



# **FINAL DECISION**

## **CitiPower distribution determination 2016 to 2020**

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

May 2016

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## Note

This attachment forms part of the AER's final decision on CitiPower'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

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## 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 CitiPower's total revenue requirement.<sup>1</sup>

This attachment sets out our final decision on CitiPower'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.

### 6.1 Final decision

We are not satisfied CitiPower's proposed total forecast capex of \$820.9 million (\$2015) reasonably reflects the capex criteria. This is 9.8 per cent greater than actual/estimated capex for the 2011–15 period (\$747.6 million). We substituted our estimate of CitiPower's total forecast capex for the 2016–20 regulatory control period. We are satisfied that our substitute estimate of \$774.8 million (\$2015) reasonably reflects the capex criteria. Table 6.1 outlines our final decision.

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

	2016	2017	2018	2019	2020	Total
CitiPower's revised proposal	166.8	200.0	180.1	153.5	120.5	820.9
AER final decision	160.3	190.7	169.0	142.9	111.9	774.8
Difference	-6.6	-9.4	-11.0	-10.5	-8.6	46.1
Percentage difference (%)	-3.9	-4.7	-6.1	-6.9	-7.1	-5.6

Source: CitiPower, *Revised proposal: Standard control - MOD 1.17 CP capex consolidation*, January 2016; AER analysis.

Note: Numbers may not add up due to rounding.

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

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

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

These reasons include our responses to stakeholders' submissions on CitiPower'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 CitiPower'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 CitiPower'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 CitiPower'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 CitiPower'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>CitiPower proposed a total capex forecast of \$820.9 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 \$774.8 million (\$2015) reasonably reflects the capex criteria. Our substitute estimate is 5.6 per cent lower than CitiPower'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 CitiPower'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 accept CitiPower's proposed augex forecast of \$201.6 million (\$2015) in its revised proposal. In reaching this view, we accept that CitiPower's forecast of maximum demand is realistic and CitiPower's forecast of proposed capex to upgrade its sub-transmission network is prudent and efficient.
Customer connections capex	We have included CitiPower forecast for connections capex of \$330.0 million (\$2015) in our capex decision. While CitiPower accepted our methodology from the preliminary decision, it submitted amendments were needed to the calculations to remove a double counting issue and to address the omission of the recoverable works. We have assessed the issues raised by CitiPower in its revised proposal and we are satisfied that CitiPower's revised forecast is consistent with the capex criteria.
Asset replacement capex	We have not included CitiPower's forecast repex of \$260.4 million in our substitute estimate. In particular we do not accept a number of CitiPower's "other" repex

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

(repex)	programs, including, pits and pillars replacement and some environmental programs and some cross arm replacement. We have instead included in our substitute estimate of overall total capex an amount of \$236.0 million (\$2015) for repex.
Non-network capex	<p>We accept CitiPower's forecast non-network capex of \$106.0 million (\$2015) as a reasonable estimate of the efficient costs a prudent operator would require for this category. We have included it in our alternative estimate of total capex for the 2016–2020 regulatory control period.</p> <p>In reaching this view, we accept CitiPower'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 CitiPower's forecast of proposed capitalised overheads of \$93.4 million (\$2015) in our substitute estimate. We have instead included in our substitute estimate of overall total capex an amount of \$92.7 million (\$2015) for capitalised overheads.</p> <p>We reduced CitiPower'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 CitiPower'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 CitiPower's proposed real labour cost escalators which form part of its total forecast capex reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2016–20 regulatory control period. We discuss our assessment of forecast our labour price growth for CitiPower in attachment 7.</p> <p>The difference between the impact of the real labour cost escalation proposed by CitiPower and that accepted by the AER in its capex decision is \$21.0 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 CitiPower a reasonable opportunity to recover at least the efficient costs it incurs in:<sup>3</sup>

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

As set out in appendix B we are satisfied that our overall capex 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.

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 CitiPower's network. We consider this

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

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

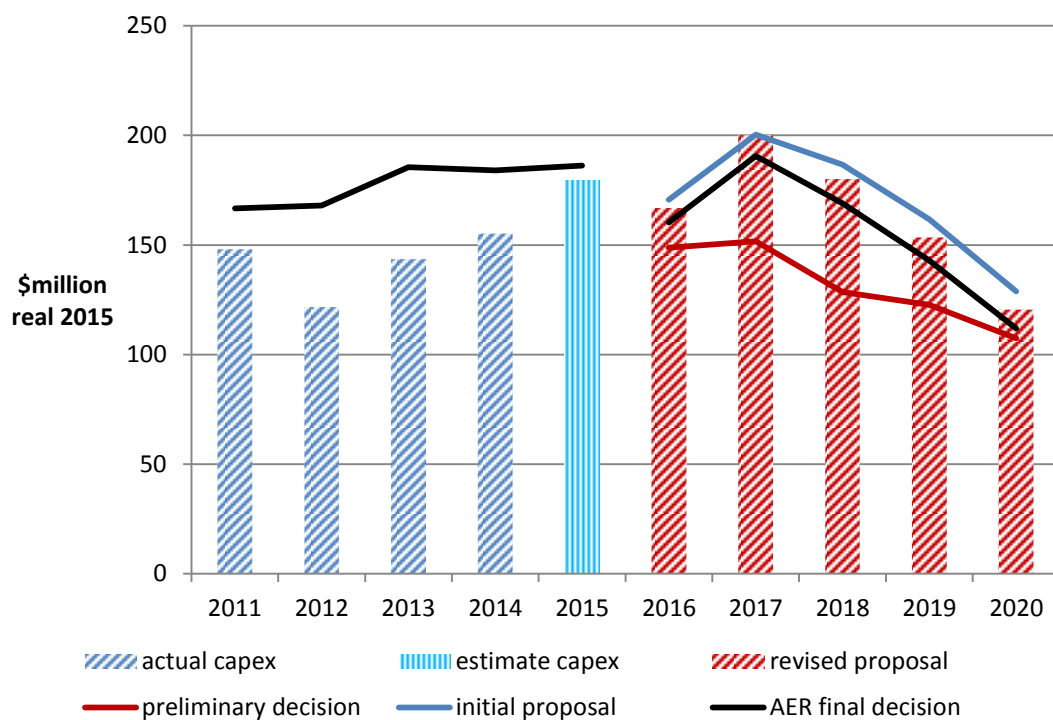
capex forecast should be sufficient for a prudent and efficient service provider in CitiPower's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

## 6.2 CitiPower's revised proposal

CitiPower's revised proposal included a total forecast capex of \$820.9 million (\$2015) for the 2016–20 regulatory control period.<sup>5</sup> This is 24.6 per cent higher than our preliminary decision and 3.2 per cent lower than CitiPower's initial regulatory proposal.

Figure 6.1 shows the difference between CitiPower'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 CitiPower spent during the 2011–15 regulatory control period.

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



Source: AER analysis.

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

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

<sup>6</sup> CitiPower, *Revised regulatory proposal 2016–2020*, January 2016, pp. 15, 193–194.

- re-proposed the project to augment its 11kV and 66kV networks and de-commission its 22kV sub-transmission network served from WMTS
- re-proposed 'un-modelled' replacement expenditure, and highlighted why the expenditure is not reflected in recent historical expenditure
- reduced augmentation expenditure across a couple of sub-transmission lines to reflect its latest 2015 demand forecasts
- re-forecasted gross customer connections adopting the AER's forecasting approach as well as correcting the AER's methodology for calculating customer contributions. CitiPower 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 CitiPower 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 CitiPower 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.
- 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

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<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).

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>

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

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<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.

In deciding whether we are satisfied that CitiPower'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 CitiPower 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 CitiPower, 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

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<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>

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<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 CitiPower'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>

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<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

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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 CitiPower. In this final decision, we are not satisfied CitiPower's total forecast capex reasonably reflects the capex criteria. We compared CitiPower's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. CitiPower'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 CitiPower'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	41.5	67.2	47.4	29.2	16.2	201.6
Connections	66.3	73.7	64.7	62.9	62.4	330.0
Replacement	44.5	45.4	56.7	52.0	37.4	236.0
Non-Network	25.3	30.8	21.2	16.5	12.2	106.0
Capitalised overheads	17.1	18.0	18.6	19.2	19.7	92.7
Labour and materials escalation adjustment	-1.8	-4.6	-5.0	-5.0	-4.5	-21.0
<b>Gross Capex (includes capital contributions)</b>	<b>192.9</b>	<b>230.6</b>	<b>203.7</b>	<b>174.8</b>	<b>143.4</b>	<b>945.2</b>
Capital Contributions	32.6	39.9	34.6	31.9	31.4	170.4
<b>Net Capex (excluding capital contributions)</b>	<b>160.3</b>	<b>190.7</b>	<b>169.0</b>	<b>142.9</b>	<b>111.9</b>	<b>774.8</b>

Source: AER analysis.

Note: Numbers may not add up due to rounding.

Our approved capex of \$774.8 million is \$115.7 million higher than our preliminary decision of \$659.1 million. The key components of our capex decision that have changed include:

- \$72 million for CitiPower's proposal to decommission and upgrade its 22kV sub-transmission network and associated extension of its 11kv network
- additional demand-driven augex (\$8.6 million) because we accept CitiPower's revised maximum demand forecasts
- additional repex (\$38 million), which mainly reflects delays in expenditure in the previous period associated with delays in transmission investment
- additional non-network capex for Power of Choice (\$8.2 million) and RIN compliance (\$5.3 million) as a result of new regulatory obligations.

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

CitiPower set out its key assumptions in its revised regulatory proposal.<sup>31</sup>

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

### 6.4.2 Forecasting methodology

The NER requires CitiPower 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>

CitiPower must include this information in its regulatory proposal.<sup>33</sup> The main points of CitiPower's forecasting methodology are set out in its regulatory proposal.<sup>34</sup>

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

<sup>31</sup> CitiPower, *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> CitiPower, *Regulatory proposal 2016–2020, Appendix E: Capital expenditure*, 30 April 2015, pp. 12–17.

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

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

<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.

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

...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 CitiPower 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 CitiPower's capex performance**

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

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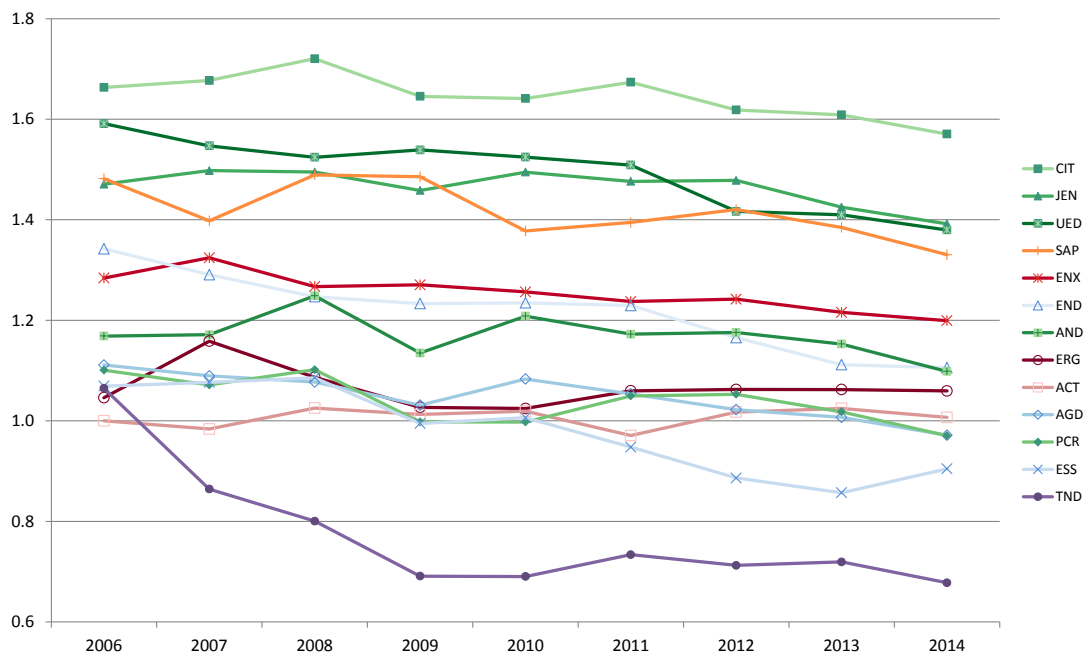
<sup>39</sup> CCP, *Advice to the AER: AER's Preliminary Decision for SA Power Networks for 2015–20 and SA Power Networks' revised regulatory proposal*, August 2015, p. 27.

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 CitiPower'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 CitiPower'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 subtransmission voltages) and transformers and other capital. CitiPower is the top performer for this measure among the distributors in the NEM.

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



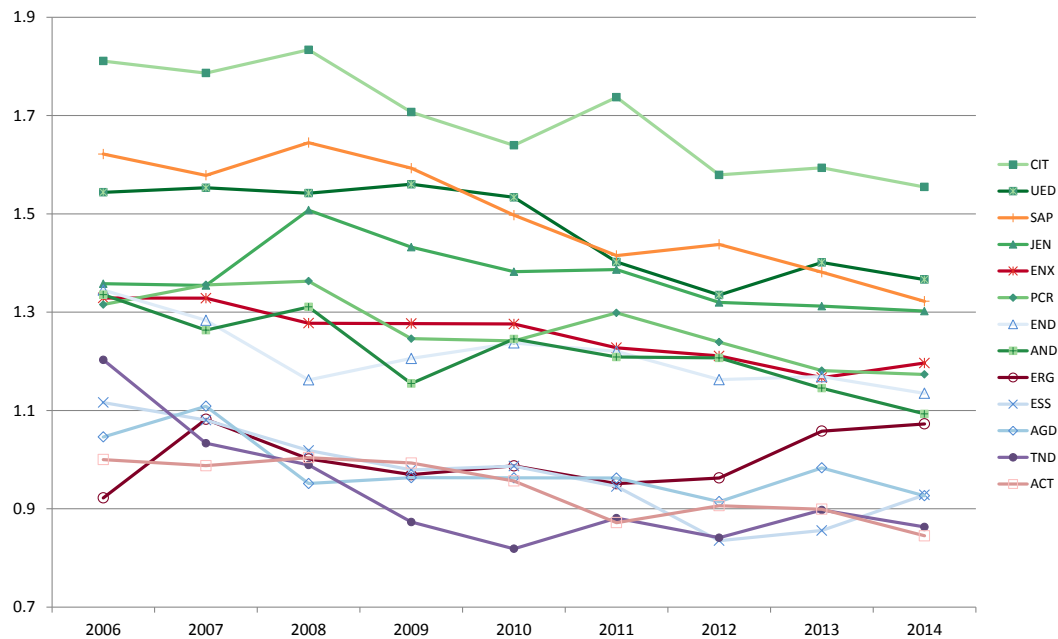
Source: AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2015, p. 11.

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). Figure 6.3 shows CitiPower is the top performer for this measure among the distributors in the NEM.

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



**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 CitiPower'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.

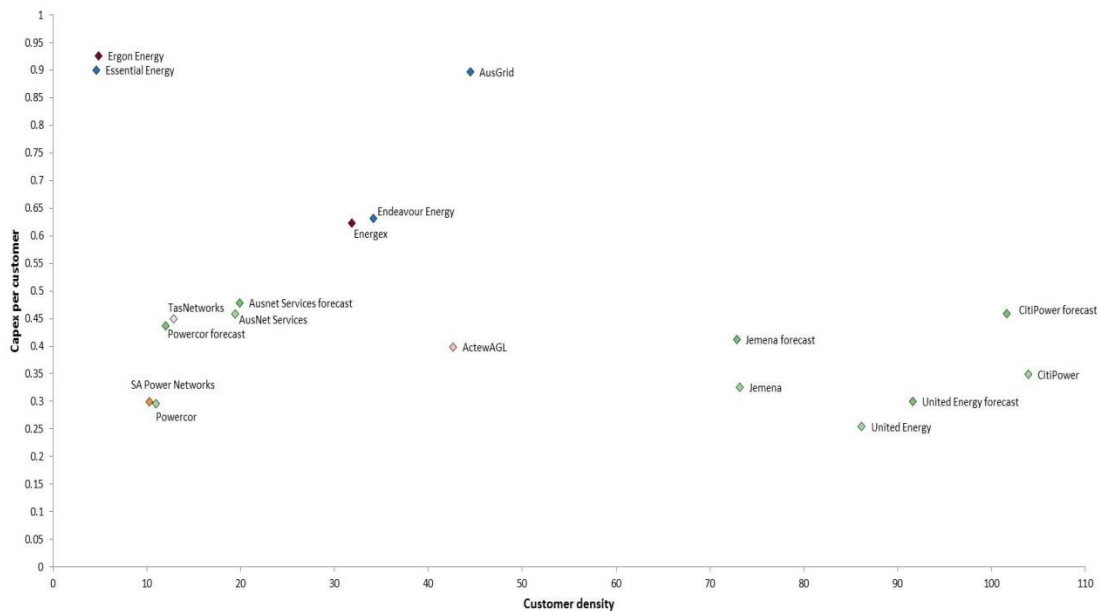
<sup>42</sup> NER, cl. 6.12.1(3).



other Victorian distributors as inputs to our assessment. We consider it is appropriate to compare CitiPower'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 CitiPower is an outlier in that it has by far the highest customer density of the distributors in the NEM. In the 2008–12 years, it spent more capex per customer than Jemena and United Energy (the closest to CitiPower in terms of customer density). Further, CitiPower's capex per customer will increase in the 2016–20 period based on their revised proposal forecast capex. CitiPower's capex per customer will be relatively high in the 2016–20 regulatory control period even when taking customer density into account.

