

# Final decision

CitiPower electricity distribution determination  
1 July 2026 – 30 June 2031

**Attachment 2 – Capital expenditure**

**April 2026**

© Commonwealth of Australia 2026

This work is copyright. In addition to any use permitted under the *Copyright Act 1968* all material contained within this work is provided under a Creative Commons Attributions 4.0 Australia licence with the exception of:

- the Commonwealth Coat of Arms
- the ACCC and AER logos
- any illustration diagram, photograph or graphic over which the Australian Competition and Consumer Commission does not hold copyright but which may be part of or contained within this publication.

The details of the relevant licence conditions are available on the Creative Commons website as is the full legal code for the CC BY 4.0 AU licence.

### **Important notice**

The information in this publication is for general guidance only. It does not constitute legal or other professional advice. You should seek legal advice or other professional advice in relation to your particular circumstances.

The AER has made every reasonable effort to provide current and accurate information, but it does not warrant or make any guarantees about the accuracy, currency or completeness of information in this publication.

Parties who wish to re-publish or otherwise use the information in this publication should check the information for currency and accuracy prior to publication.

Inquiries about this publication should be addressed to:

Australian Energy Regulator  
GPO Box 3131  
Canberra ACT 2601  
Email: [aerinquiry@aer.gov.au](mailto:aerinquiry@aer.gov.au)  
Tel: 1300 585 165

AER reference: AER23008247

### **Amendment record**

<b>Version</b>	<b>Date</b>	<b>Pages</b>
1	30 April 2026	37

## Contents

<b>2</b>	<b>Capital expenditure</b> .....	<b>1</b>
2.1	Final decision .....	3
2.2	CitiPower’s revised proposal .....	3
2.3	Reasons for final decision .....	4
<b>A</b>	<b>Reasons for decision on key capex categories</b> .....	<b>11</b>
A.1	Replacement expenditure .....	11
A.2	Augmentation expenditure .....	16
A.3	Connections .....	20
A.4	Innovation allowance.....	24
<b>B</b>	<b>Contingent Projects</b> .....	<b>29</b>
	<b>Shortened forms</b> .....	<b>34</b>

## 2 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS).<sup>1</sup> Generally, these assets have long lives, and a distributor will recover capex from customers over several regulatory control periods. A distributor’s capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulatory obligations, to maintain the safety, reliability, quality, and security of its network and contribute to achieving emissions reduction targets for reducing Australia’s greenhouse gas emissions (the capex objectives).<sup>2</sup>

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand, cost inputs, and other relevant inputs (the capex criteria).<sup>3</sup> We must make our decision in a manner that will, or is likely to, deliver efficient outcomes in terms of price, quality, safety, reliability and security of supply and contribute to achieving targets for reducing Australia’s greenhouse gas emissions for the benefit of consumers in the long term (as required under the National Electricity Objective).<sup>4</sup>

The AER capital expenditure assessment outline explains our and distributors’ obligations under the National Electricity Law and Rules (NEL and NER) in more detail.<sup>5</sup> It also describes the techniques we use to assess a distributor’s capex proposal against the capex criteria and objectives. Where relevant we also assess capex associated with emissions reduction proposals taking into account our *Guidance on amended National Energy Objectives*.<sup>6</sup>

### Total capex framework

We analyse and assess capex drivers, programs and projects to inform our view on a total capex forecast. However, we do not determine forecasts for individual capex drivers or determine which programs or projects a distributor should or should not undertake. This is consistent with our ex-ante incentive-based regulatory framework.

Once the ex-ante capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. Our assessment of the ex-ante capex is consistent with the National Electricity Objective, which in addition to providing for

---

<sup>1</sup> These are services that form the basic charge for use of the distribution system.

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

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

<sup>4</sup> NEL, ss 7, 16(1)(a).

<sup>5</sup> AER, *Capital expenditure assessment outline for electricity distribution determinations*, February 2020.

<sup>6</sup> AER, *Guidance on amended National Energy Objectives*, September 2023.

the lowest possible costs also recognises that services should be valued appropriately and adapt to changing circumstances to maintain efficiencies in the long-term interest of consumers. This incentive-based framework provides distributors with the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

Distributors may need to undertake programs or projects that they did not anticipate during the reset. Distributors also may not need to complete some of the programs or projects proposed if circumstances change. These are decisions for the distributor to make. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly.

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs.

## Assessment approach

We provide guidance on our assessment approach in several documents, including the following which are of relevance to this decision:

- AER's *Expenditure Forecast Assessment Guidelines*<sup>7</sup>
- AER's *Regulatory Investment Test for Distribution (RIT-D) – Application Guidelines*<sup>8</sup>
- AER's *Asset Replacement Industry Note*<sup>9</sup>
- AER's *Information and Communication Technologies (ICT) Guidance Note*<sup>10</sup>
- AER's *Guidance on amended National Energy Objectives*<sup>11</sup>
- AER's *An interim guidance on emissions reduction*.<sup>12</sup>

We also had regard to the guiding principles in the AER's *Better Resets Handbook – Towards consumer centric network proposals* which encourages networks to develop high quality, well-justified proposals that genuinely reflect consumers' preferences.<sup>13</sup>

Our final decision has been based on the information before us, which includes:

- the distributor's revised regulatory proposal and accompanying documents and models
- the distributor's responses to our information requests

---

<sup>7</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, October 2024.

<sup>8</sup> AER, *RIT-T and RIT-D application guidelines (minor amendments) 2017*, September 2017.

<sup>9</sup> AER, *Industry practice application note for asset replacement planning*, January 2019.

<sup>10</sup> AER, *AER publishes guidance on non-network ICT capital expenditure assessment approach*, November 2019.

<sup>11</sup> AER, *Guidance on amended National Energy Objectives*, September 2023.

<sup>12</sup> AER, *An interim guidance on emissions reduction*, June 2025.

<sup>13</sup> AER, *Better Resets Handbook – Towards consumer-centric network proposals*, December 2021.

- stakeholder comments in response to our draft decision and the distributor’s revised proposal.

## 2.1 Final decision

Our final decision is to not to accept CitiPower’s proposed total forecast capex of \$1,060.9 million (\$2025–26) for the 2026–31 period because we are not satisfied that it reasonably reflects the capex criteria. We are not satisfied that it reasonably reflects the prudent and efficient costs, and a realistic expectation of demand and cost inputs required, to meet the capex objectives. Our alternative forecast is \$1,005.0 million, which is 5.3% below CitiPower’s forecast.

We consider this forecast will provide for a prudent and efficient service provider in CitiPower’s circumstances to meet the capex objectives. Table 2-1 outlines our alternative estimate of forecast capex and compares this to CitiPower’s proposed forecast capex.

**Table 2-1 AER’s final decision on CitiPower’s total net capex forecast (\$2025–26, million)**

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower’s revised proposal	248.4	259.2	213.3	175.6	164.5	1,060.9
AER’s final decision	234.2	246.3	204.2	161.0	159.2	1,005.0
Difference (\$)	<b>-14.2</b>	<b>-12.8</b>	<b>-9.0</b>	<b>-14.5</b>	<b>-5.3</b>	<b>-55.9</b>
Difference (%)	<b>-5.7%</b>	<b>-5.0%</b>	<b>-4.2%</b>	<b>-8.3%</b>	<b>-3.2%</b>	<b>-5.3%</b>

Source: CitiPower’s revised proposal and AER analysis.

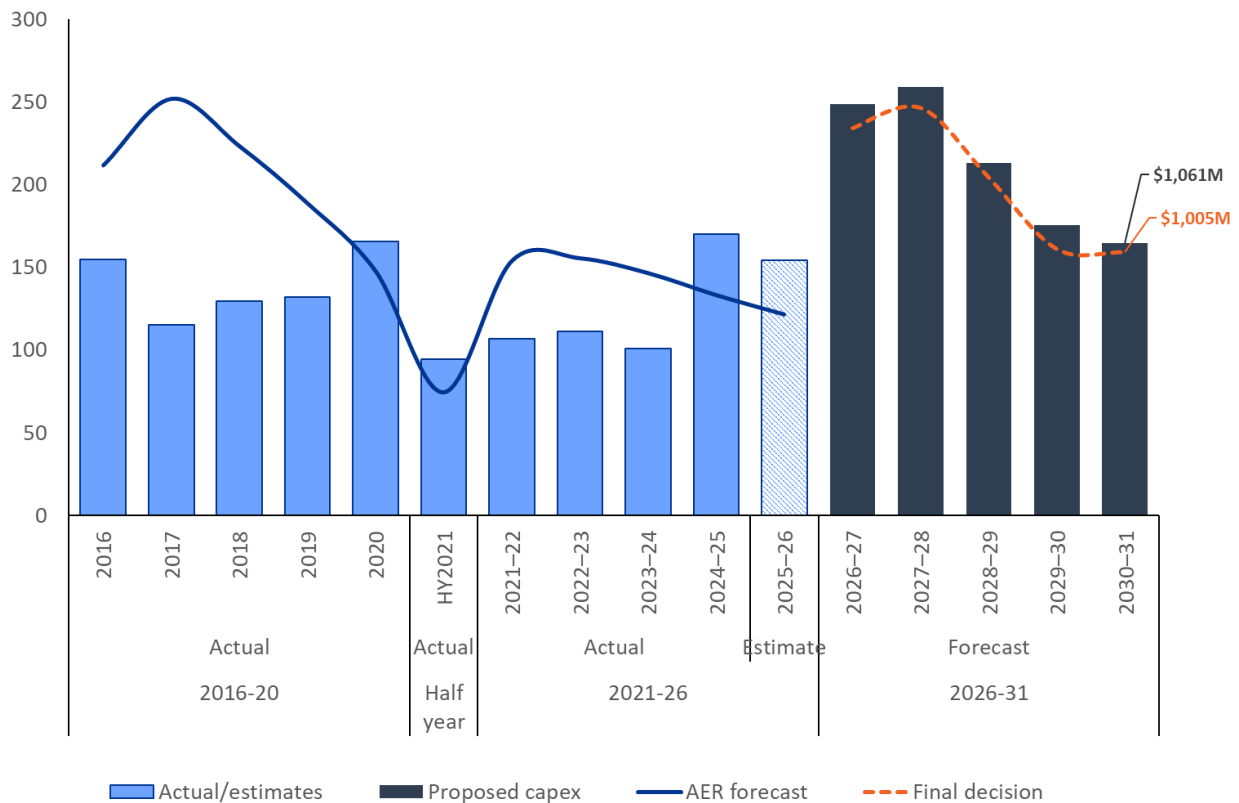
Note: Numbers may not sum due to rounding.

