Draft decision

CitiPower electricity distribution determination

1 July 2026 – 30 June 2031

Attachment 3 – Operating expenditure

September 2025

AUSTRALIAN ENERGY REGULATOR

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3 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of CitiPower's proposed opex forecast for the 2026–31 regulatory control period (2026–31 period).

3.1 Draft decision

Our draft decision is to not accept CitiPower's total opex forecast of $586.1 million,[1] including debt raising costs, for the 2026–31 period. This is because our alternative estimate of $524.4 million is materially different ($61.7 million, or 10.5% lower) than CitiPower's total opex forecast proposal.[2] Therefore, we consider that CitiPower's total opex forecast does not reasonably reflect the opex criteria.[3]

This material difference is primarily driven by including lower alternative estimates for most of CitiPower's proposed step changes, to reflect our assessment of efficient costs required for the 2026–31 period.

Our draft decision, which is less than CitiPower's proposed total opex forecast, is:

- $61.9 million (10.6%) lower than the opex forecast we approved for the 2021–26 regulatory control period (2021–26 period)
- $55.3 million (11.8%) higher than CitiPower's actual (and estimated) opex in the 2021–26 period.

In Figure 3.1 we compare our alternative estimate of opex to CitiPower's proposal for the next regulatory control period. We also show the forecasts we approved for the last 2 regulatory control periods and CitiPower's actual and estimated opex over these periods.

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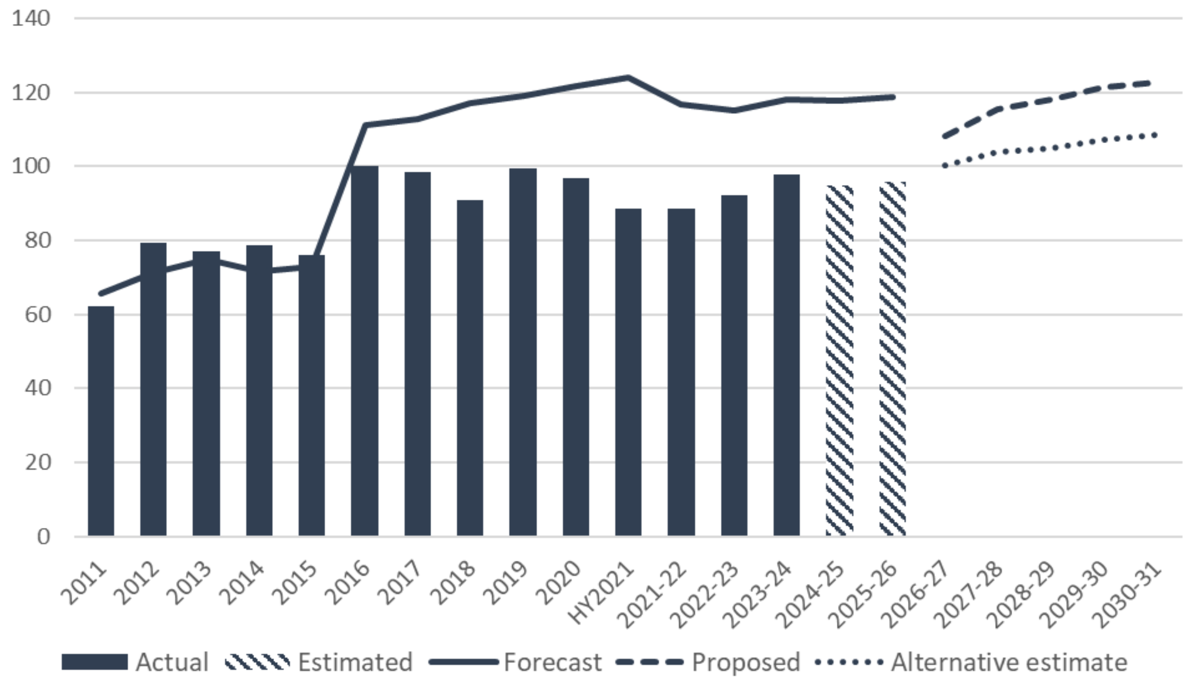
1 All dollars are in this document are in $2025–26 terms unless otherwise stated.

2 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 74.

3 NER, cl. 6.5.6(c)–(e).

Figure 3.1 Historical and forecast opex ($million, 2025–26)



Source: CitiPower, *Economic benchmarking – Regulatory Information Notice response 2010–24*; AER, *Final decision PTRM 2010–2015*; AER, *Final decision PTRM 2015–20*; AER, *Final decision 2021–26 PTRM*; CitiPower, *CP MOD 1.05 – opex*, January 2025; AER analysis.

In Table 3.1 we set out CitiPower's opex proposal, our alternative estimate for the draft decision and the differences between these forecasts.

