



FINAL DECISION

CitiPower distribution determination 2016 to 2020

Oveview

May 2016

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Note

This overview 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

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

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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
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

1 Introduction

We, the Australian Energy Regulator (AER), are responsible for the economic regulation of electricity distribution systems in Australia, except for Western Australia.¹

CitiPower is one of five distribution network service providers (distributors) in Victoria and is responsible for providing electricity distribution services in inner urban and CBD parts of Melbourne. We regulate the revenues CitiPower and other electricity distributors can recover from their customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework governing electricity networks. In regulating CitiPower, we are guided by the National Electricity Objective (NEO), as set out in the NEL. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.²

We apply incentive regulation in making our decision on a distributor's revenue to promote economic efficiency. Incentive regulation encourages distributors to spend efficiently and to share the benefits of efficiency gains with consumers.

1.1 Structure of overview

This overview provides a summary of our final decision and its constituent components. It is structured as follows:

- Section 1 highlights our process and the transitional arrangements that affect 2016 prices.
- Section 2 provides a summary of our final decision, and highlights where we made significant changes between our preliminary and final decisions.
- Section 3 provides a break-down of our revenue decision into its key components. We determine revenue using the building block approach. This section details the approved amount for each building block component.
- Section 4 sets out our final decision on classification of services, control mechanisms and incentive schemes that will apply to CitiPower. These are the decisions we make in addition to the building block revenue determination.
- Section 5 explains our views on the regulatory framework and the NEO.

¹ The Western Australian Government has signalled its intention to transfer electricity regulation to the AER in the second half of 2016. It is proposed that the first regulatory determination by the AER for Western Power's distribution (and transmission) network would be for a four year regulatory period from 1 July 2018.

² NEL, s. 7.

- Section 6 outlines both our consultation process in reaching this final decision, and our view of CitiPower’s consumer engagement undertaken in developing its regulatory proposals.
- Appendix A contains the full list of constituent components for our final decision.
- Appendix B contains a list of stakeholder submissions.

In our attachments to this decision we set out detailed analysis of the constituent components that make up CitiPower’s revised proposal and our decision on each of them.

1.2 Our process

CitiPower submitted its initial regulatory proposal for the 2016–20 regulatory control period in April 2015. We made our preliminary decision on CitiPower’s proposal in October 2015, which set out the total revenue it can recover from its customers over the 2016–20 regulatory period.

Following our preliminary decision, CitiPower submitted its revised proposal in January 2016. We received submissions from stakeholders on our preliminary decisions and the businesses’ revised proposals. We published all submissions and revised regulatory proposals on our website.

Our final decision follows extensive consultation (see section 6). We held public forums and workshops and meetings with stakeholders on many elements of our decision. The AER’s Consumer Challenge Panel (CCP3) has assisted us by advising us on issues of importance to consumers. We have sought to produce consumer friendly documents, established a consultative group with Victorian consumer representatives and held training sessions with consumers. Table 1 lists the key dates and consultation of the process.

Table 1 Key dates and consultation

Task	Date
Businesses submitted regulatory proposals to AER	30 April 2015
AER released Issues paper	9 June 2015
AER held public forum	22 June 2015
Submissions on regulatory proposals received	13 July 2015
AER preliminary decisions	29 October 2015
AER conference to explain preliminary decisions	17 November 2015
Submissions on preliminary decisions	6 January 2016
Businesses submitted revised regulatory proposals to AER	6 January 2016
Further submissions, including on revised proposals	4 February 2016
AER release of final decisions	End of May 2016

Our preliminary decision for the 2016–20 regulatory control period was the basis used for approving network prices in 2016. As required by the 'transitional arrangements' in the NER, we have revoked the preliminary decision and substitute it with this final decision—which

applies to the whole 2016–20 regulatory control period. This decision provides for adjustments over the regulatory control period to account for differences between the amount of revenue we approved for CitiPower for 2016 in the preliminary decision and in the final decision.³

1.3 Victorian electricity distribution

The electricity industry is divided into four distinct parts, with a specific role for each stage of the supply chain—generation, transmission, distribution and retail.

Electricity distributors, which are the focus of this decision, convert electricity from the transmission network into medium and low voltages and deliver that electricity to homes and businesses across Victoria. Each of Victoria’s five distributors serves a different geographic area of Victoria:

- AusNet Services operates in the eastern part of Victoria, including eastern areas of Melbourne
- CitiPower operates in inner urban and CBD parts of Melbourne
- Jemena operates in parts of northern, north-east and north-western areas of Melbourne
- Powercor operates in the western part of Victoria, including some western areas of Melbourne
- United Energy operates in the south-eastern areas of Melbourne.

AusNet Services and Powercor predominantly serve rural and regional Victoria. Jemena, United Energy and CitiPower predominantly serve urban areas.

³ NER, cl. 11.60.4(d) and (e).

2 Summary of final decision

Our final decision is that CitiPower can recover \$1500.3 million (\$ nominal, smoothed) from consumers over the 2016–20 regulatory control period, which began on 1 January 2016. This is a 18.8 per cent reduction from CitiPower's revised proposed revenue allowance of \$1847.8 million (\$ nominal, smoothed). Our final decision allows CitiPower to recover 6.1 per cent more revenue from its customers than we determined in our October 2015 preliminary decision of \$1413.4 million (\$ nominal, smoothed).

Figure 1 compares our final decision on CitiPower's revenue for 2016–20 to its proposed revenue, and to the revenue allowed and recovered during the 2011–15 regulatory period. CitiPower's annual revenue increased each year from 2011 to 2015.

This final decision results in a gradual increase in revenue over 2016–20. The more modest change in revenue over this period reflects reduced pressure on CitiPower's underlying costs, including:

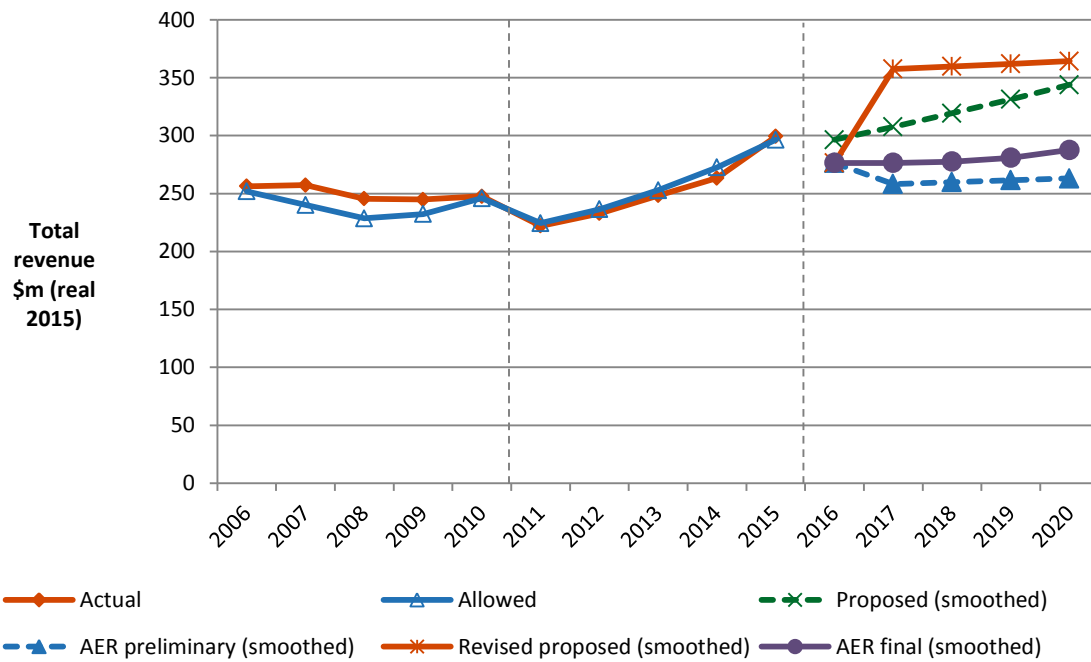
- an improved investment environment compared to 2011–15, which translates to lower financing costs
- lower forecasts of demand growth for electricity in Victoria, which means less pressure on the business to expand the capacity of its network—albeit with some 'pockets' of high growth
- reductions to energy consumers Value of Customer Reliability, which reduces the need to build new infrastructure to meet customers' expectations of reliable electricity.

Total capital expenditure (capex) is forecast to be relatively stable compared to capex in the previous period. Although there is forecast to be lower levels of net connections capex, we expect greater requirements for replacement expenditure compared to the previous period.

Some advanced metering costs that were allocated to metering services are now allocated to operating expenditure (opex) for standard control services in this final decision. This partly explains the increase in opex between our preliminary and final decisions, and compared to 2011–15.

Our October 2015 preliminary decision was used as the basis for setting network charges in 2016. In this final decision we are approving higher revenues than in the preliminary decision. Network charges over 2017–20 will therefore be somewhat higher in order to capture the difference.

Figure 1 CitiPower’s past total revenue, proposed total revenue and AER total revenue allowance (\$ million, 2015)



Source: AER analysis.

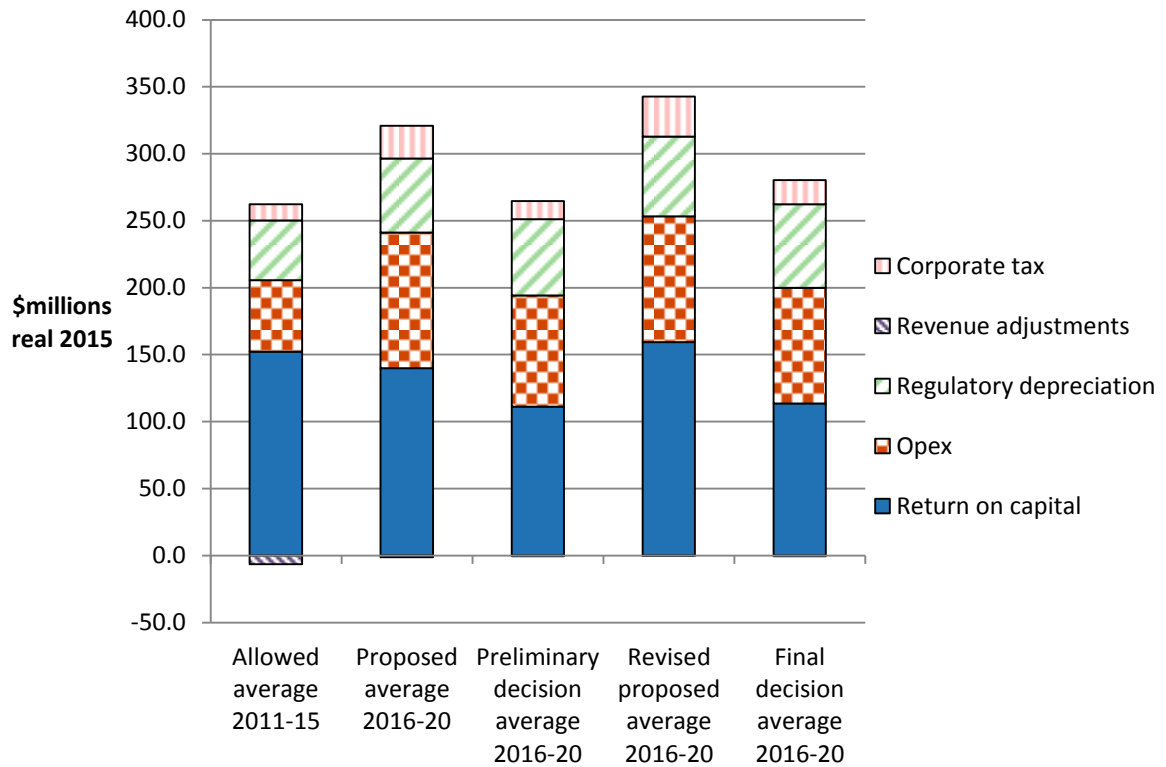
Note: Revenues relates to standard control services only.

2.1 What is driving allowed revenue?

Figure 2 compares the average annual building block revenue from our final decision against that proposed by CitiPower for the 2016–20 regulatory control period, as well as the approved average amount for the 2011–15 regulatory control period.

We approve slightly more revenue over 2016–20 than that allowed for—and recovered by—CitiPower during the previous regulatory period. We have approved significantly less revenue than CitiPower sought to recover through both its initial and its revised proposal.

Figure 2 AER's final decision on constituent components of total revenue (\$ million, 2015)

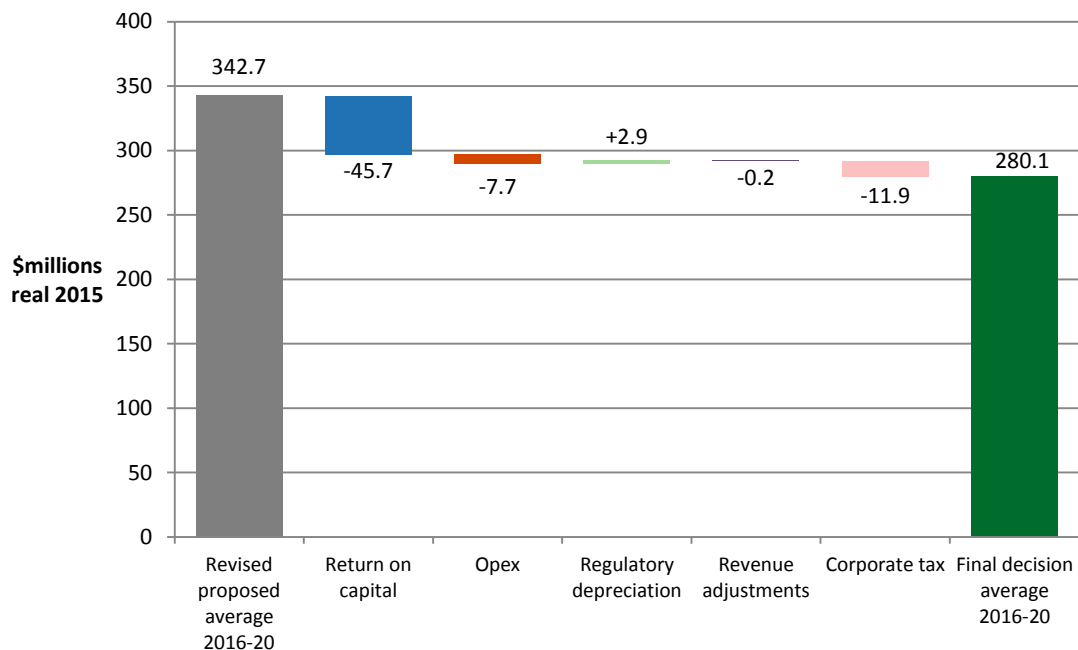


Source: AER analysis.

Note: Components of total revenue relate to standard control services only.

Figure 3 compares our final decision to CitiPower's revised proposal, broken down by the various building block components that make up the forecast revenue allowance.

Figure 3 AER's final decision and CitiPower's revised proposed annual building block costs (\$ million, 2015)



Source: AER analysis.

Note: Building block costs relate to standard control services only.