## 2.2 CitiPower’s revised proposal

CitiPower’s revised proposal forecasts \$1,060.9 million (\$2025–26) capex over the 2026–31 regulatory control period. This represents an increase of approximately 64.9% compared to actual and expected expenditure over the 2021–26 period.

Figure 2-1 outlines CitiPower’s historical capex trend, its revised proposed forecast for the 2026–31 regulatory control period, and our final decision. As can be seen, CitiPower is proposing a material step up in the forecast period relative to the current period. The main drivers of the step up are augmentation expenditure (augex), replacement expenditure (repex) and connections expenditure.

**Figure 2-1 CitiPower’s historical and forecast capex (\$2025-26, million)**



Source: CitiPower’s revised proposal and AER analysis.  
 Note: Capex is net of disposals and capital contributions.

### 2.3 Reasons for final decision

We are satisfied that our alternative forecast of total capex of \$1,005.0 million is reasonable and sufficient for CitiPower to maintain its network.

Our final decision to reduce CitiPower’s forecast by 5.3% is materially different from our draft decision of a reduction of 27.5%. This reflects CitiPower accepting some of the lower forecasts in our draft decision and our acceptance in this final decision of a higher forecast for some programs because of additional supporting information.

We reviewed CitiPower’s capex drivers, programs and projects to inform our view on a total capex forecast that reasonably reflects the capex criteria. We conducted top-down analysis such as examining trends and forecast costs compared with historical capex, and interrelationships between cost categories. To complement this, we conducted bottom-up analysis of CitiPower’s specific major programs and projects.

Our capex assessment focused primarily on the material capex categories that either represented a significant uplift in expenditure, had stakeholder interest or are new and evolving areas such as CER integration, and capex for data centres. Capex that was relatively small and forecast using established modelling approaches and inputs in line with our expectations, meant that we did not need to undertake a more detailed analysis of the individual programs and projects. Our final decision is reflective of this approach as set out in Table 2-2 and Table 2-3 below.

Overall, we found that the majority of CitiPower’s forecast of \$1,060.9 million would be required to meet the capex objectives. We have not accepted CitiPower’s forecast in full, reducing it by 5.3% because of the differences in our forecasts mostly in repex and augex. In most cases, we found that while we agree with CitiPower that some level of investment is prudent, CitiPower did not provide sufficient information to demonstrate that its preferred option is efficient. We also note that CitiPower’s higher forecast capex in its revised proposal and in our final decision reflects CitiPower’s reclassification of its proposed contingent project to augex.

For new and emerging areas of expenditure, our assessment of proposals takes account of the limitations and challenges in forecasting these areas of expenditure. We have accepted some expenditure like CitiPower’s CER forecast in full acknowledging the merits in strengthening CitiPower’s CER capability in the immediate term given the longer-term benefits. But we have also partly accepted funding emerging expenditure such as for explicit ex-ante innovation funding because there a material gap in supporting information to demonstrate the net benefits to consumers.

While our final decision is a reduction to CitiPower’s forecast, it is also a step up from CitiPower’s current period actual/estimates. Most of this step up is because:

- For augex, CitiPower provided sufficient evidence that it required more augex to address compliance requirements, network constraints and to improve customer-driven reliability.
- For connections, there was a temporary decrease in volumes in the current period due to COVID. The forecast reflects volumes which are consistent with expected economic activity and pre-COVID levels. The forecast also reflects the addition of emerging connections to CitiPower’s networks such as data centre and grid connected batteries.
- There was a significant increase in CitiPower’s property forecast relative to the current period, which is mainly driven by its Burnley depot upgrades. We found the proposed expenditure for these upgrades to be prudent and efficient.
- For repex, CitiPower provided sufficient evidence that a moderately higher forecast relative to the current period is reasonable based on the condition of its network.

Table 2-2 sets out our final decision for CitiPower by category.

**Table 2-2 AER’s final decision by capex category (\$2025–26, million)**

Category	CitiPower’s revised proposal	AER’s final decision	Difference (\$/%)	
Replacement	252.6	223.5	-29.0	-11.5%
Augmentation	242.0	221.1	-20.9	-8.6%
Connections	635.1	654.1	19.0	3.0%
ICT	110.8	110.8	-	-
Property	83.5	83.5	-	-
Fleet	21.0	21.0	-	-

Category	CitiPower's revised proposal	AER's final decision	Difference (\$/%)	
CER integration	11.5	11.5	-	-
Non-network - other	7.0	7.0	-	-
Capitalised overheads	144.6	143.3	-1.3	-0.9%
<b>Gross total</b>	<b>1,508.0</b>	<b>1,475.7</b>	<b>-32.2</b>	<b>-2.1%</b>
Less customer contributions	446.4	467.1	20.7	4.6%
Less disposals	0.7	0.7	-	-
Modelling adjustments		-3.0		
<b>Net total</b>	<b>1,060.9</b>	<b>1,005.0</b>	<b>-55.9</b>	<b>-5.3%</b>

Source: CitiPower's revised proposal, AER analysis.

Note: Numbers may not sum due to rounding.

Within these capex categories contains innovation and cyber security, which we assess separately:

- Innovation: Our forecast includes a \$2.4 million capex innovation allowance, spread between repx and augex. This is \$0.3 million (11.1%) lower than CitiPower's revised proposal.
- Cyber security: Our forecast includes CitiPower's proposed \$5.4 million of cyber security, which sits within the ICT expenditure. CitiPower accepted our draft decision for cyber security.

CitiPower updated its proposed connections forecast to \$655.8 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.<sup>14</sup>

Our final decision net capex of \$1,005.0 million does not include forecast capex approved separately in our determination for CitiPower's *unlocking CER benefits through flexible trading* cost pass through of \$3.2 million. This cost pass through capex is included in CitiPower's final decision Post Tax Revenue Model.<sup>15</sup>

Table 2-4 summarises our views on each of the capex categories and whether they are prudent and efficient and reflect the capex criteria, and the reasons for this. Several capex categories were considered and accepted in our draft decision and are reflected in this table but should be read in conjunction with our draft decision.<sup>16</sup> Further detail and reasons on the remaining capex categories that we further considered in response to CitiPower's revised proposal are contained in Appendix A.

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver or project/program. However, we use our findings on the different capex drivers to assess a regulated business's proposal as a whole and arrive at an alternative estimate for total capex where necessary. Our decision on total capex does not limit a regulated business's actual spending.

<sup>14</sup> CitiPower, *IR#095 Connection policy upfront tax recovery - Public*, March 2026.

<sup>15</sup> AER, *AER Determination: CitiPower – Unlocking CER benefits through flexible trading cost pass through*, April 2026.

<sup>16</sup> AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025.

**Table 2-4 Summary of findings and reasons, by capex category**

Issue	Findings and reasons
Replacement	<p>Our final decision does not include CitiPower’s repex forecast of \$251.2 million as part of our total capex forecast.<sup>17</sup> Instead, we have included a substitute estimate of \$222.3 million, which is \$28.9 million (11.5%) lower than CitiPower’s forecast.</p> <p>We found most aspects of CitiPower’s repex forecast to be reasonable including its revised underground cables program. However, we continue to have concerns with its substation transformers and switchgear programs, and do not consider they reasonably reflect the capex criteria.</p> <p>For substation transformers, we found that CitiPower did not justify the need to replace all other non-transformer components with its proposed transformer replacement projects. For its substation switchgear replacement projects, we maintain our draft decision of including capex for vacuum circuit breakers rather than full switchboard replacements.</p> <p>This is further discussed at Appendix A.1.</p>
Augmentation	<p>Our final decision does not include CitiPower’s augex forecast of \$240.6 million as part of our total capex forecast.<sup>18</sup> Instead, we have included a substitute estimate of \$219.9 million, which is \$20.8 million (8.6%) lower than CitiPower’s forecast.</p> <p>We found most aspects of CitiPower’s augex forecast to be reasonable including its revised Brunswick modernisation, zone substation capacity upgrades, asset relocations, CBD security of supply and HV feeder programs. However, we continue to have concerns with its customer driven electrification program and do not consider it reasonably reflects the capex criteria.</p> <p>Our final decision on CitiPower’s customer driven electrification program is to approve \$23.4 million, which is \$18.6 million higher than our draft decision. We consider this is a reasonable amount for CitiPower to balance the need to manage the issue of undervoltage and allows CitiPower to do some proactive investment.</p> <p>This is further discussed at Appendix A.2.</p>
Connections	<p>Our final decision does not include CitiPower’s connections forecast of \$635.1 million as part of our total capex forecast. CitiPower updated its proposed connections forecast to \$655.8 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections. We have included a substitute</p>

<sup>17</sup> CitiPower proposed \$252.6 million for repex. We consider \$1.4 million of this is innovation and have assessed it as such. We have assessed the remaining \$251.2 million as repex and referred to this amount in A.1.

