final decision on Ergon Energy's 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.

6.1 Final decision

We are not satisfied Ergon Energy's proposed total forecast capex of $3282.4 million ($2014–15) reasonably reflects the capex criteria. This is 39 per cent lower than the AER's allowance for the 2010–15 regulatory control period ($5399.3 million) and 13 per cent lower than actual capex for the 2010–15 regulatory control period ($3762.7 million). We substituted our estimate of Ergon Energy's total forecast capex for the 2015–20 regulatory control period. We are satisfied that our substitute estimate of $2858.1 million ($2014–15) reasonably reflects the capex criteria. Table 6.1 outlines our final decision.

1 NER, cl. 6.4.3(a).

Table 6.1 Our final decision on Ergon Energy's total forecast capex ($2014–15, million)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy's initial proposal	739.8	723.2	659.4	644.5	630	3,397.0
AER preliminary decision	540.1	495.3	428.1	381.0	337.5	2,182.0
Ergon Energy's revised proposal	749.4	685.6	634.3	610.6	602.6	3,282.4
AER final decision	667.0	601.4	553.6	522.6	513.5	2,858.1
Difference (final decision and revised proposal)	–82.4	–84.2	–80.7	–88.0	–89.1	–424.3
Percentage difference (%) (final decision and revised proposal)	–11.0	–12.3	–12.7	–14.4	–14.8	–12.9

Source: AER, *Preliminary decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 6 – Capital expenditure,* April 2015, p. 8; Ergon Energy, *Regulatory proposal (revised) 2015 to 2020,* July 2015, p. 103; AER analysis.

Note: Numbers may not add up due to rounding.

Table 6.2 summarises our findings and the reasons for our final decision.

These reasons include our responses to stakeholders' submissions on Ergon Energy's revised regulatory proposal. In the table we present our reasons by 'capex driver' (for example, augmentation, replacement, and connections). This reflects the way in which we tested Ergon Energy's total forecast capex. Our testing used techniques tailored to the different capex drivers, taking into account the best available evidence. Through our techniques we found Ergon Energy's capex forecast was higher than an efficient level, inconsistent with the NER. We are not satisfied that Ergon Energy's proposed total forecast capex is consistent with the requirements of the NER.

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our final decision concerns Ergon Energy's total forecast capex for the 2015–20 period. We do not approve an amount of forecast expenditure for each capex driver. However we use our findings on the different capex drivers to arrive at an alternative estimate for total capex. We test this total estimate of capex against the requirements of the NER (see section 6.3 for a detailed discussion). We are satisfied that our estimate represents total forecast capex that reasonably reflects the capex criteria.

Table 6.2 Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	Ergon Energy proposed a total capex forecast of $3282.4 million ($2014–15) in its revised proposal. We are not satisfied this forecast reasonably reflects the capex criteria. We are satisfied our substitute estimate of $2858.1 million ($2014–15) reasonably reflects the capex criteria. Our substitute estimate is 12.9 per cent lower than Ergon Energy's revised proposal (and 16 per cent lower than Ergon Energy's initial proposal of $3397 million ($2014–15)). The reasons for this decision are set out in this table and detailed in the remainder of this attachment.
Forecasting methodology, key assumptions and past capex performance	Ergon Energy's forecasting methodology predominately relies upon a bottom up approach. 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 expenditure as they do not adequately account for inter-relationships and synergies between projects or areas of work. In constructing our alternative estimate we addressed the concerns we have with Ergon Energy's forecasting methodology and key assumptions. Specifically, we have undertaken a top down assessment by applying our assessment techniques of benchmarking, trend analysis and an engineering review. We also addressed the deficiencies in Ergon Energy's key assumptions about forecast materials escalation rates and labour escalation rates.
Augmentation capex	We do not accept Ergon Energy's forecast augex of $608 million ($2014–15) for this category as we consider that it does not reasonably reflect the capex criteria. We consider that $543.7 million ($2014–15) is a reasonable estimate for Ergon Energy to augment its network and satisfy the capex criteria. In coming to this review, we accept the majority of Ergon Energy's revised augex forecast. However, we consider that its proposed capex to address voltage problems on its network and its system-enabling capex projects are overstated.
Customer connections capex	We are satisfied that Ergon Energy's forecast is a reasonable estimate for this category. We have included an amount of gross connections capex forecast of $419.8 million ($2014–15). In determining this, we are satisfied that the forecast methodology Ergon Energy has relied on represents an unbiased estimate of the capex it requires
Asset replacement capex (repex)	We do not accept Ergon Energy's forecast repex of $941 million ($2014–15) as a reasonable estimate for this category. We consider our alternative estimate of $786.6 million will allow Ergon Energy to meet the capex objectives and have included this amount in our alternative estimate. Our alternative estimate is 16 per cent lower than Ergon Energy's revised proposal. As part of our estimate, we accept Ergon Energy's revised forecasts for SCADA, "other" capex and remediation of low lines. Our repex estimate is lower than Ergon Energy's forecast because our business-as-usual repex estimate is lower than Ergon Energy's forecast. Also, because we used Ergon Energy's current allowance for pole top structure repex rather than its higher forecast.
Non-network capex	We accept Ergon Energy’s revised non-network capex proposal of $406.6 million ($2014–15), excluding overheads. We are satisfied that Ergon Energy has addressed the substantive issues raised in our preliminary decision in relation to forecast fleet and property capex. Specifically, Ergon Energy: • revised its fleet management and capex forecasting approaches in response to our preliminary decision, resulting in a reduction in forecast fleet capex of 12 per cent from its initial proposal • provided additional supporting evidence demonstrating that the major property project proposed for Townsville is prudent and likely to reflect the economically preferred development option for the site.

Issue	Reasons and findings
Capitalised overheads	We do not accept Ergon Energy's proposed capitalised overheads of $1051.4 million ($2014–15). We have instead included an amount of $1035.3 million ($2014–15) for capitalised overheads. We reduced Ergon Energy's capitalised overheads to reflect the reductions we made to its total capex forecast, particularly those components with overheads. We also note that 29 per cent of Ergon Energy's proposed $1051.4 million ($2014−15) total capitalised overheads is attributable to information and communications technology (ICT) services. We do not accept Ergon Energy's forecast for ICT services of $303.2 million ($2014–15). We have instead included an amount of $307.8 million ($2014–15) for ICT services.
Real cost escalators	In its revised revenue proposal, Ergon Energy updated its forecasts of real materials costs escalations it applied to various asset classes in its regulatory proposal. Ergon Energy rejected our findings on material cost escalation. We maintain our position in our preliminary decision and consider that zero per cent real cost escalation reasonably reflects the capex criteria including that it reasonably reflects a realistic expectation of the cost inputs required to achieve the capex objectives over the 2015–20 regulatory control period. This conclusion is based on the following: • the degree of potential inaccuracy of commodities forecasts • there is little evidence to support how accurately Ergon Energy's materials escalation model forecasts reasonably reflect changes in prices paid by Ergon Energy for physical assets in the past and by which we can assess the reliability and accuracy of its materials model forecasts; and • there is insufficient supporting evidence to show that Ergon Energy has considered whether there may be some material exogenous factors that impact on the cost of physical inputs. Consistent with our preliminary decision, our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to Ergon Energy's forecast capex for standard control services. We are not satisfied Ergon Energy'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 period. We discuss our assessment of forecast our labour price growth for Ergon Energy in attachment 7. The difference between the impact of the real labour and materials cost escalations proposed by Ergon Energy and those accepted by the AER in its capex decision is $188.9 million ($2014–15).

Source: AER analysis.

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

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[2]

[2] NEL, s. 7A.

As set out in appendix B, we are satisfied that our overall capex forecast is consistent with the NEO. We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.

We also consider that overall our capex forecast addresses the capital expenditure objectives.[3] In making our final decision, we specifically considered the impact our decision will have on the safety and reliability of Ergon Energy's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in Ergon Energy's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

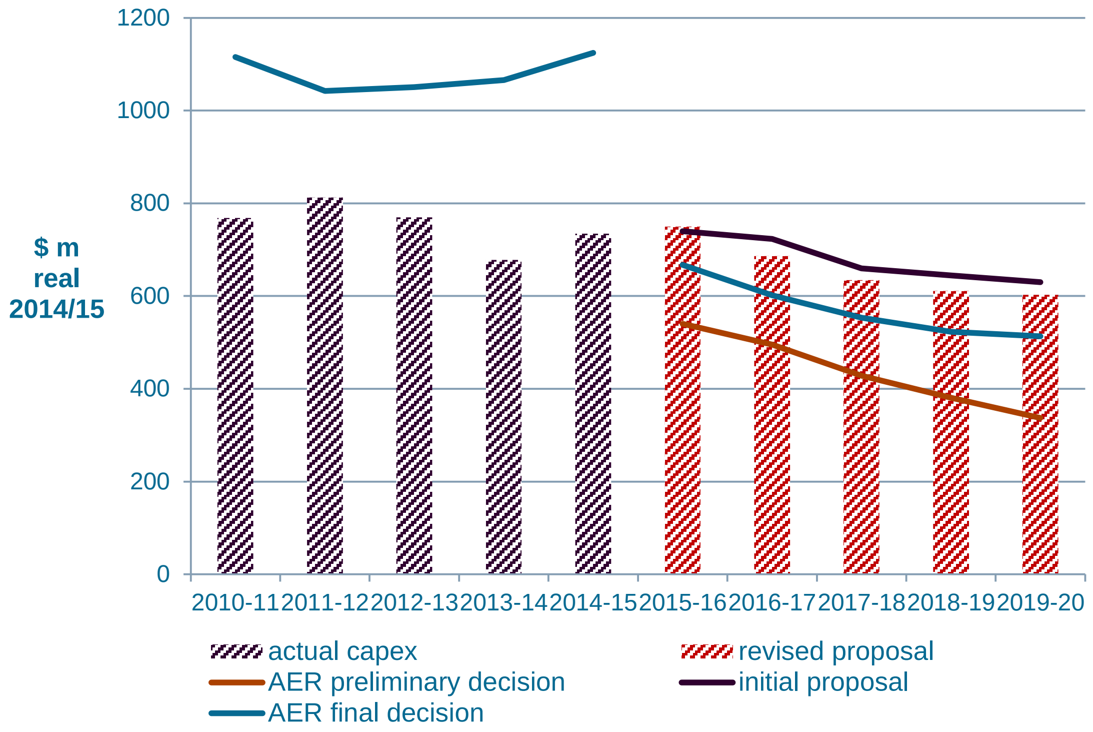
6.2 Ergon Energy's revised proposal

Ergon Energy's revised proposal was for total forecast capex of $3282.4 million ($2014–15) for the 2015–20 regulatory control period. This is 50.4 per cent higher than our preliminary decision and 3.4 per cent lower than Ergon Energy's initial regulatory proposal.

Figure 6.1 shows the difference between Ergon Energy's initial proposal, its revised proposal and our preliminary decision for the 2015–20 regulatory control period, as well as the actual capex that Ergon Energy spent during the 2010–15 regulatory control period.

3 NER, cl. 6.5.7(a).

Figure 6.1 Ergon Energy's total actual and forecast capex 2010–2020



Source: AER analysis.

Ergon Energy submitted that its revised capex proposal is lower than its initial proposal, reflecting updated market expectation of cost inputs into the future.[4]

6.3 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the distributor's total forecast capex. The starting point for our assessment is the information provided by Ergon Energy in its revised proposal. At the same time that Ergon Energy submitted its proposal, it also submitted its response to our RIN. We also took into account information that Ergon Energy provided in response to our information requests, and submissions from other stakeholders.

Our assessment approach involves the following steps:

- Our starting point for building an alternative estimate is the distributor's revised proposal.[5] We apply our various assessment techniques, both qualitative and

[4] Ergon Energy, *Regulatory proposal (revised) 2015 to 2020*, July 2015, p. 6.

quantitative, to assess the different elements of the distributor's proposal. This analysis informs our view on whether the distributor's proposal reasonably reflects the capex criteria in the NER at the total capex level.[6] It also provides us with an alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques we used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.

- Having established our alternative estimate of the *total* forecast capex, we can test the distributor's total forecast capex. This includes comparing our alternative estimate total with the distributor's total forecast capex and what the reasons for any differences are. 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 the distributor's proposal reasonably reflects the capex criteria in meeting the capex objectives, we will accept it. 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.

If we are not satisfied, the NER requires us to put in place a substitute estimate that we are satisfied reasonably reflects the capex criteria.[8] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:[9]

- 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.

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5 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 7; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

6 NER, cl. 6.5.7(c).

7 NER, cl. 6.5.7(a).

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

9 NER, cl. 6.5.7(c).

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[10] Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular categories or projects informs our assessment of the total capex forecast. The AEMC stated:[11]

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

In deciding whether we are satisfied that Ergon Energy's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.[12] Table 6.5 summarises how we took the capex factors into consideration.

In taking the capex factors into account, the AEMC noted:[13]

> …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.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.[14] In particular, we take into account whether our overall capex forecast provides Ergon Energy a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[15]

6.3.1 Expenditure Assessment Guideline

The rule changes the AEMC made in November 2012 required us to make and publish an Expenditure Forecast Assessment Guideline for electricity distribution (Guideline).[16] We released our Guideline in November 2013.[17] The Guideline sets out our proposed general approach to assessing capex (and opex) forecasts. The rule changes also require us to set out our approach to assessing capex in the relevant framework and approach paper. For Ergon Energy, our framework and approach paper stated that we

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10 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 113.

11 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012*,* November 2012, p. vii.

12 NER, cl. 6.5.7(e).

13 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 115.

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

15 NEL, s. 7A.

16 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 114.

17 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013.

would apply the Guideline, including the assessment techniques outlined in it.[18] We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

We note that RIN data forms part of a distributor's regulatory proposal.[19] In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issue in advance of a distributor lodging its regulatory proposal would specify the exact information we require.[20] Our Guideline made clear our intention to rely upon RIN data during distribution determinations.

6.3.2 Building an alternative estimate of total forecast capex

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

Our starting point for building an alternative estimate is the distributor's revised proposal.[21] 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 service provider's reliance on key assumptions that underlie its forecast. Ergon Energy has submitted further information on its forecast methodology in its revised proposal and we have addressed this below.

We have maintained in our final decision the use of the specific techniques that we used in our preliminary decision. Many of our techniques encompass the capex factors that we are required to take into account. Further detail on each of these techniques is included in appendix A and appendix B.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the distributor should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue requirement that includes an assessment of what we find to be an efficient total capex forecast.[22]

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18 AER, *Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, 119–120.

19 NER, cll. 6.8.2(c2) and (d).

20 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

21 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline,* November 2013, p. 9; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, pp. 111 and 112.

22 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. vii.

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the distributor is able to prioritise its capex program given its circumstances over the course of the regulatory control period. The distributor may need to undertake projects or programs it did not anticipate during the distribution determination. The distributor may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period in its decision-making.

As we explained in our Guideline:[23]

> 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.

In arriving at our estimate, we weight the various techniques we used in our assessment. We weight these techniques on a case by case basis using our judgement. Broadly, we give more weight to techniques we consider are more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the distributor’s capex forecast.

Where our techniques involve the use of a consultant, we consider their reports as one of the inputs to arriving at our final decision on overall capex. Our final decision clearly sets out the extent to which we accept our consultants' findings. Where we apply our consultants’ findings, we do so only after carefully reviewing their analysis and conclusions, and evaluating these against outcomes of our other techniques and our examination of Ergon Energy's proposal.

We also take into account the various interrelationships between the total forecast capex and other components of a distributor's distribution determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand
- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation

23 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.

- 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. 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.[24]
- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.[25]

6.3.3 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:[26]

> 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.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

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24 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013 , 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).

25 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

26 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 112.

Our decision on the total forecast capex does not strictly limit a distributor's actual spending. A distributor might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a distributor does not bear the full cost where unexpected events lead to an overspend of the approved capex forecast. Rather, the distributor bears 30 per cent of this cost if the expenditure is subsequently found to be prudent and efficient. Further, the pass through provisions provide a means for a distributor to pass on significant, unexpected capex to customers, where appropriate.[27] Similarly, a distributor may spend less than the capex forecast because they have been more efficient than expected. In this case the distributor will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the distributor has a reasonable opportunity to recover efficient costs. The regulatory framework allows the distributor to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the distributor should have sufficient flexibility to allow it to meet its safety and reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the distributor only spending what is efficient. As noted, the distributor and consumers share the benefits of an underspend or the costs of an overspend under the regulatory regime.

6.4 Reasons for final decision

We applied the assessment approach set out in section 6.3 to Ergon Energy. We are not satisfied that Ergon Energy's total forecast capex reasonably reflects the capex criteria. We compared Ergon Energy's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. Ergon Energy's revised proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of Ergon Energy's total forecast capex for the 2015–20 regulatory control period.

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[27] NER, rule 6.6.

Table 6.3 Our assessment of required capex by capex driver 2015–20 ($2014–15 million)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Augmentation	130.8	122.4	115.0	87.4	88.1	543.7
Connections	82.2	83.0	84.0	85.0	85.7	419.8
Replacement	179.3	164.6	140.6	152.4	149.7	786.6
Metering	2.7	3.2	3.1	2.5	2.4	13.8
Non-Network	115.1	84.8	79.3	66.3	61.0	406.6
Capitalised overheads	215.1	209.2	202.5	203.6	204.9	1,035.3
Labour and materials escalation adjustment	-28.6	-35.0	-38.8	-41.7	-44.9	-188.9
Gross Capex (includes capital contributions)	**696.6**	**632.2**	**585.6**	**555.4**	**547.1**	**3,016.9**
Capital Contributions	29.6	30.8	32.0	32.8	33.5	158.8
Net Capex (excluding capital contributions)	**667.0**	**601.4**	**553.6**	**522.6**	**513.5**	**2,858.1**

Source: AER analysis.

Note: Numbers may not add up due to rounding.

We discuss our assessment of Ergon Energy's forecasting methodology, key assumptions and past capex performance in the sections below.

Our assessment of capex drivers is in appendices A and B. These set 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 requires Ergon Energy to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. Ergon Energy must also provide a certification by its Directors that those key assumptions are reasonable.[28]

Ergon Energy's key assumptions are set out in its regulatory proposal.[29] We have assessed Ergon Energy's key assumptions in the appendices to this attachment.

[28] NER, cll. S6.1.1.1(2), (4) and (5).

[29] Ergon Energy, *Regulatory proposal*, October 2014, p. 108; Ergon Energy, *Revised regulatory proposal*, July 2015, pp. 122–123.

6.4.2 Forecasting methodology

The NER requires Ergon Energy to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its regulatory proposal.[30] Ergon Energy must include this information in its regulatory proposal.[31] The main points of Ergon Energy's forecasting methodology are set out in its regulatory proposal.[32]

In our preliminary decision we identified two aspects of Ergon Energy's forecasting methodology which indicate that its methodology is not a sufficient basis on which to conclude that its proposed total forecast capex reasonably reflects the capex criteria. These were:[33]

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

Ergon Energy provided some new information and/or clarification of its top–down assessment and risk assessment approach in its revised proposal. However, as noted by our consultant EMCa, the information is limited in scope and contains assertions that are not supported by Ergon Energy's documentation.[34]

The CCP also raised concerns with Ergon Energy's capex forecasting methodologies. In its submission, the CCP noted that Ergon Energy's capex forecasts have an insufficient regard to top-down considerations. The CCP submitted that bottom-up assessments have a tendency to overstate expenditure requirements, as they do not adequately account for interrelationships and synergies between projects or areas of work. The CCP also noted that Ergon Energy's capex forecasts are based on risk-averse and overly conservative risk assessments resulting in overstated costs.[35]

We agree with the concerns raised by both EMCa and the CCP. We consider that the information provided in Ergon Energy's revised proposal did not address the concerns set out in our preliminary decision. Hence, the concerns we raised in our preliminary decision also hold for this final decision. We discuss issues with Ergon Energy's forecasting methodology in more detail in the appendices to this attachment.

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30 NER, cll. 6.8.1A and 11.60.3(c).

31 NER, cl. S6.1.1(2).

32 Ergon Energy, *Regulatory proposal,* October 2014, p. 110.

33 AER, *Preliminary decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 6 – Capital expenditure*, April 2015, pp. 20–25.

34 EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal,* September 2015, pp. 4–7.

35 Consumer Challenge Panel (CCP 2), *Submission - AER preliminary 2015–20 revenue determinations, Energex and Ergon Energy revised revenue proposals*, 3 September 2015, pp. 16–17.

6.4.3 Interaction with the STPIS

We consider that our approved capex forecast is consistent with the setting of targets under the STPIS. Particularly, we consider that the capex allowance should not be set such that there is an expectation that it would lead to Ergon Energy systemically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow Ergon Energy 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 final decision, we have specifically considered the impact our decision will have on the safety and reliability of Ergon Energy's network. We consider our substitute estimate is sufficient for Ergon Energy to maintain the safety, service quality and reliability of its network consistent with its obligations. Our provision of a total capex forecast does not constrain a service providers 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 service provider might wish to expend particular capex differently or in excess of the total capex forecast set out in our decision. However such additional expenditure is not included in our assessment of expenditure forecasts as it is not required to meet the capex objectives. We consider the STPIS is the appropriate mechanism to provide distributors with the incentive to improve reliability performance where such improvements reflect value to the energy customer.

6.4.4 Ergon Energy's capex performance

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

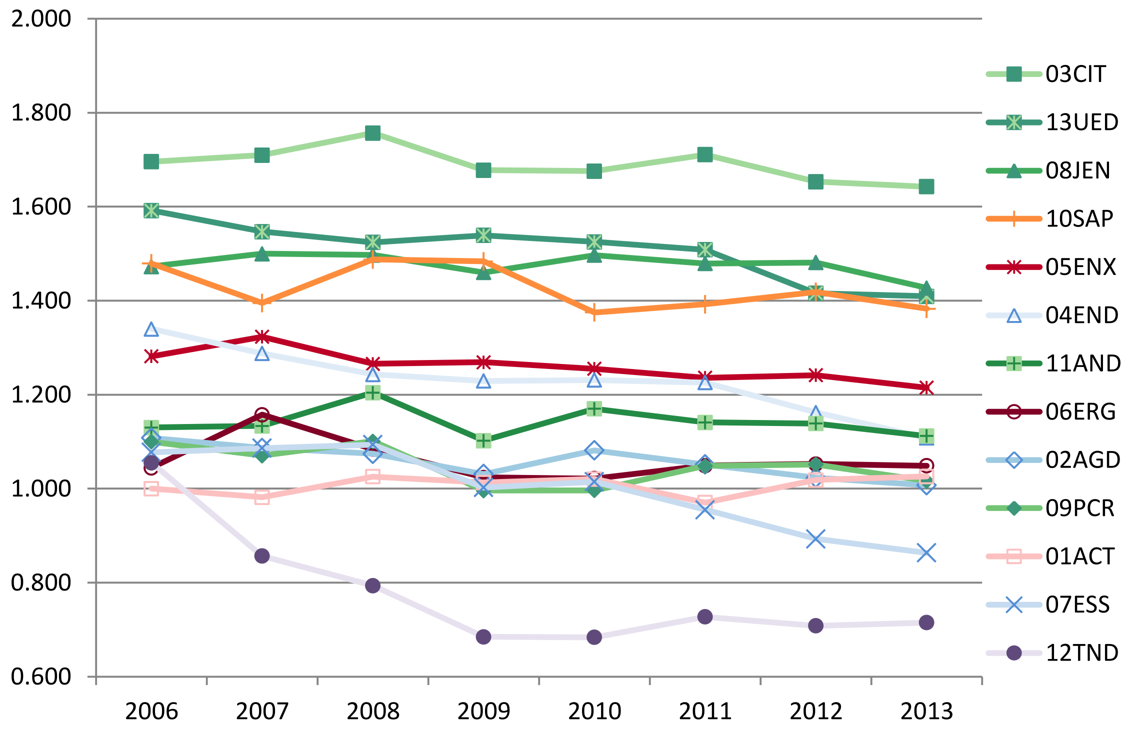
The NER sets out that we must have regard to our annual benchmarking report.[36] This section shows how we have taken it into account. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of Ergon Energy's proposal in a broader context. However, in our capex assessment we have not relied on our high level benchmarking metrics set out below other than to gain a high level insight into Ergon Energy's proposal. We have not used this analysis deterministically in our capex assessment.

[36] NER, cl. 6.5.7(e).

Partial factor productivity of capital and multilateral total factor productivity

Figure 6.2 shows a measure of partial factor productivity of capital taken from our benchmarking report. This measure incorporated the productivity of transformers, overhead lines and underground cables. Ergon Energy falls towards the lower end of the range on this assessment, falling behind the Victorian, South Australian and some NSW distributors.

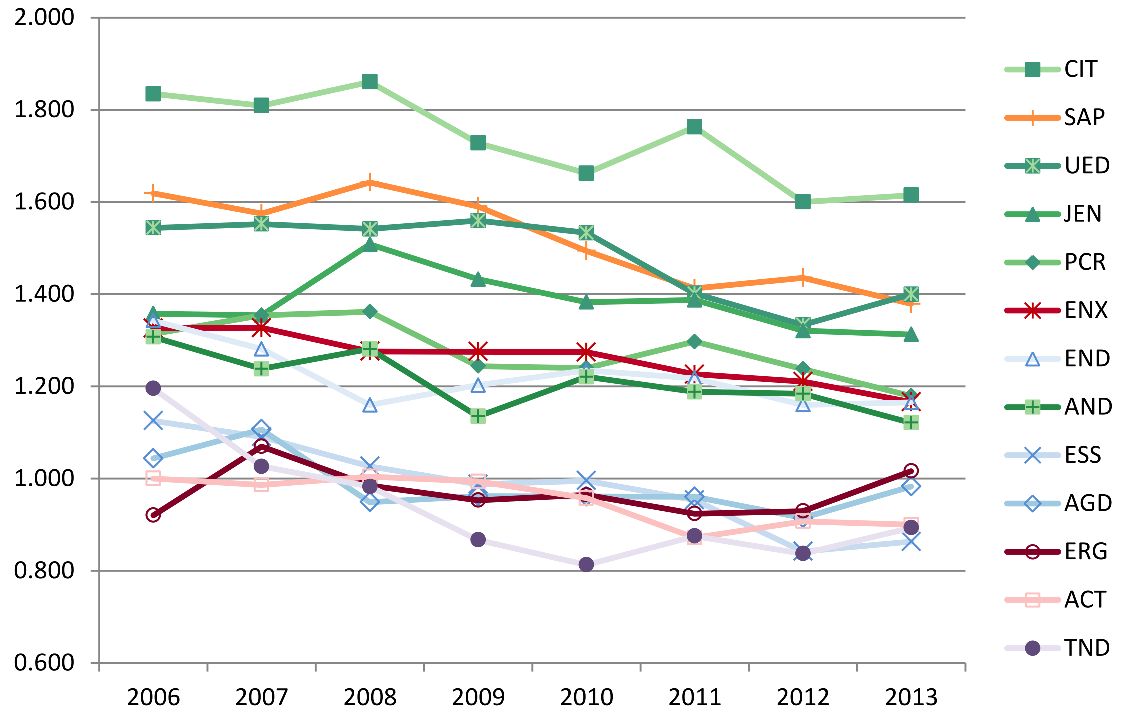
Figure 6.2 Partial factor productivity of capital (transformers, overhead and underground lines)



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 33.

Figure 6.3 shows that Ergon Energy ranks similarly on multilateral total factor productivity (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, Ergon Energy performed relatively poorly.

Figure 6.3 Multilateral total factor productivity



Source: AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014, p. 31.

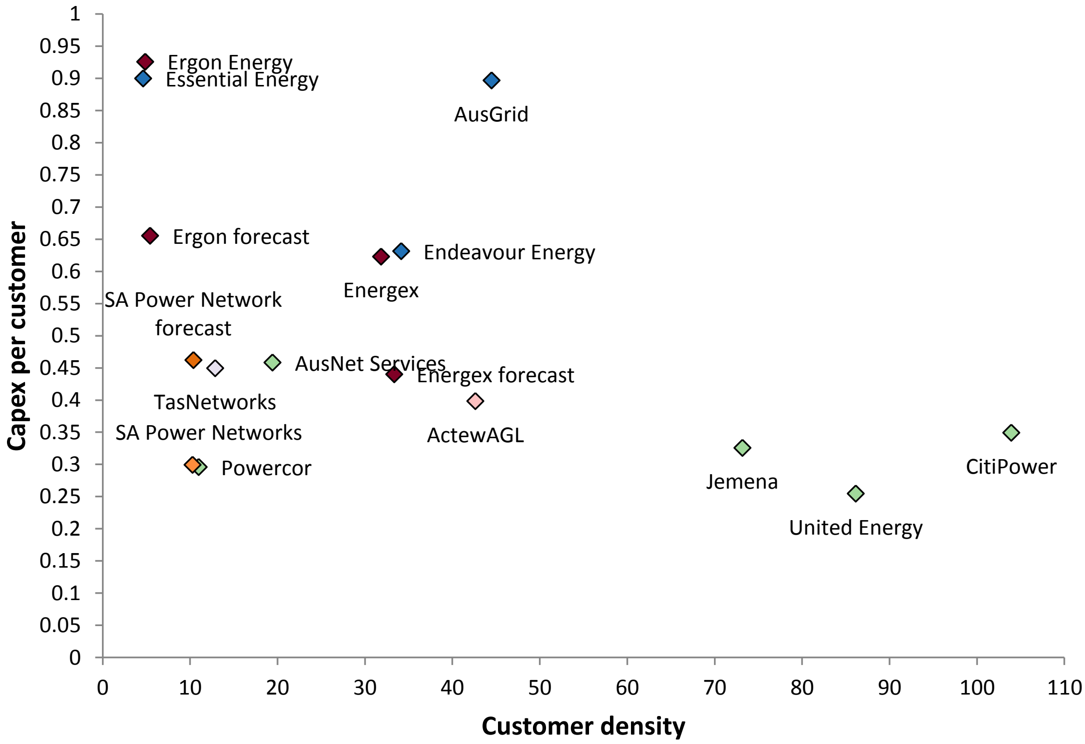
6.4.4.1 Relative capex efficiency metrics

Figure 6.4 and Figure 6.5 show capex per customer and per maximum demand, against customer density. Unless otherwise indicated as a forecast, the figures represent the five year average of each distributor's actual capex for the years 2008–12. For the QLD and SA distributors we also included the businesses' proposed capex for the 2015–20 regulatory control period. We considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

For completeness Figure 6.4 6.5 also include Energex and SA Power Networks' proposed capex for the 2015–20 regulatory control period. However we do not use comparisons of Ergon Energy's total forecast capex with the total forecast capex of these distributors as inputs to our assessment. We consider it is appropriate to compare Ergon Energy's forecast only with actual capex. This is because actual capex consists of 'revealed costs' and would have occurred under the incentives of the regulatory regime.

Figure 6.4 shows that Ergon Energy had the highest capex per customer for the 2008–2012 period. Ergon Energy's capex per customer will decrease for the 2015–20 regulatory control period based on their proposed forecast capex. However, even after this reduction Ergon Energy's capex per customer is still among the highest in the NEM.

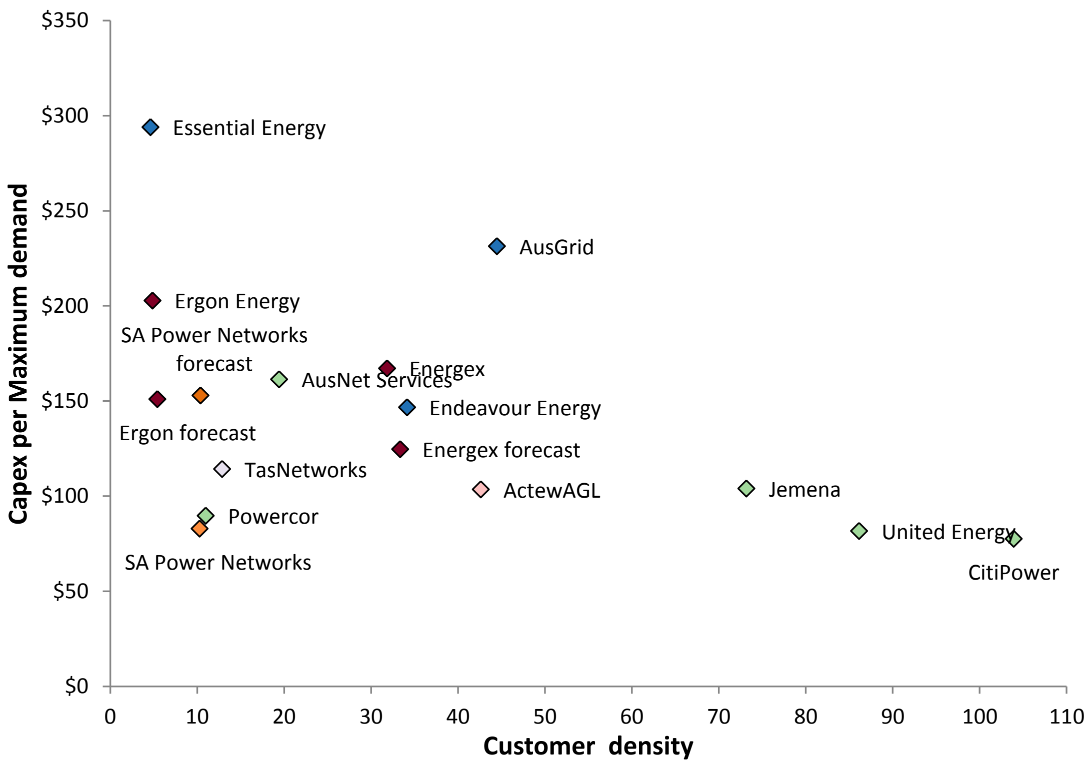
Figure 6.4 Capex per customer (000s, $2013–14), against customer density



Source: AER analysis.

Figure 6.5 shows that Ergon Energy's capex per maximum demand for the 2008–2012 period was among the highest in the NEM. Ergon Energy forecasted capex per maximum demand to decrease in the next period at a level close to the Victorian distributors.