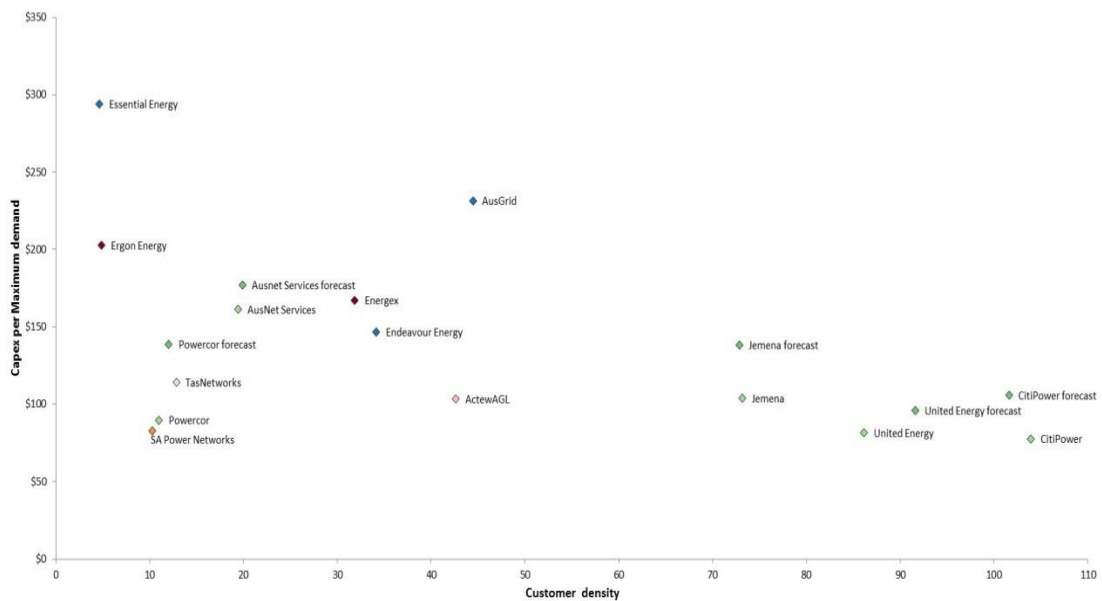
**Figure 6.4 Capex per customer (000's, \$2013–14), against customer density**



Source: AER analysis.

Figure 6.5 shows CitiPower spent less on capex per maximum demand in 2008–12 than Jemena and United Energy. Similar to Figure 6.4, capex per maximum demand 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**



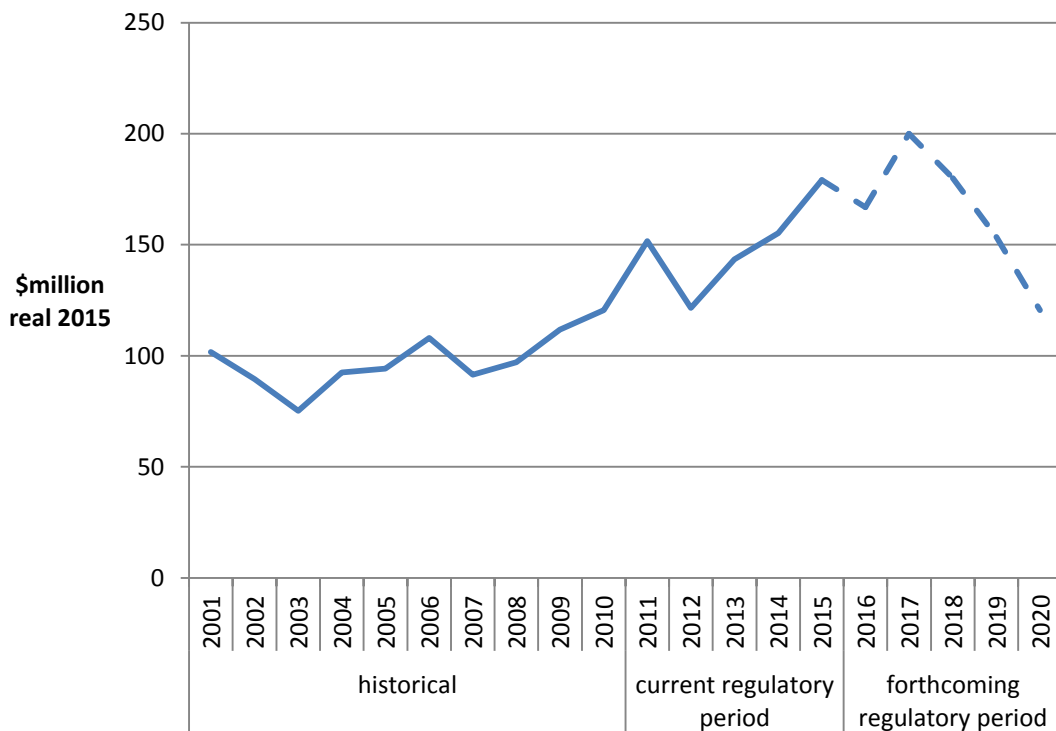
Source: AER analysis.

#### 6.4.4.3 CitiPower's historical capex trends

We compared CitiPower'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 CitiPower's forecast is significantly higher than historical levels (actual spend), particularly for the first three years of the regulatory control period. CitiPower's capex forecast falls towards the end of the regulatory control period (to bring it back in line with the average levels of the 2011–15 regulatory control period).

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



Source: AER analysis.

VECCUA noted the Victorian distributors' initial capex proposals, including CitiPower'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 CitiPower's revised total capex forecast for the 2016–20 regulatory control period is approximately \$73 million, or 10 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> CitiPower, *MOD 1.17: Capex consolidation*, April 2015; CitiPower, *Standard control: MOD 1.17: 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 CitiPower's revised proposal reflects its expected operating environment.

## 6.4.5 Interrelationships

There are a number of interrelationships between CitiPower'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 CitiPower'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 CitiPower</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 CitiPower'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 CitiPower'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 CitiPower's regulatory asset base. In particular, the CESS will ensure that CitiPower bears at least 30 per cent of any overspend against the capex allowance. Similarly, if CitiPower 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, CitiPower risks having to bear the entire overspend.
Service Target Performance Incentive Scheme (STPIS)	<p>The STPIS is related to CitiPower'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 CitiPower 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 CitiPower systematically under or over performing against its targets.</p>
Contingent project	<p>A contingent project is related to CitiPower'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 CitiPower's total forecast capex for the 2016–20 regulatory control period.</p> <p>We did not identify any contingent projects for CitiPower during the 2016–20 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 CitiPower'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).

**Table 6.5 AER consideration of the capex factors**

Capex factor	AER consideration
The most recent annual benchmarking report and	We had regard to our most recent benchmarking report in

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

benchmarking capex that would be incurred by an efficient distributor over the relevant regulatory control period	assessing CitiPower'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 CitiPower's capex performance.
The actual and expected capex of CitiPower during any preceding regulatory control periods	<p>We had regard to CitiPower'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 CitiPower's capex performance. It can also be seen in our assessment of the forecast capex associated with the capex drivers that underlie CitiPower's total forecast capex.</p> <p>For some elements of non-network, augex, repex and connections 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 CitiPower in the course of its engagement with electricity consumers	We had regard to the extent to which CitiPower's proposed total forecast capex includes expenditure to address consumer concerns that CitiPower identified. CitiPower has undertaken engagement with its customers and presented high level findings regarding its customer preferences. These findings suggest that consumers value lower prices and are satisfied with current levels of reliability.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing CitiPower's proposed real cost escalation factors. In particular, we have not accepted CitiPower's proposed labour escalation and to apply real cost escalation for materials.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion about the interrelationships between CitiPower'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 CitiPower	We had regard to whether CitiPower's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion about the interrelationships between CitiPower'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 CitiPower's proposed total forecast capex or our alternative estimate is referable to arrangements with a person other than CitiPower that do not reflect arm's length terms. We do not have evidence to indicate that any of CitiPower'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 CitiPower's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did not identify any such amounts that should more appropriately be included as a contingent project.
The extent to which CitiPower has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which CitiPower made provision for efficient and prudent non-network alternatives as part of our assessment. In particular, we considered this within our review of CitiPower's augex proposal.
Any other factor the AER considers relevant and which the AER has notified CitiPower in writing, prior to the submission of its revised regulatory	We did not identify any other capex factor that we consider relevant.

proposal, is a capex factor

Source: AER analysis.

## A Assessment techniques

This appendix describes the assessment approaches we applied in assessing CitiPower's total forecast capex. We used a variety of techniques to determine whether the CitiPower 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 CitiPower'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>

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<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

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<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

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<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 CitiPower's augex forecast.

## A.5 Engineering review

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

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<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 CitiPower'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 CitiPower'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 CitiPower'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 CitiPower's revised 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 CitiPower's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in this appendix B.

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

### **B.2 Forecast augex**

We accept CitiPower's forecast augex of \$201.6 million (\$2015) for the 2016–20 regulatory control period that it proposes in its revised augex proposal. We accept that

CitiPower's revised augex forecast reasonably reflects the capex criteria and will enable CitiPower to achieve the capex objectives.

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

**Table 6.6 CitiPower augex forecasts comparisons (\$2015 million, excluding overheads)**

	2016	2017	2018	2019	2020	Total
Initial augex forecast	42.3	67.7	47.8	29.3	16.3	203.3
AER preliminary decision	40.0	38.7	13.3	13.1	14.1	119.2
Revised Proposal	42.3	67.2	47.5	29.3	16.3	201.6
AER final forecast	42.3	67.2	47.5	29.3	16.3	201.6

Source: AER analysis.

Our reasons for accepting CitiPower's revised augex proposal are set out in sections B.2.3 and B.2.4.

## B.2.1 CitiPower's revised proposal

CitiPower's revised augex proposal is \$201.6 million (\$2015). As shown in Table 6.7, CitiPower's proposed augex forecast is comprised of capex to meet demand, capex for non-demand projects, and a small amount of capex for bushfire safety (listed as VBRC). Non-demand capex comprises the largest component of CitiPower's augex.

**Table 6.7 CitiPower's proposed augex (\$2015, million, excluding overheads)**

Category	2016	2017	2018	2019	2020	Total
Demand	13.6	14.1	10.0	10.2	10.4	58.4
Non-demand	28.0	50.5	35.2	16.8	3.8	133.45
VBRC	0.6	2.6	2.2	2.3	2.1	9.8
Total augex proposal	42.3	67.2	47.5	29.3	16.3	201.6

Source: CitiPower reset RIN; CitiPower revised regulatory proposal

Note: Numbers may not add up due to rounding.

CitiPower's revised augex forecast is \$1.7 million (\$2015) lower than its initial proposal. In developing its revised forecast, CitiPower:

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

- Provided additional supporting information for its major project to decommission its 22kV sub-transmission network

CitiPower's reasoning and revised proposal is considered in detail in section B.2.3 and B.2.4.

## **B.2.2 AER approach**

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

First, we considered CitiPower'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 CitiPower's forecasts of maximum demand likely do not reflect a realistic expectation of demand over the 2016–20 period. We considered that a forecast of \$49.8 million reflected the prudent and efficient amount to meet a realistic expectation of demand over the 2016–20 period, which was 15 per cent less than CitiPower's proposal.

CitiPower's revised proposal includes updated maximum demand forecasts and revised demand-augex, including responses to the issues we raised in the preliminary decision. We also received submissions from the Victorian Energy Consumer and User Alliance (VECUA) and the Consumer Challenge Panel (CCP) on our preliminary decision and CitiPower's revised proposal. Section B.2.3 responds to CitiPower and consumer submissions and sets out our final decision on CitiPower's demand-augex forecast.

Second, we undertook a technical review of CitiPower's major non-demand projects — its Melbourne CBD security project and its 22kV sub-transmission network decommissioning project. In undertaking these technical reviews, we drew on engineering and other technical expertise within the AER. On the basis of our analysis, we found that:

- CitiPower's proposed \$36.7 million for its proposed Melbourne CBD security project reasonably reflects the capex criteria.
- CitiPower's proposed \$74.7 million for the 22kV sub-transmission network decommissioning project is not required to address an augmentation driver, and we have not included it in our alternative estimate. We stated that, if CitiPower is of the view that, given the condition of the assets, it requires more than business as usual repex to meet the capex objectives then it should provide supporting information to this effect in its revised proposal.

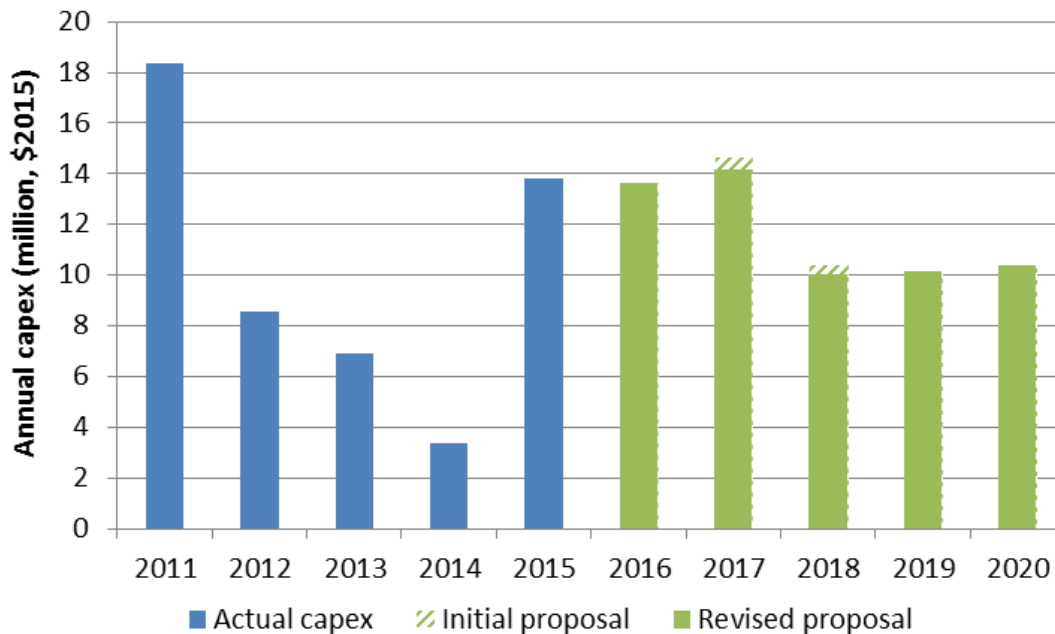
CitiPower's revised proposal includes further supporting information for the sub-transmission network decommissioning project. We consider this information in section B.2.4 which sets out our final decision on CitiPower's non-demand augex forecast.

Finally, we accepted CitiPower's proposed capex to implement the recommendations of the Victorian Bushfires Royal Commission (VBRC).

### B.2.3 Demand driven augmentation

CitiPower's revised proposal included \$58.4 million in augex to respond to forecast maximum demand over the 2016–20 period. As shown in Figure 6.7, CitiPower has decreased its proposed demand-driven augex slightly from its initial regulatory proposal. CitiPower's revised proposal is 14 per cent higher than its actual demand-augex between 2011–15.

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



Source: AER analysis, CitiPower revised proposal

As set out in Appendix C, CitiPower is forecasting growth in maximum demand over the 2016–20 period of 3 per cent annum. This growth in maximum demand is the key driver of the increase in augex forecast compared to actual expenditure in the recent regulatory control period.

In our preliminary decision, we found that CitiPower'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 CitiPower'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.

We concluded that reducing CitiPower's proposed augex by \$9.4 million would likely result in a prudent and efficient amount to meet a realistic expectation of demand over the 2016–20 period. However, we stated that we will consider updated demand forecasts and other information (such as updated demand forecasts from the AEMO) in our final decision to reflect the most up to date data. More detail about our assessment is set out in our preliminary decision.

In its revised proposal, CitiPower has reduced its overall maximum demand forecasts by approximately 12 per cent. In addition, AEMO's latest demand forecasts estimates higher levels of demand growth in CitiPower's network. As set out in Appendix C, we are satisfied that CitiPower's revised maximum demand forecasts reflect a realistic expectation of demand over the 2016–20 period.