<sup>18</sup> CitiPower proposed \$242.0 million for augex. We consider \$1.4 million of this is network innovation have assessed it as such. We have assessed the remaining \$240.6 million as augex and referred to this amount in A.2.

Issue	Findings and reasons
	<p>estimate of \$654.1 million, which is \$1.7 million (0.3%) lower than CitiPower's updated forecast.</p> <p>Our alternative forecast relates to the adjustments made to tax liability associated with customer contributions and data centres.</p> <p>For tax liability, our final decision is to apply tax liability offset for all new load customers above 22kV and embedded generators greater than 1.5MW as set out in Attachment 16 (connection policy). CitiPower provided updated information to reflect this position.</p> <p>We have also made an adjustment to CitiPower's data centre forecast. We do not agree with CitiPower's assumption that CitiPower, Powercor and United Energy's catchment would host 85% of forecast data centre demand. We consider this assumption is likely to overstate volume forecast of data centres.</p> <p>This is further discussed at Appendix A.3.</p>
ICT	<p>Our final decision includes CitiPower's ICT expenditure forecast of \$110.8 million, including cyber security expenditure, as part of our total capex forecast. CitiPower accepted our draft decision on this capex category.</p>
Property	<p>Our final decision includes CitiPower's property expenditure forecast of \$83.5 million as part of our total capex forecast. This was considered and accepted in our draft decision.</p>
Fleet	<p>Our final decision includes CitiPower's fleet expenditure forecast of \$21.0 million as part of our total capex forecast. This was considered and accepted in our draft decision.</p>
CER integration	<p>CitiPower, Powercor and United Energy ('CPU') adopted a common strategy for addressing CER. Due to the commonality between the 3 entities, we have assessed their revised CER proposal collectively.</p> <p>Our final decision accepts CPU's CER integration forecast of \$114.2 million (\$54.6 million capex, \$59.6 million opex) as part of our total expenditure forecast.</p> <p>Our draft decision accepted CPU's forecast for the Flexible Services program, the largest of the 3 CER programs. CPU's revised proposal re-proposed the same forecasts for its 2 remaining CER programs: \$9.7 million for network data visibility (\$3.5 million capex, \$6.2 million opex); and \$15.0 million for non-network marketplace (\$6.1 million capex, \$8.9 million opex). Our final decision therefore accepts CPU's CER forecast in full. We identified some information gaps, but on balance we see merit in strengthening the businesses' CER capability in the immediate term given the longer-term benefits. We also appreciate this is a new and uncertain area where quantification of costs and benefits is not straightforward.</p>

Issue	Findings and reasons
	<p>In coming to our decision, we also had regard to the Victorian Government’s submission and note its expectations in the forecast period that:<sup>19</sup></p> <ul style="list-style-type: none"> <li>• The non-network marketplace program involves consultation with third parties, so the platform is fit-for-purpose and implemented as proposed.</li> <li>• The data visibility program is prioritised in the near term and necessary changes are delivered within 12 months; that basic network data remains accessible without direct changes to requesting parties; and the DNSPs have regard to potential future obligations arising from the Integrated Distribution System Plan rule change.</li> </ul>
Non-network - other capex	Our final decision includes CitiPower’s non-network other expenditure forecast of \$7.0 million as part of our total capex forecast. This was considered and accepted in our draft decision.
Capitalised overheads	We have included an alternative forecast of \$143.3 million for CitiPower’s capitalised overheads in the total forecast capex. This is to account for our substitute estimate of total direct capex.
Innovation	<p>CitiPower, Powercor and United Energy (‘CPU’) have each proposed similar innovation expenditure proposals. As such, we have assessed their revised proposals collectively.</p> <p>Our final decision does not include CPU’s innovation expenditure forecast of \$25.4 million (\$15.2 million capex, \$10.2 million opex) as part of our total expenditure forecast. Instead, we have included a substitute estimate of \$17.2 million (\$12.4 million capex, \$4.9 million opex).</p> <p>We have accepted the forecast for 4 projects where CPU provided sufficient supporting information consistent with our ex-ante innovation criteria. However, we have not accepted its forecast for 3 projects as these projects were not innovative or it relied on overestimated benefit quantification values that we have not accepted in other parts of CPU’s proposal.</p> <p>This is further discussed at Appendix A.4.</p>
Customer contributions	We have included CitiPower’s customer contributions forecast in the total capex forecast. We have also included the tax offset for all high voltage and sub-transmission connections $\geq 22\text{kV}$ , and embedded generators greater than 1.5MW. This is discussed in Attachment 16 (connections policy) of our final decision on CitiPower’s regulatory proposal.

<sup>19</sup> Victorian Government, *Response to AER draft decisions for the Victorian Electricity Distribution Determination 2026-31*, 28 January 2026, pp 4–5.

Issue	Findings and reasons
Disposals	We have included CitiPower’s disposals forecast in the total capex forecast.
Modelling adjustment	<p>Our final decision includes standard modelling adjustments for updated inputs to inflation and labour real cost escalation.</p> <p>We have accepted CitiPower’s revised apportionment of internal labour and contract labour to its proposed investments. However, we do not accept CPU’s proposal to apply real cost escalation to contract labour. In forming this view, we have had regard to the Houston Kemp report on labour escalations.</p> <p>While we consider the report to be sound from an economic theory perspective, we consider that it does not properly distinguish between the cost of buying services through a contract service provider as being separate from the cost of buying labour.</p> <p>The calculation of service price growth is equal to the input price growth minus any productivity growth. When a network engages a service provider, the price growth it faces is after productivity growth. As such, we consider that providing real wage escalations for contract labour overstates the expenditure requirement.</p> <p>As CPU’s contracts specify the provision of contract services, our view is consistent with our decisions in previous resets. We have therefore applied real escalation to internal labour only</p>
Ex post review	<p>We are required to provide a statement on whether the roll forward of the regulatory asset base (RAB) from the previous period contributes to the achievement of the capex incentive objective.<sup>20</sup> The capex incentive objective is to ensure that, where the RAB is subject to adjustment in accordance with the NER, only expenditure that reasonably reflects the capex criteria is included in any increase in value of the RAB.<sup>21</sup></p> <p>We may exclude capex from being rolled into the RAB when a distributor has overspent the amount of capex above the forecast that does not reasonably reflect the capital expenditure criteria.</p> <p>We have reviewed CitiPower’s capex performance for the 2020 to 2023–24 regulatory years. CitiPower incurred total net capex below its regulatory forecast for the ex-post review period. On this basis, the overspending requirement for an efficiency review of past capex is not satisfied.</p> <p>We are satisfied that including this actual capex in the RAB is likely to contribute towards achieving the capex incentive objective.</p>

<sup>20</sup> NER, cl 6.12.2(b).

<sup>21</sup> NER, cl 6.4A(a).

# A Reasons for decision on key capex categories

This appendix sets out our assessment of key capex categories and programs/projects within CitiPower’s total revised capex forecast and the reasons for our decision. This appendix includes:

- replacement expenditure (A.1)
- augmentation expenditure (A.2)
- connections (A.3)
- innovation allowance (A.4).

We note that CitiPower, Powercor and United Energy submitted information that is very similar in content to support their forecasts for the same or similar list of projects for specific capex categories. Given these similarities, our assessment of innovation (at A.4) is based on the aggregate total expenditure forecast presented by these 3 businesses.

## A.1 Replacement expenditure

Replacement expenditure (repex) must be set at a level that allows a distributor to meet the capex criteria. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment determines that it is likely to fail soon or degrade in performance such that it does not meet its service requirement, and replacement is the most economic option<sup>22</sup>
- the asset does not meet the relevant jurisdictional safety regulations and can no longer be safely operated on the network, or
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

Most network assets will remain in efficient use for far longer than a single 5-year regulatory control period (many network assets have economic lives of 50 years or more). As a result, a distributor will only need to replace a portion of its network assets in each regulatory control period.

### A.1.1 AER’s final decision

We are not satisfied that CitiPower’s proposed \$251.2 million (\$2025–26) for repex would form part of a total capex forecast that reasonably reflects the capex criteria.<sup>23</sup> Our final decision includes an alternative forecast of \$222.3 million which is \$28.9 million (11.5%)

<sup>22</sup> A condition assessment may relate to assessment of a single asset or a population of similar assets. High-value/low-volume assets are more likely to be monitored on an individual basis, while low value/high volume assets are more likely to be considered from an asset category wide perspective.

<sup>23</sup> CitiPower proposed \$252.6 million for repex. We consider \$1.4 million of proposed repex is innovation and have assessed it as such. We have assessed the remaining \$251.2 million as repex and referred to this amount for the remainder of this section.

lower than CitiPower’s revised proposal. Our final decision is 10.7% higher than CitiPower’s actual/estimated repex for the 2021–26 current period.

### A.1.2 CitiPower’s revised proposal

Table A1.1 provides a breakdown of CitiPower’s revised repex. This forecast is 37.1% lower than CitiPower’s initial proposal. CitiPower accepted our draft decision for some repex programs and revised its forecast in 3 areas: underground cables, substation transformers and substation switchgear.

**Table A1.1 CitiPower’s revised repex proposal and AER’s final decision (\$2025–26, million)**

Program	CitiPower’s revised proposal	AER’s final decision	Difference (\$/%)	
Poles	28.0	28.0	-	-
Pole top structure	29.6	29.6	-	-
Underground cables	49.9	49.9	-	-
Service lines	3.0	3.0	-	-
Distribution transformers	17.6	17.6	-	-
Distribution switchgear	20.9	20.9	-	-
Substation transformers	20.8	13.6	-7.2	-34.5%
Substation switchgear	61.4	39.7	-21.7	-35.6%
SCADA	12.5	12.5	-	-
Other	7.5	7.5	-	-
<b>Total repex</b>	<b>251.2</b>	<b>222.3</b>	<b>-28.9</b>	<b>-11.5%</b>

Source: CitiPower’s revised proposal, AER analysis.