The allowed rate of return, which feeds into the return on capital building block, is the key difference between our final decision and CitiPower's revised proposal (figures 2 and 3 above), and is the main driver of allowed revenue. The allowed rate of return provides CitiPower with revenue to service the interest on its loans and give a return on equity to its shareholders. It is applied to CitiPower's asset base to determine the return on capital building block.

Prevailing market conditions for debt and equity heavily influence the rate of return. Financial conditions have changed since our last electricity determination for CitiPower in October 2010. Interest rates are lower and financial market conditions are more stable. This means that the cost of debt and the returns required to attract equity are lower.

This is reflected in a lower rate of return in this decision. Our final decision is for a rate of return of 6.11 per cent (for 2016).⁴ In comparison, CitiPower proposed 8.61 per cent in its revised proposal. The allowed rate of return of 6.11 per cent is also lower than the previous regulatory control period's 9.49 per cent.

The impact of the lower rate of return on revenue is offset by other factors to give slightly higher revenues over the 2016–20 regulatory control period compared to the 2011–15 period. The main offsetting factors are increases in operating expenditure and growth in the asset base.

⁴ For the remaining years of the regulatory control period, we will update the rate of return annually.

Opex is a key driver of allowed revenue for CitiPower (as shown in figure 2). Our benchmarking results show CitiPower has been operating relatively efficiently, which gives us confidence to base our opex forecasts on CitiPower's actual ('revealed') costs. However, we have increased CitiPower's allowance compared to the last regulatory control period.

One reason for the opex increase is step increases in the business' costs for new regulatory obligations imposed on CitiPower.

The second is reallocation of a portion of metering costs from alternative to standard control services. The costs of metering services are partly recovered from metering specific charges which are not included in the standard control revenue base we set. In this decision, we have allocated more costs to standard control services, and less to separate meter specific charges. While this increases opex and therefore standard control revenues, it decreases metering revenues. Overall the reallocation has no net impact on the average customer's electricity bill.

When a network business spends money on an asset, the value of that asset is added to its regulatory asset base. CitiPower's regulatory asset base is expected to increase by 29.0 per cent in nominal terms over the 2016–20 regulatory control period—from \$1762.9 million at 1 January 2016 to \$2274.3 million at the end of 2020. Overall forecast capital expenditure of \$845.9 million (\$ nominal) outweighs an offsetting effect of regulatory depreciation of \$334.5 million (\$ nominal).⁵

The revenue impact resulting from the higher asset base this regulatory control period compared to the last regulatory control period largely offsets the revenue impact of the lower rate of return.

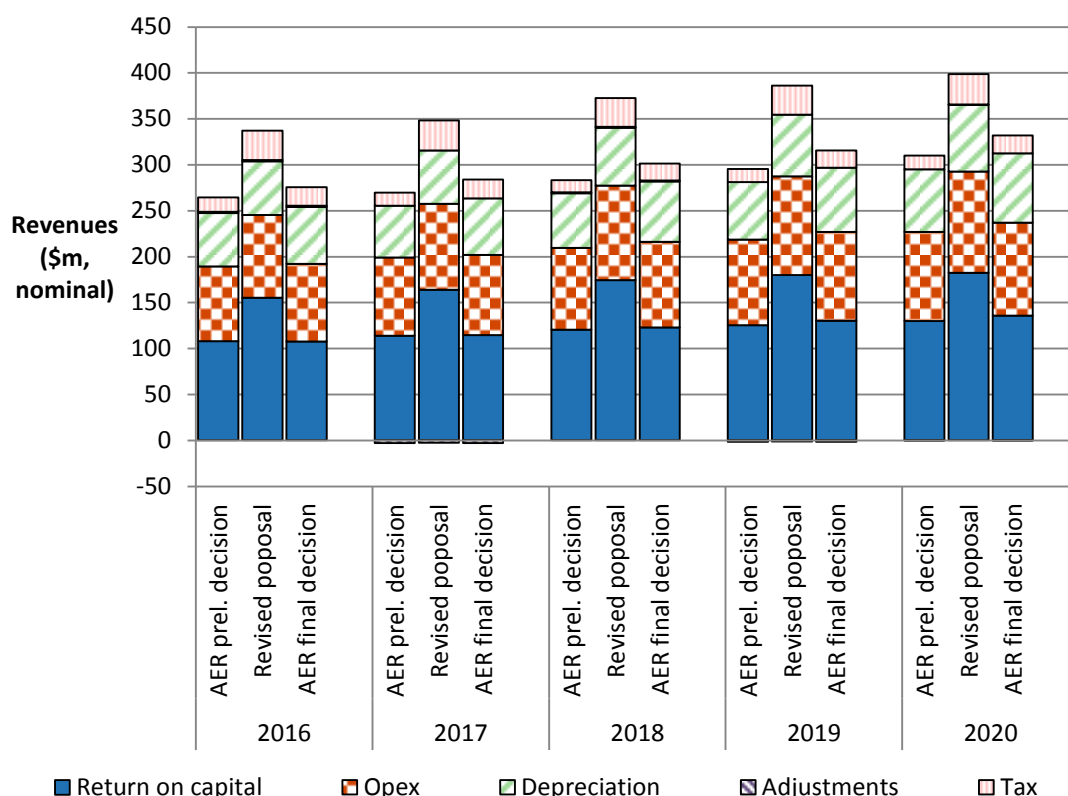
2.2 Key differences between our preliminary and final decisions

While our approved forecast revenue requirement is less than what CitiPower proposed, it is higher than our preliminary decision.

Figure 4 compares our final decision on each of the revenue building blocks to our preliminary decision and CitiPower's revised proposal.

⁵ This capex value is inclusive of equity raising costs and after adjusting for the half-WACC to account for the timing assumption in the PTRM.

Figure 4 AER's final decision and CitiPower's revised proposal building block components of total revenue – unsmoothed (\$ million, nominal)



Source: AER analysis.

Note: Building blocks relate to standard control services only.

A number of aspects of our decision on CitiPower's allowable revenue for 2016–20 have changed since our preliminary decision. The key components that have changed include:

- updating the rate of return
- elements of CitiPower's capex proposal
- allocation of metering costs.

This section provides a brief description of these issues.

2.2.1 Updated rate of return data

Our decision on the rate of return has changed from our preliminary decision (from 6.02 per cent to 6.11 per cent), but this is not due to any change in our methodology but rather the use of more current data and averaging periods. This updated data affects both the return on debt and equity components of the rate of return.

CitiPower changed its rate of return proposal between its original proposal and its revised proposal. The change increased CitiPower's forecast revenue requirement. In its original proposal, CitiPower proposed a rate of return of 7.20 per cent, which we did not accept. In its revised proposal, CitiPower increased its proposed rate of return to 8.61 per cent.

The higher rate of return in CitiPower's revised proposal is largely driven by a change to its approach to estimating the cost of debt. CitiPower previously proposed to calculate its return on debt using a hybrid transition which combines a gradual transition of the base rate to a trailing average and a backwards looking debt risk premium (no transition). However, it now proposes an immediate transition to a trailing average (using both a backwards looking base rate and debt risk premium). This approach is more favourable to CitiPower in revenue terms than that it originally proposed.

We have retained the approach to cost of debt set out in our rate of return guideline. We have not accepted either the hybrid transition proposed in CitiPower's original proposal or the immediate transition to a trailing average proposed in its revised proposal.

2.2.2 Increased capital expenditure forecast

We have increased our capital expenditure forecast from our preliminary decision to 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 augmentation expenditure (augex) (\$8.6 million) because we accept CitiPower's revised maximum demand forecasts
- \$38 million in additional replacement expenditure (repex), 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.

2.2.3 Re-allocation of Advanced Metering Infrastructure costs

Our final decision is to allocate 43 per cent of advanced metering infrastructure (AMI) information technology and communications costs to 'standard control services' (SCS) opex. This increases the total revenue approved in this decision, but does not affect overall network plus metering charges faced by energy consumers.

This decision means that some costs previously allocated to 'alternative control services' (ACS) will now be recovered through SCS. These are costs not of the actual meters themselves (which will be recovered in metering services) but rather costs of shared systems—for example communication and IT systems—that are used in both providing metering services and SCS.

In our preliminary decision, we rejected the allocation of these types of AMI costs to SCS by the businesses. We instead classified these costs under ACS, which meant ongoing AMI costs would be recovered by the businesses through a separate annual metering charge. Section 3.6.2 provides further details on our decision to allocate a portion of AMI costs to SCS.

2.3 Expected impact of decision on residential electricity bills

The annual electricity bill for customers in CitiPower's distribution area will reflect the combined cost of all the electricity supply chain components—wholesale energy generation, transmission, distribution, metering, and retail costs. This decision primarily relates to the distribution charges for SCS, which represent approximately 20 per cent, on average, of the annual electricity bill for these customers. This decision also covers charges for metering services that were previously regulated under a separate Victorian 'Order in Council'.⁶

We estimate the expected bill impact by varying the distribution and metering charges in accordance with our decision, while holding other components of the bill constant.⁷ This approach isolates the effect of our decision on electricity prices, but does not imply that other components will remain unchanged across the regulatory control period.⁸

Based on this approach, we expect that our final decision will result in annual residential electricity bills that are below 2015 levels every year from 2016 to 2020.⁹ Estimated 2016 bills have already decreased by 2.9 per cent, reflecting our preliminary decision. In 2017 and 2018, we expect small decreases of 0.8 per cent or less each year. In 2019 and 2020, we expect small increases of 0.4 per cent or less each year. By 2020, the expected annual residential electricity bill is still 3.3 per cent below the 2015 level.

We expect that a typical resident in CitiPower's distribution area with an annual electricity bill of \$1524 (\$ nominal) in 2015 will face:

- a decrease of \$45 (\$ nominal) or 2.9 per cent in 2016
- a decrease of \$12 (\$ nominal) or 0.8 per cent in 2017
- a decrease of \$1 (\$ nominal) in 2018
- an increase of \$2 and \$6 (\$ nominal) or 0.1 and 0.4 per cent in 2019 and 2020 respectively.

By comparison, had we accepted CitiPower's revised proposal, the expected annual residential electricity bill in 2020 would increase by approximately \$38 (\$ nominal) or 2.5 per cent above the 2015 level.

Table 2 shows the estimated impact of our final decision on average residential and small business customers' annual electricity bills in CitiPower's network area over the 2016–20 regulatory control period, compared with CitiPower's revised proposal. As explained above,

⁶ See section 4.2.2 below.

⁷ In attachment 1 to this decision, we present equivalent estimates based only on the changes in distribution charges (that is, holding metering charges and all other components constant).

⁸ It also assumes that actual energy demand will equal the forecast in our final decision. Since CitiPower operates under a revenue cap (see section 4.2.1 below), changes in demand will also affect annual electricity bills across the 2016–20 regulatory control period.

⁹ As set out in the body text, this section presents estimated bill impacts that consider the combined impact of changes in distribution and metering charges (but hold all other bill components constant). Attachment 1 to this decision presents equivalent estimates that isolate the effect of distribution charges (that is, they also hold metering charges constant).

these bill impact estimates are indicative only, and individual customers' actual bills will depend on their usage patterns and the structure of their chosen retail tariff offering.

Table 2 Estimated impact of final decision on average residential and small business customers' electricity bills in CitiPower's network for 2016–20 period (\$ nominal)

	2015	2016	2017	2018	2019	2020
AER final decision						
<i>Residential annual bill</i>	1524 ^a	1479	1467	1465	1468	1474
Annual change (per cent) ^c		-45 (-2.9%)	-12 (-0.8%)	-1 (-0.1%)	2 (0.1%)	6 (0.4%)
Standard control services		-22	0	2	6	10
Metering		-23	-12	-4	-4	-4
<i>Small business annual bill</i>	3359 ^b	3287	3274	3276	3285	3304
Annual change (per cent) ^c		-72 (-2.1%)	-13 (-0.4%)	2 (0%)	9 (0.3%)	19 (0.6%)
Standard control services		-49	-1	5	13	22
Metering		-23	-12	-4	-4	-4
CitiPower revised proposal						
<i>Residential annual bill</i>	1524 ^a	1479	1557	1557	1559	1562
Annual change (per cent) ^c		-45 (-2.9%)	78 (5.3%)	0 (0%)	2 (0.1%)	3 (0.2%)
Standard control services		-22	83	4	6	6
Metering		-23	-5	-4	-3	-3
<i>Small business annual bill</i>	3359 ^b	3287	3464	3469	3478	3488
Annual change (per cent) ^c		-72 (-2.1%)	177 (5.4%)	5 (0.1%)	9 (0.3%)	10 (0.3%)
Standard control services		-49	182	9	12	14
Metering		-23	-5	-4	-3	-3

Source: AER analysis; ESC, *Victorian Energy Retailers Comparative Performance Report - Pricing 2014–15*, January 2016, p. XIII; ESC, *Energy Retailers Comparative Performance Report - Pricing 2013–14 -Supplementary Report on Electricity Flexible Prices*, December 2014, p. 3.

- (a) Based on average of standing offers at June 2015 on Switchon comparison tool (postcode 3000) using annual bill for typical consumption of 4690 kWh per year. We have preserved the 2015 starting bill for comparability with our October 2015 preliminary decision.
- (b) Based on average of standing offers at June 2015 on Switchon comparison tool (postcode 3000) using annual bill for typical consumption of 12020 kWh per year. We have preserved the 2015 starting bill for comparability with our October 2015 preliminary decision.
- (c) Annual change amounts and percentages are indicative. They are derived by varying 2015 bill amounts in proportion with either total annual regulated revenue (for standard control services) or relevant alternative control services revenue (for metering) divided by forecast demand. Actual bill impacts will vary depending on electricity consumption, tariff class and other variables.