In turn, CitiPower has reduced its forecast demand-augex slightly (as shown in Figure 6.7). This reduction in demand augex in response to reduced and realistic maximum demand forecasts gives us some confidence in CitiPower's forecast capex. However, given the small decrease in demand augex, we have also looked at network utilisation to examine the impact of revised maximum demand forecasts on the need for network augmentation.<sup>67</sup>

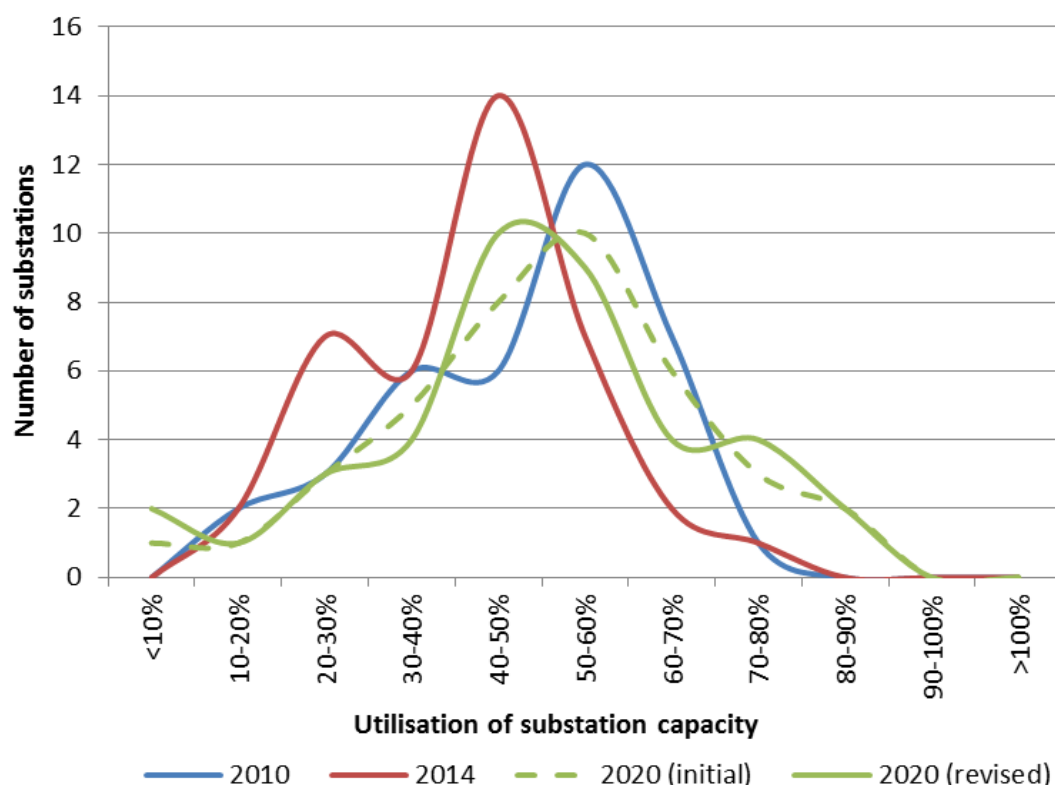
Figure 6.8 shows CitiPower's network utilisation (at the zone substation level) between 2010 and 2020. It shows that CitiPower experienced a decline in overall network utilisation between 2010 and 2014 due to augmentation and a flattening of demand (shown by a shift to the left in network utilisation by 2014). In contrast to the most recent years, CitiPower 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.

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<sup>67</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.



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



Source: AER analysis; augex model, CitiPower reset RIN, CitiPower 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>68</sup>

As further shown in Figure 6.8, CitiPower's revised demand forecasts mean that the number of moderately utilised zone substations (e.g. between 40 and 60 per cent) declines (shown by the difference between the two green lines). However, the number of highly utilised zone substations has remained the same, if not increased. This indicates that capacity constraints remain on the network and have not changed significantly between the initial and revised maximum demand forecasts.

On the basis of our acceptance of CitiPower's revised maximum demand forecasts, and the stability of CitiPower's network utilisation forecasts, we accept that CitiPower's revised augex forecast is required to meet a realistic expectation of demand over the 2016-20 period. While CitiPower has not significantly reduced its augex forecast

<sup>68</sup> We have used CitiPower's 'Transformer Normal Cyclic Total' reported in its Reset RIN, rather than using the reported 'Substation Normal Cyclic' rating. CitiPower 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 CitiPower, 2014 Reset RIN basis of preparation, p. 26.

between its initial and revised proposals, its demand-driven capex comprises a relatively small component of its total augex forecast.

The CCP's and VECUA's submissions to our preliminary decision and CitiPower's revised proposal raise some concerns with our augex allowance. The CCP submission examined trends in CitiPower 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:

- 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 during the 2016–20 regulatory control 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:

- 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 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 6.4.2, we use a combination of top-down and bottom-up assessment techniques to estimate the efficient and prudent capex that CitiPower will require to meet its obligations given expected demand growth and other augmentation drivers. Top-down and bottom-up techniques are both 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, CitiPower'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 above, which shows that a number of specific zone substations are expected to be highly utilised by the end of the 2016–20 period (and remained so between the initial and revised demand forecasts)

As we note above, CitiPower's demand-augex is 14 per cent higher than the augex CitiPower 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. CitiPower's augex forecast is driven by forecasts of maximum demand growth over the 2016-20 period. While CitiPower's trend in maximum demand growth has been relatively flat between 2009 and 2015, CitiPower is now forecasting some growth in maximum demand which is driving the increase in augex. However, as set out in Appendix C, CitiPower's maximum demand forecast for the 2016–20 period is consistent with updated independent forecasts from AEMO, which suggests that CitiPower'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. In other regulatory decisions, we also conducted bottom-up reviews by examining more localised network constraints and engaging in more detailed economic and engineering reviews augex forecast (e.g. Jemena and Powercor).

In CitiPower's proposal, it did not propose major demand-driven augex projects such as major zone substation augmentations. Instead, we determined the likely overestimation of CitiPower's demand-augex based on comparing CitiPower's demand forecasts to realistic demand forecasts and applied a top-down adjustment to CitiPower's demand-augex proposal. We considered that this top-down analysis was sufficient for us to determine an alternative estimate of augex for CitiPower. We have maintained this approach for the final decision.

We conducted more detailed technical and engineering reviews of CitiPower's non-demand augex (as set out in section B.2.4).

## **B.2.4 Non-demand driven augex**

CitiPower proposes \$133.45 million (\$2015) for non-demand related capex projects over the 2016–20 period. This is primarily comprised of two projects:

- \$36.7 million to complete its Melbourne CBD security upgrade, and
- \$74.7 million to decommissioning the CitiPower 22kV sub-transmission network and replace it with a 66kV network.

In our preliminary decision, we included an alternative estimate of \$60 million for non-demand augex.<sup>69</sup> We assessed these two large projects with the assistance of our engineering and other technical expertise. We found that:

- CitiPower's proposed \$36.7 million for its proposed Melbourne CBD security project reasonably reflects the capex criteria. CitiPower is required under the Victorian Electricity Distribution Code to upgrade the network security of the Melbourne CBD network. Based on CitiPower's supporting information, we were satisfied that the proposed capex reflects a prudent and efficient amount to meet this obligation.<sup>70</sup>
- CitiPower's proposed \$74.7 million for the 22kV sub-transmission network decommissioning project relates to asset condition rather than meeting a capacity constraint on the network. We stated that, if CitiPower is of the view that, given the condition of the assets, it requires more than business as usual repex to meet the capex objectives then it should provide supporting information to this effect in its revised proposal. We did not include this capex within our alternative estimate of augex.<sup>71</sup>

CitiPower accepted our preliminary decision for the CBD security project and its VBRC-related capex and included this capex within its revised proposal. We include this capex in our final augex estimate for CitiPower and do not re-examine it further.

CitiPower's revised proposal has retains its proposed capex for the West Melbourne 22kV decommissioning project within its augex forecast, and also submitted additional supporting information and cost-benefit analysis for this project. We have reviewed all of the material submitted by CitiPower for this project in its revised regulatory proposal. On the basis of our review, we are satisfied that the proposed capex reasonably reflects the capex criteria, and it is reasonable to include this capex within augex. Our reasons are set out below.

## **West Melbourne 22kV decommissioning project**

CitiPower proposes \$72.1 million (\$2015) over the 2016–20 regulatory control period for the joint decommissioning (with AusNet Services (transmission)) of the 22kV assets at the West Melbourne Terminal Station (WMTS) and the 22kV sub-transmission assets in the area serviced by the WMTS. The 22kV assets would be replaced by a mixture of 66kV and 11kV distribution assets, while the transmission assets would be serviced by AusNet Services' 66kV assets at the WMTS.

We did not include this project in our forecast of efficient capex in our preliminary decision. In response to our preliminary decision, CitiPower has provided further information, including an updated business plan and explanation of its net present value analysis of the project, in which it seeks to demonstrate that the upgrade is a

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<sup>69</sup> AER, *Preliminary Decision CitiPower 2016-20, Attachment 6*, October 2015, p. 45.

<sup>70</sup> AER, *Preliminary Decision CitiPower 2016-20, Attachment 6*, October 2015, pp. 47-49.

<sup>71</sup> AER, *Preliminary Decision CitiPower 2016-20, Attachment 6*, October 2015, pp. 45-47.

lower cost option than like-for-like replacement, and consequently should be included in the forecast of efficient capex.

### ***Updated business plan and net present value assessment***

The augmentation project is essentially a reconfiguration of AusNet Services' and CitiPower's transmission, sub-transmission and distribution assets, in that a different mix of assets would be used to provide essentially the same network service to customers. CitiPower submitted that the cost (in net present value terms) of the augmentation (which will take place from 2016–19) is lower than the cost of replacing the distribution and transmission assets on a like for like basis (which it considers will require replacement over the next 20 years). Consequently, CitiPower considers the reconfiguration to be the lowest cost option replacing the 22kV assets in the area serviced by the WMTS.

CitiPower submitted that the project involves:<sup>72</sup>

- decommissioning the ageing 22 kV sub-transmission network supplied from WMTS, and upgrading the 66 kV sub-transmission network connected to WMTS
- decommissioning the three ageing 22 kV substations supplied by the 22 kV sub-transmission network, and extending the 11 kV distribution network to transfer supply to the upgraded 66 kV network
- extending the 11 kV network to transfer load and enable decommissioning of a fourth zone substation
- converting two existing 22 kV feeders to 66 kV, and
- undertaking site remediation of the decommissioned zone substation sites.

CitiPower submitted that the total capex for the project is approximately \$72.1 million (\$2015).<sup>73</sup> CitiPower submitted that that the capex it would avoid by augmenting (or reconfiguring) its network (rather than like-for-like replacement) is \$99.7 million over twenty years, while the saving for AusNet Services (Transmission) is \$41 million<sup>74</sup> over ten years. CitiPower provided a net present value assessment to compare the cost of the two options (augmentation or business as usual like-for-like replacement). Table 6.8 below shows the outcome of this assessment.

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<sup>72</sup> CitiPower, *Updated business case and response to AER Preliminary Decision — WMTS22kV decommissioning*, December 2015, p. 7

<sup>73</sup> CitiPower's net present value analysis indicates that AusNet Services (Transmission) will require \$2.2 million to decommission its assets at the WMTS.

<sup>74</sup> CitiPower noted that, if the project proceeds, there will be no need for AusNet Services (Transmission) to replace the existing 22 kV switchyard and transformers at WMTS, resulting in net savings in AusNet Services' WMTS transmission rebuild project of approximately \$41 million.

**Table 6.8 Net present cost of augmentation and replacement options**

	Discounted cost	CitiPower	AusNet
Augex option	\$61,900.90	\$60,182.23	\$1,718.68
Repex option	\$93,766.01	\$65,756.85	\$28,009.16
Difference	-\$31,865.10	-\$5,574.62	-\$26,290.48

Source: Citipower, *Updated business case and response to AER Preliminary Decision — WMTS22kV decommissioning*, December 2015

We accept that, where both options provide the same service to energy customers, the lower cost option is likely to be in the long term interests of consumers.<sup>75</sup> As such, if the net present cost of the augmentation option is lower than the net present cost of like-for-like replacement, we are satisfied that the augmentation option is likely to reasonably reflect the capex criteria.

In order to test the validity of CitiPower's submission, we reviewed its business plan and conducted sensitivity testing of its net present value analysis. In relation to its business plan, the unit cost of asset replacement is consistent with observation of similar asset replacement unit costs for other distributors. Furthermore, the timing of asset replacements (at an average age of around 64 years for the power transformers) is broadly consistent with asset replacement ages observed from our calibrated predictive model (see our assessment in section B.4). Consequently, we are satisfied that the costs and timing presented in the "replacement" scenario are likely to reasonably reflect CitiPower's business as usual replacement needs going forward.<sup>76</sup>

We tested the sensitivity of CitiPower's net present value analysis under several counterfactual scenarios:

- using a higher discount rate (leading to greater discounting of future cash flows)
- assuming that like-for-like replacement would take place five years later than presented by CitiPower (resulting in the savings from the avoided like-for-like costs being more heavily discounted)
- reducing the business as usual cost of like-for-like asset replacement by 20 per cent
- delaying transmission replacement timing by five years (and holding distribution costs to the timing submitted by CitiPower), and

<sup>75</sup> Given the project is primarily driven by the condition of the 22kV asset, rather than in response to network constraints or demand growth, it is assumed that the customers serviced by these assets are likely to require similar services going forward, rather than significantly enhanced services.

<sup>76</sup> These replacements would essentially be brought forward in the planned 22kV decommissioning and upgrade project. The project would remove the majority of assets from service before the end of their expected useful life (bringing forward the associated cash flows).



- delaying distribution replacement timing by five years (and holding transmission costs to the timing submitted by CitiPower).

The augmentation (reconfiguration) option remained the lowest cost option under each of these scenarios. Based on this testing, we are satisfied that the augmentation option represents the lowest cost option to customers. That is, the cost of augmentation is lower than the avoided cost of replacing the assets on a like-for-like basis over time.

While we are satisfied that \$72 million for the augmentation project reasonably reflects the capex criteria, this is on the basis that the project is only prudent and efficient when supported by ongoing repex savings in transmission and distribution. CitiPower has identified \$33 million of savings (\$nominal, or \$30 in present value) of avoided replacement in the 2016–20 regulatory control period. On this basis, we have considered whether CitiPower's business as usual repex for the regulatory control period needs to be adjusted to reflect these savings.

We consider that CitiPower's business as usual repex for the 2016–20 regulatory control period is likely to already reflect some savings from similar augex/repex trade-offs already achieved in the 2011–15 regulatory control period. During the 2011–15 regulatory control period, CitiPower undertook a project of a similar nature where it decommissioned aging 22kV assets at its Prahran zone substation and extended its 66kV network to this supply area. The cost of this project (augex) was \$19.8 million, while the estimated avoided costs of replacing the Prahran zone substation was \$34.3 million (avoided repex).

Our predictive model (repex model) uses historical replacement volumes to estimate business as usual replacement volumes going forward. As some end of life replacement was avoided through the Prahran decommissioning, the repex model for the 2016–20 regulatory control period is likely to already reflect repex savings going forward. Given the scale of the saving achieved by the Prahran decommissioning, we consider our estimate of business as usual repex already reflects the repex savings in the next period resulting from CitiPower's augmentation expenditure on the 22kV decommissioning around the WMTS.

To the extent that CitiPower is able to derive further benefits from undertaking the augmentation above these expected benefits, these will be shared between CitiPower and customers through the capital expenditure sharing scheme. We also note that around half the savings estimated by CitiPower (\$66 million, \$nominal or \$36 million in present value terms) are likely to occur in the subsequent three regulatory periods. Consequently, this augex project is likely to provide savings to consumers beyond the end of the 2016–20 regulatory control period.

In addition, AusNet Services (Transmission) has identified \$43 million (\$nominal) of savings through the decommissioning of its 22kV assets at the WMTS (\$17 million in the next regulatory control period, and \$26 million in the period following that). AusNet Services has included these savings in its regulatory proposal for its 2017–22 regulatory control period.

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

Connections capex is incurred by CitiPower 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 CitiPower or a third party. The new customer may be required to 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, CitiPower 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 CitiPower recovers revenue associated with the capex investment. For works involving a customer contribution, CitiPower recovers revenue directly from the customer who initiates the work at the time the work is undertaken. This is different from net capex where CitiPower recovers revenue for this expenditure through both the return on capital and return of capital building blocks that form part of the calculation of CitiPower's annual revenue requirement. That is, CitiPower 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 CitiPower's revised proposal for connections capex of \$330.0 million (\$2015) reasonably reflects the capex criteria.<sup>77</sup> We have included this amount in our substitute estimate of forecast capex as shown in Table 6.9. Further, we accept CitiPower's revised proposal for customer contributions of \$170.4 million (\$2015).

**Table 6.9 AER final decision adjusted connections capex (\$2015 million excluding overheads)**

	2016	2017	2018	2019	2020	Total
Connections capex	66.3	73.7	64.7	62.9	62.4	330.0
Customer contributions	32.6	39.9	34.6	31.9	31.4	170.4

Source: AER analysis.

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<sup>77</sup> NER, cl. 6.5.7(c).



Table 6.10 provides a comparison of the forecasts expenditure on connection components.

**Table 6.10 Connections capex forecast comparison (\$2015) million, excluding overheads)**

	Initial Regulatory Proposal	Preliminary Determination	Revised regulatory proposal	Final decision
Gross connections capex	332.1	236.2	330.0	330.0
Capital contributions	144.9	58.8	170.4	170.4
Net connections capex	187.2	177.4	159.6	159.6

Source: AER analysis.