Note: Numbers may not sum due to rounding.

### A.1.3 Reasons for decision

We reviewed the information CitiPower provided in support of its revised repex forecast, including the business cases and cost-benefit models. Where required, we sought further information from CitiPower through an information request.

Our final decision is \$37.9 million higher than our draft decision. The higher repex forecast in the final decision is reflective of our finding in some cases of CitiPower’s supporting information justifying more capex (in its underground cables program). But, in other cases, we found the new and additional information supported maintaining our draft decision position (for substation transformers and substation switchgear). Where we have derived alternative forecasts, these have been based on our draft decision and additional information provided by CitiPower.

We discuss our specific findings on CitiPower’s revised repex forecast below.

## Substation transformers

We do not accept that CitiPower’s forecast of \$20.8 million for its substation transformer program would form part of a total capex forecast that reasonably reflects the capex criteria. We have included \$13.6 million for this program in our alternative capex forecast, which is 34.5% lower than CitiPower’s proposal and 43.8% higher than our draft decision.

As Table A1.2 shows, CitiPower did not accept our draft decision for 2 transformer replacement programs and its environmental transformer refurbishment program. Table A1.2 also sets out our final decision.

**Table A1.2 CitiPower’s revised substation transformer proposal and AER’s final decision (\$2025–26, million)**

Program	CitiPower’s revised proposal	AER’s final decision	Difference (\$/%)	
Armadale (AR) replacement	7.4	4.4	-3.0	-40.3%
Northcote (NC) replacement	8.6	4.4	-4.2	-48.8%
Environmental refurbishment	3.6	3.6	-	-
Minor station works	1.2	1.2	-	-
<b>Total</b>	<b>20.8</b>	<b>13.6</b>	<b>-7.2</b>	<b>-34.5%</b>

Source: CitiPower’s revised proposal, AER analysis.

Note: Numbers may not sum due to rounding.

Our draft decision did not accept CitiPower’s AR and NC replacement programs due to concerns with its modelling and high unit rates. Our substitute forecast for AR and NC was based on benchmarked unit rates for the replacement of 2 transformers.

In response to our draft decision, CitiPower provided additional information to support its AR and NC replacements programs, and its environmental program. This includes replacement cost breakdowns and more detail on its environmental risk cost methodology.<sup>24</sup>

For its environmental refurbishment program, CitiPower clarified its environmental risk cost methodology and updated its modelling to account for concerns raised in our draft decision. We found the inputs CitiPower used to quantify its environmental risks costs are reasonable and consider its preferred option is prudent and efficient.

For its AR and NC programs, we do not accept CitiPower’s revised forecast. We found that the reason for CitiPower’s high unit rates for these programs is because it is not only replacing the transformer, but all the components that supports and are attached to the transformer. CitiPower submitted the reason for this strategy is to mitigate compliance and reliability risk associated with the non-transformer components such as foundations,

<sup>24</sup> CitiPower, *REPLACEMENT: ZONE SUBSTATION TRANSFORMERS ADDENDUM*, December 2025, pp 5–8.

structures and switches.<sup>25</sup> It noted that these components are often the same age as the transformer and not replacing them at the same time has caused issues in the past.<sup>26</sup>

We consider CitiPower has not justified the need to replace all other non-transformer components with its proposed transformer replacement projects. Typically, when a transformer is in poor condition, a network service provider will replace it in situ without replacing all other components. This is because the key consequences (i.e. oil fire, long repair times, etc) are associated with the failure modes of the transformer rather than the components attached to it.

Further, while CitiPower noted compliance concerns, it has not provided any standards that it is required to comply with relating to its proposed scope of works. CitiPower also did not provide condition data on the non-transformer components it is proposing to replace. We consider that CitiPower proposed costs are overstated as it reflects the worst-case replacement requirements without sufficient information to support such requirements.

Our final decision on CitiPower's AR and NC replacement programs is to maintain our draft decision. Our alternative forecast for the final decision is higher than the draft decision because we applied a higher unit rate. CitiPower submitted that our draft decision did not consider the size and location of its proposed transformer replacements.<sup>27</sup> We accept that a higher unit rate of \$4.4 million is reasonable given its proposed scope of works. We also consider this higher unit rate sufficient for CitiPower to opportunistically replace and improve key non-transformer components in accordance with good industry practice (i.e. oil containment).

### **Substation switchgear**

We do not accept that CitiPower's forecast of \$61.4 million for its substation switchgear program would form part of a total capex forecast that reasonably reflects the capex criteria. We have included \$39.7 million for this program in our alternative capex forecast, which is 35.4% lower than CitiPower's proposal and 104.5% higher than our draft decision.

Except for one switchboard replacement project, CitiPower did not accept our draft decision.<sup>28</sup> Table A1.3 shows CitiPower's revised proposal and sets out our final decision.

---

<sup>25</sup> CitiPower, *Response to information request 072*, January 2026, p 6.

<sup>26</sup> CitiPower, *Response to information request 072*, January 2026, p 6.

<sup>27</sup> CitiPower, *REPLACEMENT: ZONE SUBSTATION TRANSFORMERS* ADDENDUM, December 2025, p 8.

<sup>28</sup> CitiPower accepted our draft decision for its Victoria Market substation switchboard replacement and did not propose any capex for this project.

**Table A1.3 CitiPower’s revised substation switchgear proposal and AER final decision (\$2025–26, million)**

Program	CitiPower’s revised proposal	AER’s final decision	Difference (\$/%)	
<i>In-flight projects</i>				
Collingwood (CW) switchboard replacement	2.2	2.2	-	-
Little Queen (LQ) switchboard replacement	13.0	13.0	-	-
Collingwood (B) switchboard replacement	18.0	18.0	-	-
<i>Forecast switchboard projects</i>				
Richmond (R) switchboard retirement	2.7	2.7	-	-
Armadale (AR) switchboard replacement	8.8	1.1	-7.6	-86.7%
Riversdale (RD) switchboard replacement	8.2	1.2	-7.0	-85.0%
Northcote (NC) switchboard replacement	8.3	1.2	-7.1	-85.0%
<b>Total</b>	<b>61.4</b>	<b>39.7</b>	<b>-21.7</b>	<b>-35.4%</b>

Source: CitiPower’s revised proposal, AER analysis.

Note: Numbers may not sum due to rounding.

Our draft decision did not accept CitiPower’s in flight LQ and B switchboard projects due to insufficient information to justify its high costs. We also did not accept CitiPower’s forecast switchboard projects due to modelling concerns and a lack of quantification for a lower cost option. For its forecast replacement projects, our draft decision included \$0.5 million per site to retrofit existing oil filled circuit breakers with low-cost vacuum circuit breakers.

CitiPower re-proposed its in-flight and R switchboard retirement projects. We reviewed its supporting information and found its revised forecast for these projects is reasonable.

CitiPower also re-proposed its original forecast full switchboard replacement options and provided additional supporting information. For these projects, we undertook analysis of CitiPower’s risk modelling and recent planning decisions for similar projects. We found:

- CitiPower’s preferred option overestimates the benefits. We consider CitiPower’s forecast for unserved energy caused by substation equipment failure is disproportionately high relative to its historical total unserved energy. This is likely due to counting low probability but high consequence events like oil fires and concurrent asset failures, which have not been captured in its recent historical data due to their rare occurrence. This overstates its base reliability benefits in its options analysis. We consider that the calibration of forecast reliability against historical events would reduce its reliability benefits and likely lead to a deferral of its proposed replacement projects into the following regulatory period. However, recognising that vacuum circuit breakers are low-cost, we consider the vacuum circuit breaker option is good industry practice

that eliminates these low probability and high consequence events (e.g. oil fires) while deferring a full switchboard replacement into the following regulatory period.

- CitiPower’s recent planning decision is inconsistent with statements in its revised proposal that vacuum circuit breakers are not a credible option.<sup>29</sup> It submitted that the vacuum circuit breaker option would accelerate deterioration of the switchboard panel and does not consider the risks associated with remaining components of the switchboard.<sup>30</sup> We reviewed CitiPower’s recent network planning reports. Its December 2023 planning report includes vacuum circuit breakers as a credible option to replace oil-filled circuit breakers at its Albert Park zone substation.<sup>31</sup> We consider this contradicts its revised proposal that vacuum circuit breakers are not a credible option given its proposal for this program would have been developed at a similar time in 2024.

Given our findings for forecast switchgear replacement programs, we therefore maintain our draft decision position that retrofitting existing oil filled circuit breakers with low-cost vacuum circuit breakers is a prudent and efficient option, deferring full switchboard replacement investments. This also alleviates our deliverability concern of whether CitiPower can complete 7 substation switchboard replacements next period given current period performance. We have included a higher forecast as we acknowledge CitiPower’s submission that our draft decision underestimated the cost of retrofitting vacuum circuit breakers.<sup>32</sup>

## A.2 Augmentation expenditure

Augmentation is capital expenditure required to build or upgrade the network to address system constraints driven by changes in demand and network utilisation to enable the network service provider to comply with quality, safety, reliability, security of supply and greenhouse gas emission reduction target requirements. CitiPower’s augmentation consists of expenditure mainly on demand driven augmentation capital expenditure, connection enablement, reliability, compliance and safety. It also includes expenditure related to the innovation allowance.

### A.2.1 AER’s final decision

We are not satisfied that CitiPower’s proposed \$240.6 million (\$2025–26) for augex would form part of a total capex forecast that reasonably reflects the capex criteria.<sup>33</sup> Our final decision includes an alternative forecast of \$219.9 million which is \$20.8 million or 8.6% lower than CitiPower’s revised proposal.

