



# **FINAL DECISION**

## **Powercor distribution determination 2016 to 2020**

### **Attachment 6 – Capital expenditure**

May 2016

© Commonwealth of Australia 2016

This work is copyright. In addition to any use permitted under the Copyright Act 1968, all material contained within this work is provided under a Creative Commons Attributions 3.0 Australia licence, with the exception of:

- the Commonwealth Coat of Arms
- the ACCC and AER logos
- any illustration, diagram, photograph or graphic over which the Australian Competition and Consumer Commission does not hold copyright, but which may be part of or contained within this publication. The details of the relevant licence conditions are available on the Creative Commons website, as is the full legal code for the CC BY 3.0 AU licence.

Requests and inquiries concerning reproduction and rights should be addressed to the:

Director, Corporate Communications  
Australian Competition and Consumer Commission  
GPO Box 4141, Canberra ACT 2601

or [publishing.unit@accc.gov.au](mailto:publishing.unit@accc.gov.au).

Inquiries about this publication should be addressed to:

Australian Energy Regulator  
GPO Box 520  
Melbourne Vic 3001

Tel: (03) 9290 1444

Fax: (03) 9290 1457

Email: [AERInquiry@aer.gov.au](mailto:AERInquiry@aer.gov.au)

## Note

This attachment forms part of the AER's final decision on Powercor's distribution determination for 2016–20. 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

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – f-factor scheme

# Contents

<b>Note .....</b>	<b>6-2</b>
<b>Contents .....</b>	<b>6-3</b>
<b>Shortened forms .....</b>	<b>6-6</b>
<b>6 Capital expenditure .....</b>	<b>6-8</b>
<b>6.1 Final decision .....</b>	<b>6-8</b>
<b>6.2 Powercor's revised proposal .....</b>	<b>6-11</b>
<b>6.3 Assessment approach.....</b>	<b>6-12</b>
6.3.1 Expenditure assessment guideline .....	6-14
6.3.2 Building an alternative estimate of total forecast capex .....	6-15
6.3.3 Comparing the distributor's proposal with our alternative estimate .....	6-17
<b>6.4 Reasons for final decision .....</b>	<b>6-18</b>
6.4.1 Key assumptions.....	6-19
6.4.2 Forecasting methodology .....	6-19
6.4.3 Interaction with the STPIS .....	6-20
6.4.4 Powercor's capex performance .....	6-21
6.4.5 Interrelationships.....	6-27
6.4.6 Consideration of the capex factors .....	6-28
<b>A Assessment techniques.....</b>	<b>6-31</b>
<b>A.1 Economic benchmarking .....</b>	<b>6-31</b>
<b>A.2 Trend analysis.....</b>	<b>6-32</b>
<b>A.3 Category analysis .....</b>	<b>6-33</b>
<b>A.4 Predictive modelling.....</b>	<b>6-33</b>
<b>A.5 Engineering review .....</b>	<b>6-34</b>
<b>B Assessment of capex drivers .....</b>	<b>6-35</b>

<b>B.1 Alternative estimate</b>	<b>6-35</b>
<b>B.2 Forecast augex</b>	<b>6-36</b>
B.2.1 Position	6-36
B.2.2 Powercor's revised proposal	6-37
B.2.3 AER approach	6-38
B.2.4 Trend and demand forecast analysis	6-39
B.2.5 Project and program analysis	6-45
<b>B.3 Forecast customer connections capex, including capital contributions</b>	<b>6-64</b>
B.3.1 AER Position	6-64
B.3.2 Revised proposal	6-65
B.3.3 Reasons for AER Position	6-65
<b>B.4 Forecast repex</b>	<b>6-69</b>
B.4.1 Position	6-69
B.4.2 Powercor's revised proposal	6-70
B.4.3 AER approach	6-71
B.4.4 AER repex findings	6-74
<b>B.5 Forecast capitalised overheads</b>	<b>6-83</b>
B.5.1 Position	6-83
B.5.2 Our assessment	6-83
<b>B.6 Forecast non-network capex</b>	<b>6-86</b>
B.6.1 Position	6-86
B.6.2 Revised proposal	6-86
B.6.3 Information and communications technology capex	6-87
<b>C Demand</b>	<b>6-95</b>
<b>C.1 AER position</b>	<b>6-95</b>
<b>C.2 AER approach</b>	<b>6-96</b>
<b>C.3 Powercor's revised proposal</b>	<b>6-97</b>

C.4 Demand trend analysis.....	6-99
C.5 Forecasting methodology analysis .....	6-101
C.6 AEMO forecasts .....	6-103
D Real materials cost escalation .....	6-107
D.1 Position.....	6-107
D.2 Powercor's revised proposal .....	6-107
D.3 Assessment approach.....	6-111
D.4 Reasons.....	6-112
D.5 Review of independent consultants' reports .....	6-118
D.6 Conclusions on materials cost escalation .....	6-124
E Contingent projects.....	6-126
E.1 Bushfire Mitigation Contingent Projects .....	6-126
E.1.1 Powercor proposal .....	6-126
E.1.2 Position .....	6-126
E.1.3 Assessment of Powercor's proposed trigger event.....	6-127
E.1.4 NER requirements.....	6-128
E.1.5 Regulatory obligation.....	6-129
E.2 Bushfire Mitigation Contingent Projects .....	6-133
E.2.1 REFCLs .....	6-134
E.2.2 Declared Areas .....	6-136
E.2.3 Number of contingent projects.....	6-138
E.2.4 Trigger events for Bushfire Mitigation Contingent Projects .....	6-139
E.2.5 AER trigger event.....	6-144
E.2.6 Assessment of the trigger events .....	6-145

## Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
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 service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia

Shortened form	Extended form
repex	replacement expenditure
RFM	roll forward model
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 are recovered (return of and on capital) as part of the building blocks that form Powercor's total revenue requirement.<sup>1</sup>

This attachment sets out our final decision on Powercor'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 cost escalators
- Appendix E - Bushfire mitigation contingent projects.

### 6.1 Final decision

We are not satisfied Powercor's proposed total forecast capex of \$1771.6 million (\$2015) reasonably reflects the capex criteria. This is 14.2 per cent greater than actual/estimated capex for the 2011–15 period (\$1550.8 million). We substituted our estimate of Powercor's total forecast capex for the 2016–20 regulatory control period. We are satisfied that our substitute estimate of \$1623.7 million (\$2015) reasonably reflects the capex criteria. Table 6.1 outlines our final decision.

**Table 6.1 Final decision on Powercor's total forecast capex (\$2015, million)**

	2016	2017	2018	2019	2020	Total
Powercor's revised proposal	356.3	364.4	353.2	349.0	348.5	1771.6
AER final decision	388.3	339.5	311.9	318.6	315.4	1623.7
Difference	-18.1	-24.9	-41.4	-30.4	-33.1	-147.9
Percentage difference (%)	-5.1	-6.8	-11.7	-8.7	-9.5	-8.3

Source: Power, *Revised proposal: Standard control - MOD 1.18 PAL capex consolidation*, January 2016; AER analysis.

Note: Numbers may not add up due to rounding.

---

<sup>1</sup> NER, cl. 6.4.3(a).

Note: The figures above do not include equity raising costs and capital contributions. For our assessment of equity raising costs, see attachment 3.

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

These reasons include our responses to stakeholders' submissions on Powercor'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 Powercor'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 Powercor's capex forecast is likely to be higher than an efficient level, inconsistent with the NER. As a result of our testing, we are not satisfied that Powercor's proposed total forecast capex is consistent with the requirements of the NER.<sup>2</sup>

Our findings on the capex drivers are part of our broader analysis and should not be considered in isolation. Our final decision concerns Powercor's total forecast capex for the 2016–20 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 the total forecast capex that as a whole reasonably reflects the capex criteria.

**Table 6.2 Summary of AER reasons and findings**

Issue	Reasons and findings
Total capex forecast	<p>Powercor proposed a total capex forecast of \$1771.6 million (\$2015) in its revised proposal. We are not satisfied this forecast reasonably reflects the capex criteria.</p> <p>We are satisfied our substitute estimate of \$1623.7 million (\$2015) reasonably reflects the capex criteria. Our substitute estimate is 8.3 per cent lower than Powercor's revised proposal.</p> <p>The reasons for this decision are summarised in this table and detailed in the remainder of this attachment.</p>
Forecasting methodology, key assumptions and past capex performance	We consider Powercor's key assumptions and forecasting methodology are generally reasonable. Where we identified specific areas of concern, we discuss these in the appendices to this capex attachment and section 6.4.2.
Augmentation capex	We have not included Powercor's forecast augex of \$310.9 million (\$2015) in our substitute estimate. We accept that Powercor's revised forecast of maximum demand is realistic and we accept the majority of its proposed capex to meet demand growth. However, we do not accept a proportion of Powercor's proposed augex to maintain voltage levels of its network, including the installation of bi-directional voltage regulators and the construction of a new Torquay zone substation. We have instead included in our substitute estimate of overall total capex an amount of \$274.3 million (\$2015) for augex.

<sup>2</sup> NER, cl. 6.5.7(c) and (d).

Customer connections capex	We have included the amount Powercor forecast for connections capex of \$724 million (\$2015) in our capex decision. Powercor's revised forecast for connections capex was consistent with our preliminary decision and as such we have included this amount in our substitute estimate.
Asset replacement capex (repex)	We have not included Powercor's forecast repex of \$672 million (\$2015) in our substitute estimate. In particular we do not accept Powercor's proposed proactive overhead conductor program and the proposed amount for switchgear replacement. We have instead included in our substitute estimate of overall total capex an amount of \$608.7 million (\$2015) for repex.
Non-network capex	<p>We accept Powercor's forecast non-network capex of \$248.0 million (\$2015) as a reasonable estimate of the efficient costs a prudent operator would require for this category. We have included it in our estimate of total capex for the 2016–2020 regulatory control period.</p> <p>In reaching this view, we accept Powercor's forecast capex for its 'Power of Choice' project and for RIN compliance are prudent and efficient.</p>
Capitalised overheads	<p>We have not included Powercor's proposed capitalised overheads of \$198.2 million (\$2015). We have instead included in our substitute estimate of overall total capex an amount of \$195.3 million (\$2015) for capitalised overheads.</p> <p>We reduced Powercor's capitalised overheads to reflect the reductions we made to their total capex forecast, particularly those components with overheads.</p>
Real cost escalators	<p>We are not satisfied that Powercor's proposed real material cost escalators, which form part of its total forecast capex, reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory period. We consider that zero per cent real cost escalation is reasonably likely to reflect the capex criteria including that it is likely to reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory period.</p> <p>We are not satisfied Powercor's proposed real labour cost escalators which form part of its total forecast capex reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period. We discuss our assessment of forecast our labour price growth for Powercor in attachment 7.</p> <p>The difference between the impact of the real labour cost escalation proposed by Powercor and that accepted by the AER in its capex decision is \$45.0 million (\$2015).</p>

Source: AER analysis.

We consider that our overall capex forecast addresses the revenue and pricing principles. In particular, we consider our overall capex forecast provides Powercor a reasonable opportunity to recover at least the efficient costs it incurs in:<sup>3</sup>

- providing direct control network services
- complying with its regulatory obligations and requirements.

As set out in appendix B we are satisfied that our overall capex forecast is consistent with the national electricity objective (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.

---

<sup>3</sup> NEL, s. 7A.

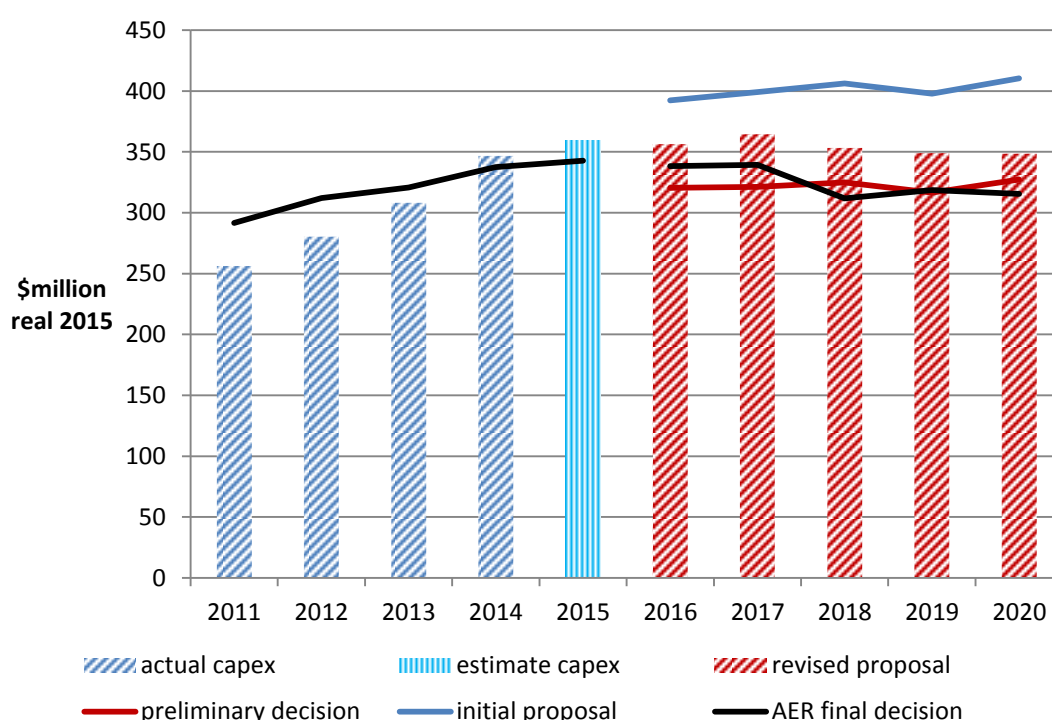
We also consider that overall our capex forecast addresses the capital expenditure objectives.<sup>4</sup> In making our final decision, we specifically considered the impact our decision will have on the safety and reliability of Powercor's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in Powercor's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

## 6.2 Powercor's revised proposal

Powercor's revised proposal included a total forecast capex of \$1771.6 million (\$2015) for the 2016–20 regulatory control period.<sup>5</sup> This is 10 per cent higher than our preliminary decision and 11.7 per cent lower than Powercor's initial regulatory proposal

Figure 6.1 shows the difference between Powercor's initial proposal, its revised proposal and our preliminary decision for the 2016–20 regulatory control period. Figure 6.1 also shows the actual capex Powercor spent during the 2011–15 regulatory control period.

**Figure 6.1 Powercor's total actual and forecast capex 2011–2020**



Source: AER analysis.

<sup>4</sup> NER, cl. 6.5.7(a).

<sup>5</sup> This is net capex, which does not include customer contributions.

Powercor submitted its revised proposal was higher than our preliminary decision because it:<sup>6</sup>

- re-proposed its proactive conductor replacement program as an un-modelled replacement category
- proposed a staged approach to the development of the new Torquay zone substation based on updated demand forecasts
- deferred some augmentation expenditure to reflect its latest 2015 demand forecasts
- re-proposed the installation of 89 bi-directional regulators
- re-forecasted gross customer connections adopting the AER's forecasting approach as well as correcting the AER's methodology for calculating customer contributions. Powercor also accounted for the Victorian Government's planned introduction of Chapter 5A
- re-proposed IT expenditure that we removed in our preliminary decision, and included new IT and communications expenditure to implement initiatives from the Power of Choice review.

### 6.3 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 information Powercor provided in its revised regulatory proposal, including its response to our RIN, is a vital part of our assessment. We also took into account information that Powercor 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 regulatory proposal.<sup>7</sup> We apply our various assessment techniques, both qualitative and 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.<sup>8</sup> 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.

---

<sup>6</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016, pp. 14–15, 185 and 221.

<sup>7</sup> 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.

<sup>8</sup> NER, cl. 6.5.7(c).

- 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:<sup>9</sup>

- 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.<sup>10</sup> Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:<sup>11</sup>

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The AEMC noted '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.<sup>12</sup>

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:<sup>13</sup>

---

<sup>9</sup> NER, cl. 6.5.7(a).

<sup>10</sup> NER, cl. 6.12.1(3)(ii).

<sup>11</sup> NER, cl. 6.5.7(c).

<sup>12</sup> AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 113.

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

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 Powercor's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.<sup>14</sup> In taking the capex factors into account, the AEMC noted:<sup>15</sup>

...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.

Table 6.5 summarises how we took the capex factors into consideration.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.<sup>16</sup> In particular, we take into account whether our overall capex forecast provides Powercor a reasonable opportunity to recover at least the efficient costs it incurs in:<sup>17</sup>

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

### 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).<sup>18</sup> We released our Guideline in November 2013.<sup>19</sup> 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 Powercor, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.<sup>20</sup> 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.<sup>21</sup> 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

---

<sup>14</sup> NER, cl. 6.5.7(e).

<sup>15</sup> AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 115.

<sup>16</sup> NEL, ss. 7A and 16(2).

<sup>17</sup> NEL, s. 7A.

<sup>18</sup> AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 114.

<sup>19</sup> AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013.

<sup>20</sup> AER, *Final Framework and approach for the Victorian Electricity Distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 119–120.

<sup>21</sup> NER, cl. 6.8.2(c2) and (d).



information we require.<sup>22</sup> 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 proposal.<sup>23</sup> We review the proposed forecast methodology and the key assumptions that underlie the distributor's forecast. We also consider the distributor's performance in the previous regulatory control period to inform our alternative estimate.

We then apply our specific assessment techniques to develop an estimate and assess the economic justifications that the distributor puts forward. Many of our techniques encompass the capex factors that we are required to take into account. Appendix A and appendix B contain further details on each of these techniques.

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.<sup>24</sup>

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:<sup>25</sup>

---

<sup>22</sup> AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 25.

<sup>23</sup> AER, *Better regulation: Explanatory statement: Expenditure forecast assessment guideline*, November 2013, p. 7; AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, pp. 111 and 112.

<sup>24</sup> AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. vii.

<sup>25</sup> AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 12.



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 Powercor's revised 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
- 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.<sup>26</sup>

---

<sup>26</sup> AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8 and 9. The Australian Competition 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

- Past expenditure was sufficient for the distributor to manage and operate its network in past periods, in a manner that achieved the capex objectives.<sup>27</sup>

### 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.<sup>28</sup>

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.

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.<sup>29</sup> Similarly, a distributor may spend less than the capex forecast because they have been more

---

Energy Australia 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).

<sup>27</sup> AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

<sup>28</sup> AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 112.

<sup>29</sup> NER, r. 6.6.

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 the underspend and 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 Powercor. In this final decision, we are not satisfied Powercor's total forecast capex reasonably reflects the capex criteria. We compared Powercor's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. Powercor's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6.3 sets out the capex amounts by driver that we included in our alternative estimate of Powercor's total forecast capex for the 2016–20 regulatory control period.

**Table 6.3 Assessment of required capex by capex driver 2016–20 (\$2015, million)**

Category	2016	2017	2018	2019	2020	Total
Augmentation	64.7	63.1	45.0	54.0	47.4	274.3
Connections	151.2	157.9	139.3	137.0	138.8	724.2
Replacement	108.9	113.8	121.3	128.2	136.5	608.7
Non-Network	57.4	57.8	51.8	43.3	37.6	248.0
Capitalised overheads	36.5	37.9	38.6	40.7	41.5	195.3
Labour and materials escalation adjustment	-3.4	-7.7	-9.2	-11.4	-13.2	-45.0
<b>Gross Capex (includes capital contributions)</b>	415.3	422.9	386.8	391.8	388.6	2005.4
Capital Contributions	77.1	83.4	74.9	73.2	73.2	381.7
<b>Net Capex (excluding capital contributions)</b>	388.3	339.5	311.9	318.6	315.4	1623.7

Source: AER analysis.

Note: Numbers may not add up due to rounding.

Our approved capex of \$1623.7 million is \$13.4 million higher than our preliminary decision of \$1610.3 million. The key components of our capex decision that have changed include:

- additional augmentation expenditure (augex) (\$32.7 million), because we accept Powercor's revised maximum demand forecasts, but have not accepted forecasts associated with the Torquay zone substation or other voltage regulation programs
- additional non-network ICT capex for Power of Choice (\$8.2 million) and RIN compliance (\$5.3 million) as a result of new regulatory obligations; and
- reduced amounts for input cost growth related to labour and materials costs (\$15.1 million).

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

Our assessment of capex drivers are 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 Powercor to include in its regulatory proposal the key assumptions that underlie its proposed forecast capex. Powercor must also provide a certification by its Directors that those key assumptions are reasonable.<sup>30</sup>

Powercor set out its key assumptions in its revised regulatory proposal.<sup>31</sup> We assessed Powercor's key assumptions in the appendices to this capex attachment.

### 6.4.2 Forecasting methodology

The NER requires Powercor to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submitted its regulatory proposal.<sup>32</sup> Powercor must include this information in its regulatory proposal.<sup>33</sup> The main points of Powercor's forecasting methodology are set out in its regulatory proposal.<sup>34</sup>

In our preliminary decision we considered Powercor's forecasting methodology was generally reasonable.<sup>35</sup> We maintain this position in this final decision. Where we

---

<sup>30</sup> NER, cl. S6.1.1(2), (4) and (5).

<sup>31</sup> Powercor, *Revised regulatory proposal 2016–2020: Attachment 2.2*, January 2016.

<sup>32</sup> NER, cl. 6.8.1A and 11.60.3(c).

<sup>33</sup> NER, cl. S6.1.1(2).

<sup>34</sup> Powercor, *Regulatory proposal 2016–2020: Appendix E: Capital expenditure*, 30 April 2015, pp. 12–17.

<sup>35</sup> AER, *Preliminary decision: Powercor distribution determination 2016–20: Attachment 6 – Capital expenditure*, October 2015, p. 21.

identified specific areas of concern regarding its revised proposal, we discuss these in the appendices to this capex attachment.

Origin and VECUA maintained their support for applying a combination of top-down and bottom-up assessment techniques. They considered this is necessary to ensure that forecast costs, including unit rates, are not overstated. A combined approach ensures inter-relationships and synergies between projects or areas of work, which are more readily identified at a portfolio level, are adequately accounted for.<sup>36</sup> AGL also supported our use of benchmarking as an input into determining total capex (and opex) forecasts.<sup>37</sup>

As we noted in previous determinations, the drawback of deriving a capex forecast through a bottom-up assessment is it does not of itself provide sufficient evidence that the estimate is efficient. Bottom up approaches tend to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work. In contrast, reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency.<sup>38</sup>

Importantly, we do not limit our capex assessment to top-down methods. We utilise a holistic assessment approach that includes techniques such as predictive modelling and detailed technical reviews (see section 6.3 and appendix A).

### 6.4.3 Interaction with the STPIS

We consider our approved capital expenditure forecast is consistent with the setting of targets under the STPIS. In particular, we should not set the capex allowance such that it would lead to Powercor systematically under or over performing against its STPIS targets. We consider our approved capex forecast is sufficient to allow a prudent and efficient service provider in Powercor's circumstances 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 specifically considered the impact our decision will have on the safety and reliability of Powercor's network.

In its submission, the Consumer Challenge Panel (CCP) noted the following explanation from the AEMC:<sup>39</sup>

---

<sup>36</sup> Origin, *Submission to AER preliminary decision Victorian networks*, 6 January 2016, p. 2; VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, p. 27.

<sup>37</sup> AGL, *Submission: AER preliminary decision on the Victorian electricity distribution network regulatory proposals*, 7 January 2016, p. 1.

<sup>38</sup> For example, see AER, *Final decision: Ergon Energy determination 2015–16 to 2019–20: Attachment 6 – Capital expenditure*, October 2015, p. 21; AER, *Final decision: SA Power Networks determination 2015–16 to 2019–20: Attachment 6 – Capital expenditure*, October 2015, pp. 20–21.

<sup>39</sup> CCP, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal*, August 2015, p. 27.

...operating and capital expenditure allowances for NSPs should be no more than the level considered necessary to comply with the relevant regulatory obligation or requirement, where these have been set by the body allocated to that role. Expenditure by NSPs to achieve standards above these levels should be unnecessary, as they are only required to deliver to the standards set. It would also amount to the AER substituting a regulatory obligation or requirement with its own views on the appropriate level of reliability, which would undermine the role of the standard setting body, and create uncertainty and duplication of roles.

NSPs are still free to make incremental improvements over and above the regulatory requirements at their own discretion. Such additional expenditure will not generally be recoverable, through forecast capital and operating expenditure. However, DNSPs are also provided with annual financial incentives to improve reliability performance under the STPIS.

We consider our substitute estimate is sufficient for Powercor 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 distributor's actual spending—either as a cap or as a requirement that the forecast be spent on specific projects or activities. It is conceivable that a distributor might wish to spend particular capital expenditure differently or in excess of the total capex forecast 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.

Under our analysis of specific capex drivers, we explained how our analysis and certain assessment techniques factor in safety and reliability obligations and requirements.

#### **6.4.4 Powercor's capex performance**

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

The NER sets out that we must have regard to our annual benchmarking report.<sup>40</sup> This section shows how we have taken it into account. We consider that this high level benchmarking at the overall capex level is suitable to gain an overall understanding of

---

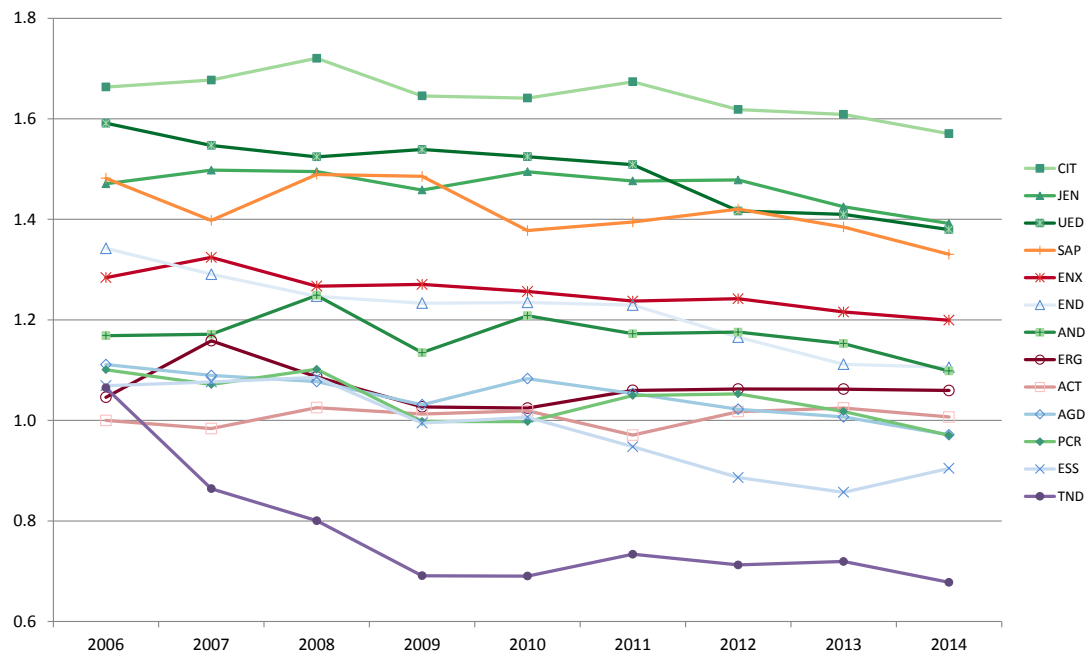
<sup>40</sup> NER, cl. 6.5.7(e).

Powercor'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 Powercor's proposal. We have not used this analysis deterministically in our capex assessment.

#### 6.4.4.1 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. It simultaneously considers the productivity of each DNSP's use of overhead lines and underground cables (split into distribution and sub-transmission voltages) and transformers and other capital. Powercor performs below the other Victorian DNSPs on this measure.

**Figure 6.2 Capital partial factor productivity for 2006–14**

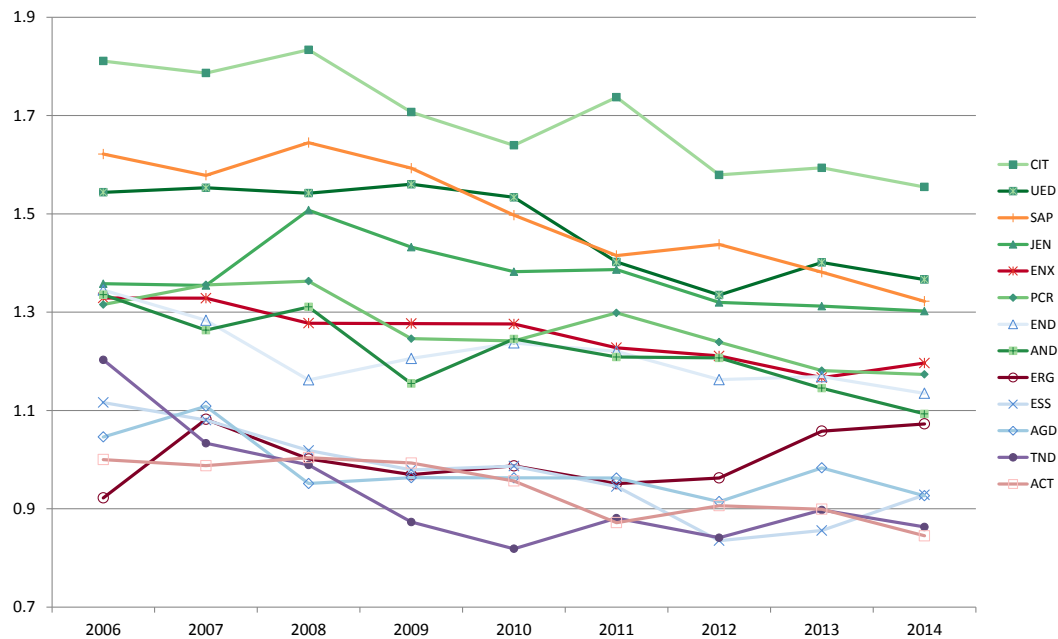


Source: AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015, p. 11.

Figure 6.3 shows Powercor's performance on MTFP. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length). Powercor is among the higher performers on this metric.



**Figure 6.3 Multilateral total factor productivity for 2006–14**



Source: AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015, p. 8.

VECUA considered we should have greater regard to capex benchmarking results, such as those in Figure 6.2 and Figure 6.3, when determining total capex forecasts.<sup>41</sup> As we noted previously, we take a holistic approach and use various techniques in our assessments of capex forecasts. Depending on the circumstances of the particular determination, we may place more or less weight on different techniques in meeting our obligations under the NER.<sup>42</sup> We detail our assessment approach in section 6.3 and appendix A.

#### 6.4.4.2 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. We considered capex per customer as it reflects the amount consumers are charged for additional capital investments.

Figure 6.4 and Figure 6.5 show the Victorian distributors generally performed well in these metrics compared to other distributors in the NEM in the 2008–12 years. For completeness, we also included the other Victorian distributors' revised proposal capex for the 2016–20 regulatory control period in the figures. However, we do not use comparisons of Powercor's total forecast capex with the total forecast capex of the

<sup>41</sup> VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, pp. 22.

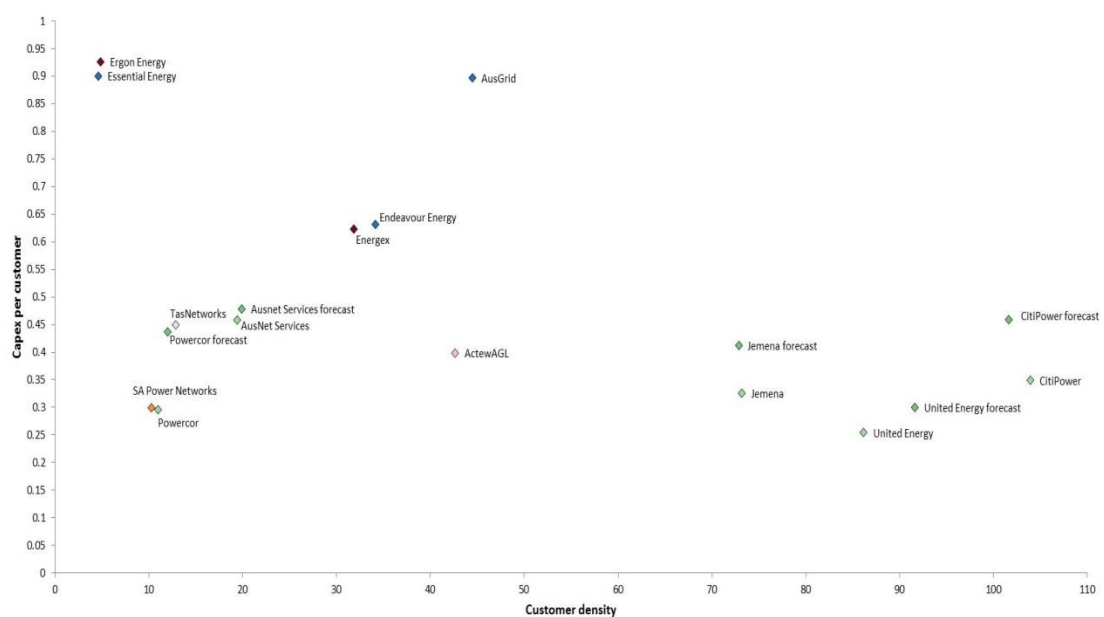
<sup>42</sup> NER, cl. 6.12.1(3).



other Victorian distributors as inputs to our assessment. We consider it is appropriate to compare Powercor's forecast only with actual capex. This is because actual capex are 'revealed costs' and would have occurred under the incentives of a regulatory regime.

Figure 6.4 shows Powercor spent the least amount of capex per customer among the low density networks in the 2008–12 years. However, Powercor's capex per customer will increase noticeably in the 2016–20 period based on their revised proposal forecast capex.

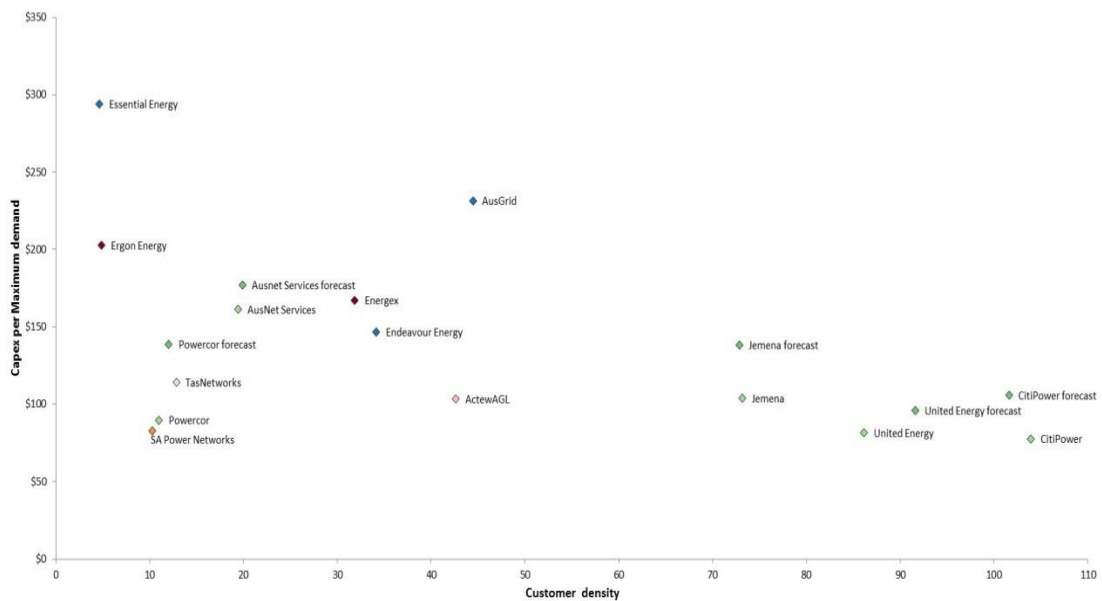
**Figure 6.4 Capex per customer (000's, \$2013–14), against customer density**



Source: AER analysis.