### B.3.2 Revised proposal

CitiPower's revised proposal accepts the reasons for our preliminary decision with respect to the volume of connections it will be required to undertake over the 2016-20 regulatory control period.<sup>78</sup> CitiPower does however consider that our preliminary decision made modelling errors which results in our preliminary decision understating the gross connections capex it required to meet the capex criteria. As Table 6.10 above shows, after correcting for these errors, CitiPower's revised proposal includes a forecast of connections capex of \$330.0 million (\$2015) for 2016-20 regulatory control period.

With respect to customer contributions, CitiPower's revised proposal includes an amount of \$170.4 million (\$2015). As Table 6.10 shows CitiPower's revised proposal represents an increase above our preliminary decision and CitiPower's initial proposal. In its revised proposal CitiPower notes that given changes to the assumptions which underpin the calculation of customer contributions it is inappropriate to rely on average historical levels to forecast the amount of capcons for the 2016–2020 regulatory control period. In particular, CitiPower's revised proposal considers that the customer contribution rate applied to its gross connections capex forecast should reflect the x factor and rate of return implicit over the 2016-20 period and be adapted to ensure that the applicable customer contribution guideline form the basis of the calculation.<sup>79</sup>

### B.3.3 Reasons for AER Position

CitiPower's revised proposal combines two separate forecasts of customer connections capex, depending on whether the category of connection has a high or

<sup>78</sup> CitiPower, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 216.

<sup>79</sup> CitiPower, *Revised Regulatory Proposal 2016–2020*, January 2016, pp. 217–218.

low volume of activity.<sup>80</sup> A contribution rate is then applied to these gross connection capex forecasts to produce the split between net capex and customer contributions.

### **Gross connections capex**

#### *Volumes*

In our preliminary decision we rejected CitiPower's methodology for forecasting high-volume connections.<sup>81</sup> In doing so, we were not satisfied that the forecast volumes represented a realistic expectation of connection activity over the 2016–2020 regulatory control period.<sup>82</sup> In particular:

- For residential connections, we were not satisfied that the forecasts of dwelling approvals represented the best possible forecast in the circumstances.<sup>83</sup>
- For commercial/ industrial connections, we were not satisfied that producing a forecast expenditure profile that purely uses GSP was appropriate.<sup>84</sup>

Noting the above, our preliminary decision included an amount for high volume connection types which trended forward the average of the actual expenditure CitiPower incurred for these types of connections over the 2011-14 period.<sup>85</sup> In doing so we considered this approach is based on verifiable data and that historical capex is an appropriate basis on which to determine forecast connections capex because the drivers of customer connections remain relatively constant across regulatory control periods.<sup>86</sup>

In its revised proposal, CitiPower accepted the use of historical averaging for forecasting the number of high-volume connections.<sup>87</sup> Consistent with the reasons set out in our preliminary decision, we are satisfied that that the drivers of high volume customer connections remain relatively constant across regulatory control periods. As such we are satisfied that the trend in historic volumes represents a realistic expectation of the connection activity that CitiPower will incur over the 2016-20 regulatory control period.

With respect to low volume categories of connections, our preliminary decision accepted CitiPower's proposal represented a realistic expectation of the required

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<sup>80</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.

<sup>81</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-55.

<sup>82</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-55.

<sup>83</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-57.

<sup>84</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-60.

<sup>85</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-51.

<sup>86</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-52.

<sup>87</sup> CitiPower, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 216.

expenditure, for the reasons set out in preliminary decision we have included these in our final decision alternative estimate.<sup>88</sup>

### *Unit costs*

Whilst CitiPower accepted the volumes underlying our preliminary decision's alternative estimate, CitiPower in its revised proposal considered that the way we constructed our alternative estimate did not appropriately trend forward the historical expenditure. In particular, CitiPower considered our preliminary decision understated historical expenditure by relying on unescalated historical nominal capex.<sup>89</sup> We have reviewed our preliminary decision calculations and we accept that the data we relied on to produce our alternative estimate is unescalated and in nominal terms. We relied on historical expenditure data provided by CitiPower's in response to information request 13, this data was labelled as real \$2015. We agree with CitiPower that our alternative estimate requires us to produce a forecast which relies on real 2015 dollars that includes escalation.<sup>90</sup> We have reviewed the connections capex model accompanying CitiPower's revised proposal and we are satisfied that the figures included in its revised proposal trend forward 2011-14 expenditure to produce a forecast in escalated real 2015 dollars, in doing so we have verified the historical expenditure against CitiPower's Category Analysis RIN. With this in mind we have included the amount included in CitiPower's revised proposal in our alternative capex estimate.

### *Recoverable works*

CitiPower in its revised proposal considers that we inadvertently omitted \$67 million (\$2015) of capex relating to recoverable works.<sup>91</sup> We have reviewed our preliminary decision and acknowledge that our alternative estimate did not include an amount for recoverable works. Consistent with our final framework and approach for Victoria these services are classified as standard control services. Recoverable works relate to customer initiated undergrounding and/or rearrangement of distribution assets serving that customer. We have assessed CitiPower's connections capex model accompanying its revised proposal and we are satisfied the amount included in its revised proposal for these services is in line with its historical expenditure. With this in mind we have included this amount in our alternative estimate.

### **Customer contributions**

When a new customer connects to the network, it may be required to provide a contribution towards the cost of the connection assets. This contribution can be monetary or in the form of contributed or gifted assets.

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<sup>88</sup> AER, *CitiPower preliminary decision 2016–20, Attachment 6 Capital expenditure*, October 2015, p. 6-64.

<sup>89</sup> CitiPower, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 216.

<sup>90</sup> CitiPower, *Response to AER information request 013* [email to AER], 30 July 2015.

<sup>91</sup> CitiPower, *Revised Regulatory Proposal 2016–2020*, January 2016, p. 215.

In this section we consider CitiPower's forecast of customer contributions. We then assess:

- whether the forecast was prepared in accordance with the relevant connection charge guideline, and
- the reasonableness of CitiPower's forecasting methodology.

#### *Connection Charge Guideline*

In its revised proposal, CitiPower 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.

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>92</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.

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

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<sup>92</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.

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>93</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>94</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.

#### *CitiPower's forecasting methodology*

We note that CitiPower's updated forecast customer contributions in its revised proposal was limited to revising incremental revenue (IR) underlying its forecast. CitiPower has assumed that the incremental costs for a particular connection remain unchanged. In adapting the incremental revenue calculations CitiPower 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 CitiPower's revised proposal and we are satisfied that CitiPower has applied a customer contribution rate applied to the gross connections capex forecast that accounts for the x factors and rate of return assumptions discussed above.<sup>95</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. 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 CitiPower's forecast reflects a realistic expectation of customer contributions it will receive over the 2016-20 regulatory control period.

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<sup>93</sup> Essential Services Commission, *Guideline No. 14 Provision of Services by Electricity Distributors*

<sup>94</sup> AER, *Connection charge guidelines for electricity retail customers Under chapter 5A of the National Electricity Rules*.

<sup>95</sup> CitiPower, *CP PUBLIC RRP MOD 1.18 CP Connections Capex.xlsx*, January 2016.

## 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>96</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 CitiPower's assets that will likely require replacement over the 2016–20 regulatory control period and the associated capital expenditure.

### B.4.1 Position

We are not satisfied that CitiPower's proposed repex of \$260 million, excluding overheads, reasonably reflects the capex criteria and therefore we do not accept CitiPower's proposed amount. We have instead included in our alternative estimate of overall total capex, an amount of \$235.5 million for repex, excluding overheads. This is 21 per cent lower than CitiPower's revised proposal. We are satisfied that this amount reasonably reflects the capex criteria.

Table 6.11 summarises the CitiPower's proposals and our alternative amounts for repex at each stage of the assessment period.

**Table 6.11 Final decision on CitiPower's total forecast repex (\$2015, million)**

	2016	2017	2018	2019	2020	Total
Initial proposal	49	50	62	57	41	260

<sup>96</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.

AER preliminary decision	38	38	48	44	32	199
Revised regulatory proposal	49	50	63	57	41	260
AER final decision	45	45	57	52	37	236
Total difference b/w final and revised	-5	-5	-6	-5	-4	-25
Percentage difference b/w final and revised (%)	-9	-9	-9	-9	-9	-9

Source: AER analysis.

Note: Numbers may not add up due to rounding.

## B.4.2 CitiPower's revised proposal

CitiPower maintained its forecast of \$260 million for repex in its revised proposal.<sup>97</sup> CitiPower agreed with our preliminary decision to accept its initial proposal for:<sup>98</sup>

- the amount for the six categories of expenditure modelled using the repex model; and
- the amount for un-modelled categories of pole top structures and SCADA expenditure.

CitiPower did not agree with our preliminary determination for:<sup>99</sup>

- the un-modelled 'other' repex category of \$85.3 million.

CitiPower's reasons for maintaining this category of repex in its forecast are:<sup>100</sup>

- historical expenditure is understated and its forecast expenditure would be consistent with history if not for the Brunswick Terminal Station (BTS) delays
- replacement of the building to house the Waratah Place (WP) zone substation is underway and is necessary to complete the CBD Security of Supply project
- the Russell Place (RP) zone substation building is past its end-of-life but is still in service to deliver synergies with the WP zone substation project, prior to its planned decommissioning in 2018; however, failure to rectify structural defects in the building will result in ongoing safety risks to the public
- the redevelopment of the Brunswick (C) zone substation is overdue as it was impacted by the delays to the upgrade of BTS

<sup>97</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 195.

<sup>98</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 205.

<sup>99</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 205.

<sup>100</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 198.



- the construction of a residential tower next to its Montague Street (MG) zone substation requires it to replace noisy transformers to comply with noise regulations
- remediation of CBD underground pits and green pillar boxes is necessary to reduce the safety risk to the community
- it must comply with a request from Yarra Valley Water to remove cross-arms from their assets, and such works have no historical precedent in our network.

CitiPower also provided a report from its consultant Jacobs to support its forecast repex for these 'other' projects.<sup>101</sup>

### **B.4.3 AER approach**

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

- analysis of CitiPower's long term total repex trends
- consideration of relevant supporting material such as business cases
- predictive modelling of repex based on CitiPower's assets in commission; and
- consideration of asset health indicators.

We have primarily used our predictive modelling to assess approximately 50 per cent of CitiPower's proposed repex. For those aspects of our assessment where we have not used predictive modelling, we have relied on the assessment of expenditure trends, the consideration of asset health indicators, and assessment of supporting material such as business cases to assess CitiPower's revised proposal. Our findings from these assessment techniques support our overall conclusion.

### **Trend analysis**

We have used trend analysis (historical expenditure) to draw general observations from historical expenditure trends 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). However, for some aspects of our assessment where we have not relied on predictive modelling, we have used historical levels of expenditure to reject CitiPower's forecast of repex or to determine our alternative estimate. In particular, where past expenditure was sufficient to meet the capex criteria, we are satisfied that it can be a reasonable indicator of whether forecast repex is likely to reflect the capex criteria.<sup>102</sup>

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<sup>101</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015.

<sup>102</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.



## Predictive modelling

Our predictive model, known as the 'repex model', can predict a reasonable amount of repex CitiPower 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 CitiPower's 'business as usual' asset replacement practices. The rationale for using calibrated replacement lives is detailed in our preliminary decision.

As part of the 'Better Regulation' process we undertook extensive consultation with service providers on the repex model and its inputs.<sup>103</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>104</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 that data. The model can also be calibrated using data on CitiPower's entire stock of network assets, along with CitiPower's recent actual replacement practices, to estimate the repex required to maintain its current risk profile.

We recognise that predictive modelling cannot perfectly predict CitiPower'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 set out our reasons for this in Appendix F of our preliminary decision.

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

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<sup>103</sup> Replacement expenditure and repex model workshops at <http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline/expenditure-forecast-assessment-guidelines-working-group-schedule>.

<sup>104</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.

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>105</sup>

We recognise there are reasons why some assets may be better assessed outside of the repex model. These reasons include a lack of commonality of assets within a category, or because we did not possess sufficient data to include some assets in the model (see appendix E of our preliminary determination).

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

### **B.4.4 AER repex findings**

#### **Trends in historical and forecast repex**

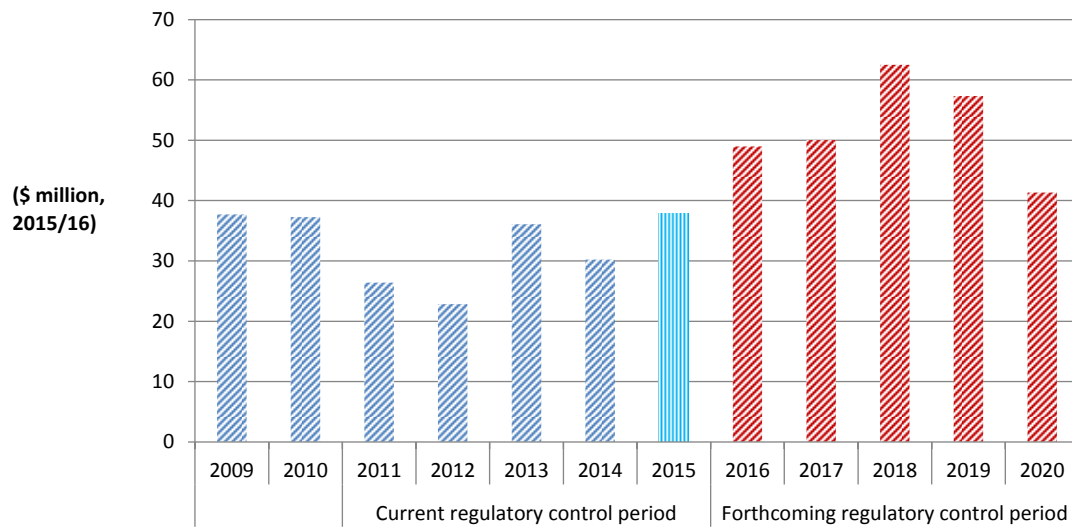
We have conducted a trend analysis of the proposed repex. The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period.<sup>106</sup> Our use of trend analysis is to gauge how CitiPower's historical actual repex compares to its expected repex for the 2016–20 regulatory control period. Figure 6.9 shows CitiPower's repex spend has been variable across time, and is forecast to increase above historical levels for the 2016–20 regulatory control period.

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<sup>105</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

<sup>106</sup> NER, cl. 6.5.7(e)(5).

**Figure 6.9 CitiPower - Actual and forecast repex (\$ million, 2015)**



Source: CitiPower, CP PUBLIC RIN 1.1 CitiPower, Vic Reset RIN 2016–20 - Consolidated Information, CitiPower, CP PUBLIC RIN 1.19 CitiPower, 2009–2013 Category Analysis RIN, and CitiPower, CP PUBLIC RIN 1.20 CitiPower, 2014 Category Analysis RIN.

When considering the above previous levels of expenditure 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, CitiPower has estimated to underspend its regulatory allowance for replacements by 22 per cent.<sup>107</sup> We note that a major feature of the regulatory framework is the incentives CitiPower has to achieve efficiency gains whereby actual expenditure is lower than the allowance. Differences between actual and allowed repex could be the result of efficiency gains, forecasting errors or some combination of the two. CitiPower noted that the underspend was due to:<sup>108</sup>

- the impact of the delayed upgrade to Brunswick Terminal Station (BTS); and
- network strategies to align major plant replacements and network augmentations.

We have examined the material accompanying CitiPower's proposal regarding the BTS project.<sup>109</sup> We are satisfied CitiPower's deferrals of expenditure in the 2011–15 regulatory control period avoided unnecessary plant replacement costs. Similarly, we are satisfied that CitiPower has demonstrated good industry practice in reconfiguring network load in cost-effective way to avoid unnecessary repex.<sup>110</sup> Accordingly, we are

<sup>107</sup> CitiPower 2016–20 Price Reset Appendix E Capital Expenditure, April 2015, p. 42.

<sup>108</sup> CitiPower, 2016–2020 Price Reset - Appendix E: Capital Expenditure, April 2015, p. 42.

<sup>109</sup> CitiPower, E.47 - CitiPower, Material Project, AUG 10 WMTS 22kV decommissioning, April 2015, pp. 4–5.

<sup>110</sup> CitiPower, 2016–20 Price Reset Appendix E Capital Expenditure, April 2015, p. 42.

satisfied that expenditure levels in the 2011–2015 years of Figure 6.9 can in part be attributed to the factors outlined above.

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>111</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>112</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 trend analysis may reflect CitiPower's aging assets.

## Predictive modelling

In our preliminary decision, we used predictive modelling to estimate how much repex CitiPower is expected to need in the future, given how old its existing 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.

In our preliminary decision we were satisfied that an amount of \$131 million of proposed repex for these six categories of assets was a reasonable estimate for the categories of repex that were subject to our predictive modelling. In its revised proposal, CitiPower accepted our preliminary determination for the six categories of expenditure modelled using the repex model.<sup>113</sup>

VECUA noted that the distributors' asset life estimates in the RINs appeared to understate the asset lives achieved in practice compared to the calibrated asset lives which reflect the distributors' actual replacement practices. VECUA was of the view we should move to standardising asset lives across distributors.<sup>114</sup> VECUA also considered that the repex model relied too heavily on asset age and that we gave insufficient consideration to asset condition information.<sup>115</sup> We consider our use of calibrated asset lives addresses this concern as the asset lives are derived from a distributor's revealed replacement approach. A distributor's replacement approach will

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<sup>111</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, pp. 19–20.