Figure 6.5 Capex per maximum demand (000s, $2013–14), against customer density



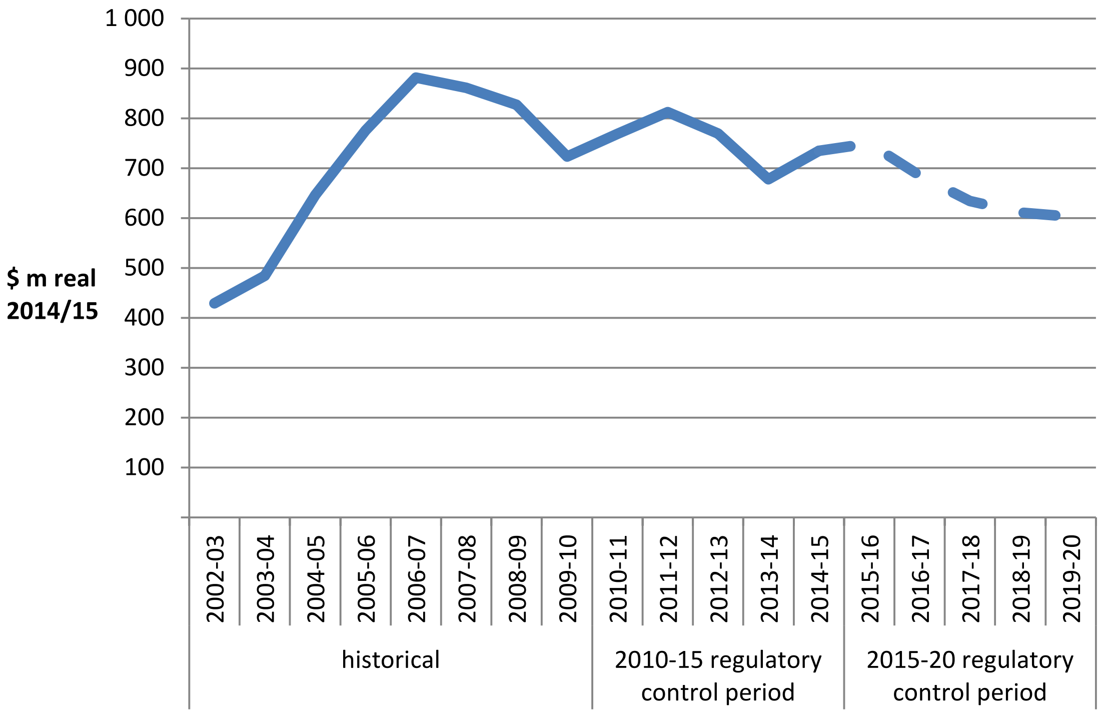
Source: AER analysis.

Ergon Energy's historic capex trends

We compared Ergon Energy'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 2002–03 and 2019–20. This figure shows that while Ergon Energy's proposed capex for the 2015–20 regulatory control period is similar to that in the previous regulatory control period, it is also a substantial increase over the expenditure in the early 2000's.

Figure 6.6 Ergon Energy total capex – historical and forecast 2002–2020



Source: AER analysis.

Submissions received by us noted that the Queensland distributors significantly increased capex expenditure post 2005. This was due to flatter demand prior to 2005 as well as a change in jurisdictional standards in 2006 which drove investment in the networks. Submissions from interested parties suggest that the AER should have regard to the level of capex in 2000 to 2005 when considering proposed capex for the 2015–20 period. Several stakeholders consider this a more like for like comparison.[37]

In considering an approved level of capex we have not only considered past capex trends, rather we have used a range of methods available to us to assess the businesses proposals. We discuss these methods in further detail in the appendices to this attachment.

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37 Consumer Challenge Panel (CCP 2), *Submission - AER preliminary 2015–20 revenue determinations, Energex and Ergon Energy revised revenue proposals*, 3 September 2015, p. 16; EUAA, *Submission to AER draft determination and Energex's revised revenue proposal for the 2015 to 2020 regulatory period,* 24 July 2015, p. 5; QCOSS, *Response to the AER preliminary decision for Queensland distributors 2015–2020,* July 2015, p. 5; Total Environment Centre, *Submission to the AER on the preliminary decisions on the QLD DB's regulatory proposals 2015–20*, July 2015, p. 5.

6.4.5 Interrelationships

There are a number of interrelationships between Ergon Energy's total forecast capex for the 2015–20 regulatory control period and other components of its distribution determination (see Table 6.4). We considered these interrelationships in coming to our final decision on total forecast capex.

Table 6.4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	There are elements of Ergon Energy's total forecast opex that are specifically related to its total forecast capex. These include the forecast labour price growth that we included in our opex forecast in attachment 7. This is because the price of labour affects both total forecast capex and total forecast opex. More generally, we note our total opex forecast will provide Ergon Energy with sufficient opex to maintain the reliability of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the repex Ergon Energy needs to spend during the 2015–20 regulatory control period.
Forecast demand	Forecast demand is related to Ergon Energy's total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme (CESS)	The CESS is related to Ergon Energy'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 note 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 prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from Ergon Energy's regulatory asset base. In particular, the CESS will ensure that Ergon Energy bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Ergon Energy can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, Ergon Energy risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	The STPIS is interrelated to Ergon Energy's total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2015–20 regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to allow Ergon Energy 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 Ergon Energy systematically under or over performing against its targets.
Contingent project	A contingent project is interrelated to Ergon Energy's total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of Ergon Energy's total forecast capex for the 2015–20 regulatory control period. We did not identify any contingent projects for Ergon Energy during the 2015–20 period. In its initial proposal Ergon Energy proposed two contingent projects during the 2015–20 period. We did not accept these in our preliminary decision and, as such, Ergon Energy removed these from its revised proposal.

Source: AER analysis.

6.4.6 Consideration of the capex factors

As we discussed in section 6.3, we took the capex factors into consideration when assessing Ergon Energy's total capex forecast.[38] 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 had regard to our most recent benchmarking report in assessing Ergon Energy's proposed total forecast capex and in determining our alternative estimate for the 2015–20 regulatory control period. This can be seen in the metrics we used in our assessment of Ergon Energy's capex performance.
The actual and expected capex of Ergon Energy during any preceding regulatory control periods	We had regard to Ergon Energy's actual and expected capex during the 2010–15 and preceding regulatory control periods in assessing its proposed total forecast. This can be seen in our assessment of Ergon Energy's capex performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie Ergon Energy's total forecast capex. For non-network capex, we rely on trend analysis to arrive at an estimate that meets the capex criteria.
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by Ergon Energy in the course of its engagement with electricity consumers	We had regard to the extent to which Ergon Energy's proposed total forecast capex includes expenditure to address consumer concerns that Ergon Energy identified. Ergon Energy 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. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Ergon Energy's proposed total forecast capex includes capex that addresses the concerns of its consumers that it has identified.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing Ergon Energy's proposed real cost escalation factors. In particular, we have not accepted Ergon Energy's proposal to apply real cost escalation for labour and materials.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We 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 Ergon Energy's total forecast capex and total forecast opex in Table 6.4 above.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to Ergon Energy	We had regard to whether Ergon Energy's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Ergon Energy's total forecast capex and the application of the CESS

[38] NER, cll. 6.5.7(c), (d) and (e).

Capex factor	AER consideration
	and the STPIS in Table 6.4 above.
The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms	We had regard to whether any part of Ergon Energy's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than Ergon Energy that do not reflect arm's length terms. We considered the arrangements between Ergon Energy 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.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of Ergon Energy's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriate be included as a contingent project.
The extent to which Ergon Energy has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which Ergon Energy made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of Ergon Energy's augex proposal.
Any other factor the AER considers relevant and which the AER has notified Ergon Energy in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis.

6.5 Transition path allowance for capex

In its revised regulatory proposal Ergon Energy did not accept our position in the preliminary determination to not provide it with a 'transition path allowance'.[39] The proposed transition path allowance was intended to mitigate the consequences of requiring service providers to immediately review, and substantially reduce, expenditure.[40]

Ergon Energy submitted that the AER has the power to incorporate a transition path that takes into account the external cost inputs faced by Ergon Energy, as well as the prudent and efficient costs of reducing expenditure to the levels required by the AER. Ergon Energy submitted that should we make a 'distribution determination that provided for significant cuts to existing levels of expenditure', we should consider providing it with a transition path through a transition path allowance. Ergon Energy

[39] AER, *Preliminary decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7: Operating expenditure,* April 2015, pp. 40–43; Ergon Energy, *Regulatory proposal 2015–20 (revised), Appendix E: The need for a 'transition path' for operating and capital expenditure,* July 2015.

[40] Ergon Energy, *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 issues paper*, 30 January 2015, pp. 10–19; Ergon Energy, *Submission on the Draft Decisions: NSW and ACT distribution determinations 2015–16 to 2018–19,* 13 February 2015, pp. 23–24.

submitted calculations of the transition path allowance that it considered to be appropriate.[41]

We note that, in the context of the AER's capex review, we are required to determine whether forecast expenditure reasonably reflects the capex criteria set out in the NER.[42] As discussed in section 6.1, we are not satisfied that Ergon Energy's forecast capex reasonably reflects the capex criteria and have therefore determined an estimate of the total required capex that we are satisfied does reasonably reflect the criteria. In doing so, we have taken into account the capex factors.[43]

The AER's consideration of this issue is explained in more detail in attachment 7 (where it relates to operating expenditure). The discussion in attachment 7 applies equally to our considerations in this attachment 6 in the context of the characteristics of our capital expenditure assessment. For example, attachment 7 discusses how our techniques account for each distributor's characteristics in the context of our opex assessment. In deriving our capex estimate as discussed above, we similarly accounted for the characteristics of Ergon Energy's distribution network such as asset condition (see appendix B.4) and peak demand (see appendix C).[44]

For these reasons, we do not consider providing transition costs is justified, as providing an allowance for this would exceed the substitute estimate that we are satisfied reasonably reflects the capex criteria.

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41 Ergon Energy, *Regulatory proposal 2015–20 (revised), Appendix E: The need for a 'transition path' for operating and capital expenditure,* July 2015.

42 NER, cl. 6.5.7(c).

43 NER, cl. 6.5.7(e).

44 More generally, the appendices to this attachment details our assessment of Ergon Energy's capex forecast and how we arrived at the capex estimate we consider reasonably reflects the capex criteria.

A Assessment techniques

This appendix describes the assessment approaches we applied in assessing Ergon Energy's proposed forecast capex. Appendix B sets out in greater detail the extent to which we relied on each of the assessment techniques.

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 we are assessing. 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:[45]

> 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.

Below we set out the assessment techniques we used to asses Ergon Energy's capex.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. The NER requires us to consider the annual benchmarking report as it is one of the capex factors.[46] Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.[47] 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.[48] As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[49]

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and overall capex efficiency. In general, these measures calculate a distributor's efficiency

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[45] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 8.

[46] NER, cl. 6.5.7(e)(4).

[47] AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines,* November 2013.

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

[49] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p. 25.

with consideration given to its inputs, outputs and its operating environment. We considered each distributor's operating environment in so far as there are factors outside of a distributor's control that affect its ability to convert inputs into outputs.[50] Once such exogenous factors are taken into account, we expect distributors to operate at similar levels of efficiency. One example of an exogenous factor we took into account is customer density. For more on how we derived these measures, see our annual benchmarking report.[51]

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

The results from 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 considered past trends in actual and forecast capex as this is one of the capex factors under the NER.[52]

Trend analysis involves comparing a distributor's forecast capex and work volumes against historical levels. Where forecast capex and volumes are materially different to historical levels, we seek to understand the reasons for these differences. In doing so, we consider the reasons the distributor provides in its proposal, as well as changes in the circumstances of the distributor.

In considering whether the total forecast capex reasonably reflects the capex criteria, we need to consider whether the forecast will allow the distributor to meet expected demand, and comply with relevant regulatory obligations.[53] 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 the distributor requires.

Maximum demand is a key driver of augmentation or demand driven expenditure. Augmentation often needs to occur prior to demand growth being realised. Hence, forecast rather than actual demand is relevant when a business is deciding the augmentation projects it will require in an upcoming regulatory control period. To the extent actual demand differs from forecast, however, a business should reassess the need for the projects. Growth in a business' network will also drive connections related

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[50] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012,* 29 November 2012, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

[51] AER, *Electricity distribution network service providers: Annual benchmarking report*, November 2014.

[52] NER, cl. 6.5.7(e)(5).

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

capex. For these reasons it is important to consider how trends in capex (in particular, augex and connections) compare with trends in 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 when 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 the distributor's capex requirements.

We looked at trends in capex across a range of levels including at the total capex level, and the category level (such as growth related capex, and repex) as relevant. We also compared these with trends in demand and changes in service standards over time.

A.3 Category analysis

Expenditure category analysis allows us to compare expenditure across NSPs, and over time, for various levels of capex. The comparisons we perform include:

- 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 use in assessing repex.

Using standardised reporting templates, we 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 (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.[54] The models draw on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.[55]

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

[55] NER, cl. 6.5.7(e)(5).

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. If we consider a distributor's proposed repex does not conform to the capex criteria, we use the repex model (in combination with other techniques where appropriate) to generate a substitute forecast.

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[56] 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.[57] 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.[58]

For our decision we have relied on input data for the augex model to review forecast utilisation of individual zone substations to assess whether augmentation may be necessary to alleviate capacity constraints. We use this analysis both as a starting point for our further detailed evaluation, and as a cross-check on our overall augex estimate. We have not otherwise used the augex model in our assessment of Ergon Energy's augex forecast.

A.5 Engineering review

We drew on engineering and other technical expertise within the AER to assist with our review of Ergon Energy's capex proposals.[59] We also relied on the technical review of our consultant, EMCa, to assist with our review of Ergon Energy's capex proposal. This involved reviewing Ergon Energy's processes, and specific projects and programs of work.

Appendix B discusses in detail our consideration of these reviews in our assessment of Ergon Energy's capex forecast.

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

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

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

59 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 86.

B Assessment of capex drivers

We present our detailed analysis of the sub-categories of Ergon Energy'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 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 Ergon Energy'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 Ergon Energy'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 techniques that we discuss in appendix A.

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 AER findings and estimates for augmentation expenditure
- Section B.3 AER findings and estimates for customer connections capex, including capital contributions
- Section B.4 AER findings and estimates for replacement expenditure
- Section B.5 AER findings and estimates for capitalised overheads
- Section B.6 AER findings and estimates for non–network capex.

In each of these sections, we examine 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 Ergon Energy's proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques, explained in section 6.3 and appendix A. Our weighting of each of these techniques, and our response to Ergon Energy's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in appendix B.

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 driven by a service provider's need to build or augment its network. The main driver of augex is maximum demand and its effect on network utilisation. It can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements. Our assessment of augex seeks to establish the prudent and efficient expenditure that Ergon Energy will require to build or augment its network in response to these drivers.

B.2.1 Position

Our estimate of required augex for Ergon Energy for the 2015–20 regulatory control period is $550.2 million ($2014–15). We accept that the majority of Ergon Energy's revised augex forecast reasonably reflects the capex criteria. However, we consider that Ergon Energy's proposed capex to address voltage problems on its network and its system-enabling capex projects are overstated. We are satisfied that our estimate of required augex, when combined with the rest of our capex decision, reasonably reflects the capex criteria and will enable Ergon Energy to achieve the capex objectives, including those relating to complying with its regulatory obligations and maintenance of the quality, reliability and security of its network.

Table 6.6 compares forecasts across the decision making process between the initial proposal and our final decision.

Table 6.6 Ergon Energy augex forecasts comparisons ($2014–15 million, excluding overheads)

	2015−16	2016−17	2017−18	2018−19	2019−20	Total
Initial augex forecast	154.3	147.1	137.7	110.9	110.2	660.1
AER preliminary decision	133.5	126.3	117.6	91.6	90.0	558.0
Revised Proposal	147.6	138.0	128.1	101.8	100.8	616.4
AER final forecast	132.3	124.4	116.8	88.6	89.2	550.2

Source: AER analysis.

Similar to its initial proposal, Ergon Energy's revised proposal augex forecast was comprised of demand-related capex (for its distribution and sub-transmission networks), reliability and quality of supply capex, and other system-enabling capex. Our final decision on these components, and the reasons for our decision, are set out in section B.2.5.

Table 6.7 sets out our final decision for each year of the 2015−20 regulatory control period. Our detailed findings are set out sections B.2.4 and B.2.5.

Table 6.7 AER's alternative estimate of augex ($2014–2015 million, excluding overheads)

	2015–16	2016–7	2017–18	2018–19	2019–20	Total
Ergon Energy revised proposal	**147.6**	**138**	**128.1**	**101.8**	**100.8**	**616.4**
Adjustment to distribution augex	-8.1	-8.5	-8.1	-8.8	-7.7	-42.5
Adjustment to other system-enabling capex	-7.2	-5.1	-3.2	-4.4	-3.8	-23.7
AER alternative estimate	**132.3**	**124.4**	**116.8**	**88.6**	**89.2**	**550.2**
Difference	-10.4%	-9.9%	-8.8%	-12.9%	-11.5%	-10.7%

Source: AER analysis.

Note: Ergon Energy's forecast includes $8.4 million related to 'metering' (as identified Ergon Energy's spreadsheet '03.03.08 Escalations Data Model'). Our alternative estimate in this table includes augex for metering. Our final decision in Attachment 6 and our capex model separates our capex metering as a separate line item. Numbers may not add up due to rounding.

B.2.2 Revised proposal

Ergon Energy's revised proposal was $616.4 million ($2014–5). Table 6.8 shows Ergon Energy's augex cost drivers and their contribution to the overall revised augex forecast.

Table 6.8 Ergon Energy's proposed augex ($2014−15 million, excluding overheads)

Category	2015−16	2016−17	2017−18	2018−19	2019−20	Total
Sub-transmission	48.3	52.4	50.6	19.6	20.9	191.8
Distribution	68.3	63.0	62.6	62.6	62.5	318.9
Quality of supply	1.2	1.2	1.2	1.2	1.1	5.8
Reliability	1.0	1.0	1.0	1.0	1.0	5.2
Other system-enabling capex	28.8	20.4	12.7	17.5	15.3	94.7
Total augex revised proposal	147.6	138.0	128.1	101.8	100.8	616.4

Source: Ergon Energy reset RIN; Ergon Energy revised proposal, Attachments 07.00.02 (revised), 07.00.04 (revised) and 07.00.05(revised); Ergon Energy response to AER 083.

Ergon Energy's revised augex forecast was 6.6 per cent lower than its initial proposal. In developing its revised forecast, Ergon Energy:

- Revised its distribution augex, but did not accept our preliminary decision

- Accepted our preliminary decision for reliability and power quality augex, which was consistent with Ergon Energy's initial proposal
- Rejected our preliminary decision for sub-transmission augex
- Rejected our preliminary decision for other system-enabling augex
- Provided some explanation for what we described as 'unexplained capex'.

Ergon Energy's reasoning and revised proposal is considered in detail in section B.2.5.

Ergon Energy also responded to some of our comments on its forecasting methodology, including advice we received from our consultants Energy Market Consulting Associates (EMCa). We consider these comments where relevant through this final decision.

B.2.3 AER approach

In our preliminary decision on Ergon Energy's augex forecast, we examined the augex proposal in four parts:

1. We considered the proposed forecast in the context of past expenditure, demand and current network utilisation. We concluded that Ergon Energy may need to augment highly utilised parts of its network over the 2015−20 regulatory control period.
2. We examined the governance processes and forecasting methodologies that underpinned Ergon Energy's forecast, which was assisted by a technical review undertaken by our independent consultants, EMCa. We concluded that Ergon Energy followed a robust methodology to estimate the cost of augmentation. However EMCa identified systemic issues of overestimation across the sample of projects which they considered meant that Ergon Energy's total forecast augex for 2015–20 was overestimated.
3. To quantify the impact of any identified biases, we had regard to the technical review of a sample of projects undertaken by EMCa. On the basis of its review, EMCa considered that Ergon Energy's sub-transmission augex forecast was over-estimated by 0 to 5 per cent, and its distribution augex forecast was overestimated by 10 to 20 per cent. We removed the impact of these identified overestimation bias evident in the Ergon Energy's forecast by applying a percentage reduction to each augex forecast component (but no adjustment to individual projects).
4. We reviewed the remaining augex forecast that was not considered by EMCa. We identified that the systemic issues identified by EMCa for Ergon Energy's distribution augex forecast were also present in Ergon Energy' forecast of 'other system-enabling' capex. On this basis, we removed the impact of these overestimation biases by applying a percentage reduction to the forecast of other system-enabling capex. We also removed the remaining unexplained capex.

We received submissions from the Queensland Council of Social Service (QCOSS), the Alliance of Electricity Customers, and the Consumer Challenge Panel (CCP). These submissions are considered in this final decision.

For our final decision on Ergon Energy's augex proposal, we adopt the same assessment approach as for our preliminary decision. The remainder of this appendix is structured as followed:

- Section B.2.4 responds to the submission from the CCP on our use of trend analysis.
- Section B.2.5 sets out our final decision on Ergon Energy's augex drivers and projects, including our responses to Ergon Energy's revised proposal submission. We are assisted by further technical analysis from our independent consultants, EMCA.[60]

B.2.4 Trend analysis

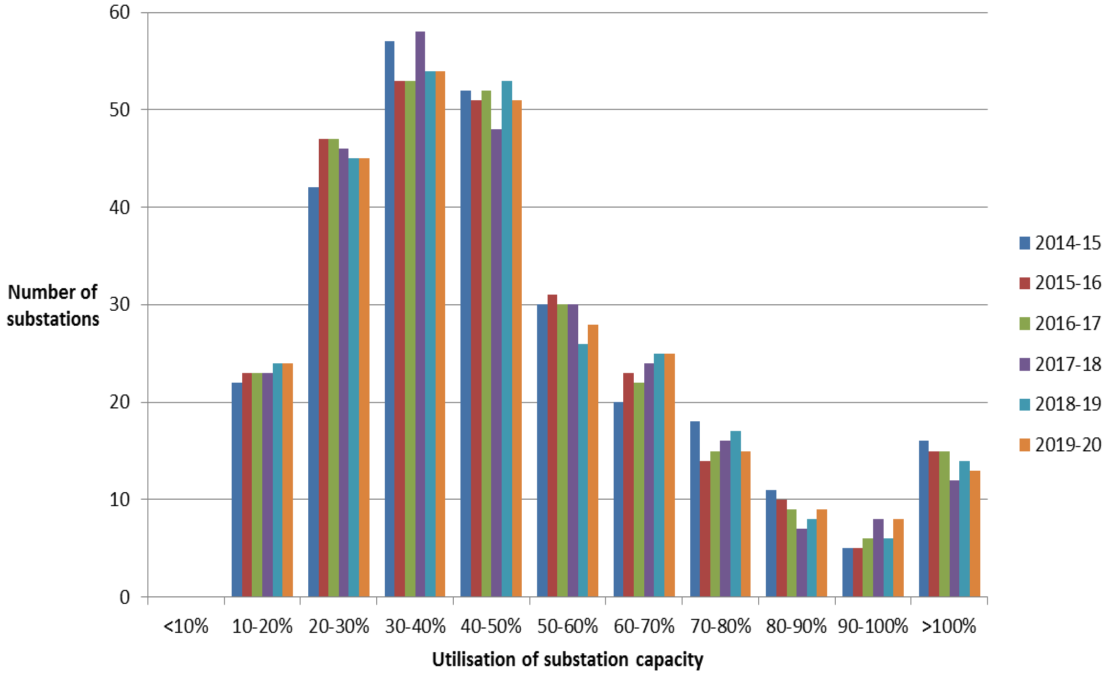
For our preliminary decision, the starting point for our analysis was reviewing the trends in Ergon Energy's augex, maximum demand and network utilisation as these are the key drivers of network augmentation. This provided us with an initial sense of whether Ergon Energy's augex forecast is reasonably required to meet forecast demand and alleviate forecast capacity constraints.

On the basis of our review we observed that:

- Ergon Energy's proposed demand-driven augex was 5 per cent lower than the 2010–15 regulatory period, but significantly lower than the previous regulatory period.
- Ergon Energy's overall network utilisation had decreased slightly between 2010 and 2014, which was consistent with a small decline in demand and network investment over this period. Declining network utilisation historically supported lower levels of augex than in previous periods, which was consistent with Ergon Energy's proposal.
- Ergon Energy's forecast network utilisation at each zone substation shows that the number of highly utilised zone substations is expected to decrease slightly over the 2015–20 period. However, there remain a number of highly utilised substations that Ergon Energy may need to augment over the 2015−20 regulatory control period. This is evident in Figure 6.7 below, which shows that Ergon Energy expects that 20 or more of its zone substations will operate above 90 per cent of its capacity by 2020 (in the absence of augmentation).

60 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015*, September 2015.

Figure 6.7 Zone substation forecast utilisation 2014–15 to 2019–20 (without additional augmentation)



Source: AER analysis; augex model, Ergon Energy 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 per cent POE maximum demand at each substation and existing capacity without additional augmentation over 2015−20.

We have maintained these views from our trend analysis for this final decision.

In Ergon Energy's submission to our preliminary decision, it stated:

> Our proposal for the 2015–20 regulatory control period provides clear evidence of Ergon Energy's declining level of augmentation expenditure which would be expected in the present circumstances, as well as the continued focus by Ergon Energy on non-network alternatives and operational responses to network contingencies in order to minimise the cost of maintaining performance at required levels. As observed by the AER certain areas of the network will reach levels of utilisation that will require augmentation during the 2015–20 regulatory control period and these are the areas that have been addressed in the Ergon Energy augex proposal.[61]

The CCP's submission to our preliminary decision and Ergon Energy's revised proposal raised some concerns with our augex allowance (and the use of trend analysis in particular).

[61] Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 6.

The CCP submitted that:

- We accepted maximum demand forecasts that are well in excess of AEMO's most recent forecasts. The CCP submitted that AEMO's 2015 connection point forecasts do not support Ergon Energy's proposed levels of augmentation.[62]
- We gave inadequate scrutiny of Ergon Energy's 'pockets of demand growth' and insufficient demonstration of associated local capacity constraints. It submitted that augex needs to be justified based on sound evidence of localised demand growth together with detailed demonstration of genuine local capacity constraints.
- We gave insufficient consideration of Ergon Energy's excess capacity and declining system utilisation. While the CCP stated that we acknowledged trends in excess capacity, it submitted that we did not quantify the impacts of excess capacity or demonstrate that it has been appropriately considered in augex assessment.[63] It submitted that system utilisation is much more material to the determination of efficient augex needs than our preliminary decision determined.[64]
- We gave insufficient consideration of capital efficiency and prudent/efficiency of the proposed augex spend.
- We were over-reliant on trend analysis rather than focus on efficient costs.

We agree with the CCP that network utilisation is an important factor to consider in reviewing augmentation requirements over time. This is because network utilisation is the fundamental driver of network augmentation due to demand growth. Network utilisation is the measure of installed network capacity that is in use (or is forecast to be in use).

As a starting point we review average utilisation rates in order for us, as well as stakeholders, to gain a broader understanding of trends over time particularly against aggregated augex trends. Similar to the CCP, we observed that there was declining system utilisation over the recent period. However, in terms of determining a level of augex for the 2015–20 period, it is also necessary to consider future demand and forecast network utilisation over this period, including localised demand growth and capacity.

For this assessment we looked at forecast network utilization at the zone substation level which gave us an indication of whether there were forecast localised capacity constraints over the 2015–20 period. This is shown in Figure 6.7 above, which shows that several specific zone substations are expected to be highly utilised by the end of

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62 Mr Hugh Grant CCP, *Advice on AER preliminary decision and Energex and Ergon Energy revised proposals*, September 2015, p. 23.

63 Mr Hugh Grant CCP, *Advice on AER preliminary decision and Energex and Ergon Energy revised proposals*,, September 2015, p. 23.

64 Mr Hugh Grant CCP, *Advice on AER preliminary decision and Energex and Ergon Energy revised proposals*,, September 2015, p. 23.

the 2015–20 period. This suggests that some augmentation is justified to alleviate forecast capacity constraints.

In some cases, this information may inform our estimate of augex. However, for our preliminary decision, our observations were primarily used to inform us and direct us to more detailed economic and engineering reviews of Ergon Energy's augex forecast.

We disagree with the CCP that we gave insufficient consideration to the prudence/efficiency of Ergon Energy's proposed augex. Our assessment of the prudency and efficiency of Ergon Energy's augex forecast was based on our detailed economic and engineering review of the proposal. We were also informed by the findings and recommendations from engineering consultants EMCa, which are set out in our preliminary decision.

Finally, all of our analysis of network utilisation trends was based on Ergon Energy's forecasts of maximum demand at the system and local levels. As set out in appendix C, we accept that Ergon Energy's maximum demand forecasts reflect a realistic expectation of demand over the 2015–20 period. Our reasons, including responding to points raised in the CCP's submission, are provided in appendix C.

B.2.5 Driver and project analysis

This section sets out our assessment of whether each component of Ergon Energy's augex forecast reasonably reflects the capex criteria. We then determine an alternative estimate for each augex component.

As discussed in section B.2.3, our decision is based on quantifying the impact of any forecasting biases within Ergon Energy's bottom-up project estimates. To quantify the impact of the forecasting biases, we have had regard to the findings of our preliminary decision (as well material taken into account in reaching that decision), Ergon Energy's revised proposal and supporting documentation, and a further review of Ergon Energy's revised proposal.[65]

Table 6.9 sets out our final decision on each component of Ergon Energy's augex proposal and the overall augex forecast.

[65] EMCa reviewed Ergon Energy's distribution and other system-enabling capex revised forecasts. EMCa did not review Ergon Energy's sub-transmission, reliability and power quality capex. We consider this separately below.

Table 6.9 AER alternative augex allowance ($2014−15 million, excluding overheads)

Category	2015−16	2016−17	2017−18	2018−19	2019−20	Total
Sub-transmission	48.3	52.4	50.6	19.6	20.9	191.8
Distribution	60.2	54.5	54.5	53.8	54.8	276.4
Quality of supply	1.2	1.2	1.2	1.2	1.1	5.8
Reliability	1.0	1.0	1.0	1.0	1.0	5.2
Other system-enabling capex	21.6	15.3	9.5	13.1	11.5	71.0
Total augex revised proposal	132.3	124.4	116.8	88.7	89.3	550.2

Source: AER analysis.

Our final decision reflects the following positions:

- We include Ergon Energy's forecast of $191.8 million for sub-transmission augex in our alternative estimate. We are satisfied that this capex reasonably reflects the capex criteria.
- We accept that the majority of Ergon Energy's $318.9 million forecast for distribution augex reasonably reflects the capex criteria. However, we consider that the proposed capex to address network voltage problems and the unspecified capex program are overstated. We have included an amount of $276.4 million for distribution augmentation in our alternative estimate.
- We include Ergon Energy's $11 million forecast for reliability and quality of supply augex in our alternative estimate. Ergon Energy's proposal is consistent with our preliminary decision. Accordingly, we are satisfied that these estimates reasonably reflect the capex criteria (for the reasons set out in our preliminary decision) and we have not considered these categories further.
- We accept that the majority of Ergon Energy's $94.7 million forecast for other system-enabling capex reasonably reflects the capex criteria. However, we consider that Ergon Energy's proposed capex for these projects is overstated by up to 20 per cent, and instead include an alternative estimate of $71 million. This is informed by a further review of Ergon Energy's material by our consultants EMCa.
- We accept Ergon Energy's explanation that the unexplained capex reflects labour cost escalations.

The following sections set out Ergon Energy's revised proposed capex for each cost driver, EMCa's assessment and findings (where relevant), and our conclusions.

Sub-transmission

Ergon Energy's revised proposal includes $192 million ($2014–15) capex to augment its sub-distribution network. This is consistent with its original proposal.

In our preliminary decision, we included $188 million in our alternative estimate for sub-transmission augmentation. Based on a review of Ergon Energy's capex from our consultant EMCa, we concluded that the vast majority of the sub-transmission capex reflected the prudent and efficient costs to augment its sub-transmission network. This was because we found that Ergon Energy:

- demonstrated probabilistic planning that correctly used of the value of customer reliability to calculate the cost of outages against the costs of augmenting the network,
- showed prudent consideration of demand management and non-network solutions, and
- sufficiently justified the need for certain projects to avoid breaching security of supply criteria and accommodate forecast demand requirements.

However, EMCa found that that there were some opportunities for Ergon Energy to optimise its sub-transmission programs, including project deferral, greater tolerance of risk and the timing of capex.[66] On this basis, we applied a 2.5 per cent reduction to the sub-transmission forecast.

In Ergon Energy's submission to our preliminary decision, it stated:

> Ergon Energy believes the sub-transmission augmentation program in our proposal has been developed to optimally reflect the timing of when constraints on the network will occur and to ensure the lowest overall cost option (non-network or network) has been selected to resolve those constraints. The range of options considered is broad and will ensure both internal and external (market based) solutions are compared to achieve the best overall solution as required by the Regulatory Investment Test for Distribution requirements of the NER.
>
> The change from deterministic to probabilistic planning during the 2010–15 regulatory control period has been reflected in the development of options for augmentation as well as consideration of the appropriate mix of non-network and network based solutions, including demand management and operational responses to meet the requirements of the security of supply criteria which is defined within our distribution licence conditions.[67]

We have included Ergon Energy's revised capex for sub-transmission augmentation in our alternative estimate of total augex. While Ergon Energy has not reduced its capex in light of our preliminary decision, we no longer intend to apply a 2.5 per cent reduction to this augex component. This is because we are generally satisfied that its approach to planning sub-transmission augmentation is prudent and efficient, and its forecast reasonably reflects of the capex criteria. To the extent that Ergon Energy is

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66 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Regulatory Proposal 2015 −20*, April 2015, p. 63−64.

67 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 15.

able to find additional efficiencies (such as through project deferrals), these efficiencies will be shared with customers through the capital expenditure sharing scheme.

Distribution

Ergon Energy's revised proposal included $319 million ($2014–15) capex to augment its distribution network. This is 7 per cent less than its original proposal (for the reasons set out below). This forecast is primary driven by existing constraints on its distribution network assets (e.g. distribution transformers, high voltage and low voltage feeders, and SWER lines), future demand forecasts, and managing future growth and penetration of solar photovoltaic (PV) systems.[68] This forecast comprises Ergon Energy's 'distribution network augmentation program'.