Similar to Figure 6.4, Figure 6.5 shows Powercor spent among the least amount of capex per maximum demand among the low density networks in the 2008–12 years. However, Powercor's metric will increase in the 2016–20 period based on their proposed forecast capex.

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



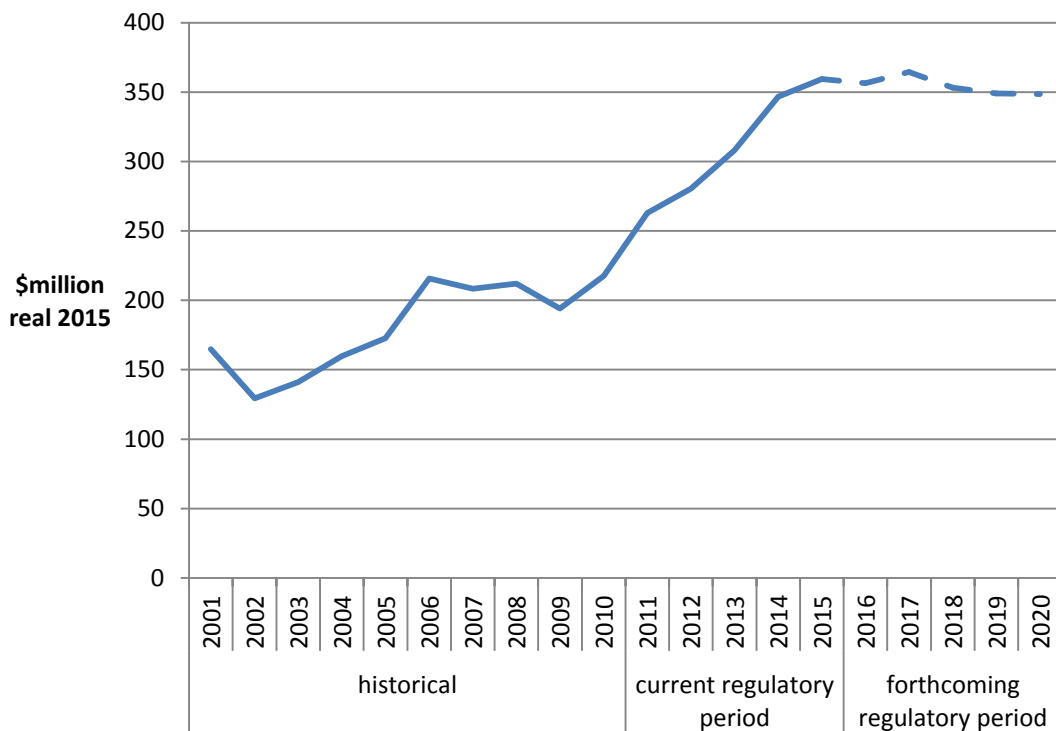
Source: AER analysis.

#### 6.4.4.3 Powercor's historical capex trends

We compared Powercor's capex proposal for the 2016–20 regulatory control period against the long term historical trend in capex levels.

Figure 6.6 shows actual historical capex and proposed capex between 2001 and 2020. This figure shows that Powercor's revised proposal forecast is significantly higher than historical levels (actual spend).

**Figure 6.6 Powercor total capex—historical and forecast for 2001–2020**



Source: AER analysis.

VECCUA noted the Victorian distributors' initial capex proposals, including Powercor's, are significantly higher than historical levels.<sup>43</sup>

The CCP was concerned the Victorian distributors' capex in recent years has been excessive. The CCP noted capex has been reasonably constant historically and stated the total capex forecasts for the 2011–15 regulatory control period were 'aberrations'.<sup>44</sup>

The CCP further noted the Victorian distributors rejected our preliminary decisions, and as a group only marginally reduced their forecast capex from actual levels of the 2011–15 period.<sup>45</sup> We note Powercor's revised total capex forecast for the 2016–20 regulatory control period is approximately \$221 million, or 14 per cent, higher than actual capex in the 2011–15 regulatory control period.<sup>46</sup> The CCP provided analysis

<sup>43</sup> VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, pp. 23–24.

<sup>44</sup> CCP, *Response to AER preliminary decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 22 February 2016 p. 19.

<sup>45</sup> CCP, *Response to AER preliminary decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 22 February 2016 p. 19.

<sup>46</sup> AER analysis; Powercor, *Standard control: MOD 1.18: Capex consolidation*, January 2016.

showing the capex for the 2011–15 regulatory control period has resulted in a more expensive asset base, even when controlling for demand and customer numbers.<sup>47</sup>

We note Origin largely agreed with our reductions to the Victorian distributors' capex forecasts in the preliminary decisions.<sup>48</sup> On the other hand, VECUA stated our preliminary decisions provided excessive capex allowances to the Victorian distributors. VECUA considered the preliminary decisions predominantly based the allowances on expenditure in the 2011–15 regulatory control period.<sup>49</sup> VECUA noted several drivers that are putting downward pressure on the Victorian distributors' capex requirement in the 2016–20 regulatory control period, including:

- the downturn in electricity demand and consumption
- excess system capacity, declining asset utilisation and reducing network ages
- lower network reliability expectations

Hence, VECUA stated the Victorian distributors' capex forecasts should revert to historical levels.<sup>50</sup>

Our detailed assessment in appendix B takes into account points made in these submissions where relevant, for example network utilisation levels and its likely impact on network augmentation requirements. In appendix B we fully examine whether Powercor's revised proposal reflects its expected operating environment.

## 6.4.5 Interrelationships

There are a number of interrelationships between Powercor's total forecast capex for the 2016–20 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	<p>There are elements of Powercor'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.</p> <p>More generally, we note our total opex and capex forecast is expected to provide Powercor</p>

<sup>47</sup> CCP, *Response to AER preliminary decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 22 February 2016 pp. 19–20.

<sup>48</sup> Origin, *Submission: Victorian networks revised proposals*, 4 February 2016, p. 1.

<sup>49</sup> VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, p. 8.

<sup>50</sup> VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, p. 20.

with sufficient opex to maintain the reliability of its network.

Forecast demand	Forecast demand is related to Powercor's total forecast capex. Specifically, augmentation capex is 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 augmentation capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme (CESS)	The CESS is related to Powercor'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 prudence of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from Powercor's regulatory asset base. In particular, the CESS will ensure that Powercor bears at least 30 per cent of any overspend against the capex allowance. Similarly, if Powercor 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, Powercor risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	<p>The STPIS is related to Powercor'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 2016–20 regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS.</p> <p>Further, the forecast capex should be sufficient to allow Powercor 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 Powercor systematically under or over performing against its targets.</p>
Contingent project	<p>A contingent project is related to Powercor'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 Powercor's total forecast capex for the 2016–20 regulatory control period.</p> <p>We identified three contingent projects for Powercor during the 2016–20 regulatory control period.</p>

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 Powercor's total capex forecast.<sup>51</sup> Table 6.5 summarises how we have taken into account the capex factors.

Where relevant, we also had regard to the capex factors in assessing the forecast capex associated with capex drivers such as repex, augex and so on (see appendix B).

<sup>51</sup> NER, cl. 6.5.7(c), (d) and (e).

**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 Powercor's proposed total forecast capex and in determining our alternative estimate for the 2016–20 regulatory control period. This can be seen in the metrics we used in our assessment of Powercor's capex performance.
The actual and expected capex of Powercor during any preceding regulatory control periods	<p>We had regard to Powercor's actual and expected capex during the 2011–15 and preceding regulatory control periods in assessing its proposed total forecast.</p> <p>This can be seen in our assessment of Powercor's capex performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie Powercor's total forecast capex.</p> <p>For some elements of non-network capex, we rely on trend analysis to arrive at an estimate that meets the capex criteria.</p>
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by Powercor in the course of its engagement with electricity consumers	We had regard to the extent to which Powercor's proposed total forecast capex includes expenditure to address consumer concerns that Powercor identified. Powercor has undertaken engagement with its customers and presented high level findings regarding its customer preferences.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing Powercor's proposed real cost escalation factors. In particular, we have not accepted Powercor's proposed cost escalation for labour.
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 Powercor'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 Powercor	We had regard to whether Powercor's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between Powercor's total forecast capex and the application of the CESS and the STPIS in Table 6.4 above.
The extent to which the capex forecast is referable to arrangements with a person other than the distributor that do not reflect arm's length terms	We had regard to whether any part of Powercor's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than Powercor that do not reflect arm's length terms. We do not have evidence to indicate that any of Powercor's arrangements do not reflect arm's length terms.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of Powercor's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We have included projects relating to Bushfire Mitigation as contingent projects (see appendix E).
The extent to which Powercor has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which Powercor made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of Powercor's augex proposal.

Any other factor the AER considers relevant and which the AER has notified Powercor in writing, prior to the submission of its revised regulatory proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.
-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------	-----------------------------------------------------------------------

Source: AER analysis.

## A Assessment techniques

This appendix describes the assessment approaches we applied in assessing Powercor's total forecast capex. We used a variety of techniques to determine whether the Powercor total forecast capex reasonably reflects the capex criteria. 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:<sup>52</sup>

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 assess Powercor'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.<sup>53</sup> Economic benchmarking applies economic theory to measure the efficiency of a distributor's use of inputs to produce outputs, having regard to environmental factors.<sup>54</sup> 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.<sup>55</sup> As the AEMC stated, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.<sup>56</sup>

---

<sup>52</sup> AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 8.

<sup>53</sup> NER, cl. 6.5.7(e)(4).

<sup>54</sup> AER, *Better regulation: Explanatory statement: Expenditure forecasting assessment guidelines*, November 2013, p. 78.

<sup>55</sup> NER, cl. 6.5.7(c).

<sup>56</sup> AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 25.



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 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.<sup>57</sup> 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.<sup>58</sup>

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.<sup>59</sup>

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 revised 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.<sup>60</sup> 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

---

<sup>57</sup> 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.

<sup>58</sup> AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015.

<sup>59</sup> NER, cl. 6.5.7(e)(5).

<sup>60</sup> NER, cl. 6.5.7(a)(3).

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 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.<sup>61</sup> The models draw

---

<sup>61</sup> NER, cl. 6.5.7(c).

on actual capex the distributor incurred during the preceding regulatory control period. This past capex is a factor that we must take into account.<sup>62</sup>

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.<sup>63</sup> 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.<sup>64</sup> 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.<sup>65</sup>

For our final 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 Powercor's augex forecast.

## A.5 Engineering review

In our preliminary decision we drew on technical and other technical expertise within the AER to assist with our review of Powercor's capex proposals.<sup>66</sup> These involved reviewing Powercor's processes, and specific projects and programs of work.

---

<sup>62</sup> NER, cl. 6.5.7(e)(5).

<sup>63</sup> Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

<sup>64</sup> For more information, see: AER, *Guidance document: AER augmentation model handbook*, November 2013.

<sup>65</sup> 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.

<sup>66</sup> 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 Powercor's forecast capex for the 2016–20 regulatory control period in this appendix. These sub-categories reflect the drivers of forecast capex over the 2016–20 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 Powercor'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 Powercor's total forecast capex that we are satisfied reasonably reflects the capex criteria. In coming to our views and our alternative estimate we 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: forecast augex
- Section B.3: forecast customer connections capex, including capital contributions
- Section B.4: forecast repex
- Section B.5: forecast capitalised overheads
- Section B.6: forecast 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 Powercor'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 Powercor'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 Forecast augex

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 the utilisation of network capacity. It can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements. This appendix deals with an assessment of Powercor's augex revised proposal.

### B.2.1 Position

We accept that the vast majority of Powercor's revised augex forecast reasonably reflects the capex criteria, including capex to meet forecast maximum demand. However, we do not accept Powercor's total augex revised forecast because:

- Powercor can prudently defer its proposed capex to construct a new Torquay zone substation
- Powercor's proposed capex to install bi-directional voltage regulators is not required to maintain voltage levels on its network and satisfy its regulatory obligations
- Powercor has over-forecast its capex to augment its low-voltage network due to demand growth and potential voltage concerns.

Our alternative estimate of required augex for Powercor for the 2016–20 regulatory control period is \$275 million (\$2015). We are satisfied that this reasonably reflects the capex criteria and will enable Powercor to achieve the capex objectives. Table 6.6 sets out our overall alternative estimate of Powercor's augex forecast, including the differences between our alternative estimate and the revised proposal.

**Table 6.6 AER's alternative estimate of augex (\$2015, million)**

	2016	2017	2018	2019	2020	Total
<b>Powercor revised proposal augex forecast</b>	<b>67.7</b>	<b>68.0</b>	<b>63.6</b>	<b>59.1</b>	<b>52.5</b>	<b>310.9</b>
AER adjustment for demand augex	-0.4	-1.5	-14.3	-0.4	-0.4	-16.8
AER adjustment for voltage compliance	-0.8	-0.8	-0.8	-0.8	-0.8	-4.1
Removal of bi-directional voltage program	-1.8	-2.6	-3.5	-3.9	-3.9	-15.7
<b>Alternative estimate</b>	<b>64.7</b>	<b>63.1</b>	<b>45.0</b>	<b>54.0</b>	<b>47.4</b>	<b>274.3</b>
Difference	-4.4%	-7.2%	-29.3%	-8.6%	-9.6%	-11.8%

Source: AER analysis.

Note: Numbers may not add up due to rounding.

Table 6.7 compares forecasts across the decision making process between the initial proposal and our final decision.

**Table 6.7 Powercor augex forecasts comparisons (\$2015 million, excluding overheads)**

	2016	2017	2018	2019	2020	Total
Initial augex forecast	87.8	79.7	72.0	68.6	55.2	362.3
AER preliminary decision	66.5	60.1	45.4	36.3	34.2	241.6
Revised proposal	67.7	68.0	63.6	59.1	52.5	310.9
AER final forecast	64.7	63.1	45.0	54.0	47.4	274.3

Source: AER analysis.

## B.2.2 Powercor's revised proposal

Powercor's revised augex proposal is \$310.9 million (\$2015). As with its initial proposal, Powercor's revised proposal identifies the major projects and programs that comprise its augex forecast for the 2016–20 period. Table 6.8 shows Powercor's augex projects and their contribution to the overall revised augex forecast.

**Table 6.8 Powercor revised augex (\$2015 million, excluding overheads)**

Category	2016	2017	2018	2019	2020	Total
Demand augex	22.7	28.6	37.0	33.4	26.0	147.7
Voltage compliance	3.3	6.6	4.3	3.7	4.5	22.4
Bi-directional voltage regulators	1.8	2.6	3.5	3.9	3.9	15.7
Deer Park Terminal Station	6.8	9.3	0.3	0.0	0.0	16.4
VBRC	27.5	14.5	14.0	14.2	13.4	84.2
Other small augex projects	5.7	7.2	4.4	3.9	4.8	24.5
Total augex revised proposal	67.7	68.0	63.6	59.1	52.5	310.9

Source: Powercor, *revised regulatory proposal*, January 2016.

Powercor's revised augex forecast is 14.3 per cent lower than its initial proposal. In its revised forecast, Powercor:

- Revised its demand-related capex downwards by 24.3 percent to reflect revised maximum demand forecasts (these forecasts are discussed in Appendix C).

- Provided additional supporting information about its major zone-substation constructions at Truganina and Torquay, and its high-voltage feeder augmentation program.

- Provided additional supporting information about its proposed program to install bi-directional voltage regulators on its rural high-voltage feeders.

Powercor's revised proposal is considered in more detail in sections B.2.4.

### **B.2.3 AER approach**

In our preliminary decision on Powercor's augex forecast, we used a combination of top-down and bottom-up assessment techniques to estimate the efficient and prudent capex that Powercor will require to meet its obligations given expected demand growth and other augmentation drivers.

First, we considered Powercor's proposed demand-driven expenditure in the context of past expenditure, demand and current utilisation of network capacity. We used our trend analysis as a starting point for our further project evaluation and as a cross-check on our overall augex estimate. On the basis of our analysis, we found in our preliminary decision that:

- Powercor's initial forecast of maximum demand likely did not reflect a realistic expectation of demand over the 2016–20 period
- On this basis, Powercor's forecast of network utilisation over the 2016–20 period was overstated. However, Powercor's major zone-substation augmentation projects may be required due to significant capacity constraints in parts of its network (e.g. west of Melbourne and the Geelong/Bellarine areas).

Second, we undertook a more detailed economic and technical review of Powercor's network planning methodology and its major augex projects and programs. This informed our top-down review by assessing whether Powercor uses processes that will derive efficient design, costs and timing for each project such that Powercor's proposed augex reflects the efficient costs that a prudent operator would require to achieve the capex objectives.<sup>67</sup> In undertaking these technical reviews, we drew on engineering and other technical expertise within the AER.

On the basis of our analysis, we formed an alternative estimate of the augex required to meet a realistic expectation of demand. We determined, based on a combination of top-down and bottom-up analysis, that \$101.7 million reasonably reflected a prudent and efficient amount for Powercor to meet a realistic expectation of demand, and we included this within our substitute estimate of total capex.

Third, we undertook a technical review of Powercor's major non-demand projects. We focused primarily on capex associated with the Deer Park terminal station and the voltage regulation program. On the basis of this review, we considered that an alternative estimate of \$55.4 million satisfied the capex criteria for these non-demand projects. We therefore included this amount in our substitute estimate.

---

<sup>67</sup> AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, p. 128.

Finally, we separately reviewed Powercor's proposed capex related to the Victorian Bushfires Royal Commission (VBRC) recommendations. We accepted Powercor's VBRC capex in our preliminary decision (which relates to pre-existing requirements as stated in its safety management plans approved by Energy Safe Victoria) and maintain this position in our final decision.

We received submissions from the Victorian Energy Consumer and User Alliance (VECUA) and the Consumer Challenge Panel (CCP) on our preliminary decision and Powercor's revised proposal. We consider these submissions below.

For our final decision on Powercor'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 updates our analysis of Powercor's augex trends, maximum demand and network utilisation in light of Powercor's revised proposal.
- Section B.2.5 updates our examination and capex estimate of Powercor's major augmentation projects and its network planning approach, and includes our final estimate of Powercor's augex.

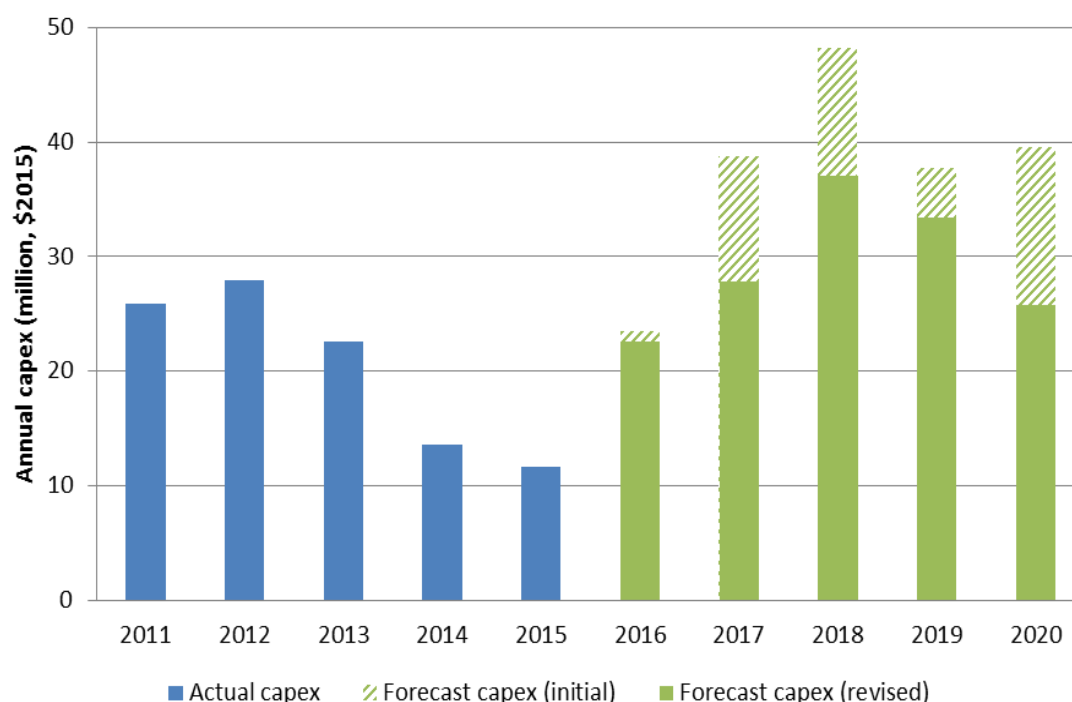
## **B.2.4 Trend and demand forecast analysis**

This section of our final decision re-examines the trend, demand and utilisation analysis we performed in our preliminary decision based on Powercor's revised augex and demand forecasts. This provided us with an initial sense of whether Powercor's revised augex forecast is reasonably required to meet forecast demand and alleviate forecast capacity constraints.

Figure 6.7 shows Powercor's forecast demand-augex compared to its actual demand augex over the 2011-15 period, including the changes between the initial and revised proposals. Powercor's initial proposal included a demand-augex forecast that was double its actual demand-augex over the 2011-15 period. However, in response to our preliminary decision, Powercor reduced its proposed augex and now proposes an increase of approximately 50 per cent compared to 2011–15.



**Figure 6.7 Powercor’s demand-driven capex historic actual and proposed for 2016–20 period (\$2015, million, excluding overheads)**



Source: AER analysis, Powercor revised proposal.

As set out in Appendix C, Powercor is forecasting 2.5 per cent annual growth in maximum demand over the 2016–20 period. This growth in maximum demand is the primary driver of the increase in augex forecast compared to actual expenditure in the recent regulatory control period.

In our preliminary decision, we found that Powercor's initial maximum demand were likely overstated when compared to a more realistic expectation of demand over the 2016–20 period. On this basis, we did not accept Powercor's initial demand-augex proposal. In forming an alternative estimate of augex, we had regard to alternative maximum demand forecasts from the Australian Energy Market Operator (AEMO) which at the time estimated flatter demand growth for the 2016–20 period.

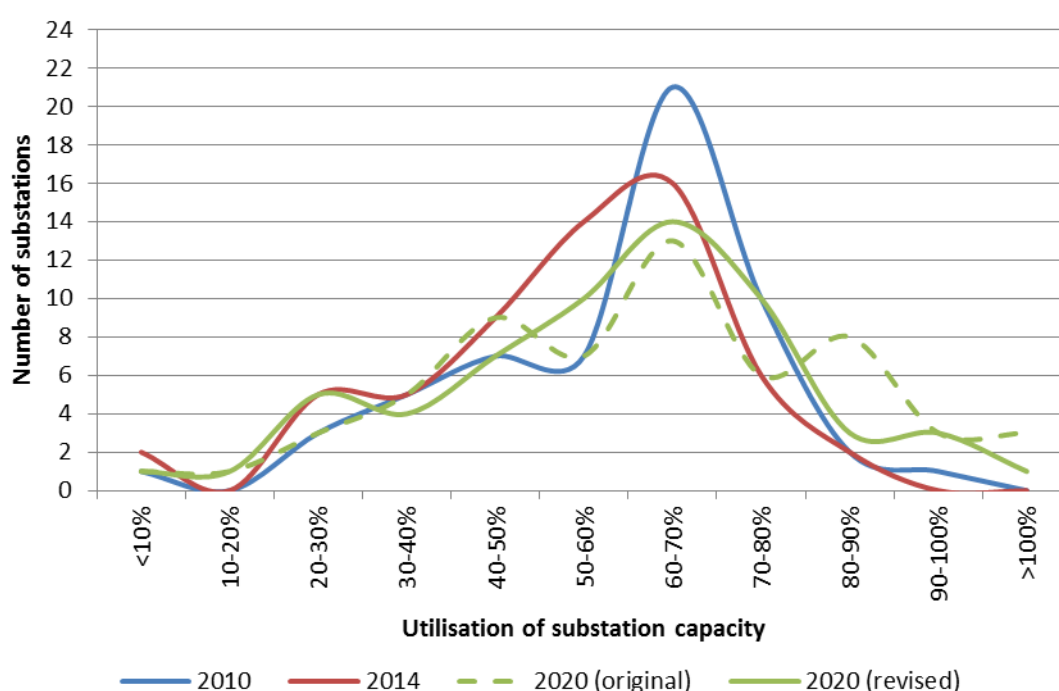
In its revised proposal, Powercor has reduced its overall maximum demand forecasts by approximately 10 per cent. In addition, AEMO's latest demand forecasts estimates higher levels of demand growth in Powercor's network. As set out in Appendix C, we are satisfied that Powercor's revised maximum demand forecast reflects a realistic expectation of demand over the 2016–20 period.

In turn, Powercor has reduced its forecast demand-augex by 25 per cent (as shown in Figure 6.7). This reduction in demand augex in response to reduced and realistic maximum demand forecasts gives us greater confidence in Powercor's forecast capex. However, to examine the impact of revised maximum demand forecasts on the need

for network augmentation, we have also looked at network utilisation using Powercor's revised demand forecasts.<sup>68</sup>

Figure 6.8 shows Powercor's network utilisation (at the zone substation level) between 2010 and 2020. It shows that Powercor experienced a decline in overall network utilisation between 2010 and 2014 due to augmentation and a flattening of demand (shown by a shift to the left in network utilisation by 2014, the red line). In contrast to the most recent years, Powercor expected that network utilization will increase overall by 2020, with more zone substations forecast to operate above 60 per cent capacity and an increase in highly utilised zone substations.

**Figure 6.8 Powercor zone substation utilisation 2010 to 2020 (without augmentation)**



Source: AER analysis; augex model, Powercor reset RIN, Powercor revised proposal (revised RIN 5.4).

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.<sup>69</sup>

<sup>68</sup> Network utilisation is a measure of the installed network capacity that is in use (or is forecast to be). Where utilisation rates are shown to be declining over time (such as from a decline in maximum demand), it is expected that total augex requirements will similarly fall.

<sup>69</sup> We have used Powercor's 'Transformer Normal Cyclic Total' reported in its Reset RIN, rather than using the reported 'Substation Normal Cyclic' rating. Powercor report that the substation normal cyclic rating reported is not the maximum cyclic rating the substation can support, as it runs zone substations based on their ability to withstand contingency events. See Powercor, 2014 Reset RIN basis of preparation, p. 26.

As further shown in Figure 6.8, Powercor's revised demand forecasts means that it expects that less of its zone substations will be highly utilised by 2020 (shown by the difference between the two green lines). This decrease in forecast network utilisation indicates that there are fewer capacity constraints on the network. Nonetheless, the remaining number of highly utilised substations suggests that there still some capacity constraints on the network.

Following this high-level review of Powercor's network utilisation, we have also examined forecast utilisation of specific substations that Powercor proposed to augment or alleviate in the 2016–20 period. We do this to assess whether augmentation may be prudent based on alleviating specific capacity constraints. This approach is supported by the VECUA in its submissions to Powercor's regulatory proposal and our preliminary decisions.<sup>70</sup>

Table 6.9 shows the forecast utilisation (without augmentation) for the Geelong East, Melton and Merbein zone substations, and the zone substations that will have their load reduced with the construction of zone substations at Truganina and Torquay. These figures show that, based on Powercor's revised demand forecasts, utilisation is expected to increase over the period in all substations, some significantly.

**Table 6.9 Utilisation of zone substations affected by augmentation**

Zone substation	2015	2020
Geelong East	0.92	1.07
Merbein	0.77	0.93
Melton	0.75	0.94
Bacchus Marsh	0.75	0.84
Laverton	0.8	0.89
Laverton North	0.75	0.78
Sunshine	0.59	0.74
St Albans	0.68	0.76
Werribee	0.83	0.86
Waurin Ponds	0.76	0.92

Source: AER analysis, Powercor's revised reset RIN.

For those zone substations that are forecast to have very high levels of utilisation, or even have reached capacity, some form of augmentation or non-network initiative may remain prudent to ease or alleviate expected load pressures. Having said that, the

<sup>70</sup> Victorian Energy Consumer and User Alliance, *Submission to the AER Victorian Distribution Networks' 2016–20 The Revenue Proposals*, 13 July 2015, p. 25.

forecast utilisation in 2020 has reduced for many zone substations due to Powercor's revised maximum demand forecasts. This is reflected in some decrease in proposed augex for the Torquay and Truganina zone substations (as discussed in section B.2.5).

The CCP's and VECUA's submissions to our preliminary decision and Powercor's revised proposal raise some concerns with our augex allowance (and the use of trend analysis in particular).

The CCP submission examined trends in Powercor and the other Victorian DNSP's augex over time, and reviewed AEMO's maximum demand forecasts. The key points from the CCP's submission are:<sup>71</sup>

- It is not convinced that the AER's augex preliminary decisions are efficient based on the long term historical data or the high level assessment of need and the low utilisation of the existing assets.
- The amount of augex in the DNSP's proposals and preliminary decisions were excessive when assessed over the longer term and trend in maximum demand. This is because the amounts of approved augex for 2016–20 exceeds the amounts actually incurred over 2001–10, a period of high demand growth, and are similar to augex incurred over 2011–15, a period of low demand growth. Recent augex overspending is the result of excessive demand forecasts.
- It considers that the only augmentation capex that is required is to strengthen the existing networks to accommodate the new developments that are forecast to be developed during the 2016–20 regulatory period. A review of AEMO's connection point demand forecasts shows that only 5 connection points forecast significant demand growth over 2016–20.

The VECUA submit that:<sup>72</sup>

- We have been over-reliant on bottom-up forecasting methodologies. Bottom up assessments have tendency to overstate expenditure requirements, as they do not adequately account for interrelationships/synergies between projects.
- Augex allowances should be made by utilising credible demand forecasts at the substation level, together with a detailed analysis of local capacity constraints, taking into account local system utilisation and excess capacity levels. They are unclear about the level of detail our analysis covers in respect to this issue.
- Despite acknowledging our acceptance of the unsustainable trends in DNSPs' growing excess capacity levels, we did not quantify the impact of this excess

---

<sup>71</sup> Consumer Challenge Panel (sub-panel 3), *Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016), pp. 48–55

<sup>72</sup> The Victorian Energy Consumer and User Alliance (VECUA), *submission to the AER on AER preliminary 2016–20 revenue determinations for the Victorian DNSPs* (Developed by Hugh Grant, Executive Director, ResponseAbility), 6 January 2016, pp. 25–28, 30–34.

capacity, nor did we demonstrate that it has been appropriately considered in augex assessments.

- It is concerned about how we treated the significant reduction in asset utilisation, labelling it a “major omission” in our preliminary determinations. VECUA asserts that system utilisation is much more material to the determination of the networks’ efficient augex needs than what we have determined.

As we state in section B.2.3, we use a combination of top-down and bottom-up assessment techniques to estimate the efficient and prudent capex that Powercor will require to meet its obligations given expected demand growth and other augmentation drivers. Both of our top-down and bottom-up techniques are valuable.

In our top down techniques, we assess network utilisation and maximum demand trends to give us a helpful high-level indicator of the need for augmentation. As noted by the VECUA, Powercor's overall network utilisation decreased over 2011-15 in the presence of network investment and low demand growth (indicating there is spare network capacity). At a high level it would be reasonable to expect that forecast demand augex would fall or remain steady. However, it is important to review forecast network utilisation as this will drive the need for augmentation. Forecast utilisation takes the existing capacity of the network and overlays that with forecast demand to come up with an expected utilisation. This is shown in Figure 6.8 and Table 6.9 above, which shows that a number of specific zone substations are expected to be highly utilised by the end of the 2016–20 period.

As we note above, Powercor's demand-augex is 50 per cent higher than the augex Powercor incurred over 2011–15. This is consistent with the CCP's observations that the augex proposed by the Victorian DNSPs over 2016–20 is broadly similar to, or above, the augex incurred over 2011-15. Powercor's augex forecast is driven by forecasts of maximum demand growth over the 2016–20 period. While we agree that maximum demand forecasts have been overestimated in recent periods, the trend in actual maximum demand growth on Powercor's network has remained relatively consistent between 2006 and 2015. As set out in Appendix C, Powercor's maximum demand forecast for the 2016–20 period is consistent with this historical trend, which suggests that Powercor's demand forecast is not excessive.

In some cases, our high-level assessment of demand forecasts and trends in network utilisation may be sufficient to inform our estimate of augex. However, for our preliminary and final decision, we also examined more localised network constraints and engaged in more detailed economic and engineering reviews of Powercor's augex forecast. This bottom-up analysis allows us to test whether augmentation is justified to alleviate specific capacity constraints and whether Powercor's proposed augmentation solution is prudent and efficient (e.g. the cost and scope of the project and the consideration of non-network alternatives).

As set out in Table 6.9 and section B.2.5 below, we examined areas of the network where network utilisation is forecast to increase and augmentation (or other non-network solutions) may be required. Our analysis suggested some augex may be prudent to alleviate localised capacity constraints on the network. We also found that

Powercor's network planning methodology and criteria reflects good industry practice and the resultant augex was generally prudent and efficient.

## B.2.5 Project and program analysis

In our preliminary decision, we examined Powercor's major augmentation projects and its network planning approach to assess whether its augex reflect the efficient costs that a prudent operator would require to achieve the capex objectives. On the basis of our analysis, we then formed an estimate of the prudent and efficient capex for each of the augex projects and programs we reviewed.

This section re-examines our project and program analysis based on Powercor's revised proposal and its additional supporting information. In particular, we review:<sup>73</sup>

- Powercor's demand-augex projects and network planning
- Powercor's voltage compliance augex programs

Our preliminary decision accepted Powercor's proposed non-demand augex related to the VBRC and the Deer Park Terminal station (and other small augex projects). Powercor accepted our preliminary decision and did not provide any new information. We retain our position and include this augex in our final estimate.

Table 6.10 sets out our final estimate of Powercor's total augex requirements for the 2016–20 period.