<sup>112</sup> Victorian Energy Consumer and User Alliance (VEUCA), *Submission on AER preliminary decision VIC EDPR 2016-2020*, 6 January 2016, pp. 38–40.

<sup>113</sup> CitiPower, *revised regulatory proposal*, January 2016, p.205

<sup>114</sup> VEUCA, *Submission on AER preliminary decision VIC EDPR 2016-2020*, 6 January 2016, p. 41.

<sup>115</sup> VECUA, *Submission on AER preliminary decision VIC EDPR 2016-2020*, 6 January 2016, pp. 46–47.

reflect several considerations including the age of the asset, but also how it manages risk on its network. It may be prudent for one distributor to replace an asset at a certain time on its network, but this same timing may not be prudent for the same asset on a different distributor's network. This may be because there may be differences in operating environments and as such the nature of the risk may differ. The use of calibrated replacement lives captures a distributor's recent replacement practices and the age of all its assets in commission. This is expected to reflect the relevant factors the distributor considers when replacing its assets.

For the reasons set out in our preliminary decision, we accept CitiPower's proposed amount of \$131 million for the six asset categories that have been assessed by our predictive modelling.<sup>116</sup>

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

In our preliminary decision we accepted CitiPower's forecast for SCADA and pole top structures of \$21 million and \$20 million, respectively. In its revised proposal, CitiPower accepted our preliminary determination for these categories.<sup>117</sup>

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>118</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>119</sup>

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<sup>116</sup> AER, *preliminary decision, CitiPower distribution determination 2016 to 2020, Attachment 6: Capital expenditure*, October 2015, pp. 6-74–79

<sup>117</sup> CitiPower, *revised regulatory proposal*, January 2016, p.205

<sup>118</sup> Victorian Government, *Submission on AER preliminary decision VIC EDPR 2016-2020*, 14 January 2016, p. 6.

<sup>119</sup> VECUA, *Submission on AER preliminary decision VIC EDPR 2016-2020*, 6 January 2016, p. 45.

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 our best high level indicator of the prudence and efficiency of the proposed expenditure. Where past expenditure was sufficient to meet the capex criteria, we are satisfied that it can be a reasonable indicator of whether forecast repex is likely to reflect the capex criteria.<sup>120</sup>

For the reasons set out in our preliminary decision, we accept CitiPower's proposed amount for SCADA and pole top structures:<sup>121</sup>

- For pole top structures we considered repex was likely to be relatively recurrent between periods, and that historical repex can be used as a good guide when assessing CitiPower's forecast. Given CitiPower's forecast for pole top structures repex was lower than its expenditure in the last period, we were satisfied this was likely to reflect the capex criteria.
- For SCADA we considered the proposed increase was modest compared to the last period, and that CitiPower had provided supporting information that demonstrated the need for greater volume replacement of these assets. We were satisfied that CitiPower's forecast SCADA repex was likely to reflect the capex criteria.

### Other repex

CitiPower forecast \$85 million in repex on 'other' un-modelled categories in the 2016–20 regulatory control period, or 33 percent of its total proposed repex. This represents a \$27 million increase from its spend on 'other' categories in the 2011–15 regulatory control period.<sup>122</sup> In our preliminary decision we did not accept this increased amount on the basis that CitiPower:<sup>123</sup>

- did not provide a robust cost-benefit analysis in support of the increased capex
- did not establish why large portions of the repex should not be regarded as “business as usual” and so fall within the repex model; or
- did not demonstrate why the growth in the “other” category is significantly higher than the growth in the prescribed asset groups (e.g. poles, transformers).

In its revised proposal CitiPower submitted additional material on the proposed programs of work. We have assessed this additional information and are satisfied that some but not all of CitiPower's forecast repex reasonably reflects the capex criteria:

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<sup>120</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 7–9.

<sup>121</sup> AER, *Preliminary decision, CitiPower distribution determination 2016 to 2020, Attachment 6: Capital expenditure*, October 2015, pp. 6-82–83.

<sup>122</sup> CitiPower, *Revised proposal*, January 2016, p. 199.

<sup>123</sup> AER, *Preliminary decision, CitiPower distribution determination 2016 to 2020, Attachment 6: Capital expenditure*, October 2015, p. 6-85.



- \$23 million on building works associated with zone substations.<sup>124</sup> We are satisfied that CitiPower has justified the need for the projects and demonstrated it deferred repex on these projects from the previous regulatory control period.
- \$15.3 million to address noise at the Montague and Armadale zone substations.<sup>125</sup> We are satisfied that CitiPower has demonstrated the need for the works due to meet its obligations from changes to the rezoning of residential areas to address noise issues.

However, we are not satisfied that there is sufficient justification to support \$16 million of the proposed repex in 'other'. We explain our reasons for this below. In summary:

- \$6 million for environmental obligations additional to the major noise replacement projects above.<sup>126</sup> We consider CitiPower has not sufficiently justified why this additional repex is required over and above the business as usual forecast derived from the repex model, given these obligations have been ongoing. The replacement of assets in the past for oil leaks from transformers and noise related issues would be expected to fall within CitiPower's existing safety/environmental obligations, and form a part of business as usual repex which has been addressed by our predictive modelling. We raised this as an issue of concern in our preliminary decision. We are also of the view that the need for these projects has not been demonstrated as the project documentation provided by CitiPower included only limited quantification of the costs and benefits of proposed options (including the preferred option) for one project, and the remaining projects did not have any supporting materials, including the absence of any cost benefits analysis.
- \$8.4 million for the replacement of pits and pillars in the CBD.<sup>127</sup> We find that CitiPower has not sufficiently demonstrated its proposed pit replacement program is prudent in its timing, volumes or cost. Overall, we consider that CitiPower has not sufficiently demonstrated its proposed pit replacement program is prudent in its timing, volumes or cost. CitiPower has also not provided sufficient supporting material to justify its forecast pillar replacement expenditure.
- \$1.5 million to remove its cross arms from Yarra Valley Water assets for operational safety reasons.<sup>128</sup> We do not consider CitiPower's forecast expenditure, which is to replace all affected assets, reflects reasonable options or rigorous cost benefit analysis.

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<sup>124</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>125</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>126</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>127</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>128</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 205.

We also find that there is insufficient justification to support an increase from CitiPower's historic expenditure of \$22 million to \$31 million for the remainder of CitiPower's proposed repex in the 'other' category.<sup>129</sup> In particular:

- \$31 million of expenditure for a category of 'General Replacements'. We note that replacement works of this nature have been undertaken historically, and were forecast to increase over the 2016–20 regulatory control period. These works appear to involve discrete asset types. However, there was no associated age profile information which would allow us to model this repex, or at least observe any age based justification for the increased expenditure. Further, CitiPower's supporting materials did not have specific information (e.g. business cases) to support the proposed increase in this category of expenditure.

As such, we are not satisfied that CitiPower's forecast \$85 million of repex on 'other' un-modelled categories in the 2016–20 regulatory control period reasonably reflects the capex criteria. We find that \$60 million of un-modelled repex reasonably reflects the capex criteria and have included this in our alternative estimate of total repex for the 2016–20 regulatory control period. We explain our reasons for this below.

### **Delayed building replacements**

CitiPower proposed \$23 million of repex on building works associated with zone substations.<sup>130</sup> It submitted the business was due to undertake these works during the 2011–15 regulatory control period, but deferred these to the 2016–20 regulatory control period due to delays in the upgrade of the Brunswick Terminal Station (BTS).

CitiPower noted that had these projects been completed during the 2011–15 regulatory control period, then it would have forecast \$62.3 million of un-modelled 'other replacement expenditure' for the 2016–20 regulatory control period, rather than \$85 million. It noted this would be a smaller increase from historical expenditure for the 'other' category in total, which would have been \$51 million.<sup>131</sup> The major projects proposed in the category are:

- Zone Substation C (Brunswick) rebuild:
  - CitiPower submitted that the redevelopment of the Brunswick zone substation is overdue as it was impacted by the delays to the upgrade of BTS.<sup>132</sup> Further, that the repex model captured associated works for transformers and switchgear, but not the costs associated with the substation civil building, switchyard cabling and associated secondary system work.<sup>133</sup>

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<sup>129</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>130</sup> CitiPower, *Information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>131</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 199.

<sup>132</sup> CitiPower, *Revised regulatory proposal*, January 2016, pp. 198, 201–202.

<sup>133</sup> CitiPower, *Revised regulatory proposal*, January 2016, pp. 201–202.



- Jacobs reviewed CitiPower's business case and supporting information and considered expenditure trends were problematic as there were limited historical examples of such expenditure for CitiPower.<sup>134</sup> Jacobs also reviewed costs compared to what it considered was a similar project (the Bouverie/Queensberry zone substation project predominately completed in the 2006–10 period). Jacobs considered that CitiPower's budget allocation for the C zone substation redevelopment was appropriate.<sup>135</sup>
- Waratah place
  - CitiPower submitted that replacement of the building to house the Waratah Place zone substation is underway and necessary for it to meet its obligations for the CBD Security of Supply project and decommissioning of the Russell Place zone substation.<sup>136</sup>
  - CitiPower's forecast for the project was based on a 2011 independent report, and was increased slightly to reflect \$2015 and some updated costing information.<sup>137</sup>
- Building Replacement Substation Russell Place
  - CitiPower submitted that the Russell Place zone substation building is past its end-of-life but is still in service to deliver synergies with the Waratah Place zone substation project, prior to its planned decommissioning in 2018; however, failure to rectify structural defects in the building will lead to safety risks<sup>138</sup>
  - CitiPower provided further supporting materials with its revised proposal including engineering reports, quotes for the works from independent civil construction groups, and a cost benefit analysis based on consultant reports considering whether the project could be further delayed.<sup>139</sup>

As outlined in the previous section on trends in historical and forecast repex, we acknowledge that part of CitiPower's underspend on repex in 2011–15 regulatory control reflects the BTS delays.

For the major projects in this category of expenditure we consider CitiPower has sufficiently justified the need. However, CitiPower's demonstration of consideration of other options and project costs were limited and was at a high level. We also consider there could be scope to break down these projects into categories that could be

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<sup>134</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015, p. 14.

<sup>135</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015, p. 16.

<sup>136</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 198; CP PUBLIC APP E.49 - CitiPower, Material Project, REPL 01 W Building replacement, p. 2.

<sup>137</sup> CitiPower response to info request #039; CP PUBLIC RRP ATT 7.1 GÇô Aurecon, Building Study Report Waratah Place (W) Zone Substation, January 2011.

<sup>138</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 198.

<sup>139</sup> CitiPower, *information request response #040, AER information request - CitiPower - 040 Capex projects.pdf* [email to AER] 1 March 2016.

included in our predictive modelling. We have reviewed the business cases and are satisfied that CitiPower has justified the need for the projects and demonstrated it deferred repex on these projects from the previous regulatory control period.

On balance, we are satisfied that the forecast of \$23 million for repex on this category of building works in 2016–20 reasonably reflects the capex criteria and have included this amount in our estimate of total repex.

### ***Environmental—major noise works***

CitiPower proposed \$15.3 million for repex to address noise at the Montague and Armadale zone substations.<sup>140</sup> CitiPower submitted the need for the works is a change in circumstances which mean it now must comply with environmental noise obligations. In particular, CitiPower submitted that it must now meet these obligations as the areas around the zone substations were rezoned for residential constructions.<sup>141</sup>

CitiPower submitted it selected the lower cost option of replacing transformers at the sites with low noise models, rather than an alternative of building enclosures.<sup>142</sup>

We have reviewed the information and note CitiPower's consideration of other options and project costs could have been expanded. For example, CitiPower could have explored the options of replacing transformers at the sites in a staged manner depending on forecast demand. This area may undergo significant changes to demand. In particular, the removal of the existing industrial supplies in the area and the replacement with residential and commercial loads is expected to contribute to changing loads and load profiles. As a result it may be prudent to defer some works as full redevelopment of the area may take place over a number of future regulatory control periods. On the other hand, there may be benefits to undertaking the works concurrently, and there could be value in providing additional spare capacity while CitiPower is meeting its environmental obligations given the unknown future load growth.

On balance, given we are satisfied that CitiPower has demonstrated a need due to a change in obligations to address noise issues we are satisfied that its forecast of \$15.3 million for repex on these major noise replacement works in the 2016–20 regulatory control period reasonably reflects the capex criteria and have included this amount in our estimate of total repex.

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<sup>140</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>141</sup> CitiPower, *Revised regulatory proposal*, pp. 202–204; CitiPower info request response #039; CP PUBLIC APP E.57 - CitiPower, Material Project, REPL 07 Environmental noise program - MG; CP PUBLIC APP E.54 - CitiPower, Material Project, REPL 06 Environmental noise program - AR.

<sup>142</sup> CitiPower, *Revised regulatory proposal*, pp. 202–204; CitiPower, *information request response #039* [email to AER], 25 February 2016; CP PUBLIC APP E.57 - CitiPower, Material Project, REPL 07 Environmental noise program - MG; CP PUBLIC APP E.54 - CitiPower, Material Project, REPL 06 Environmental noise program - AR.

### ***Environmental—other works***

CitiPower forecast \$6 million of repex relating to environmental obligations in the 2015–20 regulatory control period, which is additional to the major noise replacement projects above.<sup>143</sup> CitiPower provided supporting material for its environmental bunding program which is to address transformer oil leaks. This program represents \$4.5 million of the forecast repex for this category.<sup>144</sup> CitiPower identified that its environmental obligations require the need to mitigate oil leaks from transformers. There was no further supporting material for the remaining \$1.5 million of proposed works.

We consider CitiPower has not sufficiently justified why additional repex for the environmental bunding program and noise related capex is required over and above the business as usual forecast derived from the repex model, given these obligations have been ongoing. The replacement of assets related to upgrading or replacing bunds at zone substations and retrofitting drainage at zone substations and noise related issues would be expected to fall within CitiPower's existing safety/environmental obligations, and form a part of estimate of business as usual repex. We raised this as an issue of concern in our preliminary decision. CitiPower submitted that it proposes to install bunding for power transformers and/or radiators, where bunding does not currently exist or is inadequate, but where possible CitiPower plans to align bunding with augmentation and maintenance projects.<sup>145</sup> Relevantly, we note that CitiPower has stated that:<sup>146</sup>

CitiPower has Oil Containment Guidelines to assist it in complying with these obligations. These Guidelines provide a basis for CitiPower's 10 year work program for upgrading or replacing bunds at zone substations and retrofitting drainage at zone substations. This program includes one project per year.

And:

The program addresses the highest risk zone substation sites first and, where possible, align bunding projects with planned augmentation and maintenance projects. During the 2011–2015 period, bunding and drainage programs were undertaken at the highest risk locations, including the Rooney St depot in Burnley, as well as the Richmond (R), Deepdene (L) and Dock Area (DA) zone substations.

This program will be continued through the 2016 to 2020 period and beyond, focusing on other high risk zone substations. For CitiPower, one bunding and drainage project is planned each year at the zone substations.....

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<sup>143</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>144</sup> CitiPower PUBLIC APP E.56 - CitiPower, Material Project, REPL 09 Environmental bunding program. 5.

<sup>145</sup> CitiPower PUBLIC APP E.56 - CitiPower, Material Project, REPL 09 Environmental bunding program, p. 2.

<sup>146</sup> CitiPower PUBLIC APP E.56 - CitiPower, Material Project, REPL 09 Environmental bunding program, pp. 2–3.

This suggests that this is an ongoing activity or business as usual activity and therefore this expenditure should be reflected in our business as usual estimate.

In addition, we are also note that:<sup>147</sup>

- CitiPower's options analysis for oil bunding has not quantified the risks (i.e. the benefits from any reduced risk of oil leaks); and
- has not estimated the costs of all of the options.

We also note that for the remaining proposed projects CitiPower did not provide any further supporting information.

As such, we are not satisfied that CitiPower's additional forecast repex of \$6 million for other environmental works reasonably reflects the capex criteria and have not included this amount in our alternative estimate for the 2016–20 regulatory control period.

### ***CBD pits and pillars***

CitiPower forecast \$8.4 million of repex in the 2016–20 regulatory control period for the replacement of pits and pillars in the CBD.<sup>148</sup>

CitiPower proposed \$5.3 million to address dangerous pits in the CBD, by increasing its inspection rate for a proactive replacement program.<sup>149</sup> We are of the view that CitiPower's forecast for its pit replacement program is not sufficiently justified based on its supporting information:

- CitiPower forecast a nominal defect rate for pit inspections of 5 per cent.<sup>150</sup> This value was not supported by further information.
- Jacobs identified that temporary remediation works may be needed in some cases before permanent solutions can be rolled out.<sup>151</sup> It is unclear how CitiPower has factored this in to its forecast. We note that it has assumed a fixed unit rate per site, which would not allow for the sort of temporary remediation options identified by Jacobs.
- Jacobs noted that failing to undertake remediation now will require an extensive and reactive response in the next 5 to 10 years.<sup>152</sup> However, CitiPower has not sufficiently demonstrated why its proactive program should be limited to the next 5 years rather than be undertaken out over a longer time period.