### A.2.2 CitiPower’s revised proposal

CitiPower proposed augex of \$240.6 million. Table A2.1 provides a breakdown of CitiPower’s revised augex. This forecast is 13.2% higher than CitiPower’s initial proposal. CitiPower

---

<sup>29</sup> CitiPower, *REPLACEMENT: ZONE SUBSTATION SWITCHGEAR ADDENDUM*, December 2025, pp 9–10 8.

<sup>30</sup> CitiPower, *REPLACEMENT: ZONE SUBSTATION SWITCHGEAR ADDENDUM*, December 2025, pp 8–10.

<sup>31</sup> CitiPower, *DISTRIBUTION ANNUAL PLANNING REPORT*, December 2023, pp 72, 75 and 77.

<sup>32</sup> CitiPower, *REPLACEMENT: ZONE SUBSTATION SWITCHGEAR ADDENDUM*, December 2025, p 10.

<sup>33</sup> CitiPower proposed \$242.0 million for augex. We consider \$1.4 million of proposed augex is network innovation have assessed it as such. We have assessed the remaining \$240.6 million as augex and referred to this amount for the remainder of this section.

accepted our draft decision for some augex programs and revised its forecast for customer driven electrification, Brunswick modernisation program, zone substation capacity upgrades, asset relocations, CBD security of supply and HV feeder program.

**Table A2.1 CitiPower’s augex revised forecast by project compared with AER’s final decision (\$2026–26, million)**

Program	CitiPower’s revised proposal	AER final decision	Difference (\$/%)	
Brunswick modernisation program	51.5	51.5	-	-
Customer driven electrification	44.2	23.4	20.8	-47.0%
Zone substation capacity upgrades	20.3	20.3	-	-
Asset relocations	16.2	16.2	-	-
CBD security of supply	58.2	58.2	-	-
System security	14.1	14.1	-	-
HV feeder program	21.0	21.0	-	-
Operational technology	5.5	5.5	-	-
Fishermans Bend modernisation	5.1	5.1	-	-
Communications	4.0	4.0	-	-
Metering	0.5	0.5	-	-
<b>Total augex</b>	<b>240.6</b>	<b>219.9</b>	<b>-20.8</b>	<b>-8.6%</b>

Source: CitiPower’s revised proposal, AER analysis. Numbers may not sum due to rounding.

Note: CitiPower has proposed \$242.0 million for augex. We consider \$1.4 million of proposed augex is network innovation.

### A.2.3 Reasons for decision

We reviewed the information CitiPower provided in support of its revised augex forecast, including the business cases and cost-benefit models. Where required, we sought further information from CitiPower through an information request.

Our final decision is \$89.3 million higher than our draft decision. The higher augex forecast in the final decision is reflective of our finding in most cases of CitiPower’s supporting information justifying more capex. However, for CitiPower’s customer driven electrification program, we found the new and additional information supported a step up from our draft decision position but did not justify CitiPower’s full revised forecast.

We discuss our specific findings on CitiPower’s revised customer driven electrification forecast below. These findings were informed by EMCa’s review of Powercor’s customer driven electrification program.<sup>34</sup> CPU has used consistent methodology for all its customer

<sup>34</sup> EMCa, *EMCa assessment of selected Powercor RRP augex projects FINAL*, April 2026 pp 6–22.

driven electrification programs so EMCA’s findings on Powercor’s modelling are also relevant to CitiPower.

### Customer driven electrification

We do not accept that CitiPower’s forecast of \$44.2 million for its customer driven electrification program would form part of a total capex forecast that reasonably reflects the capex criteria. We have included \$23.4 million for this program in our alternative capex forecast, which is 47.0% lower than CitiPower’s proposal and 384.5% higher than our draft decision.

Our draft decision was an 88.2% reduction to CitiPower’s forecast. We found that the use of the Value of Customer Reliability (VCR) to value undervoltage was not appropriate and that the impacts would be much less.<sup>35</sup> We also found that the increase in voltage complaints was not reasonable. We considered that CitiPower could maintain voltage compliance obligations with existing expenditure and based our alternative expenditure on historical expenditure.

CitiPower did not accept our draft decision and re-proposed its customer driven electrification program. Table A2.2 shows CitiPower’s revised proposal and sets out our final decision.

**Table A2.2 CitiPower’s revised proposal and AER’s final decision (\$2025–26, million)**

Project	CitiPower’s revised proposal	AER final decision
Proactive investment	22.7	13.9
Reactive investment	21.5	9.6

We received several submissions from stakeholders regarding CitiPower’s customer driven electrification program.

- CCP32 commented on CPU’s engagement on these programs and was satisfied that consumers support the proposed expenditure. They also commented on the application of VCR and stated this is an important topic that would benefit from a wider discussion.<sup>36</sup>
- The Customer Advisory Panel commented on the customer driven electrification program and supports CitiPower’s business evidence-based view that customer driven electrification is outpacing the capability of existing LV networks and targeted proactive investment is the most efficient way to avoid larger costs later.<sup>37</sup>
- Nexa Advisory had concerns on the scale of augex uplifts proposed and stated that without strong least cost testing we risk locking in higher RAB growth rather than prioritising efficient utilisation of existing network capacity. They commented that the AER

<sup>35</sup> VCR seek to reflect the value different types of customers place on reliable electricity supply under different conditions.

<sup>36</sup> CCP32, *Submission – CitiPower electricity distribution proposal 2026-31*, January 2026, pp 15–16.

<sup>37</sup> Customer Advisory Panel, *Submission – CitiPower electricity distribution proposal 2026-31*, January 2026, p 6.

has a responsibility to promote long-term outcomes in line with the National Energy Objectives.<sup>38</sup>

In its revised proposal, CitiPower changed its approach for its proactive program from containing forecast decrease in compliance and increase in complaints to a proactive investment valued at 10% VCR. CitiPower is now justifying the proactive upgrades under economic grounds.<sup>39</sup>

We found that the modelling approach appears reasonable and adequate in forecasting voltage impact at LV level. We consider CitiPower's assumed value of 10% of VCR is not an unreasonable modelling assumption, though it should not be treated as a definitive value. We recognise that the value is non-zero but consider that values larger than 10% may not be indicative. Nevertheless, we accept CitiPower's use of 10% to value undervoltage in this case.

However, we do have concerns with CitiPower's economic modelling.

- We found that a few of these sub projects (totalling \$0.3 million, \$2024) included in the proactive program did not exhibit an increase in undervoltage within the next regulatory period. This indicates that the problem of undervoltage for these projects is not getting worse over the next regulatory period.
- We also found that several sub projects (totalling \$8.0 million, \$2024) had an optimal timing to be completed in 2024/2025 according to CitiPower's modelling. Given CitiPower has not addressed the issue of undervoltage in the current period by addressing the projects that are already optimal, this weakens the justification for proposing such a large program in the next regulatory period.

For its reactive program CitiPower has maintained its approach but provided further supporting information to justify its complaints forecast. We found that some expenditure is justified for CitiPower to maintain compliance but EMCa's report raised concerns with Powercor's economic modelling which also apply to CitiPower.<sup>40</sup>

We found that CitiPower has now justified its complaints forecast and has shown that complaints are trending upwards over time. However, CitiPower has increased the percentage of major complaints over time which has the effect of increasing the required expenditure. We consider that CitiPower has not justified the increase in major complaints relative to minor complaints.

Our final decision on CitiPower's customer driven electrification program is to approve \$23.4 million, which is \$18.6 million higher than our draft decision.

For CitiPower's reactive program we have used the historical complaints and reactive expenditure from 2024 and 2025 to calculate a unit cost per complaint. Using CitiPower's complaints forecast and this unit cost of \$34,374 per complaint, over the next regulatory

---

<sup>38</sup> Nexa Advisory, *Submission –Victorian electricity distribution proposals 2026-31*, January 2026, p 5.

<sup>39</sup> CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts*, December 2025, pp 29-30.

<sup>40</sup> EMCa, *EMCa assessment of selected Powercor RRP augex projects FINAL*, April 2026 pp 6–22.

period, results in a reactive forecast of \$9.6 million (\$2026 escalated). We consider that this amount will allow CitiPower to remain compliant with its obligations.

For CitiPower’s proactive program, we found that it is not reasonable for CitiPower to include sub projects for which the issue of undervoltage is not getting worse over the next regulatory period. The goal of this program is to prevent further deterioration of voltage levels and avoid further undervoltage across its network.

We also found CitiPower has not justified the size of the proposed proactive program. Given CitiPower has included \$8.0 million (\$2024) of projects for which its modelling indicates the optimal timing is in the current regulatory period, we consider CitiPower has not justified why this large program should all be completed in the next regulatory control period. The proactive program is not driven by compliance but rather because it is an efficient economic investment. Given that many of these projects are already economic according to CitiPower’s modelling, then we consider that it should have already been conducting this investment in the current period.

This results in a proactive program forecast of \$13.9 million, which we consider is a reasonable amount for CitiPower to manage the issue of undervoltage and allows some proactive investment. This is a prudent and efficient forecast based on the available data.

## A.3 Connections

The cost of electricity connections is recovered from CitiPower’s customers and is made up of the cost of connection (gross connections), minus any capital contribution a customer makes towards the cost of the connection (the result is referred to as the net connection cost). Typically, the gross connection cost is based on the forecast volumes of new connections and expected unit costs.

We assess the amount of connection costs CitiPower is proposing to recover from its customers as well as the proportion of capital contributions that is netted off the connection costs in line with CitiPower’s connections policy.<sup>41</sup>

### A.3.1 AER’s final decision

We are not satisfied that CitiPower’s proposed \$635.1 million (\$2025–26) for connections capital expenditure would form part of a total capex forecast that reasonably reflects the capex criteria. CitiPower updated its proposed connections forecast to \$655.8 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.<sup>42</sup> Our final decision includes an alternative forecast of \$654.1 million which is \$1.7 million or 0.3% lower than CitiPower’s updated revised proposal. Table A3.1 provides a breakdown of our decision for gross connections capex.