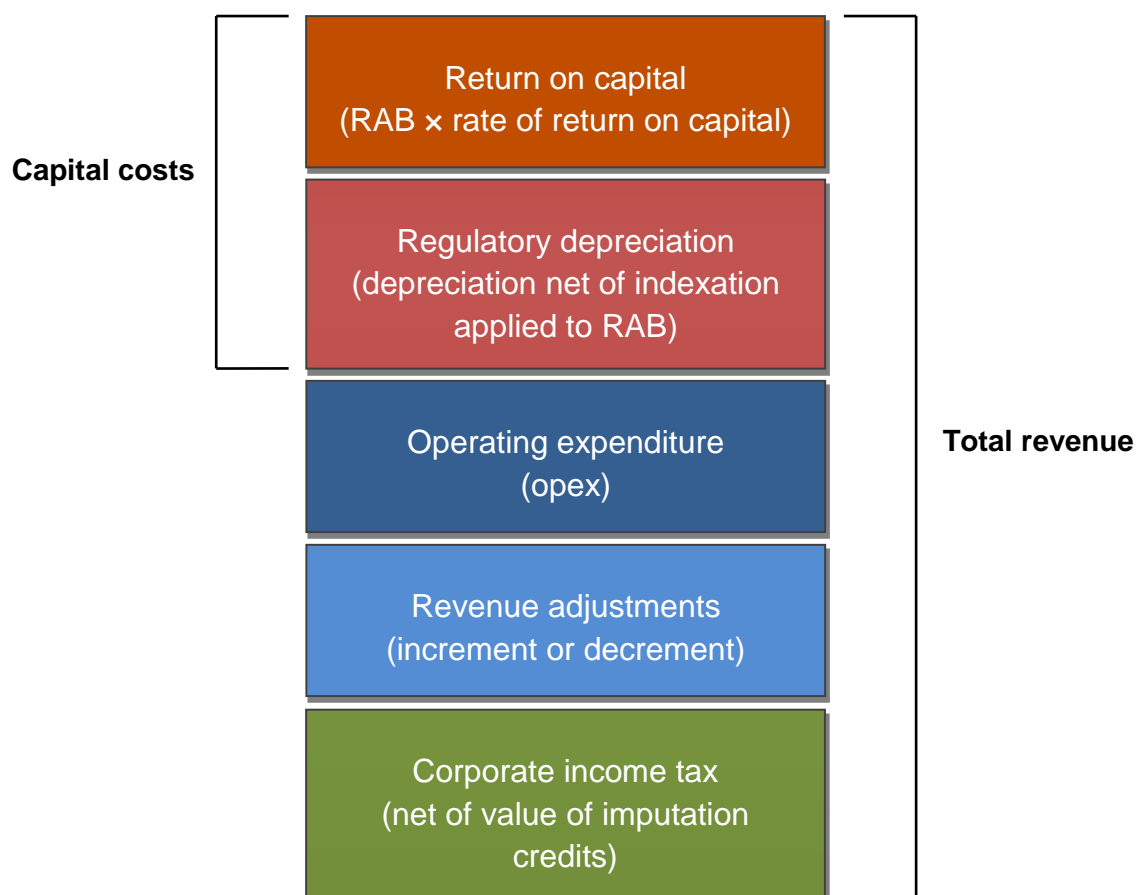
3 Key elements of decision

We use the building block approach to determine CitiPower’s annual revenue requirement. The building block approach consists of five costs that a business is allowed to recover through its revenue allowance.

The building block costs are illustrated in figure 5 and include:

1. a return on the regulatory asset base (RAB) (return on capital)
2. depreciation of the RAB (return of capital)
3. forecast opex
4. revenue increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
5. the estimated cost of corporate income tax.

Figure 5 The building block approach for determining total revenue



The building block costs are comprised of key elements that we determine through our assessment processes. For example, the size of the RAB—and therefore the revenue generated from the return on capital and return of capital building blocks—is directly affected by our assessment of capex.

This section summarises our decisions on key elements of the building blocks, including:

- RAB (section 3.1)
- rate of return (section 3.2)
- imputation credits (section 3.3)
- depreciation allowance (section 3.4)
- efficient level of capex (section 3.5)
- efficient level of opex (section 3.6)
- forecast level of corporate income tax (section 3.7)

Incentive mechanisms is covered in section 4.3.

Table 3 shows our decision on CitiPower's revenues including the building block components.

Table 3 AER's decision on CitiPower's revenues (\$ million, nominal)

	2016	2017	2018	2019	2020	Total
Return on capital	107.6	114.4	123.0	130.2	135.7	610.9
Regulatory depreciation	62.0	61.5	65.8	69.8	75.4	334.5
Operating expenditure	84.4	87.6	93.0	96.8	101.3	463.0
Revenue adjustments ^a	1.4	-2.9	1.0	-1.5	-0.1	-2.2
Net tax allowance	20.1	20.2	18.6	18.5	19.4	96.9
Annual revenue requirement (unsmoothed)	275.5	280.7	301.3	313.8	331.6	1503.1
Annual expected revenue (smoothed)^b	282.9	289.5	297.4	307.9	322.6	1500.3
X factor ^b	n/a ^c	0.00%	-0.40%	-1.20%	-2.40%	n/a

Source: AER analysis.

- (a) Revenue adjustments include efficiency benefit sharing scheme carry-overs, forecast DMIA, 2010 S-factor scheme close out and shared asset adjustments.
- (b) The X factors from 2017 to 2020 will be revised to reflect the annual return on debt update. Under the CPI-X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.
- (c) In our preliminary decision, we determined the expected revenue and associated X factor for 2016. In this final decision to update the 2016 revenue for our assessment of efficient costs, we maintained the preliminary decision expected revenue and determined X factors for the final four years of the 2016–20 regulatory control period. This is to adjust the total expected revenue requirement for the remaining four years in the 2016–20 regulatory control period for the difference between the preliminary decision revenue and our final decision on efficient costs for 2016. Expected revenue in 2016 is around 6.6 per cent lower than approved revenue in real terms, or 4.4 per cent lower in nominal terms.

3.1 Regulatory asset base

The regulatory asset base (RAB) is the value of the assets owned by CitiPower to provide distribution network services. We use the RAB to determine the return on capital and depreciation allowance (return of capital) building blocks.

We make a decision on the opening value of CitiPower's RAB as at 1 January 2016. We then roll forward the forecast RAB over the 2016–20 regulatory control period.¹⁰

Our decision is to set CitiPower's opening RAB at \$1762.9 million (\$ nominal), as at 1 January 2016. This is 2.2 per cent (\$39.7 million) lower than CitiPower's revised proposal of \$1802.6 million (\$ nominal). Our final decision is 1.8 per cent (\$32.2 million) lower than our preliminary decision value for CitiPower's opening RAB of \$1795.1 million (\$ nominal).

There are two key factors affecting the opening RAB value in this decision. First, we updated the 2015 capex estimate with a more recent estimate provided by CitiPower. Second, we have accepted CitiPower's revised proposal to use an all-lagged approach for CPI indexation in the RAB roll forward. This approach is consistent with the past treatment of the Victorian service providers' RAB by the Essential Services Commission of Victoria. Our decision to accept CitiPower's revised approach reflects our view that, to the extent possible, consistency is desirable, and our assessment of the strengths and weaknesses of possible alternative indexation approaches (specifically, partially-lagged and all-lagged approaches). Attachment 2 sets out further details of our reasoning for accepting an all-lagged approach.

Determining the opening value of the RAB

To determine the opening RAB as at 1 January 2016, we roll forward the RAB using actual capex incurred over the 2011–15 regulatory control period to determine a closing RAB value as at 31 December 2015. This roll forward includes an adjustment at the end of 2011–15 to account for the difference between actual 2010 capex and the estimate approved at the 2011–15 determination.¹¹

Tables 4 sets out our decision on the roll forward of CitiPower's RAB for the 2011–15 regulatory control period.

¹⁰ NER, cll. 6.5.1 and S6.2.

¹¹ The end of period adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2011–15 determination.

Table 4 AER's decision on CitiPower's RAB for 2011–15 regulatory control period (\$ million, nominal)

	2011	2012	2013	2014	2015 ^a
Opening RAB	1287.3	1395.7	1488.8	1580.9	1686.4
Capital expenditure ^b	140.6	118.0	141.4	156.2	147.6
Inflation indexation on opening RAB	35.9	49.1	29.8	34.2	38.9
<i>Less: straight-line depreciation</i>	68.0	74.0	79.1	84.9	92.1
Closing RAB	1395.7	1488.8	1580.9	1686.4	1780.8
Difference between estimated and actual 2010 capex					-21.4
Return on difference for 2010 capex					-12.2
Six months CPI adjustment					15.7
Closing RAB as at 31 December 2015					1762.9

Source: AER analysis.

(a) Based on estimated 2015 capex, including an updated estimate provided after the submission of CitiPower's revised proposal.

(b) Net of disposals and capital contributions, and adjusted for CPI.

Rolling forward the RAB over 2016–20

Once we have determined the opening RAB as at 1 January 2016, we roll forward that RAB over 2016–20 with forecast capex, inflation and depreciation to arrive at a forecast value for the RAB at the end of the regulatory period. Table 5 sets out our forecast RAB for CitiPower in 2016–20.

Table 5 AER's decision on CitiPower's RAB for 2016–20 regulatory control period (\$ million, nominal)

	2016	2017	2018	2019	2020
Opening RAB	1762.9	1872.9	2014.4	2132.7	2222.1
Capital expenditure ^b	172.0	203.0	184.1	159.2	127.6
Inflation indexation on opening RAB	41.0	43.5	46.8	49.5	51.6
<i>Less: straight-line depreciation</i>	103.0	105.0	112.6	119.4	127.0
Closing RAB	1872.9	2014.4	2132.7	2222.1	2274.3

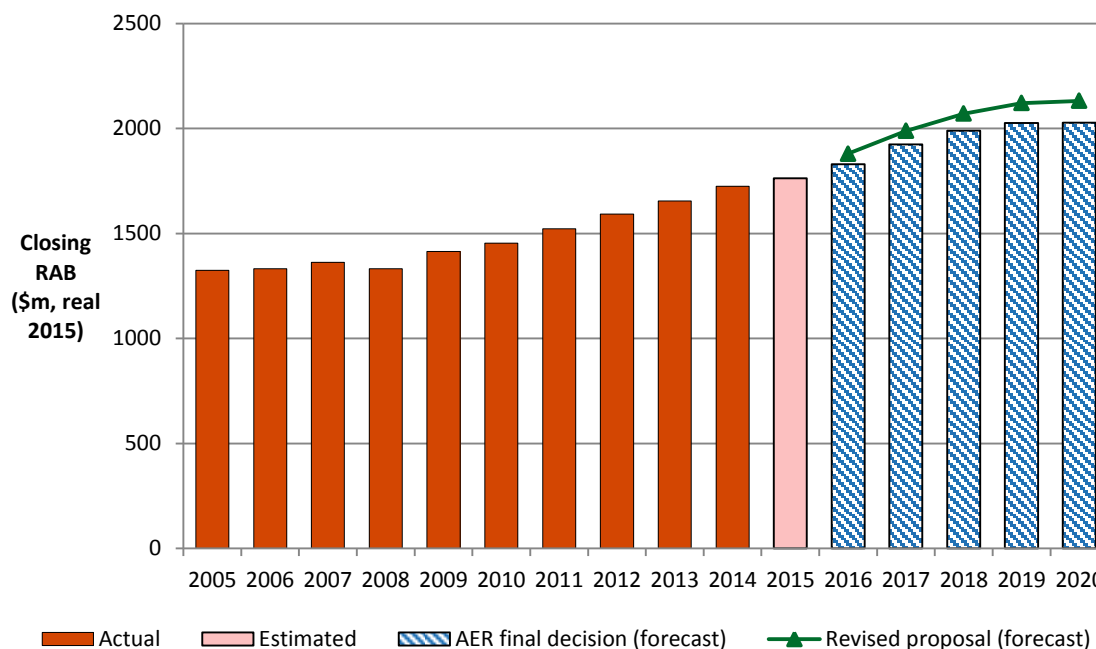
Source: AER analysis.

(a) Net of forecast disposals and capital contributions. Inclusive of equity raising costs and the half-WACC to account for the timing assumption in the PTRM.

We determine a forecast closing RAB value as at 31 December 2020 of \$2274.3 million (\$ nominal). This is \$117.0 million (or 4.9 per cent) lower than the amount of \$2391.2 million (\$ nominal) CitiPower proposed. Our decision on the forecast closing RAB reflects the amended opening RAB as at 1 January 2016, and our decisions on forecast capex (attachment 6), expected inflation (attachment 3) and forecast depreciation (attachment 5).

Figure 6 compares our final decision on CitiPower's forecast RAB to CitiPower's revised proposal and actual RAB in real dollar terms.

Figure 6 CitiPower's actual RAB, revised proposed forecast RAB and AER final decision forecast RAB (\$ million, 2015)



Source: AER analysis.

Details of our decision on the value of the RAB are set out in attachment 2.

3.2 Rate of return (return on capital)

The allowed rate of return provides a network service provider (NSP) a return on capital to service the interest on its loans and give a return on equity to investors.¹² The return on capital building block is calculated as a product of the rate of return and the value of the RAB. The rate of return is discussed in attachment 3.

We are satisfied that the allowed rate of return of 6.11 per cent (nominal vanilla) we determined contributes to the achievement of the NEO, and achieves the allowed rate of return objective set out in the NER.¹³ That is, we are satisfied that this allowed rate of return is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to CitiPower in providing standard control services.¹⁴

This allowed rate of return will apply to CitiPower for the 2016 regulatory year. A different rate of return will apply to CitiPower in each remaining regulatory year of the 2016–20

¹² The term network service provider relates to service providers that provide gas and electricity transmission and distribution services.

¹³ NER, cl. 6.5.2(b).

¹⁴ NER, cl. 6.5.2(c).

regulatory control period. This is because we will update the return on debt component of the rate of return each year to partially reflect prevailing debt market conditions in each year. We discuss this annual update further below.

In its initial and revised proposals, CitiPower proposed that we depart from the rate of return guideline (the Guideline) and our preliminary decision on the allowed rate of return for CitiPower. CitiPower provided further information in support of its revised proposal, which included a change in methodology to the calculation of return on debt. The Australian Competition Tribunal (the Tribunal) also recently reviewed several aspects of our approach to estimating the rate of return that have been contested by CitiPower as part of this revenue determination process. While it upheld a number of these, it found error in other aspects of our approach and remitted these matters back to us. On 24 March 2016, we applied to the Federal Court for judicial review of these aspects of the Tribunal's decision.

With respect to the current decision before us, we have considered the information provided by CitiPower as well as submissions from stakeholders. However, we are not satisfied that a change in our approach would produce an allowed rate of return that better achieves the allowed rate of return objective. Our reasons are highlighted below and explained in further detail in attachment 3 to this final decision.

Advice from CCP, and submissions by the Consumer Utilities Advocacy Centre, Victorian Energy Consumer and User Alliance, Victorian Government, Energy Retailers Association of Australia and Origin Energy indicated that the Victorian distributors' proposals should not depart from the Guideline, and that their proposed rates of return are excessive given the current investment environment.¹⁵ For example, VECUA stated:

The distributors' WACC proposals are excessive and are based on major unjustified departures from the AER's Rate of Return Guideline—a guideline that was developed through extensive consultation over a 12 month period with a broad range of stakeholders, including the Victorian distributors.

By contrast, the Victorian distributors' proposed departures have not been submitted to any rigorous analysis or stakeholder consultation. Most of the information used by the Victorian distributors to support their departures was already considered by the AER during the development of the rate of return guideline.¹⁶

We agree with the following aspects of CitiPower's revised rate of return proposal:

- adopting a weighted average of the return on equity and return on debt (WACC) determined on a nominal vanilla basis (as required by the rules)
- adopting a 60 per cent gearing ratio

¹⁵ Consumer Challenge Panel – Sub panel 3, Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–2020 regulatory period, 25 February 2016 (received by AER on 11 March 2016), pp. 75–114; Consumer Utilities Advocacy Centre, Re: Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015; Victorian Energy Consumer and User Alliance, Submission to the AER, Victorian Distribution Networks' 2016–20 Revenue Proposals, July 2015; Victorian Government, Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016–20, 12 February 2016, p. 1; Energy Retailers Association of Australia, Re: Issues paper – Victorian electricity distribution pricing review 2016-2020, 13 July 2015; Origin Energy, Re: Submission to AER Preliminary Decision Victorian Networks, 6 January 2016, p. 3; Origin, Re: Victorian Networks Revised Proposals, 4 February 2016, p. 2.

¹⁶ Victorian Energy Consumer and User Alliance, Submission to the AER, Victorian Distribution Networks' 2016–20 Revenue Proposals, July 2015, p. 3.