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<sup>147</sup> CitiPower PUBLIC APP E.56 - CitiPower, Material Project, REPL 09 Environmental bunding program, pp. 3–5.

<sup>148</sup> CitiPower, *response to information request #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>149</sup> CitiPower, PUBLIC APP E.55 - CitiPower, Material Project, REPL 08 Replacement of underground cable pits.

<sup>150</sup> CitiPower, PUBLIC APP E.55 - CitiPower, Material Project, REPL 08 Replacement of underground cable pits.

<sup>151</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015, p. 21.

<sup>152</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015, p. 21.

- CitiPower's program intends to target pits with significant defects. However, evidence provided by CitiPower does not demonstrate it has considered targeting or ranking based on high-risk locations which may be more prudent.
- CitiPower' assumptions are based on the consequence of a failure as "Major—Single Fatality or Permanent Disability."<sup>153</sup> We consider this consequence may be overstated. CitiPower workers are the most likely to be in proximity to a potential pit failure. However, the safe access and inspection procedures that surround access to underground areas make it likely that any safety risks that may lead to injury are identified prior to entry to the sites.
- In its supporting information CitiPower identified the likelihood of a failure as 'unlikely' which is one in every 11 to 50 years.<sup>154</sup>
- CitiPower stated that the unit rate for pit replacement is \$264,500 in its response to an information request,<sup>155</sup> but stated it is \$211,000 (direct costs) in other supporting materials.<sup>156</sup> CitiPower appears to have applied the higher unit rate in determining the total forecast repex for pit replacement.

CitiPower does not mention its pillar replacement program in specific detail in its revised proposal, supporting materials or in further information provided. Jacobs noted that CitiPower did not provide a business case for the pillar replacement component.<sup>157</sup> The basis of its pillar replacement forecast is also unclear from supporting materials that mention the program. Jacobs identified a sum of \$2.6 million for 50 pillar replacements over the 2015–20 regulatory control period.<sup>158</sup> However, CitiPower forecast \$8.4 million for pit and pillar replacement in the 2015–20 regulatory control period,<sup>159</sup> and \$5.3 million of repex on pits. This would mean \$3.1 million is included in its forecast for pillar replacement.

To identify previous replacement practices, we requested that CitiPower provide for each year of the 2011–15 period, the expenditures incurred for the maintenance, repair, replacement or upgrading of CBD pits and pillars. CitiPower responded that the categories requested could not be directly supplied as it did not have data to this detail.<sup>160</sup>

Overall, we consider that CitiPower has not sufficiently demonstrated its proposed pit replacement program is prudent in its timing, volumes or cost. CitiPower has also not provided sufficient supporting material to justify its forecast pillar replacement expenditure. We note that CitiPower's increased inspections may result in increased

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<sup>153</sup> CitiPower, *response to information request #040* [email to AER], 1 March 2016.

<sup>154</sup> CitiPower, *response to information request #040* [email to AER], 1 March 2016. p. 8.

<sup>155</sup> CitiPower, *response to information request #040* [email to AER], 1 March 2016.p. 6.

<sup>156</sup> CitiPower PUBLIC APP E.55 - CitiPower, Material Project, REPL 08 Replacement of underground cable pits, p. 6.

<sup>157</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015, p. 22.

<sup>158</sup> Jacobs, *CitiPower Proposed 2016–20 Repex Other*, December 2015, p. 22.

<sup>159</sup> CitiPower, *response to information request #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>160</sup> CitiPower, *information request response #040* [email to AER], 1 March 2016.

detection of assets in poor condition. However, it has not demonstrated that this means there has been a significant change in risk to support the need for the program in the 2016–20 regulatory control period. Further, CitiPower has not provided a robust business case or cost benefit analysis to justify its proactive replacement program for pits and pillars in the 2016–20 regulatory control period.

As a result, we are not satisfied that the amount of \$8.4 million of repex for pits and pillars reasonably reflects the capex criteria and have not included this amount in our alternative estimate for the 2016–20 regulatory control period.

### ***Yarra Valley Water***

CitiPower proposed \$1.5 million of repex for the 2016–20 regulatory control period to remove its cross arms from Yarra Valley Water assets for operational safety reasons.<sup>161</sup> The works are a result of an agreement between Yarra Valley Water and CitiPower.<sup>162</sup>

CitiPower submitted that these assets did not meet Regulation 313 of the Electricity Safety (Installations) Regulations 2009 which specifies minimum line clearances for a structure not normally accessible to a person.<sup>163</sup> Many of these installations appear to have existed in this manner for decades.<sup>164</sup> CitiPower has not sufficiently justified why the need has now arisen to address all these assets in the upcoming period.

CitiPower and Yarra Valley Water identified alternative solutions to full replacement of all the assets, which include retention of current installations subject to written agreement between parties.<sup>165</sup> However, CitiPower's proposal does not appear to reflect such options or cost benefit analysis, rather it forecasts replacement work on all affected assets.

As such, we are not satisfied the additional repex of \$1.5 million reasonably reflects the capex criteria and we have not included this amount in our estimate of total forecast repex for the 2016–20 regulatory control period.

### ***General other replacement***

CitiPower proposed \$31 million of expenditure for a category of 'General Replacements' in other repex for the 2016–20 regulatory control period. This is a \$9

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<sup>161</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 205.

<sup>162</sup> CitiPower, *information request response #040* [email to AER], 1 March 2016.

<sup>163</sup> CitiPower, *information request response #040* [email to AER], 1 March 2016.  
[http://www.austlii.edu.au/au/legis/vic/consol\\_reg/esr2009470/s313.html](http://www.austlii.edu.au/au/legis/vic/consol_reg/esr2009470/s313.html).

<sup>164</sup> CitiPower, *information request response #040* [email to AER], 1 March 2016.

<sup>165</sup> CitiPower, *information request response #040, AER information request - CitiPower - 040 Capex projects.pdf* [email to AER], 1 March 2016, p. 11.

million (40 per cent) increase compared to expenditure in this category in the 2011–15 regulatory control period of \$22 million. The category includes:<sup>166</sup>

- Other - Aerial Substation Clearance
- Other - Cable Earthing
- Other - Cabus Box
- Other - Capacitor Banks
- Other - Circuit Breaker Refurbishment
- Other - Cremorne Bridge
- Other - Distribution Substation Building / Property / Facilities
- Other - Distribution Substation Building / Property / Facilities [OH&S]
- Other - HV Earth Rectification
- Other - Instrument Transformer
- Other - Residual
- Other - Switchgear - Enhancement
- Other - Transformer Cooling Systems
- Other - Transformer Refurbishment
- Other - UGCable Refurbishment

CitiPower provided a breakdown of forecast repex for the 'General Replacements' category with its revised proposal. However, CitiPower only provided a further breakdown for the general other repex category in 2015, but submitted that the historic spend in the category was \$22 million in total for 2011–15.<sup>167</sup>

We note that in CitiPower's RIN, this repex appears to be captured in the category 'Plant and Stations Miscellaneous'. However in its RIN, CitiPower forecast \$34.5 million of expenditure over the 2016–20 regulatory control period for this category, and only \$8 million in the 2011–15 regulatory control period with negative expenditure reported in one year.<sup>168</sup> This data was not broken down into subcategories and it is unclear why there is a discrepancy. As such, we have relied on the data CitiPower provided with its revised proposal to assess this category.

We note that replacement works of this nature have been undertaken historically, and were forecast to increase over the 2016–20 regulatory control period. These works

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<sup>166</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>167</sup> CitiPower, *information request response #039, spreadsheet: Repex other analysis v 1.2* [email to AER], 25 February 2016.

<sup>168</sup> CitiPower, *information request response #002, spreadsheet: CitiPower Repex 2009-2020 220615* [email to AER] 22 June and 26 June 2015.



appear to involve discrete asset types. However, there was no associated age profile information which may allow us to model this repex, or at least observe any age based justification for the increased expenditure. Further, there was no specific information (e.g. business cases) to support the proposed increase in this category of expenditure. We also note that this increased expenditure is not consistent with indicators of asset health which suggest that past replacement practices (and by implication past levels of expenditure) have allowed CitiPower to meet the capex objectives.

Without sufficient justification to explain the need to increase repex for this category of repex, we consider the historic spend of \$22 million for the 'General Replacements' category reasonably reflects the capex criteria and have included this amount in our estimate of total repex.

## Network health indicators

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

- the measures of reliability and asset failures show that outages on CitiPower' network have been relatively stable or declining across time with the exception of a sharp decrease in 2010 (see trends in reliability and asset failure in our preliminary decision)
- measures of CitiPower' network assets residual service lives and age show that the overall age of the network is being maintained. Using age as a high level proxy for condition, this suggests that historical replacement expenditures have been sufficient to maintain the condition of the network
- 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 (see Asset utilisation discussion below).

Further, the value of customer reliability has recently fallen. Other things being equal, reductions in the value customers place on reliability should allow CitiPower to defer some repex.

The above indicators generally suggest that replacement expenditure in the past period has been sufficient to allow CitiPower to meet the capex objectives. This is consistent with our overall findings on repex from our other assessment techniques. These asset health indicators are discussed in more detail in our preliminary determination.<sup>169</sup>

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<sup>169</sup> AER, *Preliminary decision, CitiPower distribution determination 2016 to 2020, Attachment 6 Capital expenditure*, October 2015, pp. 6-85–88.



## B.5 Forecast capitalised overheads

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

### B.5.1 Position

We do not accept CitiPower's proposed capitalised overheads. We instead included in our alternative estimate of overall total capex an amount of \$92.7 million (\$2015) for capitalised overheads. This is 0.7 per cent lower than CitiPower's proposal of \$93.4 million (\$2015).<sup>170</sup> We are satisfied that this amount reasonably reflects the capex criteria.

### B.5.2 Our assessment

Our adjustment to CitiPower's overheads uses the approach from our preliminary decision.

We consider that reductions in CitiPower's forecast expenditure should see some reduction in the size of its total overheads. Our assessment of CitiPower's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in CitiPower's regulatory proposal. It follows that we would expect some reduction in the size of CitiPower'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>171</sup> We considered this split of fixed and variable overheads components was also reasonable for CitiPower. We invited CitiPower 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>172</sup>

CitiPower did not comment on this split in its revised proposal.<sup>173</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>174</sup>

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<sup>170</sup> CitiPower, *Revised regulatory proposal 2016–2020*, January 2016, p. 194.

<sup>171</sup> AER, *Preliminary decision: CitiPower distribution determination 2016–20: Attachment 6 – Capital expenditure*, October 2015, p. 95.

<sup>172</sup> AER, *Preliminary decision: CitiPower distribution determination 2016–20: Attachment 6 – Capital expenditure*, October 2015, p. 95.

<sup>173</sup> CitiPower, *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>175</sup> On the other hand, Origin also considered the proposed overheads required further examination.<sup>176</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>177</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>178</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 CitiPower's proposal, which is based on their CAM. As such, CitiPower's forecast application of the CAM underlies our estimate. We have only reduced the capitalised overheads to account for the reduced scale of CitiPower'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.

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<sup>174</sup> CitiPower, *Revised regulatory proposal: Standard control - MOD 1.17 CP capex consolidation*, January 2016, worksheet 'Oheads-Capcons-Esc'.

<sup>175</sup> Origin, *Submission to AER preliminary decision Victorian networks*, 6 January 2016, p. 2.

<sup>176</sup> Origin, *Submission: Victorian networks revised proposals*, 4 February 2016, p. 1.

<sup>177</sup> VECUA, *Submission: AER preliminary 2016–20 revenue determinations for the Victorian DNSPs*, 6 January 2016, pp. 4, 55–56.

<sup>178</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 \$24.4 million (\$2015) reduction in CitiPower's direct capex that attract overheads, we consider a reduction of \$0.7 million (\$2015) reasonably reflect the capex criteria.

## B.6 Forecast non-network capex

Non-network capex for CitiPower includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment. CitiPower's revised proposal includes forecast non-network capex of \$106.0 million (\$2015). This is an increase of \$2 million from CitiPower's initial proposal of \$104.0 million, and an increase of \$17.9 million from our preliminary decision for non-network capex of \$88.1 million.<sup>179</sup>

### B.6.1 Position

We accept CitiPower's revised proposal for non-network capex. We have included an amount of \$106.0 million (\$2015) for forecast non-network capex in our capex estimate. As discussed below, we are satisfied that CitiPower's revised forecast non-network ICT capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives.<sup>180</sup>

In coming to this view:

- We are satisfied that CitiPower's forecast ICT capex for the Power of Choice related projects reasonably reflects the prudent and efficient costs required to meet the identified regulatory obligations.
- We are satisfied that CitiPower'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 CitiPower'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 reflects the efficient costs of a prudent operator.

### B.6.2 Revised proposal

In its revised proposal, CitiPower accepted our preliminary decision on forecast non-network capex for motor vehicles, buildings and property, and tools and equipment. However, CitiPower 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>181</sup> These two elements of non-network ICT capex are discussed in turn below.

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<sup>179</sup> CitiPower, *Revised Regulatory Proposal 2016–20*, January 2016, p. 194.

<sup>180</sup> NER, cl. 6.5.7(c).

<sup>181</sup> CitiPower, *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 CitiPower's revised proposal for ICT capex. We have included an amount of \$82.4million (\$2015) 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 CitiPower proposed in its initial proposal (\$66.3 million).

In its revised proposal, CitiPower 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>182</sup> We accept this submission and have included the amount CitiPower 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>183</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 CitiPower'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>184</sup> However, following our assessment, we still consider it appropriate to include these new systems in the capex program because we are satisfied that Powercor's existing systems require upgrade and the proposed expenditure is prudent and efficient.

### Power of Choice projects

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

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<sup>182</sup> CitiPower, *Revised regulatory proposal 2016–2020*, January 2016, p. 230.

<sup>183</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>184</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>185</sup> CitiPower and Powercor share ICT systems and the capex for these changes is allocated evenly between the two distributors. We have assessed CitiPower'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 projects, we accept that there is evidence that some capex will be required to ensure compliance with certain of these regulatory obligations. Under the capital expenditure objectives, we must allow sufficient capex to allow a distributor to comply with regulatory obligations or requirements.<sup>186</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>187</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.<sup>188</sup> We address these differences in our assessment below.

### ***Assessment approach***

In assessing CitiPower'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.

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<sup>185</sup> CitiPower, *Revised regulatory proposal 2016–2020*, January 2016, pp. 231–232.

<sup>186</sup> NER, cl. 6.5.7(a)(2).

<sup>187</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>188</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.

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 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.

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

In its revised proposal, CitiPower proposed \$8.2 million for the ICT capex costs of Power of Choice changes. CitiPower proposed this ICT capex to address the AEMC's metering contestability rule change.<sup>189</sup> Within its metering contestability project, CitiPower included expenditure \$1 million to address the obligations resulting from the AEMC's shared market protocol (SMP) advice.<sup>190</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>191</sup> This rule change places new regulatory obligations on CitiPower 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>192</sup> However, the changes have the same implementation date as metering contestability (1 December 2017) and CitiPower submitted that they are inextricably linked to the metering contestability changes and that implementing them together will provide efficiencies.<sup>193</sup> Given SMP is closely linked to the metering requirements, CitiPower will need to meet these regulatory obligations.

Having accepted that the metering contestability and SMP place new regulatory obligations upon CitiPower, we considered whether CitiPower's forecasts for these projects are the efficient costs that a prudent operator would incur.

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<sup>189</sup> CitiPower, *Revised regulatory proposal 2016–2020*, January 2016, p. 232.

<sup>190</sup> CitiPower, *AER information request - CitiPower - #036 and Powercor #041 - IT capex for Power of Choice*, 19 February 2016, p. 1.

<sup>191</sup> *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12*.

<sup>192</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>193</sup> CitiPower, *AER information request - CitiPower - #036 and Powercor #041 - IT capex for Power of Choice*, 19 February 2016, p. 1. CitiPower, *AER information request - CitiPower - #041 and Powercor #045 - IT capex for Power of Choice*, 4 March 2016, pp. 1-2.



In its revised proposal, CitiPower provided a report from Accenture Strategy detailing the required process and system changes in response to the Power of Choice reforms and estimating the required labour to implement the process and system changes.<sup>194</sup> In response to our request for further details on costings, CitiPower provided a further breakdown into labour, materials and project management costs.<sup>195</sup>

In assessing CitiPower'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 CitiPower/Powercor were in line with those of Jemena and United Energy, with AusNet Services forecasting significantly higher costs, as can be seen in Table 6.12. The CitiPower/Powercor costs were the lowest estimates proposed.

**Table 6.12 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, CitiPower'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>196</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 CitiPower, we have assessed that the majority of CitiPower's/Powercor'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 CitiPower's forecast capex for this project reasonably reflects the efficient costs that a prudent operator

<sup>194</sup> Accenture Strategy on behalf of CitiPower and Powercor, *Metering Contestability - Process and System Impacts*, October 2015.

<sup>195</sup> CitiPower, *AER information request - CitiPower - #036 and Powercor #041 - IT capex for Power of Choice*, 19 February 2016. CitiPower, *AER information request - CitiPower - #041 and Powercor #045 - IT capex for Power of Choice*, 4 March 2016.