Table 6.10B.5 sets out the individual projects and programs that make up Ergon Energy's distribution augex forecast.

Table 6.10 Ergon Energy distribution augex forecast ($2014–15 million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Distribution Network Augmentation	13	20	32	32	34	132
Unspecific Distribution Network Augmentation program	19	18	18	17	17	88
Work in progress	26	14	2.0	2.0	1.0	45
Voltage issues from solar PV	9.0	9.0	9.0	9.0	9.0	44
Distribution transformers	2.0	2.0	2.0	2.0	2.0	9.0
Total	68	63	63	63	63	319

Source: Ergon Energy revised proposal, Attachment 07.00.02 (Revise); Ergon Energy response to AER ERG 093.
Note: Numbers may not add up due to rounding.

In our preliminary decision, we did not make specific adjustments to the capex for these projects. Instead, we had regard to the technical review undertaken by EMCa. EMCa concluded that the forecast for distribution augex (of which these projects are a component) was overestimated in the order of 10 to 20 per cent.

We included $274.6 million on our preliminary decision alternative estimate, which was the mid-point of EMCa's recommended range. We stated that, in the absence of evidence pointing towards to the top or bottom of the range, adopting the mid-point reflects a reasonable estimate of the level of augex Ergon Energy requires to prudently and efficiently meet the capital expenditure objectives. Our final decision includes a

68 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.02 (Revised), p. 46.

forecast of $276.4 million for distribution augmentation, which is slightly higher than our preliminary decision. In coming to our decision we first engaged EMCa to undertake a review of the new material submitted by Ergon Energy and provide advice on whether the material was sufficient for it to amend its view on the prudency and efficiency of the forecast. The results of their review are discussed below in our consideration of the voltage and unspecified distribution augmentation projects. Putting together the EMCa review of Ergon Energy's initial proposal and the new material provided by Ergon Energy, EMCa have suggested that a range of $271 million to $303 million could be said to be broadly representative of a prudent and efficient expenditure level.[69]

We then undertook our own bottom-up review of the individual programs that comprise Ergon Energy's distribution augex proposal, in particular the programs to address voltage issues from solar PV and unspecified distribution augmentation. This included reviewing all material submitted by Ergon Energy, including the original proposal and the revised proposal. In some circumstances, this includes additional technical analysis than we performed for the preliminary decision. From this review we determined the costs for these programs that would reasonably reflected the capex criteria. The components of these projects are discussed in detail in the following sections.

As set out in , our finding from our bottom-up review is a total forecast of $276.4 million for distribution augex. These individual estimates are based on a combination of our individual project reviews and EMCa's recommendations. Our alternative estimate is within the overall range of prudent and efficient expenditure for this category recommended by EMCa and is largely consistent with our preliminary decision. While it is at the lower range of EMCa's recommendations, this has been informed by our bottom-up estimate. We consider that this lends considerable support to the reductions recommended by EMCa on Ergon Energy's revised proposal.

Table 6.11 AER alternative estimate of Ergon Energy's distribution augex ($2014−15 million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Distribution Network Augmentation	13	20	32	32	34	132
Unspecified Distribution Network Augmentation program	13.8	13.1	13.1	12.4	12.4	64
Work in progress	26.0	14	2.0	2.0	1.0	45
Voltage issues from solar PV	5.4	5.4	5.4	5.4	5.4	26.4
Distribution transformers	2.0	2.0	2.0	2.0	2.0	9.0
Total	**60.2**	**54.5**	**54.5**	**53.8**	**54.8**	**276.4**

Source: AER analysis.

[69] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 19.

Note: Numbers may not add up due to rounding.

The following sections consider our review and alternative estimate of Ergon Energy's distribution augmentation programs.

Distribution network augmentation program

Ergon Energy's distribution network augmentation program relates to augmenting distribution feeders and SWER lines to address existing capacity constraints and voltage related problems.[70] This capex program reflects typical network augmentation due to demand growth and capacity constraints.

In our preliminary decision, we accepted that Ergon Energy's maximum demand forecasts reflected a realistic expectation of demand over the 2015–20 period. However, we considered that there are opportunities for Ergon Energy to optimise its distribution programs, including project deferral and though greater tolerance of risk and the timing of capex.[71] In coming to this view, we observed that:

- Ergon Energy's proposed allowance for demand growth and new large loads in specific locations which may not occur as anticipated during the 2015–20 regulatory control period. Our consultant EMCa considered that, when aggregated, it would be reasonable to make some adjustment to reflect the level of probability that not all regional demand growth will occur within the forecasted timeframe.[72]
- Ergon Energy could apply further risk analysis to consider opportunities to defer some projects with demand management or hybrid augmentation and demand management solutions.[73] In support of this, EMCa also considered that Ergon Energy's augex was not always adequately supported by cost-benefit analysis, robust options analysis and appropriately-applied risk assessment.[74]

Ergon Energy originally proposed $143 million for this augmentation program.[75] In response to our preliminary decision, Ergon Energy reduced this capex by approximately 10 per cent to $132 million based on its assessment of demand growth and risk assessment which has reduced the scope and volume of some of the proposed projects.

In terms of demand forecasts, Ergon Energy has not revised its total system maximum demand forecasts for the 2015–20 period. However, it submitted that it reviewed its

70 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.02 (Revise), p. 47.

71 AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, p. 57.

72 AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, p. 57.

73 AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, p. 57.

74 AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, p. 52.

75 Ergon Energy's supporting attachment includes the cost as $136 million, which is stated in real dollar 2012/13. We calculated the cost as $146 million in 2014/15 dollars using our assumed CPI adjustment. See Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.02.

spatial demand forecasts (which drive localised network augmentation) across its network.[76] This may have contributed to lower distribution augmentation requirements.

As part of its review of demand forecasts and project prioritisation, Ergon Energy removed 54 specified projects from its distribution augmentation program. These include all projects that Ergon Energy previously assessed as 'low' or 'moderate' risk, and a number of projects that Ergon Energy previously assessed as 'high risk'. Ergon Energy determines its risk rating based on its assessment of the consequences on network reliability, safety and capacity from a project not proceeding, and the likelihood of these consequences occurring.[77]

We engaged EMCa to review Ergon Energy's revised proposal and its submission to the issues that EMCa raised in its review of the initial proposal. EMCa concluded that:

> We consider that the basis for Ergon's exclusion of 54 projects from its revised Specified DNAP program results from Ergon implementing changes to its assessment process which appear to be aligned with our original findings. At a systemic level, we consider that this is likely to render this program more reflective of a prudent level. Whilst we are concerned by the lack of reconciliation of the impact that this has had, on balance, we consider that the reduction made by Ergon appears to be within an appropriate range.[78]

We agree with EMCa's conclusions and consider that Ergon Energy has addressed the issues raised in our preliminary decision. On this basis, we have included the proposed $132 million capex in our alternative estimate. We are satisfied that this capex reflects the prudent and efficient costs for Ergon Energy to augment its distribution network in response to demand growth and alleviating capacity constraints.

In Ergon Energy's submission to our preliminary decision, it submitted a report from consultants Jacobs Group (Australia) which suggested that Ergon Energy's network reliability would decrease based on our substitute capex for sub-transmission and distribution augmentation.[79] Jacobs' concerns should be addressed given we are accepting Ergon Energy's proposed capex for sub-transmission and distribution augmentation in its revised proposal.[80]

Unspecified distribution network augmentation program

Ergon Energy's unspecified distribution network augmentation program relates to addressing constraints and issues on Ergon Energy's low voltage network which are

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76 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.16, p. 2.

77 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.02 (Revised), pp. 50-51.

78 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 18.

79 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment EXP.09.02

80 Note that our primary reductions to Ergon Energy's augex are within its power quality forecast and other system-enabling capex forecast. These programs do not have an immediate impact on network reliability and therefore are not relevant for the Jacobs report.

"not anticipated, forecasted or planned". [81] This includes miscellaneous works to address voltage control customer complaints, small urgent works, pole removals and overloaded distribution transformers.[82]

This unspecified augmentation program will address a similar range of network issues as under its specified augmentation program. The difference is that the specified program is a planned program of work to address known network constraints (i.e. proactive work to address existing capacity constraints and demand growth) whereas the unspecified program is unplanned and Ergon Energy's approach is to respond as network issues as they arise (i.e. reactive work).

Ergon Energy proposed $88 million for this reactive program. Ergon Energy calculated its capex requirements based on the historical level of expenditure for this kind of activity over 2009–13. It then reduced this amount to account for potential overlaps with other capex programs such as refurbishment, asset replacement, street-lighting, generation and Powerlink associated works.[83] This reduced the proposed by approximately 36 per cent compared to historical spend of $137 million.

In our preliminary decision, we noted that this capex had not been supported with analysis to explain the underlying drivers of this expenditure. Our consultants EMCa also considered that the use of a historical trend to forecast expenditure in this category does not account for the expected changes in demand and energy consumption. We took this into account when making our overall downwards adjustment to Ergon Energy's distribution augex forecast.

In response to our preliminary decision, Ergon Energy's revised proposal submitted that its forecast for unspecified augmentation capex is reasonable because:

- the forecast capex is already 37 per cent below historic levels of expenditure for reactive augmentation work
- there is no evidence based on historical trends (both customer complaints and historic expenditure) to suggest that Ergon Energy's unplanned and reactive expenditure requirements will decrease in future years
- customer side increased visibility of network voltage performance (through the introduction of smart meters and other new technologies) will place further pressure on Ergon Energy's unspecified program
- its capex forecast does not have a specific low voltage augmentation investment category and the unspecified program provides support for any necessary reinforcement of the low voltage networks in the future.[84]

81 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.02 (Revised), p. 47.

82 Ergon Energy, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Attachment 07.00.02, p. 54.

83 Ergon energy, response to AER Ergon 093.

84 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 17.

Our alternative estimate for this capex is $64 million, which is 27 per cent less than Ergon Energy's proposed capex for this program. We have reviewed all the material provided by Ergon Energy in its original and revised proposals. On the basis of our review, we consider that Ergon Energy's forecast is overstated compared to a prudent and efficient amount. This is for the following reasons.

First, we consider that it is legitimate to forecast future expenditure requirements based on historical expenditure trends where it is can be demonstrated the underlying costs and drivers of this expenditure are likely to remain the same. However, Ergon Energy's original and revised regulatory proposals provided little supporting information about historical volumes and costs of reactive works and assumptions about its future requirements. While our preliminary decision found that the capex forecast was not supported by underlying driver analysis, Ergon Energy has not provided new information to support its forecast for this program of work.

This is supported by EMCa in its review of Ergon Energy's revised proposal. In response to our preliminary decision, EMCa stated that it had expected to see evidence that:

- the expenditure would be directed to network issues of sufficient risk/urgency to warrant remedial work
- the trends of network issues to be addressed support the level of expenditure proposed
- appropriate strategies would be deployed to ensure prudent and efficient expenditure, and
- the work was delivering the desired outcomes.[85]

In the absence of Ergon Energy having considered this information or evidence in preparing its capex forecast, EMCa concluded that the proposed capex for reactive work is likely overstated.[86] We agree and are not satisfied that the capex reflects a prudent and efficient amount to respond to network arises as they arise to maintain network reliability, power quality or meet forecast demand growth.

Second, one direct impact of the lack of underlying driver analysis is that the potential scope of reactive work overlaps with other planned augmentation programs. In particular:

- We have provided Ergon Energy with $28 million in capex to implement its proposed program to proactively address network voltage and capacity issues due to projected growth in solar PV installation (as discussed below). Ergon Energy

85 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, pp. 16-17.

86 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, pp. 16-17.

previously addressed network voltage issues as they arose and historical expenditure on these activities is reflected in the historical ‘unspecified’ augex.

- We have provided Ergon Energy with its proposed $9 million to augment distribution transformers that are operating above their capacity. Ergon Energy previously upgraded distribution transformer reactively and historical expenditure on these activities is reflected in the historical ‘unspecified’ augex.

As planned augmentation work on network voltage and distribution transformers is completed, this should reduce (if not eliminate) the amount of unforeseen issues that will arise due to overvoltage or capacity constrained transformers. This suggests that there will be overlap and double-counting between the planned and reactive distribution augmentation programs.

Ergon Energy submitted that it reduced its forecast capex for reactive works to account for potential overlaps with other capex programs. We asked Ergon Energy for an explanation of how it took into account overlaps with other capex programs to ensure that it has not already reduced its capex to account for its proposed capex for network voltage and distribution transformers. Ergon Energy’s replied stating:

> A two-step process was applied. First, using historic ellipse data augmentation projects were filtered by removing non-augmentation categories such as Refurbishment, Asset Replacement, Streetlighting, Generation, etc. Data was then further filtered to ensure any other sub categories such as Powerlink associated work was removed to leave all relevant historic augmentation reactive projects.[87]

Ergon Energy’s reply suggests that it did not specifically taken into account its newly planned network voltage and distribution transformers augmentation capex programs. This confirms for us that there is overlap and double-counting between the planned and reactive distribution augmentation programs.

We have estimated that the capex Ergon Energy spent on network voltage (in response to solar PV) and distribution transformer augmentation over the 2010–15 period is approximately $24 million. This reflects the amount of double-counting within the unspecified augmentation capex proposal. This is based on:

- $13 million spent to augment distribution transformers over 2010–14.[88] Ergon Energy submitted that this is a very high level estimate based on a manual audit of its systems, but we consider it should be reflective of the amount spent by Ergon Energy over this period.
- $11 million spent to address network voltage issues due to solar PV over 2010–15. Ergon Energy did not provide us with historical capex for these works and so we have estimated this based on Ergon Energy’s projected increase in solar PV issues

87 Ergon Energy response to AER Ergon 094, p. 1.

88 Ergon Energy provided us with the historical capex spent on distribution transformer augmentation in response to an information request. See Ergon Energy response to AER Ergon 096, p. 3.

over the 2015–20 period.[89] Note that this is based on the capex proposed by Ergon Energy for its voltage quality program, rather than our lower alternative estimate.

Our alternative estimate of $64 million is based on the removal of this potential double-counting from Ergon Energy's capex forecast for unspecified distribution augmentation. This is because the double-counting is the most direct and identifiable impact from the fact that Ergon Energy has not supported its capex with underlying driver and cost analysis. When combined with its planned augmentation program, we consider that this reflects a prudent and efficient amount for Ergon Energy to comply with the capex objectives.

Ergon Energy submitted that its proposed reduction in planned augmentation works means that more pressure will be placed on its unspecified augmentation works. In particular, it stated:

> Ergon Energy is also aware that reduction of the specified program by 10.1% will place some additional pressure on the unspecified sub-category. This will become evident through an increase in customer related complaints in areas such as power quality. Additionally, as noted in point (3) above, with both Ergon Energy and its customers becoming more aware of voltage levels following the introduction of smart meters, IES and other new technologies, this risk will be further exacerbated.

We consider that Ergon Energy will be well placed to manage power quality on its network over the 2015–20 period without proposed additional capex. Ergon Energy's power quality capex program is designed to manage voltage level problems over the 2015–20 period, which should alleviate most if not all pressure on the unspecific capex allowance to manage these issues. Furthermore, as set out below, we consider that Ergon Energy has significantly overstated the impact of projected growth in solar PV connections over the 2015–20 period on network voltage levels.

Remediation of power quality issues

Ergon Energy is subject to voltage level regulation under Queensland Electricity Regulation 2006. Ergon Energy submitted that the growth of solar PV systems on its network has resulted in increase in voltage levels beyond its statutory limits due to increasing number of 'two way' power flows across its low voltage network.

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[89] As set out in the 'remediation of power quality issues' section, Ergon Energy forecasts that the number of feeders that will experience voltage problems from solar PV will increase by 75 per cent between 2015 and 2020. This suggests that the number of issues that Ergon Energy remediated in 2015 was 40 per cent of the amount it forecasts for 2020. Ergon Energy submitted that the number of voltage problems rose significantly in the latter half of the 2010-15 period, with associated increases in capex required to address issues reactively (see Ergon Energy response to AER Ergon 094, pp. 1-2). On the basis of this information, we consider that the amount of work performed by Ergon Energy to address voltage problems over the 2010–15 period is approximately 25 per cent of the work forecast over the 2015–20 period, which equates to $11 million.

Ergon Energy's analysis shows that approximately 30 per cent of its feeders and networks have existing solar PV connections, and some of these currently experience overvoltage problems. Ergon Energy projects growth in solar PV connections will continue over the 2015–20 period in line with historical growth.[90] Based on its forecast growth in solar PV connections, Ergon Energy's predicts that the number of feeders and networks that will experience overvoltage problems will increase by 75 per cent by 2020.[91]

To manage the proposed impact of voltage issues on its network, Ergon Energy proposed $45 million in augex to install voltage regulators on its network and upgrade distribution transformers and low voltage feeders to lessen the voltage drop or rise along the low voltage network.[92]

Ergon Energy included this capex in its original regulatory proposal. In our preliminary decision, we drew conclusions on its proposed capex based on a technical review conducted by our consultant EMCa. Based on this review, we stated that:

> EMCa found that this capex has not been justified with a business case demonstrating an economic basis for the projects. While EMCa agrees with Ergon Energy that voltage control is a potentially costly issue associated with growth in inverter energy system connections, these costs need to be articulated in the form of a detailed business case. Additionally, EMCa considers that Ergon Energy's analysis should take into account how the uptake of solar installations will reduce augmentation.[93]

While we did not make specific adjustments to this forecast capex, our overall downwards adjustment to Ergon Energy's distribution augex forecast took into account this analysis of this capex forecast.

In its submission to our preliminary decision, Ergon Energy stated that:

> Ergon Energy challenges the reduction in the forecast expenditure for photovoltaic augmentation. We have provided sufficiently detailed technical and economic analysis, including assumptions, methodology and evidence of the impacts and associated network augmentation to manage voltage fluctuations in the network, resulting from solar system installations. The extensive supporting document "Distribution Network Impacts of Photovoltaic Connections to 2020" which totalled 390 pages, and three associated parent business cases detail and support this expenditure.[94]

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[90] Ergon Energy's medium growth forecast predicts that there will be approximately 220,000 solar PV systems installed on its network by 2020, which is approximately 30 per cent of its total customers.

[91] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 34.

[92] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, July 2015, Attachment 07.02.12, pp. 27-28.

[93] AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, p. 6-57.

[94] Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 17.

Ergon Energy also submitted that the latest forecasts of solar PV growth are higher than previously forecast which will increase the volume of work required. However, it has not proposed any additional capex in its revised proposal.

We have reviewed all the material submitted by Ergon Energy in its original and revised proposal, including its detailed supporting attachments. We have also engaged EMCa to review Ergon Energy's revised proposal.

On the basis of our review, we accept Ergon Energy's forecasts for growth in solar PV connections over the 2015–20 period. This projected increase is consistent with AEMO's forecast of solar PV growth in Queensland, increases in average installed inverter capacity, and the potential impact of the new Queensland government's one million PV installation target. However, our analysis suggests that Ergon Energy's proposed capex overstates the amount of work required to manage potential overvoltage issues on its network. This is because:

- Ergon Energy's 2014 solar PV connection standard requires that the PV systems cut out before voltage levels exceed statutory limits — compliance with this connection standard should reduce the need to correct or manage voltage issues with newly installed systems by up to 40 per cent
- Ergon Energy's meter probe program reveals that existing overvoltage issues are not significant and are largely within statutory limits. The magnitude of voltage rises above statutory limits should be within Ergon Energy's voltage control capability for a large amount of cases.

We also engaged EMCa to review the information provided by Ergon Energy in its revised proposal. Based on its analysis, EMCa stated that Ergon Energy overstates the risk to the network from solar PV connections and seeks to address all existing voltage issues. It concluded that that a more reasonable strategy would be to address known issues in areas where the PV penetration is high as a means of reducing overall program cost whilst addressing the areas in which voltage excursions are likely to be highest. EMCa concluded that, on balance, the new information provided does not fully address the concerns expressed in its original April 2015 report.[95]

Our alternative estimate for this capex is $26.4 million, which is 40 per cent less than Ergon Energy's proposed capex for this program. This primarily reflects our conclusion that Ergon Energy may not experience any additional growth in overvoltage issues if it consistently enforces its new connection standard, and our observations that Ergon Energy has overstated the significance of voltage level issues. This estimate should provide Ergon Energy with a sufficient amount to address voltage issues on its network to comply with its statutory obligations.

We note that EMCa did not quantify a prudent and efficient amount for Ergon Energy to address voltage level problems over 2015–20. Rather it considered that Ergon

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[95] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 15.

Energy's aggregate distribution augex forecast was overstated by 5 to 15 per cent (or $16 million to $48 million). However, EMCa only raised concerns with the proposed network voltage and unspecified augmentation projects. The combination of our proposed reductions to unspecified augmentation and power quality capex is $41.6 million, which is consistent with EMCa's estimate of the overestimation in these capex projects.

The remainder of this section expands on these reasons for coming to our alternative capex estimate for remediation of power issues.

Growth in voltage issues overstated

Under Queensland Electricity Regulation 2006, Ergon Energy is required to supply voltage on its low voltage network at 240 volts. However, it is permitted an allowable range of +/- 6 per cent from this standard voltage, which equates to between 225.6 volts and 254.4 volts.[96]

On 1 July 2014, Ergon Energy introduced a new standard for the connection of small-scale rooftop solar PV systems on its network (in conjunction with Energex).[97] This standard specifies technical requirements and performance standards for installed solar PV systems. Under this connection standard, a particular solar PV system must cut its electricity output to the distribution network if voltage exceeds 255 volts.[98] This is intended to allow Ergon Energy to comply with its regulatory voltage limits.

As set out in this connection standard, it is Ergon Energy's responsibility to ensure all proposed solar PV connections comply with the requirements of the standard.[99] This is recognised by Ergon Energy in its supporting documentation:

> The growth of inverter energy systems attributed issues in LV networks will significantly reduce by enforcing Ergon Energy's Connection Standard for Small Scale Inverter Energy System up to 30kVA for all new connections from Q3 2014. This standard will limit customer export capabilities to sizes acceptable without network upgrade; require the use of reactive power control strategies for active network voltage support; and introduce requirements for partial and full export limitation. This standard will help balance customer choice with network impacts.[100]

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96 See cll. 11 and 13 of *Queensland Electricity Regulation 2006*.

97 Ergon Energy and Energex, "Connection Standard: Small Scale Parallel Inverter Energy Systems up to 30 kVA". Available at https://www.ergon.com.au/network/contractors-and-industry/solar-pv-installers/connection-standard; accessed on 11 September 2015.

98 Ergon Energy and Energex, "Connection Standard: Small Scale Parallel Inverter Energy Systems up to 30 kVA", clause 6.11. Available at https://www.ergon.com.au/network/contractors-and-industry/solar-pv-installers/connection-standard; accessed on 11 September 2015.

99 Ergon Energy and Energex, "Connection Standard: Small Scale Parallel Inverter Energy Systems up to 30 kVA", clause 1. Available at https://www.ergon.com.au/network/contractors-and-industry/solar-pv-installers/connection-standard; accessed on 11 September 2015.

100 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 6.

In a response to a prior information request about solar PV and voltage issues, Ergon Energy outlined its new connection policy and stated:

> Ergon Energy reinforces the required 255V maximum voltage trip point setting at every opportunity, to both customers and installers.[101]

This suggests that Ergon Energy intends to consistently apply and enforce its solar PV connection standard. It is not clear how or whether Ergon Energy has taken this into account in its forecast increase in overvoltage issues by 2020. For example, Ergon Energy proposed an increase in overvoltage issues over the 2015–20 period which follows the growth in solar PV connections.[102] However we consider that, if Ergon Energy enforces the voltage cut-off requirements in its new connection standard, then new solar PV connections installed over 2015–20 should create very few overvoltage issues on Ergon Energy's network.

This view is supported by EMCa in its review of Ergon Energy's revised proposal:

> Ergon introduced a more robust connections policy in 2014 to help ensure that all new inverters are set to block export when the voltage exceeds 255 Volts (240V +6%). This should mitigate voltage excursion issues on all new installations, particularly if inverters with reactive power control functionality are deployed. Provided future connections can be made to comply with this requirement, the issue of the future PV connections growth rate becomes less relevant to future expenditure requirements. [103]

As noted previously, Ergon Energy forecasts that the number of feeders and networks that will experience overvoltage problems will increase by 75 per cent between 2014 and 2020.[104] This is based on forecast growth in solar PV connections. However, given the application of Ergon Energy's new connection standard, Ergon Energy should experience little, if any, additional growth in overvoltage issues if it consistently enforces its connection standard. This suggests that the Ergon Energy's proposed augex is proportionately overstated.

Managing existing overvoltage issues

Ergon Energy proposed a number of relatively high cost solutions to manage overvoltage issues on its network over the 2015–20 period. These include augmenting distribution transformers, and completely replacing some conductors, to alleviate any voltage increases on the network. We consider that Ergon Energy has overstated the impact of existing voltage increases on its network and this may have led to inflated capex proposed to manage this over the 2015–20 period.

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101 Ergon Energy, response to AER Ergon 018 (2b), p. 5.

102 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 34.

103 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 14.

104 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 34.

Ergon Energy conducted a meter data survey in parts of its network to attempt to quantify the impact and correlation of solar PV and overvoltage issues on its network. On the basis of its survey, Ergon Energy found roughly 20 percent of sites expected to have a voltage issue due to inverter energy system connections were showing voltage above statutory limits.[105] However, it also showed that the voltage on its feeders rose by an average of only 2%, or less than 5 volts, due to the impact of existing solar PV systems.[106]

This survey showed that there were some voltage increases above the statutory voltage limit of 254.4 volts. However, importantly, the results showed that both:

- voltage did not increase above 256 volts, which is only 1-2 volts above the upper limit of Ergon Energy's requirements within *Queensland Electricity Regulation 2006* (which is 254.5 volts), and
- the average voltage levels were higher than 240 volts, but the range of voltage levels (e.g. minimum to maximum voltages) was 21 volts, which is within the margins allowed within the requirements of the *Queensland Electricity Regulation 2006*.[107]

The voltage fluctuation data from Ergon Energy's meter data survey shows that the range of voltage fluctuation is smaller than the standard supply voltage range. Advice from our technical staff within the AER suggests that Ergon Energy should be able to, through its network operation activities such as adjusting distribution transformer tap settings, maintain the voltage fluctuation within the standard supply voltage range. Where distribution transformer tap setting adjustment cannot fully address the issue, Ergon also has automated zone substation transformer tap changers to dynamically maintain the voltage within adequate supply range.

Ergon Energy already contemplated these sorts of low cost measures within a newly implemented voltage management program. Ergon Energy stated that:

> In order to reduce the proportion of networks operating with voltages consistently outside, or at the higher end of the levels defined in the *Standard for Network Performance*, Ergon Energy has proposed to implement voltage management. Implementation will bring voltages closer to nominal by facilitating a comprehensive review of tap settings, line drop compensation and voltage regulation capabilities, and by developing a more refined approach to the design, control and monitoring of voltage levels in the network. While this option will not solve all of the potential impacts on the network that result from the injection of real power from the inverter energy system onto the distribution network; if used in conjunction with other legislative requirements and

105 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 38.

106 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 41.

107 Ergon Energy is allowed a margin of +/- 6 per cent from a standard 240 volts. This equates to a range of 226 to 254 volts, or 28 volts. The results of Ergon Energy's meter data survey shows the voltage at the end of a distribution feeder fluctuated between 234 volts and 255 volts, or 21 volts. See Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, pp. 39-40.

> technological devices, Ergon Energy can delay and reduce the immediate and long term network augmentation costs.[108]

We consider that Ergon Energy's voltage management, particularly at zone substation level, should be effective in mitigating many of the overvoltage issues currently being experienced on its network. This is because the existing voltage ranges on its network are close to or within statutory limits such that low-cost operational measures, such as reviewing transformer tap settings, should be effective in lowering voltage levels on its network. This would avoid some network augmentation.

Ergon Energy stated that it has already factored in the impact of its voltage management program on augmentation requirements (by otherwise reducing proposed capex). In particular, it predicted the impact of its voltage management program on network voltage and then proposed network augmentation to correct remaining forecast overvoltage issues.[109] However, we consider that Ergon Energy has understated its ability to rely on this operational solution to overvoltage issues because Ergon Energy significantly overstates expected growth in overvoltage issues on its network (due to the application of its new connection standard). This suggests that Ergon Energy overstated any augex it requires in addition to its planned voltage management program.

Ergon Energy's options analysis and risk assessment

Ergon Energy's submission to our preliminary decision provided some additional explanation of its risk assessment for power quality issues.

Ergon Energy's risk management framework applies risk ratings of between 1 and 36 based on expected legal, safety and reliability consequences and the likelihood of issues occurring.[110] Ergon Energy submitted that it rates the risk of a drop in voltage of 3.5 per cent below standard voltage as '30', and an additional voltage drop of 5.5 per cent (for a total of 9 per cent) as '36'.[111] A risk rating of between 30 and 36 is ranked as 'intolerable' or 'extreme' under Ergon Energy's risk management framework. An 'extreme' risk rating requires Ergon Energy to take immediate action "to reduce the risk to the tolerable range".[112]

Ergon Energy submitted that this risk ranking is appropriate as it prevents systemic non-compliance with the current Queensland Electricity Regulations and National Electricity Rules under normal load conditions.[113] While we agree that on-going non-compliance with regulatory obligations is something that Ergon Energy must address,

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108 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.02.12, p. 31.

109 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, July 2015, Attachment 07.02.12, pp. 32-35.

110 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.09.30 (Risk Management and Insurance).

111 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 11.

112 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.09.30 (Risk Management and Insurance), p. 3.

113 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 11.

we consider that Ergon Energy's proposed scope and costs of its program does not reflect a prudent and efficient amount to comply with its obligations. This is for the reasons set out previously in this section, and in particular that:

- new solar PV connections over the 2015–20 period will likely not contribute to overvoltage under Ergon Energy's new connection standard
- Ergon Energy overstates the significance of existing overvoltage issues on its network and it can largely manage existing risk within its current capabilities.

Our consultants EMCa also raised a number of issues with Ergon Energy's risk assessment based on its review of Ergon Energy's supporting business case. EMCa similarly observes that Ergon Energy rates the risk of not proceeding with the proposed program as 'extreme' based on Ergon Energy's assessment of the legal and regulatory consequence of failing to comply with statutory prescribed voltage limits.[114] EMCa considered that Ergon Energy's own actions in progressively addressing voltage issues over time, rather than undertaking comprehensive and immediate action, indicate that the risk is not 'extreme'.[115] It further stated that, if the physical network risk was 'extreme', then it would expect to see action by the technical regulator, such as to issue warning notices if immediate action was not taken.[116]

EMCa also considered Ergon Energy's options analysis for its proposed capex to remediate power quality issues. It concluded that:

> We remain concerned that the business case and projections are based on: (i) limited experience with the impact of relatively new enforcement of the inverter trip setting at 255V; and (ii) appear to seek to address all existing and projected voltage excursions in the network to reduce the legal/regulatory and safety risk to 'Low' by 2020. We consider that a more reasonable strategy would be to address known issues in areas where the PV penetration is high (e.g., >40%) as a means of reducing overall program cost whilst addressing the areas in which voltage excursions are likely to be highest.[117]

We consider that EMCa's observations and advice support our own conclusions that Ergon Energy's proposed capex to remediate power quality issues is overstated.

Work in progress augex

Ergon Energy proposed $45 million to complete a number of projects that are have carried over from the 2010–15 period. In particular, Ergon Energy submitted that "it is expected that approximately 75 projects initiated in the final months of 2014–15 will be

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[114] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment, 07.02.16, p. 4.

[115] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 12.

[116] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 13.

[117] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 14.

completed in the early months of 2015–16".[118] This is reflected in the fact that the majority of this capex is forecast to be incurred in 2015–16 and 2016–17 (as shown in Table 6.10 above).

Ergon Energy has not provided much information about the 75 projects it expects to initiate in 2014–15, such as whether they were originally planned for 2014–15 or were deferred from earlier years. However, we recognise that it is common for some capital works to be deferred to the next period, such as in response to reprioritisation or in response to deliverability issues. These views are supported by EMCa which conclude that, on balance, the proposed expenditure represents a prudent and efficient level.[119]

We agree with EMCa and have included Ergon Energy's proposed $45 million for this program in our alternative estimate.

Distribution transformers

Ergon Energy proposed $9 million to upgrade distribution transformers that are currently operating above their emergency capacity limits. Ergon Energy submitted that it proposed to augment less than 1 per cent of its distribution transformers and its capex forecast is half of what it spent on augmenting distribution transformers over the 2010–15 period.[120]

EMCa reviewed this capex and considered that the proposed capex likely represents a prudent and efficient forecast. This is on the basis that Ergon Energy proposed augmentation of a relatively small number of transformers based on a strategy that is compatible with a period of relatively low demand and energy growth. EMCa considered that should result in only the highest-risk transformers being augmented or replaced.[121]

We agree with EMCa and have included Ergon Energy's proposed $9 million for this program in our alternative estimate.

Reliability and power quality

In its initial proposal, Ergon Energy proposed:

- $5.5 million in capex (excluding overheads) to meet the reliability obligations set out in its Distribution Authority
- $6.5 million to extend the network monitoring of power quality to approximately 67 per cent of the network feeders.

[118] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.02, p. 438.

[119] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 14.

[120] Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 19.

[121] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 15.

We accepted both of these capex forecasts in our preliminary decision because they were significantly less than the actual capex incurred by Ergon Energy in the 2010–15 period, and our consultant EMCa did not identify any systemic issues in its review of these capex proposals.[122] Ergon Energy's revised proposal for reliability and power quality augex is consistent with our preliminary decision. Accordingly, we are satisfied that Ergon Energy's estimates reasonably reflect the capex criteria (for the reasons set out in our preliminary decision) and we have not considered these categories further.[123]

We note that Ergon Energy's need to invest in network monitoring of power quality is diminished, for the reasons set out in our review of Ergon Energy's proposed capex to remediate power quality issues. However, we have included the capex in our alternative estimate because it is a relatively low level of capex and it is the continuation of an existing program.[124]

Other system-enabling capex

Ergon Energy proposed $94.7 million ($2014−15) for what it refers to as 'other system-enabling capex'. This capex is proposed to address a number of network operation issues which fell outside of the reporting definitions for the main capex driver categories. Ergon Energy included this capex within its augex forecast.