- adopting a 10 year term for the return on debt
- estimating the return on debt by reference to a third party data series.
- estimating the risk free rate using nominal Commonwealth government securities averaged over 20 business days as close as practical to the commencement of the regulatory control period.
- extrapolating and updating the return on debt following the approach we have recently applied¹⁷
- estimating expected inflation using RBA forecasts.

However, we are not satisfied that CitiPower's proposed (indicative) 8.61 per cent rate of return for the 2016 regulatory year has been determined such that it achieves the allowed rate of return objective.¹⁸

Our allowed rate of return is a weighted average of our return on equity and return on debt estimates (WACC) determined on a nominal vanilla basis that is consistent with our estimate of the value of imputation credits.¹⁹ Also, in arriving at our decision we have taken into account the revenue and pricing principles (RPPs) set out in the NEL and are also satisfied that our decision will or is likely to contribute to the achievement of the National Electricity Objective (NEO).²⁰ Our rate of return and CitiPower's proposed rate of return is set out in Table 6.

¹⁷ As per AER, Final decision: SA Power Networks determination 2015–16 to 2019–20, Attachment 3—Rate of return, October 2015, Appendix I.

¹⁸ CitiPower, Revised regulatory proposal 2016 to 2020, 6 January 2016, p. 2611

¹⁹ NER, cl. 6.5.2(d)(1) and (2).

²⁰ NEL, s.16.

Table 6 Final decision on CitiPower's rate of return (% nominal)

	AER previous decision (2011–15)	CitiPower revised proposal (2016)	AER final decision (2016)	Allowed return over 2016–20 regulatory period
Return on equity (nominal post–tax)	10.28	9.89%	7.0	Constant (7.0%)
Return on debt (nominal pre–tax)	8.97	7.76	5.51	Updated annually
Gearing	60	60	60	Constant (60%)
Nominal vanilla WACC	9.49	8.61	6.11	Updated annually for return on debt
Expected inflation	2.57	2.50	2.32	Constant (2.32 %)

Source: AER analysis; CitiPower, Revised regulatory proposal 2016 to 2020, 6 January 2016; AER, CitiPower Pty distribution determination 2011–2015: Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012, p. 25.

Our return on equity estimate is 7.0 per cent. Consistent with the Guideline, the return on equity remains constant over the regulatory control period. Our return on equity point estimate and the parameter inputs are set out in Table 7. CitiPower proposed departing from the approach in the Guideline. We are not satisfied that doing so would result in an outcome that better achieves the allowed rate of return objective.²¹ We do not agree with CitiPower that our method applied in the preliminary decision will result in a return on equity which is inconsistent with the allowed rate of return objective.²² Our return on equity preliminary decision and this final decision is largely consistent with the views in the Guideline.

Table 7 Final decision on CitiPower's return on equity (nominal)

	AER previous decision (2011–15)	CitiPower revised proposal (2016–20)	AER final decision (2016–20)
Nominal risk free rate (return on equity only)	5.08%	2.75%*	2.48%**
Equity risk premium	5.20%	7.17%	4.55%
MRP	6.50%	7.88%	6.50%
Equity beta	0.8	0.91	0.7
Nominal post–tax return on equity	10.28%	9.89%	7.0%

Source: AER analysis; CitiPower, Revised regulatory proposal 2016 to 2020, 6 January 2016; AER, Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015, October 2010.

* Calculated with a placeholder averaging period of 20 business days to 30 September 2015.

²¹ NER, cl. 6.2.8(c)

²² CitiPower, Revised regulatory proposal 2016 to 2020, 6 January 2016, p. 10.

** Calculated with an averaging period of 20 business days up to 26 February 2016 agreed upon in advance of its commencement.

Our return on debt estimate for the 2016 regulatory year is 5.51 per cent. This estimate will change each year as we partially update the return on debt to reflect prevailing interest rates over CitiPower's debt averaging period in each year. Our return on debt estimate for future regulatory years will be determined in accordance with the methodology and formulae we have specified in this decision. As a result of updating the return on debt each year, the overall rate of return and consequently CitiPower's revenue will also be updated.

Consistent with our preliminary decision, we agree there should be a transition from the on-the-day approach to the trailing averaging approach. However, we disagree with the hybrid form of transition proposed in CitiPower's (initial) regulatory proposal.

In its revised proposal, CitiPower departed from its initial position to apply a transition to the trailing averaging approach. It now proposes to not apply a transition (that is, to immediately move to a trailing average approach). We also disagree with CitiPower on this approach.

Consistent with our preliminary decision, we apply a transition to both the base rate and debt risk premium components of the return on debt as per the Guideline.

Our final decision on the return on debt approach is to:

- estimate an on-the-day rate (that is, based on prevailing market conditions) in the first regulatory year (2016) of the 2016–20 regulatory control period, and
- gradually transition this rate into a trailing average approach (that is, a moving historical average) over 10 years.²³

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.²⁴ These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore valuable to investors and are a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

However, the estimation of the return on equity does not take imputation credits into account.²⁵ Therefore, an adjustment for the value of imputation credits is required. This adjustment could take the form of a decrease in the estimated return on equity itself. An

²³ This final decision determines the return on debt methodology for the 2016–20 regulatory control period. This period covers the first five years of the 10 year transition period. This decision also sets out our intended return on debt methodology for the remaining five years. However, we do not have the power to determine in this decision the return on debt methodology for those years. Under the NER, the return on debt methodology must be determined in future decisions that relate to that period.

²⁴ Income Tax Assessment Act 1997, parts 3–6.

²⁵ While the return on equity is not reduced to take into account the value of imputation credits, we note our estimate of the MRP does consider the value we use for imputation credits to ensure it reflects the value to investors in the domestic Australian market inclusive of credits.

alternative but equivalent form of adjustment, which is employed under the NER, is via the revenue granted to a service provider to cover its expected tax liability. Specifically, the NER require that the estimated cost of corporate income tax be determined in accordance with a formula that reduces the estimated cost of corporate tax by the 'value of imputation credits' (represented by the Greek letter, γ , 'gamma').²⁶ This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors.

We adopt a value of imputation credits of 0.4 for this decision, based on our conceptual approach and a wide range of relevant evidence. Estimating the value of imputation credits is a complex and imprecise task, and as such, requires the use of regulatory judgement. There is no consensus among experts on the appropriate value or estimation techniques to use. Conceptually, the value of imputation credits must be between 0 and 1, and the range of expert views on the value of imputation credits is almost this wide.

We do not accept CitiPower's proposed value of imputation credits of 0.25.²⁷ We assessed its reasoning in its revised proposal, and respond in detail in attachment 4. After CitiPower submitted its revised proposal, a number of service providers made late submissions.²⁸ These late submissions asked us to take into account a range of issues identified in the recent Australian Competition Tribunal (the Tribunal) decisions for ActewAGL Distribution, Ausgrid, Endeavour Energy, Essential Energy and Jemena Gas Networks.²⁹ We have considered these submissions as fully as possible in the limited time permitted, and we set out our response in attachment 4. We also sought expert advice from Dr Martin Lally (Lally), in response to the issues raised in these submissions.³⁰

In light of the above, in coming to a value of imputation credits of 0.4:

- We adopt a conceptual approach consistent with the Officer framework, which we consider best promotes the objectives and requirements of the NER. We consider this conceptual approach allows for the value of imputation credits to be estimated on a consistent basis with the allowed rate of return and allowed revenues under the post-tax framework in the NER.³¹
- We use the widely accepted approach of estimating the value of imputation credits as the product of two sub-parameters: the 'distribution rate' and the 'utilisation rate'. We use a wide range of relevant evidence to estimate these parameters, having regard to expert advice on each source of relevant evidence.

²⁶ NER, cll. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3.

²⁷ CitiPower, Revised regulatory proposal, January 2016, pp. 354–375.

²⁸ United Energy, Submission on AER preliminary determination - Submission on gamma, 26 April 2016; CitiPower/Powercor, Submission on implications of recent Australian Competition Tribunal Decision, 18 April 2016; ActewAGL, Implication of recent Tribunal decisions for final decision and updates to the allowed rate of return and forecast inflation estimate, 12 May 2016.

²⁹ For example, see Australian Competition Tribunal, Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, 26 February 2016, para 1(c).

³⁰ Lally, Gamma and the ACT Decision, May 2016.

³¹ In finance, the consistency principle requires that the definition of the cash flows in the numerator of a net present value (NPV) calculation must match the definition of the discount rate (or rate of return / cost of capital) in the denominator of the calculation (see Peirson, Brown, Easton, Howard, Pinder, Business Finance, McGraw-Hill, Ed. 10, 2009, p. 427). By maintaining this consistency principle, we provide a benchmark efficient entity with an ex ante total return (inclusive of the value of imputation credits) commensurate with the efficient financing costs of a benchmark efficient entity.

- Overall, the evidence suggests a range of estimates for the value of imputation credits might be reasonable. With regard to the merits of the evidence before us, we choose a value of imputation credits of 0.4 from within a range of 0.3 to 0.5.
- Lally's latest advice recommended a value of imputation credits of at least 0.5. This is higher than the estimate of 0.4 we adopt in this decision. We maintain our approach and final estimate because we consider it meets the requirements of the NER, taking into account the importance of regulatory certainty and predictability.

We elaborate on our reasons for this decision in attachment 4.

3.4 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital) (box 1). We are required to decide whether to approve the depreciation schedules submitted by CitiPower.³² In doing so, we make a determination on the indexation of the RAB and depreciation building blocks for CitiPower's 2016–20 regulatory control period.

Box 1: What is depreciation?

Regulated service providers invest in large sunk assets to provide electricity distribution services to customers. While some of the cost of such assets may be recovered from customers upfront, a greater proportion is recovered over time. A depreciation charge is used for this purpose. This is particularly important for long-lived assets, since it spreads the cost across the current and future customers who benefit from the use of the asset.

Depreciation reflects the use of an asset each year and accounts for its loss of value due to wear and tear over its useful life.³³ Some assets, such as land, are not depreciated as they have an unlimited useful life.³⁴

For assets that do depreciate, there are several methods that can be employed to calculate the annual depreciation amount. Under a 'straight-line approach', the asset is reduced by a constant amount each period. That is, the asset value is depreciated evenly over its useful life. Alternatively, under a 'diminishing value approach', a constant percentage is applied to the asset value to work out the annual depreciation amount.³⁵ Applying a constant percentage leads to a reducing annual depreciation amount over time as the asset value declines.

³² NER, cl. 6.12.1(8).

³³ NER, cl. 6.5.5(b).

³⁴ For example, see Australian Accounting Standards Board, *AASB 116, Property, plant and equipment*, December 2015, paragraph 58.

³⁵ For example, an asset with 10 year life could have a depreciation percentage of 10 per cent (i.e. 1/10) applied to the remaining asset value each year. This percentage may also have a multiple applied. For example, tax law may allow the 10 per cent to be doubled to 20 per cent for certain assets. The higher the multiple applied, the greater the decrease in the value of the asset early in its life due to faster depreciation.

Our decision is to determine a regulatory depreciation allowance of \$334.5 million (\$ nominal) for CitiPower.³⁶ This amount represents an increase of \$15.6 million or 4.9 per cent from the \$318.9 million (\$ nominal) in CitiPower's revised proposal for the 2016–20 regulatory control period.³⁷ It represents an increase of \$30.0 million or 9.8 per cent from the \$304.6 million (\$ nominal) in our preliminary decision.

Our final decision implements straight-line depreciation using the year-by-year tracking approach, which is the same approach used in CitiPower's revised proposal and our preliminary decision. Straight-line depreciation is often implemented using an approach known as weighted average remaining life (WARL). The key difference is that WARL makes one depreciation calculation for all assets in an asset class, but year-by-year tracking performs multiple depreciation calculations within each asset class, disaggregating assets by year of expenditure. Both these approaches ensure that the initial capital investment is recovered (in real terms) over the lives of the assets, without over or under recovery.

The use of WARL remains our preferred approach because it meets the requirements of the NER and avoids the additional complexity inherent in year-by-year tracking. However, because year-by-year tracking also meets the requirements of the NER, we must accept CitiPower's revised proposal to use this approach. The transition to year-by-year tracking produces a slight increase in the regulatory depreciation allowance for the 2016–20 regulatory control period, as a by-product of discontinuing the aggregation that previously occurred.

We accept CitiPower's proposed asset classes, its straight-line depreciation method, and the standard asset lives used to calculate the regulatory depreciation allowance.³⁸ The adoption of year-by-year tracking means it is no longer necessary to explicitly calculate remaining asset lives as at 1 January 2016.

We have made determinations on other components of CitiPower's proposal that also affect the forecast regulatory depreciation allowance—for example, capex (attachment 6), expected inflation (attachment 3) and the opening RAB value (attachment 2).³⁹

Table 8 sets out our decision on CitiPower's depreciation allowance for 2016–20.

Table 8 AER's decision on CitiPower's depreciation allowance for 2016–20 regulatory control period (\$ million, nominal)

	2016	2017	2018	2019	2020	Total
Straight-line depreciation	103.0	105.0	112.6	119.4	127.0	567.0
<i>Less: inflation indexation on opening RAB</i>	41.0	43.5	46.8	49.5	51.6	232.4
Regulatory depreciation	62.0	61.5	65.8	69.8	75.4	334.5

³⁶ These figures reflect the regulatory depreciation building block allowance, which is calculated as straight-line depreciation less the indexation adjustment on the RAB. The straight-line depreciation figures are presented in the second row of table 8 below.

³⁷ CitiPower, *Revised regulatory proposal*, January 2016, p. 251.

³⁸ The standard asset lives are used to depreciate forecast capex.

³⁹ NER, cl. 6.5.5(a)(1).

Source: AER analysis.

3.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. The return on and return of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

We estimate total capex of \$774.8 million (\$2015) for CitiPower's 2016–20 regulatory control period—which is a 5.6 per cent reduction to CitiPower's forecast capex of \$820.9 million (\$2015). We are satisfied our substitute estimate of CitiPower's total forecast capex reasonably reflects the capex criteria. Our decision represents an increase of \$115.7 million (or 17.6 per cent) from our preliminary decision, primarily driven by increased augex. Our repx and non-network capex allowance has also increased from our preliminary decision. Table 9 shows our decision compared to CitiPower's forecast.