**Table 6.10 AER alternative estimate of Powercor's augex forecast (\$2015, million, excluding overheads)**

Category	2016	2017	2018	2019	2020	Total
Demand augex	22.3	27.1	22.8	33.0	25.7	130.9
Voltage compliance	2.5	5.8	3.5	2.9	3.7	18.3
Bi-directional voltage regulators	0.0	0.0	0.0	0.0	0.0	0.0
Deer Park Terminal Station	6.8	9.3	0.3	0.0	0.0	16.4
VBRC	27.5	14.6	14.1	14.4	13.6	84.2
Other small projects	5.6	6.4	4.3	3.7	4.4	24.5
Total augex revised proposal	64.7	63.1	45.0	54.0	47.4	274.3

Source: AER analysis.

Note: Numbers may not add up due to rounding.

<sup>73</sup> Note that our preliminary decision accepted Powercor's proposed non-demand augex related to the VBRC and the Deer Park Terminal station. Powercor accepted our preliminary decision and did not provide any new information. We retain our preliminary decision and we not include any further discussion in this decision.

## Demand-augex program

Powercor proposes \$147 million capex to augment network capacity in response to forecast maximum demand growth. This is comprised of capex to augment zone substations, high-voltage feeders, sub-transmission lines, and its low-voltage network.

In section B.2.4 above, we considered Powercor's maximum demand forecasts and network utilisation, which are the primary drivers of demand-related capex. In this section we also consider Powercor's governance and forecasting process to assess how it goes about making investment and operational decisions. This is a critical element to ensure that Powercor proposes a prudent and efficient amount of capex to meet demand growth and alleviate network constraints. Our approach is set out further in our preliminary decision and our Expenditure Forecast Assessment Guideline.<sup>74</sup>

In the preliminary decision, we examined Powercor's forecasting approach by reviewing its network planning approach and the business case documents for its key demand-related augmentation projects. In summary, we found that Powercor's network planning methodology and criteria reflects good industry practice because Powercor applies cost-benefit and probabilistic network planning methods to its augmentation projects. This gave us a level of confidence that Powercor's overall approach to augmentation was sound. See our preliminary decision for detailed reasons.<sup>75</sup>

However, we considered that Powercor's proposed augex was overstated because:

- Powercor used an outdated estimate of VCR for some of its augmentation cost-benefit analyses, which meant that it overestimated the benefits of proposed augmentation. Powercor used its 2013 estimates of VCR instead of the lower AEMO 2014 Victorian VCR estimate, which we considered is more accurate and up-to-date.<sup>76</sup>
- Powercor's forecasts of maximum demand for the 2016–20 period likely overstate demand compared to a more realistic expectation of demand (as discussed above).

On the basis of our analysis, we formed an alternative estimate of prudent and efficient capex for a number of Powercor's demand-related augex projects.<sup>77</sup> In particular:

- We formed an alternative estimate of Powercor's Truganina zone substation based on a combination of a lower VCR and questions about the proposed cost of installing a third transformer.<sup>78</sup>
- We formed an alternative estimate of Powercor's high-voltage feeder augmentation program based primarily on realistic demand forecasts.<sup>79</sup>

---

<sup>74</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, p. 44; AER, *Explanatory Statement - Expenditure Forecast Assessment Guideline*, November 2013, pp. 81–83, 84–86, 167–168.

<sup>75</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, pp. 44–45.

<sup>76</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, p. 45.

<sup>77</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, p. 46.

<sup>78</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, pp. 46–48.



- We did not accept Powercor's proposed capex to build a Torquay zone substation based on realistic demand forecasts and technical questions about its voltage requirements.<sup>80</sup>

In response to our preliminary decision, Powercor updated its maximum demand forecasts (including at the individual zone substation level) and applied AEMO's 2014 Victorian VCR estimate. Powercor then updated its cost-benefit analyses and made adjustments to several of its demand-related augmentation projects and programs. The key changes from Powercor's updated analysis are:

- Powercor defers \$31.6 million of augex for high-voltage feeders (or 30 percent) based on reduced maximum demand forecasts.<sup>81</sup>
- Powercor retains its proposal to build the Truganina zone substation and states that it is still supported by revised demand forecasts and the latest VCR estimate. However, lower demand forecasts mean that Powercor defers \$5 million (or 21.5 per cent) for two feeders from the 2016–20 period.<sup>82</sup>
- Powercor revisited its proposal for a new Torquay zone substation in light of reduced demand forecasts, and now proposes a staged development approach that defers \$8 million (or 37.1 per cent) from the 2016–20 period.<sup>83</sup>
- Powercor includes a new sub-transmission line project, but reduces its overall augex for sub-transmission lines by \$2.2 million.

We reviewed all of the material submitted by Powercor in its revised regulatory proposal and additional information in response to information requests. In particular we reviewed Powercor's updated cost-benefit analyses (including consideration of non-network alternatives), business cases and demand forecasts for its Truganina and Torquay zone substation projects, and its high-voltage feeders augmentation program. Similar to our preliminary decision, we drew on our engineering and other technical expertise to conduct these assessments.

Based on our review, we are largely satisfied that Powercor has responded to the issues we raised in our preliminary decision and provided additional information that supports its augmentation programs. When combined with our conclusions about Powercor's governance and augmentation planning approach, and our acceptance of Powercor's revised demand forecasts, we are satisfied that the majority of Powercor's demand-related augex reasonably reflects the capex criteria.

However, we consider that:

- Powercor can prudently defer its Torquay zone substation project into the next regulatory control period (2021–25).

---

<sup>79</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, pp. 54–60.

<sup>80</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, pp. 51–53.

<sup>81</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, pp. 209–210.

<sup>82</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, pp. 200–203.

<sup>83</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, p. 204.



- Powercor has overstated its demand augex for its low-voltage network.

We have formed an alternative estimate of Powercor's demand-related augex of \$130.9 million (\$2015), which reflects the two issues raised above. Table 6.11 shows our alternative estimate of demand augex including differences between our estimate and Powercor's revised proposal.

**Table 6.11 AER's alternative estimate of demand augex (\$2015, million)**

	2016	2017	2018	2019	2020	Total
<b>Powercor demand augex revised proposal</b>	<b>22.6</b>	<b>27.9</b>	<b>37.0</b>	<b>33.4</b>	<b>25.8</b>	<b>147.7</b>
AER adjustment for Torquay zone substation	0.0	-1.1	-13.9	0.0	0.0	-15.0
AER adjustment for demand augex for LV network	-0.4	-0.4	-0.4	-0.4	-0.4	-1.8
<b>Alternative estimate</b>	<b>22.3</b>	<b>26.4</b>	<b>22.8</b>	<b>33.0</b>	<b>25.4</b>	<b>130.9</b>
Difference	-0.4	-1.5	-14.3	-0.4	-0.4	-16.8

Source: AER analysis.

Note: Numbers may not add up due to rounding.

The next sections consider in further detail the Torquay zone substation project and low-voltage network demand augex, and how we reached our alternative estimates.

### ***Torquay zone substation project***

Powercor proposes \$15.5 million (\$2015) to construct a new zone substation in Torquay (including escalators) in 2017 and 2018. This zone substation is intended to ease capacity constraints at the existing Waurin Ponds zone substation and resolve anticipated low voltage problems due to growing demand in the Torquay and Surf Coast region of Victoria.

Powercor originally proposed \$20.7 million for this project within its initial regulatory proposal. In our preliminary decision, we excluded this capex from our alternative estimate of total capex because:<sup>84</sup>

- Powercor's proposed cost to build the new Torquay zone substation by 2018 likely exceeded the benefits delivered to consumers if it applied realistic assumptions of VCR and maximum demand forecasts.
- Powercor should be able to effectively manage voltage levels on its feeders over the 2016–20 period through other means, including voltage regulators, due to lower than forecast demand growth.

<sup>84</sup> AER, *Preliminary Decision Powercor 2016-20*, Attachment 6, October 2015, pp. 51–53.

In its revised proposal, Powercor has revisited its capex for a new Torquay zone substation in light of reduced demand forecasts, and now proposes a staged development approach that will defer \$8 million from the 2016-20 period.<sup>85</sup> This staged approach includes establishing an initial zone substation with a single transformer by 2018, and will then expand capacity further in 2022 as demand grows.<sup>86</sup>

We have reviewed all of the material submitted by Powercor for this project in its revised proposal, including a cost-benefit spreadsheet, an updated business case and responses to information requests. Based on our review, we are satisfied that:

- Powercor's maximum demand forecasts represent a realistic expectation of demand over the 2016–20 period (see Appendix C for more detail).
- Powercor has applied cost-benefit analysis, using AEMO's 2014 Victorian VCR.
- Powercor's revised scope of work for the Torquay zone substation represents a prudent and efficient solution to meet capacity constraints at Waurin Ponds and meet demand in Torquay and Surf Coast, given a realistic expectation of demand.

While the scope of Powercor's proposal to construct the Torquay zone substation is prudent and efficient, it is also important that the timing of this project is prudent. Powercor proposes to construct the new zone substation by 2018. This timing appears to be influenced by predicted emerging voltage issues on its network, rather than the need to prudently and efficiently respond to demand. Powercor submits that the existing feeders supplying Torquay from the Waurin Ponds zone substation will be unable to satisfy minimum voltage requirements prescribed in the Victorian Electricity Distribution Code by 2018, and constructing the new zone substation by 2018 will address these voltage issues.<sup>87</sup>

We have examined the proposed timing of this project by examining the timing from an economic perspective and then considered the proposed voltage issues. We find that:

- Powercor's proposed timing to construct the new zone substation is not prudent and efficient from an economic perspective. Based on Powercor's own approach to network augmentation and its cost-benefit analysis spreadsheet, the optimal time to construct this zone substation is 2022. See further below for more details.
- Powercor's proposed voltage issues can be managed until 2022 through significantly lower-cost options, including investing in a voltage regulator and operational measures. See further below for more details.

In combination, this suggests that Powercor can prudently defer the construction of the Torquay zone substation beyond the 2016–20 regulatory control period. To assist

---

<sup>85</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, p. 204; Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.11.

<sup>86</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.11, p. 17.

<sup>87</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.11, pp. 4–5.

Powercor to manage any voltage issues on its network, we include \$0.49 million in our alternative estimate to install a voltage regulator. This is set out in Table 6.12.

**Table 6.12 AER alternative estimate for Torquay zone substation project**

	2016	2017	2018	2019	2020	Total
<b>Powercor augex forecast</b>	<b>0.0</b>	<b>1.1</b>	<b>14.4</b>	<b>0.0</b>	<b>0.0</b>	<b>15.5</b>
Deferral of Torquay zone substation	0.0	-1.1	-14.4	0.0	0.0	-15.5
Addition of voltage regulator	0.0	0.0	0.49	0.0	0.0	0.49
<b>AER alternative estimate</b>	<b>0.0</b>	<b>0.0</b>	<b>0.49</b>	<b>0.0</b>	<b>0.0</b>	<b>0.49</b>
Difference	0.0	-1.1	-13.9	0.0	0.0	-15.01

Source: AER analysis, Powercor augmentation capex model; Powercor response to AER information request 040.

### *Economic cost-benefit analysis*

To determine the optimal timing of the Torquay project from an economic perspective, we examined when the annual benefits to consumers (in terms of the reduction in energy not supplied) outweigh the annualised capital cost of the project. This is consistent with Powercor's suggested approach within its network augmentation planning guideline.<sup>88</sup>

We have used Powercor's cost-benefit model spreadsheet for our analysis.<sup>89</sup> This spreadsheet sets out in detail the annualised benefits to consumers under six different project options. These economic benefits represent the value to consumers by reducing expected unserved energy compared to the 'do nothing' scenario. These benefits are compared against the cost of each option to determine the solution that is most cost-beneficial in net present value.

Table 6.13 sets out the benefits to consumers from Powercor's proposal to construct the Torquay zone substation, and the annualised capital cost of the project.<sup>90</sup> This shows that the annualised capital costs of the project will outweigh the benefits to consumers until 2022, after which the benefits outweigh the costs. This suggests that constructing the zone substation in 2022 is economically optimal.

<sup>88</sup> Powercor, *Network Augmentation Planning Policy & Guidelines*, p. 21.

<sup>89</sup> Provided by Powercor as part of its response to AER information request 040, 23 February 2016.

<sup>90</sup> This is calculated using an annual discount rate of 7.3%, which is consistent with Powercor's cost-benefit analysis.

**Table 6.13 Annualised benefits to consumers and capital costs (\$million)**

	2018	2019	2020	2021	2022	2023
Consumer benefits	-0.15	0.13	0.18	0.44	0.77	2.27
Annualised capital cost	1.13	1.13	1.13	1.13	1.13	1.13

Source: Powercor Torquay cost-benefit analysis model (submitted within response to AER information request #40, 23 February 2016).

Notes: These values assume that Powercor can transfer a small proportion of demand to nearby zone substations (Powercor's modelling provides an option to turn on/off load transfer between local zone substations, which we have turned on for this analysis).

One of the benefits of delaying major augmentations for as long as is possible is that it allows time for a greater understanding of factors such as actual demand growth and alternative augmentation options. Powercor has already revised the scope of its Torquay project based on revised maximum demand forecasts (between the initial and revised proposals), which demonstrates the value from new information. By deferring this project further, Powercor will have the opportunity to observe the growth and continue to assess the need and timing of future augmentations, particularly given the rapid technology development and use in distributed generation and energy storage. This minimises the potential that consumers will fund underutilised or stranded assets.

### *Voltage issues*

Powercor's proposal to construct the Torquay zone substation by 2018 is driven by emerging voltage issues on the existing feeders supplying the Torquay region. These issues were not explicitly factored into Powercor's economic cost-benefit analysis, but were separate factors that drove the timing of constructing the new zone substation.

As noted above, the Victorian Electricity Distribution Code requires that:

- Powercor maintain voltage variation within +/- 10 per cent to customers on high-voltage rural feeders (Torquay and surrounding areas are classified as rural), and
- Powercor maintain low-voltage +10% and -6% to customer on low-voltage supply.<sup>91</sup>

Powercor used Sincal modelling to determine the likely impact of low voltage on these feeders supplied from Waurin Ponds to the voltage levels in the Torquay and Surf Coast areas. This modelling simulates the likely voltage level of a high-voltage feeder and across the network to a customer's point of supply, at a given level of forecast maximum demand. The output of this modelling predicts that high-voltage supply on two of the five feeders supplying the Torquay area will drop by more than 10 per cent by 2018.<sup>92</sup> The remaining three feeders will be within the allowable voltage range

<sup>91</sup> Clause 4.2.2 of the Victorian Distribution Code.

<sup>92</sup> These are feeders WPD014 and WPD 021. See Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.11, p. 3.

specified in the Victorian Electricity Distribution Code. It also predicts that voltage levels experienced by some end-customers will drop by more than 6 per cent.<sup>93</sup>

Powercor submits that:

Powercor is currently taking action, including the installation of voltage regulators and high voltage capacitors, to manage voltage issues in the Torquay and Surf Coast area. However, by 2018, such measures will be unable to ensure Powercor's on-going compliance with the minimum voltage requirements prescribed in the Code. There is, therefore, a need for Powercor to take further action.<sup>94</sup>

While we recognise the potential for voltage issues on its network, Powercor has not verified its modelling with actual field measurement of voltage levels experienced across its network in the Torquay and Surf Coast regions (including at customer premises using Advanced Metering Infrastructure smart meters where available). This would confirm the presence or potential of low voltage issues and also to test the accuracy of the model output.<sup>95</sup> The absence of field measurement makes it difficult to ascertain that actual and material voltage issues need to be addressed on the network.

In our preliminary decision, we noted that a common and relatively low cost method for correcting feeder voltage drops is to install voltage regulators at the load end of the feeders. A voltage regulator is designed to maintain a predetermined level of voltage, giving a boost to compensate the drop in voltage along distribution feeders before reaching customers. Powercor currently uses voltage regulators on two of the five feeders supplying Torquay.<sup>96</sup>

In response to our comments in the preliminary decision, Powercor's did not dismiss the use of voltage regulators. Rather, its revised proposal states:

Jumbo feeders are not standard in our network, and would be difficult to cater for the planned and unplanned outages in the meshed feeder network around Torquay. Larger regulators would be a significantly more expensive option than our preferred solution, given that the costs would be sunk when Torquay zone substation is established.<sup>97</sup>

Powercor's statement that installing large voltage regulators would be significantly more expensive than its preferred option appears to be due to additional costs that Powercor includes in its analysis. Powercor considered an option to resolve the Waurn Ponds capacity and voltage constraints through a combination of new voltage regulators, upgraded feeders and a new transformer in Waurn Ponds (known as 'option 6' in its cost-benefit analysis). Powercor's cost-benefit model shows that this

---

<sup>93</sup> Powercor, *response to AER information request 046*, 4 March 2016, pp. 1 and 4.

<sup>94</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.11, p. 5.

<sup>95</sup> We sought information from Powercor about actual voltage measurements on its network in the Torquay area. Powercor did not provide any measurements and instead provided output from its Sincal modelling. See Powercor, *response to AER information request 046*, 4 March 2016.

<sup>96</sup> Powercor, *response to AER information request 046*, 4 March 2016 and *response to AER information request 048*, 8 March 2016.

<sup>97</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, p. 203.

option presents similar economic benefits to consumers in terms of resolving expected unserved energy, but would still require a Torquay zone substation in 2025. Powercor therefore dismissed it.

We agree with Powercor's decision to dismiss this option as an alternative to building a new zone substation — this is because it involves high-cost interim solutions (e.g. feeder and transformer upgrades) which may not necessarily avoid the need to construct a new Torquay zone substation in the future. However, we consider that adopting some form of voltage regulation may be a low-cost interim solution to addressing voltage issues supplying the Torquay area until it becomes economically optimal to construct a new zone substation in 2022 (as opposed to 2025).

As noted previously, Powercor's supporting documentation shows that it expects that two of the five feeders supplying the Torquay area will experience lower than minimum required voltage levels by 2018.<sup>98</sup> To address the predicted voltage drop on the two feeders, Powercor could install voltage regulators on each feeder at a cost of \$0.49 million per regulator.<sup>99</sup>

Powercor already has high-voltage regulators installed on one of these feeders (the feeder named WPD014).<sup>100</sup> Powercor submits that predicted voltage issues on this feeder will be upstream of these existing regulators (meaning closer to the Waurm Ponds zone substation).<sup>101</sup> An effective operational solution would be for Powercor to relocate one or more of these voltage regulators further upstream so that it could manage voltage for the electricity being delivered to residential end-users.<sup>102</sup>

On this basis, we consider that providing \$0.49 million for a voltage regulator on the remaining feeder without any voltage regulation is sufficient for Powercor to manage predicted voltage issues until it becomes economic to construct a new zone substation in Torquay. This may represent a non-network solution that allows Powercor to prudently defer the need for network augmentation.

Note that Powercor also has number of operational measures available to it to manage voltage levels on its network:

- It can boost voltage supply capability by up to 10 per cent by adjusting the setting on its existing distribution transformer 'taps'. While this is manually intensive, this work would only be required where low voltage issue arises.

---

<sup>98</sup> These are feeders WPD014 and WPD 021. See Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.11, p. 3.

<sup>99</sup> Powercor estimates the cost of installing a large voltage regulator within its response to AER information request 040, 23 February 2016, p. 4.

<sup>100</sup> Powercor, *response to AER information request 046*, 4 March 2016, p. 3.

<sup>101</sup> Powercor, *response to AER information request 046*, 4 March 2016, p. 3.

<sup>102</sup> Furthermore, one voltage regulator is located close its high-voltage customer at the Alcoa Anglesea coalmine. Given that the Alcoa Anglesea coalmine closed its operations on 31 August 2015, Powercor will no longer need a high-voltage regulator to maintain voltage at this location. See [http://www.alcoa.com/australia/en/news/releases/2015\\_08\\_31\\_Anglesea\\_closes.asp](http://www.alcoa.com/australia/en/news/releases/2015_08_31_Anglesea_closes.asp).

- It can respond to fluctuations in voltage at the zone substation level through voltage control facilities such as line drop compensation, which automatically raises and lowers voltage at the zone substation.

In combination with using voltage regulators, these operational measures should allow Powercor to manage voltage levels to its customers until it becomes economically viable to construct a new zone substation. This minimises the potential for consumers to be funding assets stranded assets, or assets before they are necessary.

### ***Low-voltage network augex program***

Powercor proposes \$6.2 million (\$2015) for augmentation on its low-voltage (LV) network (e.g. LV feeders and distribution substations) due to forecast growth in maximum demand. This forms parts of its overall demand-augex proposal.

Powercor states that its low-voltage augex is not driven by its maximum demand forecasts, but it 'reactive in nature'. This means it responds to localised issues found during Powercor's summer and winter load testing programs, unplanned overload outages, and through customer complaints, rather than forecast based on demand.<sup>103</sup> Because it is not driven directly by maximum demand forecasts, Powercor forecasts this capex based on the historical average augex on its LV network from 2009–15.<sup>104</sup>

In our preliminary decision, we accepted the use of historical trend for this capex but disagreed with Powercor's use of the 2009-15 averaging period. As shown in Figure 6.9 below, Powercor's historical augex on LV feeders has been trending downwards consistently between 2009 and 2015. We considered that an averaging process that picks up two high years in 2009 and 2010 may tend to bias the capex forecast upward.

We instead substituted an averaging period of 2011 to 2014, which reduced Powercor's augex to \$4.4 million over the 2016-20 period. We considered this reflected the prudent and efficient amount for Powercor to meet expected demand growth in its low-voltage network.

In Powercor's revised proposal, it disagreed with our decision to substitute a more recent averaging period. It submits that:

The larger sample size is considered more accurate and appropriate as it better reflects a long term average of the range of summer conditions that would be expected, for example the summers of 2011/12 and 2014/15 were extremely mild and consequently many temperature sensitive demand hot-spots were hidden in those years.<sup>105</sup>

---

<sup>103</sup> Powercor, *response to AER information request 048*, 8 March 2016, p. 1.

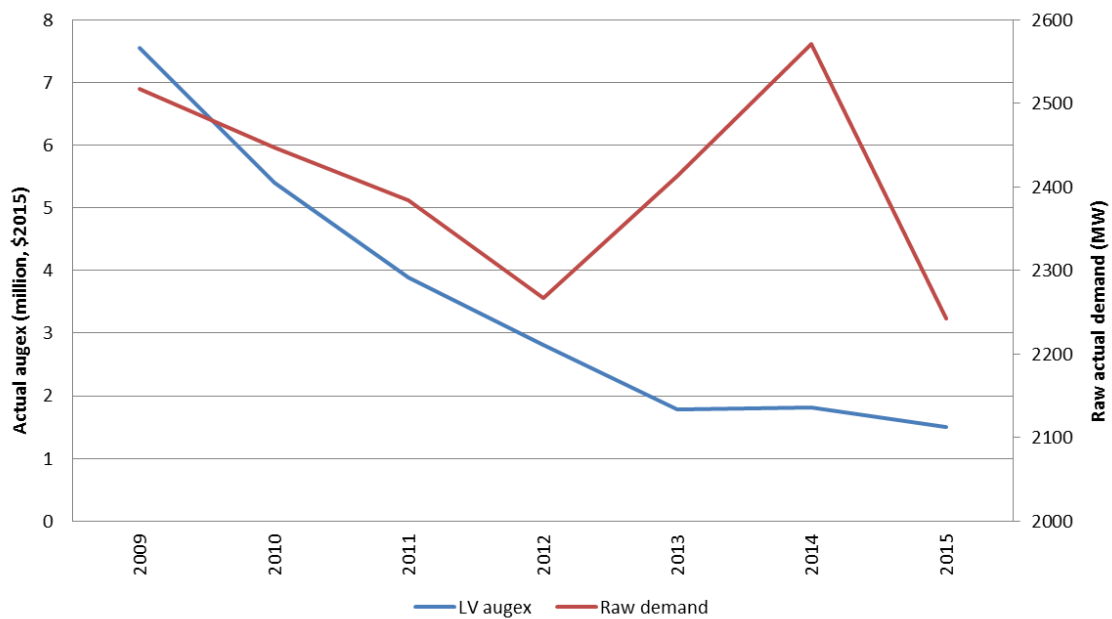
<sup>104</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, p. 205.

<sup>105</sup> Powercor, *response to AER information request 048*, 8 March 2016, p. 1.



Figure 6.9 compares Powercor's historical LV augex against its historical raw maximum demand over the 2009-15 period.<sup>106</sup> Because hot weather is generally reflected in an increase in maximum demand (for example, due to higher use and installation of air conditioners), we would expect to see a correlation between rises in Powercor's maximum demand and augex on its low voltage network. Instead, this data shows that Powercor experienced a rise in maximum demand in both 2013 and 2014 and yet it did not incur any additional augex on its low voltage network.

**Figure 6.9 Powercor's historic LV augex (\$2015) and raw maximum demand between 2009 and 2015**



Source: AER analysis, Powercor's revised regulatory proposal.

This suggests that the high augex experienced in the earlier years of the 2009-2015 period may not reflect what Powercor will incur during periods of high demand. Instead, the more recent years may better reflect Powercor's operating practices and investment decisions during periods of both high and low demand. Therefore, we retain our view in the preliminary decision that adopting a more recent averaging period will provide Powercor with a sufficient amount to manage demand growth on its low-voltage network over the 2016-20 period. This reduces Powercor's proposed augex to \$4.4 million over the 2016-20 period (which is the same as our preliminary decision, and \$1.8 million less than Powercor proposes).

<sup>106</sup> We have used raw maximum demand because it shows the actual peaks in maximum demand experienced on the network. To determine an underlying trend in maximum demand over time, such as for demand forecasting purposes, historical demand is typically 'weather normalised' to smooth out the peaks and troughs. Powercor's weather-normalised historical demand is shown in Appendix B.



In addition, Powercor has reduced its maximum demand forecasts for the 2016–20 period (as set out in Appendix C). This supports our position that Powercor will require less augex than it proposes to augment its LV network because Powercor has not updated this augex forecast in response to reduced demand forecasts.

## Voltage compliance programs

Powercor proposes \$38 million in augex to address compliance with voltage level regulations in the Victorian Electricity Distribution Code. This Code requires that Powercor maintain a specified voltage level at the point of customer supply, with an allowance for +/- 6 per cent on high-voltage feeders and +/- 10 per cent in rural areas.<sup>107</sup>

Powercor proposes:

- \$22.4 million for 'business as usual' voltage compliance works
- \$15.7 million for a new program to install 89 bidirectional regulators along its high-voltage network to manage expected fluctuations in voltage due to expected growth in small customer solar photovoltaic (PV) systems (i.e. solar panels).

Our assessment of each of these two programs is set out below.

### *Business-as-usual voltage compliance*

Powercor proposes \$22.4 million in capex to address expected demand-driven voltage issues to comply with the Victorian Electricity Distribution Code.<sup>108</sup> Powercor states that:

The voltage compliance program is focused on the management of voltage with respect to load growth. This program has a range of project types ranging from conductor upgrades, load balancing, new cap banks as well as 12 new regulators and two upgraded regulators. The two regulators to be upgraded are not uni-directional regulators but smaller bi-directional regulators that need upgrading for more capacity.<sup>109</sup>

Powercor's \$22.4 million voltage compliance program is made up of:

- \$10.4 million for high-voltage feeders, comprised of a large number of small projects such as voltage regulators and conductor upgrades (as outlined by Powercor above)

---

<sup>107</sup> Clause 4.2.2 of the Victorian Distribution Code.

<sup>108</sup> In our preliminary decision, we incorrectly stated that this voltage compliance capex was for Powercor to install 89 bidirectional voltage regulators on its network to manage voltage levels on long feeders driven by the uptake of solar PV generation. We have corrected this in our final decision. Powercor's proposal to install bi-directional voltage regulators is a separate program and is considered in the next section below.

<sup>109</sup> Powercor, *response to AER information request 037*, 9 February 2016, p. 2.

- \$11.9 million for its low-voltage network, calculated based on the historical average augex on its low-voltage network from 2009–15 (excluding capex that is not related to voltage compliance, such as capacity augmentation).

For the reasons set out below, we accept Powercor's forecast capex for high-voltage feeders but consider that Powercor has overstated its forecast capex for low-voltage network. Our alternative estimate for voltage compliance is \$18.3 million (\$2015), which is shown in Table 6.14.

**Table 6.14 AER alternative estimate for voltage compliance**

	2016	2017	2018	2019	2020	Total
<b>Powercor voltage compliance forecast</b>	<b>3.3</b>	<b>6.6</b>	<b>4.3</b>	<b>3.7</b>	<b>4.5</b>	<b>22.4</b>
AER adjustment for LV network	-0.8	-0.8	-0.8	-0.8	-0.8	-4.1
<b>Alternative estimate</b>	<b>2.5</b>	<b>5.8</b>	<b>3.5</b>	<b>2.9</b>	<b>3.7</b>	<b>18.3</b>

Source: AER analysis.

In our preliminary decision, we reviewed the projects Powercor proposed for its high-voltage feeders.<sup>110</sup> We considered that expenditure for eight of its individual voltage regulator projects could be deferred to the following regulatory control period, based on reduced demand forecasts.<sup>111</sup> This was supported by our conclusions that Powercor's maximum demand forecasts did not reflect a realistic expectation of demand.

Powercor initially proposed \$15.4 million in capex for voltage compliance on its high-voltage feeders. Powercor has reduced this proposed capex for voltage compliance on high-voltage feeders by \$5 million, based on reduced maximum demand forecasts. Given that Powercor has responded to revised demand forecasts by reducing or deferring capex for this program, we are satisfied that this capex represents a prudent and efficient amount for Powercor to manage voltage quality on its high-voltage network over 2016-20.

Powercor has not updated its \$11.9 million capex for voltage compliance on its low-voltage network in response to reduced maximum demand forecasts. As stated above, Powercor adopts a similar historical averaging methodology as its demand-augex for its low-voltage network. As we set out above in our position on Powercor's demand-augex for its LV network, we consider that trending forward historical augex based on an averaging period from 2009-15 likely overstates the amount of capex required over the 2016-20 period. If Powercor instead adopts an averaging period from 2011-15, we

<sup>110</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, pp. 59–60. This was within the context of Powercor's overall augex for its high-voltage feeders.

<sup>111</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, October 2015, pp. 59–60.

calculate that this reduces its capex for voltage compliance on its LV network to \$7.8 million (\$2015).

In response to an information request about this augex, Powercor submits that:

The LV capex was not reduced in response to the reduced maximum demands as it is forecast that there will be an offsetting increase in voltage issues caused by high levels of solar penetration. In the past, voltage issues at the low voltage level have been primarily caused by voltage drop at both the low and high voltage levels. Powercor is now experiencing an increase in voltage issues caused by new solar installations which are increasing the voltage levels to above the limits specified in the Victorian Electricity Distribution Code and causing appliances and devices to cease functioning correctly, or fail.<sup>112</sup>

As we discussed below in our assessment of Powercor's bi-directional voltage regulator program, Powercor has provided little evidence to demonstrate that it is currently, or is expected to, experience voltage levels on its high-voltage network that exceed the limits specified in the Victorian Electricity Distribution Code. Powercor similarly provides little evidence that it will expect an increase in incidents where voltage levels exceed the limits for its low-voltage network. This means we are not satisfied that decreases in voltage compliance works due to reduced demand forecasts will be offset by increases due to increases in solar PV installations.

### ***Bi-directional voltage regulator program***

Powercor proposes \$15.7 million in augex to install 89 bidirectional regulators along its HV network to manage expected fluctuations in voltage due to solar PV systems. Powercor submits that this will allow it to maintain compliance with its obligations in the Victorian Electricity Distribution Code in relation to voltage levels at customer premises.<sup>113</sup>

Traditionally, electricity flows in one direction from generators and transmission and distribution networks to customers. Powercor uses uni-directional voltage regulators on its feeders to maintain a predetermined range of voltages, giving a boost to compensate the drop in voltage along long distribution feeders. With the increasing uptake of solar PV systems, excess supply of solar PV (above consumers' demand) is exported back onto the network. Powercor submits that bi-directional voltage regulators will allow Powercor to manage voltage levels for power flows in either direction, based on recommendations in a report from AECOM.

In our preliminary decision, we considered, that based on information provided by Powercor, investment in bi-directional voltage regulators was not required over the 2016–20 period for Powercor to manage voltage levels on its network. In support of our position, we noted that all of Powercor's feeders are currently within regulatory voltage level requirements, and Advanced Metering Infrastructure meters are recommended to

---

<sup>112</sup> Powercor, *response to AER information request 048*, 8 March 2016, p. 1.

<sup>113</sup> Powercor, *Regulatory Proposal 2016-2026*, April 2015, Appendix E.67, p. 1.

be used to assess voltage impacts. These issues suggested bidirectional regulators are not a necessity at present.

Powercor has retained this capex in its revised proposal, providing additional information on the concerns we raised in our preliminary decision. Powercor also submits that, without installing the bi-directional regulators on its network, it is likely to be uneconomic for customers to connect embedded generators to certain feeders in the 2016–20 regulatory control period.<sup>114</sup> It submits that this will be inconsistent with the Federal and State Government's objective to promote decarbonisation of our economy, and contrary to the policy positions of the Victorian Government to increase the penetration of solar PV in Victoria.<sup>115</sup>

We have reviewed all of the material submitted by Powercor in its revised regulatory proposal, including reviewing the AECOM report and additional information from Powercor in response to information requests. Based on our review, we have not included Powercor's proposed capex to install bi-directional voltage regulators on its network in 2016–20. This is because:

- Powercor has not demonstrated to our satisfaction that the projected growth in PV installations over the 2016–20 period will cause its high-voltage feeders to be non-compliant with voltage regulations contained in the Victorian Electricity Distribution Code.
- Powercor has not reasonably considered other options to manage voltage levels on its network in the presence of increasing uptake of solar PV. This raises the potential that consumers will fund underutilised or stranded assets in bi-directional voltage regulators.

The remainder of this section considers:

- Powercor's predicted voltage issues and whether Powercor is likely to be non-compliant with voltage regulations contained in the Victorian Electricity Distribution Code
- Powercor's consideration of alternative solutions to manage predicted voltage issues due uptake of solar PV systems.

### **Predicted voltage issues**

Powercor's does not submit that it is currently experiencing voltage issues on its rural feeders. Rather, it considers that additional bi-directional regulators are required on 47 of its long rural feeders to address predicted future voltage issues on these feeders due to estimated growth in solar PV penetration.

Powercor's proposal is based primarily on a study undertaken by engineering consultant AECOM. AECOM studied the impact of solar PV cell installation on

---

<sup>114</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, Attachment 7.9, p. 1.

<sup>115</sup> Powercor, *Revised Regulatory Proposal 2016-2026*, January 2016, p. 206.

Powercor's HV network for urban, rural short and rural long feeders.<sup>116</sup> Using a small sample of feeders, AECOM modelled the voltage fluctuation along the distance of the feeder at different levels of load and solar PV penetration.