---

<sup>41</sup> The connections policy specifies the categories of persons that may be required to pay a connection charge, the services for which a charge may be made, the basis on which the charge is determined, how this is paid and the threshold below which a retail customer (not being a non-registered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation.

<sup>42</sup> CitiPower, *IR#095 Connection policy upfront tax recovery - Public*, March 2026.

**Table A3.1 CitiPower's revised proposal and AER's final decision (\$2025–26, million)**

Connection project	CitiPower's updated revised proposal	AER's final decision
Business-as-usual connections	643.5	643.5
Data Centres	81.9	70.5
Capital contribution tax liability	-69.6	-59.9
<b>Gross connections total</b>	<b>655.8</b>	<b>654.1</b>

Source: AER analysis.

Note: CitiPower initially proposed \$90.3 million as capital contribution tax liability. It updated its capital contribution tax liability to \$69.6 million following our position on the recovery of the upfront tax liability associated with the contributions for large connections.

The alternative forecast relates to our adjustments for CitiPower's data centre connection program and the tax liability for capital contributions.

For tax liability, our final decision is to apply tax liability offset for all new load customers above 22kV and embedded generators greater than 1.5MW. CitiPower provided updated tax liability values to meet this requirement as part of an information request.<sup>43</sup> Our capex allowance is adjusted to reflect the updated information.

In relation to data centres, we consider CitiPower's forecast likely overstates the volume of data centres forecast for the 2026–31 regulatory control period. CitiPower's proposal and reasons for our decision in relation to data centres are set out below.

### A.3.2 CitiPower's revised proposal

CitiPower's revised data centre connections forecast is \$81.9 million in gross capex, or \$12.3 million in net capex. CitiPower also proposed \$69.6 million or 85% of gross capex as capital contributions.

CitiPower proposed a data centre forecast broadly following our draft decision guidance. The guidance included 3 categories of data centre connections:

- type 1 – Committed in-flight projects which have committed work agreement signed and it is likely these data centres will be established within the early years of the forecast period
- type 2 – Projects that are between the connection enquiry to connection offer stage and these data centres will likely be established in middle of the forecast period
- type 3 – Future project which are anticipated but enquiries have not yet been received and these data centres will be established towards the end of the forecast period.

CitiPower did not include any type 1 data centres.

<sup>43</sup> CitiPower, *IR#095 Connection policy upfront tax recovery - Public*, March 2026.

For type 2 data centre connections, CitiPower, Powercor and United Energy (CPU) jointly engaged an independent consultant, Mandala Partners', to develop and apply a weighted probability assessment framework ('CPU probability assessment framework') for all data centre enquiries they had received. The CPU probability assessment framework includes factors such as grid connection and firm offers, construction phase, proponent track record with establishing data centres in Australia, site identification and feasibility, and utility assessment. The CPU probability assessment framework was applied to determine the probable data centre capacity (in MW) that would likely be built and energised within CitiPower's catchment in the 2026–31 regulatory control period.

Then, using historical cost of connecting data centres with similar scope, CitiPower determined the forecast capex for data centres.

For type 3 data centre connections, CPU jointly engaged Mandala Partners' to identify future projects to anticipate any future enquiries they may receive. Mandala Partners' applied a linear regression-based analysis to estimate data centre demand that may eventuate towards the end of the forecast period and is not yet in CitiPower's pipeline (i.e. where enquiries are anticipated in future).

Furthermore, CitiPower revised its connections policy with respect to tax liability. From 1 July 2026, all high voltage and sub transmission connections, including data centres, connected to its network will be liable for the tax payable on their capital contributions.

### **A.3.3 Reasons for decision**

We have reviewed the information CitiPower provided in support of its data centre connection revised capex forecast, including the business cases and other relevant artifacts. Where required, we have sought further information from CitiPower through information requests.

We have assessed CitiPower's data centre forecast by examining the forecast volumes of new data centre connections and expected unit costs including the capital contributions. Our assessment is described below.

#### **A.3.3.1 Volumes**

We consider CitiPower has not sufficiently supported the forecast volume of data centres that will likely be established in the 2026–31 regulatory control period.

In principle, we consider CitiPower's methodology of applying the CPU probability assessment framework to the enquires it has received is reasonable for type 2 data centres. However, we are concerned that the CPU probability assessment framework appears to result in higher demand than anticipated as per AEMO's data centre forecasts.

CPU jointly has also undertaken the top-down assessment using AEMO's data centre forecasts as a starting point and converted it to installed capacity expected within the CPU's catchment.<sup>44</sup> They calculated AEMO's step change scenario would represent 1,663MW of installed data centre capacity within CPU's catchment. They also assume that approximately 85% of the data centres usage will be in CPU's catchment in the forecast period. Then, they

---

<sup>44</sup> CitiPower, *Connections: Data Centre Connections*, 1 December 2025, pp 11-13.

escalated the installed data centre capacity to reflect the additional enquiries CPU received since the data for AEMO’s step change scenario was collected. This escalation effectively doubles AEMO’s step change scenario forecasts to 3,338MW. Based on the modified AEMO’s data, CPU considered that their total bottom-up forecast demand of 3,576MW for CPU’s joint catchment area was reasonable.<sup>45</sup>

We do not agree with the aggregated forecast of CPU’s AEMO-modified escalated data centre volumes. We consider its underlying assumption that CPU’s catchment would represent 85% of installed data centre is likely overstated. Even though CPU may have 85% of the data centre capacity in the current period, we do not consider this metric is reflective for the forecast period. In reaching this position, we had regard to the data centre forecasts and the maturity levels of these forecasts from other Victorian distribution businesses’ regulatory proposals. Based on our assessment, we consider CPU’s top-down challenge used to justify its bottom-up forecast is likely to be overstated. Subsequently, we consider that CitiPower’s data centre volume forecast, which is based on an allocation from the CPU forecast, is also likely to be overstated.

Further, CPU’s sensitivity analysis predicted data centre demand to range from 2,570MW to 3,549MW across CPU’s catchment.<sup>46</sup> We note that CPU’s forecast demand of 3,576MW is at the higher end of the sensitivity range. Based on this, and the assumption that CPU will receive 85% of forecast data centre capacity, we consider the aggregate CPU forecast is likely to be overstated.

We also consider that the population of the data centres in CitiPower’s probability assessment framework may include some future data centre projects that will be completed towards the end of the forecast period. Therefore, there might be an overlap between CitiPower’s type 2 and type 3 forecast. Holistically, this has resulted in a forecast that is likely to overstate the volume of data centres CitiPower requires.

In developing an alternative estimate, we considered whether the supporting evidence provided by CitiPower was sufficiently robust. We acknowledge that CitiPower’s type 2 data centre volumes are built on enquires it has received to date and the maturity levels of these enquiries. We consider this is relatively robust information. However, CitiPower’s type 3 projections are more speculative and less robust, so we have elected to omit type 3 data centres from our alternative forecast.

We also note that the Capital Expenditure Sharing Scheme (CESS) now allows us with the ability, at our discretion, to exclude any CESS penalty that arises from data centre capex. This provides an added level of protection for CitiPower if there is an increase in the volume of data centres above our alternative forecast.

### **A.3.3.2 Unit rate and capital contribution**

CitiPower has applied the capital contribution formula and used a mixture of historical capital contribution rates and forecasting assumptions. This formula is applied to each data centre

---

<sup>45</sup> CitiPower, *Connections: Data Centre Connections*, 1 December 2025, pp 11–13.

<sup>46</sup> CitiPower, *Connections: Data Centre Connections*, 1 December 2025, p 9.

across a range of scenarios using relevant unit rates on a case-by-case basis to arrive at the lowest cost to consumers.

Furthermore, we note that CitiPower has not expressly included overheads as part of its capital contribution formula.

As per our draft decision, we are satisfied by this approach. This approach is consistent with the current connection charge guidelines.<sup>47</sup>

### A.3.3.3 Tax liability associated with capital contribution

In relation to tax liability associated with customer contributions, we did not agree with CitiPower’s proposal to recover tax payable from all high voltage and sub transmission connections. Instead, our final decision is to apply tax liability offset for all new load customers above 22kV and embedded generators greater than 1.5MW. Reasons for our decisions on this matter are set out in Attachment 16 (connection policy).

To be consistent with our position on the recovery of the upfront tax liability associated with the contributions for large connections (including data centres), we have updated modelling to reflect our final decision threshold of new load customers above 22kV and embedded generators greater than 1.5MW. This has no impact on net capex.

## A.4 Innovation allowance

In this section, we set out our assessment of the innovation expenditure proposed by CitiPower, Powercor and United Energy (‘CPU’).

### A.4.1 AER’s final decision

We are not satisfied that CPU’s revised proposal of \$25.4 million for innovation expenditure (\$15.2 million capex, \$10.2 million opex) would form part of a total forecast that reasonably reflects the expenditure criteria. Our final decision includes an alternative forecast of \$17.2 million (\$12.4 million capex, \$4.9 million opex). Table A4.1 provides the breakdown of expenditure across the 3 businesses.

**Table A4.1 AER’s final decision by business (\$2025–26, million)**

Business	Capex	Opex	Total expenditure
CitiPower	2.4	1.1	3.5
Powercor	6.3	2.0	8.3
United Energy	3.7	1.8	5.4
<b>Total innovation expenditure</b>	<b>12.4</b>	<b>4.9</b>	<b>17.2</b>

Note: Numbers don’t add due to a rounding error

<sup>47</sup> AER, *Connection charge guidelines for electricity customers – Under chapter 5A of the National Electricity Rules*, October 2024.