Table 9 AER decision on total net capex (\$ million 2015)

	2016	2017	2018	2019	2020	Total
CitiPower's revised proposal	166.8	200.0	180.1	153.5	120.5	820.9
AER 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

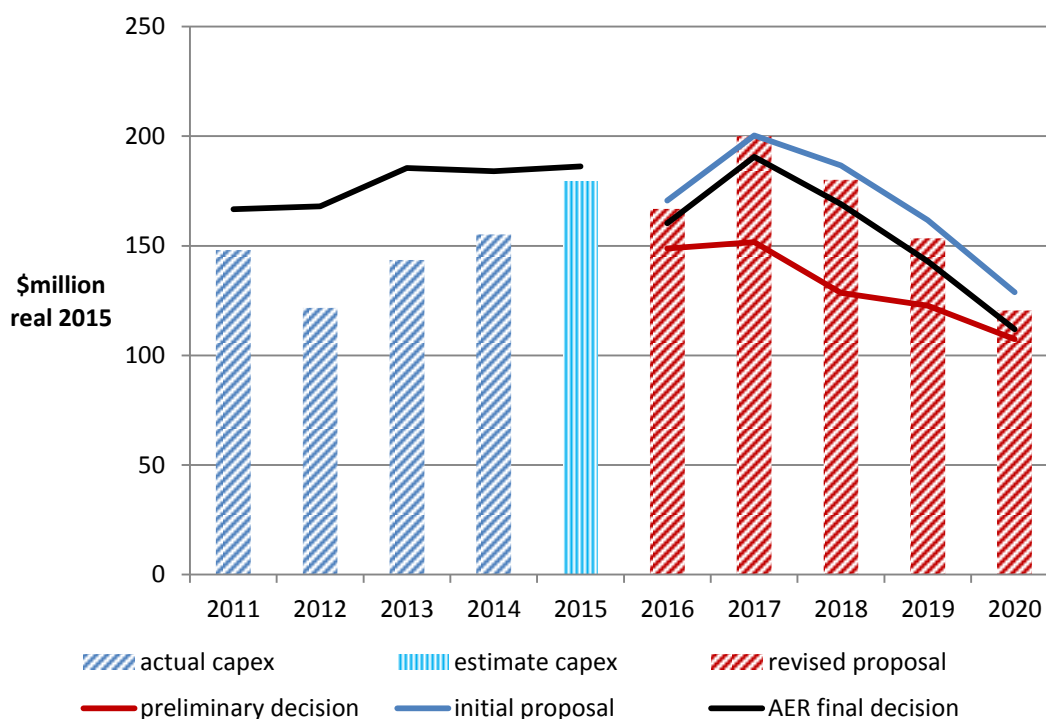
Source: AER analysis.

Note: Numbers may not add up due to rounding.

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

Figure 7 shows our capex decision compared to CitiPower's proposal, its past allowances and past actual expenditure.

Figure 7 CitiPower total actual and forecast capex 2011–2020



The key points of our capex decision for CitiPower are:⁴⁰

- Our alternative estimate of total capex includes \$236.0 million (\$2015) for repex. This is 9.4 per cent lower than CitiPower’s forecast of \$260.4 million (\$2015).
 - This decision includes an amount for business as usual asset replacement and some additional expenditure for building works that were delayed during the 2011–15 period due to delays to the Brunswick Terminal station and additional expenditure on transformer replacement related to noise obligations.
- We have included CitiPower’s revised forecast of augex of \$201.6 million (\$2015).
 - This decision includes capex for two major non-demand driven projects—the completion of the Melbourne CBD security upgrade, and the upgrade of CitiPower’s sub-transmission network.
 - This decision reflects a softening of demand for electricity in Victoria, which means less pressure on the business to expand the capacity of its network—albeit with some 'pockets' of high growth.⁴¹ CitiPower has also reduced its forecast of demand in its revised proposal, further delaying the need for some network investment.

⁴⁰ We obtained CitiPower’s proposed capex figures from its RIN. Our assessment used information from information subsequently provided by CitiPower.

⁴¹ Maximum demand for electricity is a key driver of the level of investment required in a regulatory period. Developments in the Australian and Victorian electricity markets in recent years have influenced electricity consumption patterns and led to a softening of maximum demand. These include household installations of photo-voltaic (PV) cells, changing customer behaviours and the increased focus on energy efficiency. This means that CitiPower is likely to be under less pressure to expand its network than in previous regulatory periods to meet the needs of additional customers or any increased demand from existing customers.

- Reductions to energy consumers' Value of Customer Reliability also reduce the need to build new infrastructure to meet customers' expectations of reliable electricity.⁴²
- We have included the amount in CitiPower's 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 proposal has demonstrated is consistent with the capex criteria.
- We have included CitiPower's forecast for customer contributions capex of \$170.4 million (\$2015) in our capex decision. CitiPower notes that the forecasts in its revised proposal have been updated to reflect changes since the preliminary decision. We examined each of the changes to its proposal by assessing the material supporting CitiPower's updated forecasts and we are satisfied that the forecast reflect is a realistic expectation of the customer contributions CitiPower will receive over the 2016–20 regulatory control period.
- We accepted CitiPower's estimate of non-network capex of \$106.0 million (\$2015) and have included it in our alternative estimate of capex.

The detailed reasons for our final decision on CitiPower's capex are set out in attachment 6 of this decision.

3.6 Operating expenditure

Operating expenditure (opex) is the costs of running an electricity distribution network and maintaining its assets. It includes labour and other non-capital costs.

We are not satisfied CitiPower's forecast opex of \$467.3 million (\$2015) over the 2016–20 regulatory control period reasonably reflects the opex criteria. We have determined an alternative estimate of total opex of \$431.5 million (\$2015).

We have increased our opex forecast by \$18.2 million from our preliminary decision. The difference between our preliminary and final decisions largely reflects a decision to allow a proportion of smart metering costs to be allocated to SCS from ACS, as well as the inclusion of four additional step changes.

Attachment 7 sets out our detailed reasons for our decision on CitiPower's total forecast opex. We compare our estimate with CitiPower's proposal in table 10.

Table 10 AER decision on total opex (\$ million, 2015)

Year ending 30 June	2016	2017	2018	2019	2020	Total
CitiPower proposal	93.3	94.7	102.6	105.3	105.2	501.0

⁴² In planning network augmentation, the Victorian businesses apply a measure of customers' willingness to pay, in dollar terms, for the reliable supply of electricity—known as the Value of Customer Reliability (VCR). This allows the businesses to compare the economic cost to customers from network outages against the cost of augmenting the network. This is a commonly used assessment and reflects good industry practice.

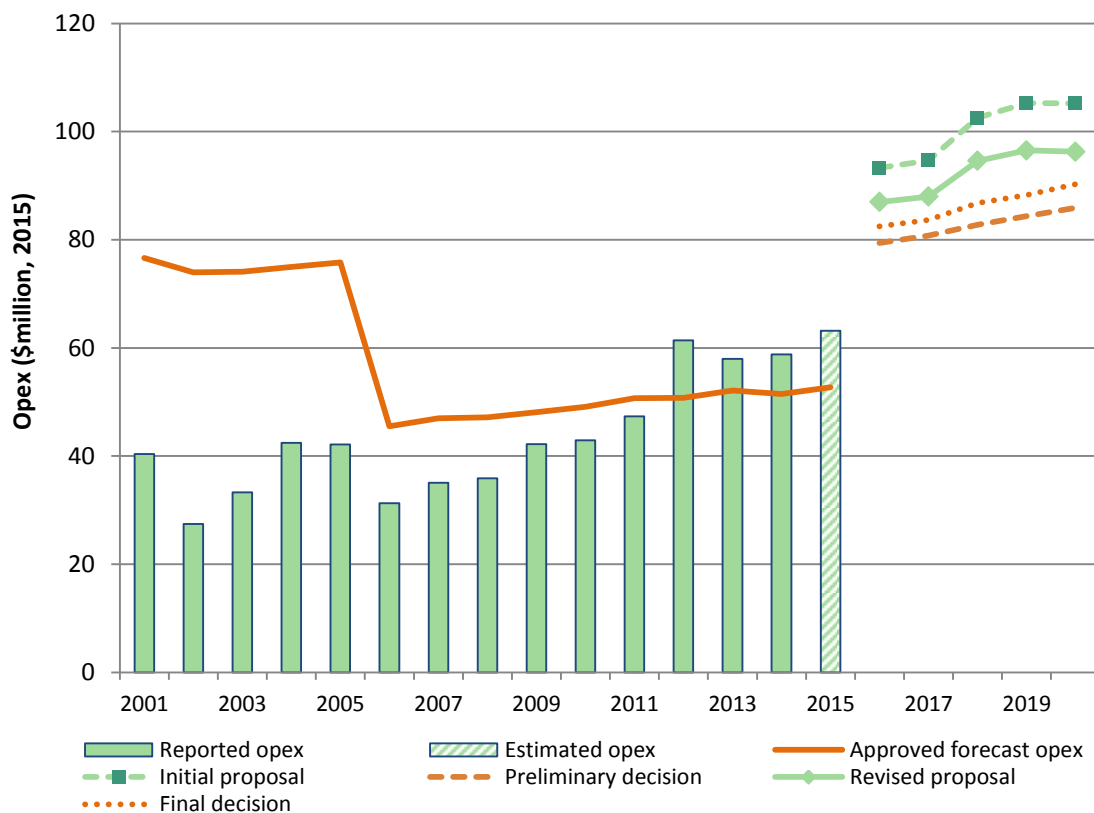
AER preliminary decision	79.4	80.8	82.8	84.4	85.9	413.3
CitiPower revised proposal	87.9	88.9	95.6	97.6	97.4	467.3
AER decision	82.5	83.7	86.8	88.3	90.3	431.5
Difference	-5.4	-5.3	-8.8	-9.3	-7.1	-35.9

Source: AER analysis.

Noted: Includes debt raising costs. Excludes DMIA.

Figure 8 shows our decision compared to CitiPower's proposal, its past allowances and past actual expenditure.

Figure 8 AER decision compared to CitiPower's past and proposed opex (\$ million, 2015)⁴³



Source: AER analysis

Note: standard control services

3.6.1 The components of our estimate of opex

We have used CitiPower's actual opex for 2014 as the basis for forecasting total opex. Based on our benchmarking results we find that CitiPower has been operating relatively

⁴³ We note the main reason we and CitiPower expect opex to increase in the 2016 to 2020 regulatory control period is because of changes in the way CitiPower allocates its costs. For instance, from 2016 CitiPower will expense all corporate overheads, whereas previously it partially capitalised these costs.

efficiently—such that we can use CitiPower’s 2014 opex as a basis for assessing overall forecasts going forward. This is referred to as the revealed cost approach.

However, the base level of opex has increased due to an adjustment to reflect CitiPower's capitalisation policy change which means that it now expenses a greater proportion of its overheads (with a commensurate adjustment to its allocation of overheads to capex). As discussed below we have also included an adjustment to reflect the change in service classification for some advanced metering infrastructure (AMI) opex from alternative control services to standard control services. The impact of this reallocation is revenue neutral, for the reasons discussed in the section below.

To this base level of opex, we have applied a forecast annual rate of change that accounts for the forecast change in opex due to price, output and productivity growth over the regulatory control period. Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than CitiPower's estimate over the forecast period. This is due largely to the difference between how we and CitiPower have forecast labour price growth over the regulatory control period.

To forecast labour price growth, CitiPower used wage increases in its existing enterprise agreement until their expiry, and then used Frontier Economics' recommended extrapolation of long term enterprise agreements from a comparator group of service providers. CitiPower’s forecast is higher than ours, which we base on forecasts of growth in the utilities WPI from Deloitte Access Economics and CIE. The reasons for our approach are discussed below (see box 2).

CitiPower identified a number of cost drivers that it considers will require increased opex over the forecast period. We refer to these cost drivers as possible ‘step changes’. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs.⁴⁴ We typically compensate a network business for step changes only if efficient base year opex, and the rate of change in opex of an efficient service provider, do not already compensate the business for the proposed costs.⁴⁵

CitiPower proposed \$23.9 million for step changes in its revised proposal, of which we have accepted \$12.8 million. We have included step changes in our final decision opex forecast for the following proposals:

- Customer relationship management system
- Mobile devices
- RIN compliance
- Introduction of chapter 5A.⁴⁶

These step changes relate to the costs of complying with new or changed regulatory obligations or efficient capex/opex trade offs.

⁴⁴ We expect total opex to be relatively stable over time. For example, as some non-recurrent costs increase, others will fall away. Efficient discretionary changes in inputs—that are not required to increase output—should have a net negative impact on expenditure over the long term, as the business seeks to improve its efficiency.

⁴⁵ AER, Expenditure Forecast Assessment Guideline, November 2013, p. 24.

⁴⁶ There was also a commercial-in-confidence step change.

Box 2: Forecasting labour price growth

Forecast labour price growth is a component of the opex rate of change. We forecast labour price growth as part of our opex forecast to account for changes in prices over time.

To forecast labour price growth, we use the forecast change in the wage price index (WPI) for the electricity, gas, water and waste services industry (the utilities industry).

For these decisions, we have used forecasts of Victorian utilities WPI growth by Deloitte Access Economics (DAE) and the Centre for International Economics (CIE). We consider the average of these forecasts represents a realistic expectation of the cost inputs required to achieve the opex objectives. This is because these forecasts are forward looking, draw on current market information from multiple sources, and account for important drivers of labour price growth (including enterprise agreements).

CitiPower and Powercor adopted a different approach to ours to forecast labour price growth.

CitiPower proposed a hybrid forecasting method based on:

- the annualised wage growth rates in its enterprise agreements for the period up until the expiry of those agreements
- the five year historical average enterprise agreement wage growth rate for all privately owned electricity networks as calculated by Frontier Economics for the period after the expiry of its current agreements.

We are not satisfied that CitiPower's forecast of labour price growth represents a realistic expectation of the cost inputs required to achieve the opex objectives because:

- CitiPower's backward looking historic average forecasting approach does not account for the labour market conditions expected to prevail in the forecast period. We note that wage price growth for the utilities industry and the economy as a whole is currently the lowest on record. CitiPower's labour price forecasting approach does not account for the impact this would have on labour price growth over the forecast period.
- CitiPower did not use the same forecasting approach for all years of the forecast period. We consider this hybrid forecasting method would result in an upwardly biased total forecast of labour price growth over the regulatory control period.
- We do not consider compliance with enterprise agreements or section 50 of the Fair Work Act 2009 (Cth) is a regulatory obligation or requirement as defined in section 2D of the National Electricity Law (NEL). The Tribunal recently considered this matter following applications by the NSW/ACT businesses. The AER has sought review of the Tribunal's decision in the Federal Court.⁴⁷

We also consider that adopting the wage rate increases in an individual firm's enterprise agreements would reduce the incentive to negotiate efficient wages. If a firm is confident that we will use the wage rate increases in its enterprise agreements to forecast price growth then it has no incentive to minimise those wage increases, as they will be passed through to consumers. This outcome would be inconsistent with the ex ante incentive-based regulatory framework under the NER.

⁴⁷ On 24 March 2016, The Australian Energy Regulator (AER) announced it had applied to the Federal Court for a judicial review of the Australian Competition Tribunal decisions to set aside the NSW and ACT electricity and gas distribution network revenue determinations. See also: AER, media release: *AER appeals against electricity and gas price decisions*, 24 March 2016.

3.6.2 Advanced metering infrastructure

Victorian energy consumers have made a substantial investment in advanced metering infrastructure (AMI)—also known as 'smart meters'. Smart meters can record electricity usage every 30 minutes and give customers access to accurate real-time information about their electricity consumption. The rollout of AMI required an upgrade of the network as well as metering replacement.

The costs for the installation and operation of the smart meters were previously regulated under an 'Order in Council'. This meant cost recovery for these services was separate to the network charges derived from our revenue determination processes.

The smart meter rollout is now largely completed so the Victorian distributors have entered a 'business-as-usual' phase. The capex component for metering will fall in 2016–20, although opex is still required to maintain the metering infrastructure.

As part of this decision, we considered how certain AMI costs should be allocated between standard control services (SCS) and alternative control services (ACS).