AECOM found that the impact of projected uptake of solar PV on feeder voltage levels were within the prescribed regulatory obligations in the Victorian Electricity Distribution Code.<sup>117</sup> However, it suggested that the increasing penetration of solar PV means that "it is important to control the HV network and monitor effects of solar penetration to minimize effect and additional costs to customers connected." AECOM recommended that Powercor should install bi-directional regulators on its rural long HV feeders:

Existing regulators with a unidirectional control system should be replaced with controllers which are capable of bi-directional current flow on rural long feeders. This will prevent the tapping mechanism reaching its maximum or minimum tapping range and not being able to regulate the voltage adequately.<sup>118</sup>

Given AECOM's observations that none of the feeders it modelled showed voltages outside the range required in the Victorian Electricity Distribution Code, we asked Powercor to further explain what specific technical issues it is seeking to resolve with its the voltage regulator program. In response, Powercor stated that:

This statement is based on the results of the limited feeders studied with none of the feeder's model containing unidirectional regulators. Therefore the correct interpretation is that the modelling demonstrates that HV networks with bidirectional regulators can manage high penetrations of PV and reverse powerflow as applied in the modelling.<sup>119</sup>

We do not dispute that reverse power flows may occur where there are high penetration levels of solar PV on a feeder. We also accept that bi-directional voltage regulators will assist Powercor to manage voltage levels on its feeders in the presence of reverse power flows. However, reverse power flows do not necessarily result in voltages that are outside of the required ranges. Powercor has an allowable voltage range of +/- 10% on its rural long feeder and to exceed this allowance will likely require a significant level of reverse power flow. Powercor has not provided evidence that it will experience voltage levels that exceed its regulatory voltage levels due to reverse power flows. The AECOM report did not find that then feeder voltages would exceed these limits.

Furthermore, AECOM's findings on the impact of solar PV across Powercor's network are based on simulations using Sincal software, as opposed to real measured data on voltage levels on the network. AECOM states that more accurate network monitoring and modelling is required:

---

<sup>116</sup> Aecom, *Solar PV impact study, Strategy recommendations*, 15 October 2014.

<sup>117</sup> Aecom, *Solar PV impact study, Strategy recommendations*, 15 October 2014, p. ii.

<sup>118</sup> Aecom, *Solar PV impact study, Strategy recommendations*, 15 October 2014, p. 75.

<sup>119</sup> Powercor, *response to AER information request 037*, 9 February 2016.

Metered data at solar cell connection points should be obtained on the selected distribution feeders to perform additional studies. This will provide more accurate network modelling and will also present the impacts on the system voltages during the different loading periods.<sup>120</sup>

As we stated in our preliminary decision, we consider that AECOM's recommendation to engage in additional studies is an indication that the need for bidirectional regulators is not immediate. Powercor has Advanced Metering Infrastructure smart meters and installed voltage measurement stations at all zone substations, which enables detailed analysis of voltage levels across its entire network in near real time. This information could provide accurate identification of how feeder voltage responds to each level of PV penetration, trends and forecasts of PV penetration by feeder, and trending of when/if reverse flows could occur.

Powercor has stated that it is actively monitoring lines susceptible to voltage issues and monitoring voltage in areas where groups of solar PV generators are increasingly causing fluctuations in voltage levels.<sup>121</sup> We consider that the direct measurement of voltage outcomes will allow Powercor to consider the actual quantum and impact of additional solar panel installation on power quality problems, and its ability to manage these problems using existing assets and technology.

### **Powercor's consideration of alternatives**

Powercor has a number of alternative options to manage voltage levels on its network in the presence of increasing solar PV installations, which are also identified by AECOM in its report. We consider two alternatives in this section:

- Customer solar PV connections agreements.
- Grid and residential battery storage.

In summary, we consider that Powercor has not reasonably considered the costs and benefits of these alternative options to managing voltage levels on its network. Powercor has only conducted an initial qualitative assessment. Given our position that Powercor should rely on actual voltage level measurement to determine which feeders are at risk of exceeding the voltage obligations, investing in bi-directional voltage regulators without considering alternative options raises the potential that consumers will fund underutilised or stranded assets.

First, Powercor has a small customer connection agreement in place for customers connecting solar PV systems to the distribution network. AECOM suggested that Powercor's reinforce its customer connection agreement with future customer connections of solar PV to mitigate voltage management issues.<sup>122</sup>

---

<sup>120</sup> Aecom, *Solar PV impact study, Strategy Recommendations*, 15 October 2014, p. i.

<sup>121</sup> Powercor, *Regulatory Proposal 2016-2026*, April 2015, Appendix E, pp. 85–86.

<sup>122</sup> Aecom, *Solar PV impact study, Strategy recommendations*, 15 October 2014, p. ii.



Other DNSPs in the NEM have altered their connection agreements to address concerns with PV saturation and voltage fluctuations on the distribution network. For example, Ergon Energy and Energex's 2014 solar PV customer connection standard required that customer PV systems limit or modify power output to reduce the risk of voltage before voltage levels exceed statutory limits.<sup>123</sup> In our regulatory determination for Ergon Energy and Energex, we considered that compliance with its customer connection standard would reduce the need to correct or manage voltage issues associated with newly installed solar PV systems.<sup>124</sup>

Powercor submits that it does not wish to implement restrictions in the customer connection agreements.<sup>125</sup> Instead, Powercor submits that new standards for solar PV systems will reduce the need for restrictions on customers:

New generation inverters that comply with the new standard AS4777.2 (mandatory from October 2016) will contain new features that allow power exports to be reduced when LV volts reach a specified limit, thus allowing a far simpler and faster connection assessment process without restrictions. LV customers connected downstream of a HV unidirectional regulator that reach reverse power flow will require restrictions to be applied, the likely outcome being a zero export limit, or an offer involving customer-funded augmentation works, depending on the customer equipment.<sup>126</sup>

While we recognise that Powercor does “does not wish” to implement restrictions to customer connections because it may limit customer PV generation exports to the grid, the cost to a customer in limiting PV exports (including via the new standard AS4777.2) may be a magnitude less than the cost of installing or replacing a voltage regulator on the distribution system. Powercor has not performed any economic cost-benefit analysis of whether the long-term benefits to customers from Power investing in new voltage regulators will outweigh the costs from imposing restrictions on customer' solar PV voltage output during times of high voltage rises on the network.

As noted above, we consider that Powercor should rely on actual voltage level measurement to determine which feeders are at risk of exceeding the voltage obligations. We do not consider that deterministic PV solar penetration levels or the presence of reverse flows is sufficient evidence. Any alterations to the small customer connection agreement should reflect this approach.

In addition, AECOM notes that other DNSPs are trialling the use of battery storage programs as a means to manage voltage compliance issues. In particular, it notes that AusNet Services was trialling grid battery storage over two years to "manage peak

---

<sup>123</sup> Ergon Energy and Energex's 2014 solar PV connection standard required that customer PV systems cut out before voltage levels exceed statutory limits. 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.

<sup>124</sup> AER, *Preliminary Decision Ergon Energy 2015-16 to 2019-20*, October 2015, Attachment 6, p. 55.

<sup>125</sup> Powercor, *response to AER information request 037*, 9 February 2016, p. 3.

<sup>126</sup> Powercor, *response to AER information request 037*, 9 February 2016, p. 3.

demand, voltage imbalance, power factor correction, and various other power quality functions in grid parallel and island operation."<sup>127</sup>

AusNet Services also published the results of a recent residential battery storage trial (which was funded from its Demand Management Innovation Allowance).<sup>128</sup> The results of the trial showed that residential battery storage system was able to significantly reduce the amount of solar power that was exported to the grid.<sup>129</sup> On the basis of this data, AusNet Services suggested that "battery storage can facilitate an increased PV penetration of two to three times for a given voltage limit constraint."<sup>130</sup>

We asked Powercor about this option. It responded that:

Powercor is presently trialling both large batteries and residential storage systems. While the technology is mature the price of these systems is still probative, Powercor's reason for our trials is to seek out opportunities for demand management and engineering learnings on how to best deploy both physically and from a demand management perspective. Residential systems are only being installed by large companies like us trying to understand this new technology or being taken up by early adopters. Our research and present industry studies indicate that large scale take up will not be viable before 2020.<sup>131</sup>

We agree that residential systems are presently being installed by early adopters and large companies. However a large number of new entrants have announced the availability of residential storage systems and the volumes are expected to increase exponentially.<sup>132</sup> AusNet Services also concluded that that the financial performance of the residential battery storage trial was sufficient to warrant a further ongoing work stream aimed at realising the benefits of storage and managing customer uptake.<sup>133</sup>

Given Powercor's expectation that large-scale take-up of battery storage systems will become viable after 2020 (and further evidence from AusNet Services' trials), this lends support to our position that Powercor should rely on actual voltage level measurement to identify real issues before investing in bi-directional over the 2016–20 period. This minimise the potential for consumers to be funding underutilised or stranded assets.

---

<sup>127</sup> Aecom, *Solar PV impact study, Strategy recommendations*, 15 October 2014, p. 78.

<sup>128</sup> AusNet Services, *Demand Management Case Study: Residential Battery Storage Trial*. Available at [http://www.ausnetservices.com.au/CA257D1D007678E1/Lookup/ManagingUsage/\\$file/Case%20study%20Residential%20Storage%20Trial.pdf](http://www.ausnetservices.com.au/CA257D1D007678E1/Lookup/ManagingUsage/$file/Case%20study%20Residential%20Storage%20Trial.pdf); accessed on 4 April 2016.

<sup>129</sup> AusNet Services, *Demand Management Case Study: Residential Battery Storage Trial*, p. 10.

<sup>130</sup> AusNet Services, *Demand Management Case Study: Residential Battery Storage Trial*, p. 10.

<sup>131</sup> Powercor, *response to AER information request 037*, 9 February 2016, p. 3.

<sup>132</sup> AEMO, *Emerging Technologies Information Paper, National Electricity Forecasting Report*, June 2015.

<sup>133</sup> AusNet Services, *Demand Management Case Study: Residential Battery Storage Trial*, p. 13.



## B.3 Forecast customer connections capex, including capital contributions

Connections capex is incurred by Powercor 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 Powercor or a third party. The new customer may provide a contribution towards the cost of the new connection assets. This contribution can be monetary or in contributed assets. In calculating the customer contribution, Powercor is required to take into account the forecast revenue anticipated from the new connection. 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.

The mix between net capex and capcons is important as it determines from whom and when Powercor recovers revenue associated with the capex investment. For works involving a customer contribution, Powercor recovers revenue directly from the customer who initiates the work at the time the work is undertaken. This is different from net capex where Powercor recovers revenue for this expenditure through both the return on capital and return of capital building blocks that form part of the calculation of Powercor's annual revenue requirement. That is, Powercor recovers net capex investment across the life of the asset through revenue received for the provision of standard control services.

### B.3.1 AER Position

We are satisfied Powercor's revised proposal for connections capex of \$724.2 million (\$2015) reasonably reflects the capex criteria.<sup>134</sup> We have included this amount in our substitute estimate of forecast capex as shown in Table 1. Further, we accept Powercor's revised proposal for customer contributions of \$381.7 million (\$2015).

**Table 6.15 AER final decision adjusted connections capex (\$2015 million excluding overheads)**

	2016	2017	2018	2019	2020	Total
Connections capex	151.2	157.9	139.3	137.0	138.8	724.2
Customer contributions	77.1	83.4	74.9	73.2	73.2	381.7

Source: AER analysis.

Table 2 provides a comparison of the forecasts expenditure on connection components.

---

<sup>134</sup> NER, cl. 6.5.7(c).

**Table 6.16 Connections capex forecast comparison (\$2015) million, excluding overheads)**

	Initial Regulatory Proposal	Preliminary Determination	Revised regulatory proposal	Final decision
Gross connections capex	774.1	724.6	724.2	724.2
Capital contributions	316.0	358.8	381.7	381.7
Net connections capex	458.1	365.8	342.5	342.5

Source: AER analysis.

### B.3.2 Revised proposal

As Table 6.16 above shows, Powercor's revised proposal includes a forecast of connections capex of \$724.2 million (\$2015) for 2016–20 regulatory control period. With respect to customer contributions, Powercor's revised proposal includes an amount of \$381.7 million (\$2015). As Table 6.16 shows Powercor's revised proposal accepts our preliminary decision for gross connections capex and has upwardly revised its forecast for customer contributions.

In its revised proposal, Powercor accepted our preliminary decision forecasts for both high and low volume gross connections capex and associated recoverable works and gifted assets. Powercor did update its methodology for calculating customer contributions to reflect anticipated changes in regulations, correcting for the change in x factor and rate of return, and correction of a reporting error.<sup>135</sup>

### B.3.3 Reasons for AER Position

Powercor's revised proposal accepts our preliminary decision forecast of gross connection capex.<sup>136</sup> In our preliminary decision we set out the reasons why we are satisfied historical capex is an appropriate basis on which to determine forecast connections capex. We consider that the drivers of customer connections remain relatively constant across regulatory control periods. In addition we consider that there are no external or exogenous factors identified that would result in expenditures that were inconsistent with recently observed trends. With the above in mind, we have

<sup>135</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, p. 214.

<sup>136</sup> High volume categories of connection follow the RIN definitions of residential complex at LV, residential complex HV works connected at LV, and commercial/industrial HV works connected at LV. Low volume categories of connection follow the RIN definitions of commercial/industrial connected at HV, embedded generation, and recoverable works (reported as quoted services). In determining its forecasts for these low volume categories, CitiPower used forecasts of customer connections estimated using a bottom-up build of major projects.

included Powercor's revised proposal amount in our final decision for gross connections capex.

As noted above, Powercor has updated its customer contributions forecast. Powercor relies on deriving a contribution rate which it applies to the gross connection capex forecasts to produce the net capex and customer contributions forecasts.<sup>137</sup>

Below we consider Powercor's updated forecast of customer contributions. In particular, we have assessed whether the forecast was prepared in accordance with the relevant connection charge guideline as well the reasonableness of Powercor's forecasting methodology.

### **Connection Charge Guideline**

In its revised proposal, Powercor noted:

In the period since April 2015 when we submitted our regulatory proposal, the Victorian Government has announced its intention that we adopt Chapter 5A of the Rules during the 2016–2020 regulatory control period. This will impact the calculation of customer contributions, as it will also require the ESCV to rescind Guidelines 14 and 15. While the legislative bill that was introduced into the Victorian Parliament in December 2015 did not specify a date from when we would adopt the new Rule, a default date of 1 January 2017 was contained in the draft legislation. For the purposes of this revised proposal, we therefore assume that customer contributions will be calculated:

- in 2016, in accordance with Guideline 14 and 15; and
- in 2017 to 2020, in accordance with Chapter 5A of the Rules.<sup>138</sup>

CCP3 considers that although there is forecast legislative change to alter the capital contribution assessment process, the basis of the calculations should continue on current rules (ESCV guidelines) until the change comes into effect and there should be a pass through change triggered to reflect the difference in approach.<sup>139</sup>

Comparing ESC Guideline 14 with the AER's Connection charge guidelines we note that both these guidelines prescribe similar methods for calculating customer contributions. In simple terms, both guidelines calculate the contribution as the difference between the cost to the distributor of connecting the customer to the distribution network and the revenue the distributor will receive from that connection.

---

<sup>137</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 215.

<sup>138</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 213.

<sup>139</sup> CCP3, *report on AER Preliminary Decisions and DNSPs' Revised Proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016, p. 55.

Therefore we consider any differences between the two guidelines must relate to the assumed future incremental revenue or the assumed incremental cost for each forecast connection.

#### *Incremental revenue*

Both the ESC and AER guidelines rely on assumptions on the revenue that the distributors will receive for each connection. Under ESC guideline 14 the calculation of the revenue the distributor will earn from each connection relies on assuming that the price path for the last year of the price determination continues over the 30 years for domestic customers and 15 years for all other customers.<sup>140</sup> The AER's connection policy uses a flat real price path after the end of the relevant distribution determination, for the remaining life of the connection, when estimating the incremental revenue.<sup>141</sup>

#### *Incremental cost*

Similar to incremental revenue discussed above, both the ESC and AER guidelines rely on assumptions on the costs of the connection requiring a customer contribution. These costs, or incremental costs, represent the expenditure that the distributors will incur as part of the connection. We view the method to calculate the incremental cost of connections to be similar under both guidelines. That is both factor in the impact the connection has on the network and downstream augmentation in determining incremental cost. We do consider a difference exists between the two guidelines regarding the treatment of operating, maintenance and other costs. That is the ESC Guideline 14 includes opex in its calculation of incremental cost whereas the AER's connection policy does not include these costs.

#### *Powercor's forecasting methodology.*

We note that Powercor's updated forecast customer contributions in its revised proposal was limited to revising incremental revenue (IR) underlying its forecast, Powercor has assumed that the incremental costs for a particular connection remain unchanged. In adapting the incremental revenue calculations Powercor has applied the x factor and rate of return assumptions that would be applied to calculate incremental revenue in 2014, 2016 and 2017, assuming Chapter 5A takes effect from 1 January 2017 and using the AER's preliminary determination values for 2016 to 2020.

We have reviewed the calculations accompanying Powercor's revised proposal and we are satisfied that Powercor has applied a customer contribution rate that accounts for the x factors and rate of return assumptions discussed above.<sup>142</sup>

We consider that accounting for the differences between the ESC Guideline 14 and the AER connection policy would be immaterial to the forecast of customer contributions.

---

<sup>140</sup> Essential Services Commission, Guideline No. 14 Provision of Services by Electricity Distributors.

<sup>141</sup> AER, Connection charge guidelines for electricity retail customers Under chapter 5A of the National Electricity Rules.

<sup>142</sup> Powercor, *PAL PUBLIC RRP MOD 1.19 PAL Connections Capex.xlsx*, January 2016.

Further, we consider it is likely that Chapter 5A will be adopted in Victoria over the course of the 2016–20 regulatory control period under the AER's Connection Charge Guideline under Chapter 5A of the NER. On this basis, we are satisfied that Powercor's forecast reflects a realistic expectation of customer contributions it will receive over the 2016–20 regulatory control period.

## B.4 Forecast repex

Replacement capital expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria.

Replacement can occur for a variety of reasons, including when:

- an asset fails while in service, or presents a real risk of imminent failure
- a condition assessment of the asset<sup>143</sup> determines that it is likely to fail soon (or degrade in performance, such that it does not meet its service requirement) and replacement is the most economic option
- the asset does not meet the relevant jurisdictional safety regulations, and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

The majority of network assets will remain in efficient use for far longer than a single five year regulatory control period (many network assets have economic lives of 50 years or more). As a consequence, a distributor will only need to replace a portion of its network assets in each regulatory control period. Our assessment of repex seeks to establish the portion of AusNet Services' assets that will likely require replacement over the 2016–20 regulatory control period and the associated capital expenditure.

Our assessment of repex seeks to establish the portion of Powercor's assets that will likely require replacement over the 2016–20 regulatory control period, and the associated expenditure. Powercor's forecast of repex includes estimates of the capex it considers necessary to comply with safety obligations implemented in response to the 2009 Victorian Bushfires Royal Commission (VBRC).

### B.4.1 Position

We do not accept Powercor's proposed repex of \$672 million, excluding overheads. We have instead included in our alternative estimate of overall total capex, an amount of \$609 million (\$2015) for repex, excluding overheads. This is nine per cent lower than Powercor's revised proposal. We are satisfied that this amount reasonably reflects the capex criteria.

Powercor's revised proposal forecast of \$672 million for repex is 7 percent lower than the \$722 million in its initial proposal.

Table 1 summarises Powercor's proposals and our alternative amounts for repex at each stage of the assessment period.

---

<sup>143</sup> A condition assessment may relate to assessment of a single asset or a population of similar assets. High value/low volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

**Table 1: Final decision on Powercor's total forecast repex (\$2015, million)**

	2016	2017	2018	2019	2020	Total
Initial regulatory proposal	131	129	145	151	166	722
AER preliminary decision	111	109	122	127	140	609
Revised regulatory proposal	120	126	134	142	151	672
AER final decision	109	114	121	128	137	609
Total difference b/w final and revised	-12	-12	-13	-13	-14	-64
Percentage difference b/w final and revised (%)	-10	-10	-9	-10	-9	-10

Source: AER analysis.

Note: Numbers may not add up due to rounding.

## B.4.2 Powercor's revised proposal

In its revised proposal Powercor accepted the following parts of our preliminary decision:<sup>144</sup>

- repex assessed using the repex model for all modelled asset categories except for the overhead conductors group, and one asset category in switchgear
- un-modelled repex for pole top structures, SCADA and "other".

The issues Powercor raised in revised proposal that it did not accept from our preliminary decision were:<sup>145</sup>

- Powercor considered its proactive overhead conductor replacement program warranted a forecast higher than the business as usual amount predicted by the repex model.
- Powercor was of the view that there was a modelling error relating to the switchgear category, high voltage (HV) fuses and surge protectors. It submitted its correction to the repex model increasing its forecast by approximately \$9 million.

Powercor submitted its forecast for the overhead conductor categories in the repex model included:<sup>146</sup>

- business as usual replacements

<sup>144</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 192.

<sup>145</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 189, 190, 192.

<sup>146</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 190.

- a proactive conductor replacement program.

In its revised proposal, Powercor has removed the proactive conductor replacement program from its overhead conductor expenditure and reallocated it to the un-modelled replacement category. It also updated its forecast expenditure for the proactive replacement program from \$73.8 million to \$31.5 million to distinguish it from VBRC related obligations. This distinction was necessary as the Victorian Government will require a non-like for like replacement of conductors in specified high bush fire risk areas.<sup>147</sup> As such, the initial proactive conductor program proposal effectively double counted some expenditure that Powercor sought as a contingent project related to likely 'VBRC' obligations.<sup>148</sup>

Powercor submitted that it paused its proactive conductor replacement program in 2011 on basis that the Powerline Bushfire Safety Taskforce (PSBT) recommended targeted replacement of power-lines with underground or insulated cable in the highest fire risk areas.<sup>149</sup> Powercor submitted that as a result, like-for-like replacement was deferred given new conductor technologies may be required for some conductor replacements. Powercor also submitted that it re-commenced this proactive program in 2014 on the basis that the Victorian Government and ESV provided clarity on locations where conductors would be replaced under the PSBT recommendations.<sup>150</sup>

Powercor retained Jacobs to review its updated business case and supporting documentation. It considered the proactive replacement program should be undertaken in the forthcoming period on the basis that:<sup>151</sup>

- delay in undertaking the program will result in a rapid increase in the failure rate
- delay in undertaking the program will lead to excessive costs in the future as the necessary volume of work will exceed the capacity to deliver
- expenditure and timing of the program is prudent
- the option selected for undertaking the program is the most efficient on a net present value basis
- there is a material discrepancy in the regulatory allowances for overhead conductor replacement between Powercor and AusNet Services.

### B.4.3 AER approach

We have applied several assessment techniques consistent with our preliminary decision to assess Powercor's forecast of repex against the capex criteria. These techniques are:

---

<sup>147</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 193,. 196.

<sup>148</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 189, 190, 192.

<sup>149</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, pp. 6–7

<sup>150</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 193; Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, December 2015 p. 4.

<sup>151</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 195–197.



- analysis of Powercor's long term total repex trends
- predictive modelling of repex based on Powercor's assets in commission
- consideration of various asset health indicators.

We primarily use our predictive modelling to assess approximately 63 per cent of Powercor's proposed repex. For the remaining categories of expenditure, we do not use our predictive modelling but rely instead on the analysis of historical expenditure and business case justifications for those categories.

We note that the assessment of long term trends, the consideration of asset health indicators are also considered as part of our assessment process. Our findings from these assessment techniques are consistent with our overall conclusion.

## Trend analysis

We have used trend analysis to draw general observations from the historic trend analysis in relation to total repex. 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).

## Predictive modelling

Our predictive model, known as the 'repex model', can predict a reasonable amount of repex Powercor 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 Powercor's 'business as usual' asset replacement practices. We explain the calibrated replacement life scenario, along with other input scenarios, further below.

As part of the 'Better Regulation' process we undertook extensive consultation with service providers on the repex model and its inputs.<sup>152</sup> The repex model we developed through this consultation process is well-established and was implemented in a number of revenue determination processes including the recent NSW/ACT and QLD/SA decisions. This assessment technique builds on repex modelling we undertook in previous Victorian and Tasmanian distribution pricing determinations.<sup>153</sup>

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 using

---

<sup>152</sup> AER, *Expenditure Forecast Assessment Guideline - Explanatory statement*, p 1.

<sup>153</sup> We first used the predictive model to inform our assessment of the Victorian distributors' repex proposals in 2010. We undertook extensive consultation on this technique in developing the Expenditure Forecasting Assessment Guideline. We have since used the repex model to inform our assessment of repex proposals for Tasmanian, NSW, ACT, QLD and SA distributors.

that data. The model can also be calibrated using data on Powercor's entire stock of network assets, along with Powercor's recent actual replacement practices, to estimate the repex required to maintain its current risk profile.

We recognise that predictive modelling cannot perfectly predict Powercor'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 F of our preliminary decision. We also note that the service providers (including Powercor) rely on similar predictive modelling to support their forecast amount for repex.<sup>154</sup>

We use predictive modelling to estimate a value of 'business as usual' repex for the modelled expenditure categories to assist in our assessment.

Any material difference from the 'business as usual' estimate could be explained by evidence of a non-age related increase in asset risk in the network (such as a change in jurisdictional safety or environmental legislation) or evidence of significant asset degradation that could not be explained by asset age. We use our qualitative techniques to assess whether there is any such evidence. In this way, we consider that the repex model serves as a 'first pass' test, as set out in our Expenditure Guideline.<sup>155</sup>

We recognise there are reasons why some assets may be better assessed outside of the repex model. Where we considered it was justified, we separately assessed expenditure for such assets outside the model using techniques other than predictive modelling.

## Network health indicators

We have used a number of asset health indicators with a view to observing asset health. Asset utilisation is one such indicator. We have had regard to changes in asset utilisation to provide an indication as to whether Powercor's assets are likely to deteriorate more or less than would be expected given the age of its assets. Asset utilisation in some circumstances is a useful check on the outcomes of our predictive modelling in that unlike the other indicators, and the predictive modelling itself, it is not age based.

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

---

<sup>154</sup> Powercor, *Revised regulatory proposal*, May 2016, p 114.

<sup>155</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

have provided context for our decision and the findings are consistent with our overall conclusion.

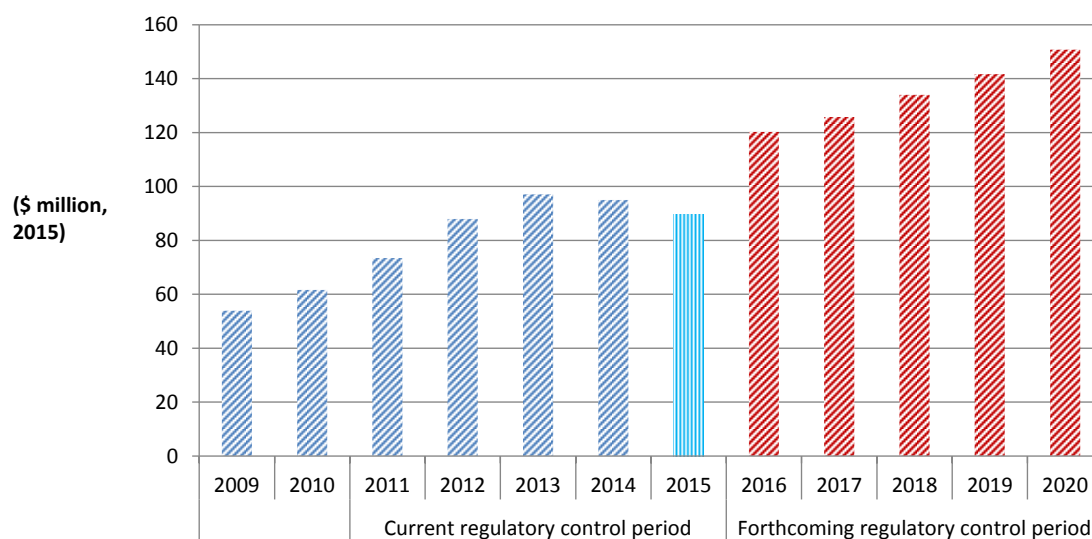
Similar to trend analysis, our use of these high level indicators has been to inform the relative efficiency of Powercor's previous repex. However, we have not used this analysis in rejecting Powercor's proposal and in developing our alternative estimate. We used this analysis as a cross-check with the findings of other techniques.

#### 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. Our use of trend analysis is to gauge how Powercor's historical actual repex compares to its expected repex for the 2016–20 regulatory control period. Figure 6.10 shows Powercor's repex spend has been trending up with the exception of 2014 and 2015.

**Figure 6.10 Powercor - Actual and revised forecast repex (\$ million, 2015)**



Source: PAL PUBLIC RRP MOD 1.18 PAL Capex Consolidation - RPP Base Capex, PAL PUBLIC RIN 1.19 Powercor, 2009-2013 Category Analysis RIN and PAL PUBLIC RIN 1.20 Powercor, 2014 Category Analysis RIN, Powercor, *Revised regulatory proposal*, January 2016.

Note: Powercor's forecast repex includes forecast VBRC repex.

When considering the above trend we acknowledge there are limitations in long term year on year comparisons of replacement expenditure. In particular we are mindful that during the 2011–15 regulatory control period, Powercor expects to overspend its

regulatory allowance for replacements by one per cent.<sup>156</sup> Powercor in its initial proposal noted this expenditure reflects a range of competing factors:

- a higher volume and expenditure on pole replacements undertaken during the period as a result of the higher volume of defects identified by the asset inspection regime than originally forecast
- a higher volume and expenditure on cross-arm replacements undertaken during the period as a result of the higher defect volumes identified by the asset inspection regime than originally forecast
- a lower than anticipated volume and expenditure on the proactive overhead conductor replacement works program, as a result of the program being paused due to the uncertainty surrounding the Powerline Bushfire Safety Taskforce's (PBST) requirements for the undergrounding of assets; and
- an unanticipated obligation to install new generation electronic ACRs to SWER lines.

An increasing or decreasing trend does not, in and of itself, indicate that a service provider has proposed repex that is likely to reflect or not reflect the capex criteria. In the case of Powercor, which has proposed an increase in repex from the last regulatory control period, we must consider whether it has sufficiently justified that this increase is required to reflect the capex criteria. We use our predictive modelling, the views of stakeholders, the material put forward by Powercor in support of its revised forecast, and our consideration of any repex required to meet the new safety obligations arising from the recommendations of the VBRC, to help us form a view on whether Powercor has sufficiently justified its increase in repex from the last period.

The CCP was concerned that the amount of repex sought in the revised proposals was only marginally lower than that initially sought. The CCP noted actual repex in the 2011–15 period was far greater than the previous 2006–10 period. It considered longer term trends in repex show that historic, lower, levels of repex maintained the Victorian distributor's reliability levels. CCP questioned why higher levels of repex are required now to provide the same level of reliability sought by consumers.<sup>157</sup> The Victorian Energy Consumer and User Alliance (VECUA) also submitted it was concerned with repex increasing significantly from the 2006–10 period to now.<sup>158</sup> Although repex is to some extent predictable it can be lumpy depending on the age of the distributor's population of assets. Our repex forecast takes into account the age profile of the network assets. As such, increases in forecast repex that may not be in line with historical trend analysis may reflect CitiPower's aging assets.

---

<sup>156</sup> Powercor, *Regulatory Proposal 2016–2020, Appendix E: Capital Expenditure*, April 2015, p. 45.

<sup>157</sup> CCP3, *Report on AER Preliminary Decisions and DNSPs' Revised Proposals*, February 2016, pp. 19–20.

<sup>158</sup> VECUA, *Submission on AER preliminary decision VIC EDPR 2016-2020*, January 2016, pp. 38–40.

## Predictive modelling

We use predictive modelling to estimate how much repex Powercor is expected to need in future, given how old its current assets are, and based on when it is likely to replace the assets. We modelled six asset groups using the repex model. These were poles, overhead conductors, underground cables, service lines, transformers and switchgear. To ensure comparability across different service providers, these asset groups have also been split into various asset sub categories. SCADA and network protection assets were not modelled, nor were the specialised categories of capex defined by Powercor that were not classified under the eight asset groups identified above. These asset categories have not generally been considered suitable for repex modelling either because of lack of commonality, or because we did not possess sufficient data to include them in the model (see appendix E of the preliminary determination). In total, the assets modelled represent 63 per cent of Powercor's proposed repex. Our predictive modelling calculation process is described at appendix F of the preliminary determination.

We consider the best estimate of business as usual repex is provided by using calibrated asset replacement lives and unit costs derived from Powercor's recent forecast expenditure. This estimate uses Powercor's own unit costs, but it effectively 'calibrates' the proposed forecast replacement volumes to reflect a volume of replacement that is consistent with Powercor's recent observed replacement practices, rather than relying on a purely aged based indicator.

In total for all six modelled categories we included an amount of \$375 million in our alternative estimate of total forecast capex, compared to Powercor's forecast of \$452 million for these categories, excluding overheads. This is consistent with the forecast provided for in our preliminary decision.

We have had regard to Powercor's revised proposal and whether it is appropriate to forecast repex on the basis of a business as usual estimate, or whether Powercor has provided sufficient evidence to suggest that its replacement needs are beyond business as usual requirements in the next period.

As noted above, Powercor has accepted the majority of our predictive model findings from our preliminary decision, with the exception being a proactive conductor replacement program and the findings from one subcategory of switchgear (HV fuses and surge diverters).

We outline our assessment of these aspects of the revised proposal below.

### ***Business as usual repex—proactive conductor replacement***

Powercor engaged Jacobs to review this business case program as well as our preliminary determination.<sup>159</sup> Jacobs reviewed the program in the context that it is required to mitigate risks associated with:

- a rapid increase in failure rate due to the age profile of the network and condition<sup>160</sup>
- failing to fulfil its regulatory and legal obligations under the National Electricity Rules, Victorian Electricity Distribution Code and regulations both from a network security and from a network safety perspective.<sup>161</sup>

In its review, Jacobs considers the program is prudent and reflects the most efficient option on an NPV basis.<sup>162</sup> Jacobs' findings were based on Powercor's supporting materials. Jacobs did not undertake its own independent modelling or assessment of Powercor's assumptions.<sup>163</sup> Further, Jacobs considered that there is a material discrepancy between our preliminary decision for Powercor compared with that made for AusNet Services.

We have assessed this program and are of the view that there is not sufficient evidence indicating that conductor failure rates have or are likely to increase due to non-age related factors. Powercor has projected conductor failures to increase per annum on the basis of asset age.<sup>164</sup> We accept that failures per annum are likely to increase given the age profile of these assets, where an increasing number of assets will approach the end of their economic life. The calibrated replacement lives of the repex model, which are based on actual replacement practices and Powercor's asset age profile, reflect the factors Powercor considers in determining when it replaces these assets. Consequently, the use of calibrated replacement lives trends forward Powercor's recent asset replacement practices, including any proactive replacement practices.