## A.4.2 CPU’s revised proposal

CPU proposed \$25.4 million (\$15.2 million capex, \$10.2 million opex) for network innovation expenditure in its revised proposal. All 3 businesses have used the same business case, proposing different expenditure for the same projects.

The program included 12 projects in total, with CitiPower and United Energy proposing 9 and 11 of the projects respectively.<sup>48</sup> CPU’s revised proposal is comprised of:

- 5 projects that were accepted in our draft decision
- 3 re-proposed projects from CPU’s initial proposal that were not accepted in our draft decision, and
- 4 new projects.

Similar to its initial proposal, CPU has proposed to self-fund 10% of the total program across both the capex and the opex. As supporting material, CPU provided a program summary of each project and a cost-benefit model.

Table A4.2 sets out CPU’s revised network innovation total expenditure proposal and compares this with their initial proposal, our draft and final decision.

**Table A4.2 CPU’s innovation proposals and AER’s decisions (\$2025–26, million)**

	CPU initial proposal	AER draft decision	CPU revised proposal	AER final decision
Innovation capex	23.2	5.3	15.2	12.4
Innovation opex	18.1	4.0	10.2	4.9
<b>Total innovation expenditure</b>	<b>41.3</b>	<b>9.3</b>	<b>25.4</b>	<b>17.2</b>

Source: AER analysis.

## A.4.3 Reasons for decision

We recognise the importance of innovation investment in supporting the energy transition and protecting customers. Trials and pilots enable businesses to test and explore new ideas, concepts and technology before committing to implementation of solutions and rolling these into business-as-usual activities. We acknowledge the potential benefits of having explicit ex-ante innovation funding within the regulatory framework, together with on-going consumer oversight, performance reporting and information sharing.

We consider funding through a distribution determination where this meets our ex-ante innovation criteria.<sup>49</sup> In response to our Draft Decision, CPU’s Customer Advisory Panel submits that it appreciates that AER’s rigour in assessing projects against the ex-ante

<sup>48</sup> CitiPower’s program does not contain the Non-Lithium Storage Technologies or the Grid Forming Technology Trial projects. United Energy’s program does not contain the Non-Lithium Storage Technologies project.

<sup>49</sup> AER, *Final decision Attachment 05 – Capital expenditure – Ausgrid – 2024-29 Distribution determination revenue proposal*, 30 April 2024, pp 35–41.

innovation criteria and understands the AER’s reluctance to approved funding for unspecified projects.<sup>50</sup>

While we acknowledge the potential benefits of ex-ante innovation expenditure, we are conscious of the more cautious support among some consumer groups in previous processes. Some issues raised include whether innovation proposals could already be funded through the regulatory allowance and other regulatory mechanisms.<sup>51</sup> We therefore appreciate the need for transparency about the ex-ante innovation expenditure to ensure that the proposed trials and pilots are likely to result in net benefits to consumers.

We consider that our final decision strikes the appropriate balance of supporting innovation investment where sufficient supporting information has been provided to demonstrate likely net benefits to consumers.

We have not accepted CPU’s forecast in full as some of the proposed projects did not align with the criteria for ex-ante innovation projects.<sup>52</sup> At a high level, these criteria are:

- The projects must be innovative
- The justification for the proposed project must be linked to the expenditure objectives
- The proposed projects cannot be funded elsewhere
- The proposed projects must be prudent – deployed at a scale consistent with a trial/pilot
- There is stakeholder support for the innovation criteria.

Our alternative forecast is \$17.2 million. We have accepted the forecast for the 4 new projects as CPU provided sufficient supporting information consistent with our assessment criteria for ex-ante innovation projects. These are:

- Non-Lithium Storage Technologies
- Grid Forming Technology Trial
- VPP Integration with Hot Water Load Control
- Inverter Based Load Modelling

Of the remaining 3 projects, CPU did not provide sufficient information to demonstrate that the projects were innovative and/or relied on assumptions which overstated the benefits of the project. We discuss our findings of these projects below:

---

<sup>50</sup> Customer Advisory Panel, *Report on the AER’s Draft Decision and CitiPower’s Revised Regulatory Proposal 2026-31*, January 2026, p 8.

<sup>51</sup> AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026-31*, September 2025, pp 54-55.

<sup>52</sup> AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026-31*, September 2025, pp 54-55.

#### **A.4.3.1 Community Energy Fund**

CPU's Community Energy Fund is for \$7.7 million total expenditure (\$3.1 million capex, \$4.6 million opex). This project was originally proposed as part of the Customer Assistance Package in CPU's initial proposal (\$6.3 million opex).

Our draft decision did not include this expenditure in our alternative estimate of opex as we considered that duplicative of similar initiatives already provided or supported by other existing programs.

We note that the Customer Advisory Panel supports this project being included in the CPU's innovation forecast, noting that the project aims at identifying opportunities to leverage community energy projects when deploying non-network solutions to enable CER to improve reliability, security and power quality.<sup>53</sup>

Our final decision does not include expenditure for this project in our overall capex forecast. CPU did not provide specific information about these projects. Its modelling indicates that there will likely be 15 projects across the fund lifespan, with 200 customers per project. Of these projects, it is assumed that 50% will relate to local storage and 10% will assist worst served areas. We consider that there is insufficient detail about the project to assess whether this project is innovative and likely to result in overall benefits to consumers. We do not consider that the benefits of non-specific projects to be realisable. There is also a question as to whether CPU is the appropriate entity to allocate this funding to community actors.

#### **A.4.3.2 Regional Electrification Trials**

CPU's Regional Electrification Trials project is for \$2.0 million total expenditure (\$1.0 million capex, \$1.0 million opex). Powercor and United Energy have re-proposed this project in their respective revised proposals, expanding the duration of the trial from 2 years to 5 years and amending the scope from farming to include dairy, food processing and manufacturing.

Our draft decision did not include this expenditure as we did not consider that CPU had provided sufficient detail as to why this project is innovative. We also did not consider the use of the customer value of improving worst served areas, the primary driver of the estimated benefits, to be appropriate. Our wider capex assessment has not accepted the use of this value as it has been used in addition to our Value of Customer Reliability methodology.

Our final decision maintains our draft decision. We have not included expenditure for this project in total capex forecast. We continue to have the same concerns as set out in our draft decision about the use of customer value of improving worst-served areas. This value comprises 99.1% of the total expected benefits. Once this benefit is removed, the benefit cost ratio of the program is reduced to 0.01. We therefore consider the benefits of this project to be overstated.

#### **A.4.3.3 Behavioural Price Signals Trial**

CPU's Behavioural Price Signals Trial project is for \$3.0 million total expenditure (\$2.3 million capex, \$0.7 million opex).

---

<sup>53</sup> Customer Advisory Panel, *Report on the AER's Draft Decision and Powercor's Revised Regulatory proposal 2026-31*, January 2026, p 8.

Our draft decision did not include this expenditure as we did not consider that this project fulfilled the criteria of being innovative. Rather, we considered this an activity that would better be described as business-as-usual expenditure. We note that all Victorian DNSP's proposed some form of dynamic tariff trial in their respective initial proposals and that none were accepted in our draft decisions.

Our final decision maintains our draft decision. We have not included expenditure for this project in our total capex forecast. We consider that the benefits of this project are overstated. CPU have assumed a customer inconvenience factor representing the value of deferred energy usage such as needing to delay charging an electric vehicle. This value is derived using a proportion of the value of customer reliability. The value of customer reliability is a willingness to pay to avoid an outage. It follows then that this value captures all of the inconvenience caused by an outage. As a result, adding another value in addition to this willingness to pay is likely to represent a double count of benefits. This value represents 84.9% of the total expected benefits. Therefore, once more reasonable adjustments are made, we found that this project did not result in overall net benefits.

#### **A.4.3.4 Quick Connections Points**

We also note that we have re-categorised Powercor's Community Quick Connection Points project from resilience to innovation. We consider that the project is better treated as innovation given its characteristics. We have also made a reduction to the project of \$3.0 million from Powercor's proposed \$5.0 million. The reasons for the reduction are discussed in Attachment 2 of our final decision on Powercor's 2026–31 Distribution Determination.<sup>54</sup>

---

<sup>54</sup> AER, *Attachment 2 – Capital Expenditure – Final decision – Powercor electricity distribution determination 2026–31*, April 2026, p 29.

## B Contingent Projects

Contingent projects are usually significant network augmentation projects that are reasonably required to be undertaken to achieve the capex objectives. However, unlike other proposed capex projects, the need for the project within the regulatory control period and the associated costs are not sufficiently certain. Consequently, expenditure for such projects does not form a part of the total forecast capex that we approve in this determination. Such projects are linked to unique investment drivers and are triggered by defined ‘trigger events’. The occurrence of the trigger event must be probable during the relevant regulatory control period.<sup>55</sup> The cost of the projects may ultimately be recovered from customers in the future if certain predefined conditions (trigger events) are met.

This appendix details our assessment of CitiPower’s Laurens Street Zone (LS Zone) Substation and Richmond Zone (R Zone) Substation contingent project proposals as part of its revised proposal for the 2026–31 regulatory control period.

### B.1.1 AER’s final decision

Our final decision is to accept CitiPower’s proposed LS Zone Substation (\$54 million, \$2025–26, unescalated) and R Zone Substation (\$65 million, \$2025–26, unescalated) contingent projects for the 2026–31 regulatory control period. We have concluded that both contingent projects may be reasonably required to be undertaken to achieve the capex objectives over the 2026–31 period.<sup>56</sup>

### B.1.2 CitiPower’s proposal

In its revised proposal, CitiPower proposes \$119 million (\$2025–26, unescalated) for 2 contingent projects for the 2026–31 regulatory control period. CitiPower submits the proposed projects are probable to occur by 2031.<sup>57</sup>

The 2 proposed contingent projects are:

- LS Zone Substation (\$54.0 million)
- R Zone Substation (\$65.0 million).