A portion of these costs (43 per cent) have been allocated to SCS because some of the IT systems, for example, customer information and billing systems, support network services.⁴⁸ This is a departure from our preliminary decision, which allocated 100 per cent of AMI costs to ACS. This decision increases CitiPower's opex allowance by \$14.0 million (3.2 per cent) from the amount included in our preliminary decision but leads to a similar reduction in CitiPower's opex allowance for metering.

Further details on our allocation of AMI costs are provided in box 3 and attachment 7.

Box 3: Allocation of smart metering costs to standard control services

Standard control services are services that are central to electricity supply and therefore relied on by most (if not all) customers, such as building and maintaining the shared distribution network.

Alternative control services are customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.

The two types of services are treated differently in a regulatory context. We regulate standard control services by determining prices or an overall cap on the amount of revenue that may be earned. The costs associated with these services are shared by all customers via their regular electricity bill. We regulate alternative control services by setting service specific prices to enable the distributor to recover the efficient cost of each service from customers using that service.

The Victorian distribution businesses allocated a significant amount of opex for smart metering or 'AMI' under standard control services in their regulatory proposals for 2016–20.

Our preliminary decision rejected the allocation of AMI costs to standard control services. Instead, we allocated 100 per cent of these costs to alternative control services. We noted that until we issue a new distribution ring fencing guideline that sets out how metering costs should be treated, we considered all costs formerly regulated under the AMI Order in Council should be allocated to

⁴⁸ The remaining 57 per cent will be recovered through annual metering charges.

alternative control services. We considered this approach would also assist in promoting transparency around trends in AMI and standard control expenditure.

The businesses opposed our preliminary decision to allocate all AMI costs to alternative control services. In support of their position, the businesses highlighted that a number of the IT systems rolled out as part of the AMI service would be needed even if the businesses did not provide a metering service. The businesses expressed the view that the forthcoming ring fencing guideline was not relevant to our decision on the appropriate allocation of AMI costs as part of these determinations. Such a delay, the businesses argued, may also create distortions in the market for metering services, which will soon be opened up to competition.

The Victorian Government submitted that a portion of AMI costs should be allocated back to standard control services rather than alternative control services. The Consumer Challenge Panel (CCP) and Vector, on the other hand, agreed with our preliminary decision.

We have reviewed the businesses' revised proposals and supplementary information provided. EMCa provided us with analysis and advice that we considered in arriving at our final decision.⁴⁹ EMCa advised that costs should be directly attributed (to distribution network SCS or metering ACS) only where the relevant systems are solely used to provide that service or where use for the other services can be considered immaterial as defined by Australian accounting standards. Where costs are shared and material, it recommended the costs be allocated on a causal basis. We agree with this approach and have implemented it in reaching our final decision.

For instance, customer information systems and network billing systems are allocated solely to SCS because these systems are solely used to support SCS. On the other hand, all communications costs are allocated to metering ACS on the basis that these systems were primarily put in place to support the remote collection of metering data.

3.7 Corporate income tax

The NER requires us to make a decision on the estimated cost of corporate income tax for CitiPower's 2016–20 regulatory control period.⁵⁰ The estimated cost of corporate income tax contributes to our revenue decision. It enables CitiPower to recover the costs associated with the estimated corporate income tax payable during the regulatory control period.

As shown by Table 11, our decision on the estimated cost of corporate income tax is \$96.9 million (\$ nominal) for CitiPower over the 2016–20 regulatory control period. This amount represents a decrease of \$63.6 million or 39.6 per cent from the \$160.5 million (\$ nominal) in CitiPower's revised proposal.⁵¹ Our decision represents an increase of \$24.1 million (or 33.1 per cent) from the \$72.8 million (\$ nominal) estimated cost of corporate income tax in our preliminary decision.

Table 11 AER's decision on CitiPower's cost of corporate income tax allowance for 2016–20 regulatory control period (\$ million, nominal)

	2016	2017	2018	2019	2020	Total
Tax payable	33.6	33.7	31.0	30.9	32.4	161.5

⁴⁹ EMCa, Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure, 6 April 2016.

⁵⁰ NER, cl. 6.4.3(a)(4).

⁵¹ CitiPower, *Revised regulatory proposal*, January 2016, p. 392.

Less: value of imputation credits	13.4	13.5	12.4	12.4	12.9	64.6
Corporate income tax allowance	20.1	20.2	18.6	18.5	19.4	96.9

Source: AER analysis.

Our decision reflects our amendments to some of CitiPower’s proposed inputs for forecasting the cost of corporate income tax such as the opening tax asset base and the remaining tax asset lives. It also reflects our decision on the value of imputation credits—gamma—(attachment 4). Changes to the building block costs also affect revenues, which in turn impacts the tax calculation. The changes affecting revenues are discussed in attachment 1.

Details of our decision on the corporate income tax allowance are set out in attachment 8.

4 Service classification, control mechanisms and incentive schemes

This section explains our approach to service classification (section 4.1), the forms of regulation to apply (section 4.2) and incentive schemes to promote efficiency (section 4.3).

4.1 Classification of services

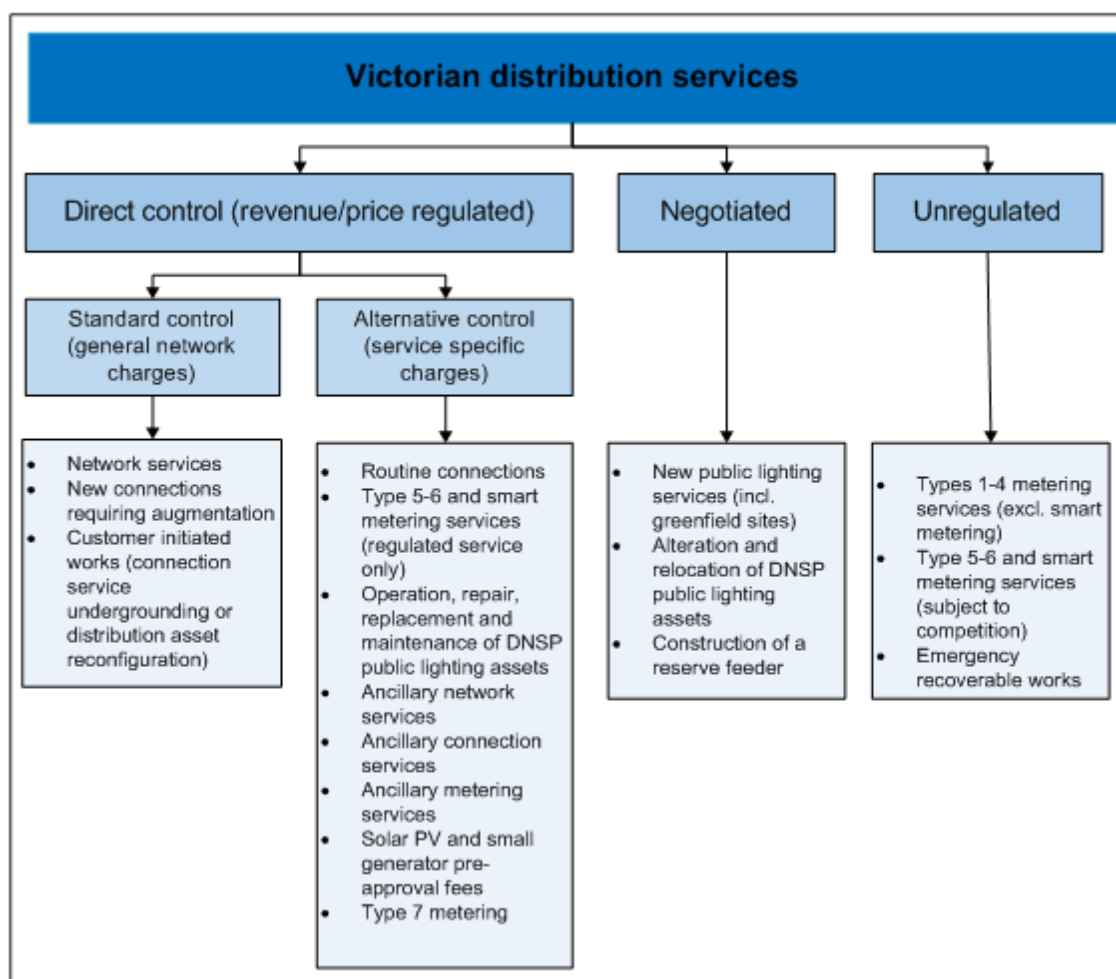
Service classification is inherently linked to the type of economic regulation, if any, to apply to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our decision on service classification reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Services are classified as either 'direct control', 'negotiated' or 'unregulated' services.

- Direct control services are services where we directly control prices by setting a revenue cap or the prices a distributor may charge. These services can be further split by 'standard control' and 'alternative control' services. Our decision on the forms of regulation to apply to standard control and alternative control services is outlined in the following section.
 - Standard control services are services that are central to electricity supply and therefore relied on by most (if not all) customers.
 - Alternative control services are customer specific or customer requested services.
- Negotiated services are services that require a less prescriptive regulatory approach because the relevant parties have sufficient market power to negotiate the provision of those services. Distributors and customers are able to negotiate prices, and we are available to arbitrate if necessary.
- Unregulated services are services that are not distribution services, or services that are contestable and therefore do not need to be regulated. We have no role in regulating these services.

Figure 9 summarises our decision on service classification for CitiPower for the 2016–20 regulatory control period.

Figure 9 AER decision on 2016–20 service classifications for CitiPower



4.2 Regulatory control mechanisms

This section sets out our decision on the type of regulation to apply to standard control services (section 4.2.1) and alternative control services (section 4.2.2).

4.2.1 Standard control services

We have decided CitiPower will be subject to a 'revenue cap' form of control for standard control services over the next regulatory control period. This decision is consistent with our final framework and approach (F&A).⁵²

The control mechanism, which describes how the revenues will vary from year to year, is discussed in attachments 14 and 16. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap.

⁵² The F&A is the first step in our determination of a business' allowable revenue. The F&A determines, amongst other things, which services we will regulate and the broad nature of the regulatory arrangements. AER, Final framework and approach for the Victorian Electricity Distributors – Regulatory control period commencing 1 January 2016, October 2014.

4.2.2 Alternative control services

Alternative control services (ACS) do not form part of a business' revenue cap. Rather, the prices of these services are generally set individually.

Our decision for services other than metering is that the form of control mechanism to apply will be price caps. We have decided a revenue cap will operate for metering services during the 2016–20 regulatory control period. This decision is consistent with our F&A. As per past regulatory practice, CitiPower must demonstrate compliance with the control mechanism through an annual pricing proposal.

We have set charges for fee based and quoted services that reflect the costs incurred by CitiPower to provide these services. CitiPower only earns revenues on these activities where they are specifically requested by individual customers. Further details on our decision on alternative control services are in attachment 16.

The charges for public lighting have been set on the same basis as the 2011–15 regulatory control period. That is with CitiPower operating, maintaining and replacing luminaires it owns on behalf of municipal councils in its distribution area. It does this in accordance with both our decision and the Public Lighting Code. There has been an increase in charges as a result of higher opex, mostly associated with the growth in labour costs.

The AMI rollout that commenced in 2009 under an Order in Council (the Order) is now largely completed. In the 2016–20 regulatory control period, metering in Victoria is entering a 'business-as-usual' phase.

For metering services, we have set charges that recover the efficient opex and capex associated with the ongoing provision of meters to customers from 2016. This means that we regulate metering services under the NEL and NER, subject to certain modifications set out in the Order. Those modifications contain the requirement for us to set meter restoration and exit fees. None of the businesses proposed meter restoration fees. We have set exit fees in this decision—see attachment 16.

The completion of the AMI roll out means that Citipower needs less revenue to provide metering services. Our final decision on the approved revenue requirement results in a decrease in metering charges.

As discussed in section 2.2.3, we have allocated 57 per cent of costs to ACS for IT and communications costs partly incurred in providing AMI services.

4.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to CitiPower are:

- efficiency benefit sharing scheme (EBSS)
- capital expenditure sharing scheme (CESS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme (DMIS)

- f-factor scheme.

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced with the incentives under our STPIS. This encourages businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets.

4.3.1 Efficiency benefit sharing scheme

The EBSS provides an incentive for service providers to pursue efficiency improvements in opex.

As opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period.⁵³ Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period to forecast opex for the next regulatory control period. We call this the 'revealed cost approach'.

However, using a network business' past information to set future targets can reduce the incentives of the business to reduce its costs—since the business knows that any cut in its expenditure will decrease its revenue allowance in the future.

To encourage a business to become more efficient it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the distributor to retain efficiency savings and losses for a longer period of time. In this way, the EBSS can provide businesses with an additional reward for reductions in opex and additional penalties for increases in opex.

Under the EBSS, a business gets to keep the benefits of any efficiency gains for a full five year period, but after that all the gains are passed on to consumers in the form of lower network charges. Efficiency gains made in year 1 or 2 of the regulatory period benefit the business as much as efficiency gains made in year 4 or 5. This ensures the business faces a continuous incentive to pursue efficiency gains over the regulatory control period. The EBSS also discourages a service provider from inflating its base year opex in order to receive a higher opex allowance in the following regulatory control period.⁵⁴

Our final decision for the EBSS carryover amounts from the application of the EBSS in the 2011–15 regulatory control period is outlined in table 12. It is consistent with our preliminary decision which CitiPower accepted in its revised proposal (updated for the most recent CPI).⁵⁵

⁵³ Step changes provide for increases where this is not the case.

⁵⁴ These concepts are explained more fully in the explanatory statement to the EBSS, AER, Efficiency benefit sharing scheme for electricity network service providers - explanatory statement, November 2013.

⁵⁵ CitiPower, Revised regulatory proposal, January 2016, p. 391.

Table 12 AER’s decision on CitiPower’s EBSS carryover amounts (\$ million, 2015)

	2016	2017	2018	2019	2020	Total
CitiPower proposal	-3.6	-2.0	0.7	-1.8	0.0	-6.7
AER preliminary decision	-0.1	-2.7	1.0	-1.3	0.0	-3.1
CitiPower revised proposal	-0.1	-2.7	1.0	-1.3	0.0	-3.1
AER final decision	-0.1	-2.7	1.0	-1.3	0.0	-3.2

Note: The increase in the final decision reflects the most recent CPI.

Our decision is to apply version two of the EBSS to CitiPower in the 2016–20 regulatory control period.⁵⁶ This decision is consistent with our preliminary decision. Our decision on the EBSS is outlined in attachment 9.

4.3.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides an incentive for service providers to pursue efficiency improvements in capex. Similar to the EBSS, the CESS provides a network service provider with the same reward for an efficiency saving and same penalty for an efficiency loss regardless of which year they make the saving or loss.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

Our decision is to apply version one of the CESS, as set out the Capital expenditure incentives guideline, to CitiPower in the 2016–20 regulatory control period as CitiPower proposed. This decision is consistent with our preliminary decision. Attachment 10 sets out our reasons for our decision on CESS.

4.3.3 Service target performance incentive scheme (STPIS)

The service target performance incentive scheme (STPIS) is intended to balance a business’ incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to distributors to maintain and improve service performance where customers are willing to pay for these improvements.