In its initial proposal, Powercor sought \$74 million for overhead conductor replacement. However, Powercor in its revised proposal removed the replacement of overhead conductor that is anticipated to be subject to new regulatory obligations relating to bushfire safety risk, which significantly reduced its repex forecast for this category.

We consider that Powercor has not sufficiently established a need for overhead conductor repex above the business as usual estimate. In particular, we consider that Powercor has not established that there is likely to be increased conductor failures that are non-age related in the non-bushfire safety areas and therefore whether the safety risk of these assets has increased.

---

<sup>159</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, December 2015.

<sup>160</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, December 2015 p. 4.

<sup>161</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, December 2015 p. 5.

<sup>162</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, December 2015 p. 4.

<sup>163</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, pp. 4–5.

<sup>164</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 192.



Powercor submitted that the additional repex it has sought for the proactive replacement program will avoid additional resource costs associated with earlier replacement on the basis that there is a 'bow wave' of future replacements.<sup>165</sup> However, Powercor has not provided sufficient analysis that demonstrates that it is more cost effective to bring forward these asset replacements. We acknowledge that over future regulatory periods an increasing volume of Powercor's overhead conductor assets will approach the end of their economic life. However, the proposed proactive program brings forward around 15 years of works without sufficient cost-benefit analysis taking into account the cost of bringing forward that repex. Further, we do not consider that Powercor has demonstrated the net benefit to consumers of proactively replacing these overhead conductor assets over and above replacement based on its current practices which allows for an increase which is reflective of age based factors.

Powercor submitted that because it paused its proactive conductor replacement program in 2011, that a business as usual repex forecast is not sufficient as it does not reflect the program.<sup>166</sup> While we do not agree that the proactive replacement program is sufficiently justified, we note that given Powercor recommenced its proactive replacement of conductors in 2014 our predictive modelling outcomes are influenced by these recent proactive replacement practices. That is, we note our preliminary decision which reflects Powercor's business as usual asset replacement practices already includes some replacement volumes due to the proactive replacement of conductors.

Powercor noted some of the calibrated replacement lives in our repex model for overhead conductor categories were older than any currently installed assets.<sup>167</sup> The calibrated replacement lives are a representation of Powercor's trends in replacement. For example, Powercor replaced a low volume of these assets in recent years despite those assets being old. This suggests those assets can last longer before replacement.

Powercor also submitted that it proposed a lower amount of repex than AusNet Services for overhead conductor replacement. It questioned why we approved AusNet Services' proposed repex and estimated a lower amount for Powercor, especially considering that Powercor has almost twice the distance of overhead conductor on its network compared to AusNet Services.<sup>168</sup> Powercor submitted that in our preliminary decision we accepted AusNet Services' conductor replacement program which included proactive and reactive elements, and so our predictive modelling captured this expenditure as part of its business as usual replacements.<sup>169</sup> However, we note that AusNet Services' Bushfire Mitigation Plan approved by the ESV is a regulatory obligation to replace overhead conductors and we note that Powercor does not have a similar regulatory obligation for conductor replacement separate to the Victorian Governments impending regulatory requirements in codified bushfire areas.

---

<sup>165</sup> Jacobs, *Powercor Repex other support, repex-other proactive re-conditioning*, December 2015, p. 16.

<sup>166</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 190.

<sup>167</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 193.

<sup>168</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 191.

<sup>169</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 195.

### *Switchgear category modelling*

Powercor submitted that we made an error in the preliminary decision in the repex modelling for the switchgear category HV fuses and surge diverters.<sup>170</sup> It particular, Powercor considered that we used volumes for the period from 2009 to 2013 for HV fuses and surge diverters but included volumes for 2014 for all other replacement categories assessed using the repex model.<sup>171</sup> It submitted this was inconsistent with the repex model handbook, and meant forecast expenditure for switchgear was understated. Powercor submitted a supporting repex model with its revised proposal correcting the error.<sup>172</sup>

Powercor proposed \$76 million of repex for switchgear in its initial proposal. In our preliminary determination we forecast \$53 million for the modelled switchgear group. Powercor accepted our preliminary decision which included the \$53 million for switchgear, but proposed that the error in a single category should result in an increase to the forecast of \$62 million for switchgear. It also noted its historic repex for switchgear was \$67 million, which was above what is now being forecast.<sup>173</sup>

We have reviewed our modelling and do not consider that our calibration process was in error for this category. It appears that in replicating the calibration process, Powercor did not apply the second calibration set out in the repex model handbook which takes into account a growth factor.<sup>174</sup>

We performed the calibration steps set out in the handbook again for this category. For the first calibration we use a calibration volume based on five years of Powercor's data provided, including the 2014 year it considered we excluded. The second calibration step then involves adjusting the calibration volume to allow for the trend in replacement volumes seen in the forecast, then determining a new calibrated mean. Performing the first calibration replicated the mean life Powercor submitted as a correction with its revised proposal. Then, performing the second calibration resulted in the mean life utilised in our preliminary decision.<sup>175</sup>

This approach is consistent with our modelling for all other categories in the preliminary decision and is consistent with the repex model handbook developed during our

---

<sup>170</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 191–192.

<sup>171</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 191–192.

<sup>172</sup> Powercor, *Revised regulatory proposal*, January 2016, pp. 191–192.

<sup>173</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 192; PAL PUBLIC RRP MOD 1.53 PAL Repex Output with Switchgear adjustment and Proactive Conductor in Repex Other

<sup>174</sup> The first calibration step uses a calibration volume based on five years of recent replacement volumes to calculate calibrated replacement lives. From applying these lives in the model, a second calibration is performed to allow for any trend in replacement volumes observed through the forecast—a 'growth factor'. The model determines the annual percentage increase in the forecast volumes seen from using the first calibrated lives in the model. Then we apply this to determine new calibration volumes, and re-adjust the calibrated asset lives so the replacement volumes in the first year of the forecast period reflect this growth. AER repex model handbook, pp. 20–21.

<sup>175</sup> The adjusted calibration volume was similar to the sum of four years of Powercor's data. However, this is coincidental and simply a result of applying the growth factor step as set out in the repex model handbook.



consultation process on the expenditure assessment guideline. We verified that we applied the calibration process as set out in the repex model handbook using the two step calibration process consistently to all the modelled categories. Powercor accepted our application of this calibration process for all other modelled categories, so we do not see a reason to depart from it for this category. Therefore we have included an amount for this category in our repex forecast which is the same as our preliminary decision of \$29 million rather than the \$38 million in Powercor's revised proposal.

## Un-modelled repex

In our preliminary decision we did not include the following asset categories in our repex modelling:

- supervisory control and data acquisition (SCADA), network control and protection (collectively referred to as SCADA)
- pole top structures; and
- assets identified in the "other" category.

These categories of assets account for around 37per cent of Powercor's' initial and revised regulatory proposals. These asset categories have not generally been considered suitable for repex modelling either because of lack of commonality, or because we did not possess sufficient data to include them in the model (see appendix E of our preliminary determination).

The Victorian Government considered there was limited assessment of the distributor's proposed expenditure on SCADA systems, noting that where forecast repex was lower than historic that we had accepted the forecast. It considered this approach may incentivise distributors' to achieve a more consistent level of spending, rather than incur lumpy expenditure that would be expected for these expenditure categories.<sup>176</sup> VECUA considered we had not justified our decision to on repex forecasts for un-modelled repex categories on the basis of the distributors' 2011–15 historic repex.<sup>177</sup>

We recognise there will be period-on-period changes to repex requirements that reflect the lumpiness of the installation of assets in the past. Using predictive tools such as the repex model allows us to take this lumpiness into account in our assessment. For repex categories we do not model, historical expenditure is one of our key high level indicators of the prudence and efficiency of the proposed expenditure. Where appropriate, we also look at individual items in more detail by reviewing business and engineering cases, such as where significant departures from trend are apparent. In the case of pole top structures, SCADA and other repex, there were no indications that this was a concern. Also, where past expenditure was sufficient to meet the capex

---

<sup>176</sup> Victorian Government, *submission on preliminary decision*, January 2016, p. 6.

<sup>177</sup> VECUA, *Submission on AER preliminary decision VIC EDPR 2016-2020*, January 2016, p. 45.

criteria, we are satisfied that it can be a reasonable indicator of whether forecast repex is likely to reflect the capex criteria.<sup>178</sup>

Powercor accepted our preliminary decision for pole top structures, SCADA and other repex. For the reasons set out in our preliminary decision, we accepted Powercor's proposed amount for pole top structures, SCADA and other repex.<sup>179</sup>

- For pole top structures we were not satisfied that AusNet Services' forecast repex for pole top structures reasonably reflected the capex criteria and included this amount in our alternative estimate of total forecast capex. We noted that Powercor's proposed expenditure is significantly higher than its historical expenditure. Given the significant increase in expenditure proposed by Powercor, we carried out a limited set of calibrated repex model scenarios to test whether they would support Powercor's proposal. The outcomes of the calibrated repex model did not support Powercor's proposed expenditure. We considered Powercor's historical expenditure reasonably reflects the capex criteria and included this in our alternative estimate of total forecast capex.
- For SCADA we were satisfied that Powercor's forecast SCADA repex reasonably reflected the capex criteria and included this amount in our alternative estimate of total forecast capex on the basis that this was consistent with past levels of expenditure.
- For 'other' repex excluding the VBRC related repex, we noted that Powercor's forecast for repex on other assets in the 2016–20 regulatory control period is slightly lower than what it spent on these categories in the 2011–15 regulatory control period. On this basis we were satisfied that Powercor's forecast repex for other assets of \$49 million (when excluding VBRC repex) reasonably reflected the capex criteria and included this amount in our alternative estimate of total forecast capex. In addition, in our preliminary decision we accepted Powercor's proposal to replace a volume of its SWER lines in response to jurisdictional safety obligations arising in response to the recommendations of the VBRC (\$56 million). Given this, we accepted Powercor's forecast for this category of repex reasonably reflects the capex criteria (including the VBRC related costs).

## Network health indicators

As noted above in our preliminary decision, we have looked at network health indicators and benchmarks to form high level observations about whether Powercor's past replacement practices have allowed it to meet the capex objectives. While this has not been used directly either to reject Powercor's repex proposal, or in arriving at an alternative estimate, the findings are consistent with our overall findings on repex. In summary we observed that:

---

<sup>178</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.

<sup>179</sup> AER, *Preliminary decision, Powercor distribution determination 2016 to 2020, Attachment 6: Capital expenditure*, October 2015, pp. 6-106–6-107

- the measures of reliability and asset failures show that outages on Powercor's network have been trending downwards
- measures of Powercor's network assets residual service lives and age show that the overall age of the network is generally reducing. This also suggests that historical replacement expenditures have at least been sufficient to meet the capex objectives
- asset utilisation has reduced in recent years which means assets are more lightly loaded, this is likely to have a positive impact on overall asset condition.

Further, the value of customer reliability has recently fallen in Victoria.<sup>180</sup> Other things being equal, this fall should result in the deferral of repex as the value customers place on reliability for replacement projects has fallen.

The above indicators generally suggest that replacement expenditure in the past period has been sufficient to allow Powercor to meet the capex objectives. This is consistent with our overall findings on repex from our other assessment techniques. The asset health indicators are discussed in more detail in our preliminary determination.<sup>181</sup>

---

<sup>180</sup> AEMO, *Value of Customer Reliability Review - Final Report*, September 2014

<sup>181</sup> AER, *Preliminary decision, Powercor distribution determination 2016 to 2020, Attachment 6: Capital expenditure*, October 2015, pp. 6-107-111.

## B.5 Forecast capitalised overheads

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

### B.5.1 Position

We do not accept do not accept Powercor's proposed capitalised overheads. We instead included in our alternative estimate of overall total capex an amount of \$195.3 million (\$2015) for capitalised overheads. This is 1.5 per cent lower than Powercor's proposal of \$198.2 million (\$2015).<sup>182</sup> We are satisfied that this amount reasonably reflects the capex criteria.

### B.5.2 Our assessment

Our adjustment to Powercor's overheads use the approach from our preliminary decision.

We consider that reductions in Powercor's forecast expenditure should see some reduction in the size of its total overheads. Our assessment of Powercor's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in Powercor's regulatory proposal. It follows that we would expect some reduction in the size of Powercor'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.

As we noted in our preliminary decision, our assessment in the Queensland distribution determinations found Energex's overheads comprised 75 per cent fixed and 25 per cent variable components.<sup>183</sup> We considered this split of fixed and variable overheads components was also reasonable for Powercor. We invited Powercor to provide a more appropriate split, with evidence, in its revised regulatory proposal if it did not consider this split is reasonable for its circumstance.<sup>184</sup>

Powercor did not comment on this split in its revised proposal.<sup>185</sup> It also used the method in our preliminary decision when calculating the overheads component of its capex forecast, including the 75 per cent fixed to 25 per cent variable split.<sup>186</sup>

---

<sup>182</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016, p. 186.

<sup>183</sup> AER, *Preliminary decision: Powercor distribution determination 2016–20: Attachment 6 – Capital expenditure*, October 2015, p. 128.

<sup>184</sup> AER, *Preliminary decision: Powercor distribution determination 2016–20: Attachment 6 – Capital expenditure*, October 2015, p. 128.

<sup>185</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016.

Origin agreed that reductions in forecast expenditure should see a reduction in the size of both the total overheads and the level of capitalised overheads.<sup>187</sup> On the other hand, Origin also considered the proposed overheads required further examination.<sup>188</sup> Similarly, VECUA did not agree with the preliminary decisions' method of adjusting overheads on the basis of the distributor's capex forecast. Rather, VECUA recommended we determine efficient capitalised overheads based on benchmark efficient costs.<sup>189</sup>

We undertook a detailed investigation on the relationship between overheads and capex during the NSW and ACT distribution determinations. We accepted that a portion of overheads are relatively fixed in the short term and so does not vary with the level of expenditure. Our analysis also suggested a portion of overheads should vary in relation to the size of the expenditure. Due to data and other issues, however, we considered our proposed method was not sufficiently robust to enable a mechanistic adjustment to a distributor's capitalised overheads.<sup>190</sup> Without evidence to the contrary, we consider our assessment approach from the Queensland distribution determinations results in capitalised overheads that reasonable reflect the capex criteria. We look to refining our approach to assessing overheads as an on-going process.

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. It 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 Powercor's proposal, which is based on their CAM. As such, Powercor's forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of Powercor'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.

---

<sup>186</sup> Powercor, *Revised regulatory proposal: Standard control - MOD 1.18 PAL capex consolidation*, January 2016, worksheet 'Oheads-Capcons-Esc'.

<sup>187</sup> Origin, *Submission to AER preliminary decision Victorian networks*, 6 January 2016, p. 2.

<sup>188</sup> Origin, *Submission: Victorian networks revised proposals*, 4 February 2016, p. 1.

<sup>189</sup> VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, pp. 4, 55–56.

<sup>190</sup> AER, *Final decision: Ausgrid distribution determination 2015–16 to 2018–19: Attachment 6 – Capital expenditure*, April 2015, pp. 83–84; AER, *Final decision: Essential Energy distribution determination 2015–16 to 2018–19: Attachment 6 – Capital expenditure*, April 2015, pp. 90–91; AER, *Final decision: Endeavour Energy distribution determination 2015–16 to 2018–19: Attachment 6 – Capital expenditure*, April 2015, pp. 61–62; AER, *Final decision: ActewAGL distribution determination 2015–16 to 2018–19: Attachment 6 – Capital expenditure*, April 2015, pp. 73–74.

As a result of a \$99.9 million (\$2015), or six per cent, reduction in Powercor's direct capex that attract overheads, we consider a reduction of \$2.9 million (\$2015) reasonably reflect the capex criteria.

## B.6 Forecast non-network capex

Non-network capex for Powercor includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment. Powercor's revised proposal includes forecast non-network capex of \$248.0 million (\$2015). This is a decrease of \$14.1 million from Powercor's initial proposal of \$262.1 million, and an increase of \$21.6 million from our preliminary decision for non-network capex of \$226.4 million.<sup>191</sup>

### B.6.1 Position

We accept Powercor's revised proposal for non-network capex. We have included an amount of \$248.0 million (\$2015) for forecast non-network capex in our capex estimate. As discussed below, we are satisfied that Powercor's revised forecast non-network ICT capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives.<sup>192</sup>

In coming to this view:

- we are satisfied that Powercor's forecast ICT capex for the Power of Choice related projects reasonably reflects the prudent and efficient costs required to meet the relevant regulatory obligations.
- we are satisfied that Powercor's forecast ICT capex for RIN reporting compliance reasonably reflects an efficient capex to opex trade-off which minimises the total cost to customers of achieving compliance with RIN reporting requirements.
- we are satisfied that Powercor's forecast capex for the motor vehicles, buildings and property, and plant and equipment categories of non-network capex, consistent with our preliminary decision, reasonably reflect the efficient costs of a prudent operator.

### B.6.2 Revised proposal

In its revised proposal, Powercor accepted our preliminary decision on forecast non-network capex for motor vehicles, buildings and property, and tools and equipment. However, Powercor sought additional ICT capex of \$8.2 million (\$2015) to comply with the AEMC's rule changes relating to the Power of Choice review, and \$5.3 million (\$2015) for system upgrades to meet RIN reporting obligations.<sup>193</sup> These two elements of non-network ICT capex are discussed in turn below.

---

<sup>191</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016, p. 186.

<sup>192</sup> NER, cl. 6.5.7(c).

<sup>193</sup> Powercor, *RIN reporting compliance*, December 2015, p. 22. Powercor, *PAL PUBLIC RRP ATT 8.7 - CitiPower and Powercor, Metering contestability - pre-gate approval.docx*, December 2015, p. 3.

### B.6.3 Information and communications technology capex

We accept Powercor's revised proposal for ICT capex. We have included an amount of \$160.3 million (\$2105) for forecast ICT capex. This includes amounts for Power of Choice projects (\$8.2 million), RIN reporting compliance (\$5.3 million) and the ICT projects that Powercor proposed in its initial proposal (\$142.4 million).

In its revised proposal, Powercor accepted the 10 per cent reduction that we had applied across its entire initial proposal ICT forecast, but submitted that it should not apply to the 'smarter networks' and 'customer relationship management' and 'billing system' projects because we had found these costs to be prudent and efficient.<sup>194</sup> We accept this submission and have included the amount Powercor proposed in its revised proposal for these ICT projects, excluding those amounts proposed for Power of Choice and RIN reporting compliance.

We received a submission on ICT capex from the Consumer Challenge Panel. The CCP submitted that it is concerned about the high level of ICT capex being sought by all the Victorian distributors. It noted that all distributors are forecasting non-network capex well above the long term averages of the 2001–2010 period.<sup>195</sup> We note the CCP's general concern about the high levels of ICT capex proposed but take the view that the historic spending from 2001–2010 is not necessarily the best guide to the prudent and efficient level of ICT spending for the current regulatory period. In our assessment, we recognise that ICT expenditure is typically lumpy and its timing is dependent on necessary system upgrades, technology obsolescence, as well as other requirements such as new regulatory obligations.

The CCP also reiterated its concerns with Powercor's proposed new customer relationship management and billing system, capex for which we included in our preliminary decision. The CCP submitted that it is concerned that this project may not deliver economic benefits within the current regulatory control period.<sup>196</sup> However, following our assessment, we still consider it appropriate to include these new systems in the capex program because Powercor's existing systems require upgrade and the proposed expenditure is prudent and efficient.

### Power of Choice projects

Powercor did not include ICT capex for changes due to the AEMC's Power of Choice reforms in its initial proposal. In its revised proposal, Powercor, together with CitiPower, proposed \$16.3 million (\$2015) for Power of Choice changes on the basis

---

<sup>194</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016, p. 224.

<sup>195</sup> Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, p. 61.

<sup>196</sup> Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, pp. 63–64.



that the AEMC had finalised its rule change on metering contestability since its initial proposal was submitted.<sup>197</sup> Powercor and CitiPower share ICT systems and the capex for these changes is allocated evenly between the two distributors. We have assessed Powercor's proposed forecast of \$8.2 million for additional ICT capex and have included it in our capex estimate.

Since 2014 the AEMC has made several rule changes relating to its Power of Choice review, including in November 2015 making rules for the introduction of metering contestability. These various rule changes give rise to new regulatory obligations for distributors. Following assessment of the various proposed projects, we accept that it is likely that there will be some cost involved in complying with these rule changes. Under the capital expenditure objectives, we must allow sufficient capex to enable a distributor to comply with regulatory obligations or requirements.<sup>198</sup>

The CCP submitted that it was not convinced that there is a need to increase ICT costs to accommodate the Power of Choice rule changes, noting that the AEMC did not explicitly identify any costs that it expected to be incurred as a result of the changes.<sup>199</sup> However, following our assessment, we are satisfied the distributors have clearly demonstrated that they will need to modify their ICT systems to address the changes. We note the CCP is concerned also by the difference in costs proposed by each distributor in relation to the Power of Choice rule changes. We address these differences in our assessment below.<sup>200</sup>

### **Assessment approach**

In assessing Powercor's Power of Choice program, we have examined the proposed projects and identified which of these are in response to regulatory obligations.

We evaluated the projects proposed by each distributor as set out in its proposal. Where a distributor's project costs were not fully supported by a detailed business case with sufficiently supported cost estimation, we also sought further information from the distributor in relation to how the capex forecast was derived. We recognise that the Victorian distributors for the most part have not been able to provide detailed assessment of the capex required or completed a detailed business case for these projects. This is understandable given that these rule changes are recent and there is still time to complete more detailed project plans before implementation is required.

As part of our assessment, we also had regard to information provided by all of the Victorian distributors given that each must meet the same regulatory obligations and

---

<sup>197</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016, pp. 225–226.

<sup>198</sup> NER, cl. 6.5.7(a)(2).

<sup>199</sup> Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, p. 63.

<sup>200</sup> Consumer Challenge Panel CCP3, *Response to the AER Preliminary Decisions and revised proposed for Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period*, 25 February 2016, p. 63.

are subject to the same operating environment. The fact that the obligations and the operating environment apply to all the Victorian distributors allows for a degree of comparability in assessing proposed costs. Accordingly, where the distributor's justification for forecast costs did not justify the capex proposed, we considered the distributor's proposed capex compared to what other Victorian distributors proposed to address that particular regulatory obligation. We then examined the distributor's proposal in order to assess any factors that might explain the need for different capex requirements.

### ***Powercor's Power of Choice program***

In its revised proposal, Powercor proposed \$8.2 million for the ICT capex costs of Power of Choice changes. Powercor proposed this ICT capex to address the AEMC's metering contestability rule change.<sup>201</sup> Within its metering contestability project, Powercor included \$1 million of expenditure to address the obligations resulting from the AEMC's shared market protocol (SMP) advice.<sup>202</sup> The metering contestability rule change will introduce competition in metering and facilitate a market led deployment of advanced (smart) meters. The SMP will provide a standard form of communication for energy companies seeking access to services enabled by advanced meters.

The AEMC made its rule change for metering contestability in November 2015.<sup>203</sup> This rule change places new regulatory obligations on Powercor that justify the inclusion of additional ICT capex.

For SMP, the AEMC has released a final advice, but the final form of those changes is not entirely known because the form of the implementation of SMP has not yet been decided.<sup>204</sup> However, the changes have the same implementation date as metering contestability (1 December 2017) and Powercor submitted that they are inextricably linked to the metering contestability changes and that implementing them together will provide efficiencies.<sup>205</sup> Given SMP is closely linked to the metering requirements, Powercor will need to meet these regulatory obligations.

Having accepted that the metering contestability and SMP place new regulatory obligations upon Powercor, we considered whether Powercor's forecasts for these projects are the efficient costs that a prudent operator would incur. In its revised proposal, Powercor provided a report from Accenture Strategy detailing the required process and system changes in response to the Power of Choice reforms and

---

<sup>201</sup> Powercor, *Revised regulatory proposal 2016–2020*, January 2016, p. 226.

<sup>202</sup> Powercor, *AER information request - CitiPower - #036 and Powercor #041 - IT capex for Power of Choice*, 19 February 2016, p. 1.

<sup>203</sup> *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12*.

<sup>204</sup> AEMC, *Final advice: Implementation advice on the shared market protocol*, 8 October 2015. AEMC, *Consultation paper: National Electricity Amendment (Updating the electricity B2B framework) Rule 2015*, 17 December 2015.

<sup>205</sup> Powercor, *AER information request - CitiPower - #036 and Powercor #041 - IT capex for Power of Choice*, 19 February 2016, p. 1. Powercor, *AER information request - CitiPower - #041 and Powercor #045 - IT capex for Power of Choice*, 4 March 2016, pp. 1-2.

estimating the required labour to implement the process and system changes.<sup>206</sup> In response to our request for further details on costings, Powercor provided a further breakdown into labour, materials and project management costs.<sup>207</sup>

In assessing Powercor's forecast costs, we compared its forecasts to those of the other Victorian distributors for projects to meet the same regulatory obligations. The combined cost of Powercor/CitiPower were in line with those of Jemena and United Energy, with AusNet Services forecasting significantly higher costs, as can be seen in Table 6.17. The Powercor/CitiPower costs were the lowest estimates proposed.

**Table 6.17 Range of forecast costs for Power of Choice projects**

Project	CitiPower/Powercor <sup>a</sup>	AusNet Services	Jemena	United Energy
Metering competition	\$14.25 million	\$27.80 million	\$17.50 million	\$14.29 million
SMP	\$2.08 million	\$6.57 million	\$2.89 million	\$3.69 million

Source: AER analysis.

a. CitiPower and Powercor have joint ICT systems and have proposed a joint program for Power of Choice. This program is allocated 50/50 to each distributor.

Excluding AusNet Services' higher estimates, which we found to be unsupported, Powercor's proposed estimate was comparable to the other distributors' estimates where they proposed capex for a comparable project to address the same regulatory obligation.<sup>208</sup>

We have had regard to the circumstances of the other Victorian distributors which are subject to a similar operating environment (e.g. all of the Victorian distributors have similar metering arrangements and business process obligations). Further, from the information provided by Powercor, we have assessed that the majority of Powercor/CitiPower's costs are capitalised labour costs to amend existing systems and processes. This is similar to the nature of the costs that the other Victorian distributors expect to incur. This provides for a degree of comparability for assessing the proposals submitted by all of the Victorian distributors.

On the basis of the information available to us, we consider that Powercor's forecast capex for this project reasonably reflects the efficient costs that a prudent operator would incur. Therefore, we have included this amount in our alternative capex forecast.

<sup>206</sup> Accenture Strategy on behalf of CitiPower and Powercor, *Metering Contestability - Process and System Impacts*, October 2015.

<sup>207</sup> Powercor, *AER information request - CitiPower - #036 and Powercor #041 - IT capex for Power of Choice*, 19 February 2016. Powercor, *AER information request - CitiPower - #041 and Powercor #045 - IT capex for Power of Choice*, 4 March 2016.

<sup>208</sup> All the Victorian distributors proposed comparable projects for metering contestability and SMP/B2B projects; all distributors, excepting Powercor/CitiPower, proposed comparable projects for network pricing arrangements.

## RIN reporting compliance

In our preliminary decision, we acknowledged that RIN compliance is a new regulatory obligation that may give rise to additional compliance costs. However, on the basis of the information provided by Powercor, we were not satisfied that the magnitude of Powercor's proposed capex for RIN compliance costs of \$19.5 million (\$2015) was prudent and efficient.<sup>209</sup>

In its revised proposal, Powercor proposed an alternative RIN compliance solution involving a mix of both capex and opex. Powercor proposed total RIN compliance costs of \$7.8 million (\$2015), comprising capex of \$5.3 million for ICT system changes, together with an opex step change of \$2.5 million.<sup>210</sup> Powercor's forecast RIN compliance costs represent 50 per cent of total RIN compliance costs for the combined CitiPower/Powercor project, allocated equally across both businesses. On a total project basis, the revised RIN compliance costs (capex and opex) for CitiPower/Powercor of \$15.5 million (\$2015) reflect a reduction of \$12.3 million or 44 per cent from the initial proposal.

Origin Energy submitted that it does not support the inclusion of expenditure for system upgrades associated with regulatory reporting obligations. Origin Energy recognised that the businesses may incur some costs to enhance systems to map data from existing systems into the RIN format but submitted that these costs would not be material as the majority of information would be captured as a matter of course and the mapping into the AER format would not be onerous.<sup>211</sup>

We reviewed Powercor's proposal in which it identified a number of issues requiring action to achieve compliance, including:<sup>212</sup>

- systems do not capture volume and expense by asset, asset attribute or activity categorisations consistent with RIN requirements
- outage and incident data does not meet RIN reporting requirements
- installed asset information is incomplete
- connection activity and cost is not tracked to individual asset and category level
- metering activity and cost detail reported does not align with RIN reporting requirements.

In our view, these issues reflect both the need to re-map existing data as identified by Origin Energy but also the need for new data acquisition, storage and manipulation processes and capabilities. In our preliminary decision, we acknowledged that RIN

---

<sup>209</sup> AER, *Preliminary decision - Powercor distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, pp. 6-134 to 6-135.

<sup>210</sup> Powercor, *Attachment 1.56 - PAL RIN Compliance Expenditure*, 'Summary of Costs' tab, January 2016. Excludes escalation.

<sup>211</sup> Origin Energy, *Re: Submission to AER Preliminary Decision Victorian Networks*, 6 January 2016, p. 2.

<sup>212</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 12.

compliance, including the requirement to report 'actual' rather than 'estimated' data, is a new regulatory obligation that may give rise to justifiable compliance costs.<sup>213</sup> Each business is starting from a different position regarding its existing systems and data availability. While it is possible that RIN compliance costs may be relatively immaterial for some businesses, in other cases they may be more significant. In assessing the need for any RIN compliance costs, we must be satisfied that they reflect the efficient costs that a prudent operator would require to comply with its regulatory obligations.<sup>214</sup> This will maximise the net benefits of RIN reporting to consumers in terms of enhanced industry efficiency, transparency, governance and data availability.

Powercor submitted a business case and detailed costing model in support of its revised forecast RIN compliance costs.<sup>215</sup> This business case addressed a number of key factors relevant to assessing the prudence and efficiency of a proposed capex project, including:

- a description of the need for investment, with some supporting evidence as to the current state of ICT and business systems and RIN reporting compliance<sup>216</sup>
- evidence that a suitable range of alternative options, including a 'do nothing' option, has been considered<sup>217</sup>
- an analysis of costs and benefits of the preferred option<sup>218</sup>
- evidence that the lowest cost option which meets regulatory requirements has been selected such that the preferred option is economically justified.<sup>219</sup>

Powercor's revised proposal for the RIN compliance project reflects an alternative approach to meeting RIN reporting obligations. Powercor's initial proposal provided for a capex only solution to deliver fully automated RIN reporting with the ability to adapt to changing RIN reporting obligations over time. This option is no longer preferred, as Powercor's understanding of its existing position and needs has developed. The preferred option identified in Powercor's revised proposal provides a reduced level of capex for targeted enhancements to key systems, but with a trade-off for increased operating costs and a reduced ability to adapt to future changes in RIN requirements.<sup>220</sup>

Powercor's business case demonstrates that the total cost of this approach is lower than the alternative options identified, which seek to achieve a fully automated RIN reporting function and the ability to adapt to possible future RIN requirement

---

<sup>213</sup> AER, *Preliminary decision - CitiPower distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, p. 6-135.

<sup>214</sup> NER, cl. 6.5.7(c).

<sup>215</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015; and CitiPower, *Attachment 1.56 - PAL RIN compliance expenditure*, January 2016.

<sup>216</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 6–14.

<sup>217</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 15–16.

<sup>218</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 17–18.

<sup>219</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 18.

<sup>220</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 15–16.

changes.<sup>221</sup> In our view, the mix of capex and opex proposed by Powercor reflects an efficient trade-off between systems investments and manual solutions.<sup>222</sup> This is evident in the 44 per cent reduction in total (capex and opex) costs compared with the initial capex only option. This opex for capex trade-off delivers the overall least cost solution identified by Powercor to achieve the required business outcomes.

We note that, in part, the reduction in Powercor's forecast RIN compliance costs also arises from focussing on delivering existing RIN reporting obligations rather than the capacity to adapt to future RIN requirement changes.<sup>223</sup> We agree that it is prudent for Powercor to seek to comply with applicable regulatory obligations, rather than unspecified possible future obligations which may or may not arise.<sup>224</sup>

In assessing Powercor's revised proposal, we have also considered the proposed RIN compliance costs in the context of similar costs proposed by other distributors. While we recognise that each business is starting from a different position regarding its existing systems, processes and data availability, we would expect some consistency in the magnitude of costs required by services providers in similar circumstances. In our view, Powercor is likely to be in similar circumstances as SA Power Networks in terms of the capability of its existing systems and processes to gather, store and report the required RIN data. This is because Powercor and SA Power Networks share common ownership and some key ICT systems, and are at similar stages in their ICT investment lifecycles.<sup>225</sup> In our recent final decision for SA Power Networks, following a review of prudent and efficient RIN reporting costs by our ICT consultant Nous Group, we made allowance for total RIN compliance costs of \$15.0 million (\$2014–15).<sup>226</sup> The combined total capex and opex costs for Powercor and CitiPower of \$15.8 million (\$2015) are therefore approximately equivalent to the prudent and efficient level of costs for RIN compliance included in our final regulatory determination for SA Power Networks.

In their initial proposals, CitiPower and Powercor proposed an allocation of combined RIN compliance costs of 30 per cent to CitiPower and 70 per cent to Powercor, based on relative customer numbers. In their revised proposals, CitiPower and Powercor allocated the forecast RIN compliance costs equally to each business. We sought further information to justify this allocation of costs.<sup>227</sup> Powercor advised that it amended the cost allocation approach to reflect its revised solution to achieving RIN compliance as the capex component of the revised solution involves system changes

---

<sup>221</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 18.

<sup>222</sup> NER, cl. 6.5.7(e)(7).

<sup>223</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 16.

<sup>224</sup> NER, cl. 6.5.7(a)(2).

<sup>225</sup> Refer to Powercor, *Regulatory proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, pp. 142–143 and SA Power Networks, *Regulatory proposal 2015–20*, November 2014, pp. 232–236.

<sup>226</sup> AER, *Final decision - SA Power Networks distribution determination 2015–20 - Attachment 6 - Capital expenditure*, October 2015, p. 6-124; and AER, *Final decision - SA Power Networks distribution determination 2015–20 - Attachment 7 - Operating expenditure*, October 2015, p. 7-75.

<sup>227</sup> AER, *Information request - Powercor 035 - IT capex for RIN compliance and Power of Choice*, 28 January 2016.



that are not primarily driven by customer numbers.<sup>228</sup> On this basis, we are satisfied that the proposed allocation of costs for this project is likely to be efficient.