CitiPower submits that the proposed contingent projects would be reasonably required to meet the NER capital expenditure objectives to meet or manage expected demand and to maintain the quality, reliability and security of supply.

For the LS Zone Substation CitiPower submits that the inner North is currently experiencing a period of rapid growth, with the BQ and VM Zone Substations forecast to exceed their summer and winter N-1 ratings in the 2026–31 regulatory periods. It submits that this growth will likely be accelerated with the construction of the Arden Precinct. CitiPower proposes an augex project to address this and proposes the LS Zone Substation as a contingent project if the load growth from the Arden Precinct necessitates additional investment.

---

<sup>55</sup> NER, cl 6.6A.1(c)(5).

<sup>56</sup> NER, cl 6.6A.1(b)(1).

<sup>57</sup> CitiPower, *Revised Proposal 2026-31 – Revenue and expenditure forecasts*, December 2025, pp 69–71.

CitiPower submits that maximum demand at the R Zone Substation currently exceeds its summer and winter N-1 ratings and will remain above these rating in the 2026–31 regulatory period. Its preferred option for managing this issue in the 2026–31 period is to transfer load from the R Zone Substation to adjacent substations. It has included the R Zone Substation as a contingent project because if the demand exceeds its current forecast it will need to introduce an additional measure to meet the demand.

We note that in CitiPower’s initial proposal it submitted the J Zone Substation as a contingent project. In its revised proposal, CitiPower stated that it has now included the J Zone Substation in its expenditure forecast for the CBD security of supply augex program. This was based on AER advice and updated demand forecasts which suggest the contingent project portion of this program will be required during the next regulatory control period. Specifically, its revised proposal includes the first 2 years of construction, with the complexity of rebuilding a CBD zone substation forecast to take 4 years for completion. We have accepted this expenditure as part of the CBD security of supply augex program. Please see Appendix A.2 for further discussion of this project.

### **B.1.3 Assessment approach**

A contingent project should reflect a project that CitiPower can reasonably expect would occur in the 2026–31 period, with uncertainty related to the scope, timing and costs of the contingent project.

We reviewed CitiPower’s proposed contingent projects against the assessment criteria in the NER. We considered whether:

- the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capex objectives<sup>58</sup>
- the proposed contingent project capex is not otherwise provided for in the capex proposal<sup>59</sup>
- the proposed contingent project capex reasonably reflects the capex criteria, taking into account the capex factors<sup>60</sup>
- the proposed contingent project capex exceeds the defined threshold<sup>61</sup>
- the trigger events in relation to the proposed contingent project are appropriate.<sup>62</sup>

CitiPower’s revenue proposal included a description of each contingent project, proposed trigger events, project requirement, proposed capex and demonstration of rules compliance.

We reviewed each project based on CitiPower’s and our own analysis. We reviewed whether each contingent project is reasonably likely to be required in the 2026–31 regulatory control period based on the materiality and plausibility of the trigger conditions. This gives us a high-

---

<sup>58</sup> NER, cl 6.6A.1(b)(1). Relevantly, a distribution network service provider must include forecast capex in its revenue proposal which it considers is required to meet or manage expected demand for standard control services over the regulatory control period (see NER, cl 6.5.7(a)(1)).

<sup>59</sup> NER, cl 6.6A.1(b)(2)(i).

<sup>60</sup> NER, cl 6.6A.1(b)(2)(ii).

<sup>61</sup> NER, cl 6.6A.1(b)(2)(iii).

<sup>62</sup> NER, cl 6.6A.1(b)(4).

level view of whether the project is reasonably required to achieve any of the capex objectives and reflect the capex criteria.

We also considered whether the proposed trigger events for each project are appropriate. This includes having regard to the need for the trigger event:

- to be reasonably specific and capable of objective verification<sup>63</sup>
- to be a condition or event which, if it occurs, makes the project reasonably necessary in order to achieve any of the capex objectives<sup>64</sup>
- to be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole<sup>65</sup>
- to be described in such terms that it is all that is required for the revenue determination to be amended<sup>66</sup>
- to be a condition or event, the occurrence of which is probable during the 2024–29 period but the inclusion of capex in relation to it (in the total forecast capex) is not appropriate because either:
  - it is not sufficiently certain that the event or condition will occur during the regulatory control period or if it may occur after that period or not at all, or
  - assuming it meets the materiality threshold, the costs associated with the event or condition are not sufficiently certain.<sup>67</sup>

## B.1.4 Reasons for decision

### LS Zone Substation

Our draft decision did not include the LS Zone Substation in our alternative forecast. We found that the additional load advised by CitiPower from the new Arden precinct meant the occurrence of the trigger event in the 2026–31 period was extremely likely. We considered that the project did not meet the requirements of NER cl 6.6A.1(c), in that the timing of the trigger events were reasonably known such that it is sufficiently certain that they will occur in the regulatory control period. We also had concerns that the trigger event did not include determination by the AER in its RIT-D trigger. We recommended that CitiPower either provide additional evidence or include this expenditure in its capex in the revised proposal.

In its revised proposal, CitiPower has re-proposed its LS Zone Substation as a contingent project. Based on information provided by CitiPower we are now satisfied that the timing is not sufficiently certain.

We also had concerns around the trigger events not including determination by the AER in its RIT-D trigger. In response to an information request, CitiPower has now provided updated triggers.<sup>68</sup>

---

<sup>63</sup> NER, cl 6.6A.1(c)(1).

<sup>64</sup> NER, cl 6.6A.1(c)(2).

<sup>65</sup> NER, cl 6.6A.1(c)(3).

<sup>66</sup> NER, cl 6.6A.1(c)(4).

<sup>67</sup> NER, cl 6.6A.1(c)(5).

<sup>68</sup> CitiPower, *IR#069 Contingent Projects - Public*, January 2026.

- *CitiPower receives a connection application or applications for 25 MW of load in the Ardern precinct that will increase annualised expected unserved energy above the annualised cost of the contingent project within 3 years of a contingent project application; and*
- *The Australian Energy Regulator is satisfied CitiPower has completed a Regulatory Investment Test for Distribution (RIT-D) to determine the preferred credible option to connect and supply the load or loads, pursuant to the NER; and*
- *CitiPower commits to proceed with the preferred credible option from the RIT-D, subject to the AER amending CitiPower’s 2026–31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Chief Executive Officer of CitiPower will be sent to the AER to confirm such commitment.*

*For the purposes of this trigger: 'Regulatory investment test for distribution' has the meaning given to that term in the NER.*

Given that CitiPower has addressed our concerns we now consider the revised trigger wording meets the requirements of clauses 6.6A.1(c) and hence can be accepted.

We consider the LS Zone Substation contingent project may be reasonably required to be undertaken to achieve the capital expenditure objectives and have accepted it in our final decision.

## **R Zone Substation**

Our draft decision did not include the R Zone Substation in our alternative forecast. We found that part of the expenditure for the project (the switchboard replacement) was also included as part of the repex forecast. Given that part of the expenditure was accounted for in the forecast capex this does not satisfy the NER requirements to be a contingent project. We also had concerns that the trigger event did not include determination by the AER in its RIT-D trigger.

In its revised proposal, CitiPower has re-proposed its R Zone Substation as a contingent project. CitiPower has provided additional evidence in its revised proposal and via information requests to support why the switchboard replacement is necessary to be included are part of repex and is not also included in the contingent project. CitiPower has confirmed that the switchboard is being retired due to safety concerns and given the contingent project may not actually occur it will still need to do the switchboard retirement. CitiPower submitted that there are existing risks at the substation that are economic to intervene on independently from the substation rebuild. Based on the new information it is clear that there is no double counting of expenditure and the switchboard retirement is separate from the contingent project.

We also had concerns around the trigger events not including determination by the AER in its RIT-D trigger. In response to an information request, CitiPower has now provided updated triggers.<sup>69</sup>

---

<sup>69</sup> CitiPower, *IR#069 Contingent Projects - Public*, January 2026.

- *Richmond supply area that increases annualised expected unserved energy above the annualised cost of the contingent project within 3 years of a contingent project application; and*
- *The Australian Energy Regulator is satisfied CitiPower has completed a Regulatory Investment Test for Distribution (RIT-D) to determine the preferred credible option to connect and supply the load or loads, pursuant to the NER; and*
- *CitiPower commits to proceed with the preferred credible option from the RIT-D, subject to the AER amending CitiPower’s 2026–31 regulatory determination pursuant to the NER. To provide objective verification of this trigger, a letter from the Chief Executive Officer of CitiPower will be sent to the AER to confirm such commitment.*

*For the purposes of this trigger: 'Regulatory investment test for distribution' has the meaning given to that term in the NER.*

Given that CitiPower has addressed our concerns we now consider the revised trigger wording meets the requirements of clauses 6.6A.1(c) and hence can be accepted.

We consider the R Zone Substation contingent project may be reasonably required to be undertaken to achieve the capital expenditure objectives and have accepted it in our final decision.

## Shortened forms

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CER	customer energy resources
CESS	capital expenditure sharing scheme
CPU	CitiPower, Powercor and United Energy (collectively)
DNSP or distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
ESV	Energy Safe Victoria
EV	electric vehicle
ICT	information and communication technology
kV	kilovolts
LV	low voltage
NEL	National Electricity Laws
NER	National Electricity Rules
opex	operating expenditure
RAB	regulated asset base
repex	replacement expenditure
SCS	standard control service
VCR	value of customer reliability