<sup>196</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.



would incur. Therefore, we have included this amount in our alternative capex estimate.

## 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 CitiPower, we were not satisfied that the magnitude of CitiPower's proposed capex for RIN compliance costs of \$8.4 million (\$2015) was prudent and efficient.<sup>197</sup>

In its revised proposal, CitiPower proposed an alternative RIN compliance solution involving a mix of both capex and opex. CitiPower 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>198</sup> CitiPower'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 \$15.6 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>199</sup>

We reviewed CitiPower's proposal in which it identified a number of issues requiring action to achieve compliance, including:<sup>200</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.

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<sup>197</sup> AER, *Preliminary decision - CitiPower distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, pp. 6-102 to 6-103.

<sup>198</sup> CitiPower, *Attachment 1.56 - CP RIN Compliance Expenditure*, 'Summary of Costs' tab, January 2016. Excludes escalation.

<sup>199</sup> Origin Energy, *Re: Submission to AER Preliminary Decision Victorian Networks*, 6 January 2016, p. 2.

<sup>200</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 12.

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 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>201</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>202</sup> This will maximise the net benefits of RIN reporting to consumers in terms of enhanced industry efficiency, transparency, governance and data availability.

CitiPower submitted a business case and detailed costing model in support of its revised forecast RIN compliance costs.<sup>203</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>204</sup>
- evidence that a suitable range of alternative options, including a 'do nothing' option, has been considered<sup>205</sup>
- an analysis of costs and benefits of the preferred option<sup>206</sup>
- evidence that the lowest cost option which meets regulatory requirements has been selected such that the preferred option is economically justified.<sup>207</sup>

CitiPower's revised proposal for the RIN compliance project reflects an alternative approach to meeting RIN reporting obligations. CitiPower'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 CitiPower's understanding of its existing position and needs has developed. The preferred option identified in CitiPower'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>208</sup>

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<sup>201</sup> AER, *Preliminary decision - CitiPower distribution determination 2016–2020 - Attachment 6 - Capital expenditure*, October 2015, p. 6-103.

<sup>202</sup> NER, cl. 6.5.7(c).

<sup>203</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015; and CitiPower, *Attachment 1.56 - CP RIN compliance expenditure*, January 2016.

<sup>204</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 6–14.

<sup>205</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 15–16.

<sup>206</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 17–18.

<sup>207</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 18.

<sup>208</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 15–16.

CitiPower'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 changes.<sup>209</sup> In our view, the mix of capex and opex proposed by CitiPower reflects an efficient trade-off between systems investments and manual solutions.<sup>210</sup> This is evident in the 44 per cent reduction in total costs (capex and opex) compared with the initial capex only option. This opex for capex trade-off delivers the overall least cost solution identified by CitiPower to achieve the required business outcomes.

We note that, in part, the reduction in CitiPower'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>211</sup> We agree that it is prudent for CitiPower to seek to comply with applicable regulatory obligations, rather than unspecified possible future obligations which may or may not arise.<sup>212</sup>

In assessing CitiPower'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, CitiPower 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 CitiPower and SA Power Networks share common ownership and some key ICT systems, and are at similar stages in their ICT investment lifecycles.<sup>213</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>214</sup> The combined total capex and opex costs for CitiPower and Powercor 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

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<sup>209</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 18.

<sup>210</sup> NER, cl. 6.5.7(e)(7).

<sup>211</sup> CitiPower, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 16.

<sup>212</sup> NER, cl. 6.5.7(a)(2).

<sup>213</sup> Refer to CitiPower, *Regulatory proposal 2016–20, Appendix E: Capital Expenditure*, April 2015, pp. 133–134 and SA Power Networks, *Regulatory proposal 2015–20*, November 2014, pp. 232–236.

<sup>214</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.

further information to justify this allocation of costs.<sup>215</sup> CitiPower 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 that are not primarily driven by customer numbers.<sup>216</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 CitiPower in support of the forecast RIN compliance capex, we are satisfied that CitiPower's revised proposal capex for the RIN reporting compliance project reflects a reasonable estimate of the efficient costs of a prudent operator.<sup>217</sup> The business case submitted by CitiPower 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 CitiPower's forecast RIN compliance capex in our estimate of overall non-network ICT capex. CitiPower's forecast RIN compliance opex step change is discussed in attachment 7 of this final decision.

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<sup>215</sup> AER, *Information request - CitiPower 034 - IT capex for RIN compliance and Power of Choice*, 28 January 2016.

<sup>216</sup> CitiPower, *Response to AER information request 034* [email to AER], 4 February 2016, p. 1.

<sup>217</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>218</sup> This attachment sets out our decision on CitiPower's forecast maximum demand for the 2016–20 period.<sup>219</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>220</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.

### C.7 AER position

We are satisfied that the maximum demand forecast for the 2016–20 period proposed by CitiPower, in its revised proposal (January 2016), is a realistic expectation of demand.<sup>221</sup> In coming to this view, we take into account the following:

- CitiPower's revised maximum demand forecast is slightly above growth in maximum demand between 2009 and 2015, using weather adjusted historical demand. We consider that the impact of faster population growth, load transfer and block load additions may be driving maximum demand growth on parts of CitiPower's network. We discuss this in section C.10.
- Recent revisions to the maximum demand forecast from the Australian Energy Market Operator (AEMO) give support to CitiPower's revised maximum demand forecast. While CitiPower forecasts slightly higher maximum demand than AEMO, this is likely driven by differences in methodology. We discuss this in section C.12.
- CitiPower's demand forecasting methodology is reasonable when considered against the assessment principles set out in the AER's Expenditure Forecast Assessment Guideline.<sup>222</sup> We discuss this in section C.11.

This decision is made for CitiPower'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.

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<sup>218</sup> NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

<sup>219</sup> 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.

<sup>220</sup> Other factors, such as network utilisation, are also important high level indicators of growth capex requirements.

<sup>221</sup> NER, cl. 6.5.6(c)(3) and 6.5.7(c)(3).

<sup>222</sup> AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 21–23.

## C.8 AER approach

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

- CitiPower's revised proposal
- most recently released forecasts from AEMO<sup>223</sup>
- a report by our internal economic consultant, Dr Darryl Biggar, on CitiPower's revised demand forecast<sup>224</sup>
- stakeholder submissions in response to CitiPower's revised proposal (as well as submissions made in relation to the Victorian distribution determinations).

In our preliminary decision, we were not satisfied that CitiPower'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>225</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 would not grow as strongly as forecasted by CitiPower over the 2016–20 period.
- We examined CitiPower's forecasting methodology. We considered that this methodology effectively assumed that there is a fixed underlying relationship between demand and certain identified demand-drivers (for example, weather). We considered that this relationship has been incorrectly estimated in their model, using the past ten years of historic data and was assumed to continue to hold into the future. We were not satisfied that this reflected a realistic expectation of demand over the 2016–20 period since we were not confident that the drivers used in CitiPower's model were able to fully capture recent changes in demand..
- Independent forecasts from AEMO better explained the actual demand pattern seen on all distributors' networks. This was because it did not assume a fixed structural relationship between demand and demand-drivers over a long period and, instead, placed greater reliance on industry knowledge and judgement. While not without its limitations, we considered that AEMO's forecasts better reflected recent changes in the electricity market.

At the time of our preliminary decision, CitiPower (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

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<sup>223</sup> AEMO, *2015 AEMO Transmission Connection Point Forecasting Report*, September 2015.

<sup>224</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016.

<sup>225</sup> AER, *Preliminary decision CitiPower distribution determination – Attachment 6 – Capital Expenditure*, October 2015, pp. 6-115 to 6-109.

demand forecasts and other information (such as AEMO's most recent demand forecasts) in our final decision.

## C.9 CitiPower's revised proposal

CitiPower 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. CitiPower attributes this to reductions in forecast demand drivers including the Gross State Product (GSP) and retail electricity prices.<sup>226</sup> Demand is now forecasted to start at a lower level than was forecasted in the initial proposal. However, CitiPower has maintained the same demand growth rate as in its initial proposal.

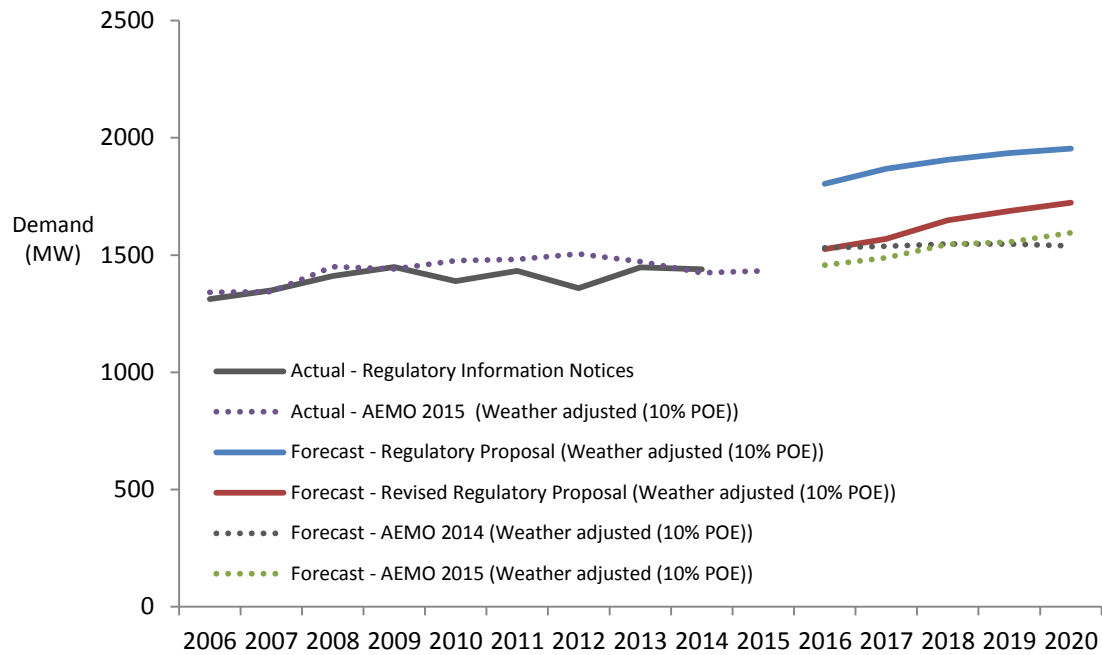
Figure 6.10 and Table 6.13 shows CitiPower's revised maximum demand forecast for the 2016–20 regulatory control period. CitiPower's revised forecast estimates slightly higher growth rate than the maximum demand between 2006 and 2015 (using weather adjusted historical demand). Figure 6.10 and Table 6.13 also provides AEMO's latest system demand forecast for its network (the 2015 connection point forecasts), which shows that CitiPower forecasts maximum demand to grow at a slightly faster rate than AEMO.

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<sup>226</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p.109.



**Figure 6.10 Maximum system demand (Non-coincident, 10% PoE, MW)**



Source: AER analysis, CitiPower, Reset RIN 2016–20, April 2015; CitiPower, 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; CitiPower, Economic Benchmarking RIN (Actual) for 2006–13; CitiPower, Economic Benchmarking RIN (Actual) for 2014.

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

**Table 6.13 Maximum system demand (Non-coincident, 10% PoE, MW)**

	2016	2017	2018	2019	2020	Average annual growth (2016-20)
Regulatory Proposal	1803	1868	1906	1935	1954	2.0%
Revised Regulatory Proposal	1525	1569	1648	1688	1723	3.1%
AEMO connection point forecast (2014)	1530	1537	1547	1548	1539	0.1%
AEMO connection point forecast (2015)	1457	1489	1546	1555	1595	2.3%

Source: CitiPower, Reset RIN 2016–20, April 2015; CitiPower, 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.



CitiPower engaged the Centre for International Economics (CIE) to develop its demand forecast. CitiPower's regulatory proposal provided a brief summary of CIE's demand forecasting method, including approaches to:<sup>227</sup>

- 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.

CitiPower's revised regulatory proposal sets out that the following aspects of its maximum demand forecast were updated from the initial proposal:<sup>228</sup>

- CitiPower 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
- CitiPower's internal bottom-up forecast for more recent demand data and local information, and
- reconciliation of the top-down and bottom-up forecasts.

CitiPower 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 CitiPower's demand forecast meets the requirements of the NER better than AEMO's forecast.<sup>229</sup>

## C.10 Demand trend analysis

Our first step in examining CitiPower'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 CitiPower's revised demand forecast is slightly higher than the underlying historical demand trend since 2006. However, this increase in demand is supported by independent forecasts from AEMO.

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<sup>227</sup> CitiPower, *Revised regulatory Proposal 2016–20*, April 2015, p. 86.

<sup>228</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p.109.

<sup>229</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p.111.

We have examined CitiPower'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 CitiPower, it can be seen that the actual underlying demand trend has grown slightly over the past 10 years and has flattened in recent years. This trend can be seen in Figure 6.10. CitiPower's revised forecasts include some growth over 2016–20. As we set out in our preliminary decision, we consider that growth in rooftop solar and energy efficiency has contributed to reduced electricity drawn from the grid, and this may have dampened maximum demand growth on CitiPower's network.

CitiPower attributes its forecasts of demand growth to forecasts of faster demand growth in specific areas of its network. This is driven by forecast population growth along established and proposed transport corridors driven by zoning changes. CitiPower also submits that loads will be transferred around the network due to the retirement of the 22 kV sub-transmission network, and block loads will also be added to the network from public transport infrastructure projects.<sup>230</sup> We found CitiPower's submission accords with independent population projections from the Victorian Department of Environment, Land, Water and Planning.<sup>231</sup>

Consistent with our preliminary decision, we have also compared CitiPower's revised system demand forecast with AEMO's connection point forecast for CitiPower's network in this determination.<sup>232</sup> AEMO's 2015 connection point forecast show a lower starting demand and a slightly higher demand growth rate for CitiPower'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>233</sup> AEMO's 2015 connection point forecast is also closer to CitiPower'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 CitiPower's revised demand forecast. We consider AEMO's 2015 connection point forecast and its comparison to CitiPower's revised demand forecast in section C.12.

In our preliminary decision, we compared CitiPower's demand forecast with CitiPower'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

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<sup>230</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p.111.

<sup>231</sup> State Government of Victoria, Department of Environment, Land, Water and Planning, *Victoria in Future 2015, Population and Household Projections to 2051*.

<sup>232</sup> We have used AEMO's 2015 connection point forecasts. These forecasts were not available to us and CitiPower at the time we made our preliminary decision (for the preliminary decision, we compared CitiPower'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>233</sup> AEMO, 2015 AEMO transmission connection point forecasting report for Victoria, September 2015, p. 8.

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 CitiPower'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 2010 and 2011, and 2012 and 2013, we concluded that this indicated a flattening of maximum demand in recent years.<sup>234</sup> Having re-evaluated historical demand trends using weather adjusted demand data, CitiPower's historical demand trend is generally consistent with the observations in our preliminary decision.

## C.11 Forecasting methodology analysis

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

- CitiPower/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>235</sup>
- CitiPower/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>236</sup>

In response, CitiPower 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>237</sup>
- Its demand forecast reflects recent and future changes in the electricity markets and demand drivers.<sup>238</sup>
- The AER does not have reason to conclude that demand will soften over the 2016–20 regulatory control period.<sup>239</sup>

A large proportion of CitiPower's revised proposal discusses and critiques AEMO's forecasting methodology, and states that AEMO's forecasts do not reflect a realistic

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<sup>234</sup> AER, *Preliminary decision CitiPower distribution determination, Attachment 6 – Capital Expenditure*, October 2015, p. 6-142.

<sup>235</sup> AER, *Preliminary decision CitiPower distribution determination, Attachment 6 – Capital Expenditure*, October 2015, p. 6-119.

<sup>236</sup> AER, *Preliminary decision CitiPower distribution determination, Attachment 6 – Capital Expenditure*, October 2015, p. 6-120.

<sup>237</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 115.

<sup>238</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 115.

<sup>239</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 118.

expectation of demand. This is because we formed a view that AEMO's forecasts likely reflected a realistic expectation of demand, rather than CitiPower's initial proposal. For the reasons set out in this section, and section C.12, we consider that the updated forecasts provided by both CitiPower 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.

In this section we discuss and form a view on CitiPower's forecasting methodology, taking into account the supporting information in CitiPower'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 CitiPower'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 CitiPower's forecasting methodology is sophisticated and largely justifiable when considered against the assessment principles in the AER's Expenditure Forecast Assessment Guideline<sup>240</sup>.<sup>241</sup> In particular, CitiPower's demand forecasting model:

- allows demand growth to vary by local population forecasts and local responsiveness to economic and weather conditions.<sup>242</sup>
- allows for a more complex relationship between demand and temperature than a simple linear relationship.<sup>243</sup>

These views are formed based on updated material provided in CitiPower's revised proposal. Dr Biggar also reconsidered his position based on CitiPower's revised proposal, taking into account all elements of CitiPower's methodology previously not considered. However, Dr Biggar retained some of his concerns with CitiPower's methodology that were raised in his first report on CitiPower.<sup>244</sup> In particular, Dr Biggar remains concerned that CitiPower's top-down demand forecast (prepared by CIE) does

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<sup>240</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>241</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 18.