In summary, having reviewed the information submitted by Powercor in support of the forecast RIN compliance capex, we are satisfied that Powercor's revised proposal capex for the RIN reporting compliance project reflects a reasonable estimate of the efficient costs of a prudent operator.<sup>229</sup> The business case submitted by Powercor supports the proposed option for achieving RIN compliance at a substantially lower cost than CitiPower/Powercor's initial proposal through a more efficient mix of both capex and opex. The total forecast costs are equivalent to the costs allowed in our final regulatory determination for SA Power Networks following an independent review of the prudent and efficient ICT costs required to achieve RIN compliance. We will make allowance for Powercor's forecast RIN compliance capex in our estimate of overall non-network ICT capex. Powercor's forecast RIN compliance opex step change is discussed in attachment 7 of this final decision.

---

<sup>228</sup> Powercor, *Response to AER information request 035*, 4 February 2016, p. 1.

<sup>229</sup> NER, cl. 6.5.7(c).

## C Demand

The expected maximum demand is a key input into a distributor's forecast capex and opex and to our assessment of that forecast expenditure.<sup>230</sup> This attachment sets out our decision on Powercor's forecast maximum demand for the 2016–20 period.<sup>231</sup>

Forecast system maximum demand provides a high level indication of the need for expenditure on the network. Forecasts of increasing system demand generally signal an increased requirement for growth capex, and the converse for forecasts of stagnant or falling system demand.<sup>232</sup> Accurate, or at least unbiased, demand forecasts are important inputs to ensuring efficient levels of investment in the network. For example, overestimates of expected demand may lead to inefficient expenditure as distributors install unnecessary capacity in the network.

In this section, demand refers to summer peak demand (MW), unless otherwise indicated. The demand data reviewed in this section are non-coincident summer peak demand data with probability of exceedance (POE) of 10 percent and has been weather adjusted and summated at the transmission connection point level.

### C.1 AER position

We are satisfied that the maximum demand forecast for the 2016–20 period proposed by Powercor, in its revised proposal (January 2016), is a realistic expectation of demand.<sup>233</sup> In coming to this view, we take into account the following:

- Powercor's revised maximum demand forecast is generally consistent with growth in maximum demand between 2006 and 2015, using weather adjusted historical demand. This is discussed further in section C.4.
- Powercor submits that population growth and agricultural expansion will drive faster demand growth in specific areas of its network.<sup>234</sup> In recent years, changes in the electricity market such as increasing energy efficiency, solar generation and changing customer behaviour have also reduced maximum demand growth across the National Electricity Market (NEM). However, we consider that these factors may be outweighed over the 2016-20 period from faster population growth and agricultural expansion and likely drive continued maximum demand growth. This is discussed further in section C.4.
- Recent revisions to the maximum demand forecast from the Australian Energy Market Operator (AEMO) give support to Powercor's revised maximum demand

---

<sup>230</sup> NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

<sup>231</sup> In this attachment, 'demand' refers to summer maximum, or peak, demand (megawatts, MW) unless otherwise indicated.

<sup>232</sup> Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.

<sup>233</sup> NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

<sup>234</sup> AER, *Preliminary Decision Powercor 2016-20, Attachment 6*, January 2016, p.111.



forecast. While Powercor forecasts slightly higher maximum demand than AEMO, this is likely driven by differences in methodology. This is discussed further in section C.6.

- Powercor's demand forecasting methodology is reasonable when considered against the assessment principles set out in the AER's Expenditure Forecast Assessment Guideline.<sup>235</sup> This is discussed further in section C.5.

This decision is made for Powercor's total system maximum demand forecast and does not specifically consider localised demand growth (spatial demand) that may drive the need for specific growth projects or programs. We consider the relevant capex growth projects that are driven by localised maximum demand in section B.2.

## C.2 AER approach

Our consideration of Powercor's revised maximum demand forecast draws upon:

- Powercor's revised proposal
- most recently released forecasts from AEMO<sup>236</sup>
- A report by our internal economic consultant, Dr Darryl Biggar on Powercor's revised demand forecast<sup>237</sup>
- Stakeholder submissions in response to Powercor's revised proposal (as well as submissions made in relation to the Victorian distribution determinations more generally).

In our preliminary decision, we were not satisfied that Powercor's initial maximum demand forecast was a realistic expectation of demand over the 2016–20 regulatory control period. Our decision took into account the following factors:<sup>238</sup>

- Our analysis of observed changes in the electricity market (such as the strong uptake of solar PV, changing behaviour in consumers' use of electricity and energy efficiency measures) suggested that electricity demand will not grow as strongly as forecast by Powercor over the 2016–20 period.
- We examined Powercor's forecasting methodology. We considered that this methodology effectively assumes that the historical relationship between demand and its drivers (for example, weather) will continue to hold over the 2016–20 period. We were not confident that the resulting forecasting methodology is able to fully capture changes in demand in recent years. Therefore, we were not satisfied

---

<sup>235</sup> AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 21–23.

<sup>236</sup> AEMO, *2015 AEMO Transmission Connection Point Forecasting Report*, September 2015.

<sup>237</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016.

<sup>238</sup> AER, *Preliminary decision Powercor distribution determination – Attachment 6 – Capital Expenditure*, October 2015, p. 6-139.

that Powercor's forecast reflected a realistic expectation of future demand over the 2016–20 period.

- AEMO forecasted less maximum demand and lower growth in maximum demand than Powercor. We considered that AEMO's forecasting methodology did not assume a fixed structural relationship between demand and demand drivers over a long period. Instead, AEMO's methodology placed greater reliance on industry knowledge and judgment. While not without its limitations, we considered that AEMO's forecast better reflected recent changes in the electricity market. For this reason, we considered AEMO's independent forecast can better explain the actual demand pattern seen on all distributor's networks.

At the time of our preliminary decision, Powercor (and the Victorian electricity businesses) were in the process of updating their demand forecasts as part of the 2015 distribution annual planning report (DAPR). In addition, AEMO updated their most recent Victorian maximum demand forecast, which was too late to be considered as part of our preliminary decision. Hence, we stated that we would consider updated demand forecasts and other information (such as AEMO's most recent demand forecasts) in our final decision.

### **C.3 Powercor's revised proposal**

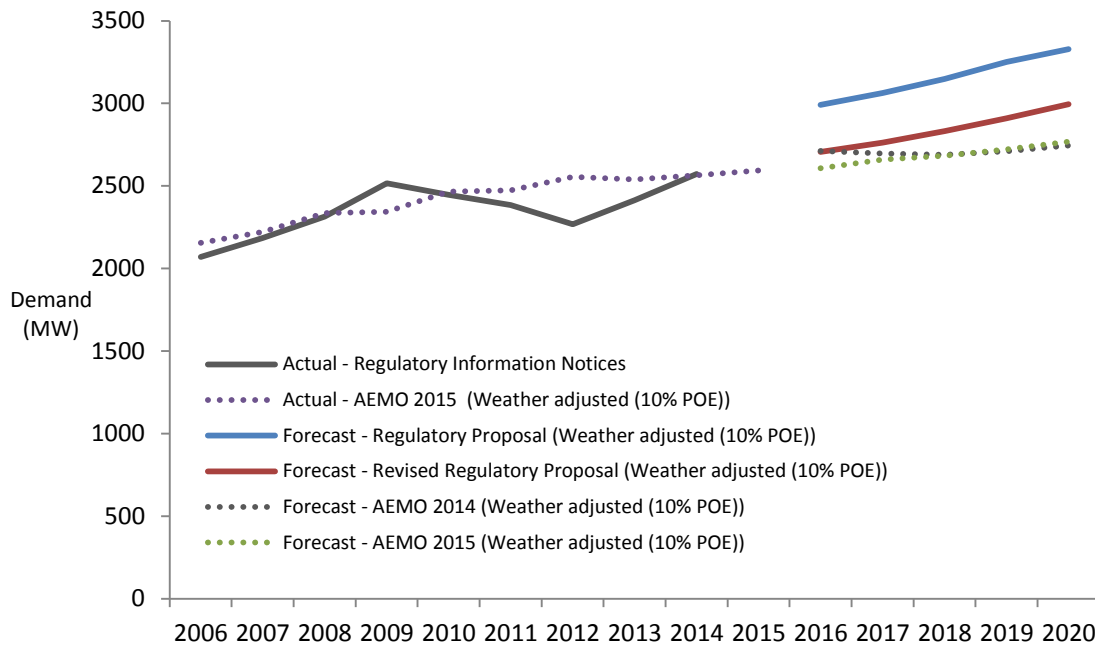
Powercor has revised its demand forecast to take into account data for the most recent summer (2014–15). This revised forecast is considerably lower than the forecast provided in its initial regulatory proposal. Powercor attributes this to reductions in forecast demand drivers including the Gross State Product (GSP) and retail electricity prices.<sup>239</sup> Demand is now forecasted to start at a lower level than was forecasted in the initial proposal. However, Powercor has maintained the same demand growth rate as in its initial proposal.

Figure 6.11 and Table 6.18 shows Powercor's revised maximum demand forecast for each year of the 2016–20 regulatory control period. Powercor's revised forecast is generally consistent with growth in maximum demand between 2006 and 2015, using weather adjusted historical demand. Figure 6.11 and Table 6.18 also provides AEMO's latest system demand forecast for its network (the 2015 connection point forecasts), which shows that Powercor forecasts maximum demand to grow at a slightly faster rate than AEMO.

---

<sup>239</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.109.

**Figure 6.11 Maximum system demand (Non-coincident, 10% PoE, MW)**



Source: AER analysis, Powercor, Reset RIN 2016–20, April 2015; Powercor, revised Reset RIN 2016–20, January 2016; AEMO, Dynamic interface for connection points in Victoria, September 2014; AEMO, Dynamic interface for connection points in Victoria, 22 December 2015; Powercor, Economic Benchmarking RIN (Actual) for 2006–13; Powercor, Economic Benchmarking RIN (Actual) for 2014.

Note: The actual raw demand for 2015 is not yet available from Powercor.

**Table 6.18 Maximum system demand (Non-coincident, 10% PoE, MW)**

	2016	2017	2018	2019	2020	Average annual growth (2016-20)
Regulatory Proposal	2990	3063	3148	3250	3329	2.72%
Revised Regulatory Proposal	2706	2762	2832	2909	2995	2.57%
AEMO connection point forecast (2014)	2711	2696	2688	2711	2744	0.3%
AEMO connection point forecast (2015)	2607	2659	2684	2721	2768	1.5%

Source: AER analysis, Powercor, Reset RIN 2016–20, April 2015; Powercor, revised Reset RIN 2016–20, January 2016; AEMO, Dynamic interface for connection points in Victoria, September 2014; AEMO, Dynamic interface for connection points in Victoria, 22 December 2015.

Powercor engaged the Centre for International Economics (CIE) to develop its demand forecast. Powercor's regulatory proposal provided a brief summary of CIE's demand forecasting method, including approaches to:

- demand drivers
- accounting for economic conditions such as income and electricity prices

- projections of customer numbers by tariff class, and
- post model adjustments for block loads and embedded generation.<sup>240</sup>

Powercor's revised regulatory proposal sets out that the following aspects of its maximum demand forecast were updated from the initial proposal:<sup>241</sup>

- Powercor engaged CIE to update its top-down forecast for actual 2014–15 summer demand. The CIE used the same GSP and retail electricity price as AEMO's 2015 state-wide demand forecasts
- information on demand drivers
- economic consultant, Oakley Greenwood updated forecasts of the impact of disruptive technologies such as electric vehicles and battery storage on maximum demand
- information on block loads
- Powercor's internal bottom-up forecast for more recent demand data and local information, and
- reconciliation of the top-down and bottom-up forecasts.

Powercor engaged the Cambridge Economic Policy Associates (CEPA) to assess both its and AEMO's connection point forecasts against the requirements of the NER and the AER's forecasting principles. The CEPA considered Powercor's demand forecast meets the requirements of the NER better than AEMO's forecast.<sup>242</sup>

## C.4 Demand trend analysis

Our first step in examining Powercor's forecast of maximum demand is to look at whether the forecast is consistent with, or explained by, long term demand trends and changes in the electricity markets. As set out below, we consider that Powercor's revised demand forecast is consistent with the underlying historical demand trend since 2006.

We have examined Powercor's actual demand trend using weather adjusted historical demand. Weather adjustment of actual demand data removes the effect of random weather factors on observed electricity demand.

Using AEMO's actual weather adjusted demand data for Powercor, it can be seen that the actual underlying demand trend has been growing fairly consistently over the past 10 years and has only mildly flattened out in recent years. This trend can be seen in Figure 6.11. Powercor's revised forecasts include strong growth over 2016–20, but they are generally consistent with the underlying historical demand trends. While growth in rooftop solar and energy efficiency has contributed to reduced electricity

---

<sup>240</sup> Powercor, *Regulatory Proposal 2016–20*, April 2015, p. 96.

<sup>241</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.109.

<sup>242</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.102.

drawn from the grid, this has not significantly dampened maximum demand growth on Powercor's network.

Powercor attributes forecasts of strong demand growth to forecasts of faster demand growth in specific areas of its network. This is driven by forecast population growth in the western suburbs of Melbourne and the Greater Geelong region, and projected capacity expansion in the Warrnambool and Murray River regions.<sup>243</sup> We found Powercor's submission accords with independent population projections from the Victorian Department of Environment, Land, Water and Planning, which show that the western suburbs of Melbourne and the Greater Geelong region will be the fastest growing regions over the 2011–31 period.<sup>244</sup>

Consistent with our preliminary decision, we have also compared Powercor's revised system demand forecast with AEMO's connection point forecast for Powercor's network in this determination.<sup>245</sup> AEMO's 2015 connection point forecast show a slightly lower starting demand and a slightly higher demand growth rate for Powercor's network than it previously forecast. AEMO attributes the higher demand growth forecast to population and economic growth in Victoria, and some changes in forecasting methodology.<sup>246</sup> AEMO's 2015 connection point forecast is also closer to Powercor's lower revised demand forecast, and both forecasts also exhibit a similar upward sloping pattern.

These observations suggest that AEMO's 2015 connection point forecast lend support to Powercor's revised demand forecast. We consider AEMO's 2015 connection point forecast and its comparison to Powercor's revised demand forecast in more detail in section C.6.

In our preliminary decision, we compared Powercor's demand forecast with Powercor's actual demand during the 2006 to 2015 period. For our final decision we have enhanced this analysis by using weather adjusted demand data. This is because random weather factors have a strong impact on peak electricity demand (such as the peaks and troughs in demand between 2009 and 2014). This enables us to draw more robust inferences about changes in the underlying level of demand for electricity from the historic data.

Using non-weather adjusted actual demand, we observed that Powercor's demand grew steadily from 2006 to 2009, then reduced and did not reach the 2009 peak again until 2014. While there was some growth in demand between 2013 and 2014, we

---

<sup>243</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p. 111.

<sup>244</sup> State Government of Victoria, Department of Environment, Land, Water and Planning, *Victoria in Future 2015, Population and Household Projections to 2051*, p. 1.

<sup>245</sup> We have used AEMO's 2015 connection point forecasts. These forecasts were not available to us and Powercor at the time we made our preliminary decision (for the preliminary decision, we compared Powercor's initial demand forecast with AEMO's 2014 connection point forecasts). See AEMO, 2015 AEMO transmission connection point forecasting report for Victoria, September 2015.

<sup>246</sup> AEMO, 2015 AEMO transmission connection point forecasting report for Victoria, September 2015, p. 8.

concluded that this indicated a flattening of maximum demand in recent years.<sup>247</sup> Having re-evaluated historical demand trends using weather adjusted demand data, Powercor's historical demand trend did not show a significant flattening of demand growth between 2009 and 2014.

## C.5 Forecasting methodology analysis

In the preliminary decision, we reviewed Powercor's forecasting methodology (from CIE) and identified the following concerns:

- Powercor/CIE's forecasting model assumes a fixed and unchanging relationship between demand and key demand drivers. This assumption will not capture recent changes in the market and therefore does not provide a reliable guide to future demand forecasts.<sup>248</sup>
- Powercor/CIE's modelling enforces a single relationship between maximum demand and weather and other key drivers across the entire ten year period which is assumed to continue to hold in the future.<sup>249</sup>

In response, Powercor submits that:

- Its demand forecast uses the most recent ten years of data to ensure that its methodology directly takes into account changes in energy market conditions that occurred in recent history.<sup>250</sup>
- Its demand forecast reflects recent and future changes in the electricity markets and demand drivers.<sup>251</sup>
- The AER does not have reason to conclude that demand will soften over the 2016–20 regulatory control period.<sup>252</sup>

A large proportion of Powercor's revised proposal discusses and critiques AEMO's forecasting methodology, and states that AEMO's forecasts do not reflect a realistic expectation of demand. This is because we formed a view that AEMO's forecasts likely reflected a realistic expectation of demand, rather than Powercor's initial proposal. For the reasons set out in this section, we consider that the updated forecasts provided by both Powercor and AEMO, together with the supporting material, provide sufficient reason for us to depart from our preliminary decision. That said, we are satisfied that AEMO's methodology is a reasonable basis for preparing maximum demand forecasts, and remains a reasonable comparison point.

---

<sup>247</sup> AER, *Preliminary decision Powercor distribution determination, Attachment 6 – Capital Expenditure*, October 2015, p. 6-142.

<sup>248</sup> AER, *Preliminary decision Powercor distribution determination, Attachment 6 – Capital Expenditure*, October 2015, p. 6-150.

<sup>249</sup> AER, *Preliminary decision Powercor distribution determination, Attachment 6 – Capital Expenditure*, October 2015, p. 6-151.

<sup>250</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.115.

<sup>251</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.115.

<sup>252</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.115.

In this section we discuss and form a view on Powercor's forecasting methodology, taking into account the supporting information in Powercor's revised proposal. We have again sought advice from internal economic consultant, Dr Darryl Biggar, on the technical aspects of this material.

In summary, we find that Powercor's demand forecasting methodology is likely to result in a forecast which is a realistic expectation of demand. We drew upon Dr Biggar's conclusion that Powercor's forecasting methodology is sophisticated and largely justifiable when considered against the assessment principles in the AER's Expenditure Forecast Assessment Guideline<sup>253</sup>.<sup>254</sup> In particular, Powercor's demand forecasting model:

- allows demand growth to vary by local population forecasts and local responsiveness to economic and weather conditions.<sup>255</sup>
- Allows for a more complex relationship between demand and temperature than a simple linear relationship.<sup>256</sup>

These views are formed based on updated material provided in Powercor's revised proposal. Dr Biggar also reconsidered his position based on Powercor's revised proposal, taking into account all elements of Powercor's methodology previously not considered. However, Dr Biggar retained some of his concerns with Powercor's methodology that were raised in his first report on Powercor.<sup>257</sup> In particular, Dr Biggar remains concerned that Powercor's top-down demand forecast (prepared by CIE) does not fully allow the possibility that the relationship between demand and temperature relationship could change over time.<sup>258</sup>

In our preliminary decision, we considered that Powercor's demand forecast did not reflect recent and future changes in demand trends. In its revised proposal, Powercor disagreed with this view. Powercor submitted that its use of the most recent ten years of data reflect recent changes in demand trends.<sup>259</sup> Dr Biggar examined this issue in his report. Dr Biggar stated that, while Powercor's model uses a dataset which covers

---

<sup>253</sup> AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 21–23. While the principles are matters that we consider could be relevant in a comparison of alternative assessment techniques or forecasting methods, they do not limit the matters to which we could have regard. Other matters could arise in the context of a particular determination that we consider are relevant. Conversely, we may not consider that all of the principles are relevant, so we will not necessarily have regard to each of them when considering the appropriateness of a technique or forecasting methodology.

<sup>254</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 18.

<sup>255</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 13.

<sup>256</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 16.

<sup>257</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 4.

<sup>258</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 5.

<sup>259</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p. 113.



the time period for the recent energy market developments, it does not go far enough to fully capture the effects of these developments. This is because Powercor's model does not directly include solar PV penetration and energy efficiency requirements. As a result, Dr Biggar is concerned that Powercor's model does not adequately allow for changes in the relationship between demand and its key drivers over time.<sup>260</sup>

We agree with Dr Biggar and consider there remains a flaw within Powercor's forecasting methodology that it assumes a historical relationship between demand and its drivers (for example, weather) will continue to hold over the 2016–20 period. Having said that, the long-term underlying trend in demand over Powercor's network suggests that demand has been largely consistent between 2006 and 2014 (as set out in section C.4). This suggests that any fixed structural relationships within Powercor's methodology may still produce realistic forecasts in the near-term.

Given that Powercor's demand forecasting methodology is largely justifiable when considered against the assessment principles in the AER's Expenditure Forecast Assessment Guideline. It is likely that the resulting forecasts will reflect a realistic expectation of demand. However, Powercor's forecasting methodology should be reviewed overtime to ensure that it accurately captures changing patterns in the market over time.

In its submission on our preliminary decisions for the Victorian electricity distributors, the Victorian Government notes that the electricity distributors may seek additional expenditures through revised demand forecasts.<sup>261</sup> We will review the impact of Powercor's revised demand forecast on augex in section B.2.

## C.6 AEMO forecasts

We have used AEMO's connection level demand forecast as an independent point of comparison to assess Powercor's proposed demand forecast. As such AEMO's independent forecast forms a valuable part of our assessment approach.

The Standing Council on Energy and Resources (SCER) first identified the need for AEMO to provide independent demand forecast information to us to facilitate our regulatory process. The SCER recognised this need against the backdrop of declining electricity demand in many regions of the NEM since 2009. As a result, SCER proposed a rule change that would task AEMO with providing demand forecasts to us in a manner which would facilitate our ability to interrogate demand forecasts submitted by network businesses to regulatory processes.

In its rule change determination, the Australian Energy Market Commission (AEMC) noted the need for AEMO's demand forecasts due to potentially significant changes in

---

<sup>260</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 5.

<sup>261</sup> The Victorian Government, *Submission to the AER on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016–20*, January 2016, p. 1.



the types and location of electricity generation, technology development and patterns of demand which will lead to uncertainty for network investment. The AEMC concluded that AEMO's connection level demand forecasts will reduce these investment risks borne by consumers by providing an alternative forecast for comparison.<sup>262</sup>

Consistent with policy intention of the development of AEMO's demand forecasting function, we have compared an NSP's demand forecast with AEMO's independent forecast. We have applied this approach in all determinations since the rule change came into effect, starting with the NSW, ACT and Queensland electricity distribution businesses. In two separate submissions, Origin Energy and AGL express support for our use of the latest AEMO connection point forecast in our assessment process.<sup>263</sup>

We used AEMO's 2015 connection point forecast in our comparison with Powercor's forecast in sections C.3 and C.4. AEMO's 2015 forecast shows higher maximum demand and demand growth rate than the 2014 forecast. AEMO attributes the increased demand forecast to population and economic growth in Victoria, as well as improvements to its forecasting methodology through adjustments for historical rooftop PV and the reconciliation process.<sup>264</sup>

Powercor supports AEMO's developments of its forecasting methodology and agrees that in the future, AEMO's forecasts may be able to provide a suitable comparison point for assessing the reasonableness of distributors' forecasts.<sup>265</sup> However, Powercor submits the following issues with AEMO's forecasting methodology:

- AEMO uses time trends to develop its connection point forecasts, which do not consider demand and economic drivers at the local point.<sup>266</sup> Powercor considers that the inclusion of local knowledge results in better forecasts.<sup>267</sup>
- AEMO's use of a cubic relationship between demand and time, and the off-the-point approach are controversial. Powercor considers that this raises doubt over the appropriateness of AEMO's forecasts.<sup>268</sup>
- The divergence between AEMO's baseline connection point forecasts and the state-wide forecasts is of concern because the large gap between the forecasts implies that one of these forecasts is inaccurate.<sup>269</sup>
- AEMO's approach lacks the level of transparency necessary for stakeholders to assess the robustness of its forecasts.<sup>270</sup>

---

<sup>262</sup> COAG Energy Council Senior Committee of Officials, *Australian Energy Market Operator access to information for developing demand forecasts*, pp. 3–4.

<sup>263</sup> Origin Energy, *Submission to AER preliminary decision Victorian networks*, 6 January 2016, p.2. AGL, *Submission to AER preliminary decision on the Victorian electricity distribution network regulatory proposals*, 7 January 2016, p. 1.

<sup>264</sup> AEMO, *2015 AEMO transmission connection point forecasting report for Victoria*, September 2015, pp. 4, 8.

<sup>265</sup> Powercor, *Further submission to the AER regarding preliminary determination*, 4 February 2016, p. 13.

<sup>266</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.123.

<sup>267</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.123.

<sup>268</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.114.

<sup>269</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p.126.

As a result, Powercor considers that AEMO's forecasts do not provide a realistic expectation of demand.<sup>271</sup> Conversely, Powercor considers that its forecasting methodology better meets the requirements of the NER and NEL than AEMO's.<sup>272</sup> Powercor considers that, if AEMO's forecasts are adopted for its network, expenditure forecasts will be below the expenditure required to meet the operating and capital expenditure objectives in the NER.<sup>273</sup>

In his report for Powercor, Dr Biggar reviewed Powercor's criticisms of AEMO's connection point forecasts and forecasting methodology.<sup>274</sup> Dr Biggar considers AEMO's approach has a solid foundation, being based on a methodology proposed by ACIL Allen. The ACIL Allen methodology has been consulted on and is being improved over time.<sup>275</sup>

Dr Biggar noted Powercor's concerns about the lack of transparency relating to how AEMO reconciles the state-wide forecasts and the connection point forecasts. Dr Biggar considered this to be a possible area for improvement.<sup>276</sup> We consider that the reconciliation process may explain the majority of the difference in forecasts from Powercor and AEMO. However, in total, Dr Biggar concluded that both AEMO and Powercor's methodologies appear to be reasonable when considered against the AER's assessment principles.<sup>277</sup>

The Victorian Energy Consumer and User Alliance (VECUA) submitted that the Victorian distributors' maximum demand forecasts show much higher growth rates than AEMO's projections. The VECUA considers that AEMO has over-estimated its energy forecasts in recent years and considers that AEMO's latest forecasts may also be over-estimated. The VECUA considers that the AER should substitute the distributors' demand and energy forecasts with credible independent forecasts.<sup>278</sup>

While we note VECUA's observations, we consider that AEMO's connection point forecasts are different to energy forecasts provided in its National Electricity Forecasting Report (NEFR) because they are forecasted at the connection point level. The SCER also intended for us to use AEMO's connection point forecasts as an independent source for comparison against DNSPs' demand forecasts.

---

<sup>270</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p. 114.

<sup>271</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p. 119.

<sup>272</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p. 111.

<sup>273</sup> Powercor, *Revised regulatory proposal 2016–20*, January 2016, p. 119.

<sup>274</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, pp. 8–19.

<sup>275</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 20.

<sup>276</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 19.

<sup>277</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 20.

<sup>278</sup> The Victorian Energy Consumer and User Alliance (VECUA), *submission to the AER on AER preliminary 2016-20 revenue determinations for the Victorian DNSPs* Developed by Hugh Grant, Executive Director, ResponseAbility, 6 January 2016, pp. 26–27.

While this is a new forecast, we have found this to be a useful tool in our recent determinations for the NSW, ACT and Queensland electricity distribution businesses. As such, we will continue to use AEMO's connection point forecasts in this determination. We understand that AEMO will continue to update and improve its methodology over time, including in response to feedback from the businesses in the NEM and other stakeholders. Ultimately the test of accuracy of any forecast will be its performance overtime in predicting actual demand.

## D Real materials cost escalation

The real escalation of the cost of materials is a method for accounting for expected changes in the costs of key inputs to forecast capital expenditure. In recent revenue determinations some service providers have proposed input cost escalations (in real dollars) in support of their capital expenditure proposals. These capex proposals (supported by models) included forecasts for changes in the prices of commodities such as copper, aluminium, steel and crude oil, rather than the prices of the physical inputs provided by network services (e.g., poles, cables, transformers).

### D.1 Position

We are not satisfied that Powercor's proposed real material cost escalators (leading to cost increases above CPI) which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period.<sup>279</sup> Instead we consider that zero per cent real cost escalation reasonably reflects a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period and will contribute to a total forecast capex that reasonably reflects the capex criteria. We have arrived at this conclusion on the basis that:

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

### D.2 Powercor's revised proposal

In its initial regulatory proposal, Powercor proposed a materials price growth rate of zero (in real terms) because it expected its materials input costs, considered in aggregate, to grow in the 2016–2020 regulatory control period at approximately the same rate as CPI.<sup>280</sup> In its revised proposal, Powercor submitted that it now expects there to be real price growth of materials costs in the period. Powercor stated that since its initial proposal was submitted in April 2015, the value of the Australian dollar

---

<sup>279</sup> NER, cl. 6.5.7(a).

<sup>280</sup> Powercor, *Regulatory Proposal 2016–20*, April 2015, p. 73.

has fallen considerably against the United States dollar. Powercor also stated that this decline is not expected to be reversed over the 2016–2020 regulatory control period.<sup>281</sup>

Powercor engaged Jacobs to forecast real and nominal material price escalation indices for each year of the 2016–2020 regulatory control period. Powercor submitted that Jacobs forecast the AUD/USD exchange rate for each year of the 2016–2020 regulatory control period as outlined in Table 6.19.

**Table 6.19 Jacobs forecast Australia/United States exchange rate (AUD/USD)**

	2016	2017	2018	2019	2020
\$AUD/\$US	0.708	0.700	0.694	0.687	0.695

Source: Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

Powercor submitted that as the average AUD/USD exchange rate over 2014 was 0.903, there is now a significant divergence between the exchange rate underpinning its expenditure forecasts for the 2016–2020 regulatory control period and the forecast exchange rates over that period.<sup>282</sup> Powercor stated that the commodities used to produce the finished goods it buys for the purposes of operating, maintaining and undertaking capital works on its network (i.e. copper, aluminium, steel and oil) are traded in an international market. Powercor further stated that as these commodities prices are quoted in USD in the international market, the AUD/USD exchange rate directly impacts on its materials cost in AUD terms.<sup>283</sup>

Powercor submitted that the forecasts prepared by Jacobs indicate that its materials costs will increase at a greater rate than CPI over the 2016–20 regulatory control period, in part informed by the downturn in the AUD/USD exchange rate expected to continue over the period. On this basis, Powercor proposed to apply real materials price growth rates to its expenditure forecasts for the 2016–20 regulatory control period.<sup>284</sup>

Real cost escalation indices for the following material cost drivers were calculated for Powercor by Jacobs:<sup>285</sup>

- aluminium
- copper
- steel

<sup>281</sup> Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, p. 91.

<sup>282</sup> Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

<sup>283</sup> Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

<sup>284</sup> Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

<sup>285</sup> Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016–2020*, 17 November 2015.

- oil, and
- construction costs.

Table 6.20 outlines Powercor's real materials cost escalation forecasts.

**Table 6.20 Powercor's real materials cost escalation forecast—real annual year to date change (per cent)**

	2016	2017	2018	2019	2020
Aluminium	-3.1	2.8	2.6	5.6	6.9
Copper	-4.0	-1.6	-1.6	4.0	7.5
Steel	10.5	2.6	1.1	1.1	-0.1
Oil	20.9	12.2	6.3	3.4	1.3
Construction costs	-5.0	0.0	0.0	0.0	0.0

Source: Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015, p. 2.

On the basis of these individual material (and labour) cost escalators, Powercor through its consultant Jacobs, submitted escalation indices specific to various asset classes common to Powercor's asset base.<sup>286</sup> These escalation factors were determined by applying a percentage contribution, or weighting, by which each of the underlying cost inputs were considered to influence the total price of each asset.<sup>287</sup> Table 6.21 outlines Powercor's proposed real cost escalation indices by asset class.

**Table 6.21 Powercor real annual year to date average price escalation indices**

	2016	2017	2018	2019	2020
Asset classes					
AI Conductor	0.980	1.016	1.015	1.032	1.040
Buildings	1.000	1.000	1.000	1.000	1.000
Cable AI	1.014	1.022	1.015	1.022	1.024
Cable Cu	0.994	0.999	0.995	1.024	1.042
Civil	1.000	1.000	1.000	1.000	1.000

<sup>286</sup> Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015.

<sup>287</sup> Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015, p. 1.

	2016	2017	2018	2019	2020
Communications - Pilot Wires/OPGW	1.000	1.000	1.000	1.000	1.000
Earth grid / Copper rods	0.977	0.990	0.989	1.028	1.052
IT & Communications	1.000	1.000	1.000	1.000	1.000
Metering	1.008	0.998	0.992	0.990	0.989
Motor Vehicles	1.000	1.000	1.000	1.000	1.000
Non-Network assets	1.000	1.000	1.000	1.000	1.000
Office Equipment & Furniture	1.000	1.000	1.000	1.000	1.000
Other Equipment	1.000	1.000	1.000	1.000	1.000
P&C	1.008	0.998	0.992	0.990	0.989
Pit	1.000	1.000	1.000	1.000	1.000
Plant & Equipment	1.000	1.000	1.000	1.000	1.000
PVC Conduit	1.059	1.033	1.015	1.006	1.000
Reactive/Capacitive	1.039	1.019	1.009	1.014	1.014
SCADA	1.000	1.000	1.000	1.000	1.000
Street Lighting	1.016	1.006	1.003	1.002	1.000
Structure	1.000	1.000	1.000	1.000	1.000
Substation Bays	1.013	1.001	0.996	0.996	0.995
Substation Establishment	1.000	1.000	1.000	1.000	1.000
Switchgear	1.020	1.003	0.995	0.996	0.995
Transformers	1.039	1.019	1.009	1.014	1.014
Wood pole x-arms structure + insulators	1.030	1.014	1.003	0.997	0.993
Wood Poles	1.000	1.000	1.000	1.000	1.000

Source: Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015, pp. 2–3.

The impact of the real materials cost escalation indices by asset class on its proposed capital expenditure submitted by Powercor is shown in Table 6.22.

**Table 6.22 Capital expenditure to account for real materials price growth (\$ million 2015)**

	2016	2017	2018	2019	2020
Materials	0.3	1.2	1.7	2.5	3.3

Source: Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, p. 98.

## D.3 Assessment approach

We assessed Powercor's proposed real material cost escalators as part of our assessment of Powercor's revised total capex under the NER. Under the NER, we must accept Powercor's capex forecast if we are satisfied it reasonably reflects the capex criteria.<sup>288</sup> Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.<sup>289</sup>

We have applied our approach as set out in our Expenditure Forecast Assessment Guideline (Expenditure Guideline) to assessing the input price modelling approach to forecast materials cost.<sup>290</sup> In the Expenditure Guideline we stated that we had seen limited evidence to demonstrate that the commodity input weightings used by service providers to generate a forecast of the cost of material inputs have produced unbiased forecasts of the costs the service providers paid for manufactured materials.<sup>291</sup> We considered it important that such evidence be provided because the changes in the prices of manufactured materials are not solely influenced by the changes in the prices of raw materials that are used.<sup>292</sup> In other words, the price of manufactured network materials may not be well correlated with raw material input costs. We expect service providers to demonstrate that their proposed approach to forecast network assets cost changes reasonably reflect changes in raw material input costs.