Distributors can only retain their rewards for sustained and continuous improvements to the reliability of supply to customers. Once improvements are made, the benchmark performance targets will be tightened in future years.

⁵⁶ AER, Efficiency benefit sharing scheme for electricity network service providers, November 2013.

Our decision is to apply the service standards component (the s-factor) of our national STPIS to CitiPower for the 2016–20 regulatory control period. This decision is consistent with our final F&A and our preliminary decision. We will not apply the guaranteed service level component to CitiPower as the existing Victorian jurisdictional arrangements will continue to apply.⁵⁷ Our decision is to set revenue at risk for CitiPower at the range ± 5.0 per cent.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

Attachment 11 sets out our decision on CitiPower’s service component parameter values.

4.3.4 Demand management incentive scheme

The demand management incentive scheme (DMIS) includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

Our decision is to continue Part A of the DMIS for CitiPower in the 2016–20 regulatory control period (that is, the DMIA component). We will not apply Part B of the DMIS to CitiPower for the 2016–2020 regulatory control period because we have decided to apply a revenue cap form of control. This is consistent with our proposed approach in our final F&A paper⁵⁸ and our preliminary decision.

CitiPower maintained that distributors should be able to seek AER pre-approval for additional funding above the capped amount. However, we do not consider that it is appropriate to provide for expenditure beyond the capped allowance, in advance of consultation on a new DMIS and DMIA. Consistent with our preliminary decision, the current innovation allowance amount of \$0.2 million (\$2015) per annum (or \$1 million over the period) will continue in the 2016–20 regulatory control period.

Attachment 12 sets out our decision on CitiPower’s DMIS.

4.3.5 f-factor scheme

The f-factor is an incentive scheme to reduce the risk of fire starts due to electricity infrastructure and the risk of loss or damage caused by such fire starts. The f-factor scheme is prescribed by the *f-factor scheme order 2011* (the Order) issued under the National Electricity (Victoria) Act 2005. The Order confers functions and powers on the AER to implement the f-factor.

⁵⁷ AER, Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016, 24 October 2014, pp. 96–97.

⁵⁸ AER, Final Framework and Approach for the Victorian Electricity Distributors, October 2014, p. 114.

As explained in the F&A paper, the Victorian Government advised that it intended to review the f-factor scheme in 2015 to determine how the incentive has performed in delivering efficient improvements to power line bushfire safety. As a new scheme has not been made as yet by the Victorian Government, we will retain the current incentive framework for the purpose of this decision to set the target based on a five year historical average and an incentive rate of \$25 000 per fire start. We will amend this scheme as appropriate to reflect any changes legislated by the Victorian Government following the review.

Attachment 18 sets out our decision on the f-factor scheme.

5 Understanding the NEO

The NEO is the central feature of the regulatory framework. The NEO is to:

promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.⁵⁹

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.⁶⁰ The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.⁶¹

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.⁶² We have also considered the quality and reliability of services provided to consumers. For example, opex allowances have been set so CitiPower may meet existing and new regulatory requirements. Repex allowances take into account the age and condition of assets. We have allowed sufficient augex and connections capex to cater for expected areas of growth. Our capex allowance is based on a contemporary estimate of the value of customer reliability. And the STPIS encourages maintenance, and indeed improvement of, service quality.

The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.⁶³ At the same time, however, there are a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would.

For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.⁶⁴ This could have significant longer term pricing implications for those consumers who continue to use network services.

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the

⁵⁹ NEL, s. 7.

⁶⁰ Hansard, SA House of Assembly, 9 February 2005, pp. 1451–1460.

Hansard, SA House of Assembly, 27 September 2007, pp. 963–972.

Hansard, SA House of Assembly, 26 September 2013, pp. 7171–7176.

⁶¹ Hansard, SA House of Assembly, 26 September 2013, p. 7173.

⁶² Hansard, SA House of Assembly, 9 February 2005, p. 1452.

⁶³ Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].

Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.

AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, p. 50.

⁶⁴ NEL, s. 7A(7).

network than is sustainable. This could create longer term problems in the network⁶⁵ and could have adverse consequences for safety, security and reliability of the network.

The NEL also includes the revenue and pricing principles (RPP),⁶⁶ which support the NEO. As the NEL requires,⁶⁷ we have taken the RPPs into account throughout our analysis. The RPPs are:

A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—

- providing direct control network services; and
- complying with a regulatory obligation or requirement or making a regulatory payment.

A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

- efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
- the efficient provision of electricity network services; and
- the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—

- in any previous—
- as the case requires, distribution determination or transmission determination; or
- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
- in the Rules.

A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all elements of the NEO and consider each of the RPPs.⁶⁸ For example:

⁶⁵ NEL, s. 7A(6).

⁶⁶ NEL, s. 7A.

⁶⁷ NEL, s. 16(2).

⁶⁸ Hansard, SA House of Assembly, 27 September 2007 pp. 965. Hansard, SA House of Assembly, 26 September 2013, p. 7173.

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide CitiPower with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a network service provider in our assessment of CitiPower's forecast capital expenditure and operating expenditure proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of CitiPower's distribution system in our demand forecasting and augmentation determinations (Refer to capex attachment 6).
- Our application of the EBSS, CESS, STPIS and DMIS in this determination provides CitiPower with effective incentives which we consider will promote economic efficiency with respect to the direct control services that CitiPower provides throughout the regulatory control period. (Refer to attachments 9, 10, 11 and 12).
- We have determined CitiPower's opening RAB taking into account the RAB adopted in the previous distribution determination. (Refer to attachment 2, regulatory asset base).
- The allowed rate of return objective reflects the revenue and pricing principle in s.7A(5). We have determined a rate of return that we consider will provide CitiPower with a return commensurate with the regulatory and commercial risks involved in providing direct control services. (Refer to attachment 3, rate of return).
- Our financing determinations provide the distributor with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, the AER is also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the determination are each set too conservatively.⁶⁹ The legislative

⁶⁹ AEMC, Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006, p. 52.

framework recognises the complexity of this task by providing the AER with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.⁷⁰

5.1 Achieving the NEO to the greatest degree

A distribution determination is a complex decision and must be considered as such. In most instances, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, chapter 6 of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several plausible point estimates.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. Where this is the case, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.⁷¹

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NEO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. This is our role under the NEO.

In coming to this final decision we have considered CitiPower's initial and revised regulatory proposal. We have examined each of the building block components of the revised proposal and the incentive mechanisms that would apply across the next regulatory control period. We have considered the submissions we received in regard to CitiPower's initial and revised proposal and our preliminary decision. We have conducted our own analysis and engaged expert consultants to help us better understand if and how CitiPower's revised proposal contributes to the achievement the NEO. We have also considered how our constituent decisions relate to each other, the impact that particular constituent decisions have on other constituent components of our decision, and have described these interrelationships in this final decision. We have undertaken an extensive and consultative regulatory review process to ensure we have canvassed stakeholder issues and made as much of this information

⁷⁰ NEL, s. 88.
AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, p. 8.

⁷¹ NEL, s. 16(1)(d).

publicly available as practicable. We have had regard to and weighed up all the information assembled before us in making this final decision.

Therefore, we are satisfied that among the options before us our final decision on CitiPower's distribution determination for the 2016–20 regulatory control period contributes to the achieving the NEO to the greatest degree.

5.1.1 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.⁷² Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our final decision. These considerations are explored in the relevant attachments.

⁷² SCER, Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper, 6 June 2013, p. 6.

6 Consultation

Stakeholder participation is important to informed decision making under the NEL and NER. It allows us to take a range of views into account when considering how a proposal or decision contributes to the NEO. Effective consultation and engagement provide confidence in our processes and are good regulatory practice.

We have undertaken extensive consultation in developing this final decision (section 6.1). We have also taken into account the network businesses' consultation with their customers (section 6.2).

6.1 Our consultation process

In developing this final decision, we have considered views presented to us by all stakeholders. We also received advice from expert consultants and our CCP.

The NER sets out a process for both consultation on our decisions and publication of information that will inform those decisions. Under the transitional rules for this decision, we must:

- publish the regulatory proposals and any supporting material
- invite written submissions on the regulatory proposals
- hold a public forum on the regulatory proposals
- publish a preliminary determination and reasoning
- invite written submissions on the revocation and substitution of the preliminary determination
- publish a final determination and reasoning.

In developing this final decision, in addition to the above steps, we:

- published an issues paper
- published a consumer guide on this process and our assessment approach
- allowed for further submissions by stakeholders on the distribution businesses' revised proposals
- allowed for further submission by stakeholders on submissions made to the preliminary decisions
- sought advice from the CCP on both the preliminary and final decisions
- held meetings with the Victorian consultative group, which includes Victorian consumer representatives, among others
- held training sessions on the building block model for members of the Victorian consultative group and other stakeholders
- held a workshop on demand management with members of the Victorian consultative group and the distribution businesses
- held a workshop on demand forecasts with AEMO and the distribution businesses

- held meetings with the distribution businesses on various elements of their regulatory proposals
- sought further information from the distribution businesses about the regulatory proposals when questions arose, including through information requests.

This process builds on consultation we undertook with a broad range of stakeholders as part of the Better Regulation program. Following changes to the NER in 2012, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.⁷³

This gives us confidence the approaches set out in our various guidelines, which we have applied in this decision, will result in outcomes that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation guidelines are available on our website⁷⁴ and include:

- Expenditure forecast assessment guideline
- Expenditure incentives guideline
- Rate of return guideline
- Consumer engagement guideline for network service providers
- Shared assets guideline
- Confidentiality guideline.

The guidelines provide businesses, investors and consumers predictability and transparency of our approach to regulation under the new rules.

6.2 Consumer engagement

Recent changes to the NER provide further support for consumer involvement in the regulatory process, and enable us to engage more productively with energy consumers and businesses.⁷⁵ Chapter 6 of the NER was amended to, among other things, require:

- distributors to submit an overview with their regulatory proposal which describes how they have engaged with consumers and sought to address any relevant concerns identified by that engagement⁷⁶
- the AER to publish an issues paper after receiving the distributor's regulatory proposal.⁷⁷ The purpose of the issues paper is to assist consumer representative groups to focus on the key preliminary issues on which they should engage and comment⁷⁸

⁷³ AER, Overview of the Better Regulation reform package, April 2014, pp. 4 and 7–13.

⁷⁴ www.aer.gov.au/Better-regulation-reform-program

⁷⁵ AEMC, Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012.

⁷⁶ NER, cl. 6.8.2(c1)(2).

⁷⁷ NER, cl. 6.9.3(b).

⁷⁸ AEMC, Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule

- the AER, when determining capex and opex allowances, to have regard to the extent to which the forecast includes expenditure to address the concerns of consumers as identified by the distributor in the course of its engagement with the consumers.⁷⁹

Our Better Regulation Consumer engagement guideline sets out our expectations of how the network businesses should engage with their customers. We expect the network businesses to demonstrate a commitment to ongoing and genuine consumer engagement on issues relevant to consumers. We want to see businesses being more accountable to their consumers.⁸⁰ We understand the businesses may need some time to develop and implement robust and comprehensive engagement strategies and approaches.⁸¹

More specifically, the guideline sets out our expectations that the network businesses should develop consumer engagement approaches and strategies that address best practice principles.⁸² We identify four components of best practice for consumer engagement. Each component is underpinned by four principles that are expected to characterise company interactions with consumers.

The four components of best practice are:

1. Priorities—we expect the businesses to identify consumer cohorts and their relevant views, outline their engagement objectives, and discuss how to achieve those objectives
2. Delivery—we expect the businesses to address priorities through ‘robust and thorough’ consumer engagement
3. Results—we expect the businesses to articulate the outcomes from their engagement processes and how success has been measured
4. Evaluation and review—we expect the businesses to evaluate and review the effectiveness of their engagement processes

Four principles support each of these components of best practice:

- Clear, accurate and timely communication—we expect the businesses to provide information to consumers that is clear, accurate, relevant and timely, recognising the different communication needs and wants of consumers
- Accessible and inclusive—we expect the businesses to recognise, understand and involve consumers early and throughout the expenditure process
- Transparent—we expect the businesses to clearly identify and explain the role of consumers in the engagement process, and to consult with consumers on information and feedback processes
- Measurable—we expect the businesses to measure the success, or otherwise, of their engagement activities⁸³

2012.

⁷⁹ NER, cll. 6.5.6(e)(5A) and 6.5.7(e)(5A).

⁸⁰ AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 5.

⁸¹ AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 12.

⁸² AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 5.

⁸³ AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 7.

As set out in the guideline, we monitor consumer engagement activities through the CCP and our ongoing engagement with stakeholders. We may publicly comment in our decisions on any shortcomings that we identify from an expenditure proposal that reflect weaknesses in consumer engagement.⁸⁴

In its most recent advice to us, the CCP stated there is a need for the AER to address the extent to which the businesses are following our consumer engagement guideline, carrying out consumer engagement effectively and appropriately, and drawing substantiated conclusions from their consumer engagement activities.⁸⁵

We have considered the material presented in CitiPower's regulatory proposal (section 6.2.1), and stakeholder views presented to us in submissions (section 6.2.2) to form a view of its progress in implementing improved engagement strategies and approaches (section 6.2.3). We have not undertaken a substantive review of CitiPower's consumer engagement approaches and strategies against the above best practice principles as part of this process.

6.2.1 CitiPower's consumer engagement activities

CitiPower submitted it undertook a Price Reset Stakeholder Engagement Program to understand the needs, concerns and preferences of its customers and other stakeholders.⁸⁶ The engagement program included:

- on-line surveys
- focus groups and interviews
- a Directions and Priorities consultation paper, and
- regional engagement forums.

CitiPower summarised its customer feedback into six key insights:

- Customers want reliable supply for a reasonable price.
- They want efficient and targeted investment across the networks.
- They want the distributors to pay close attention to safety and maintenance and they support additional investment in activities that reduce risk of fire danger.
- They expect forward and proactive planning to ensure the resilience, capacity and capability of the networks.
- They say future needs are best met by a smart grid to enable choice and flexibility.
- They want greater access to readily understandable information about their electricity usage.⁸⁷

⁸⁴ AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 12.

⁸⁵ Consumer Challenge Panel – Sub panel 3, Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period, 25 February 2016, pp. 7–8.

⁸⁶ CitiPower, Regulatory proposal, Appendix A – Our consumer engagement, April 2015, p. 4.

⁸⁷ CitiPower, Regulatory proposal, Appendix A - Our customer engagement, April 2015, pp. 47–50.