<sup>242</sup> Dr Darryl Biggar, *Maximum demand forecasts: response to CitiPower and Powercor revised regulatory proposal*, February 2016, p. 14.

<sup>243</sup> Dr Darryl Biggar, *Maximum demand forecasts: response to CitiPower and Powercor revised regulatory proposal*, February 2016, p. 15.

<sup>244</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 4.

not fully allow the possibility that the relationship between demand and temperature relationship could change over time.<sup>245</sup>

In our preliminary decision, we considered that CitiPower's demand forecast did not reflect recent and future changes in demand trends. In its revised proposal, CitiPower disagreed with this view. CitiPower submitted that its use of the most recent ten years of data reflect recent changes in demand trends.<sup>246</sup> Dr Biggar examined this issue in his report. Dr Biggar stated that, while CitiPower's model uses a dataset which covers 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 CitiPower's model does not directly include solar PV penetration and energy efficiency requirements. As a result, Dr Biggar is concerned that CitiPower's model does not adequately allow for changes in the relationship between demand and its key drivers over time.<sup>247</sup>

We agree with Dr Biggar and consider there remains a flaw within CitiPower'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 CitiPower's network suggests that demand has been largely consistent between 2006 and 2014 (as set out in section C.10). This suggests that any fixed structural relationships within CitiPower's methodology may still produce realistic forecasts in the near-term.

Given that CitiPower'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, CitiPower's forecasting methodology should be reviewed over time 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>248</sup> We will review the impact of CitiPower's revised demand forecast on augex in section B.2.

## C.12 AEMO forecasts

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

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<sup>245</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 5.

<sup>246</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 115.

<sup>247</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 5.

<sup>248</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 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 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>249</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 also support for our use of the latest AEMO connection point forecast in our assessment process.<sup>250</sup>

We used AEMO's 2015 connection point forecast in our comparison with CitiPower's forecast in sections C.9 and C.10. 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>251</sup>

CitiPower 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>252</sup> However, CitiPower submits the following issues with AEMO's forecasting methodology:<sup>253</sup>

- Key drivers of demand are not incorporated at the connection point level and therefore do not allow the responsiveness of demand to key drivers to differ spatially.

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<sup>249</sup> COAG Energy Council Senior Committee of Officials, *Australian Energy Market Operator access to information for developing demand forecasts*, pp. 3–4.

<sup>250</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>251</sup> AEMO, *2015 AEMO transmission connection point forecasting report for Victoria*, September 2015, pp. 4, 8.

<sup>252</sup> CitiPower, *Further submission to the AER regarding preliminary determination*, 4 February 2016, p. 13.

<sup>253</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, pp. 124–133.



- The reconciliation process under-utilises information at the connection point level and results in a simple apportionment of state-wide forecast growth across connection points.
- AEMO's forecasts are insufficiently weather adjusted and therefore result in unrealistically low starting point for the forecasts, leading to lower demand across the demand forecast period
- AEMO's forecasting methodology is not transparent.

As a result, CitiPower considers that AEMO's forecasts do not provide a realistic expectation of demand.<sup>254</sup> Conversely, CitiPower considers that its forecasting methodology better meets the requirements of the NER and NEL than AEMO's.<sup>255</sup> CitiPower considers that, if AEMO's forecasts are adopted for its network, expenditure forecasts will be less than those required to meet the capital and operating expenditure objectives.<sup>256</sup>

In his report for CitiPower, Dr Biggar reviewed CitiPower's criticisms of AEMO's connection point forecasts and forecasting methodology.<sup>257</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>258</sup>

Dr Biggar acknowledged that CitiPower/CIE's modelling approach to weather adjustment is more sophisticated than AEMO's approach.<sup>259</sup> However, Dr Biggar noted that the final test of any forecasting methodology is the quality of the forecasts. That is, size of the deviation between the forecast and the actual value.<sup>260</sup>

Dr Biggar noted CitiPower'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>261</sup> We consider that the reconciliation process may explain the majority of the difference in forecasts from CitiPower and AEMO. However, in total, Dr Biggar concluded that both AEMO and CitiPower's methodologies appear to be reasonable when considered against the

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<sup>254</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 124.

<sup>255</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 133.

<sup>256</sup> CitiPower, *Revised regulatory proposal 2016–20*, January 2016, p. 124

<sup>257</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, pp. 8–19.

<sup>258</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 20.

<sup>259</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 16.

<sup>260</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 17.

<sup>261</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 19.

AER's assessment principles.<sup>262</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>263</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.

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 over time in predicting actual demand.

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<sup>262</sup> Dr Darryl Biggar, *Maximum demand forecasts: Response to CitiPower and Powercor Revised Regulatory Proposal*, February 2016, p. 20.

<sup>263</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.



## D Real material 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.13 Position

We are not satisfied that CitiPower'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>264</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 CitiPower'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 CitiPower's material input cost escalators model as a predictor of the prices of the assets used to provide network services; and
- CitiPower 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.14 CitiPower's revised proposal

In its initial regulatory proposal, CitiPower 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>265</sup> In its revised regulatory proposal, CitiPower submitted that it now expects there to be real price growth of materials costs in the period. CitiPower stated that since its initial regulatory proposal was submitted in April 2015, the value of the

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<sup>264</sup> NER, cl. 6.5.7(a).

<sup>265</sup> CitiPower, *Revised Regulatory Proposal 2016–20*, January 2016, p. 95.

Australian dollar has fallen considerably against the United States dollar. CitiPower also stated that this decline is not expected to be reversed over the 2016–2020 regulatory control period.<sup>266</sup>

CitiPower engaged a consultant, Jacobs, to forecast real and nominal material cost driver price escalation indices for each year of the 2016–2020 regulatory control period. CitiPower reported that Jacobs also forecast the AUD/USD exchange rate for each year of the 2016–2020 regulatory control period as outlined in Table 6.14.

**Table 6.14 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: CitiPower, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

CitiPower 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>267</sup> CitiPower 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 (namely, copper, aluminium, steel and oil) are traded in an international market. CitiPower 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>268</sup>

CitiPower submitted that the forecasts prepared by Jacobs indicate that its materials costs will increase at a greater rate than CPI over the 2016–2020 regulatory control period, in part informed by the downturn in the AUD/USD exchange rate expected to continue over the period. On this basis, CitiPower proposed to apply real materials price growth rates to its expenditure forecasts for the 2016–2020 regulatory control period.<sup>269</sup>

Real cost escalation indices for the following material cost drivers were calculated for CitiPower by Jacobs:<sup>270</sup>

- aluminium
- copper

<sup>266</sup> CitiPower, *Revised Regulatory Proposal 2016–20, January 2016*, p. 91.

<sup>267</sup> CitiPower, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

<sup>268</sup> CitiPower, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

<sup>269</sup> CitiPower, *Revised Regulatory Proposal 2016–20, January 2016*, p. 92.

<sup>270</sup> CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - Jacobs, Escalation indices forecast 2016–2020*, 17 November 2015.

- steel
- oil, and
- construction costs.

Table 6.15 outlines CitiPower's real materials cost escalation forecasts.

**Table 6.15 CitiPower'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: CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015, p. 2.

On the basis of these individual material (and labour) cost escalators, CitiPower through its consultant Jacobs, calculated escalation indices specific to various asset classes common to CitiPower's asset base.<sup>271</sup> These escalation factors were determined by applying a percentage contribution, or weighting, by which each of the underlying cost drivers were considered to influence the total price of each asset.<sup>272</sup> Table 6.16 outlines CitiPower's real cost escalation indices by asset class.

**Table 6.16 CitiPower 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

<sup>271</sup> CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015.

<sup>272</sup> CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - Jacobs, Escalation indices forecast 2016-2020*, 17 November 2015, p. 1.

	2016	2017	2018	2019	2020
Civil	1.000	1.000	1.000	1.000	1.000
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
Underground cabling less cable	1.042	1.023	1.011	1.005	1.000
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: CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - 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 CitiPower is shown in Table 6.17.

**Table 6.17 Capital expenditure to account for real materials price growth (\$ million 2015)**

	2016	2017	2018	2019	2020
Materials	0.6	1.5	1.8	2.0	2.0

Source: CitiPower, *Revised Regulatory Proposal 2016–20*, January 2016, p. 92.

## D.15 Assessment approach

We assessed CitiPower's proposed real material cost escalators as part of our assessment of CitiPower's revised total capex under the NER. Under the NER, we must accept CitiPower's capex forecast if we are satisfied it reasonably reflects the capex criteria.<sup>273</sup> Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.<sup>274</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>275</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>276</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>277</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 CitiPower's proposed material cost escalation, we:

- reviewed the Jacobs report commissioned by CitiPower<sup>278</sup>
- reviewed the capex forecast model used by CitiPower; and
- reviewed the approach to forecasting network asset costs in the context of electricity service providers mitigating such costs and producing unbiased forecasts.

<sup>273</sup> NER, cl. 6.5.7(c).

<sup>274</sup> NER, cl. 6.5.7(c)(3).

<sup>275</sup> AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, pp. 50–51.

<sup>276</sup> AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

<sup>277</sup> AER, *Better Regulation - Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, p. 50.

<sup>278</sup> CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - Jacobs, Escalation indices forecast 2016–2020*, 17 November 2015.

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 settle on using CPI as the acceptable surrogate for materials price escalation for future resets.<sup>279</sup>

## D.16 Reasons

We consider whether a forecast is based on a sound and robust methodology in assessing whether CitiPower's proposed total revised capex reasonably reflects the capex criteria.<sup>280</sup> This criteria includes that the total forecast capex reasonably reflects a realistic expectation of cost inputs required to achieve the capex objectives.<sup>281</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 CitiPower 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

CitiPower 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. CitiPower also submitted that this reduction in the AUD/USD exchange rate was also expected to continue over the 2016-20 regulatory control period. Further, CitiPower submitted that it had not expected this reduction when its initial proposal was submitted in April 2015.

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

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<sup>279</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>280</sup> NER, cl. 6.5.7(c).

<sup>281</sup> NER, cl. 6.5.7(c)(3).

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>282</sup> Table 6.18 compares SKM/Jacobs exchange rate forecast in December 2013 with Jacobs forecast for CitiPower in January 2016.

**Table 6.18 SKM/Jacobs forecast Australia/United States exchange rate (\$AUD/\$US)**

CitiPower	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 CitiPower, *Revised Regulatory Proposal 2016–20*, January 2016, p. 92.

As Table 6.18 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>283</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>284</sup> Frontier Economics' report shows forecast exchange rates by BIS Schrapnel and SKM for the period 2014 to 2019.<sup>285</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 US\$0.87 between 2014 to 2016 while 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

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

<sup>283</sup> Bloomberg Markets, *AUDUSD Spot Exchange Rate*, 3 May 2016.

<sup>284</sup> AusNet Services, *Transmission Revenue Proposal, Appendix 4F - Advice on Cost Escalation Rates for Materials Inputs*, 30 October 2015, p. 7.

<sup>285</sup> AusNet Services, *Transmission Revenue Proposal, Appendix 4F - Advice on Cost Escalation Rates for Materials Inputs*, 30 October 2015, p. 7.



at the end of 2015 was US\$0.73.<sup>286</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 rate forecast models which suggests a “no change” forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.<sup>287</sup>

In its revised regulatory proposal, CitiPower 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>288</sup> We have reviewed Reserve Bank of Australia historical AUD/USD exchange rates and note that when CitiPower submitted its initial proposal in April 2015, the AUD/USD exchange rate during April 2015 was an average of \$0.78 which is below the AUD/USD exchange rate of \$0.903 referred to by CitiPower in its revised regulatory proposal.<sup>289</sup> We note that when CitiPower 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

CitiPower'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 CitiPower'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, CitiPower 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. CitiPower's proposal does not include supporting data or information which demonstrates movements or

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<sup>286</sup> Reserve Bank of Australia, *Exchange Rates - Daily - 2014 to Current*.

<sup>287</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>288</sup> CitiPower, *Revised Regulatory Proposal 2016–20, January 2016*, pp. 91–92.

<sup>289</sup> Reserve Bank of Australia, *Exchange Rates - Daily - 2010 to 2013*.

interlinkages between changes in the input prices of commodities and the prices CitiPower paid for physical inputs. CitiPower'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 CitiPower's assets. For these reasons, there is no basis on which we can conclude that the forecasts are reliable.

## **Materials input cost model forecasting**

CitiPower 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 CitiPower have explained or quantified this relationship, particularly in respect to movements in the prices between the commodity inputs and the physical assets and the basis for the derivation of commodity input weightings for each asset class.

We recognise that active trading on 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. CitiPower 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 CitiPower 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>290</sup>

- the substitution potential between opex and capex when the relative prices of operating and capital inputs change.<sup>291</sup> For example, CitiPower 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 CitiPower 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>292</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>293</sup>

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<sup>290</sup> NER, cl. 6.5.7(e)(7).

<sup>291</sup> NER, cl. 6.5.7(e)(6).

<sup>292</sup> NER, cl. 6.5.7(c)(3).

<sup>293</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.

- 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>294</sup> and
- the difficulty in forecasting nominal exchange rates (used to convert most materials which are priced in \$US to \$AUS). A review of the economic literature of exchange rate forecast models suggests a “no change” forecasting approach may be preferable to the forward exchange rate produced by these forecasting models.<sup>295</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>296</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>297</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 CitiPower as part of this decision.<sup>298</sup>

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<sup>294</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>295</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>296</sup> NER, cl. 6.5.7(e)(7).

<sup>297</sup> NEL, s. 7A(3)(a).

<sup>298</sup> NER, cl. 6.5.7(e)(8).

## Selection of commodity inputs

The limited number of material inputs included in CitiPower's capex forecast model may not be representative of the full set of inputs or input choices impacting on changes in the prices of assets purchased by CitiPower. CitiPower'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.17 Review of independent consultant's reports

We have reviewed a number of recent energy service provider consultant's reports to further support for our position to not accept CitiPower's proposed materials cost escalation. We have considered the relevance of those submissions to the issues raised by CitiPower 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 CitiPower'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>299</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>300</sup> BIS Schrapnel are forecasting the Australian dollar to fall to US\$0.77 in 2018.<sup>301</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

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<sup>299</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>300</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>301</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.

period.<sup>302</sup> In its report submitted in respect to our review of Jemena Gas Networks access arrangement for the 2016–20 access arrangement period, BIS Schrapnel stated that exchange rate forecasts are not authoritative over the long term.<sup>303</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>304</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>305</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>306</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.

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<sup>302</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 10.

<sup>303</sup> BIS Schrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. A-7.

<sup>304</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>305</sup> BIS Schrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, April 2014, p. 48.

<sup>306</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 3.



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>307</sup> This is consistent with our view that there are likely to be a significant number of material exogenous factors that impact on the price of assets that are not captured by the material input cost model used by CitiPower.

CEG provide the following quote from the International Monetary Fund (IMF) in respect of futures markets:<sup>308</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>309</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>310</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

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<sup>307</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

<sup>308</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

<sup>309</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 5–6.

<sup>310</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.



while futures prices and forecasts today may well be a very precise estimate of current expectations of the future, they are at best an imprecise estimate of future values.

This statement again is consistent with our view about the degree of the precision and accuracy of futures prices in respect of predicting electricity service providers future input costs. CEG also highlights the (poor) predictive value of LME futures for actual aluminium prices.<sup>311</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>312</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>313</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>314</sup>

These statements by CEG support our view that the capex forecast model used by CitiPower 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 CitiPower.

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>315</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.

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<sup>311</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 5.

<sup>312</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.

<sup>313</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 19.

<sup>314</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 23.

<sup>315</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>316</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 CitiPower'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>317</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>318</sup> SKM also stated that LME steel futures are still not yet sufficiently liquid to provide a robust price outlook.<sup>319</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>320</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>321</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 CitiPower with those derived by BIS Schrapnel and CEG as shown in Table 6.19.

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<sup>316</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 4.

<sup>317</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 8.

<sup>318</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 12.

<sup>319</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 16.

<sup>320</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 18.

<sup>321</sup> SKM, *TransGrid Commodity Price Escalation Forecast 2013/14 - 2018/19*, 9 December 2013, p. 20.

**Table 6.19 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: CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - 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 6.19 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 CitiPower'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>322</sup>

<sup>322</sup> NER, cl. 6.5.7(a).

## D.18 Conclusions on materials cost escalation

We are not satisfied that CitiPower 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, CitiPower 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 CitiPower'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>323</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>324</sup> CEG stated that futures prices are unlikely to exactly predict future spot prices given that all manner of unexpected events can occur.<sup>325</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>326</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, then real cost escalation should not be applied in determining a service provider's required capital expenditure.

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 Australian gas networks, we took a similar approach where costs were escalated annually by CPI. For CitiPower, we consider that in the absence of a well-founded materials cost escalation forecast, CitiPower's proposed real material cost escalators do not reflect a realistic expectation of the cost inputs required to achieve the capex

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<sup>323</sup> CitiPower, *Revised Regulatory Proposal 2016–20: Attachment 4.33 - Jacobs, Escalation indices forecast 2016–2020*, 17 November 2015, p. 12.

<sup>324</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>325</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, pp. 4–5.

<sup>326</sup> CEG, *Escalation factors affecting expenditure forecasts*, December 2013, p. 13.

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.