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

- reviewed the Jacobs report commissioned by Powercor<sup>293</sup>
- reviewed the capex forecast model used by Powercor, and
- reviewed the approach to forecasting network asset costs in the context of electricity service providers mitigating such costs and producing unbiased forecasts.

We received a submission from the Consumer Challenge Panel Sub Panel 3 (CCP3) who stated that since the decline in the price of input materials used in the materials escalation build-up in earlier resets, CPI has been used as the surrogate for material price escalation. The CCP3 submitted that this process has been biased in favour of the networks, as consumers paid a premium when materials escalation exceeded CPI, but when materials escalation might be lower than CPI, the CPI has been used. To avoid the outcome of such an approach, the CCP3 considers that the AER should

---

<sup>288</sup> NER, cl. 6.5.7(c).

<sup>289</sup> NER, cl. 6.5.7(c)(3).

<sup>290</sup> AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, pp. 50–51.

<sup>291</sup> AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

<sup>292</sup> AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

<sup>293</sup> Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016–2020*, 17 November 2015.



settle on using CPI as the acceptable surrogate for materials price escalation for future resets.<sup>294</sup>

## D.4 Reasons

We consider whether a forecast is based on a sound and robust methodology in assessing whether Powercor's proposed total revised capex reasonably reflects the capex criteria.<sup>295</sup> This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.<sup>296</sup> In making our assessment, we do recognise that predicting future materials costs for electricity service providers involves a degree of uncertainty. However, for the reasons set out below, we are not satisfied that the materials forecasts provided by Powercor satisfy the requirements of the NER. Accordingly, we have not accepted it as part of the total forecast capex in our Final Decision. We are satisfied that zero per cent real cost escalation is reasonably likely to reflect the capex criteria and this has been taken into account into our alternative estimate.

### Exchange rate considerations

Powercor stated that the primary basis for proposing real price growth rates for materials costs for capital expenditure was the impact on its capital expenditure forecasts of the downturn in the AUD/USD exchange rate. Powercor also submitted that this reduction in the AUD/USD exchange rate was also expected to continue over the 2016-20 regulatory control period. Further, Powercor submitted that it had not expected this reduction when its initial proposal was submitted in April 2015.<sup>297</sup>

Whilst we recognise that exchange rate movements are likely to have an impact on commodity price forecasts and therefore the cost of network assets, we maintain our view that like other elements of commodity price forecasting, exchange rate forecasting during a regulatory control period is subject to the same uncertainties and potential forecasting inaccuracies. To illustrate this uncertainty, we have compared a number of energy service provider consultant's actual and forecast exchange rates which supports our view regarding the significant degree of uncertainty in forecasting commodity prices.

As part of its recent revenue proposal, TransGrid commissioned Sinclair Knight Merz (SKM) (now part of the Jacobs Group) in 2014 to provide a commodity price escalation forecast report.<sup>298</sup> Table 6.23 compares SKM/Jacobs exchange rate forecast in December 2013 with Jacobs forecast for Powercor in January 2016.

---

<sup>294</sup> Consumer Challenge Panel Sub Panel 3 (CCP3), *Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, February 2016, p, 70.

<sup>295</sup> NER, cl. 6.5.7(c).

<sup>296</sup> NER, cl. 6.5.7(c)(3).

<sup>297</sup> Powercor, *Revised Regulatory Proposal 2016–20*, January 2016, p. 91.

<sup>298</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013-14 - 2018-19*, 9 December 2013.

**Table 6.23 SKM/Jacobs forecast Australia/United States exchange rate (\$AUD/\$US)**

Powercor	2016	2017	2018	2019
\$AUD/\$US	0.708	0.700	0.694	0.687
TransGrid	2015-16	2016-17	2017-18	2018-19
\$AUD/\$US	0.888	0.878	0.857	0.846

Source: SKM, *TransGrid Commodity Price Escalation Forecast 2013-14 - 2018-19*, 9 December 2013, p. 3 and Powercor, *Revised Regulatory Proposal 2016–20*, January 2016, p. 92.

As Table 6.23 shows, there is considerable variation in the exchange rate forecasts by the same consultant over a three year period. Also, we have reviewed Bloomberg exchange rate forecast data and note that on 3 May 2016 the Bloomberg 52 week Australian/US dollar exchange rate forecast was over a range of about 13 cents between 0.6827 to 0.8164.<sup>299</sup> Extrapolating an exchange rate forecast over a five year regulatory control period is likely to be subject to greater risks and uncertainties given the number of factors that can influence exchange rate movements.

We have also compared a number of consultant's actual and forecast exchange rates in a report provided by Frontier Economics in a recent proposal from AusNet Services.<sup>300</sup> Frontier Economics' report shows forecast exchange rates by BIS Schrapnel and SKM for the period 2014 to 2019.<sup>301</sup> In Figure 1 of Frontier Economics' report, BIS Schrapnel forecast the Australian/US dollar exchange rate to be between about US\$0.90 to \$US0.87 between 2014 to 2016 whilst SKM forecast the Australian dollar to be between about US\$0.93 to US\$0.89 over the same period. Actual exchange rate data shows that aside from a period in January 2015 and four days in May 2015, the Australian dollar has consistently been below US\$0.80 during 2015 and at the end of 2015 was US\$0.73.<sup>302</sup> This overestimation of the Australian dollar by the consultants illustrates the difficulty in forecasting foreign exchange movements during a regulatory control period and is another example of the potential inaccuracy of modelling material input cost escalation. This outcome and the comparison of SKM/Jacobs exchange rate forecasts in December 2013 and January 2016 is consistent with our review of the empirical analysis of commodity forecasts which supports the assumption that the appropriate rate of change for materials inputs is zero per cent. This position is supported by a review of the economic literature of exchange

<sup>299</sup> Bloomberg Markets, *AUDUSD Spot Exchange Rate*, 3 May 2016.

<sup>300</sup> AusNet Services, *Transmission Revenue Proposal, Appendix 4F - Advice on Cost Escalation Rates for Materials Inputs*, 30 October 2015, p. 7.

<sup>301</sup> AusNet Services, *Transmission Revenue Proposal, Appendix 4F - Advice on Cost Escalation Rates for Materials Inputs*, 30 October 2015, p. 7.

<sup>302</sup> Reserve Bank of Australia, *Exchange Rates - Daily - 2014 to Current*.

rate forecast models which suggests a “no change” forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.<sup>303</sup>

In its revised regulatory proposal, Powercor stated that the average AUD/USD exchange rate over 2014 was \$0.903 and that since its initial regulatory proposal was submitted in April 2015, the value of the Australian dollar has fallen considerably against the United States dollar.<sup>304</sup> We have reviewed Reserve Bank of Australia historical AUD/USD exchange rates and note that when Powercor submitted its initial proposal in April 2015, the AUD/USD exchange rate during April 2015 was an average of \$0.78 which is significantly below the AUD/USD exchange rate of \$0.903 referred to by Powercor in its revised regulatory proposal.<sup>305</sup> We note that when Powercor submitted its initial proposal in April 2015 it would have been aware of the decline in the AUD/USD exchange rate but did not propose real materials cost escalation for its material inputs.

## Capital expenditure forecast model

Powercor's capex forecast model does not demonstrate how and to what extent material inputs have affected the past cost of inputs such as cables and transformers. In particular, there is no supporting evidence to substantiate how accurately Powercor's materials escalation forecasts reasonably reflected changes in prices they paid for assets in the past to assess the reliability of forecast materials prices. Further, Powercor has not demonstrated the impact on its materials costs of variations in either the actual or forecast AUD/USD exchange rate.

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

---

<sup>303</sup> R. Meese, K. Rogoff, (1983), *Empirical exchange rate models of the seventies: do they fit out of sample?*, Journal of International Economics, 14, B. Rossi, (2013), *Exchange rate predictability*, Journal of Economic Literature, 51(4), E. Fama, (1984), *Forward and spot exchange rates*, Journal of Monetary Economics, 14, K. Froot and R. Thaler, (1990), *Anomalies: Foreign exchange*, the Journal of Economic Perspectives, Vol. 4, No. 3, CEG, *Escalation factors affecting expenditure forecasts*, December 2013, and BIS Shrapnel, *Real labour and material cost escalation forecasts to 2019/20, Australia and New South Wales*, Final report, April 2014.

<sup>304</sup> Powercor, *Revised Regulatory Proposal 2016–20, January 2016*, pp. 91-92.

<sup>305</sup> Reserve Bank of Australia, *Exchange Rates - Daily - 2010 to 2013*.

## Materials input cost model forecasting

Powercor has used its consultant Jacobs to estimate cost escalation factors in order to assist in forecasting future operating and capital expenditure. These cost escalation factors include commodity inputs in the case of capital expenditure. The consultant has adopted a high level approach, hypothesising a relationship between these commodity inputs and the physical assets it purchased. Neither the consultant's report nor Powercor have explained or quantified this relationship, particularly in respect to movements in the prices between the commodity inputs and the basis for the physical assets and the derivation of commodity input weightings for each asset class.

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

## Materials input cost mitigation

As discussed in our recent previous decisions for energy businesses, we consider that there is some potential for Powercor to mitigate the magnitude of any overall input cost increases. This could be achieved by:

- potential commodity input substitution by the electricity service provider and the supplier of the inputs. An increase in the price of one commodity input may result in input substitution to an appropriate level providing there are no technically fixed proportions between the inputs. Although there will likely be an increase in the cost of production for a given output level, the overall cost increase will be less than the weighted sum of the input cost increase using the initial input share weights due to substitution of the now relatively cheaper input for this relatively expensive input.
- We are aware of input substitution occurring in the electricity industry during the late 1960's when copper prices increased, potentially impacting significantly on the cost of copper cables. Electricity service provider's cable costs were mitigated as relatively cheaper aluminium cables could be substituted for copper cables. We do however recognise that the principle of input substitutability cannot be applied to all inputs, at least in the short term, because there are technologies with which some inputs are not substitutable. However, even in the short term there may be substitution possibilities between operating and capital expenditure, thereby

potentially reducing the total expenditure requirements of an electricity service provider<sup>306</sup>

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.<sup>307</sup> For example, Powercor has not demonstrated whether there are any opportunities to increase the level of opex (e.g. maintenance costs) for any of its asset classes in an environment of increasing material input costs
- the scale of any operation change to the electricity service provider's business that may impact on its capex requirements, including an increase in capex efficiency, and
- increases in productivity that have not been taken into account by Powercor in forecasting its capex requirements.

By discounting the possibility of commodity input substitution throughout the 2016–20 regulatory control period, we consider that there is potential for an upward bias in estimating material input cost escalation by maintaining the base year cost commodity share weights. The examples of mitigation of input cost increases have been identified by us as potential reasons why input costs may not increase to the full extent of any future commodity price increase. We acknowledge that some of the examples of input cost mitigation may be limited in the short-run, but consider that input cost mitigation should not be discounted in all circumstances.

## Forecasting uncertainty

The NER requires that we must be satisfied that the total forecast capital expenditure for a DNSP reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.<sup>308</sup> We consider that there is likely to be significant uncertainty in forecasting commodity input price movements. The following factors have assisted us in forming this view:

- recent studies which show that forecasts of crude oil spot prices based on futures prices do not provide a significant improvement compared to a 'no-change' forecast for most forecast horizons, and sometimes perform worse<sup>309</sup>
- evidence in the economic literature on the usefulness of commodities futures prices in forecasting spot prices is mixed. Only for some commodities and for some forecast horizons do futures prices perform better than 'no change' forecasts,<sup>310</sup> and

---

<sup>306</sup> NER, cl. 6.5.7(e)(7).

<sup>307</sup> NER, cl. 6.5.7(e)(6).

<sup>308</sup> NER, cl. 6.5.7(c)(3).

<sup>309</sup> R. Alquist, L. Kilian, R. Vigfusson, *Forecasting the Price of Oil*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1022, July 2011 (also published as Alquist, Ron, Lutz Kilian, and Robert J. Vigfusson, 2013, *Forecasting the Price of Oil*, in *Handbook of Economic Forecasting*, Vol. 2, ed. by Graham Elliott and Allan Timmermann (Amsterdam: North Holland), pp. 68–69 and pp. 427–508) and International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, pp. 25–31.

- the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in \$US to \$AUS). A review of the economic literature of exchange rate forecast models suggests a “no change” forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.<sup>311</sup>

## Strategic contracts with suppliers

We consider that electricity service providers may be able 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 (e.g. by including fixed prices in long term contracts). We also consider there is the potential for double counting where contract prices reflect this allocation of risk from the electricity service provider to the supplier, where a real escalation is then factored into forecast capex. In considering the substitution possibilities between operating and capital expenditure,<sup>312</sup> we note that it is open to an electricity service provider to mitigate the potential impact of escalating contract prices by transferring this risk, where possible, to its operating expenditure.

## Cost based price increases

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 note that this approach would be less likely to promote efficient investment.<sup>313</sup> It also would not result in a capex forecast that was consistent with the nature of the incentives applied under the CESS and the STPIS to Powercor as part of this decision.<sup>314</sup>

## Selection of commodity inputs

The limited number of material inputs included in Powercor's capex forecast model may not be representative of the full set of inputs or input choices impacting on

---

<sup>310</sup> International Monetary Fund, *World Economic Outlook — Recovery Strengthens, Remains Uneven*, Washington, April 2014, p. 27, Chinn, Menzie D., and Olivier Coibion, *The Predictive Content of Commodity Futures*, Journal of Futures Markets, 2014, Volume 34, Issue 7, p. 19 and pp. 607–636 and T. Reeve, R. Vigfusson, *Evaluating the Forecasting Performance of Commodity Futures Prices*, Board of Governors of the Federal Reserve System, International Finance Discussion Papers, Number 1025, August 2011, pp. 1 and 10.

<sup>311</sup> R. Meese, K. Rogoff, (1983), *Empirical exchange rate models of the seventies: do they fit out of sample?*, Journal of International Economics, 14, B. Rossi, (2013), *Exchange rate predictability*, Journal of Economic Literature, 51(4), E. Fama, (1984), *Forward and spot exchange rates*, Journal of Monetary Economics, 14, K. Froot and R. Thaler, (1990), *Anomalies: Foreign exchange*, the Journal of Economic Perspectives, Vol. 4, No. 3, CEG, *Escalation factors affecting expenditure forecasts*, December 2013, and BIS Shrapnel, *Real labour and material cost escalation forecasts to 2019/20, Australia and New South Wales*, Final report, April 2014.

<sup>312</sup> NER, cl. 6.5.7(e)(7).

<sup>313</sup> NEL, s. 7A(3)(a).

<sup>314</sup> NER, cl. 6.5.7(e)(8).



changes in the prices of assets purchased by Powercor. Powercor's capex forecast model may also be biased to the extent that it may include a selective subset of commodities that are forecast to increase in price during the 2016–20 period.

## Commodities boom

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

## D.5 Review of independent consultants' reports

We have reviewed a number of recent energy service provider consultants' reports to further support for our position to not accept Powercor's proposed materials cost escalation. We have considered the relevance of those submissions to the issues raised by Powercor in order to arrive at a position that takes into account all available information. Our views on these reports are set out below. Overall, these reports lend further support to our position to not accept Powercor's proposed materials cost escalation.

### BIS Schrapnel report

Jemena commissioned BIS Schrapnel to provide an expert opinion regarding the outlook for a range of material cost escalators relevant to its electricity distribution network in Victoria as part of its 2016-20 regulatory control period proposal.<sup>315</sup> BIS Schrapnel acknowledged that as well as individual supply and demand drivers impacting on the forecast price of commodities, movements in the exchange rate also impact on the price of commodities. BIS Schrapnel stated that movements in the Australian dollar against the US dollar can have significant effects on the domestic price of minerals and metals.<sup>316</sup> BIS Schrapnel are forecasting the Australian dollar to fall to US\$0.77 in 2018.<sup>317</sup> This is significantly lower than the exchange rate forecasts by SKM of between US\$0.91 to US\$0.85 from 2014-15 to 2018-19 submitted as part of our recent review of TransGrid's transmission determination for the 2015–18 regulatory period.<sup>318</sup> In its report submitted in respect to our review of Jemena Gas Networks

---

<sup>315</sup> Jemena, *Regulatory Proposal 2016 – 20: Attachment 8-8 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014.

<sup>316</sup> Jemena, *Regulatory Proposal 2016–20: Attachment 8-8 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 37.

<sup>317</sup> Jemena, *Regulatory Proposal 2016–20: Attachment 8-8 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 4.

<sup>318</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.

access arrangement for the 2016–20 access arrangement period, BIS Schrapnel stated that exchange rate forecasts are not authoritative over the long term.<sup>319</sup>

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

BIS Schrapnel stated that for a range of items used in most businesses the average price increase would be similar to consumer price inflation and that an appropriate cost escalator for general materials would be the CPI.<sup>320</sup> In its forecast for general materials such as stationary, office furniture, electricity, water, fuel and rent for Jemena Gas Networks, BIS Schrapnel assumed that across the range of these items, the average price increase would be similar to consumer price inflation and that the appropriate cost escalator for general materials is the CPI.<sup>321</sup>

This treatment of general business inputs supports our view that where we cannot be satisfied that a forecast of real cost escalation for a specific material input is robust, and cannot determine a robust alternative forecast, zero per cent real cost escalation is reasonably likely to reflect the capex criteria and under the PTRM the electricity service provider's broad range of inputs are escalated annually by the CPI.

## Competition Economists Group report

A number of electricity service providers commissioned the Competition Economists Group (CEG) to provide real material cost escalation indices in respect to revenue resets for these businesses recently undertaken by us. These businesses included ActewAGL, Ausgrid, Endeavour Energy, Essential Energy and TasNetworks (Transend).

CEG acknowledged that forecasts of general cost movements (e.g. consumer price index or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs (e.g. energy costs and equipment leases etc.).<sup>322</sup> This is consistent with the Post-tax Revenue Model (PTRM) which reflects at least in part movements in an electricity service provider's intermediary input costs.

CEG acknowledged that futures prices will be very unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.<sup>323</sup> This is consistent

---

<sup>319</sup> BIS Schrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A-7.

<sup>320</sup> Jemena, *Regulatory Proposal 2016–20: Attachment 8-8 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 43.

<sup>321</sup> BIS Schrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 48.

<sup>322</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.

<sup>323</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.



with our view that there are likely to be a significant number of material exogenous factors that impact on the price of assets that are not captured by the material input cost model used by Powercor.

CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets:<sup>324</sup>

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

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

Figures 1 and 2 of CEG's report respectively show the variance between aluminium and copper prices predicted by the London Metals Exchange (LME) 3 month, 15 month and 27 month futures less actual prices between July 1993 and December 2013.<sup>325</sup>

Analysis of this data shows that the longer the futures projection period, the less accurate are LME futures in predicting actual commodity prices. Given the next regulatory control period covers a time span of 60 months we consider it reasonable to question the degree of accuracy of forecast futures commodity prices towards the end of this period.

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

In respect of forecasting electricity service provider's future costs, CEG stated that:<sup>326</sup>

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

---

<sup>324</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

<sup>325</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5–6.

<sup>326</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

This statement again is consistent with our view about the degree of the precision and accuracy of futures prices in respect of predicting electricity service providers future input costs. CEG also highlights the (poor) predictive value of LME futures for actual aluminium prices.<sup>327</sup>

CEG also acknowledge that its escalation of aluminium prices are not necessarily the prices paid for aluminium equipment by manufacturers. As an example, CEG referred to producers of electrical cable who purchase fabricated aluminium which has gone through further stages of production than the refined aluminium that is traded on the LME. CEG also stated that aluminium prices can be expected to be influenced by refined aluminium prices but these prices cannot be expected to move together in a 'one-for-one' relationship.<sup>328</sup>

CEG provided similar views for copper and steel futures. For copper, CEG stated that the prices quoted for copper are prices traded on the LME that meet the specifications of the LME but that there is not necessarily a 'one-for-one' relationship between these prices and the price paid for copper equipment by manufacturers.<sup>329</sup> For steel futures, CEG stated that the steel used by electricity service providers has been fabricated, and as such, embodies labour, capital and other inputs (e.g. energy) and acknowledges that there is not necessarily a 'one-for one' relationship between the mill gate steel and the steel used by electricity service providers.<sup>330</sup>

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

CEG has provided data on historical indexed aluminium, copper, steel and crude oil actual (real) prices from July 2005 to December 2013 as well as forecast real prices from January 2014 to January 2021 which were used to determine its forecast escalation factors.<sup>331</sup> For all four commodities, the CEG forecast indexed real prices showed a trend of higher prices compared to the historical trend. Aluminium and crude oil exhibited the greatest trend variance. Copper and steel prices were forecast to remain relatively stable whilst aluminium and crude oil prices were forecast to rise significantly compared to the historical trend.

---

<sup>327</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

<sup>328</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.

<sup>329</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.

<sup>330</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 23.

<sup>331</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, Figures 3, 4 and 5, pp. 23, 25 and 28.

## Sinclair Knights Mertz report

Sinclair Knights Mertz (SKM, now Jacobs SKM) were commissioned by TransGrid to provide real material cost escalation indices in respect to the revenue reset for TransGrid recently undertaken by us.

SKM cautioned that there are a variety of factors that could cause business conditions and results to differ materially from what is contained in its forward looking statements.<sup>332</sup> This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the cost of assets that are not captured by Powercor's capex forecast model.

SKM stated it used the Australian CPI to account for those materials or cost items for equipment whose price trend cannot be rationally or conclusively explained by the movement of commodities prices.<sup>333</sup>

SKM stated that the future price position from the LME futures contracts for copper and aluminium are only available for three years out to December 2016 and that in order to estimate prices beyond this data point, it is necessary to revert to economic forecasts as the most robust source of future price expectations.<sup>334</sup> SKM also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.<sup>335</sup>

SKM stated that in respect to the reliability of oil future contracts as a predictor of actual oil prices, futures markets solely are not a reliable predictor or robust foundation for future price forecasts. SKM also stated that future oil contracts tend to follow the current spot price up and down, with a curve upwards or downwards reflecting current (short term) market sentiment.<sup>336</sup> SKM selected Consensus Economics forecasts as the best currently available outlook for oil prices throughout the duration of the next regulatory control period.<sup>337</sup> The decision by SKM to adopt an economic forecast for oil rather than using futures highlights the uncertainty surrounding the forecasting of commodity prices.

## Comparison of independent consultant's cost escalation factors

To illustrate the potential uncertainty in forecasting real material input costs, we have compared the material cost escalation forecasts derived by Jacobs for Powercor with those derived by BIS Schrapnel and CEG as shown in Table 6.24.

---

<sup>332</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.

<sup>333</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.

<sup>334</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.

<sup>335</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 16.

<sup>336</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.

<sup>337</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.

**Table 6.24 Real material input cost escalation forecasts (per cent)**

	2015 (%)	2016 (%)	2017 (%)	2018 (%)	2019 (%)
Aluminium					
Jacobs		-3.1	2.8	2.6	5.6
CEG	8.3	0.9	1.8	2.9	2.8
BIS Shrapnel	9.5	8.0	8.2	5.1	-7.0
Copper					
Jacobs		-4.0	-1.6	-1.6	4.0
CEG	-1.4	-1.5	-0.4	1.2	1.1
BIS Shrapnel	0.4	3.5	7.7	2.1	-10.0
Steel					
Jacobs		10.5	2.6	1.1	1.1
CEG	-4.2	1.8	0.9	1.0	1.0
BIS Shrapnel	4.8	4.7	3.0	2.7	-11.0
Oil					
Jacobs		20.9	12.2	6.3	3.4
CEG	-9.0	1.2	1.0	0.9	1.0
BIS Shrapnel	-1.9	-1.1	4.3	2.5	-7.7

Source: Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015, p. 2, CEG, *Updated cost escalation factors*, December 2014, pp. 6, 7, 9 and 10 and BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. iii.

As Table 6.24 shows, there is considerable variation between the consultant's commodities escalation forecasts. The greatest margins of variation are 22.0 percentage points for oil in 2016 (where Jacobs has forecast a real price increase of 20.9 per cent and BIS Schrapnel a real price decrease of 1.1 per cent) and 14.0 percentage points for copper in 2019 (where Jacobs has forecast a real price increase of 4.0 per cent and BIS Shrapnel a real price decrease of 10.0 per cent). These forecast divergences between consultants further demonstrate the uncertainty in the modelling of material input cost escalators to reliably and accurately estimate the prices of intermediate outputs used by service providers to provide network services. This supports our view that Powercor's forecast real material cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period.<sup>338</sup>

<sup>338</sup> NER, cl. 6.5.7(a).

## D.6 Conclusions on materials cost escalation

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

CEG, in its report to electricity distribution service providers, identified a number of factors which are consistent with our view that Powercor's capex forecast model has not demonstrated how and to what extent material inputs are likely to affect the cost of assets. Jacobs stated that the Australian CPI is used to account for those materials or cost items in equipment whose price trend cannot be rationally or conclusively explained by the movement of commodity prices.<sup>339</sup> BIS Schrapnel and CEG acknowledged that forecasts of general cost movements (e.g. CPI or producer price index) can be used to derive changes in the cost of other inputs used by electricity service providers or their suppliers separate from material inputs.<sup>340</sup> CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.<sup>341</sup> CEG also stated that while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.<sup>342</sup>

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

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

In previous AER decisions, including our recent preliminary decisions for the Victorian distribution networks and final decisions for the New South Wales and ACT distribution networks as well as our final decisions for Envestra's Queensland and South

---

<sup>339</sup> Powercor, *Revised Regulatory Proposal 2016–20: Attachment 4.34 - Jacobs, Escalation indices forecast 2016–2020*, 17 November 2015, p. 12.

<sup>340</sup> Jemena, *Regulatory Proposal 2016–20: Attachment 8-8 BIS Schrapnel, Real Labour and Material Cost Escalation Forecasts to 2020 - Australia and Victoria*, November 2014, p. 43 and CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.

<sup>341</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

<sup>342</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

Australian gas networks, we took a similar approach where costs were escalated annually by CPI. For Powercor, we consider that in the absence of a well-founded materials cost escalation forecast, Powercor's proposed real material cost escalators do not reflect a realistic expectation of the cost inputs required to achieve the capex objectives. We consider escalating real costs annually by the CPI reasonably reflects a realistic expectation of the cost inputs required to achieve the capex objectives and will contribute to a total forecast capex that reasonably reflects the capex criteria.

## **E Contingent projects**

### **E.1 Bushfire Mitigation Contingent Projects**

In their initial proposal Powercor noted that new regulations being developed by the Victorian Government would result in the need for additional capital expenditure in the 2016-2020 regulatory control period. Powercor proposed to address this need through two contingent projects. The AER agreed with Powercor's proposal but did not accept Powercor's proposed trigger event.

#### **E.1.1 Powercor proposal**

In its revised regulatory proposal Powercor proposed a single contingent project of approximately \$163.1 million (\$2015). Powercor have sought to amend their approach as follows:

Having regard to those proposed regulations, in our revised regulatory proposal we propose that there be one contingent project in our distribution determination for the 2016–2020 regulatory control period in respect of new or changed obligations or requirements with respect to earth fault standards and standards for asset construction and replacement in prescribed areas of the State. We propose that this contingent project be termed a 'bushfire mitigation contingent project'. We have forecast contingent capital expenditure in respect of this contingent project of approximately \$163.1 million (\$2015). We have formulated our proposed trigger event for this contingent project having regard to the AER's comments on our trigger events for the REFCLs and codified areas contingent projects in its preliminary determination.<sup>343</sup>

In its revised proposal Powercor has not accepted our alternative trigger event. Powercor has proposed an alternative wording which Powercor considered will improve the interpretation of the trigger event for each contingent project. We have not accepted Powercor's proposed trigger event as drafted but we have amended it as set out in section E.2.4 below.

#### **E.1.2 Position**

Based on the evidence submitted by Powercor and other information before us, we are satisfied that three bushfire mitigation contingent projects are reasonably required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements and would be a prudent and efficient investment in the network.

In summary, we consider that:

---

<sup>343</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, p. 405



- subject to the amendments noted in this determination, Powercor's bushfire mitigation project satisfies the requirements of clause 6.6A.1(b) of the NER
- Powercor's proposed bushfire mitigation contingent project is to address future obligations associated with the pending *Bushfire Mitigation Regulations Amendment 2016* (Vic) which is intended to implement recommendation 27 of the Victorian Bushfires Royal Commission (VBRC). We consider this event is probable within the regulatory control period but the timing is uncertain
- Powercor proposed that their single contingent project be funded in two or more tranches. This approach is not consistent with the NER. We consider each tranche should comprise a contingent project
- after further discussion with Powercor we have settled on three contingent projects in lieu of the tranches proposed by Powercor, each sized to meet the materiality criteria set in rule 6.6A.1(b)(2)(iii)
- Powercor's proposed contingent project capex will be required to maintain the reliability and safety of its network and to comply with applicable regulatory obligations or requirements when the regulations are made.

For these reasons, we accept Powercor's proposed capex for the bushfire mitigation program satisfies the capex criteria, subject to the amendment made to the divide the contingent project into three contingent projects. The total forecast set for this purpose is \$107.35 million (\$2015). Each of these reasons is discussed further below.

### **E.1.3 Assessment of Powercor's proposed trigger event**

We have considered Powercor's proposed trigger event as set out in their revised proposal.<sup>344</sup> We have rejected Powercor's proposed trigger event and, after discussion with Powercor, substituted a suitable trigger event. This is because we were concerned the Powercor proposal did not satisfy the NER in a number of respects. The first was that it sought to be a trigger for a single contingent project but approval of the project was to be sought in tranches. In our view, each tranche is a contingent project and must have an associated trigger event.

Also, we have not accepted Powercor's approach to the Declared Areas component of the trigger event. We consider it does not adequately define how the location of a project will be established.<sup>345</sup> As we discuss further below, in the draft regulations the identification mechanism is different from that of the earth fault standards project but its approval process includes acceptance of an amended Bushfire Mitigation Plan by Energy Safe Victoria (ESV). We also consider that the cost uncertainty for projects in Declared Areas should be subject to more rigour.

---

<sup>344</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, pp. 437-438

<sup>345</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, pp. 437-438; NER, cl. 6.6A.1(c)(3)

The earth standards project limb of the regulations requires the distributor to undertake a point score assessment of a list of targeted zone substations, modify their Bushfire Mitigation Plan and seek acceptance of the amended plan from ESV. We consider this limb will satisfy the NER requirements for a trigger event to relate to specific locations and not the network in general.<sup>346</sup>

In the draft regulations the identification mechanism for defining a Declared Area is that the Emergency Management Commissioner will make a declaration that a specific region of Powercor's network is subject to the increased construction standards. In the Bushfire Mitigation Plan the distributor will describe how, in relation to the Declared Area they will undertake works to address the amended construction standards specified in the regulations. However, the final identification of locations will be by the distributor identifying specific projects in their work program and by being subject to a declaration. These projects will then be reported to ESV as an amendment to the Bushfire Mitigation Plan and subject to acceptance by ESV. The Commissioner may make more than one declaration over the course of the 2016-2020 regulatory control period. We have taken this difference into account in refining the trigger events for these contingent projects.

Powercor also proposed a number of other amendments to the trigger event which we had proposed in our preliminary decision in response to the initial contingent projects proposal. We have accepted these amendments in principle as they constructively address practical matters including: the nature of the changed regulatory obligation, the approval process that governs amendments to the Bushfire Mitigation Plan and the form of the project costings to be submitted with an application.

## **E.1.4 NER requirements**

### **Contingent projects**

Clause 6.6A.1 of the NER concerns the acceptance of a contingent project in a distribution determination. The rule applies to any proposed capital expenditure that is probable in a regulatory period but either the cost, or the timing of the expenditure is uncertain.

To ensure consumers do not pay for an uncertain event until the trigger event has occurred, the forecast associated with a contingent project is not included in the capex determined in a decision. The function of the forecast is as a placeholder; the forecast is the best current estimate of the costs likely to arise if the event trigger occurs. However, when the event occurs the distributor has a further opportunity to demonstrate the forecast costs that arise as a consequence of the event. It is not until the trigger event occurs that the AER undertakes a detailed examination of the efficient costs required to satisfy the capex factors set out in clause 6.5.7. The forecast may differ from the initial forecast. Additional capex will only be added to the capex

---

<sup>346</sup> NER, cl. 6.6A.1(c)

allowance if the associated trigger event occurs and we determine the forecast is reasonable or we determine an alternative amount.

Contingent projects are also subject to a materiality test. The materiality test requires the cost exceed either \$30 million or 5 per cent of the value of the annual revenue requirement for the relevant distributor for the first year of the relevant regulatory control period, whichever is the larger amount.

A trigger event must be specified for a contingent project. The trigger event is subject to the requirements set out in clause 6.6A.1(c) of the NER.

## **E.1.5 Regulatory obligation**

### **New regulations**

The planned new Victorian Government regulations are intended to give effect to recommendation 27 of the Victorian Bushfires Royal Commission. They will apply in High Bushfire Risk Areas (HBRA) of the State.

The State amend the Regulations under Victoria's Electricity Safety Act 1998 and otherwise take such steps as may be required to give effect to the following:

- the progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk. The replacement program should be completed in the areas of highest bushfire risk within 10 years and should continue in areas of lower bushfire risk as the lines reach the end of their engineering lives
- the progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives. Priority should be given to distribution feeders in the areas of highest bushfire risk.

In particular, the Victorian Government has developed new regulatory standards for the use of Rapid Earth Fault Current Limiting (REFCL) devices and changes to the design standards that apply to new line construction and the reconstruction of assets in certain areas (Declared Areas).<sup>347</sup> The Victorian Government published the *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment* (RIS) on 17 November 2015. The regulations are to be made in 2016.

The contingent project mechanism was added to the NER to assist distribution networks faced with large but uncertain capital requirements to manage the risk of being required to fund major investments at short notice. We consider the impact of the Victorian regulations is a clear example of uncertain capital requirements that

---

<sup>347</sup> The draft regulations do not mandate the use of a REFCL device. However, it is currently the only known technology capable of meeting the performance standard defined in the regulations.

Powercor will face in the next regulatory control period. In specifying a contingency project, an indicative amount (forecast) is required to be set out in the determination. Ultimately, the approved costs may be higher or lower than this forecast, depending on our consideration of the application at the time.

This uncertainty is evidenced by the RIS which stated the average cost per installation to be \$9.2 million if all existing surge diverters require replacement or \$6.6 million on average, if only one-third of the surge diverters require replacement.<sup>348</sup> The submission by the Victorian Government draws particular attention to the variation in these estimates.<sup>349</sup> It also notes that individual project costs may vary widely. We note there is considerable variability in current project estimates by distributors, from around \$2 million to \$13.4 million.