Ergon Energy initially proposed $99 million for these programs.[125] In our preliminary determination, we did not accept Ergon Energy's forecast and instead included an amount of $82.4 million in our alternative estimate, a reduction of 15 per cent. Based on our review of Ergon Energy's supporting documentation, we considered there were a number of systematic issues with Ergon Energy's approach to developing the forecast programs of work. These included:[126]

- Costs estimates of a number of projects appeared at best preliminary and the benefits to consumers and Ergon Energy had generally not been quantified and assessed against the costs of the programs.
- Ergon Energy did not substantiate its risk ratings and it was not evident the proposed workload has been optimised for risk.
- There was insufficient exploration of alternative options and solutions, and the cost/benefit of these options to achieve the desired outcomes.

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[122] AER, *Preliminary Decision Ergon Energy determination 2015-20, Attachment 6: Capital expenditure*, pp. 6-58 to 6-61.

[123] Note that Ergon Energy's forecast for reliability and power quality augex includes $5.8 million ($2015) of 'metering' capex that we separately identify within our capex model. We have identified the specific amount of metering capex that is within the reliability and power quality forecasts based on Ergon Energy's spreadsheet '03.03.08 Escalations Data Model', attached to its revised regulatory proposal.

[124] As set out in Ergon Energy, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Attachment 07.00.05, p. 25 and Ergon Energy, *Power Quality Monitoring Strategy 2012−20.*

[125] Ergon Energy, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Attachment 07.00.04, p. 6.

[126] AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, pp. 6-61 to 6-63.

- Performance outcomes and targets for the projects were generally not defined in term of improvement in service performances, productivity, safety and cost.

We considered that these issues were evident in other areas of Ergon Energy's augex proposal that were reviewed by our consultants EMCa (notably the review of Ergon Energy's distribution and sub-transmission augex forecasts). Although EMCa did not review other system-enabling capex for our preliminary decision, our 15 per cent reduction reflected the scope of systemic biases identified by EMCa in Ergon Energy's sub-transmission and distribution augex.

In response to our preliminary decision, Ergon Energy reduced its proposed capex to $94 million but generally proposed the same program of works. Ergon Energy's revised proposal is described in more detail below.

We have included $71 million in our alternative estimate for other system-enabling capex. In coming to this view, we have reviewed all information before us, including the information provided by Ergon Energy in its revised proposal. Given the technical material provided by Ergon Energy in support of its proposal, we have also relied upon additional technical advice from our consultants' EMCa. On the basis of that further information and analysis, primarily the additional advice from our consultants EMCa and the information provided by Ergon Energy in its revised proposal, we have departed from our preliminary determination.

Revised Proposal

In its revised proposal Ergon Energy did not accept our preliminary determination of $82.4 million ($2014–15) for other system-enabling capex. Ergon Energy's revised proposal is for $94 million ($2014−15). This is a reduction of $4 million ($2014−15) from their initial proposal,[127] but $11.6 million more than our preliminary decision.[128]

Broadly, this capex is comprised of three programs to address data and communications, legislative compliance and miscellaneous network upgrades:

- **Operation technology projects** – $47 million for seven projects aimed at installing remote communication technologies associated with data acquisition and data management to monitor network performance and risk.
- **Protection projects** – $20 million for two projects associated with installing equipment to protect feeders and substations by monitoring network faults and operating network assets to comply with technical legislative and regulatory requirements.
- **Miscellaneous projects –** $27 million for three projects designed to augment power supply on substations and retrofit feeders with additional equipment to reduce the likelihood of potential safety risks and service outages to customers.

[127] Ergon Energy, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Attachment 07.00.04, pp. 8-9.

[128] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.04, pp. 8-9.

Ergon Energy's revised proposal maintains the operation technology projects and protection projects outlined in its initial proposal. Ergon Energy submitted that we had endorsed the need for expenditure in other system-enabling capex. Ergon Energy did not agree that there was a systematic bias of 15 per cent in its forecasting and business risk justification.[129]

Ergon Energy also noted that:

> EMCa did not review the Other Systems Capex category, and as such the systematic biases that were claimed to be evident in subtransmission and distribution are not material to the way the costing model is applied to Other System Enabling Capex.[130]

The key difference in Ergon Energy's revised regulatory proposal is under the 'Miscellaneous' sub-category, with the largest change being the expenditure proposed for substation power transformer bundling. In Ergon Energy's revised proposal it proposed expenditure of $11 million ($2014−15) on substation power transformer bundling to mitigate non-compliant transformer bunds.[131] This is $2 million ($2014−15) less than Ergon proposed in its initial proposal.[132]

As set out below, we engaged consultants EMCa to review Ergon Energy's other system-enabling capex in its revised proposal, and the supporting documentation submitted with its revised proposal. We provided EMCa's report to Ergon Energy for comment on 7 October 2015 and received a response from Ergon Energy on 14 October 2015. We consider Ergon Energy's response in our assessment below.

AER Position

We do not accept Ergon Energy's revised proposal of $94.7 million for other system-enabling capex and instead include $71 million in our alternative estimate.

In coming to this view, we have reviewed all information provided by Ergon Energy, including in its revised proposal and submission in response to our preliminary decision. As noted above, we also engaged EMCa to review all information provided by Ergon Energy.[133] In particular, EMCa reviewed each individual project within the 'other system-enabling capex' proposal and formed a view on Ergon Energy's analysis of the need, cost and options for investment.

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[129] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.04.

[130] Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 23.

[131] A transformer bund captures transformer oil spills and prevents oil migration to adjacent transformers, other site equipment and the environment; Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.04.

[132] Ergon Energy, *Regulatory proposal: July 2015 to June 2020*, 31 October 2014, Attachment 07.00.04.

[133] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, pp. 47-65.

Based on its review, EMCa identified systematic issues in Ergon Energy's other system-enabling capex that have led to a higher level of expenditure than required. We have summarised these issues as: [134]

- Ergon Energy's costs estimates and risk assessments of a number of projects appear at best preliminary and the benefits to consumers and Ergon Energy have generally not been quantified and assessed against the costs of the programs.
- The proposed capex has not been optimised for risk with Ergon tending to adopt a conservative approach when selecting the treatment option even when this did not appear to be justified by the supporting evidence.
- There is inadequate exploration of alternative options and solutions, and the cost benefit of these options to achieve the desired outcomes.

EMCa advised us that the combined impact of these biases is that Ergon Energy's forecast capex is overstated by between 20 and 30 percent. While EMCa's reasoning is similar to our views in the preliminary decision, this range is a higher proportion than EMCa identified for Ergon Energy's overall distribution augex forecast in the original and revised proposals. However, in support of this, EMCa stated that "there is evidence of systemic issues similar in nature to those that we encountered in reviewing other components of proposed expenditure, though with greater impact".[135]

We agree with EMCa's findings. We consider that EMCa has demonstrated that it has applied independent technical expertise to Ergon Energy's own planning documentation and supporting evidence. Further, EMCa's reasoning is generally consistent with our findings in our preliminary decision that there are systemic issues present within the other system-enabling capex forecast.

In coming to this view, we have also considered Ergon Energy's review of EMCa's report on that we received on 14 October 2015. Because we received Ergon Energy's response to EMCa's report close to our deadline for making a final decision on Ergon Energy's revised proposal, it has not been possible for us to make any further requests for information in relation to the matters raises in Ergon Energy's response, including from our consultants EMCa. Our consideration of Ergon Energy's response is contained within the individual project reviews below.

We note that one of Ergon Energy's key points in its response to EMCa's report is that EMCa's analysis is incorrect because it did not consider all information about Ergon Energy's proposed other system-enabling capex. This is because Ergon Energy's supporting attachments to the regulatory proposal only contain summary information from its project business cases. Ergon Energy stated that it holds more complete and detailed information about its financial, risk and options analysis within its internal

134 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, pp. 47-65.

135 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 64.

‘business case tool’ software package, which has not been available to us, EMCa or other stakeholders to assess Ergon Energy’s other system-enabling capex.[136] According to Ergon Energy, visibility of this information requires online access to the software tool or screenshots of the relevant information.[137]

Where Ergon Energy considers that there is relevant information that it wants us to take into account in making our decision, it is Ergon Energy’s responsibility to provide this information to us as part of its regulatory proposal (or in response to information requests), including so that the information can be made available to relevant stakeholders. If supporting information is not provided to us as part of a regulatory proposal (including a revised proposal), it is difficult for us and our consultants to take this information into account (either at all or at an earlier stage) when making our determinations. Our preliminary decision highlighted our concerns with Ergon Energy’s risk assessment and options analysis for its other system-enabling capex projects.[138] Based on our decision, Ergon Energy had an opportunity to provide more detailed information in its revised proposal about its risk assessment and options analysis that are contained within its internal business case tool software package. Ergon Energy did not do so.

In its response to EMCa’s report, Ergon Energy has now provided us with a number of screen shots from its ‘business case tool’ software. Ergon Energy stated that this provides evidence of investment options, cost and risk analysis that it developed and considered as part of the business investment governance process.[139] Ergon Energy also invited us and EMCa to gain direct access to its business case software or request specific screenshots to complete our assessment.[140] Given the statutory timeframe in which we must make our final decision on Ergon Energy’s revised proposal, we have been unable to seek views from EMCa in relation to this information, or request additional information from Ergon Energy. In particular, while we have had regard to Ergon Energy's response in assessing the revised proposal (as noted within the individual project reviews below) we have not been able to fully test this new information with EMCa or Ergon Energy. .

Based on our consideration of EMCa’s report and the information provided by Ergon Energy, we have reduced Ergon Energy’s forecast by 25 per cent. This reflects mid-point of EMCa's recommended range for other system-enabling capex which, as noted above, we agree with.[141] We do not consider that Ergon Energy’s additional information contained in its response to EMCa’s report justifies a lesser level of adjustment.

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136 Ergon Energy response to AER Ergon 103, pp. 2-3.

137 Ergon Energy response to AER Ergon 103, p. 2.

138 AER, *Preliminary Decision Ergon Energy determination 2015-20*, Attachment 6, pp. 61-63.

139 Ergon Energy response to AER Ergon 103, pp. 2-3.

140 Ergon Energy response to AER Ergon 103, p. 2.

141 Note that Ergon Energy’s forecast for other system-enabling augex includes $2.6 million ($2015) of ‘metering’ capex that we separately identify within our capex model. We identified the specific amount of metering capex that is within the other system-enabling forecasts based on Ergon Energy’s spreadsheet ‘03.03.08 Escalations Data

We consider that adopting the mid-point reflects a reasonable estimate of the efficient level of other system-enabling capex that a prudent operator in Ergon Energy's position would require in order to meet the capex objectives. While this amount is lower than our estimate in the preliminary decision, it reflects the additional evidence from EMCa that the extent of the systemic issues within the forecast is greater than we considered in the preliminary decision.

The remainder of this section provides our assessment of each of Ergon Energy's other system-enabling capex programs in more detail, including EMCa's review.

Operational Technology

Ergon Energy proposed $47 million for an 'operational technology' program. Ergon Energy's revised proposal included the following explanation of this program:

> Ergon Energy is committed to giving customers greater choices about how they manage their power and take advantage of local generation sources (such as photovoltaics and batteries). Expenditure is proposed to support the transition to a smart network to facilitate consumer choices, improve the utilisation of the existing power network and to defer capital intensive augmentation projects. This is a new capital expenditure requirement in the 2015–20 regulatory control period.[142]

Table 6.12 sets out the individual projects that comprise Ergon Energy's proposed 'operational technology' capex forecast.

Table 6.12 Ergon Energy operational technology capex forecast ($2014–15 million, excluding overheads)

Category	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Integrated Network Operations Centre	0.7	0.1	0.2	0.3	0.5	2.0
Alternative Data Acquisition Service	1.8	0.0	1.2	0.0	1.3	4.0
Distribution Management System	9.2	4.7	0.0	0.0	0.0	14
Master SCADA systems	2.8	2.9	1.9	4.7	1.7	14
Operational Network Security	3.3	1.5	0.0	0.0	0.0	5.0
Regulator Remote Communications Strategy	1.2	1.2	0.8	1.3	1.2	6.0

Model', attached to its revised regulatory proposal. In our final decision, we reduced this forecast of $2.6 million by 25 per cent to be consistent with our overall decision on Ergon Energy's other system-enabling capex forecast.

142 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.04 (Revised), p. 9.

Meter Configuration Management System	0.5	1.0	0.9	0.2	0.0	3.0
Total	19	12	5.9	7.9	5.9	47

Source: Ergon Energy, revised regulatory proposal, attachment 07.00.04 (revise), p. 16.

EMCa reviewed each of these projects based on the supporting documentation and attachments included within Ergon Energy's revised proposal.

On the basis of EMCa's review, we accept the proposed capex for the Distribution Management System. This is a suite of integrated applications that model the distribution network and provides tools for operating the network. EMCa considered that Ergon Energy's proposal to establishing a contemporary Distribution Management System is consistent with utility strategies in Australia and around the world. It also considered the associated capex represents a prudent and efficient amount. This conclusion is reflected in EMCA's recommended overall adjustment to the other system-enabling capex, which we have accepted.

For the remaining projects within this category, we are satisfied there is a need to address many of the issues raised by Ergon Energy. A number of these projects are aimed at monitoring and managing the increasing number of 'intelligent electronic devices' (IEDs) on Ergon Energy's network. EMCa considered that there may be a need to monitor and manage the functionality of IEDs and these projects met this need.

However, we do not consider the forecast capex reflects the efficient amount a prudent operator would require to address these issues. This is due to a number of systemic issues which overstate the scope and cost of the projects. These are as follows.

First, Ergon Energy identified the risk of not proceeding with these projects as generally medium or high (meaning that they require active monitoring and management, under Ergon Energy's risk management framework). EMCa found that Ergon Energy did not provide risk analysis to support its assessment of medium to high risk, and its risk assessment was often unsubstantiated.[143]

Second, and related, the cost-benefit analysis undertaken for these project either did not quantify the benefit to consumers (instead relying on qualitative assumptions), or showed that the cost of the project outweighed the benefit over the 2015–20 period.[144] In some circumstances, additional on-going operating costs were not provided or included within the analysis.[145]

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[143] This is evident in the Integrated Operations Centre, Master SCADA systems, Operational Network Security, Regulator Remote Communications Strategy projects.

[144] This is evident in the Operational Network Security and Integrated Operations Centre projects.

[145] This is evident in the Alternative Data Acquisition Service project.

Ergon Energy submitted that extra financial and risk information for all considered options is also contained in the Ergon Energy business case tool software (which was not previously supplied to us). Ergon Energy provided some screenshot extracts of its risk assessment tool in its response to EMCa's report.[146]

We have reviewed these extracts with the help of engineering and other technical expertise within the AER. Our review of Ergon Energy's screenshots from its business case tool confirms our positions stated above. In particular, these screenshots show that Ergon Energy has assessed risks in accordance with its risk management framework. However, it is not clear how Ergon Energy has quantified or monetarised these risks. Furthermore, Ergon Energy does not appear to explicitly compare the value of risk reduction (e.g. the benefit) against the proposed cost of the project. This suggests that the present value analysis from the business case tool is used only to establish relative merits of the options, and does not demonstrate that a positive value to customers would be delivered from the proposed capex.

This is consistent with EMCa's overall findings in its review of Ergon Energy's risk management framework that Ergon Energy has not displayed evidence of optimal risk/cost assessment and that its risk assessment is not robust.[147] These views have also informed our alternative estimate of Ergon Energy's repex forecast (see appendix B.4).

Third, in some circumstances, the cost of a project (in net present cost terms) was only marginally lower than Ergon Energy's existing operating practices.[148] EMCa considered that this 'was not a compelling margin', especially given the lack of other supporting information.

Finally, EMCa considered that a number of the cost estimates are preliminary.[149] Ergon Energy submitted that it agrees that in some cases costings and risks are at a preliminary level.[150] However, Ergon Energy considered "it is not appropriate to assume that all costs will be reduced as investments pass through the governance process or that these early estimates are not themselves sound."[151] While we agree that not all costs will necessarily be lower in practice, the preliminary stage of the project development makes it difficult for us to be satisfied that the estimated costs are efficient and reliable, or that Ergon Energy has considered all relevant options to further reduce costs.

146 Ergon Energy response to AER Ergon 103 (annotated comments to EMCa report), pp. 14-15, 19 and 24.

147 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 46.

148 This is evident in the Alternative Data Acquisition Service project.

149 This is evident in the Master SCADA System, Meter Configuration Management System projects.

150 Ergon Energy response to AER Ergon 103, p. 4.

151 Ergon Energy response to AER Ergon 103, p. 4.

EMCa analysis indicated there are apparent overlaps in proposed functionality between the network monitoring projects,[152] at least in the short term. These projects are designed to increase Ergon Energy's ability to address network issues through increased monitoring ability of intelligent electronic devices. Given the proposed increase in SCADA functionality to monitor intelligent electronic devices, proposed in the Master SCADA System business case, EMCa suggested that there is overlap between the other monitoring projects.[153]

Ergon Energy submitted that the existing SCADA system has not been designed to collect and manage new types of information from intelligent electronic devices.[154] Ergon Energy's reasoning in relation to the functionality of the SCADA system appears sound. Ergon Energy also submitted that it disagrees with EMCa that there is any overlap in the functionality of the projects. Instead, it submitted that the solutions provided by each project are "synergistic not overlapping" and together form a "single network solution, with clearly defined boundaries of scope and capability".[155]

We recognise that there are different functions performed by each of these projects, in the sense that each system does not replicate the functionality of each other. The key issues are whether the costs of each project reflect the efficient costs in order to maintain the reliability and security of Ergon Energy's network, and whether some capex can prudently be deferred into the next regulatory control period (or beyond). In this respect, we consider that with the proposed increase in SCADA functionality over the 2015–20 period, a prudent operator would likely defer some of these projects to the next regulatory control period without a loss to network service levels.

We also note that the Regulator Remote Communications Strategy project involves installing communications devices on voltage regulators.[156] The installation of voltage regulators is part of Ergon Energy's proposed capex to remediate voltage fluctuations due to growth in solar PV installations on its network. As we have set out previously, we consider that Ergon Energy has overstated the need to augment its network in response to forecast growth in solar PV connections (including installing voltage regulators). Consistent with this position, Ergon Energy's proposed capex to install monitors on its voltage regulators is similarly overstated.

On the basis of these reasons, we consider that the operational technology capex proposed by Ergon Energy, as a whole, does not reasonably reflect the capex criteria.

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152 These are the Master SCADA System, Integrated Operations Centre, and Alternative Data Acquisition Service projects.

153 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, pp. 47-65.

154 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.04 (Revised), p. 18.

155 Ergon Energy response to AER Ergon 103 (annotated comments to EMCa report), p. 25.

156 See Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.04.10, (Regulator Remote Comms Strategy Business Case), p. 7.

In particular, this is due to:

- the potential to prudently defer some capex due to similar functionality between the network monitoring projects
- our conclusion that Ergon Energy will require less capex to install communications devices on its voltage regulators, and
- the systemic issues identified within the business cases (in particular around the quantification of risk and the cost/benefit analysis) which potentially overstate the scope and cost of the projects.

This supports our adjustment to Ergon Energy's overall forecast estimate for other system-enabling capex.

Protection

Ergon Energy proposed $20 million for a ‘protection’ capex program. Ergon Energy’s revised proposal included the following explanation of this program:

> Protection assets are critical to the safety and reliability of the distribution network. These assets monitor and operate plant, detect network faults and operate circuit breakers in substations and downstream distribution feeders. All of these asset types have a natural physical life, as well as an economic and technological support life.[157]

This capex program is comprised of two projects:

- Protection Review Program Rectification ($17 million) — the continuation of an existing program to augment substations and distribution feeders “to ensure that protection equipment adequately protects the public, staff, environment and plant from network faults”, and
- Sensitive Earth Fault Protection Program ($3 million) — the continuation of an existing program to retrofit Sensitive Earth Fault protection equipment on 19 distribution feeders (or 4 per cent of total feeders). This equipment assists with detecting phase-to-ground currents and providing a trip signal or alarm, which will help avoid personal injury and bushfires.

The Protection Review Program Rectification is aimed at compliance with the NER (schedule 5.1.9 (c)), and internal company standards with respect to protection and substation requirements. EMCa stated that it supports the need for this program. However, it considered that Ergon Energy has not provided a case that justifies the proposed capex for the program. This is primarily because:[158]

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[157] Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.00.04 (Revised), p. 28.

[158] EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy’s Revised Regulatory Proposal 2015 −20*, September 2015, p. 60.

- Ergon Energy did not demonstrate any link between capex and expected safety outcomes or targets. For example, it did not provide evidence to show increasing 'mal-operation' of existing protection assets or a direct link to safety incidents from existing assets.
- The avoided risk from implementing the project was $5.4 million, whereas the net present cost of implementing the project was $17.4 million. The cost of the program is disproportionately high compared to the monetised benefit.
- Ergon Energy considered options to both slow down and accelerate this project. Ergon Energy chose the accelerated option, but did not provide a compelling case for doing so.

We agree with EMCa and consider that this supports less capex than Ergon Energy proposed for this project over the 2015–20 period. Ergon Energy disagreed with EMCa's analysis and submitted that electrical safety risks must be mitigated So Far As Is Reasonably Practical (SFAIRP). It further stated that this is a legislative obligation "supersedes the basic cost benefit analysis, requiring mitigating actions regardless of risk level until the cost is 'grossly disproportionate' to the benefit to be gained."[159] In Ergon Energy's submission to our preliminary decision, it states that the relevant legislative obligations are *Queensland Work Health and Safety Act 2014* and *Queensland Electrical Safety Act 2002*.[160]

We recognise that Ergon Energy has obligations under the *Queensland Work Health and Safety Act 2014* and *Queensland Electrical Safety Act 2002* to eliminate or minimise risks to the health and safety of persons as far as is reasonably practicable.[161] This involves a consideration of whether the cost of doing so is grossly disproportionate to the risk being eliminated or minimised.[162] As we explain in the explanatory statement to our expenditure forecast assessment guideline, where investments are intended to meet regulatory obligations (as Ergon Energy considers is the case in this instance) we do not expect the investments to necessarily be net benefit positive.[163] Where investment costs outweigh the benefits, the cost benefit analysis should show the chosen option is the least negative from a net benefit perspective.

If Ergon Energy considers an analysis based on SFAIRP is more appropriate than a standard cost/benefit analysis, then it should provide us with an SFAIRP based cost/benefit analysis and indicate to us what it considers a reasonable cost/benefit threshold to be. In the SFAIRP case, this would involve demonstrating that the cost involved in reducing the risk any further would be grossly disproportionate to the benefit gained from further risk reduction.

159 Ergon Energy response to AER Ergon 103 (annotated comments to EMCa report), p. 39.
160 See Ergon Energy, Submission to the AER on its Preliminary Decision, 3 July 2015, Attachment SUB09.1007, p. 8.
161 For example, see clause 17, *Queensland Work Health and Safety Act 2014.*
162 For example, see clause 18(e), *Queensland Work Health and Safety Act 2014.*
163 AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013, pp. 126–127.

We consider that Ergon Energy has not demonstrated that proposed cost of this program satisfies the SFAIRP principles. In particular, Ergon Energy's supporting business case (attachment 07.04.11 Protection Review Rectification Strategy) shows no reference to SFAIRP principles and why the proposed costs are not grossly disproportionate to the reduction in risk. This makes it difficult for us to be satisfied that the proposed capex reflects the efficient costs that a prudent operator would require to maintain the safety and security of the distribution system to meet its regulatory obligations and requirements.

EMCa also considered Ergon Energy's approach and application of SFAIRP and the related As Low as Reasonably Practicable (ALARP) principles in its review of Ergon Energy's revised proposal.[164] EMCa reviewed the list of programs in respect of which Ergon Energy submitted that it employed SFAIRP principles and found no evidence or references to SFAIRP (with the exception of the conductor clearance to ground remediation business case). EMCa also stated that:

> We also did not find evidence of rigorous analysis of risk to demonstrate that the ALARP test had been applied correctly, or that the justification of the expenditure was supported by the assessment of risk.

The Sensitive Earth Fault Protection Program is aimed at compliance with Ergon Energy's obligations under the *Electrical Safety Act 2002 (Qld)* and associated Regulations and Codes of Practice to maintain a safe and reliable supply of electricity to customers. Based on its review of this project, EMCa stated that the program and type of equipment proposed by Ergon Energy is an industry standard protection scheme.[165] EMCa also considered that the costs of the program likely represent a prudent and efficient level of expenditure because the ratio of cost to benefit (1:5) was indicative of a prudent initiative.[166] This conclusion is reflected in EMCa's recommended overall adjustments to the other system-enabling capex forecast.

Miscellaneous (safety and environmental)

Ergon Energy proposed $27 million for two safety-related projects and one environmental project:

- Low voltage spreader and fuses ($8 million) – a project to install low voltage spreaders (which reduce the risk of conductors clashing) and low voltage fuses (which reduce the risk of conductors overloading from heat and fault currents) on all of its network feeders and distribution transformers.

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164 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, pp. 66-67.

165 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 61.

166 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 61.

- Substation AC system upgrades ($8 million) – a project to install a new internal substation LV supply system to 'mitigate public safety risks due to transfer of earth potential rise'. This will replace existing out-dated substation power systems that may cause risks to public safety.[167]
- Substation Power transformer bunding ($11 million) – a project to mitigate non-compliant transformer bunds at substations. A transformer 'bund' is a wall or perimeter that is designed to prevent oil spillages from transformers in zone substations. Ergon Energy proposed that this project is required to comply with its obligations under the Environmental Protection Act 2003.

EMCa reviewed each project proposed by Ergon Energy. Its views, and our position for each project, are considered in turn.

Safety-related projects

Ergon Energy proposed that the first two safety-related projects will mitigate public safety concerns. It also stated that a driver of these projects is its obligations under the Queensland Electrical Safety Act and that it must undertake mitigation measures So Far as Reasonably Practical. This means that it must undertake mitigation measures unless the cost is grossly disproportionate.

In relation to the low voltage spreaders and fusers project, EMCa lends some support for this project, stating that:

> Ergon Energy's business case presents a reasonable risk assessment based on a well-known and researched set of hazards and common industry solutions. However, it does not provide a robust business case for retrofitting LV spreaders on all spans in the entire network and LV fuses on all transformers.[168]

Ergon Energy's proposed approach involves installing low voltage spreaders and fusers over the 2015–25 period through a staged approach.[169] EMCa recognised that Ergon Energy had considered a staged approach which involves lower capex than alternative options (e.g. completing the project within the 2015–20 period). However EMCa also suggested that more robust risk/benefit trade-off analysis would reveal whether the scope of the project was properly optimised and prioritised, and expects

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167 According to Ergon Energy's submission, a substation AC system provides services such as lighting, pumping, general 240V and 415V power supply. Ergon Energy stated that these systems were historically designed to be external to the substation, whereas modern substations are designed with embedded power systems. Ergon Energy notes that these historical designs have resulted in steadily increasing 'step and touch potentials' for these customers fed from these supplies or for staff in substations fed from these supplies. See Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 24.

168 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 62.

169 Ergon Energy, *Revised Regulatory proposal: July 2015 to June 2020*, 3 July 2015, Attachment 07.04.03, pp. 14-15.

that Ergon Energy will find opportunities for prudent deferral relative to the expenditure allowance it has proposed.[170]

In relation to the substation AC system upgrades project, EMCa stated that there is a real safety hazard (potentially fatal) from these existing AC power systems. However, in its experience, it considered that the likelihood of a hazard occurring was very low, which should have resulted in a 'Moderate' risk assessment under Ergon Energy's risk framework.[171] On this basis, EMCa suggests that Ergon Energy's risk assessment of the safety implications was overstated.

Ergon Energy submitted that:

> Based upon its knowledge of its own network, Ergon Energy disagrees with EMCa as to the level of concern about the issue because at specific substation sites the disparate earthing systems are in fact solidly connected. Thus earth potential rise transfer already occurs at these sites. Therefore Ergon Energy considers that EMCa's assessment for its risk evaluation is significantly understated and the present risk level remains high.[172]

Ergon Energy considered two options for upgrading substation power systems – a 10 year program and a 20 year program – and it chose the 10 year program. It calculated the cost/benefit ratio of each option as, respectively, 1:0.25 and 1:0.5. EMCa considered that, given Ergon Energy has overstated the risk to safety, the cost-benefit analysis may support a 20 year program. EMCa also stated that, with more analysis, Ergon Energy could identify an optimised program of work commencing with the highest risk locations and requiring significantly less than the proposed expenditure in the 2015–20 period.[173]

In Ergon Energy's response to EMCa's review, it also notes that it is required to mitigate risks to safety so long as the cost is not grossly disproportionate to that risk (SFAIRP principles). As we noted above, we accept that investments for health and safety do not necessarily need to be net benefit positive so long as the cost benefit analysis shows that the chosen option is the least negative from a net benefit perspective. Based on review of Ergon Energy's supporting documentation, Ergon Energy has not demonstrated to us why the proposed cost/benefit ratio of 1:0.25 is not grossly disproportionate to the reduction in risk, in particular when compared to the alternative option which provides a cost/benefit ratio of 1:0.5. This makes it difficult for us to be satisfied that the proposed capex reflects the efficient costs that a prudent operator would require to maintain the safety and security of the distribution system to meet its regulatory obligations and requirements.

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170 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 62.

171 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 63.

172 Ergon Energy response to AER Ergon 103 (annotated comments to EMCa report), p. 46.

173 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 63.

Ergon Energy's submission to our preliminary decision stated that our original 15 per cent reduction to the other system-enabling capex forecast was made without an understanding of the safety implications of reduced capex.[174] Ergon Energy points to the 'Substation AC System Upgrades' project in particular, stating that:

> Ergon Energy questions whether the AER has considered the need for resolving this safety issue, or the background provided in the submission document. As such, the AER has not met its obligations to achieve the NEO [National Electricity Objective]. Ergon Energy contends that the AER should review its decision in regards to funding reductions related to resolving this long term public and staff safety issue.[175]

In our preliminary decision, we did not specifically outline the safety implications from our 15 per cent adjustment. However, we do not agree that this did not allow Ergon Energy to comply with its safety obligations or otherwise maintain the safety of the network. This is because our preliminary decision did not reduce Ergon Energy's proposed capex for its safety projects specifically, but rather reduced the overall capex for the other system-enabling capex projects based on what we considered were the inefficiencies or biases present in the forecast. Ergon Energy is not prevented from prioritising its capex within this capex forecast (or its total capex allowance) to address high priority safety issues.

Having said that, we consider the safety implications of our capex allowance in this final decision. In particular, we have had regard to EMCa's findings and advice on the potential risk to network safety on Ergon Energy's network (in the absence its safety projects) and the prudent and efficient capex to maintain safety of the network. We have also considered Ergon Energy's response to EMCa's report. As set out above, EMCa advises that Ergon Energy has likely overstated the risk to safety from existing substation AC power systems. In addition, for both safety projects, EMCa concludes that Ergon Energy will likely be able to reduce its capex requirement over the 2015–20 period through prioritising its works program to address the most high-risk issues.

We agree with EMCa and consider that this supports less capex than Ergon Energy proposed for both safety projects over the 2015–20 period, and the substation AC system upgrade project in particular. EMCa's reasoning is generally consistent with both its own findings, and our findings in our preliminary decision, that there are systemic issues present across Ergon Energy's capex forecast. While we have not made specific adjustments in respect of these capex projects, these reasons support our overall adjustment to the other system-enabling capex proposal.

Environmental project

Ergon Energy's proposed Substation Power Transformer Bunding project is aimed at complying with its obligations under the *Environmental Protection Act 1994* and

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174 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 22.

175 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 24.

Australian Standard 1940 The Storage and Handling of Flammable and Combustible Liquids or equivalent standard.

In relation to this project, EMCa observes that Ergon Energy identifies a common industry non-compliance issue with transformers oil containment and proposed to address all non-compliant sites within seven years.[176] However, EMCa considered that Ergon Energy has overstated the risk of oils spills due to inadequate containment. This is because Ergon Energy proposed to complete the project before the end of the 2015–20 regulatory period without any engineering or economic justification for this timeframe.[177]

EMCa suggested that an alternative option considered by Ergon Energy (to complete the same program within 14 years) presents a more efficient cost/benefit outcome.[178] On this basis, EMCa concluded that Ergon Energy's risk assessment is 'conservative' (that is, tending to overestimate the extent of the risk) and the selected option is not representative of a prudent and efficient program based on the information presented.

Ergon Energy disagreed that it has proposed to address all non-compliant sites within seven years. Instead, it stated that it has proposed to address only evaluated high risk sites by the end of the 2015–20 regulatory period.[179] This is consistent with Ergon Energy's supporting document which shows that it proposed to address high-risk sites only. However, as noted by EMCa, Ergon Energy does not support its 'high risk' ranking with analysis (e.g. number, severity and trend of oil spills due to inadequate bunding).[180] Therefore Ergon Energy has not demonstrated that addressing those sites assessed as having high risk would satisfy the capital expenditure criteria.

Ergon Energy also submits that it is required to take all reasonable and practical measures to prevent or minimise any environmental harm, and it is appropriate to use the As Low As Reasonably Practical (ALARP) principle, which mean that risk should be mitigated to the point where the cost is 'grossly disproportionate'.[181] As we noted above, we accept that investments for health and safety do not necessarily need to be net benefit positive so long as the cost benefit analysis shows that the chosen option is the least negative from a net benefit perspective. Based on review of Ergon Energy's supporting documentation, Ergon Energy has not demonstrated that proposed cost of this program satisfies the SFAIRP principles. In particular, Ergon Energy's supporting business case (attachment 07.04.01 Zone Substation Bunding Upgrade Program) shows no reference to ALARP principles and why the proposed costs are not grossly

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176 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 64.

177 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 64.

178 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 64.

179 Ergon Energy response to AER Ergon 103 (annotated comments to EMCa report), p. 48.

180 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon Energy's Revised Regulatory Proposal 2015 −20*, September 2015, p. 64.

181 Ergon Energy response to AER Ergon 103 (annotated comments to EMCa report), p. 48.

disproportionate to the reduction in risk. This makes it difficult for us to be satisfied that the proposed capex reflects the efficient costs that a prudent operator would require to maintain the safety and security of the distribution system to meet its regulatory obligations and requirements.