CitiPower submitted it responded to this customer feedback in its regulatory proposal by investing in technology to connect more embedded generation, and work with local government to introduce new types of energy efficient street lighting.⁸⁸

CitiPower highlighted, at a high level, how its proposal is consistent with customer feedback received.⁸⁹ Further, CitiPower submitted that concerns raised by their stakeholders have influenced their capex or opex proposals, for example, CitiPower's proposed repex and customer connections capex.⁹⁰

6.2.2 Stakeholder submissions

Victorian Energy Consumer and User Alliance (VECUA) recognise that consumer engagement is a new space for distributors. VECUA provided some perspectives to assist us in our assessment of the distributors' claims, and to assist the distributors to improve their ongoing consumer engagement efforts.⁹¹

Specifically, VECUA submitted that the distributors need to have consumers more involved in their decision-making regarding options and preferred solutions, to provide consumers with more detailed information, and to better enable consumers to challenge the distributors through their participation. VECUA noted that a deeper level of consumer participation will result in revenue proposals that better reflect consumers' long term interests.⁹²

Consumer Utilities Advocacy Centre (CUAC) submitted that while CitiPower published regular information about its plans, CUAC found it difficult to arrange meetings with the business.⁹³

The Ethnic Communities' Council of NSW (ECC) considers one of the major criticisms of the process of consumer consultation and engagement by network businesses (with the exception of Jemena) is that it has been, and continues to be, largely a process of one-way information transfer:

There is little indication or transparency of how, if at all, such consultation and communication has been used to shape the networks' initial proposals and their subsequent revised proposals.⁹⁴

Further, the ECC submits that detailed information on the methodologies employed by networks to consult with consumers is not easily found, nor is information about the spread

⁸⁸ CitiPower, Regulatory proposal, April 2015, p. 66.

⁸⁹ CitiPower, Regulatory proposal, April 2015, pp. 64–66.

⁹⁰ CitiPower, Regulatory proposal, Appendix E Capital expenditure, April 2015, pp. 19, 102.

⁹¹ Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals, 13 July 2015, p. 49.

⁹² Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks' 2016–20 Revenue Proposals, 13 July 2015, p. 51.

⁹³ Consumer Utilities Advocacy Centre, RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015.

⁹⁴ Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, p. 3.

and diversity of consumers engaged and consulted, and by what means, especially those with a first language other than English.⁹⁵

The ECC provides some perspectives to assist us and the distributors to engage with culturally and linguistically diverse energy consumers.⁹⁶ Similarly, the Ethnic Communities' Council of Victoria submitted that Victorian distribution businesses should engage more with culturally and linguistically diverse consumers—particularly those who may be disadvantaged by 'price-based mechanisms' to balance quality and service with operational costs.⁹⁷

Origin raises concerns about the ability of stakeholders to engage with the material submitted by the Victorian electricity distributors in their initial and revised proposals:

The Victorian DNSPs have collectively submitted over 70,000 pages of material to address matters raised in the AER's preliminary decision. This is in addition to the vast quantity of information submitted in their substantive regulatory proposals.

We recognise the importance for regulated [distributors] to present robust and accurate regulatory submissions to support their proposed expenditure and revenue allowances. However, we are concerned that the quantity of information, not just in this process, but in all recent network reviews, makes it increasingly challenging for stakeholders to meaningfully contribute to the regulatory debate.⁹⁸

In its most recent advice, CCP raised concerns about whether the network businesses consulted with their customers on significant changes in their position particularly on the cost of debt in the revised proposals, which would have a significant impact on network charges:

... the [return on debt] proposals, and the impact of these proposals on the price paths, represent a substantial change from the pricing proposals that the DNSPs' put to their customers as part of their original customer engagement programs. CCP3 is not aware whether this new approach has been canvassed by the DNSPs with their consumers and whether the DNSPs have established a consensus with their customers that this increase (well above market rates) is in the consumers' long-term interests.⁹⁹

CCP raised other more general concerns that may apply to the Victorian distribution businesses' consumer engagement activities. For example, CCP notes: information provided and questions to consumers in workshops, focus groups and surveys are potentially open to bias;¹⁰⁰ the full context of an issue is not always provided;¹⁰¹ and the selection of attendees

⁹⁵ Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, p. 3.

⁹⁶ Ethnic Communities' Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, pp. 4–5.

⁹⁷ Ethnic Communities' Council of Victoria, Submission to the Australian Energy Regulator Victoria Electricity Pricing Review, 15 July 2015, p. 6.

⁹⁸ Origin, Re: Victorian Networks Revised Proposals, 4 February 2016, p. 1.

⁹⁹ Consumer Challenge Panel – Sub panel 3, Overview: 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. 35.

¹⁰⁰ Consumer Challenge Panel – Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, p. 6.

¹⁰¹ Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, pp. 6–7.

at the various consumer engagement activities can lead to bias.¹⁰² VECUA raised similar concerns.¹⁰³

As part of this process, CCP observed consumer engagement activities undertaken by some of the businesses only.¹⁰⁴ CCP noted that its concerns do not necessarily apply to each Victorian distributor and does not cite specific examples.¹⁰⁵

6.2.3 Our view of CitiPower's consumer engagement

Overall, we consider CitiPower has taken important initial steps to engage with its customers, although we note CUAC identified CitiPower could be more accessible to consumer representatives.¹⁰⁶

VECUA and the CCP indicated there are further opportunities for CitiPower to improve the way it objectively seeks consumer feedback in developing its regulatory proposals.¹⁰⁷ Further, the ECC indicates CitiPower could be more transparent in the way it reports its consumer engagement activities and how they affected its initial and revised regulatory proposals.¹⁰⁸ We expect CitiPower to consider these submissions in developing its consumer engagement program going forward.

Additionally, we are concerned that CitiPower did not engage with its customers on its change in position particularly on cost of debt between the initial and revised proposals (discussed in section 3.2). The Victorian Government, Origin and CCP considered the higher rates of return submitted by the Victorian electricity distributors in their revised proposals—which would lead to significant increases in customer charges—were ‘opportunistic’.¹⁰⁹

We expect the businesses to involve consumers throughout the process, and to provide information to consumers that is clear, accurate, relevant and timely.¹¹⁰ Although explaining

¹⁰² Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, pp. 7–8.

¹⁰³ Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks’ 2016–20 Revenue Proposals, 13 July 2015, pp. 51–53.

¹⁰⁴ Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, p. 5.

¹⁰⁵ Consumer Challenge Panel - Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, p. 5.

¹⁰⁶ Consumer Utilities Advocacy Centre, RE Victorian electricity distribution pricing review (EDPR), 2016 to 2020, 13 July 2015.

¹⁰⁷ Victorian Energy Consumer and User Alliance, Submission to the AER Victorian Distribution Networks’ 2016-20 Revenue Proposals, 13 July 2015, pp. 49–53; Consumer Challenge Panel – Sub panel 3, Response to proposals from Victorian electricity distribution network service providers, 5 August 2015, pp. 4–9.

¹⁰⁸ Ethnic Communities’ Council of NSW, Submission concerning the Victorian Distribution Networks Revised Revenue Proposal 2016-20 Submissions to AER January 2016, 4 February 2016, p. 3.

¹⁰⁹ Victorian Government, Submission on the Victorian electricity distribution network service providers’ preliminary distribution determinations for 2016–20, 12 February 2016, p. 1; Minister for Industry, and Energy and Resources, Hon Lily D’Ambrosio MP, Letter to AER: Distribution Businesses Revised Regulatory Proposals, 29 January 2016, pp. 1–2; Origin, Re: Victorian Networks Revised Proposals, 4 February 2016, p. 1; Consumer Challenge Panel – Sub panel 3, Response to AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period, 25 February 2016, p. 8.

¹¹⁰ AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 7.

rate of return concepts is inherently difficult, this does not mean the business should avoid engaging on this aspect of the regulatory proposal—especially when it has decided to change its approach from its initial proposal and where this would have a significant effect on network charges.

A Constituent decisions and revocation of preliminary decision

In November 2012, the AEMC introduced major changes to the economic regulation of electricity distributors under chapter 6 of the National Electricity Rules. To allow consumers to receive the benefit of the new rules, the AEMC made transitional rules under chapter 11 of the NER. Those rules required the AER to make a preliminary distribution determination for each of the Victorian distributors prior to the commencement of the 2016–20 regulatory control period.

The AER made its preliminary decision for CitiPower for the 2016–20 regulatory control period in October 2015. That distribution determination formed the basis for approving network prices for CitiPower for 2016.

At the same time as we made the preliminary decision, we invited submissions on the revocation and substitution of that distribution determination.

As required by the transitional rules,¹¹¹ we now revoke the preliminary decision and substitute it with this new distribution determination. This new distribution determination (referred to as our final decision) takes effect at the date it is made and applies in respect of the 2016–20 regulatory control period.

The final decision provides for adjustments over the regulatory control period to account for differences between the revenue that we approved for CitiPower, in the preliminary and final decisions, for the 2016 regulatory year.¹¹²

Our final distribution determination is predicated on the following decisions (constituent decisions):¹¹³

Constituent decision

In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to CitiPower for the 2016–20 regulatory control period (listed by service group):

- Standard control services include network services, connection services requiring augmentation, customer initiated works (connection service undergrounding or distribution asset reconfiguration)
- Alternative control services include routine connections, type 5–6 and smart metering services (regulated service only), operation, repair, replacement and maintenance of public lighting assets, ancillary network services, ancillary connection services, ancillary metering services, solar PV and small generator pre-approval fees, type 7 metering
- Negotiated distribution services include new public lighting services (incl. greenfield sites), alteration and relocation of DNSP public lighting assets, construction of a reserve feeder
- Unregulated services include type 1 to 4 metering services (excl. smart metering), type 5–6 and

¹¹¹ NER, cl. 11.60.4.

¹¹² NER, cl. 11.60.4(d) and (e).

¹¹³ NER, cl. 6.12.1.

smart metering services (subject to competition), emergency recoverable works.

Attachment 13 of the final decision discusses classification of services.

In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in CitiPower's building block proposal. Our final decision on CitiPower's annual revenue requirement for each year of the 2016–20 regulatory control period is set out in attachment 1 of the final decision.

In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves CitiPower's proposal that the regulatory control period will commence on 1 January 2016. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves CitiPower's proposal that the length of the regulatory control period will be five years from 1 January 2016 to 31 December 2020.

In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d), the AER does not accept CitiPower's proposed total forecast capital expenditure of \$820.9 million (\$2015). Our substitute estimate of CitiPower's total forecast capex for the 2016–20 regulatory control period is \$774.8 million (\$2015). This is discussed in attachment 6 of the final decision.

In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept CitiPower's proposed total forecast operating expenditure inclusive of debt raising costs and exclusive of DMIA of \$467.3 million (\$2015). Our substitute estimate of CitiPower's total forecast opex for the 2016–20 regulatory control period is \$431.5 million (\$2015). This is discussed in attachment 7 of the final decision.

In accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination.

CitiPower did not include any proposed contingent projects in its regulatory proposal for the 2016–20 regulatory control period. Therefore,

- in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors
- in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects
- in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.

In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept CitiPower's proposal of 8.61 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 6.11 per cent as set out in table 3.1 of attachment 3 of the final decision. This rate of return will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 (appendix I) of the final decision.

In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in attachment 4 of the final

decision.

In accordance with clause 6.12.1(6) the AER's decision on CitiPower's regulatory asset base as at 1 January 2016 in accordance with clause 6.5.1 and schedule 6.2 is \$1762.9 million (\$ nominal). This is set out in attachment 2 of the final decision.

In accordance with clause 6.12.1(7) the AER does not accept CitiPower's proposed corporate income tax of \$160.5 million (\$ nominal). Our decision on CitiPower's corporate income tax is \$96.9 million (\$ nominal). This is set out in attachment 8 of the final decision.

In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by CitiPower. This is set out in attachment 5 of the final decision.

In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply:

- In accordance with clause 6.12.1(9) of the NER, the AER's decision is to apply version two of the EBSS to CitiPower in the 2016–20 regulatory control period. This is set out in attachment 9 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to CitiPower in the 2016–20 regulatory control period. CESS is discussed in attachment 10 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to CitiPower for the 2016–20 regulatory control period. STPIS is discussed in attachment 11 of the final decision.
 - We will apply the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) reliability of supply parameters, and momentary average interruption frequency index (MAIFI). We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as CitiPower must comply with its existing Victorian jurisdictional guaranteed service level scheme.
 - A beta of 2.5 will be used to calculate the major event day boundary.
 - Our decision on the SAIDI and SAIFI incentive rates and performance targets to apply to CitiPower for the 2016–20 regulatory control period are set out in tables 11-1 and 11-2 of attachment 11 of this final decision.
 - Our decision on the customer service incentive rate and performance target are set out in section 11.1 of attachment 11 of this final decision.
 - The revenue at risk for CitiPower will be capped at ± 5.0 per cent. Within this there will be a cap of ± 0.5 per cent on the telephone answering parameter for performance.

Note: The meaning for year “t” under the price control formula for this determination is different to that in Appendix C of STPIS. Year “t+1” in Appendix C of STPIS is equivalent to year “t” in the price control formula of this decision.

- In accordance with Division 4 of Part 3 to the National Electricity (Victoria) Act 2005 and the NER, the AER will make a final adjustment to close out the ESCV's s-factor scheme for the 2006–10 regulatory control period by including the adjustment amount shown in attachment 11 in the 'revenue adjustments' row of the post-tax revenue model.

- The AER has determined to continue Part A of the Demand Management Innovation Scheme (DMIS) for CitiPower in the 2016–20 regulatory control period (that is, the DMIA component). DMIS is discussed in attachment 12 of the final decision.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.

In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for CitiPower for any given regulatory year is the total annual revenue calculated using the formula in attachment 4 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14 of the final decision.

In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps for all services other than metering, for which a revenue cap will apply. This is discussed in attachment 16 of the final decision.

In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is CitiPower must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 14 in the final decision.

In accordance with clause 6.12.1(14) the AER's decision is that the additional pass through events set out in attachment 15, Table 15–1 will apply to CitiPower for the 2016–20 regulatory control period.

In accordance with clause 6.12.1(15) the AER's decision is to approve CitiPower's proposed negotiating framework. The negotiating framework that is to apply to CitiPower is set out at attachment 17 of the final decision.

In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in May 2015 to CitiPower. This is set out is at attachment 17 of the final decision.

In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes for CitiPower is set out in attachment 14 of the final decision.

In accordance with clause 6.12.1(18) the AER's decision on depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of CitiPower's regulatory control period (1 January 2021). This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(19) the AER's decision on how CitiPower is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 14 of the final decision.

In accordance with clause 6.12.1(20) the AER's decision is we require CitiPower to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the final decision.

In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the Victorian F-Factor Scheme Order In Council 2011, we will apply the f-factor scheme based on an incentive rate of \$25,000 per fire start higher/lower than the f-factor target as set out in attachment 18 of the final decision.

B List of stakeholder submissions

Submission from	Date received
ActewAGL Distribution	4 February 2016
AGL	8 January 2016 *
AusGrid	3 February 2016
AusNet Services	4 February 2016
CitiPower	4 February 2016
CitiPower and Powercor	18 April 2016 *
Consumer Challenge Panel subpanel 3	25 February 2016 *
Eastern Alliance for Greenhouse Action	6 January 2016
Ethnic Communities' Council of NSW	20 January 2016
Jemena	4 February 2016
Origin Energy	6 January 2016; 4 February 2016
Powercor	4 February 2016
RESPAresearch	1 December 2015
Spark Infrastructure	4 February 2016
Street Light Group of Councils	6 January 2016
United Energy	4 February 2016
Vector Ltd	21 December 2015
Victorian Energy Consumer and User Alliance (VECUA)	6 January 2016
Victorian Government	14 January 2016 *
Victorian Government	29 January 2016
Victorian Government	12 February 2016 *

* These submissions were received after the consultation period ended.