## Victorian electrical safety framework

In Victoria, the safety obligations of major electricity companies are contained in the *Electricity Safety Act 1998* (Vic). Section 99 of this Act mandates that major electricity companies must submit an approved Electricity Safety Management Scheme (ESMS) to Energy Safe Victoria for acceptance.<sup>350</sup> These schemes are regulated by Energy Safe Victoria. Each of the five Victorian distributors is classed as a 'major electricity company' under this Act.

It is compulsory for Powercor to comply with the accepted ESMS for its network.<sup>351</sup> Further, the Act requires that each major electricity company must submit a Bushfire Mitigation Plan for its network to Energy Safe Victoria (ESV) and must comply with that plan.<sup>352</sup> The Bushfire Mitigation Plan forms part of an accepted ESMS.<sup>353</sup>

The new regulations will require each distributor to include details in their Bushfire Mitigation Plan of how it will enhance network protection capabilities for polyphase powerlines originating from prescribed zone substations and how powerlines in Declared Areas will be placed and underground or insulated. We note these provisions because they are material to the task of defining trigger events for the contingent projects. A particular challenge imposed by the new regulations is determining a trigger event which is capable of identifying the location of a project and of objective verification.<sup>354</sup>

The requirements of the new regulations mean that the location of every earth fault standards project will be known to the safety regulator, ESV, before work commences.

---

<sup>348</sup> ACIL Allen Consulting, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment (RIS)*, 17 November 2015, p. 70

<sup>349</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016-20*, Second submission, p. 2.

<sup>350</sup> *Electricity Safety Act 1998* (Vic), s. 99.

<sup>351</sup> *Electricity Safety Act 1998* (Vic), s. 106.

<sup>352</sup> See, *Electricity Safety Act 1998* ss. 113A, 113B and 113C.

<sup>353</sup> *Electricity Safety Act 1998* (Vic), s. 113D.

<sup>354</sup> NER, cl. 6.6A.1(c).

We also note that the regulations exclude large areas of Powercor's network but focus on specific zone substations and well defined high risk, high fire loss consequence areas of the State. The requirements of the new regulations also mean that the location of every new construction standards project will be known to the safety regulator, ESV, before work commences. The distributor will be required to submit formal remediation plans to ESV for their acceptance.

We consider these requirements of the regulations mean the occurrence of a trigger event which includes reference to the Bushfire Mitigation Plan of a distributor will be reasonably specific and capable of objective verification<sup>355</sup> and be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole.<sup>356</sup>

### *What is Rapid Earth Fault Current Limiting (REFCL) technology?*

Currently, the best available technology for complying with the proposed earth fault standards obligation is by installing a REFCL at the zone substation. The REFCL is a relatively new technology which can substantially reduce the risk of a fallen powerline igniting a bushfire. It is an extension of resonant earth system technology, which is commonly used in Europe and elsewhere. The REFCL device is capable of detecting when a power line has fallen to the ground and almost instantaneously shuts off power on the fallen line.

Installation of a REFCL requires significant investment in additional measures to prepare the network to operate safely with the device. This is because when a fault occurs the network which normally operates at 12.7 kV line voltage is subjected to 22 kV line voltage. This higher voltage can damage other components if they are not upgraded to withstand the higher voltage. Another requirement is to balance the capacitance of the network. Capacitance is a technical parameter. On longer feeders it can involve significant line work and cost to achieve this requirement.

### *Line hardening costs*

The REFCL device when operating will introduce temporary line voltages that exceed the common ratings of current equipment. This necessitates a survey of every affected line to identify assets which do not have a sufficiently high voltage rating. Some assets will be sufficiently rated such that they do not require replacement or modification. However, a considerable number will require replacement or modification to operate safely with a REFCL installed. This uncertainty is generally referred to as 'hardening cost uncertainty' within the industry.

It should be noted that the focus here is on surge diverters as it is a major cost element which has attracted disagreement in the RIS consultation process. This element may also be subject to a significant degree of discretion or exercise of judgement when

---

<sup>355</sup> NER, cl. 6.6A.1(c)(1).

<sup>356</sup> NER, cl. 6.6A.1(c)(3).

planning and implementing projects by distributors. However, the total hardening costs necessarily involve many other elements including, for example, capacitance balancing, cable insulation and joints, pole top insulators, voltage regulators and automatic circuit reclosers. These elements and other components may be incompatible with a resonant earth neutral system. Upgrading these elements can add considerably to hardening costs. They are not discussed further because there is general agreement these elements are essential to a REFCL project and are readily identifiable. These costs will be examined in detail when a contingent project is triggered at a future date.

Although all the Victorian distributors operate detailed Geographical Information Systems, data on maximum voltage ratings is generally not held or is missing or incomplete for many of the assets listed or held in those systems. It was not generally foreseen that assets which operate at a nominal line to earth voltage of 12.7 kV would be operated at a line to earth voltage of 22 kV, even if only for short periods.<sup>357</sup> The ability of a surge diverter to withstand the higher voltage is dependent on a number of factors including age, condition, technology and time duration of the event. However, operation at 22 kV is a standard operating mode for a REFCL. A surge diverter rated for 12.7 kV operation is unlikely to survive extended operation at 22 kV and may create additional hazards in some failure modes.

We have considered the view expressed in the Consumer Challenge Panel (CCP) submission that the AER should not fund surge diverter replacements on the grounds a reduction in reliability is acceptable.<sup>358</sup> However, we consider that some cost must be incurred to address the preceding surge diverter safety issues. This will arise where a surge diverter is still required for safety reasons or where redundant units are to be removed but not replaced. Until a contingent project is triggered and a detailed application made for funding, the AER will not have sufficient information to address this matter in greater detail.

To assist in assessing the likely cost of these contingent projects for the purpose of establishing the size of the contingent project amount, at least on an indicative basis, the AER asked Powercor to provide costed alternative options to minimise the cost of upgrading surge diverters.<sup>359</sup> Powercor advised that it had calculated the lowest cost option was direct replacement of under-rated surge diverters.<sup>360</sup> The AER has reviewed the options as costed by Powercor. Based on those costings we accept replacement is a reasonable option. This does not mean the AER endorses full replacement as being necessary - all options should be explored before settling on full replacement on any given feeder.

---

<sup>357</sup> In three phase 22 kV systems the line to line voltage is 22 kV but the line to earth voltage is only 12.7 kV.

<sup>358</sup> Consumer Challenge Panel, CCP3, *Victorian DNSPs revenue reset - Comments on AER Preliminary Decisions*, 25 February 2016, p. 65.

<sup>359</sup> AER, *Information Request AER IR039 (Powercor)*, 5 February 2016.

<sup>360</sup> Powercor, *response to information request AER IR039 (Powercor): VBRC capex*, 12 February 2016, p. 1.



It is plausible that on some 12.7 kV lines, some surge diverters may already be rated for 22 kV line to earth operation. In some instances a hazard assessment may determine that the number of surge diverters may be rationalised. Until detailed line surveys are completed there will remain considerable uncertainty as to the true cost of the installation of each REFCL at a specific location. These surveys are labour intensive and thus it is not realistic to expect them to be undertaken until a specific need arises. This matter has been taken into account in the formulation of the contingent project trigger in the following sections.

### *What are Declared Areas?*

The term "Declared Areas" (in the preliminary decision these were referred to as "Codified Areas") is a reference to 'declared' high bushfire risk areas of Victoria. In the draft bushfire mitigation regulations, areas which are the subject of a Declaration by the Emergency Management Commissioner are to be subject to new, higher powerline construction standards.

We further examine these uncertain cost elements below.

## **E.2 Bushfire Mitigation Contingent Projects**

In its preliminary proposal Powercor proposed two contingent projects: REFCLs (\$63 million) and Codified Areas (\$235 million), which we accepted. In its revised proposal, Powercor amended these amounts to a single contingent project of approximately \$163.1 million (\$2015).

We forecast approximately \$163.1 million (\$2015) of capital expenditure as reasonably necessary for the purpose of undertaking the bushfire mitigation contingent project. This comprises:

- our forecast capital expenditure of approximately \$105.8 million (\$2015) in respect of capital projects concerning the new or changed regulatory obligation or requirement in respect of earth fault standards; and
- our forecast capital expenditure of approximately \$57.3 million (\$2015) in respect of capital works concerning the new or changed regulatory obligation or requirement in respect of standards for asset construction and replacement in a prescribed area of the State.<sup>361</sup>

The proposal to consolidate the two streams of work into a single stream is supported by the Victorian Government on the basis that the work arises from a common obligation imposed by the planned amendment to the Bushfire Mitigation Regulations.<sup>362</sup> We consider this approach is reasonable. The need is established by the planned regulations and the regulations will also impose a common governance

---

<sup>361</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, p. 434.

<sup>362</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016-20*, p. 2-3.



framework. As discussed in this determination, we are satisfied that the activities can also be subject to a common trigger event.

In our preliminary decision we proposed to address the uncertainty in the capital requirements for this work progressively, across the regulatory control period. We said:

To minimise the risk that the appropriate capital amounts may be difficult to accurately identify our preference is deal with the capital need progressively across the next regulatory control period. This can be achieved by dealing with the contingent project program in tranches. By doing so, both the service providers and the AER, as well as stakeholders, can better identify costs as they arise in the initial tranche of projects and apply corrections based on actual outcomes to the second and any subsequent tranches of projects. Each tranche must be sized to meet the applicable materiality threshold.<sup>363</sup>

We note that our proposal to organise the contingent program into tranches has been interpreted differently to our intention, which was for Powercor to specify a number of contingent projects (i.e. tranches) spaced through the next regulatory control period, not a single contingent project approved in tranches. We note that the NER does not provide for approval of a single project in tranches. We discussed this issue with Powercor. Powercor acknowledged the AER's intention to divide the contingent project into up to three contingent projects.<sup>364</sup> We consulted with Powercor in formulating the modified approach of dividing the capital works requirement into three contingent projects and developing the replacement trigger events.

Before we address the tasks of dividing the work into tranches and determining the trigger events, we examine the overall forecasts for the affected work streams.

## E.2.1 REFCLs

Powercor estimated that to comply with this new obligation they will have to install REFCLs at 12 zone substations during the 2016–2020 regulatory control period, in addition to the two REFCLs already funded by us and which are to be installed at the Woodend and Gisborne zone substations.<sup>365</sup>

While we have not identified with any certainty the zone substations in which we will install REFCLs in the 2016–2020 regulatory control period, we have selected 12 zone substations for the purposes of preparing this cost forecast and have taken into account the particular characteristics of those zone substations and the variations with the size of the associated network compared to the base zone substation.<sup>366</sup>

---

<sup>363</sup> AER, *Preliminary decision, Powercor distribution determination 2016–2020*, October 2015, Attachment 6, p. 124

<sup>364</sup> File note of conversation Paul Dunn, AER with Brent Cleeve, Powercor, 24 February 2016.

<sup>365</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, p. 435.

<sup>366</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, p. 435.

We accept the Powercor estimate of 12 REFCLs is reasonable for the purpose of establishing a forecast. The actual number may vary depending on a point score assessment which can only be undertaken after the regulations are promulgated. In preparing this estimate Powercor has arrived at an average cost per installation of \$8.82 million (\$2015). The RIS suggests that for full replacement of surge diverters the average cost is approximately \$9.2 million (\$2015), or, if one-third of the surge diverters are replaced an average cost of \$6.6 million.<sup>367</sup>

We note that in support of their Revised Regulatory Proposals, Powercor and AusNet Services each referred to their submission to the Victorian Government consultation on the *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, November 2015 (i.e. the RIS). We have considered these submissions. The submissions by Powercor and AusNet Services each challenge the RIS costings, particularly in relation to the assumptions concerning the cost and number of surge diverters (surge arresters or lightning arresters) that would require replacement when a REFCL is installed.<sup>368</sup>

A submission by the CCP stated:

What concerns CCP3 is the apparent dichotomy of views as to what is required to implement recommendation 27 (preventing falling lines from starting a fire). A low cost solution has been developed using rapid earth fault current limiting (REFCL) devices, yet the DNSPs propose to also implement replacement of all surge devices to maximise the benefit of the REFCL devices so that supply can continue even when a powerline has fallen, enhancing reliability. As noted in section 2, consumers do not want to pay more for enhanced reliability, so CCP3 considers that the proposed surge diverter replacement program is not needed.<sup>369</sup>

We consider that as the Powercor estimate is based on full replacement and the average cost is close to the RIS estimate that the estimate is reasonable. However, as set out earlier in this determination, there is considerable uncertainty as to the need to replace all the surge diverters. Until a better investigation of each affected line is undertaken, there is not sufficient evidence for us to determine whether full, partial, or any replacement is necessary.

We understand that at the trial installation at Frankston South, the replacement rate was around one-third. In the preliminary decision for Jemena, the proportion of surge diverter replacement for their REFCL projects was less than one-third, on the basis most units were already adequately rated. We note the two units sought by United Energy also have an average unit cost much lower than Powercor. Although the shorter length of the feeders involved is a factor, we do not consider that factor alone

---

<sup>367</sup> ACIL Allen Consulting, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment (RIS)*, 17 November 2015, p. 70.

<sup>368</sup> AusNet Services, *RIS Response - Electricity Safety (Bushfire Mitigation) Regulations 2015*, 30 December 2015; Powercor, *Response to RIS - Electricity Safety (Bushfire Mitigation) Regulations 2015*, 30 December 2015.

<sup>369</sup> Consumer Challenge Panel, CCP3, *Victorian DNSPs revenue reset - Comments on AER Preliminary Decisions - Overview*, 25 February 2016, p. 24.

adequately explains the difference in average cost. A replacement rate of one-third is the basis of the Victorian Government RIS which was developed after extensive consultation with the Victorian distributors. For the purpose of setting a forecast for these contingent projects we prefer the RIS estimate.

Therefore, our total forecast for REFCL projects is set at  $12 \times \$6.6 = \$79.2$  million (\$2015). This amount will be distributed across up to three contingent projects as discussed later in this section. It is possible that a higher percentage of surge diverters will require replacement and Powercor may incur higher costs. Following the occurrence of a trigger event for a project it will be incumbent on Powercor to provide supporting evidence to demonstrate that a higher proportion should be replaced. This may result in a different forecast than the forecast which has been set here.

## E.2.2 Declared Areas

Powercor has developed a forecast of contingent capital expenditure based on the per kilometre cost to underground the sections and /or spans of electric lines which may need replacing during the 2016–2020 regulatory control period. The forecast is based on maps supplied by the Victorian Government of the expected target areas which, under the draft regulations, must be declared by the Essential Services Commissioner. Powercor expected that replacement works are likely to be the majority of works carried out during the 2016–2020 regulatory control period.

Having regard to the polygon maps supplied by the Victorian Department of Economic Development, Jobs, Transport and Resources on 12 October 2015 we estimate that over the 2016–2020 regulatory control period we will need to replace a total 90.1km of bare open wire conductor with an underground electric line in the areas of our distribution network marked on those polygon maps based on the condition of the line segments.<sup>370</sup>

The Victorian Government submission to the AER questions whether the projects proposed by the Victorian distributors in Declared Areas have correctly interpreted the scope and intent of the new regulations or if they are costed correctly.<sup>371</sup> Powercor also states in its revised proposal that the scope of works required to meet the requirements of the draft regulations in Declared Areas remains uncertain.<sup>372</sup> Of the total 90.1km of bare open wire conductor which Powercor estimated it would need to replace, Powercor assumed that 66.73km of polyphase electric lines would be replaced and 23.35km of single wire earth return (SWER) electric lines would be replaced.<sup>373</sup> In the absence of a declaration by the Emergency Management Commissioner and a more detailed investigation by Powercor, we accept these estimates as a reasonable basis to establish the forecast for this work. We note these estimates may later be found to

---

<sup>370</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 436.

<sup>371</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016-20*

<sup>372</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 435.

<sup>373</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 436.

be inaccurate and require adjustment based on the final form of the regulations and other work, which has yet to commence.

Powercor calculated the average cost per kilometre for SWER electric lines as the difference in unit cost between work undertaken for the Powerline Replacement Fund (\$256,669 per km) less the average unit cost reported the 2014 category analysis regulatory information notice (RIN) (\$51,700 per km). We have compared this estimate with the RIS and the our RIN information. We consider the amounts are consistent with our data sources. Therefore, we accept this estimate of \$4.79 million (\$2015).

Powercor calculated the average cost per kilometre for polyphase electric lines as the difference in unit cost between work undertaken for the Powerline Replacement Fund (\$842,005 per km) less the average unit cost reported the 2014 category analysis regulatory information notice (RIN) adjusted to exclude 66kV polyphase electric lines (\$55,400 per km).<sup>374</sup> We have also compared this estimate with the RIS and our RIN information. The estimate is approximately double the amount calculated in the RIS for this work. The Victorian Government commented on this difference in their submission.

Powercor has sourced the cost for undergrounding polyphase powerlines from the costs revealed through the Powerline Replacement Fund. The high cost revealed was heavily influenced by one 5.61 km of powerline that was in an expensive part of the state to underground powerlines. The Regulatory Impact Statement estimated a low cost for replacing polyphase powerlines of \$300,000 per km (prior to 2020) and a high cost of \$400,000 per km.<sup>375</sup>

As the rate proposed by Powercor appears high compared to the RIS and to the equivalent rates for similar work by other distributors, we have not accepted this estimate. The replacement rate published in the Victorian Government RIS was developed after extensive consultation with the Victorian distributors, we prefer the RIS estimates. There is uncertainty in the RIS estimates and both Powercor and AusNet have estimated higher rates than the RIS for this work. As the areas subject to these new requirements are likely to be in more remote areas we consider, on balance that the mid-point of the cost rates proposed in the RIS is appropriate, \$350,000 per km. Based on this rate, we consider the forecast for 66.73 km of polyphase line replacement should be set at \$23.36 million (\$2015).

Therefore, our total forecast for Declared Area projects is set at \$28.15 million (\$2015). This amount will be distributed across up to three contingent projects as discussed in the next section. Following the occurrence of a trigger event for a project it will be incumbent on Powercor to provide supporting evidence to demonstrate that a higher rate should apply. This may result in a different forecast for this work than the forecast which has been set here.

---

<sup>374</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 437

<sup>375</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016-20*, 12 February 2016, p. 3

### E.2.3 Number of contingent projects

As we discussed in our preliminary decision, in relation to the two contingent projects Powercor proposed initially, there is substantial uncertainty as to the cost impact that will result when the Bushfire Mitigation Regulations Amendment is enacted. The discussion here has highlighted that although the RIS has helped to reduce that uncertainty, significant issues remain to be addressed. This is a symmetrical risk in that any error in setting an ex-ante allowance may result in either the service provider or customers bearing excessive costs. This risk is higher than normal because the largest element of this cost will arise from the deployment on an unprecedented scale of the new REFCL technology. Neither us nor the businesses currently have sufficient experience of this technology to be able to forecast the efficient cost of deploying the new technology with confidence.

We therefore proposed that the work should proceed in tranches and Powercor has adopted that suggestion. The regulations impose a timetable for earth fault risk reduction which is assessed through a point score system. The construction standards risk reduction profile is managed through an inspection regime. Both limbs require that targeted locations be notified to the safety regulator, ESV and the target locations recorded through the applicable Bushfire Mitigation Plan (BMP) and actioned in accordance with the Plan. This is a dynamic process that extends across the regulatory control period and beyond.

It is not required that the whole program be known at the outset nor is the sequencing of target locations known with certainty until the amended BMP is accepted by the ESV.<sup>376</sup> There is no limit on the number of times a BMP may be amended. However, in practice amendments are not frequent.

Having regard to the BMP amendment process and the materiality threshold for contingent projects, for Powercor, based on the forecasts set in the preceding section which total \$107.35 million (\$2015), the maximum number is three tranches. We note that when we apply the materiality threshold set out in cl.6.6a.1(b)(2)(iii) for Powercor is to be set on the basis of 5 per cent of first year revenue (i.e. \$32 million) as this is greater than \$30 million.

We consider that either two or three tranches is manageable within the remainder of the regulatory control period. As we discuss in the next section, Powercor will be allowed flexibility to identify the projects that constitute a tranche within the limitations imposed by the need to satisfy the trigger event. In particular, a key requirement is to have obtained an acceptance or provisional acceptance from ESV of an amended BMP that requires works be undertaken at a nominated location. It will be incumbent on Powercor to manage its program of works according to the number of tranches available and the obligations imposed by the regulations. We consider three tranches

---

<sup>376</sup> For the sake of brevity we have said 'accepted'. A revised BMP may be 'accepted or accepted in part' by the ESV. All have the effect of requiring the distributor to undertake the associated work.

to be a reasonable maximum number. It should be noted that Powercor is not obliged to utilize all three contingent projects. Also, the actual amounts of individual projects will be linked to the approval given by the ESV to a specific program of works and may not correspond to the amounts set out here.

We have determined that Powercor may divide its 'bushfire mitigation contingent project' program into three tranches as follows:

Bushfire Mitigation contingent project 1 – \$36 million (\$2015)

Bushfire Mitigation contingent project 2 – \$36 million (\$2015)

Bushfire Mitigation contingent project 3 – \$35.35 million (\$2015)<sup>377</sup>

## **E.2.4 Trigger events for Bushfire Mitigation Contingent Projects**

For a contingent project a trigger event must be defined. Powercor proposed that the trigger event for each of their two proposed VBRC contingent projects should be the occurrence of a regulatory event, being the introduction of a new regulatory obligation by the State of Victoria. In our preliminary decision we rejected Powercor's proposed trigger event, which only referred to a change in regulations by the Victorian Government.

We considered this was an insufficient description of the factors which should be addressed before a contingent project could be approved. We substituted an alternative trigger event that comprised three factors which, taken collectively, we consider form the necessary conditions for a trigger event. We said:

Each contingent project category is to contain one or more tranches. These contingent projects are each subject to the three part trigger:

1. Passage by the State of Victoria of a law or regulations or other regulatory instrument that gives effect to recommendation 27 of the Victorian Bushfires Royal Commission, whether in part or in full.
2. The formation of capital projects into tranches. All the projects which constitute a tranche must be listed in a regulatory instrument or a bushfire mitigation plan approved by Energy Safe Victoria for completion in the 2016–2020 regulatory control period.
3. Every project incorporated in a tranche must be subject of a detailed design investigation which accurately identifies the scope of works and proposed costings.<sup>378</sup>

---

<sup>377</sup> The amounts shown here are notional budgets only. Actual amounts will vary as applications are received.

<sup>378</sup> AER, *Preliminary decision, Powercor distribution determination 2016–2020*, October 2015, Attachment 6, p. 125.



In its revised regulatory proposal Powercor has not accepted our trigger event. However, Powercor has accepted our approach to the description of the trigger event in three limbs. Powercor proposed an alternative wording:

In circumstances where a new or changed regulatory obligation or requirement (within the meaning given to that term by section 2D of the National Electricity Law) in respect of earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State is imposed on Powercor during the 2016–2020 regulatory control period, a bushfire mitigation contingent project trigger event occurs in respect of a tranche of capital projects or proposed capital works required for compliance with that regulatory obligation or requirement when either or both of the following occurs:

1. For capital projects concerning a new or changed regulatory obligation or requirement in respect of earth fault standards:

(i) Powercor has formed the capital projects into the tranche. Each of the capital projects must be listed for commencement or completion in the 2016–2020 regulatory control period in a regulatory instrument or a bushfire mitigation plan accepted or provisionally accepted or determined by Energy Safe Victoria; and

(ii) for each project in the tranche Powercor has completed a project scope which identifies the scope of works and proposed costings.

2. For proposed capital works concerning a new or changed regulatory obligation or requirement in respect of standards for asset construction and replacement in a prescribed area of the State, Powercor has completed a forecast of capital expenditure required for complying with the new or changed regulatory obligation or requirement.

As set out in the following paragraphs, we agree on some of the drafting proposed by Powercor but, for the reasons stated, we do not accept this trigger event as drafted.

We consider the Powercor proposal to refer to the passage of Victorian legislation or regulations in the form set out in section 2D of the NEL has merit.<sup>379</sup> At the time of our preliminary decision the form of the impending regulations was unknown. Our drafting sought to address this uncertainty by referring to the intent of the impending regulations. Powercor's drafting captures the effect of the change in regulations in terms that have a direct connection to the NEL. This drafting is also flexible if the Victorian Government were to adopt a different approach to these obligations or to change the scope of the regulations to consider matters other than the recommendations of the VBRC. Subject to the further amendments discussed in the following paragraphs, we have adopted this form of drafting.

---

<sup>379</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, pp. 437-438.



With respect to the second limb of our proposed trigger event Powercor suggested amendments to better reflect the requirements of the NER and the operation of the *Electricity Safety Act 1998* (Vic).<sup>380</sup>

Powercor noted that clause 6.6A.2(b)(v) and (vi) of the Rules provide that while contingent projects must be commenced during the relevant regulatory control period, they can be completed after the end of that regulatory control period. Our initial understanding was that the projects nominated for commencement in the 2016–20 regulatory control period were intended to be completed within the period. However, as capital works can suffer delays for unforeseen reasons, for a contingent project the NER makes provision for any work not completed in accordance with the initial timetable to continue into the next regulatory control period. We have amended the trigger event accordingly.

Further, Powercor submitted that under the *Electricity Safety Act 1998*, ESV does not approve a BMP. Rather, ESV may accept or provisionally accept a plan or, if no plan is submitted, determine a plan. We agree with Powercor that the trigger event should be amended to better reflect the alternative terms as provided for in that Act for acceptance or determination by ESV of a Bushfire Mitigation Plan.

In combining what were two projects originally into a common project Powercor has sought to create two projects with different trigger criteria. In support of this drafting Powercor has said:

Fourthly, we observe that the concept of tranching is not appropriate for proposed capital works concerning the new or changed regulatory obligation or requirement in respect of standards for asset construction and replacement in a prescribed area of the State. This is because this regulatory obligation concerns a new requirement for electric lines that are constructed or replaced in certain prescribed areas. We will not be undertaking a dedicated program with set periods for completion in respect this regulatory change. This is because when the new standard is implemented for an electric line depends on when the line is constructed or replaced, such that the timing of the required works and the incurring of costs will turn on matters other than the imposition of the new requirement.<sup>381</sup>

We do not agree with Powercor.<sup>382</sup> In its proposal Powercor make clear that there is uncertainty as to the locations which will be subject to the requirement to be reconstructed and the locations may change over the course of the regulatory control period.

The Proposed Bushfire Mitigation Regulations provide...for the Emergency Management Commissioner to declare an area of land to be an 'electric line

---

<sup>380</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 438–439.

<sup>381</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 439.

<sup>382</sup> NER, cl. 6.6A.1(c)(3)

construction declared area' by notice published in the Government Gazette (proposed regulation 5A)....

And

...there will not be any certainty regarding the areas for which we will be subject to the above obligations unless and until the Emergency Management Commissioner makes a declaration. Furthermore, the declared areas can change over the course of the 2016–2020 regulatory control period.<sup>383</sup>

Our intention when we proposed that the program be organised into tranches was to allow Powercor the flexibility to dynamically adjust its program of work if the locations to be treated were subject to a change in priority over the course of the regulatory control period. We said:

Although the Victorian Government may nominate that specific installations must be delivered by a particular date, this will not prevent the businesses from organising their programs into a different program. To achieve operational efficiencies the AER will allow projects to be swapped between tranches so long as this does not result in double counting for the purposes of assessing whether the trigger for a tranche has occurred.<sup>384</sup>

The mechanism for determining a change in priority of the REFCL program is now proposed to be through amendment of the Bushfire Mitigation Plan in response to a point score assessment of particular zone substations located in the areas set out in the regulations. When our preliminary decision was made the mechanism for prioritisation of the work program was unknown. The draft regulations assist in removing some of the uncertainty but it remains clear that the order of projects cannot be settled until the distributor undertakes further work. This approach requires the flexibility inherent in our approach to be continued to ensure that the contingent projects match the obligation that is to be imposed on Powercor.

We believe the same flexibility consideration applies to 'Declared Areas', although the mechanism that will result in a change of target locations differs. In the latter case, the target areas will be set by the Emergency Management Commissioner making a declaration that a specific region is a priority. This declaration in conjunction with Powercor's works program will identify the locations within the Powercor network where enhanced construction standards are to apply. Powercor will be required to report these locations to ESV. In practice, having regard to the lead times inherent in capital projects, we consider it probable that the number of declarations made by the Commissioner will be limited. However, as there is a distinct prospect of more than one tranche we consider a common approach should apply to both types of capital works.

---

<sup>383</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 435.

<sup>384</sup> AER, *Preliminary decision, Powercor distribution determination 2016–2020*, October 2015, Attachment 6, p. 125.

For us to approve the forecast for a contingent project we must be satisfied of the efficient cost faced by the service provider.<sup>385</sup> Powercor queried our intent when we required the project be subject to a detailed design investigation as part of the trigger event.

... the AER's trigger event required that each capital project within a tranche be the subject of a detailed design investigation. Capital projects undertaken by our business proceed through various stages of design investigation and the term 'detailed design investigation' suggests a late stage of project design, which requires significant expenditure to be incurred (in some cases millions of dollars) to get to that design stage.<sup>386</sup>

In its application Powercor make a number of statements that emphasise that these projects are uncertain in a number of material respects and, as a consequence, Powercor has adopted conservative estimates of the likely future costs for the purpose of estimating the likely costs.<sup>387</sup> We recognise that the decisions we make on ex-ante approval of capex will invariably incorporate a greater or lesser degree of uncertainty depending on the nature of the capital expenditure sought and the circumstances of the particular project. We have noted that under the draft regulations significant uncertainty currently exists as to the efficient cost a prudent operator would require to undertake these works. At this stage of the Victorian Government process to introduce these new requirements this level of uncertainty is understandable.

The contingent project mechanism is intended to assist in addressing these uncertainties. The current task is to set an indicative forecast for these projects based on the available information. At the time of the occurrence of the trigger event the same level of information is unlikely to be an adequate basis to set the contingent project forecast which will eventually flow from these projects.

By the time the trigger event occurs we expect that the business will have taken active steps to properly resolve the key uncertainties to an acceptable standard, as is the case for any normal future capital expenditure. It will be incumbent on Powercor to lodge sufficient supporting information to us to support their contingent project application when the trigger event occurs for each tranche. We expect that the business will prepare a reasonably detailed planning report or scope of works that identifies the key cost elements for each location in sufficient detail to be able to prepare a reliable forecast of expected costs. Powercor proposed that this take the form of a project scope of works and proposed costings. This is consistent with the normal approach to capital projects. We will assess the application and the supporting information in accordance with the NER when it is lodged.

We expect each tranche of these works to be discrete. It is not our intention that multiple applications should be considered concurrently for similar works. The

---

<sup>385</sup> NER, cl. 6.6A.1(b)(2)(ii).

<sup>386</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 439.

<sup>387</sup> Powercor, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 435-436.

assessment of a contingent project is a complex and resource intensive task. If concurrent applications were to arise for a business it would be appropriate for the business to delay its application to consolidate the applications into a single, larger tranche to minimise the risk of processing delays that would be likely to arise with multiple or concurrent applications.

## **E.2.5 AER trigger event**

### ***Bushfire Mitigation contingent project 1***

In circumstances where a new or changed regulatory obligation or requirement (within the meaning given to that term by section 2D of the National Electricity Law) ("relevant regulatory obligation or requirement") in respect of earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State is imposed on Powercor during the 2016–20 regulatory control period, the trigger event in respect of bushfire mitigation contingent project 1 occurs when all of the following occur:

1. Powercor has identified the proposed capital works forming a part of the project, which must relate to earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State and which are required for complying with the relevant regulatory obligation or requirement. The proposed capital works must be listed for commencement in the 2016–20 regulatory control period in regulations or legislation, or in a project plan or bushfire mitigation plan, accepted or provisionally accepted or determined by Energy Safe Victoria;
2. for each of the proposed capital works forming a part of the project Powercor has completed a forecast of capital expenditure required for complying with the relevant regulatory obligation or requirement;
3. for each of the proposed capital works forming a part of the project that relate to earth fault standards, Powercor has completed a project scope which identifies the scope of the work and proposed costings.

### ***Bushfire Mitigation contingent project 2***

In circumstances where a new or changed regulatory obligation or requirement (within the meaning given to that term by section 2D of the National Electricity Law) ("relevant regulatory obligation or requirement") in respect of earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State is imposed on Powercor during the 2016–20 regulatory control period, the trigger event in respect of bushfire mitigation contingent project 2 occurs when all of the following occur:

1. Powercor has identified the proposed capital works forming a part of the project, which must relate to earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State and which are required for complying with the relevant regulatory obligation or requirement. The proposed capital works must be listed for commencement in the 2016–20 regulatory control

period in regulations or legislation, or in a project plan or bushfire mitigation plan, accepted or provisionally accepted or determined by Energy Safe Victoria;

2. For each of the proposed capital works forming a part of the project Powercor has completed a forecast of capital expenditure required for complying with the relevant regulatory obligation or requirement;
3. for each of the proposed capital works forming a part of the project that relate to earth fault standards, Powercor has completed a project scope which identifies the scope of the work and proposed costings;
4. The AER has made a determination under clause 6.6A.2(e)(1) of the NER in respect of bushfire mitigation contingent project 1.

### ***Bushfire Mitigation contingent project 3***

In circumstances where a new or changed regulatory obligation or requirement (within the meaning given to that term by section 2D of the National Electricity Law) ("relevant regulatory obligation or requirement") in respect of earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State is imposed on Powercor during the 2016–20 regulatory control period, the trigger event in respect of bushfire mitigation contingent project 3 occurs when all of the following occur:

1. Powercor has identified the proposed capital works forming a part of the project, which must relate to earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State and which are required for complying with the relevant regulatory obligation or requirement. The proposed capital works must be listed for commencement in the 2016–20 regulatory control period in regulations or legislation, or in a project plan or bushfire mitigation plan, accepted or provisionally accepted or determined by Energy Safe Victoria;
2. for each of the proposed capital works forming a part of the project Powercor has completed a forecast of capital expenditure required for complying with the relevant regulatory obligation or requirement;
3. for each of the proposed capital works forming a part of the project that relate to earth fault standards, Powercor has completed a project scope which identifies the scope of the work and proposed costings;
4. The AER has made a determination under clause 6.6A.2(e)(1) of the NER in respect of bushfire mitigation contingent project 2.

## **E.2.6 Assessment of the trigger events**

We consider these trigger events satisfy clause 6.6A.1(c) of the NER. The trigger events are:

- reasonably specific and capable of objective verification;
- if the event occurs, undertaking the contingent project is reasonably necessary to achieve the capital expenditure objectives;

- will generate increased costs that relate to a specific location;
- the occurrence of that event is all that is required for the distribution determination to be amended; and
- the event is probable during the regulatory control period, but the inclusion of capital expenditure in relation to it under clause 6.5.7 is not appropriate because the costs associated with the event are not sufficiently certain.