For these reasons, we agree with EMCa and consider that this supports less capex than Ergon Energy forecast for this transformer bunding project over the 2015–20 regulatory control period.

Unexplained capex

In our preliminary decision, we identified $30 million worth of capex that we could not explain. This capex was the difference between our assessment of Ergon Energy's proposal and the total augex forecast contained in the reset RIN. On this basis, we excluded the capex from our alternative estimate and invited Ergon Energy to provide an explanation in its revised proposal.

Ergon Energy's submission to our preliminary decision stated that this 'unexplained' capex is due to applying different labour, material and CPI cost escalation methodologies to the proposal (and supporting documentation) and the reset RIN.[182] In particular, it stated that the difference is due to the reset RIN forecasts, which include full labour, materials and CPI cost escalation, while the expenditure stated in the regulatory proposal documentation only includes escalation for CPI.[183]

We accept Ergon Energy's explanation and no longer exclude this capex from our alternative estimate of total augex. This is consistent with our forecasts for other expenditure categories (e.g. repex, non-network) which include all cost escalators. We have ensured that the augex forecast we have assessed for this final decision (including the individual programs and projects) is inclusive of all cost escalators.

We separately form a view on Ergon Energy's cost escalation method and amount in section D.

B.3 AER findings and estimates for customer connections capex, including capital contributions

Connections capex is incurred by Ergon Energy to connect new customers to its network and where necessary augment the shared network to ensure there is sufficient capacity to meet the new demand.

New connection works can be undertaken by Ergon Energy or a third party. The new customer provides a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer

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182 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 26.

183 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.07, p. 26.

contribution, Ergon Energy is required to take into account the forecast revenue anticipated from the new connection[184]. These contributions are subtracted from total gross capex and as such decrease the revenue that is recoverable from all consumers. Customer contributions are sometimes referred to as capital contributions or capcons.

B.3.1 AER Position

We accept Ergon Energy's revised proposal for net connections capex of $279.5 million ($2014–15). Similarly, we accept Ergon Energy's proposed forecast for customer contributions of $158.3 million ($2014–15).

Our preliminary decision accepted Ergon Energy's proposed connections forecast and customer contributions forecast. We accepted the forecast after considering trends relative to recent expenditure and our assessment that the forecast was consistent with expected construction activity in Queensland. Our preliminary decision set out our full reasons for accepting the Ergon Energy's forecasts.[185]

Ergon Energy in its revised proposal noted that there was an error in the historic information it provided in its RIN response.[186] This error meant that Ergon Energy underreported historical expenditure. Ergon Energy has submitted corrected data that shows that there is a downward trend between historical expenditure and their forecast. We note that this error was not applicable to the forecast connections capex for the 2015–20 regulatory control period or the level of customer contributions.[187]

In this final determination, we maintain our view that both the connection and customer contribution forecasts are reasonable, having regard to the forecast trend of construction activity in Queensland. Ergon Energy has not altered its connections forecast from the initial proposal.

B.4 AER findings and estimates for replacement expenditure

Repex is driven by the inability of network assets to meet the needs of consumers and the overall network. The decision to replace can be based on cost, quality, safety, reliability, security, or a combination of these factors. In the long run, a service provider's assets will no longer meet the requirements of consumers or the network and will need to be replaced, refurbished or removed.[188]

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184 In Queensland, the National Energy Customer Framework (NECF) and chapter 5A of the NER specifies that AER approves a connection guideline for Ergon Energy which determines these customer connection charges

185 AER, *Ergon Energy Preliminary Determination Attachment 6 – Capital expenditure,* pp. 6-63 – 6-64.

186 Ergon Energy, Submission on Ergon Energy Reset RIN responding to material issue, p.15.

187 Ergon Energy, Submission on Ergon Energy Reset RIN responding to material issue, p.16.

188 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.

Replacement is commonly driven when the condition of the asset means that it is no longer economic or safe to be maintained. It may also occur due jurisdictional safety regulations, or because the risk of using the asset exceeds the benefit of continuing to operate it on the network. Technological change may also advance the timing of the replacement decision and the type of asset that is selected as the replacement.

Electricity network assets are typically long-life assets and the majority will remain in use for far longer than a single five year regulatory period. Many of these assets have economic lives of 50 years or more. As a consequence, a service provider will only replace a portion of its network assets in each regulatory control period. The majority of network assets will remain in commission well beyond the end of any single regulatory control period.

Our assessment of repex seeks to establish the portion of Ergon Energy'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 Ergon Energy's revised proposed repex of $941 million ($2014–15). We have instead included in our alternative estimate of overall total capex, an amount of $786 million for repex, excluding overheads. This represents 84 per cent of Ergon Energy's revised proposal. We are satisfied that this amount reasonably reflects the capex criteria.

B.4.2 Revised proposal

Ergon Energy's revised proposal at $941 million, is $47 million or 5.25 per cent higher than its initial proposal of $894 million. Ergon Energy submitted that it rejected our preliminary decision due to:[189]

- Disagreement with the findings of the AER's repex consultant Energy Market Consulting Associates' (EMCa) that Ergon Energy's initial proposal provided insufficient justification for the proposed amount of repex.
- Disagreement with the findings and decisions of the AER which are based upon the AER's predictive modelling because they assert this modelling has a number of limitations and relies on invalid assumptions.
- Concerns that the AER had not adequately considered the NEO in its preliminary decision.

We note that Ergon Energy's revised forecast is higher than their initial proposal due in part to errors they made in preparing the RIN for their initial proposal.[190] These errors

[189] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 1.
[190] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, pp. 33-36.

led to Ergon Energy incorrectly understating expenditure across a number of categories.

B.4.3 AER approach

In our preliminary decision, we applied several assessment techniques to assess Ergon Energy's forecast of repex against the capex criteria. These techniques were:

- analysis of Ergon Energy's historical total repex trends
- predictive modelling of repex based on Ergon Energy's assets in commission
- technical review of Ergon Energy's approach to forecasting, costs, work practices and risk management
- consideration of various asset health indicators and comparative performance metrics.

As noted in our preliminary decision, we drew general observations from Ergon Energy's historical total repex trends, asset health indicators and comparative performance metrics, but do not rely on these techniques in deciding whether to reject Ergon Energy's repex forecast, or in forming our alternative estimate, except where explicitly noted.[191] We use predictive modelling to assist us in assessing approximately 69 per cent of Ergon Energy's proposed repex. This assessment is considered in combination with the findings of our consultant, EMCa, who provided technical advice on Ergon Energy's repex forecast. For the remaining categories of expenditure, we may use predictive modelling where suitable asset age data and historical expenditure are available, but also rely on analysis of historical expenditure in conjunction with the findings of our consultant.

We have adopted the same assessment approach in this final decision, and, in doing so, have considered the further information put forward by Ergon Energy in its revised proposal.

Ergon Energy's revised proposal also incorporates predictive modelling to some extent, though Ergon Energy relies on other forecasting techniques to determine its estimate of repex.[192] Ergon Energy's forecasting techniques are assessed as part of EMCa's technical review.

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

191 We relied on our observations of historical repex, in conjunction with the findings of our technical review, in relation to pole top structures, SCADA and "other" asset categories. For these asset categories, we placed limited or no weight on predictive modelling. The reasons are set out in our assessment below.

192 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 27.

limitations, we have used this analysis to draw general observations in relation to the modelled categories of repex, but we have not used it to reject Ergon Energy's forecast of repex or develop our alternative estimate. However, we have relied on trend analysis, in combination with the findings of EMCa, to assist our assessment of the unmodelled categories of repex.

Predictive modelling

The repex model can predict the reasonable amount of repex Ergon Energy would require if it maintains its current risk profile for condition-based 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 Ergon Energy's 'business as usual' asset replacement practices. We explain the calibrated replacement life modelling scenario, along with other modelling input scenarios, further below.

Ergon Energy stated that the AER has made a large number of assumptions in its use of the repex model and asserts that "the use of incorrect assumptions has led to inappropriate decisions".[193] We recognise that to perform our predictive modelling, and as is the case with any modelling, we must necessarily make some assumptions. As part of the 'Better Regulation' process the AER undertook extensive consultation with both DNSPs and TNSPs in developing the repex model. This consultation process was used by the AER to develop and enhance the repex model and the assumptions underlying the model. The repex model which was developed through this consultation process is well-established and has been implemented by the AER in a number of revenue determination processes including the recent NSW/ACT revenue determination process.

We recognise that our predictive modelling cannot perfectly predict Ergon Energy'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 of our preliminary decision. We also note that the NSPs themselves include repex modelling in their repex proposals. Ergon Energy noted that, despite its concerns with the repex model, it has "developed a suite of repex models based upon its annual performance RIN back-cast data" in support of its revised proposal.[194]

We use predictive modelling to estimate a quantum of ‘business as usual’ repex for the modelled categories to assist in our assessment. However, predictive modelling is not the only assessment technique we have relied on in assessing Ergon Energy's proposal. Our technical review, which is qualitative in nature, allows us to form a view

193 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 6.

194 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 31.

on whether or not 'business as usual' expenditure appropriately reflects the capex criteria.

The repex model has the advantage of providing both a bottom up assessment, as it is based on detailed sub-categories of assets using data provided by the service providers, and once aggregated it provides a well-founded high level assessment of that data. The model can also be calibrated (i.e. business as usual scenario) using updated data on Ergon Energy's entire stock of network assets, along with Ergon Energy's actual replacement practices, to estimate the repex required to maintain its current risk profile.

We recognise that there are reasons why some assets may be better assessed outside of the repex model. 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.[195]

Where we considered it was justified, we have separately assessed those assets which we thought may be better assessed outside the model by using techniques other than predictive modelling. We use our qualitative techniques, particularly EMCa's technical review, to assess whether there is any such evidence.

Technical review

Ergon Energy's proposed repex was subject to a technical review by EMCa. EMCa assessed Ergon Energy's approach to forecasting, including whether Ergon Energy has had regard to robust cost-benefit analysis where appropriate. It also assessed Ergon Energy's costs, work practices and risk management approach. This was to identify whether risk was systematically overestimated or underestimated and in turn the repex forecasts are likely to be overstated or underestimated, respectively. EMCa provided a further report in response to Ergon Energy's revised proposal. We evaluated EMCa's findings in its further report in the course of our repex assessment in this final decision.

We have relied on EMCa's reports in assessing whether Ergon Energy's asset risk profile (i.e. asset condition) 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 an analysis of historic repex, to inform our assessment of repex programs to which we did not apply our predictive modelling.

Asset health indicators and comparative performance metrics

We have used a number of asset health indicators with a view to observing asset health. Asset utilisation is one such indicator. Asset utilisation changes for some assets

195 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

may provide an indication as to whether Ergon Energy's assets are likely to deteriorate more or less than would be expected given the age of its assets.

In the preliminary decision, we observed that Ergon Energy's residual replacement lives and levels of asset utilisation did not suggest that it had an underlying, non-age related issue with the condition of its assets. We did not rely on this analysis in rejecting Ergon Energy's proposal and in developing our alternative estimate. However, this observation is consistent with our overall finding that Ergon Energy's business as usual practices would allow it to meet the capex objectives. This is also the case in this final 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.[196]

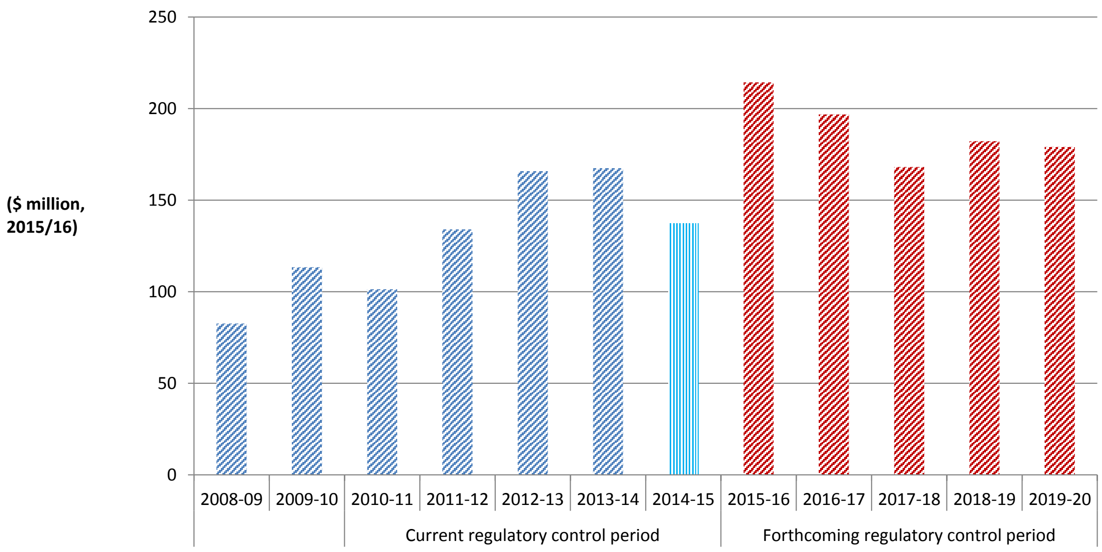
Our use of trend analysis is to gauge the degree to which the proposed repex is consistent with past expenditure. We recognise the limits of expenditure trends, especially in circumstances where replacement needs may change over time (e.g. a service provider may have a lumpy asset age profile or legislative obligations may change over time).

Figure 6.8 shows Ergon Energy's repex spend since the early 2000s is highly variable with its proposal for the 2015−20 regulatory control period well above the long term average repex.

In their revised proposal Ergon Energy was concerned that we had not specifically referenced their proposal document *07.00.01 Asset Renewal Expenditure Forecast Summary 2015–20.* This was a document which we reviewed when reaching our preliminary decision. We have had regard to the equivalent document from the revised proposal (*Submission to the AER on its Preliminary Determination: Asset Renewal*) as footnoted in this appendix, along with all other material submitted by Ergon Energy that is relevant to repex.

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

Figure 6.8 Ergon Energy ─ Actual and expected repex ($m 2015–16)



Source: AER analysis.

Technical review

Our preliminary decision set out our approach to engaging EMCa to undertake a technical review to test Ergon Energy's repex forecast against the capex criteria. We engaged EMCa to test whether Ergon Energy's:

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

Broadly, on these aspects EMCa found in its April 2015 report that:[197]

- Ergon Energy had developed a bottom-up program broadly based upon identified focus areas, however it was seeking to include increased levels of repex in some programs for which there was insufficient justification
- Elements of Ergon Energy's proposed repex had not been subject to rigorous top down challenge to achieve and demonstrate an optimal risk/cost position
- Prudency of the repex forecast was limited by:
  - insufficient project and program analysis
  - bias in replacement programs towards bulk replacements of targeted asset categories with insufficient justification

[197] EMCa, *Review Ergon Energy's Proposed Augex and Repex*, April 2015, p. iii.

  - application of risk assessments that appear to result in a reactive approach to identified issues
  - step changes in expenditure that appear to align with revenue reset regulatory control periods and lack of identified condition data from which to make informed asset management decisions.
- We engaged EMCa to consider whether Ergon Energy's revised proposed forecast repex reflected an efficient and prudent expenditure forecast. EMCa reviewed new information Ergon Energy provided with its revised proposal in response to EMCa's April 2015 report.

The focus of the further advice was whether the new information and revisions to the proposal made by Ergon Energy would cause EMCa to change the views from its initial April report. Broadly, EMCa found that:[198]

- The systemic issues identified in EMCa's initial review have not been adequately addressed
- The systemic issues are likely to remain present, leading to an over-estimation bias
- A level of conservatism towards risk remains evident
- Ergon Energy's revised proposal has inadequate links to prudent needs analysis
- There is insufficient evidence of the establishment of an optimal risk/cost position for the portfolio or top-down level.

EMCa's findings on the revised proposal

EMCa noted that the repex component of Ergon Energy's revised proposal was within one per cent of its initial proposal. For the most part, Ergon Energy did not update the supporting information originally submitted with its initial proposal. However, it did provide clarifications on:

- its use of cost based risk management information in its proposed replacement of transformers and switchgear and
- included a business case in support of a newly included program to remediate low ground clearance conductors.[199]

EMCa expressed concern with Ergon Energy's largest proposed repex program, its line asset defect management program, which represents 37 per cent of its proposed repex. It noted that it expected Ergon Energy could reduce its generalised line asset defect management program by a larger amount than the amount included in its revised proposal. Specifically, EMCa noted that it would expect Ergon Energy to have

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198 EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal, September* 2015, p.iii.

199 EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal, September* 2015, p.45.

provided analysis for its line asset replacement defect management program to clearly demonstrate that:

- the expenditure was directed to network issues of sufficient risk/urgency to warrant remedial work, and separate to those identified within its target programs
- appropriate strategies are being deployed to ensure prudent and efficient expenditure
- opportunities to package work across multiple programs have been assessed; and
- Ergon Energy has removed any potential overlap in its programs that may lead to an inefficient forecast (such as where its conductor replacement program and other repex programs are likely to resolve low ground clearance issues and vice versa).[200]

EMCa considered that, based on a review of a sample of expenditure included in Ergon Energy’s revised proposal, the systematic issues identified in its initial report had not been adequately addressed. Specifically, these concerns are:[201]

- the top-down challenge process appears to have embedded a level of conservatism towards risk
- insufficient evidence is presented regarding the establishment of an optimal risk/cost position for the portfolio
- There is an absence of robust risk assessment.

EMCa concluded that these systemic issues were likely to result in an over-estimation in Ergon Energy’s forecast.[202]

A summary of EMCa's findings on specific programs is presented in table B.8 below. We consider EMCa's findings support the outcomes of our overall assessment which is that a lower amount of repex than Ergon Energy'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.

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200 EMCa, *Review of proposed capital expenditure in Ergon Energy’s revised regulatory proposal, September* 2015, pp. 45, 46.

201 EMCa, *Review of proposed capital expenditure in Ergon Energy’s revised regulatory proposal, September* 2015, p. 46.

202 EMCa, *Review of proposed capital expenditure in Ergon Energy’s revised regulatory proposal, September* 2015, p. 46.

Table 6.13 EMCa review of asset replacement programs

Asset category	EMCa's consideration
Poles	EMCa noted that proposed expenditure on this asset type is broadly consistent with expenditure in the last year of the 2010-15 regulatory period. EMCa did not identify any systemic issues with the poles category.
Pole top structures	In its advice from its earlier report, EMCa considered the development of a targeted program to manage sub-transmission pole tops is reasonable. However, it considered there was insufficient analysis provided by Ergon Energy to conclude that the proposed program reflects optimal timing, volume and cost. EMCa noted that Ergon Energy did not provide new information on this program, and subsequently did not consider there was sufficient analysis to justify the proposed level of expenditure.
Overhead conductor	In its advice from its earlier report, EMCa expressed reservations about the completeness of Ergon Energy's analysis supporting its overhead conductor program and considered the justification for the forecast repex was not proven. However, EMCa considered the focus of the program due to the associated elevated risk was consistent with industry practice. Ergon Energy did not provide new information in the revised proposal or make material adjustments to its forecast. EMCa did not consider there was sufficient analysis to justify the proposed level of expenditure.
Transformers	There was evidence of application of Condition Based Risk Management (CBRM) methodologies however there was insufficient justification to support the proposed repex forecast. EMCa also noted that it was concerned that Ergon Energy had not demonstrated that it had taken a prudent risk-based approach to its transformer replacement program.
Switchgear	There was evidence of application of CBRM methodologies however there was insufficient analysis to support the proposed repex forecast. EMCa also noted that it was concerned that Ergon Energy had not demonstrated that it had taken a prudent risk-based approach to its switchgear replacement program.
Service Lines	There was insufficient demonstration of a needs based assessment of the proposed forecast. The assumptions Ergon Energy applied have resulted in an inflated forecast for particular replacement programs within the category. EMCa found that there is evidence of conservative risk assessments with a bias to including projects and programs that may otherwise have been reviewed as a consequence of a more rigorous top down challenge process.
Underground cables	EMCa did not identify any systemic issues in its review of the underground cables asset category.
SCADA network control and protection systems	In its advice from its initial report, EMCa considered that Ergon Energy did not provide sufficient justification for the change in performance and risk levels for the proposed repex given the current age and condition of its protection relay population. Ergon Energy lowered its repex for this category in its revised proposal. In its advice on the revised proposal, EMCa noted that it was not clear that the reductions resulted from a top down review of the program or to address systemic issues..
"Other"	In its initial report, EMCa observed the forecast repex was broadly consistent with the historic averages. EMCa did not identify any systemic issue in its review of this asset category. Ergon Energy included a new program of works to remediate low conductor spans in the “other” asset category in the revised proposal, which increased its proposed expenditure by approximately 75 per cent. EMCa considered this program separately. EMCa remained of the view that, without the low conductor expenditure, there were no systemic issues for this category.
Low spans remediation	EMCa considered this program presented a number of systemic issues. It identified a conservative approach to risk, an internally inconsistent approach to risk across the program, insufficient options in the business case and insufficient consideration of opportunities for work prioritisation. EMCa noted that, while the low spans program is likely to be required, it was neither prudent nor efficient.

Source EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015−20*, April 2015, pp. 72–86.
EMCa, *Review of proposed capital expenditure in Ergon Energy's revised regulatory proposal, September* 2015, pp. 24–45.

Predictive modelling

We use predictive modelling to estimate how much repex Ergon Energy is expected to need in future, given how old its current assets are, and based on when it is likely to need to replace its assets. In this final decision, as in our preliminary decision, we have arrived at a modelling outcome based on calibrated replacement lives as the basis for our repex estimate. When combined with forecast unit costs based on Ergon Energy's data, this results in an estimate that reflects Ergon Energy's existing approach to managing asset risk. This modelling outcome gave an estimate of $542.2 million for the six modelled asset categories.[203] We have decided to apply this estimate after considering the findings from our technical review.

The 'business as usual' repex estimate from our predictive modelling is based on:

- Ergon Energy's current risk profile as evidenced by its own replacement practices. Our estimate trends forward Ergon Energy's current approach to asset risk management, weighted by the actual age of its assets.
- Ergon Energy's own forecast unit costs for the next regulatory control period. These reflect the unit costs Ergon Energy expects to incur over the next five year period based on information it provided under the RIN and which it recently updated.

This estimate uses Ergon Energy's own forecast unit costs, but it effectively 'calibrates' the proposed forecast replacement volumes to reflect a volume of replacement that is consistent with Ergon Energy's recent observed replacement practices.

In our preliminary decision, we ultimately decided that the service provider's own data provided the best estimation of unit cost, and applied Ergon Energy's forecast costs rather than the industry benchmark. We are of the same view in the final decision.

In its revised proposal, Ergon Energy has not accepted our predictive modelling outcomes because it considered that we have made a large number of assumptions in using the repex model.[204] Ergon Energy disagrees with these assumptions and therefore the model's findings. Ergon Energy's submission on the repex model is considered further below.

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[203] As in the preliminary decision, we accepted Ergon Energy's proposed expenditure on pole and overhead conductor replacement ($84 million and $216 million, respectively). For these two categories, the estimates from our predictive modelling were higher than Ergon Energy's forecast. For the remaining four asset categories, the AER adopted the outcome of the calibrated repex model, being $242 million.

[204] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 6.

For the reasons we outline below, we do not agree with Ergon Energy's submission that the repex model is not fit for purpose or relies on incorrect assumptions. Consequently, our final decision maintains our position from the preliminary decision. However, we have updated our modelling to take account of Ergon Energy's corrected historical and forecast RIN data.

Submissions on Ergon Energy's initial and revised proposal also considered that Ergon Energy's proposed repex for the 2015–20 regulatory control period was higher than necessary:

- The CCP considered the distributors' proposals were not justified on asset condition and that the risks and drivers of repex were not substantially justified. The CCP also noted the variation in distributors' estimated asset lives, and was of the view we should have a more standardised approach to asset lives.[205] We consider this supports our use of calibrated asset lives.
- Cotton Australia submitted that the average age of Ergon’s assets continues to fall, and this appears to be driven by excessive expenditure in replacement. There should be clear guidance as to reasonable average and maximum age for distribution assets.[206]
- Total Environment Centre supported reductions to forecast repex. It stated that the distributors had not made a case for a significant increase in repex and appeared to have overly conservative approaches to asset management.[207]
- The Chamber of Commerce and Industry Queensland supported reductions to the repex, particularly as it was a large part of capex. It considered the levels of repex proposed by the network businesses was concerning given the average age of assets have been rapidly decreasing since 2006.[208]
- The Energy Retailers Association of Australia supports the decision to adopt risk based and relevant unit cost forecasts to determine the capital expenditure allowance in preference to trending historic spends. It supports the proposed reductions repex set out in our preliminary decision.[209]
- Origin Energy considered that the proposed repex programs were high in Queensland. It agreed with our view that in the absence of evidence to demonstrate otherwise, to the extent that forecast unit costs are higher than

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205 Consumer Challenge Panel Subpanel 2, *Submission, AER Preliminary 2015-20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, September 2015, pp. 30–33.

206 Cotton Australia, *RE AER Determination Ergon*, 24 July 2015, p. 2.

207 Total Environment Centre, *Submission to the AER on the Preliminary Decisions on the QLD DBs’ Regulatory Proposals 2015-20*, July 2015, pp. 7–8.

208 Chamber of Commerce and Industry Queensland, *Submission to the AER on the Preliminary Determinations for Ergon Energy and Energex Revenue Determination*, July 2015, p. 4.

209 Energy Retailers Association of Australia, *Preliminary Decisions for Ergon Energy and Energex determinations 2015-16 to 2019-20*, July 2015, p. 1.

historical unit costs, that historic unit costs are more likely to reflect a realistic expectation of future input costs.[210]

Professionals Australia submitted our reduction to forecast repex would create safety risks.[211]

In relation to this, we are satisfied that the business as usual approach described above will provide Ergon Energy with sufficient capex to manage the replacement of its assets and meet the capex objectives of maintaining safety, reliability and security of the distribution system. This is because the business as usual will continue Ergon Energy's replacement practices that it used to meet the capex objectives in the last regulatory control period.

However, we also considered whether the service provider’s replacement practices from the last regulatory control period did more than maintain safety, reliability and security of the distribution system, such that applying the business as usual approach for asset replacement may result in replacement practices that provide for a higher level of expenditure than is necessary to satisfy the capex objectives.

In considering the efficiency of recent replacement practices, we have placed some weight on the ex-ante capex incentive framework under which the service providers' operate. There are incentives embedded in the regulatory regime that encourage a service provider to spend capex efficiently (which may involve spending all of the allowance, less or more, in order to meet the capex objectives). A service provider is only funded in the regulatory control period to meet the capex allowance. The service provider keeps the funding cost obtained over the regulatory control period of any unspent capex for that period, and, conversely, bears the funding cost of any capital expenditure that exceeds the allowance. In this way, the service provider has an incentive to spend efficient capex, or close to the allowance set by the regulator, as it is essentially rewarded (penalised) for any underspend (overspend). This provides some assurance that a service provider reacting to these incentives will undertake efficient capex to meet the capex objectives. This means that to some extent we can rely on the ex-ante capex framework to encourage the service providers to engage in efficient and prudent replacement practices.

Going forward, this incentive will be supplemented by a Capital Expenditure Sharing Scheme, which will provide a constant incentive to spend efficient capex over the regulatory control period, as well as the ability to exclude capex overspends from the RAB as part of an ex-post review. These additional arrangements will provide us with greater confidence that the service provider’s past replacement practices are likely to reflect efficient and prudent costs, such that business as usual asset replacement approach is likely to be consistent capex objectives.

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210 Origin Energy, *Re Submission to AER Preliminary Decision Queensland Electricity Distributors,* July 2015, pp. 6–7.

211 Professionals Australia, ***Response to the Australian Energy Regulator’s preliminary determinations***, July 2015, pp. 4–9.

Possible future rule changes may also extend the regulatory investment test for distribution (RIT-D) to repex. Such a change would make it incumbent upon the service provider to develop credible options for asset replacement, including considering whether the asset life could be extended or whether the asset could be retired rather than replaced or expenditure be deferred because of the use of non-network options.

Finally, the collection of a longer period of data on changes in the asset base as part of our category analysis RIN will provide us with further information into the service providers' asset replacement practices over a longer period of time. This will further inform our understanding of business as usual replacement practice to estimate repex. More time series data would also strengthen our ability to use benchmarked information (e.g. asset life inputs) in the repex model in the future, which is intended to drive further efficiency in replacement expenditure.

Model 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 cost of replacing a single unit or an asset (i.e. on average, how much each asset costs to replace).

In the preliminary decision, we described using the repex model to create three modelling scenarios.[212] In each of the three modelling scenarios (base case scenario, calibrated scenario and benchmark scenario) we combined different data for the final two inputs.

Under all scenarios, the first input is Ergon Energy's asset age profile (how old Ergon Energy's existing assets are). This is a fixed input in all three scenarios.

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

- 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. In doing this it calculates how many assets are likely to need replacement in the near future.[213] The model then applies a unit cost input to calculate how much expenditure is needed for that amount of replacement in each asset category. This is aggregated across all asset categories to a total repex forecast for each of the next 20 years.

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[212] AER, *Preliminary decision, Ergon Energy distribution determination, Attachment 6*, April 2015, pp. 139-41.

[213] The repex model predicts replacement volumes for the next 20 years.

Table B.9 outlines the replacement lives and unit cost inputs we tested in the repex model. As part of our assessment, we compared the outcomes of using Ergon Energy'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 calculate calibrated replacement lives that are based on Ergon Energy's past five years of actual replacement data. This reflects Ergon Energy's recent past replacement practices.[214]

We calculated historic unit costs by dividing historic expenditure by historic volumes. We calculate forecast unit costs by dividing forecast expenditure by forecast volumes. Forecast unit costs were significantly lower than historical unit costs.

Detail on how we prepared the model inputs is at appendix E in our preliminary decision.[215] The table below describes the modelling process undertaken for the preliminary decision.

Table 6.14 Repex model inputs

Input	AER comments in preliminary decision
Mean replacement lives	
Ergon Energy estimated replacement lives	When used in the repex model, Ergon Energy's estimated replacement lives produced forecast repex estimates higher than when we used any other replacement lives, and higher than Ergon Energy's own repex forecast. The model also forecast a sharp 'step-up/trend down' forecast expenditure profile. That is, it predicted there was a significant amount of repex required in the first year of the forecast period. This indicates the replacement lives used by Ergon Energy are likely to be too short and do not represent its actual replacement behaviour as they predict a large unrealistic 'backlog' of replacement of assets that were far older than would be expected if the replacement lives were accurate.
Calibrated replacement lives based on Ergon Energy data	We considered Ergon Energy's estimated replacement lives were not appropriate. By contrast, calibrated replacement lives reflect Ergon Energy's actual approach to replacement in the most recent five years.
Benchmark estimated 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. As with Ergon Energy's estimated replacement lives, we found using these benchmark replacement lives produced sharp 'step-up/trend down' forecast expenditure, 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 Ergon Energy's own forecasts.
Benchmark 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.

[214] For discussion on how we prepared each of the inputs see: AER, *Preliminary decision, Ergon Energy distribution determination, Attachment 6*, *Appendix E*, April 2015.

[215] AER, *Preliminary decision, Ergon Energy distribution determination, Attachment 6*, *Appendix E*, April 2015.

Input	AER comments in preliminary decision
	When applied to the model for Ergon Energy, these lives produced outcomes lower than when we used the calibrated lives based on Ergon Energy's data. The calibrated benchmark replacement lives will reflect to some extent the particular practices of a distributor and this may not be applicable to the business under review. At most, this input allowed us to check that Ergon Energy's calibrated lives were reasonable against its peer service providers in the NEM.
Unit cost of replacement	
Ergon Energy unit costs (historic) Unit costs achieved in the most recent five years	When used in the repex model, Ergon Energy's historic unit costs as submitted under its RIN gave forecast outcomes several times higher than when we used any other unit cost, and several times higher than Ergon Energy's own repex forecast. This indicates historic unit costs are not likely to reflect a realistic expectation of future input costs.
Industry Benchmark 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. Applying the average benchmark unit costs in the repex model for Ergon Energy gave an outcome that was slightly lower compared to when we used Ergon Energy's own forecast unit costs. The outcomes when using the first quartile and lowest unit cost benchmark numbers were significantly lower. We considered the benchmark average unit cost was a useful comparison with the cost of other distributors in the NEM.
Ergon Energy unit costs (forecast) Unit costs Ergon Energy forecasts for the next five years	As outlined above we considered it was not appropriate to use Ergon Energy's historic unit costs. We compared industry benchmark unit costs to Ergon Energy's forecast unit costs and observed that Ergon Energy's forecast unit costs did not result in significantly higher forecasts. As a result we accepted the use of Ergon Energy's own forecast unit costs rather than industry benchmarks.

Source: AER analysis.

Ergon Energy's submission on the repex model

Ergon Energy submitted that there are a number of limitations of the repex model. These are detailed below. It follows that, given our conclusions below, we do not agree with the assertion of Ergon Energy that we have relied on invalid assumptions in our use of the repex model.

Calibration period

The calibrated replacement lives used in the repex model are based on Ergon Energy's recent asset replacement practices to estimate a replacement life for each asset type. These replacement lives are calculated by using Ergon Energy's past five years of replacement volumes, and its current asset age profile (which reveals the number of assets in Ergon Energy's network and the age of those assets), to find the age at which, on average, Ergon Energy replaces its assets. The calibrated replacement life represents this age. We explain the process of calculating calibrated replacement lives in our repex model handbook.[216]

[216] AER, *Replacement expenditure model handbook*, November 2013, p. 20.

A service provider 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 a service provider 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 their obligations.

We reviewed the submission of Ergon Energy. However, we maintain our reasoning from the preliminary decision. In doing so, we note that our predictive modelling approach is well established having been used by us in previous distribution determinations and by other regulators.[217] It has been refined following extensive consultation as part of the 'Better Regulation' program. It was clear from our engagement with stakeholders in that process that calibration is understood to be an integral part of good practice in repex modelling for the very reason that it utilises up-to-date data provided by the business being regulated. The calibration process is not an arbitrary or one which involves manipulation of inputs to arrive at a pre-determined outcome. It is a systematic process, relying on real observations of the service provider's replacement practices, with a transparent purpose.

Ergon Energy considered one of the weaknesses of the model is its assumption that the historical data is sufficiently extensive as to provide reasonable long term indication of average asset performance.[218] We consider this does not correctly interpret the workings of the model. Using calibrated replacement lives in the repex model does not trend forward past expenditure or volumes. Instead, it trends forward Ergon Energy's asset replacement practices from the last period, given its current stock of assets in commission and asset age profile. It is akin to maintaining a business as usual approach. We have further assessed whether there is evidence that Ergon Energy requires a different forecast from the business as usual forecast to meet the capex criteria through the findings of the technical review.

Ergon Energy submitted that the particular climate cycle in Queensland directly influences asset failure and given the point in the climate cycle, the model is likely to under-estimate future asset failure. Climatic events can produce asset failure but this does not mean the model will under-estimate future asset failure. We use calibrated replacement lives which form the basis of a business as usual forecast for repex as they are derived from the service provider's actual replacement practice observed over the past five years. A five year period is appropriate as it is the length of a regulatory control period and also reflects the recent asset replacement program of the distributor.

If underlying circumstances are different in the next regulatory control period, then the business as usual approach to replacement age may no longer allow a service

[217] OFGEM, Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment, March 2013, p. 44; AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, October 2010; AER, Final decision: Aurora Energy distribution determination, April 2012.

[218] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 33.

provider to meet its obligations. We consider a change in underlying circumstances is constituted by 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 regulatory obligations (e.g. obligations governing safety and reliability). While it is conceivable that climate changes in the long term may increase the operating risk over time, we do not consider the change would be material within the span of a five year regulatory period. We also note that the climatic conditions described by Ergon Energy are capable of being dealt with during the regulatory period through the nominated natural disaster pass-through event, provided the event meets the materiality threshold (see attachment 15 of this final decision).

Homogeneous assets

The data used in the repex model was subject to consultation and refinement as part of the Better Regulation process in 2013 to help ensure the comparability of the asset subcategories. By specifying asset subcategories at a detailed and granular level, we have ensured that each asset population contains assets that are close to each other in function. Further, when aggregated across the asset population, individual differences between asset units will tend to become less important. Further discussion of this is included in appendix E of the preliminary decision.

Ergon Energy submitted that repex modelling requires that there is sufficient homogenous population base to generate meaningful statistics.[219] We recognise that assets are not perfectly homogeneous as differences in local conditions and environmental factors will influence the type of asset being installed, and the type of labour and equipment required for installation. However, when the assets are similar to each other in function they can be considered as a population rather than individually.

In addition, we derived unit costs from Ergon Energy's own forecasts, so any prediction of lower asset volumes will result in a proportional, pro rata reduction in the forecast expenditure on that asset from the repex model. That is, our approach to estimating repex maintains the predicted cost mix, while adjusting for differences in volume.

Ergon Energy submitted that a valid modelling function would need to have at least 50-70 asset categories. We disagree with this and consider the detailed and granular asset subcategories modelled contain sufficiently comparable units to allow for meaningful statistical analysis of the population.

Population size and historical data

As noted above, as part of the Better Regulation program, we engaged in an extensive data collection process with industry. Part of this was defining and collecting information suitable for use in predictive modelling. The full process is set out in

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219 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 25.

Appendix E of the preliminary decision. A key consideration was determining a set of asset subcategories that were granular enough to be compared across different service providers. The process involved extensive consultation with service providers and other stakeholders, and the outcome was the sub category list included in templates 2.2 and 5.2 of the reset RIN. Further information on this process is included in the relevant Better Regulation Guidelines and explanatory statements.[220] Population size is considered in the repex handbook.[221] The repex model uses the entire asset population, in the form of the asset age profile, to derive its estimate.

The degree of confidence from a statistical function is related to population size, with higher populations leading to greater degrees of confidence. Ergon Energy has some asset classes with small populations (smaller than 100 units). However, the asset subcategories with relatively small populations do not make up a significant part of Ergon Energy repex program. For this reason we do not consider it necessary to exclude any assets because of the size of their population.

Asset utilisation as an indicator of asset condition

Consistent with our preliminary decision we consider that an important determinant of Ergon Energy's repex requirements is the condition of its assets currently in commission.[222] In assessing this we have considered:

- utilisation of the network (where spare capacity should be correlated to asset condition).
- the age of Ergon Energy's network.

Ergon Energy submitted that "general use of forecast asset utilisation as an indicator of future asset condition is flawed".[223] We recognise that:

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

As noted in our preliminary decision, limited weight was put on a number of our assessment techniques, which encompassed asset utilisation. We recognise that only limited conclusions can be drawn about asset condition from their utilisation. Consequently, utilisation was used to draw general observations about the condition of

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220 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

221 AER, *Replacement expenditure model handbook*, November 2013, p. 10.

222 AER, *Preliminary decision, Ergon Energy distribution determination, Attachment 6*, April 2015, pp. 87-88.

223 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p.38.

Ergon Energy's assets, but was not relied upon in either rejecting Ergon Energy's proposed repex, nor in forming our alternative estimate.

The relationship between age and condition

Using past volumes to find calibrated replacement lives takes into account all the factors that drove replacement in the previous regulatory control period. Age is used in the calibrated repex model as a proxy for these drivers. The average age of replacement in the calibrated model is based on the age of assets still in commission.

Ergon Energy submitted that age is too simplistic a measure of asset condition.[224]

However, we consider that, if a significant number of older assets remain in service at the end of a regulatory control period, we can reasonably infer that their replacement was not required to meet reliability and safety obligations in that regulatory control period. Using the calibration process allows us to trend forward the distributor's replacement practices into the next regulatory control period, using the asset age profile to estimate business as usual repex. Age is used as a proxy for condition in this scenario, but we have not deterministically applied a replacement age. Rather, we have estimated a replacement age that would allow Ergon Energy to continue its current replacement practices. Ergon Energy's forecasting methods, including its CBRM and other supporting material, were considered as part of the technical review by EMCa. This technical review assisted us in determining whether Ergon Energy had justified, based on changes in asset risk (i.e. asset condition) that an increase above the business as usual repex predicted by the calibrated repex model

Calibration period

Ergon Energy submitted that the repex model used in the preliminary decision uses one year of forecast data (being the last year of the 2010-15 period, for which the last year is an estimate). Ergon Energy considered that this does not align with the age profile data, as the last year of data used in the calibration process is estimated.

We have remodelled the data using 2009–10 to 2013–14 (i.e. the last five years of actual data). Remodelling of the data resulted in a forecast $7 million or 1 per cent higher than predicted at the draft decision for the modelled repex categories. We consider that remodelling using historically observed volumes, rather than estimated volumes from the 2014-15, addresses the issue raised by Ergon Energy.[225] In any case the differences in the two estimates are small.

Use of benchmarks

We developed benchmarks that were used to compare distributors with an average across the NEM, as well as a quartile and "best" estimate. As noted in Appendix E of the preliminary decision, the categories included in our Category Analysis RIN were

224 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p.26.

225 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 29.

subject to a thorough process of consultation during their development to ensure they were suitable for use in the repex model and allowed for comparisons to be made between distributors.

Ergon Energy submitted that it is “procedurally and mathematically inappropriate” to calculate industry lowest or lowest quartile calibrated benchmark costs based upon the AER’s asset groups unless the underlying information is based upon the same asset subgroup types.[226] In this case, the benchmarks were used to draw observations regarding the relative efficiency of Ergon Energy's unit costs and replacement practices. However, they were not used to quantify an alternative estimate of prudent and efficient capex.

Use of forecast unit costs

Ergon Energy submitted that the AER has selectively utilised combinations of back cast volumes with forecast unit cost rates which can lead to a “doubling” effect on the result of the model.[227] Forecast unit costs are based on the costs that Ergon Energy has proposed. The calibrated repex model uses historical volumes, not unit costs, to calibrate the asset replacement lives. In the case of Ergon Energy, the repex model has, on aggregate, predicted a lower volume of replacement than Ergon Energy has forecast. Using the forecast unit rate effectively provides a pro rata adjustment to the proposed expenditure to reflect this adjustment in volumes.

Use of standard deviation and a tolerance band

Calibration of the repex model requires that the standard deviation is related to the mean replacement age in a consistent manner. Ergon Energy submitted that, in place of the calibrated scenario utilised by the AER, we should instead establish a ‘tolerance band' around any repex forecast, and consider a distributor's repex is prudent and efficient if it falls within that band. In doing so, it disputed the use of a square root as the standard deviation.[228]

The square root is an accepted form of standard deviation in a normally distributed population. In particular, this is used by Ofgem in its own version of the repex model,[229] and has been used by a number of distributors in repex models submitted to the AER. The use of a square root standard deviation is also consistent with our modelling of all other distributors since the Better Regulation process, and was part of the model consulted on during Better Regulation.[230] We do not consider there is a compelling reason to depart from this assumption.

[226] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 31.

[227] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 31.

[228] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 32.

[229] OFGEM, *Strategy decisions for the RIIO-ED1 electricity distribution price control - Tools for cost assessment*, March 2013, p. 44.

[230] Replacement expenditure model handbook, November 2013, p. 20.

Using base repex as a trigger for the calibrated repex model

Using calibrated lives in the repex model is described in our guide to the repex model, and was consulted on as part of the Better Regulation process. This modelling approach provides us with an estimate of business as usual repex. We consider that the process of using the last five years of historical RIN data provided by Ergon Energy, together with its asset age profile, allow us to make such an estimate.

Ergon Energy submitted that, while we have to consider the un-calibrated replacement life estimates as part of its assessment, it does not consider this allows us to reject Ergon Energy's estimates and proceed to substitute its own without taking into account Ergon Energy's RIN data and calibrated repex models which were derived from Ergon Energy's estimates.[231]

We note that the calibrated repex model is only used following consideration of our other assessment techniques, particularly the technical review, which relies on the findings of our consultant, EMCa. The AER does not view a "rejection" of the uncalibrated base case as the basis for adopting the business as usual assessment, but rather, the qualitative information and findings on Ergon Energy's forecasting. In this case, we considered the systemic issues identified by EMCa before choosing to adopt the business as usual estimate of the calibrated repex model.

Un-modelled repex

As with the preliminary decision, 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 Ergon Energy's RIN response was not included in the repex model. As noted in Appendix E of the preliminary decision, 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.[232] Together, these categories of repex account for $292.9 million or 31 per cent of Ergon Energy's proposed repex.

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

SCADA, network control and protection

We have included Ergon Energy's revised proposal of $109 million for replacement of SCADA, network control and protection (collectively referred to as SCADA) in its alternative estimate of capex. Ergon Energy's initial proposal included $163 million for SCADA.

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231 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 32.

232 AER, *Preliminary decision, Ergon Energy distribution determination, Attachment 6*, *Appendix E*, April 2015, p. 141.

Ergon Energy identified a need for repex to address its aging protection relay asset population. However, EMCa raised concerns with the application of the risk assessment framework supporting the replacement program, considering there was a potential overestimation of risk. EMCa concluded Ergon Energy did not provide sufficient justification for the change in performance and risk levels for the proposed repex given the current age and condition of its protection relay population.[233]

Ergon Energy's revised proposal stated that they have "significant obsolescence issues relating to RTU (Remote Terminal Unit) assets".[234] Ergon Energy was concerned that EMCa did not give adequate consideration to SCADA in their review of Ergon Energy's initial proposal. EMCa has reviewed the additional information provided by Ergon Energy and concluded that, while it was not clear that the reductions put forward by Ergon Energy resulted from a top down review of the program or to address systemic issues, it noted that the reduction might reasonably reflect reductions that would address these issues.

We are satisfied that Ergon Energy's proposed repex of $109 million for SCADA reasonably reflects the capex criteria. We have formed this view on the basis of EMCa's further advice and after observing that Ergon Energy proposed to spend around 15 per cent less on SCADA than it did in the 2010–15 regulatory period.

Pole top structures

In the preliminary decision, we did not consider that there was sufficient justification to support Ergon Energy's forecast expenditure of $103 million for pole top structure replacement, a 69 per cent or $42 million increase on the previous regulatory control period. Ergon Energy's revised proposal raised concerns that we did not include pole top structures in the repex model despite being provided with estimated age information. We continue to consider, in accordance with our reasoning in the preliminary decision, that it is appropriate to exclude pole top structures from the model as it is related to expenditure on overall pole replacement and therefore modelling may result in double counting of replacement volumes.[235] However, as we have asset age and historical replacement data, we tested whether predictive modelling would support Ergon Energy's proposed step increase over historical expenditure. The calibrated repex outputs for pole top structure replacement are $60 million where forecast unit costs are used and $68 million where historical unit costs are used. From this, we observe that Ergon Energy's repex for pole top structures is likely to be closer to its expenditure in the 2010–15 regulatory period.

Ergon Energy's expenditure on pole top structures remained relatively constant over the 2010–15 regulatory control period. Ergon Energy's proposal for the next period has a step increase in repex that remains at a constant higher level over the 2015–20 regulatory control period. EMCa observed that the increase is attributed to Ergon

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[233] EMCa, *Review Ergon Energy's Proposed Augex and Repex*, April 2015, pp. 82–83.

[234] Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 64.

[235] AER, *Preliminary decision, Ergon Energy distribution determination, Attachment 6*, *Appendix E*, April 2015, p. 141.

Energy's proposed sub-transmission line pole top replacement program. On the basis of improved data from its asset inspection and defect management program, Ergon Energy determined it was imprudent to continue its line rebuild projects. Instead, Ergon Energy proposed to expand its pole-top replacement program in its place.

EMCa stated that Ergon Energy's proposed pole top replacement program appeared to be based on subjective assessments and no sensitivity analysis or risk assessment was provided. EMCa considered that there was insufficient analysis provided by Ergon Energy to conclude that the proposed program reflects optimal timing, volume and cost.[236]

In its revised proposal, Ergon Energy's raised concerns that EMCa's findings would remove funding allocation for an essential safety mitigation program.[237]

EMCa provided updated advice in response to the revised proposal. EMCa noted that Ergon Energy did not provide new information, and consequently did not consider there was sufficient analysis to justify the proposed level of expenditure. EMCa also considered Ergon Energy's line asset defect program, which accounts for around $57 million of the proposed expenditure on pole top structures. In its initial report to the AER, EMCa considered that there appeared to be overestimation bias in this program of works. In particular, it expected to see greater analysis of condition data and defect trends to support the forecast replacement volumes. In its further report on the revised proposal, EMCa noted that Ergon Energy had provided some further clarification on the program. However, it did not consider that the new information was sufficiently compelling to address the nature of its concerns, or demonstrate that the expenditure is prudent and efficient.

In reaching our view on Ergon Energy's pole top structures, we have considered EMCa's specific views on pole top structures, and EMCa's overall views on systemic issues with Ergon Energy's forecasting approach and assessment of risk, as well as the revised information provided by Ergon Energy. We do not consider there is sufficient justification to support the significant step change proposed by Ergon Energy. We consider Ergon Energy's pole top repex from the previous regulatory control period of $61 million is likely to reasonably reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

Other repex

In the preliminary decision, we considered Ergon Energy's forecast of $38 million for "other" repex was reasonable. The assets included in "other" in the preliminary decision included:

- Capacitor banks
- Current transformers

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236 EMCa, *Review Ergon Energy's Proposed Augex and Repex*, April 2015, pp. 83–85.

237 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 63.

- Static var compensators; and
- Voltage transformers.

EMCa observed the forecast repex was broadly consistent with the historic averages with the exception of 2017–18 which is dominated by expenditure for a single project for replacement of a static var compensator. EMCa did not identify any systemic issue in its review of this asset category.[238]

In their revised proposal, Ergon Energy forecast $42 million for "other repex".[239] [240] This increase was due to an error in Ergon Energy's initial proposal which resulted in the forecast being understated. EMCa provided further advice on the revised proposal. In this advice, EMCa remained of the view that, there were no systemic issues for this category.[241]

We consider that, given EMCa's advice, and that the proposed expenditure is in line with expenditure on this category from the 2010–15 regulatory control period, Ergon Energy's forecast repex of $42 million is likely to reflect the capex criteria and have included this amount in our alternative estimate of total forecast capex.

Conductor clearance to ground defect remediation program

Ergon Energy proposed repex of $36.4m for a 'conductor clearance to ground' backlog remediation program in 2015/16. This expenditure was not included in its initial proposal.

We engaged EMCa to provide advice on the prudency and efficiency of this new program.

EMCa noted that Ergon Energy provided limited information to support its risk assessments of regulatory non-compliance (including degrees of non-compliance). EMCa considered that it had not seen sufficient evidence to justify the need for the proposed level of expenditure and that is supported by assessment of the legal, regulatory and/or safety risks.[242]

EMCa noted that, based on the volume of defects when compared with Ergon Energy's normal inspection processes, development of a dedicated program would seem reasonable. However, on reviewing the business case in support of the proposed expenditure, EMCa noted that it found evidence that the forecast exhibits many of the

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238 EMCa, *Review Ergon Energy's Proposed Augex and Repex*, April 2015, p. 85.

239 Ergon Energy, *Submission to the AER on its Preliminary Determination: Asset Renewal*, July 2015, p. 35.

240 Ergon Energy included an additional amount of $36 million in the "other" asset category for its Conductor clearance to ground defect remediation program. This is considered separately below.

241 EMCa's advice also considered the Conductor clearance to ground defect remediation program separately from the "other" category.

242 EMCa, *Review of Proposed Network Augmentation and Replacement Expenditure in Ergon’s Regulatory Proposal 2015−20*, April 2015, pp. 42–43.

systemic issues observed in the development of Ergon Energy's total repex, which reflect an inflated forecast. The systemic issues it identified include:

- conservative approach to risk, which includes a bias to include full programs in the forecast to be completed as quickly as possible and within the 2015–20 regulatory control period rather than adopting a prudent risk management approach giving consideration to the risk/cost trade-off across the portfolio of work
- internally inconsistent approach to risk across its portfolio that raises concerns regarding the prudency of some work
- insufficient options analysis including consideration of risk treatment options that might result in more efficient costs for this program; and
- insufficient consideration of opportunities for prioritisation of work, including addressing the highest risk sites first and packaging work with other programs.

EMCa noted that, while a program to address low clearances is likely to be required, it considered the program that Ergon Energy proposed is neither prudent nor efficient. EMCa noted that it is likely that Ergon Energy can find opportunity to change the scope of the program, to prioritise, to identify complementary efficiencies and to identify mitigation measures which would contribute to a prudent and efficient program.

We note the concerns expressed by EMCa in its report. However, we also note that this program relates to the replacement of overhead line assets on Ergon Energy's network, such that it would fall under the "modelled" asset category of overhead conductor. If the $37 million proposed by Ergon Energy was included in this category, Ergon Energy's proposal would total $253 million ($37 million + $216 million). This amount would be lower than the business as usual expenditure estimated by the repex model for this category of $413 million. Given that, if the expenditure had been proposed as "overhead conductor", we would have accepted the forecast as being lower than the business as usual amount, we consider that the expenditure is likely to reflect the capex criteria, and have included it in our alternative estimate.

B.5 AER findings and estimates for capitalised overheads

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

B.5.1 Position

We do not accept Ergon Energy's proposed capitalised overheads. We have instead included in our alternative estimate of overall total capex an amount of $1035.3 million ($2014–15) for capitalised overheads. This is two per cent lower than Ergon Energy's proposal of $1051.4 million. We are satisfied that this amount reasonably reflects the capex criteria.

B.5.2 Our assessment

We consider that reductions in Ergon Energy's forecast expenditure should see some reduction in the size of Ergon Energy's total overheads. Our assessment of Ergon Energy's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in Ergon Energy's proposal. It follows that we would expect some reduction in the size of Ergon Energy'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 also 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 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 Ergon Energy's proposal, which is based on its CAM. As such, Ergon Energy's forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of Ergon Energy'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.

Our adjustments to Ergon Energy's overheads use the approach from our preliminary decision (which used information that Ergon Energy provided). We consider that a $1.0 million reduction in Ergon Energy's forecast capex should result in a $0.05 million reduction in Ergon Energy's capitalised overheads.[243] We reduced Ergon Energy's direct capex (that attract overheads) by $412.9 million. We therefore consider a reduction of $16.1 million in capitalised overheads reasonably reflect the capex criteria.[244]

We also note that a proportion of Ergon Energy's proposed capitalised overheads is attributable to information, communications and technology (ICT) services. We discuss our assessment of Ergon Energy's forecast for ICT services in section B.6.

[243] AER, *Preliminary decision: Ergon Energy determination 2015−16 to 2019−20: Attachment 6 − Capital expenditure*, April 2015, pp. 89–90.
Note, we did not apply this adjustment to the SPARQ component of capitalised overheads. We made the adjustment to the SPARQ component of capitalised overheads separately (see section B.6).

[244] This includes the adjustments to the SPARQ component of capitalised overheads as we mentioned previously.

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

The non-network capex category for Ergon Energy includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and plant and equipment.

Ergon Energy's revised proposal included forecast non-network capex of $483.0 million ($2014–15) including overheads and real cost escalation. This is a reduction of $23.3 million or 5 per cent from Ergon Energy's initial proposal of $506.3 million ($2014–15).

B.6.1 Position

We accept Ergon Energy's revised forecast for non-network capex of $406.6 million ($2014–15) excluding overheads and real cost escalation as a reasonable estimate of the efficient costs required for this capex category. This reflects our conclusions that:

- Ergon Energy's revised fleet capex management and forecasting approaches address the issues set out in our preliminary decision. We are therefore satisfied that Ergon Energy's revised fleet capex forecast of $174.9 million ($2014–15) reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.
- Ergon Energy has provided additional supporting documentation which demonstrates that the major property project proposed for Townsville is likely to reflect the economically preferred development option for this site. On this basis, we are satisfied that Ergon Energy's revised buildings and property capex forecast of $238.8 million ($2014–15) reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives.

The majority of Ergon Energy's ICT expenditure was not included in the non-network capex category in Ergon Energy's proposal. Ergon Energy's ICT services are delivered by SPARQ Solutions (SPARQ) which is a jointly owned company between Energex and Ergon Energy, and is classified by Ergon Energy as a capitalised overhead rather than non-network capex. However, we have included the assessment of this expenditure under the non-network category (section B.6.6) to allow comparisons with other network service providers and for consistency with our other regulatory determinations. There is no regulatory requirement that Ergon Energy report its ICT expenditure in the non-network category. The actual adjustment to total capex is included in the capitalised overheads section B.5.

B.6.2 Revised proposal

In its revised proposal, Ergon Energy did not agree with our preliminary decision to reduce forecast capex for non-network buildings and property, or motor vehicles. Ergon Energy's revised proposal for non-network capex:

- included forecast motor vehicle fleet capex of $174.9 million ($2014–15), a reduction of $24 million from its initial proposal, reflecting revisions to fleet management and forecasting approaches
- included forecast buildings and property capex of $238.8 million ($2014–15), approximately in line with its initial proposal, reflecting the reinstatement of the Townsville major property project omitted from our preliminary decision
- accepted our preliminary decision on non-network property disposals relating to the three major property projects at Rockhampton, Maryborough and Toowoomba.

These issues are discussed in turn below.

B.6.3 Fleet capex

In its revised proposal, Ergon Energy proposed capex of $174.9 million ($2014–15) for standard control service fleet assets in the 2015–20 regulatory control period.[245] This is $24 million ($2014–15) or 12.1 per cent less than Ergon Energy proposed for standard control service fleet vehicle capex in its initial proposal.[246] Ergon Energy's fleet assets are used to undertake construction and maintenance activities and to enable services to core functions such as customer service. Ergon Energy’s fleet assets include motor vehicles and other plant and equipment.[247]

In our preliminary decision, we considered that an alternative forecast fleet capex of $160 million ($2014–15) reasonably reflected the efficient costs that a prudent operator would require to meet the capex criteria.[248] Our key reasons for reducing Ergon Energy's proposed fleet capex were:

- significant increases in the forecast quantities and unit costs of a large number of vehicles
- vehicle cost data suggesting that Ergon Energy's optimal replacement age for its fleet assets is less than the actual or observed optimal replacement age. This view was supported by benchmark analysis of the reported comparative replacement

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245 Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment 07.00.06 (Revised) Fleet expenditure forecast summary*, p. 4.

246 Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment SUB00.01 Submission to the AER Preliminary Determination_redacted PUBLIC*, pp. 49-50 and AER, *Information request ERGON ENERGY 016*, 13 January 2015, p. 11.

247 Ergon Energy, *Regulatory proposal*, October 2014, *Attachment 07.00.06 Ergon Energy Fleet Expenditure Forecast Summary*, p. 3.

248 AER, *Preliminary Decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 6 − Capital expenditure*, April 2015, p. 6-110.

criteria for fleet assets of other electricity service providers, which showed that Ergon Energy's proposed fleet capex program assumed a higher frequency of fleet asset replacement than benchmark distributors

- Ergon Energy's estimated costs for Elevated Work Platforms (EWPs) for heavy commercial vehicles used the highest estimated unit cost of its forecasts for all fleet assets of this type
- Ergon Energy did not justify its policy of maintaining a local presence in respect to the NER requirement that a forecast of required capital expenditure reasonably reflect the capex criteria
- Ergon Energy's vehicle/staff ratio increased by about 22 per cent during the 2010–15 regulatory control period and Ergon Energy advised that its level of operation personnel is anticipated to remain fixed at current levels with no forecast increase for the 2015–20 regulatory control period. This suggests that Ergon Energy has some capacity to not require an increase above current levels in its proposed increased fleet asset acquisition program for the 2015–20 regulatory control period without diminishing its ability to meet its fleet service requirements
- maintaining a historical trend expenditure allowance for fleet capex is consistent with an environment where the business size, as measured by operational employee numbers, and service requirements have not materially changed
- it appeared that Ergon Energy may have over-specified its proposed fleet acquisition program because:
    - there appeared to be a lack of management oversight in respect to the achievement of optimised financial and operation outcomes for Ergon Energy's fleet assets that are not the responsibility of the Fleet Manager
    - there was a paucity of information in the setting of vehicle standards in respect to how capital costs, operating costs, depreciation, reliability/breakdown cost and vehicle safety are assessed to form each vehicle's standard, and
    - that vehicle standards were higher than required operation standards for some vehicles.

Ergon Energy submitted that its revised proposal forecasts reflect a new approach in respect to fleet management and forecasting, taking into account its own review of other network service provider approaches and the AER's decisions for other network businesses. Ergon Energy stated that the AER's preliminary decision confirmed its proposed change of direction in respect to fleet management and forecasting.[249]

In particular, Ergon Energy has revised its fleet capex forecasting approach by replacing the previous age based criteria with a kilometre based criteria for a number

[249] Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment SUB00.01 Submission to the AER Preliminary Determination_redacted PUBLIC*, p. 50.

of fleet assets (passenger vehicles, 2WD commercial and 4WD commercial light and light service vehicles), extending the replacement age of some assets (e.g. trailers) and having a condition based assessment at the time of development of annual replacement programs. Ergon Energy also stated that a new model has been developed to provide the granularity required to refine the forecast costing as highlighted by the AER in its preliminary decision.[250]

Ergon Energy stated that the importance of maintaining a local presence and the ability to respond promptly was highlighted by feedback from its online stakeholder survey, and through other regional stakeholder engagement, as well as during its response to major storm events, including Cyclone Yasi. Ergon Energy stated that in its customer research, its customers indicated that Ergon Energy's investment priorities should be maintaining the reliability of supply, with strong support given to maintaining local depots and sufficient disaster capability response.[251]

In respect to issues raised in the AER's preliminary decision, Ergon Energy stated that:[252]

- the reference to operating expenditure for passenger vehicles appears to reference a supporting document from UMS for the purpose of determining the optimal replacement point and that these forecasts were the basis of what it asked for and were only used for modelling purposes. Since Ergon Energy have now amended its forecasting approach, the AER's concerns now appear redundant
- a comparison of fleet assets to headcount over the course of the regulatory control period 2010–15 indicates an improvement of six per cent in the employee to fleet asset ratio
- the luxury name plate vehicles referenced in the AER's preliminary determination (e.g. Mercedes), at face value, may appear to be an unwarranted expense. However, they were selected after considering safety, operational suitability, technical compliance, manufacturers' support and operational expense criteria. They meet safety, compliance and suitability requirements at a lower operating cost than similar types of vehicles.

Ergon Energy stated that during the regulatory control period 2010–15, it achieved fleet capex expenditure below that originally forecast, and that allowed by the AER, in response to a reduction in demand by reducing the numbers and extending the operating life of some fleet assets. Ergon Energy also stated its revised fleet expenditure forecast has been developed using an approach which models assets throughout their lifecycle and the costs incurred from replacing assets with different

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250 Ergon Energy, *Regulatory proposal*, October 2014, *Attachment 07.00.06 Ergon Energy Fleet Expenditure Forecast Summary*, p. 8 and *Attachment 07.06.01 (Revised) Fleet Management Strategy*, pp. 5-6.

251 Ergon Energy, *Regulatory proposal*, October 2014, *Attachment 07.00.06 Ergon Energy Fleet Expenditure Forecast Summary*, p. 5.

252 Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment SUB00.01 Submission to the AER Preliminary Determination_redacted PUBLIC*, p. 50.

replacement parameters of either kilometres or age. Ergon Energy submitted that its revised fleet expenditure model takes into account the number of assets required based on the workforce demand, the replacement point for each fleet asset and the cost of providing new fleet assets.[253]

AER assessment

We have reviewed Ergon Energy's revised proposal and consider that Ergon Energy's forecast standard control fleet capex of $174.9 million ($2014–15) reasonably reflects the efficient costs that a prudent operator would require to meet the capex criteria.[254] In coming to this view, we acknowledge that Ergon Energy has responded to the issues raised by us in our preliminary decision, in particular:

- by adopting a revised forecasting approach reflecting amended asset replacement criteria (from an age basis to a kilometre basis for certain vehicle classes). This has led to a reduction in its total proposed fleet size from 1,820 to 1,519 vehicles (16.5 per cent reduction) and its total plant and equipment from 404 to 238 assets (41.1 per cent reduction).[255] Ergon Energy provided further evidence of the impact of its revised forecasting approach which showed:[256]
    - the total number of forecast fleet replacement and rebuilds has reduced by 23.4 per cent between its initial and revised regulatory proposals
    - a significant reduction in the number of forecast purchases for vehicles that have had their replacement criteria changed from an age to a kilometre basis – passenger vehicles have reduced from 180 to 49 vehicles, 2WD commercial from 120 to 95 vehicles, 4WD commercial light from 655 to 626 vehicles and 4WD commercial light service from 460 to 210 vehicles
    - the extension of the replacement age for trailers from 10 to 15 years has seen the forecast quantity fall from 191 to 24.
- the forecast unit price for EWPs falling from $380,000 to $335,858[257]
- justifying its proposal to maintain local depots on the basis of maintaining the reliability of supply and sufficient disaster capability response
- an improvement of six per cent in the employee to fleet asset ratio over the course of the regulatory control period 2010–15.

[253] Ergon Energy, *Regulatory proposal*, October 2014, *Attachment 07.00.06 Ergon Energy Fleet Expenditure Forecast Summary*, p. 11.

[254] NER, cl. 6.5.7(c)(1).

[255] Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment 07.06.13 Fleet Capex Model, template Sum5yr (AER), AER analysis*.

[256] Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment 07.06.13 Fleet Capex Model, template Sum5yr (AER), AER analysis*.

[257] Ergon Energy, *Revised revenue proposal*, July 2015, *Attachment 07.06.13 Fleet Capex Model, template Sum5yr (AER), AER analysis*.

We have examined the potential ownership cost of equivalent suitable vehicles to some of those proposed by Ergon Energy and consider that Ergon Energy has not materially over-specified these vehicles. We also asked Ergon Energy to provide details of its proposed In Vehicle Monitoring System (IVMS).[258] On the basis that the use of IVMS technology is becoming increasingly adopted throughout industry, and that the proposed amount of capex by Ergon Energy for this technology is consistent with other electricity service providers, we consider that Ergon Energy's proposed IVMS is justified and the proposed capex of $3.7 million ($2014–15) to be reasonable.

We received a submission from the Consumer Challenge Panel which addressed some fleet capex issues raised in our preliminary decision.[259] In particular, the CCP queried our preliminary decision to allow fleet capex consistent with historical expenditure when Ergon Energy:[260]

- had proposed a 25 per cent increase in fleet capex, despite its vehicle/staff ratio increasing by over 20 per cent over the previous regulatory period
- demonstrated systemic deficiencies in the setting of vehicle standards and the use of the highest estimated unit costs for all fleet assets, resulting in higher fleet capital and operating costs
- utilised a higher frequency of fleet asset replacement than other Australian electricity distributers.

We have reviewed the issues raised by the CCP and consider that they have been addressed by:

- Ergon Energy's revised forecasting approach for fleet capex, reflecting amended asset replacement criteria
- our review of the potential ownership cost of equivalent suitable vehicles to those proposed by Ergon Energy where we consider that Ergon Energy has not over-specified these vehicles
- Ergon Energy in its revised proposal significantly reducing its proposed total fleet and plant and equipment assets.

In summary, we consider Ergon Energy's revised revenue proposal of forecast standard control fleet capex of $174.9 million ($2014–15) reasonably reflects the efficient costs that a prudent operator would require to meet the capex criteria.[261] We note that this represents an increase of 9 per cent from our preliminary decision based on Ergon Energy's historical expenditure. We are satisfied that this slight increase is justified on the basis of Ergon Energy's improved forecasting methodology, the new

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[258] AER, *Information request Ergon Energy 078*, 31 July 2015, p. 1.

[259] Mr Hugh Grant CCP2, *AER Preliminary 2015---20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015.

[260] Mr Hugh Grant CCP2, *AER Preliminary 2015-20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, pp. 38-39.

[261] NER, cl. 6.5.7(c)(1).

IVMS expenditure adding to historical costs, and the fact that the operating life of some of its fleet assets was extended during the 2010–15 regulatory control period.

B.6.4 Buildings and property capex

In our preliminary decision, we found that Ergon Energy's forecast capex for non-network buildings and property was in line with actual and estimated capex in the 2010–15 regulatory control period.[262] In relation to Ergon Energy's program of major building projects we concluded that:[263]

- the documentation submitted by Ergon Energy generally provided sufficient justification to support the need, costs and timing of the proposed projects
- Ergon Energy had excluded the 'do nothing' option as part of its options ranking process for the Townsville major property project
- on the basis of Ergon Energy's 20 year net present value (NPV) analysis of construction and lifecycle costs and benefits, the 'do nothing' option was in fact the highest NPV option of all eight options evaluated for the Townsville project
- it was not clear that Ergon Energy's options evaluation process for the Townsville major property project necessarily supported the selection of the preferred option
- the work undertaken at the Townsville site in the 2010–15 regulatory control period as 'stage one' of the redevelopment is a standalone improvement, such that further work in the 2015–20 regulatory control period is not necessarily required
- we were not satisfied that Ergon Energy's forecast capex for the Townsville property project is efficient, or that a prudent operator would necessarily proceed with Ergon Energy's preferred development option.

Ergon Energy's revised proposal for non-network buildings and property capex of $238.8 million ($2014–15) included forecast capex for the Townsville major property project, consistent with its initial regulatory proposal. Ergon Energy submitted a revised NPV analysis and additional documentation in support of the need for and efficiency of the Townsville project. Ergon Energy submitted that:[264]

- the 'do nothing' option had been deliberately excluded from the financial ranking of options due to the risks associated with this option
- an efficient and prudent operator cannot retain the known risks to health and safety and to the long term operational effectiveness of the business identified in the Townsville site assessment, site condition and asbestos inspection reports

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262 AER, *Preliminary decision - Ergon Energy distribution determination - Attachment 6 - Capital expenditure*, April 2015, p. 6-100.

263 AER, *Preliminary decision - Ergon Energy distribution determination - Attachment 6 - Capital expenditure*, April 2015, pp. 6-101 to 6-104.

264 Ergon Energy, *SUB09.01 Submission to the AER on its Preliminary Determination: Capital expenditure - Buildings and property*, July 2015, pp. 5 to 13.

- by extending the original NPV analysis to a 30 year timeframe, the preferred development option is shown to be more cost effective than the 'do nothing' option within the 40 year useful life of the redeveloped assets
- completion of the Townsville redevelopment project is necessary to realise the full benefit of work already completed for stage one of the project and to meet development approval conditions imposed by Townsville City Council
- non-completion of the stage two works proposed for the 2015–20 regulatory control period would leave the site in contravention of applicable building codes and legislation and lead to higher operating costs than any of the other assessed options
- the Evans & Peck report undertaken for the shareholder ministers and relied upon by the AER in making the preliminary decision does not fully consider or understand the dependencies between the two stages of development or the array of risks and issues that would remain on site if the project concluded at the end of stage one.

We have reviewed the additional supporting documentation provided by Ergon Energy in relation to the Townsville major property project. On the basis of this additional information, we are now satisfied that Ergon Energy's options evaluation process for the Townsville major property project supports the selection of the preferred development option.

From an economic perspective, Ergon Energy's extended NPV analysis shows that the proposed option has the highest NPV of all eight options considered by Ergon Energy when the construction and lifecycle costs and benefits are assessed over a 30 year period.[265] We consider this assessment period is reasonable, given the 40 year useful life of the redeveloped property assets.

In our view, the non-financial considerations and risks associated with the 'do nothing' option outlined by Ergon Energy in its revised proposal further support selection of the development option. The key points drawn from the Townsville site assessment, condition assessment and asbestos inspection reports include:[266]

- site accommodation is dispersed and intermingled with heavy vehicle traffic areas, resulting in operational inefficiencies and safety hazards
- operational buildings are generally in poor condition and substandard in terms of amenity, appointment and space
- office accommodation is at maximum capacity and leased demountable buildings are being used to compensate

[265] Ergon Energy, *SUB09.04 Garbutt_Townsville_Assumptions Calculations_30 years*, July 2015.

[266] Ergon Energy, *SUB09.01 Submission to the AER on its Preliminary Determination: Capital expenditure - Buildings and property*, July 2015, pp. 6 to 8.

- fire services do not meet current Australian standards, including the absence of fire sprinkler systems in any building
- a range of legislative non-compliance issues and structural, mechanical and architectural deficiencies exist across all buildings on the site
- asbestos containing material exists in six buildings, with the combination of asset deficiency and building age contributing to increasing risk that asbestos fibres will be disturbed

On the basis of the information provided, we agree with Ergon Energy that a prudent operator would seek to address these issues rather than pursue a 'do nothing' approach. The widespread nature of the issues identified suggests a comprehensive approach to resolving the areas of non-compliance, safety risk and asset deficiency is likely to be prudent.

We have also reconsidered the question of whether the stage two development works at Townsville are an integral and necessary continuation of the stage one works completed in the 2010–15 regulatory control period. In our preliminary decision, we had regard to the report prepared by Evans & Peck for Ergon Energy's shareholder ministers which stated that the stage one redevelopment was a standalone improvement to the Townsville site.[267] The additional information provided with Ergon Energy's revised proposal suggests this statement is incorrect. Ergon Energy submitted that:[268]

- the need to maintain business operations during the redevelopment process necessitated the redevelopment of the office accommodation and new logistics warehouse as stage one, prior to demolishing the remaining buildings and developing the old warehouse into the new workshop building
- the development application decision made by Townsville City Council[269] relates to both development stages as a single body of work
- the majority of conditions stipulated in the development application decision require the stage two demolition of buildings in order to create space for the necessary parking, drainage, traffic management and landscaping civil works
- the operating and maintenance savings associated with the project can only be achieved once staff are consolidated into the three redeveloped buildings and the twelve redundant buildings are demolished. This outcome will be achieved at the end of stage two of the redevelopment.

Given these points, we agree with Ergon Energy's view that there are inherent dependencies between the two stages of work at the Townsville site.[270]

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[267] Evans & Peck, *07.08.09 - Garbutt Site Redevelopment Review*, May 2014, p. 5.

[268] Ergon Energy, *SUB09.01 Submission to the AER on its Preliminary Determination: Capital expenditure - Buildings and property*, July 2015, pp. 9 to 12.

[269] Ergon Energy, *SUB09.02 City of Townsville Development Application Decision Notice*, 28 August 2012.

On the basis of the information submitted by Ergon Energy in its revised proposal, and having regard to both financial and non-financial considerations, we are satisfied that the forecast capex for the Townsville major property project is likely to reflect the efficient costs a prudent operator would require to achieve the capex objectives. We have included the costs of the Townsville major property project in our estimate of forecast non-network buildings and property capex, which is consistent with Ergon Energy's revised regulatory proposal.

B.6.5 Non-network property disposals

In our preliminary decision, we found that Ergon Energy's business cases for the major property projects in Townsville, Rockhampton, Maryborough and Toowoomba all account for property disposals related to the development projects. However, in modelling its forecast revenues for the 2015–20 regulatory control period, Ergon Energy had not accounted for any property disposals in this period.[271]

In its revised proposal, Ergon Energy accepted our decision to account for property disposals related to the projects in Rockhampton, Maryborough and Toowoomba, valued at $13.2 million.[272] However, Ergon Energy also proposed to reinstate the Townsville major property project as part of its forecast capex for the 2015–20 regulatory control period. As discussed above, we have accepted Ergon Energy's revised proposal in relation to the Townsville property project. We have therefore accounted for the property disposal related to the Townsville project, valued at $5.3 million[273], in modelling Ergon Energy's required revenues for the 2015–20 regulatory control period.

B.6.6 SPARQ ICT expenditure included within overheads

Ergon Energy's ICT expenditure is divided between the expenditure for end user devices (part of the non-network capex forecast) and the expenditure for all other ICT (part of the SPARQ ICT expenditure forecast). The SPARQ ICT expenditure forecast includes both opex and capex. The ICT opex forecast is discussed in Attachment 7. The SPARQ ICT expenditure is included in the capitalised overheads category, which is discussed in section B.5.

In Ergon Energy's revised proposal, it proposed $466.4 million ($2012─13) for ICT expenditure, 1.1 per cent less than its initial proposal. This forecast includes:

- Asset service fees ($197.8 million) ─ this fee consists of SPARQ's finance and depreciation charge for Energex's consumption of ICT assets held by SPARQ,

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[270] Ergon Energy, *SUB09.01 Submission to the AER on its Preliminary Determination: Capital expenditure - Buildings and property*, July 2015, p. 10.

[271] AER, *Preliminary decision - Ergon Energy distribution determination - Attachment 6 - Capital expenditure*, April 2015, p. 6-105.

[272] Ergon Energy, *SUB09.01 Submission to the AER on its Preliminary Determination: Capital expenditure - Buildings and property*, July 2015, p. 13.

[273] Ergon Energy, *Garbutt Redevelopment_Gate 3 8 Options-v1.10*, Option Lifecycle Benefits tab.

- Operational support and telecommunications pass through ($248.2 million) - for SPARQ's costs associated with the ongoing operation, support and maintenance of ICT services and for the costs of carrier, mobile, data, voice and device management services,
- Non-capital project costs ($20.4 million) ─ for non-recurrent opex reflecting the ICT specific expenses which cannot be capitalised.

Ergon Energy treats these costs as indirect opex. In its revised proposal, Ergon Energy included SPARQ's proposed ICT capex forecast of $226.1 million ($2012─13).[274] This is $0.5 million higher than its initial proposal.

In our preliminary decision we did not propose any changes to Ergon Energy's SPARQ ICT capex forecast. However, with a view to reconsidering the level of the proposed expenditure at the final decision stage, we raised concerns with four aspects of Ergon Energy's ICT expenditure forecast, that:

- using the 2012–13 as a base year for forecasting 'operational support' and 'telecommunications pass through' does not capture the efficiencies identified by the Independent Review Panel on Network Costs (the IRP) and ITNewCom (SPARQ's consultant);
- Ergon Energy is over recovering the financing costs which SPARQ charges to Ergon Energy via the asset service fee;
- Ergon Energy is relying on SPARQ ICT costs, the majority of which have not been market tested; and
- Ergon Energy is not transparently reporting its ICT costs.[275]

Ergon Energy addressed each of these areas in its revised proposal.

Prior to our preliminary decision, we engaged Deloitte Access Economics to conduct an analysis of Ergon Energy and Energex's operating expenditure for the 2015–20 regulatory control period, including its ICT forecasts.

Regarding the 2012–13 base year for forecasting 'operational support' and 'telecommunications pass through' costs, Ergon Energy disagreed with our assessment that base year was inefficient.[276] Ergon Energy pointed out that the IRP concluded that SPARQ was delivering operational support efficiently, compared to other organisations.[277]

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274 Ergon Energy, *Revised proposal: Forecast Expenditure Summary: Information, Communication and Technology 2015 to 2020*, July 2015, p. 10. SPARQ's ICT capex does not directly appear in Ergon Energy's reporting. The ICT capex is translated into the asset service fees, which are reported as opex.

275 AER, *Ergon Energy Preliminary Decision - Attachment 6: Capital expenditure*, April 2015, p. 6-91.

276 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 17.

277 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 17.

To address our concerns about over or under recovery due to the WACC used, Ergon Energy submitted that SPARQ will use Ergon Energy's approved WACC and will update it annually.[278] KPMG, Ergon Energy's consultant, compared the revenue allowance derived from using the SPARQ asset charging model and associated reporting of IT expenditure to that derived from putting Ergon Energy's IT capex and opex into our PTRM. KPMG found no material difference in the revenue allowances resulting from these different calculation methods.

Ergon Energy submitted that there has been an increase in the number of outsourced ICT services that it uses, so that for the coming regulatory control period approximately 46 per cent of operational support services provided by SPARQ will be outsourced.[279] Ergon Energy noted that our consultants Deloitte raised concerns about a lack of market testing of SPARQ's services and consequently implied cost inefficiency. Ergon Energy submitted that Deloitte's conclusion of inefficiency due to low levels of outsourcing is incorrect because that low level does not take into account that the panel arrangements are relatively new and only for capital works.[280]

Ergon Energy suggested that we and our consultants, Deloitte, have drawn incorrect conclusions from the Independent Review Panel on Network Costs Report and the ITNewCom report. Specifically, Ergon Energy disagreed with our statement that the IRP recommended that competitive pressure should be placed on SPARQ through the market testing of the services it provides to Ergon Energy and that there should be changes to the relationship between Ergon Energy and SPARQ. Ergon Energy disagreed with Deloitte's suggestion that the businesses should put competitive pressure on SPARQ by issuing market contracts themselves. It submitted that there was no evidence that Deloitte's suggestion would produce efficiencies. Ergon Energy also stated that given the specialist nature of the ICT work, SPARQ is in a stronger position than itself to extract value through market contracts.[281]

Regarding its reporting approach for ICT expenditure, Ergon Energy acknowledged that its model is different to other businesses. However, it noted that there is a trend in the ICT industry towards software as a service and other cloud based solutions, so that in the future other businesses may have similar reporting approaches.[282] It also submitted that as KPMG's analysis found no material difference between the SPARQ approach and our PTRM, it will continue to use the SPARQ approach.[283] KPMG

278 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 13.

279 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 15.

280 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 14.

281 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 15.

282 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 10.

283 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, pp. 10-11.

submitted that the ICT recovery model is transparent and understood by internal stakeholders.[284] As justification, KPMG provided information on the four categories of IT expenditure that SPARQ uses, including a description of how, broadly, the asset service fees are calculated. Ergon Energy also submitted on the appropriate benchmark for ICT expenditure and Ergon Energy's relative efficiency. Ergon Energy submitted that we should have used a different benchmark of 7 per cent for regulated ICT capex as a percentage of regulated capex, rather than 4.48 per cent for corporate ICT capex as a percentage of total corporate capex because the latter benchmark includes capex for unregulated services.[285] Ergon Energy cited KPMG's benchmarking as showing that Ergon Energy's ICT capex is trending in line with the industry mean for the upcoming regulatory control period. Ergon Energy submitted that benchmarking for ICT capex should not be given significant weight because of the variability of ICT expenditure.[286]

Nous Group report on ICT capital expenditure

We engaged Nous Group (Nous) to evaluate Ergon Energy and Energex's ICT programs of work as completed by SPARQ from two perspectives, a bottom up evaluation of individual projects and an assessment of the degree to which efficiencies are being achieved in the SPARQ delivery arrangements.[287] Nous found that 80 per cent of Ergon Energy's SPARQ ICT capex program is justified based on Ergon Energy's documentation.[288] However, Nous identified three programs that were not fully justified and therefore may not be prudent and efficient capex:

- replacement of an asset inspections solution and works management capability as part of the enterprise asset management upgrade, estimated at $26.1 million
- upgrading of PEACE (customer information and network billing functionality), $10.4 million
- updates to the business analytics platform, $10.2 million.[289]

Nous noted that based on the business cases provided most projects are planned to be internally delivered by SPARQ, which is at odds with current trends in ICT delivery. It also noted that there will be a significant increase in the number of common solutions across Ergon Energy and Energex in the coming regulatory control period, indicating that there are efficiencies from the SPARQ delivery model.[290] Nous stated that there is

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284 KPMG on behalf of Energex and Ergon Energy, *Appendix 4.10 Report to the Board of SPARQ Solutions on ICT Expenditure Forecast for the period: 2015 to 2020 - KPMG*, 25 June 2015, p. 10.

285 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, pp. 12-13.

286 Ergon Energy, *Submission to the AER on its Preliminary Decision: Capitalised overheads and ICT expenditure, 3 July 2015*, p. 17.

287 We received the Nous report after Ergon Energy submitted its revised proposal. Because of this, we sought comment from Ergon Energy on the contents of the report.

288 Nous Group, *Ergon Energy's ICT Expenditure 2015-20*, July 2015, p. 5.

289 Nous Group, *Ergon Energy's ICT Expenditure 2015-20*, July 2015, pp. 8-10, 15-18.

290 Nous Group, *Ergon Energy's ICT Expenditure 2015-20*, July 2015, p. 23.

a need for market testing of ICT services, but contrary to the findings of the IRP, argued that there can be greater efficiencies by continuing to combine services for Ergon Energy and Energex. It suggested that SPARQ move towards a role as a broker of market services rather than continuing as a developer and operator, for common services. Additionally, Ergon Energy and Energex should individually test the market for non-common services. Nous did not suggest any changes to the ICT capex forecast as a result of these observations.[291]

As we received the Nous report after we received Ergon Energy's revised proposal, we sought comment from Ergon Energy on the report.[292] Ergon Energy agreed with Nous' suggested deferral of the PEACE upgrade. In its revised proposal Ergon Energy had already deferred this project due to adjustments in its current work program.[293] Ergon Energy submitted that the replacement of the asset inspection and works management capabilities in the enterprise asset management upgrade are core capabilities of its particular configuration of that system, contrary to Nous' view, and therefore are not discretionary and need to be completed at the same time as the upgrade of the enterprise asset management system. It also disputed the estimate of the cost of these upgrades, submitting that the cost is significantly less than the $26.2 million estimated by Nous.[294] Ergon Energy provided further information to justify the upgrade to its business analytics platform and explained that because the components of the platform will become unsupported during the regulatory control period it is necessary to upgrade them in this period.[295] We accept Ergon Energy's justification that these elements of the enterprise asset management project and the business analytics platform upgrade are necessary at this time. Therefore, we are not making the adjustments suggested by Nous in this regard.

In its response to the Nous report, Ergon Energy also explained that it has updated its forecast expenditure for its Network Information Enablement program due to the project spanning two regulatory control periods and changes to the particular project. Ergon Energy noted that as Nous supported the project in its report, and that since the overall expenditure remain consistent with the business case provided, it did not expect the change in cash flow to impact Nous' assessment of the program.[296] We accept Ergon Energy's explanation for the change to its forecast for the Network Information Enablement program.

Ergon Energy noted Nous' recognition of the potential efficiency benefits of common solutions between Ergon Energy and Energex. However, Ergon Energy disputed Nous' assessment that most of ICT projects are being delivered internally by SPARQ. It reiterated its submissions that it is moving towards more outsourcing, particularly

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291 Nous Group, *Ergon Energy's ICT Expenditure 2015-20*, July 2015, p. 25.

292 AER, *Ergon Energy Information Request 075*, 17 July 2015.

293 Ergon Energy, *Response to AER Information Request 075*, 31 July 2015, p. 3. Ergon Energy, *07.00.07 (Revised) ICT Expenditure Forecast Summary*, 3 July 2015, p. 10.

294 Ergon Energy, *Response to AER Information Request 075*, 31 July 2015, pp. 3-4.

295 Ergon Energy, *Response to AER Information Request 075*, 31 July 2015, p. 4.

296 Ergon Energy, *Response to AER Information Request 075*, 31 July 2015, p. 3.

through the panel arrangements for ICT capital works.[297] Ergon Energy submitted that the Nous report supports its ICT delivery model and the benefits that the arrangement with SPARQ provides.[298] In our view, Ergon Energy should seek to market test more ICT expenditure, both within the SPARQ model, as it is currently doing, and independently from SPARQ.

AER assessment

We accept Ergon Energy's revised forecast of SPARQ ICT capex of $226.1 million ($2012–13) for the 2015–20 regulatory control period.[299] This forecast reflects the deferral of the PEACE upgrade and the other changes that Ergon Energy made due to projects spanning two regulatory control periods. Ergon Energy provided further information that satisfied us that the other projects that Nous suggested could be deferred are prudent and efficient, so we have accepted that expenditure.[300] Based on the information provided by Ergon Energy, we are satisfied that Ergon Energy's revised forecast IT program is required to meet the capex objectives.[301] We accept that Ergon Energy's forecast capex for this program reasonably reflects the efficient costs that a prudent operator, with a realistic expectation of cost inputs, would require to meet the capex objectives.[302]

The SPARQ ICT capex forecast of $226.1 million ($2012–13) translates into asset service fees of $205 million for the 2015–20 regulatory control period. The other components of the SPARQ forecast are the operational support, telecommunications pass through, and non-capital project costs. We accept these costs as proposed in the revised proposal. Therefore, Energex's revised ICT expenditure forecast for the 2015–20 regulatory control period is $473.5 million ($2012–13). This is an increase of $1.8 million from Ergon Energy's original proposal.

We have some concerns in relation to the SPARQ arrangement, although overall we are satisfied that Ergon Energy's forecast for SPARQ ICT capex reasonably reflects the efficient costs that a prudent operator would require to achieve the capex objectives. Below we explain our concerns and provide suggestions of how Ergon Energy can resolve them over the next regulatory period.

We still have concerns regarding over or under recovery of expenditure relating to the asset service fee due to the SPARQ funding and asset charging model. SPARQ will use our approved WACC, rather than its proposed WACC, to calculate the finance charges and this WACC value will be updated annually. We encourage Ergon Energy to move from the SPARQ asset charging model to reporting its IT capex directly in its

297 Ergon Energy, *Response to AER Information Request 075*, 31 July 2015, pp. 4-5.
298 Ergon Energy, *Response to AER Information Request 075*, 31 July 2015, p. 5.
299 Ergon Energy, *07.00.07 (Revised) ICT Expenditure Forecast Summary*, 3 July 2015, p. 10.
300 Ergon Energy, *Response to AER Information Request 086*, 21 August 2015, pp. 1-3.
301 NER, cl. 6.5.7(a).
302 NER, cl. 6.5.7(c).

capex, as it does for end user devices, so that there is no possibility of over or under recovery due to financing charges.

We acknowledge that SPARQ has been moving towards greater use of outsourcing for both operational services and capital works. However, we still have concerns that there could be inefficiencies in SPARQ's forecasts because SPARQ itself is not subject to competitive pressures. We disagree with Ergon Energy's submission that the IRP did not recommend that there should be further outsourcing of operational services.[303] The IRP recommended, in Recommendation 15, that Ergon Energy, itself, issue market tenders for delivery of capital projects and for the delivery of operational ICT services, to test the services currently delivered by SPARQ.[304] QCOSS also noted that Ergon Energy and Energex have not implemented the market testing recommended by the IRP. It is suggested that we should only accept ICT costs that have been market tested.[305] Origin Energy also submitted that it continues to have concerns with the level of Ergon Energy's ICT forecast.[306] We accept that Ergon Energy is moving towards more market testing and outsourcing and we encourage this to continue. However, based on the information Ergon Energy submitted on specific projects and the further analysis undertaken for this determination, we are satisfied that Ergon Energy's revised ICT forecast reflects the efficient costs that a prudent operator would incur.

While we have approved certain capex allowances for ICT services, we still have some concerns about the transparency of the SPARQ ICT asset charging model. We suggest that Ergon Energy address these issues over the forthcoming regulatory period. For example, we acknowledge that the SPARQ model may not produce materially different revenue requirements than using the PTRM. However, that the two models may produce financially similar outcomes is not itself conclusive proof that the SPARQ model is transparent.

Ergon Energy's ICT capex is not reported in the year that it is incurred; instead ICT capex becomes part of the SPARQ's asset service fee which is a combination of finance and depreciation charges for assets incurred previously and in the current year. Because of this Ergon Energy's ICT capex cannot be directly compared to other businesses' and its forecasts cannot be easily compared to previous expenditure. We disagree with Ergon Energy's conclusion that because other businesses may be moving towards using cloud based solutions, that models similar to the SPARQ ICT model will become more common. We consider that as cloud solutions where software and/or hardware are provided as services are adopted, businesses will substitute opex for capex, which will be reported as opex rather than as indirect opex due to an asset services fees as occurs with Ergon Energy.

303 Ergon Energy, *07.00.07 (Revised) ICT Expenditure Forecast Summary*, 3 July 2015, pp. 15-16.

304 Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, p. 55.

305 QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020*, 3 July 2015, pp. 11, 17.

306 Origin Energy, *Submission to AER preliminary decision Qld electricity distributors*, 3 July 2015, p. 10.

To promote transparency, Ergon Energy should report its ICT capex in the year when the assets are purchased. Particularly given that Ergon Energy submitted that there is no material difference in the reporting approaches, we encourage Ergon Energy to report its ICT capex as it does for its other assets.

C Maximum demand forecast

This appendix sets out our observations of forecast maximum demand in Ergon Energy's network for the 2015–20 regulatory control period. Maximum demand forecasts are an important consideration in estimating Ergon Energy's capex and opex, and to our assessment of that forecast expenditure.

We consider Ergon Energy's demand forecasts at the system level and the more local level. System demand represents total demand in the Ergon Energy distribution network. System demand trends give a high level indication of the need for expenditure on the network to meet changes in demand. Forecasts of increasing system demand generally signal an increased requirement for growth capex, and converse for forecasts of stagnant or falling system demand.

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.

In our preliminary decision, we accepted Ergon Energy's demand forecast submitted as part of its original proposal. However, we stated that our final decision will take into account the Australian Energy Market Operator's (AEMO) forecasts that were scheduled to be published by July 2015.

In our consideration of Ergon Energy's demand forecasts, we have had regard to:

- Ergon Energy's proposal
- AEMO's independent demand forecasts
- long-term demand trends and changes in the electricity market, and
- stakeholder submissions in response to Ergon Energy's revised proposal (as well as submissions made in relation to the Queensland electricity distribution determinations more generally).

These are set out in more detail in the remainder of this appendix.

C.1 AER position

We consider that Ergon Energy's maximum demand forecasts reflect a realistic expectation of demand over the 2015–20 period. This is because:

- Ergon Energy's forecast of low demand growth over the 2015–20 period is consistent with recent trends in electricity demand and consumption. Growth in consumption due to population and income growth is likely to be offset by continued investment in rooftop solar PV and energy efficiency, and this is reflected in Ergon Energy's forecast.

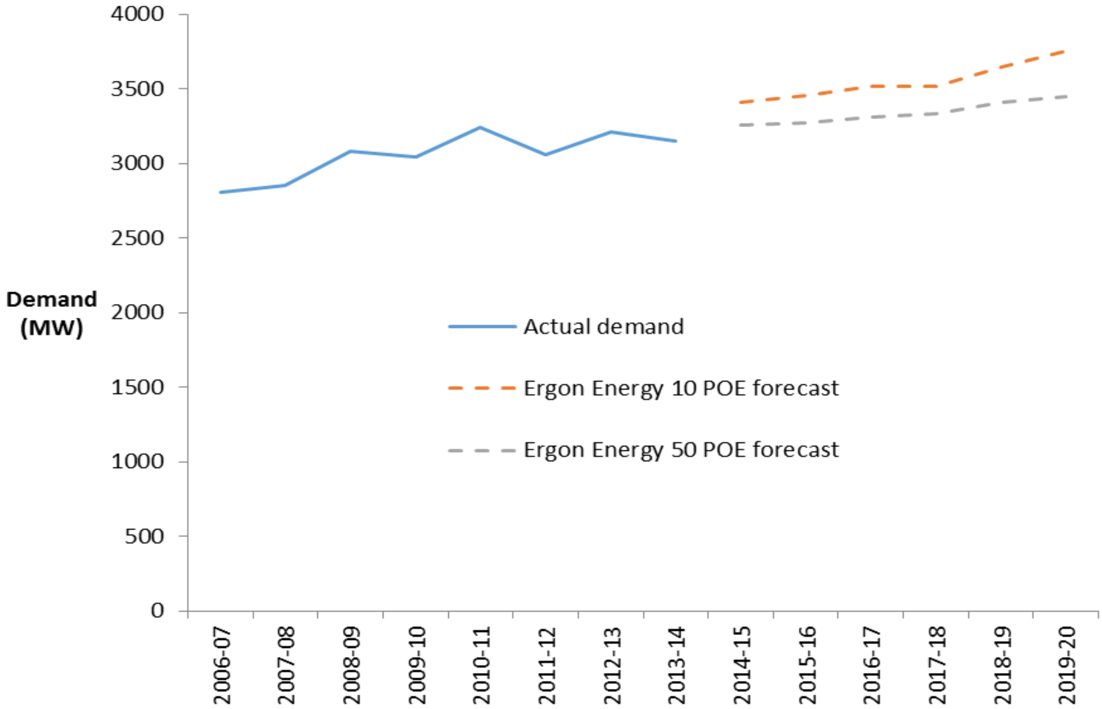
- Independent demand forecasts from AEMO are consistent with the forecast growth in demand for Ergon Energy's network.[307]
- Ergon Energy has progressively downgraded its demand forecasts in recent years as actual demand is lower than previously forecast as forecasting methods improve. Ergon Energy's demand forecasts for the 2015–20 period are now consistent with the trend in actual demand in recent, and more likely reflects a realistic expectation of demand than prior forecasts.

These are set out in more detail in the remainder of this appendix.

C.2 Ergon Energy's revised proposal

Ergon Energy has forecast an average annual growth in peak demand of around 1.1 per cent in the 2015−20 regulatory control period. As shown in Figure 6.9, this is broadly consistent with its growth in maximum demand over the 2010−15 regulatory control period.

Figure 6.9 Ergon Energy maximum demand forecast (MW, non-coincident, summated transmission connection point forecasts)



[307] AEMO published its first connection point forecasts for Energex and Ergon in June 2015. These forecasts provide an independent assessment of expected demand on Ergon Energy's and Energex's networks. In our preliminary decision, we stated that we would take AEMO's forecasts into account for our final decision.

Source: Ergon Energy revised regulatory proposal; Ergon Energy response to AER Ergon 088.

Note: Ergon Energy provided us with amended non-coincident demand forecasts (as measured at the transmission point level) relative to the forecasts it included within its reset RIN. These amendments correct for errors in the original submission, rather than updated demand forecasts. See Ergon Energy response to AER Ergon 088, p. 1.

Ergon Energy updated its maximum demand forecasts since its original regulatory proposal. Ergon Energy submitted that its updated forecasts of maximum demand under 'low growth' and 'medium growth' scenarios are consistent with the equivalent forecasts developed in 2014 for the regulatory proposal.[308] It also notes that the actual demand experienced over 2014–15 correlated with Ergon Energy's most recent demand forecast for that year.[309]

In light of this, Ergon Energy has not submitted to us revised maximum demand forecast numbers (at the total system level) and stated that:

> Consequently expenditure forecasts supporting the original proposal are predominantly being maintained, however, detailed spatial forecasts are still being reviewed for the whole network based on the 2015 low growth forecast.[310]

Ergon Energy previously stated that the biggest influence on future demand is forecast to be due to be economic growth predicted over the 2015–20 period.[311] Ergon Energy also provided some additional information about economic factors that may drive some growth in maximum demand over the 2015–20 period:[312]

- Overall economic growth in Queensland will remain below its long-run average as mining investment declines. However, solid growth is still expected for 2015–16.
- Household spending growth will gradual pick up as low interest rates will continue to bolster consumer spending and the upswing in Australian housing market will be expected to continue.
- The lower Australian dollar will also provide a further boost to other exports, and support Queensland's tourism sector.

C.3 AEMO forecasts

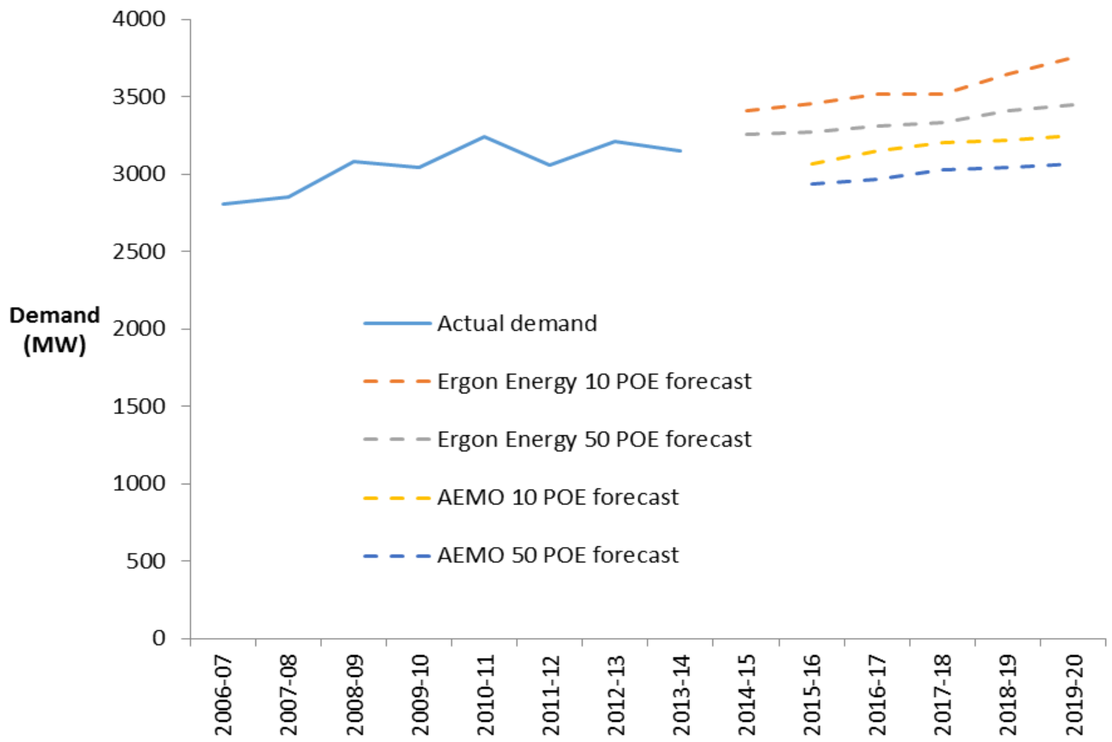
In June 2015, AEMO published its first connection point forecasts for Queensland. These forecasts are AEMO's independent electricity maximum demand forecasts at transmission connection point level, over a 10-year outlook period. The Standing

308 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.17, pp. 2-3.
309 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.17, p. 2.
310 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.17, p. 2.
311 Ergon Energy, *Distribution Annual Planning Report 2014/15 to 2018/19*, Part A, p. 56.
312 Ergon Energy, *Submission to the AER on its Preliminary Decision*, 3 July 2015, Attachment SUB09.17, pp. 3-4.

Council on Energy Resources (SCER) intended these demand forecasts inform our regulatory determinations.[313]

Figure 6.10 shows our comparison between Ergon Energy's system demand and AEMO's summated connection point demand for the Ergon Energy's network. It shows the growth trend for Ergon Energy's system demand forecast is consistent with AEMO's connection point forecasts for Ergon Energy's network for the 2015–20 period. This gives us a level of confidence the trend in Ergon Energy's forecasts are realistic (although the level of Ergon Energy's demand forecasts are higher than AEMO's).

Figure 6.10 Comparison of AEMO and Ergon Energy's summated connection point forecasts (MW, non-coincident)



Source: Ergon Energy revised regulatory proposal; Ergon Energy response to AER Ergon 088; AEMO 2015 Queensland Connection Point Forecasts.

In the next section, we discuss some of the predicted trends in demand from AEMO's connection point forecast report.

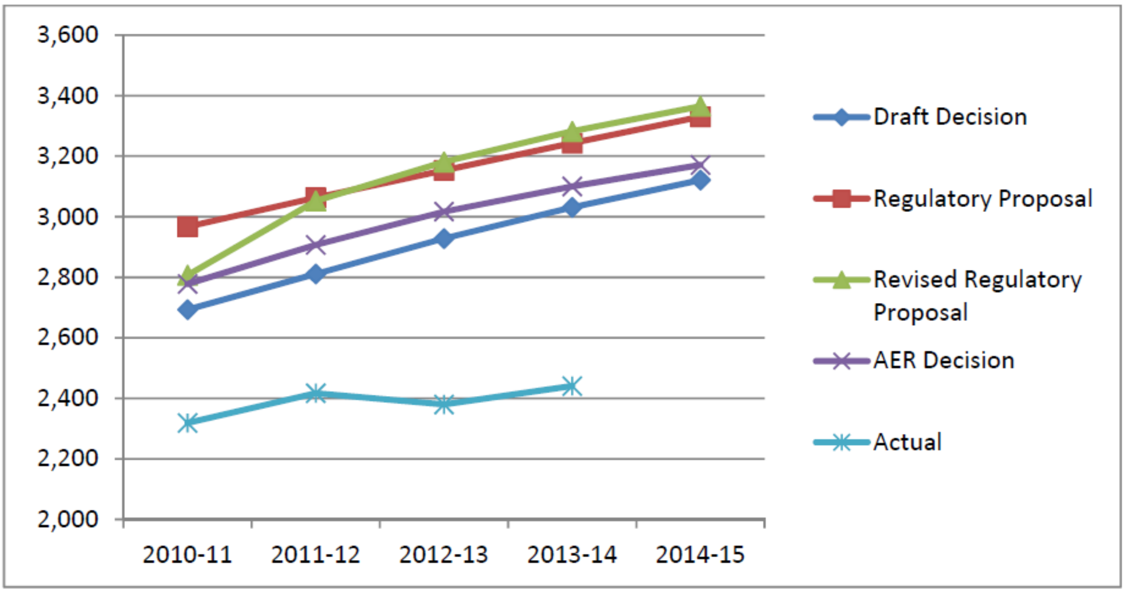
C.4 Demand trends

The recent trend in demand forecasts across the NEM is that demand forecasts are actually progressively downgraded over time as actual demand is lower than

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

previously forecast as forecasting methods improve. Ergon Energy follows this pattern because it is forecasting low demand growth over the 2015–20 period and it has been progressively downgrading its forecasts since its regulatory proposal for the 2010–15 period. This is reflected in the following chart taken from Ergon Energy's revised proposal.

Figure 6.11 Ergon Energy actual and forecast maximum demand 2010–11 to 2014–15



Source: Ergon Energy revised regulatory proposal, Attachment 07.00.02 (Revise), p. 16.

A major driver of flattening demand forecasts is changing electricity consumption patterns in Queensland and across the NEM. While Ergon Energy has submitted that a major driver of predicted growth in maximum demand is growth in economic activity, there is strong evidence to suggest that energy consumption in Queensland is being offset by solar PV and energy efficiency measures. As set out in AEMO's connection point forecasting report, this is contributing to flattening of demand:

- In Queensland, AEMO reported that residential and commercial consumption declined from 2009–10 to 2014–15 due to a rapid increase in electricity prices, uptake of rooftop PV, and greater customer engagement in reducing electricity consumption (e.g. energy efficiency).[314]
- AEMO forecasts continued growth in residential and commercial solar PV due to incentives from the Clean Technology Investment Fund and Small-scale Renewable Energy Scheme and reductions in the cost of solar PV technology.[315]

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314 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, pp. 25-26.

315 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, pp. 28-29.

However, the impact of solar PV will likely have a diminishing impact on maximum demand over the longer-term as peak daily demand shifts to the evening.[316]

- AEMO also forecasts increased energy efficiency savings over the 2014–15 to 2024–25 period.[317]

As set out in AEMO's connection point forecast report for Queensland, the impact of expected continued growth in solar PV and energy efficiency is that this will offset growth in consumption and maximum demand from population and income growth.[318] As set out in section C.3 above, this resulted in AEMO forecasting only small increases in residential and commercial maximum demand over the 2015–20 regulatory control period.[319] While these results reflect the total residential and commercial demand in Queensland, we consider that they are applicable to Ergon Energy's network.

The Queensland Council of Social Service (QCOSS) submitted that it is not reasonable for Ergon to forecast growth in maximum demand across its network above the direction of historical trends.[320] It stated that, in areas of Ergon Energy's network where growth is driven by residential and commercial load, there is unlikely to be significant growth in maximum demand during 2015–20.[321]

The Alliance of Electricity Consumers also submitted that Ergon Energy's forecasts of energy consumption are overstated and have always been optimistic.[322] It noted that, over time, electricity consumption failed to increase in the Ergon Energy distribution area even though forecasts predicted significant growth.[323]

The CCP submitted that the Queensland distributors have track records of consistently over-estimating their demand forecasts.[324] It also submitted that Ergon Energy is forecasting demand growth levels exceed AEMO's Queensland demand forecasts (as set out in the 2015 National Electricity Forecasting Report), which predict flat or declining demand.[325]

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316 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, pp. 28-29.

317 AEMO, *Detailed summary of 2015 electricity forecasts, 2015 National Electricity Forecasting Report*, June 2015, p. 29.

318 AEMO, *Transmission Connection Point Forecasting Report for Queensland*, June 2015, p. 4.

319 AEMO, *Transmission Connection Point Forecasting Report for Queensland*, June 2015, p. 4.

320 QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020*, 3 July 2015, p. 9.

321 QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-2020*, 3 July 2015, p. 9.

322 Alliance of Energy Consumers, *Submission to Energex and Ergon Energy's Revised Regulatory Proposals (Qld)*, 24 July 2015, p. 12.

323 Alliance of Energy Consumers, *Submission to Energex and Ergon Energy's Revised Regulatory Proposals (Qld)*, 24 July 2015, p. 12.

324 Mr Hugh Grant CCP2, *Advice on AER preliminary decisions and revised proposals from Energex, Ergon Energy and SA Power Networks*, July 2015, p. 19.

325 Mr Hugh Grant CCP2, *Advice on AER preliminary decisions and revised proposals from Energex, Ergon Energy and SA Power Networks*, July 2015, p. 19.

We do not necessarily agree with the CCP and QCOSS. As set out above:

- Ergon Energy's forecast demand growth is supported by AEMO's demand forecasts released in its 2015 Queensland connection point forecasts. AEMO forecasts approximately 1.1 per cent demand growth on Ergon Energy's network over 2015–20 (which excluded any LNG demand).
- Ergon Energy's most recent maximum demand forecast are considerably lower than previous forecasts, and we consider that they more realistically reflect the recent and forecast trends in consumption and demand in Queensland
- Ergon Energy's forecasts of maximum demand are consistent with trends in actual demand over the 2010–15 period. While Ergon Energy forecasts small growth in demand over 2015–20, its 50 PoE demand forecast is generally lower than that experienced between 2012–13 and 2013–14.

In response to the Alliance of Electricity Consumers' submission, we note that maximum demand forecasts and energy consumption forecasts are not necessary correlated. Maximum demand is much more sensitive to times of peak energy consumption (e.g. hot summer days when air conditioners are switched on), and therefore maximum demand can grow while overall energy consumption falls. We agree with the Alliance of Electricity Consumers' position that previous forecasts of energy consumption and maximum demand have been overstated. However for the reasons set out in this appendix, we consider that Ergon Energy's most recent maximum demand forecasts reflect a realistic expectation of demand for the 2015–20 period.

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. Ergon Energy in its revised regulatory proposal includes forecasts for changes in the prices of commodities such as copper, aluminium, steel and oil, rather than the prices of physical inputs themselves (e.g. poles, cables, transformers) used to provide network services. Ergon Energy has also escalated construction costs in its forecast.

D.1 Position

We are not satisfied that Ergon Energy's revised 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 control period.[326] We maintain our view, as set out in our preliminary decision, 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.

Consistent with our position in the preliminary decision, our approach to real materials cost escalation does not affect the proposed application of labour and construction cost escalators which apply to Ergon Energy's forecast capex for standard control services.

D.2 Ergon Energy's revised proposal

In its revised proposal, Ergon Energy has applied the same material and labour cost escalators to various asset classes proposed in its initial regulatory proposal submitted in October 2014.[327] It has updated its forecasts of real labour and construction indices and materials costs escalations. Ergon Energy stated that its escalations forecasts are provided by an independent engineering and economic forecaster using their forecast model and the latest information and analysis available to them. Ergon Energy also stated that as a result of its updated forecast, it has revised down the amount of forecast materials costs over the regulatory control period 2015–20 and that a number of asset classes are now forecast to have lower than Consumer Price Index (CPI) escalation of materials over the regulatory control period.[328]

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

327 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 7.

328 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 7.

Table 6.15 shows the revised real cumulative material cost escalators calculated for Ergon Energy by Jacobs[329].

Table 6.15 Ergon Energy's revised cumulative real materials cost escalation forecast—inputs (real indices)

	2015–16	2016–17	2017–18	2018–19	2019–20
Aluminium	1.243	1.255	1.265	1.295	1.325
Copper	0.941	0.924	0.913	0.941	0.973
Steel	1.122	1.141	1.150	1.154	1.166
Oil	0.839	0.949	1.018	1.034	1.012
Construction index	0.825	0.744	0.723	0.726	0.749

Source: Ergon Energy, *Revised regulatory proposal,* 06.02.07 Jacobs Addendum Cost Escalation Factors 2015-20, template *Cost Drivers for Materials*.

Ergon Energy, through its consultants Jacobs, applied these materials costs escalations (along with real labour and construction indices) to each of its asset classes for input into the Post Tax Revenue Model (PTRM).[330]

In its revised proposal, Ergon Energy rejected our findings on material cost escalation because:[331]

- the AER has given no weight to the NER criteria of a realistic expectation of the cost of inputs, in part, because the AER considers that recognition of actual cost inputs faced by a distributor does not sit comfortably in incentive based regulation;
- the AER justifies its position of a zero per cent real materials escalation based on a misconstruction of the concept of a 'random walk' forecast, opting for the conservative approach of not allowing any real materials escalation;
- Ergon Energy can provide examples of how its cost of materials and finished goods used in the asset classes have varied historically;
- the AER assumes that Ergon Energy have selectively chosen the weightings of the materials in its composition of materials for asset classes, and;
- the AER has a default view that Ergon Energy is inefficient in its procurement practices.

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[329] Ergon Energy, *Revised regulatory proposal,* 06.02.07 Jacobs Addendum Cost Escalation Factors 2015-20, template *Cost Drivers for Materials*.

[330] Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 7.

[331] Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, pp. 10-20.

Ergon Energy provided more specific details in rejecting the AER's findings on material cost escalation as detailed below.[332]

Realistic expectation of cost inputs

Ergon Energy stated that the AER has given no weight to the NER criteria of a realistic expectation of the cost of inputs, in part, because the AER considers that recognition of actual cost inputs faced by an electricity service provider does not sit comfortably in incentive based regulation. Ergon Energy further stated that the third expenditure criterion of achieving the capital and operating objectives of the NER recognises that the cost inputs faced by an electricity service provider are, for the most part, exogenous, and can vary from one region to another. Ergon Energy commented that how an electricity service provider acquires and utilises those inputs may well be matters of prudency and efficiency, and the NER aim to produce incentives for an electricity service provider to continually improve these areas. Ergon Energy concluded that to apply notions of 'efficiency' in relation to cost inputs implies that the electricity service provider can control costs that are, in truth, outside of the provider's control.[333]

Materials input costs

Ergon Energy has provided examples of the relative movement in the commodity prices for transformers and cables that are included in the rise and fall clauses of procurement contracts commencing in March 2011. Ergon Energy stated that the inclusion of rise and fall clauses in procurement contracts of key commodities is an accepted risk mitigation practice that, over the long term, minimises purchase costs and is also normal practice to ensure a balance between fixed and variable components to the price adjustment. Ergon Energy claims that the inclusion of fixed and variable components in its contracts for goods and services supports its contention that it does not cherry pick the commodities in its PTRM forecasts. Ergon Energy stated that there are agreed commodities (negotiated between seller and buyer) used to mitigate procurement price risks by allowing price rises and falls for elements outside the control of either party. Ergon Energy further stated that the indices used to vary the purchase price over the term of the contract are the same indices (albeit forecast futures) used for forecasting real materials escalation in the broad asset classes in the PTRM.

Ergon Energy claim that in forecasting future capital adjustments to the RAB in the PTRM it is common sense to incorporate forecast changes in the prices of inputs as required by the criteria in the NER. The forecast is therefore related to the way prices are forecast to move in future procurement contracts.

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[332] Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, pp. 10-20.

[333] Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 10.

Ergon Energy acknowledges that an asset class in the PTRM is not an aggregation of homogeneous units. To illustrate this, Ergon Energy provided the example of the asset class of Distribution Lines made up of over 1,000 distribution feeders, with each feeder made up of key switching points, isolating transformers and other components. Ergon Energy stated that as a typical feeder asset can consist of three phase, single phase and Single Wire Earth Return (SWER) lines and a mix of aluminium, copper and steel conductors on wood and concrete poles, disaggregating forecasts of assets into commodity components would be similar to un-baking a cake. Ergon Energy contends that there is no direct correlation between actual prices paid and the basis of materials escalation in the asset classes in the PTRM. Instead, Ergon Energy relied on a consultant with experience in the field of power distribution engineering and econometric modelling to model the expected future costs of an asset class under the assumptions of a modern standard and reasonable mix of materials and goods, in each asset class.[334]

Materials input cost forecasting

Ergon Energy claim that the forecast of new or replacement assets in an asset class will lead to a bias that understates the future asset cost, as capital replacement of assets often involves like for like replacements due to inherent and inherited characteristics of the assets and design standards that applied at the time of the original asset construction. Ergon Energy provided an example of a section of overhead copper conductor which would most likely need to be replaced by a similar copper conductor section, due to design, operational or physical constraints and not an aluminium conductor which would be the modern equivalent standard conductor of choice for new assets.

Ergon Energy stated that whilst suppliers carry the risk for the majority of exogenous events such as failures in the manufacturers supply chains, the only exogenous event where risk is shared with Ergon Energy is usually exchange rate and commodity price variations.[335]

Materials input cost mitigation

Ergon Energy responded to the AER's view in its preliminary decision of commodity substitution as a viable materials cost mitigation strategy with reference to the move by distributors to a standard of aluminium conductor for overhead lines in place of the dominant copper conductor standard. Ergon Energy stated that no rational distributor ever contemplated substitution of its existing copper lines with an aluminium line. Rather, new lines, and where allowed by other constraints, replacement lines, are aluminium. Ergon Energy stated that it can never escape its past and that inherent and

[334] Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, pp. 11-17.

[335] Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 17.

inherited factors will always see a new standard take time to become the dominant standard in the network. Ergon Energy also stated that in an asset that is measured in terms of many tens of years of life, it is unlikely a new standard will become dominant for many generations, let alone within a regulatory control period and that it still has many copper feeder sections compared to aluminium feeders.

In respect of the substitution potential between operating and capital expenditure, Ergon Energy claim that the potential is extremely limited as operating expenditure costs are largely dominated by non-asset related activities such as vegetation management and customer services which do not have a high material component. Ergon Energy stated that in its operating expenditure forecast, the materials forecast is zero real escalation.

Ergon Energy stated that scale is already factored into the capital forecasts and that over the forecast regulatory control period capital investment in its network is expected to decline. Ergon Energy also stated that Jacobs' forecast of materials is based on an assumption of modern assets built with modern construction standards which meant that productivity is inherent in its modelling.[336]

Forecasting uncertainty

Ergon Energy contends that although the economic literature in respect to commodities forecasting is inconclusive between using futures as an indicator of future price or a 'random walk' forecast, it does not lessen the importance of future price forecasting. Ergon Energy stated that this would be particularly so when times are volatile or there are seismic shifts in technology costs, for instance the sustained rise in copper costs compared to aluminium, forcing a review of design standards for distribution networks.[337]

Strategic contracts with suppliers

In respect to the AER's position that Ergon Energy can mitigate its risks associated with changes in material inputs by including hedging strategies or price escalation provisions in contracts with suppliers, Ergon Energy provided a copy of an extract from a letter from one of its suppliers in response to an enquiry about fixed pricing for cables.[338] Ergon Energy stated that the extract shows that the supplier would need to increase their price as they now assume all the risk and that the effect would be to raise the average price of the items.[339]

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336 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 17.

337 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 17.

338 Ergon Energy, *Revised regulatory proposal, SUB09.08 Ergon Energy - Capex Real labour and materials escalations - Response_ CONFID*, Appendix C.

339 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, pp. 18-19.

Cost based price increases

Ergon Energy stated that if the AER believes that real materials cost escalation is a cost based approach then equally so is labour and construction real price escalation, which the AER has accepted as having a real escalation impact on input prices.[340]

Selection of commodity inputs

Ergon Energy stated that the number and range of material commodities, and other factors used in pricing of goods inputs, reflect the terms in procurement contracts and the critical components in the whole of life costs reflected in energy losses in the copper and aluminium content of these goods and materials. Ergon Energy claim that the commodities and indices used by Jacobs are limited to those that it considers are significant in modern assets.[341]

Commodities boom

Ergon Energy stated that although it agrees with the AER that the commodities boom has subsided, it considers that cycles of commodity booms and busts are inevitable and while forecasts are not certain, it is still important for customers and shareholders it forecast what is a major cost of providing network assets – the cost of materials and goods. Ergon Energy also stated that its approach is to base its forecasts of materials on a realistic view of the forecast of the underlying costs of those materials, which is also the basis of procurement contract pricing and risk management of the supplier pricing.[342]

D.3 Reasons

We are not satisfied for the reasons set out below that Ergon Energy's proposed forecast is based on a sound and robust methodology and accordingly, consider that it does not reasonably reflect the capex criteria.[343] This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[344] Accordingly, we have not included it in our alternative estimate of total forecast capex. We are satisfied that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and this is reflected in our alternative estimate.

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340 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 20.

341 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 20.

342 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, p. 20.

343 NER, cl. 6.5.7(c).

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

This conclusion is based on the following:

- the degree of potential inaccuracy of commodities forecasts;
- there is little evidence to support how accurately Ergon Energy's materials escalation model forecasts reasonably reflect changes in prices paid by Ergon Energy for physical assets in the past and by which we can assess the reliability and accuracy of its materials model forecasts; and
- there is insufficient supporting evidence to show that Ergon Energy has considered whether there may be some material exogenous factors that impact on the cost of physical inputs.

The weight of the information clearly evidences that there is a real potential for inaccuracy in commodity forecasts. For example, in our preliminary decision for Ergon Energy we reviewed a number of independent consultant's report for Australian energy businesses on material cost escalation. We reported that overall, these reports lend further support to our position to not accept Ergon Energy's proposed materials cost escalation.[345] Further, to illustrate the potential uncertainty in forecasting real material input costs, we also compared the material cost escalation forecasts derived by the consultants. This comparison showed that there is considerable variation between the consultant's commodities escalation forecasts, further demonstrating the uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of intermediate outputs used by service providers to provide network services.[346]

The potential for inaccuracy in commodity forecasts in conjunction with the lack of evidence in support of Ergon Energy's forecasts is such that we cannot conclude with a sufficient degree of certainty that commodity forecasts are either accurate or likely to be accurate. We associate this possibility with a real risk that consumers would pay more than Ergon Energy's costs for its physical assets if we were to accept its material cost escalation.

Our decision not to accept Ergon Energy's material cost escalation means that Ergon Energy's real costs will be escalated annually by no more than CPI under its tariff variation mechanism. As part of its tariff variation mechanism, by default CPI ensures that Ergon Energy's increased costs generally will be taken into account. This is not to suggest that CPI measures are a proxy for the movement in the prices of Ergon Energy's physical assets. We acknowledge that CPI is directed at measuring changes in the price of a basket of goods and services which account for a high proportion of expenditure by the CPI population group (i.e. metropolitan households); it does not measure the movement in the prices paid for the physical assets purchased by network service providers. However, the CPI provides for a necessary degree of certainty for Ergon Energy and consumers that a measured and well understood basis for increasing Ergon Energy's costs is reflected in its revenue and prices. By contrast, the degree of possible inaccuracy of commodities' forecasts is such that it is not

[345] AER, *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, pp. 6-127-131.
[346] AER, *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, pp. 6-132-133.

reasonable to use commodities' forecasts, in addition to CPI, to reflect changes in the prices paid by Ergon Energy for assets. Commodities' forecasts do not display the same level of rigour as CPI to satisfy us that consumers should incur additional costs above CPI. In reaching this conclusion, we have had regard to the revenue and pricing principle that Ergon Energy should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control services. We consider that if we were to apply Ergon Energy's material costs escalation, there is possibility that it will recover in excess of its efficient costs. This, combined with an absence of evidence to support a conclusion that it would be in the long term interests of consumers to incur prices that reflected more than the CPI, were fundamental to our conclusion.

In the following discussion, we have addressed each of the specific points raised by Ergon Energy in its revised proposal.[347]

Realistic expectation of cost inputs

We agree with Ergon Energy's statement that the expenditure criteria of the NER requires an electricity service provider's forecast expenditure to be a realistic expectation of cost inputs. In our preliminary decision for Ergon Energy we stated that allowing individual material input costs that constitute cost escalation reflects more cost based price increases. We considered this cost based approach reduces the incentives for electricity service providers to manage their capex efficiently, and may instead incentivise electricity service providers to over forecast their capex.[348]

We acknowledge that cost inputs faced by an electricity service provider may be exogenous, and may be outside the control of the service provider. We maintain our view that allowing changes in input costs to flow through to an electricity service provider's forecast expenditure is more reflective of a cost based pricing mechanism and accordingly, there is a risk that it may not incentivise businesses to minimise their expenditure. Such an approach is less likely to promote efficient investment in electricity services.[349] Our position recognises that although cost inputs may be outside the control of the electricity service provider, it has a degree of control over the total cost of inputs required to maintain a reliable supply of electricity. We do accept, however, that if such input costs are reliably forecast then they may reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives. Our analysis below reveals that we have given weight to the NER criteria of a realistic expectation of the cost of inputs by carefully examining the reliability of Ergon Energy's proposed forecast and by considering the degree of control over the total cost of its inputs.

347 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, pp. 10-20.

348 AER, *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 6-127.

349 NEL, s. 7.

Materials input costs

We acknowledge that the inclusion of rise and fall clauses of key commodities in Ergon Energy's procurement contracts for transformers and cables is an accepted risk mitigation practice. However, in the context of real material cost escalation as an input to an electricity service provider's forecast capex, the issue of the degree of potential inaccuracy of commodities forecasts remains. Forecasting the movement of commodities included in the rise and fall clauses in Ergon Energy's procurement contracts for five years of the 2015–20 regulatory period does not mitigate Ergon Energy from the risk of the potential inaccuracy of commodities forecasts. Rise and fall clauses in procurement contracts are based on actual prices or indices rather than longer term forecasts over five years of a regulatory control period.

Our concerns with the accuracy and reasonableness of commodities forecasts remain. Whether this forecasting uncertainty is embedded in an electricity service provider's procurement contract or an asset category does not diminish this uncertainty.

We also acknowledge Ergon Energy's claim that an asset class in the PTRM is not an aggregation of homogeneous units and that disaggregating forecasts of assets into commodity components would be unrealistic. We consider that whilst Ergon Energy's approach of engaging a consultant with experience in power distribution engineering and econometric modelling may be a reasonable approach to model the future costs of an asset class by assuming a weighting of commodity inputs for each asset class, we maintain our view that Ergon Energy has not provided information which explains the basis for the weightings or that the weightings applied have produced unbiased forecasts of the costs of Ergon Energy's assets.[350] For these reasons, there is no basis on which we can conclude that the forecasts are reliable.

Materials input cost forecasting

Whilst we acknowledge Ergon Energy's argument that the capital replacement of assets can require like for like replacement where there are inherent or inherited characteristics of the assets which restrict replacement by a lower priced or superior performing asset, we consider that there are likely to be assets or components of Ergon Energy's suite of assets that could be replaced by newer, cheaper or technologically advanced assets or components. We also consider that in instances where assets can only be replaced on a like for like basis, it is not necessarily the case that the forecast of new or replacement assets will lead to a bias that understates the future asset cost as stated by Ergon Energy given the number of factors that can impact on the cost of assets, including those identified by Ergon Energy as exchange rate and commodity price variations.

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350 AER, *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 6-124.

In respect of our decision on real materials cost escalation, Ergon Energy's revised submission of forecast lower than CPI price changes for some of its asset classes did not have any impact on our conclusions as to the basis of these forecasts.

Materials input cost mitigation

In our preliminary decision, we stated that potential commodity input substitution is possible following an increase in the price of one commodity input providing there are no technically fixed proportions between the inputs. We provided the example of input substitution occurring in the electricity industry during the late 1960's when copper prices increased and electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables.[351]

In its revised proposal, Ergon Energy stated that no rational distributor ever contemplated substituting its existing copper lines with an aluminium line. We concur with Ergon Energy's statement that copper lines should not be replaced with aluminium lines if the copper line does not need replacement, but rather when the copper line needs to be replaced or new lines need to be added. We also accept that an electricity distribution system has inherent and inherited factors that limit the potential uptake of new standards. We do, however, not consider that during a regulatory control period there is no potential for some commodity input substitution for assets owned and operated by Ergon Energy.

Forecasting uncertainty

Ergon Energy contended that although the economic literature in respect to commodities forecasting is inconclusive it does not lessen the importance of future price forecasting. We maintain our view expressed in Ergon Energy's preliminary decision that the NER requires that an electricity service provider's forecast capital expenditure reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.[352] We consider that there is likely to be significant uncertainty in forecasting commodity input price movements. We formed this view in part on the basis of:

- recent commodity studies and evidence in economic literature on the usefulness of commodities futures prices
- the difficulty in forecasting nominal exchange rates; and
- our review of independent expert's reports.[353]

To illustrate the potential inaccuracy of commodities forecasts we compared the real cumulative materials escalation rates provided by Jacobs to Ergon Energy in its

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351 AER, *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 6-125.

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

353 *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 6-126.

original and revised revenue proposals.[354] Table 6.16 compares Jacob's real cumulative cost escalation forecasts for October 2014 and July 2015.

Table 6.16 Ergon Energy's real cumulative materials cost escalation forecasts October 2014 and July 2015

	2014–15	2015–16	2016–17	2017–18	2018–19
Aluminium					
October 2014	1.092	1.117	1.139	1.161	1.188
July 2015	1.243	1.255	1.265	1.295	1.325
Difference (%)	13.9%	12.4%	11.1%	11.5%	11.6%
Copper					
October 2014	0.914	0.905	0.904	0.905	0.910
July 2015	0.941	0.924	0.913	0.941	0.973
Difference (%)	2.9%	2.1%	0.9%	4.0%	7.0%
Steel					
October 2014	1.071	1.052	1.048	1.051	1.061
July 2015	1.122	1.141	1.150	1.154	1.166
Difference (%)	4.8%	8.5%	9.8%	9.8%	9.9%
Oil					
October 2014	1.077	1.072	1.053	1.042	1.055
July 2015	0.839	0.949	1.018	1.034	1.012
Difference (%)	-22.1%	-11.5%	-3.3%	-0.8%	-4.1%

Source: Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* Table 1, October 2014 and *Revised regulatory proposal*, *06.02.07 Jacobs Addendum Cost Escalation Factors 2015-20*, July 2015.

As Table 6.17 shows, there is reasonable variation between Jacob's commodity cost escalation forecasts between October 2014 and July 2015, a period of eight months. Aluminium and oil showed the greatest forecast variation between the two periods, with oil showing a reduced forecast value in July 2015.

[354] Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* Table 1, October 2014 and *Revised regulatory proposal*, *06.02.07 Jacobs Addendum Cost Escalation Factors 2015-20*, July 2015.

To further demonstrate the potential uncertainty of commodities forecasts, Jacobs in its report to Ergon Energy included analysis demonstrating the volatility of forward forecasts for commodity prices.[355] Table 6.17 shows Jacob's analysis of the changing real annual cost escalation rates for its four main commodities forecasts in November 2010, March 2011 and December 2011 for the period between 2011–12 to 2016–17.

Table 6.17 Jacobs' real commodity forecasts 2011–12 to 2016–17

	2011–12	2012–13	2013–14	2014–15	2015–16	2016-17
November 2010						
Aluminium	1.129	0.989	0.994	0.978	0.981	0.987
Copper	1.093	0.931	0.925	0.907	0.906	0.907
Steel	1.131	0.987	0.962	0.963	0.965	0.972
Oil	1.131	0.960	0.963	0.982	1.008	0.991
March 2011						
Aluminium	1.170	0.989	0.989	0.970	0.973	0.979
Copper	1.178	0.940	0.923	0.896	0.892	0.891
Steel	1.133	0.975	0.986	0.970	0.972	0.979
Oil	1.087	0.952	1.087	0.967	0.911	1.011
December 2011						
Aluminium	0.876	1.021	1.045	1.039	1.037	1.032
Copper	0.874	0.982	0.999	0.984	0.980	0.975
Steel	1.026	1.043	1.010	1.009	1.013	1.009
Oil	1.019	1.019	0.972	0.984	1.007	1.045

Source: Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* Table 23, October 2014.

As Table 6.17 shows, and as Jacobs stated in its report, the variations in commodities forecasts demonstrate the uncertainties in global markets at the time and the associated variability in any forecast movement in material costs for different asset types.[356]

Jacobs also analysed the impact of changes in the forecast of materials only cost escalation factors for a sample of asset categories based on the volatility of commodity price forecasts.[357] Table 6.18 shows the impact of changes in commodity forecasts

[355] Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* Tables 23 and 24, October 2014.

[356] Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* p. 48, October 2014.

[357] Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* p. 48, October 2014.

between November 2010 and December 2011 on a sample of asset categories for the period 2011–12 to 2016–17.

Table 6.18 Impact of changes in Jacobs' forecast real materials only cost escalation factors on sample Ergon Energy asset categories 2011–12 to 2016–17

	2011–12	2012–13	2013–14	2014–15	2015–16	2016-17
November 2010						
OH distribution lines	1.070	0.990	0.982	0.983	0.991	0.989
Distribution equipment	1.041	0.990	0.985	0.987	0.993	0.991
Distribution transformers	1.065	0.984	0.977	0.977	0.984	0.983
March 2011						
OH distribution lines	1.074	0.985	1.004	0.982	0.977	0.992
Distribution equipment	1.046	0.987	1.001	0.984	0.980	0.991
Distribution transformers	1.077	0.980	0.994	0.974	0.970	0.983
December 2011						
OH distribution lines	0.990	1.018	1.007	1.007	1.011	1.013
Distribution equipment	0.993	1.009	1.001	1.001	1.004	1.006
Distribution transformers	0.984	1.013	1.004	1.003	1.006	1.007

Source: Ergon Energy, *Regulatory proposal*, *Attachment 06.02.02 – Jacobs: Cost Escalation Factors 2015-2020,* Table 24, October 2014.

As Table 6.18 illustrates, the uncertainty of commodity price forecasts can have a significant impact on an electricity service provider's asset forecasts.

Strategic contracts with suppliers

We maintain our view that the potential exists for electricity service providers to 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. We acknowledge that there may be supply contracts where the opportunity to mitigate the risks associated with changes in material input costs is limited as shown in the example provided by Ergon Energy, but consider that the potential may exist in other supply contracts where there may be some scope for Ergon Energy to negotiate contracts such that risks of material input costs are shared between the parties. Further, we consider that Ergon Energy may have exaggerated the risk of input cost fluctuation as manufacturers can manage their input cost risks through futures contracts, leading to a more stable price for their products.

Cost based price increases

We maintain our view that we consider that real labour and construction cost escalators can be more reliably and robustly forecast than material input cost escalators because they are not intermediate inputs, and in the case of construction costs, can be forecast with greater precision because the drivers are reasonably transparent and can be predicted with some degree of accuracy.

We also maintain the view expressed in our preliminary decision that accepting the pass through of material input costs to input asset prices is reflective of a cost based pricing approach. We consider this cost based approach reduces the incentives for electricity service providers to manage their capex efficiently, and may instead incentivise electricity service providers to over forecast their capex. In taking into account the revenue and pricing principles, we noted that this approach would be less likely to promote efficient investment.[358]

Selection of commodity inputs

We acknowledge that the examples of distribution transformer contracts included in Ergon Energy's revised proposal included the material commodities forecast by Ergon Energy in its real materials escalation capex models.[359] We consider, however, that the examples of procurement contracts (distribution transformers) provided by Ergon Energy are not exhaustive of its distribution assets and that Ergon Energy's real materials escalation capex models are unlikely to capture all material inputs included in all of Ergon Energy's assets.

Commodities boom

Whilst Ergon Energy stated that it agrees with the AER that the commodities boom has subsided, it considers that it is still important it forecast the cost of materials and goods, a major cost of providing network assets. Whilst we acknowledge that materials is a major cost of providing network services, for the reasons we have outlined we do not consider that Ergon Energy's proposed forecast is based on a sound and robust methodology and accordingly, consider that it does not reasonably reflect the capex criteria.[360]

D.4 Labour and construction escalators

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

358 AER, *Preliminary Decision Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 6-127.

359 Ergon Energy, *Revised regulatory proposal, SUB09.09 Ergon Energy - Capex Real labour and materials escalations - Response_ PUBLIC*, Table 6.

360 NER, cl. 6.5.7(c).

We consider that labour and construction related cost escalation reasonably reflects a realistic expectation of the cost inputs required to achieve the opex and capex objectives.[361] We consider that real labour and construction related 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).

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

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