Table 3.1 Comparison of CitiPower's opex proposal and our alternative opex estimate ($million, 2025–26)

Category	CitiPower proposal	AER draft decision	Difference ($)
Based on estimated opex in 2024–25	**474.1**	**473.9**	**–0.2**
2024–25 to 2025–26 increment	**5.5**	**5.5**	**0.0**
Remove category specific forecasts	**1.2**	**–0.2**	**–1.4**
Base year adjustment: licence fees	**–1.8**	**–1.8**	**0.0**
Trend: Output growth	19.3	**6.6**	**–12.6**
Trend: Price growth	10.1	8.7	–1.4
Trend: Productivity growth	–7.2	–7.2	0.1
Total trend	**22.1**	**8.2**	**–13.9**
Step change: customer assistance package	6.8	–	**–6.8**
Step change: vegetation management	33.6	8.7	–24.9
Step change: CER integration	12.3	9.4	–2.9
Step change: cloud services	11.2	1.2	–10.0
Step change: ICT modernisation	11.6	8.6	–3.0
Step change: fleet electrification	–0.2	–0.2	–
Total step changes	**75.3**	**27.8**	**–47.6**
GSL	0.3	**0.2**	**–0.0**
Innovation Fund	2.9	0.5	–2.4
Debt raising costs	6.5	6.2	–0.3
Customer assistance package	–	4.0	4.0
Total category specific forecasts	**9.6**	**10.9**	**1.3**
Total	**586.1**	**524.4**	**–61.7 (–10.5%)**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to total due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

The key differences between CitiPower's opex proposal, which we have not accepted, and our alternative estimate are that we have:

- included a lower alternative estimate for the vegetation management step change ($24.9 million lower)
- included a lower alternative estimate for the CER integration step change ($2.9 million lower)
- included lower alternative estimates for the cloud services ($10.0 million lower) and ICT modernisation ($3.0 million lower) step changes. We discuss these further in section 3.3.4.

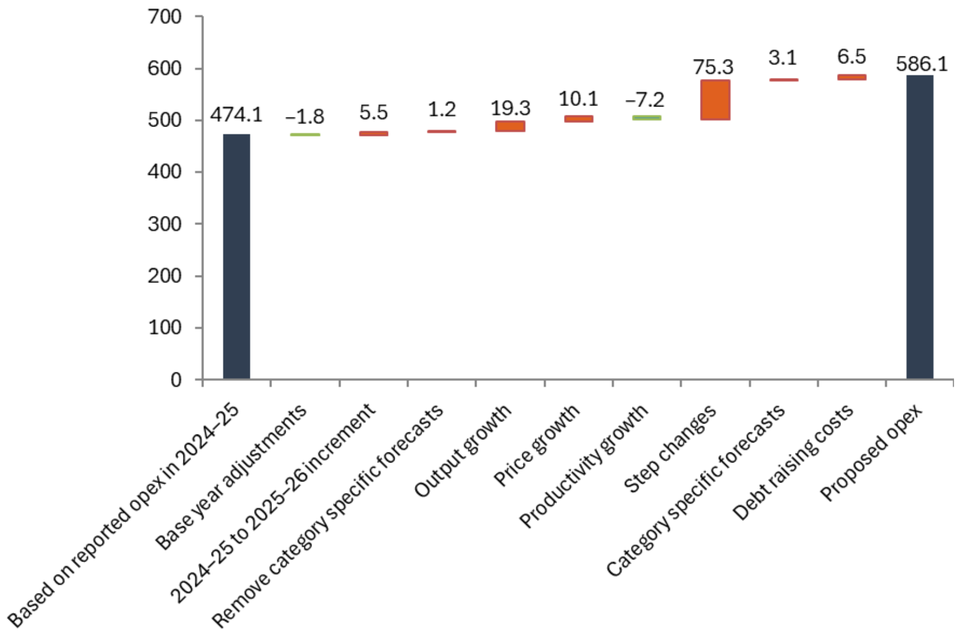
- reclassified the customer assistance package step change as a category specific forecast and included a lower amount ($2.8 million lower). We discuss this further in sections 3.3.4 and 3.3.5.
- used our output growth forecast, reducing forecast opex by $12.6 million. We discuss this further in section 3.3.3.2.

3.2 CitiPower's proposal

CitiPower's proposal applied a base–step–trend approach to forecast opex for the 2026–31 regulatory control period, consistent with our standard approach.[4]

CitiPower's forecast applying our base–step–trend approach is set out in Table 3.1. In Figure 3.2 below we show the different components that make up CitiPower's opex forecast for the 2026–31 period.

Figure 3.2 CitiPower's opex forecast ($million, 2025–26)



Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.

3.2.1 Stakeholder views

We received 4 submissions that commented on CitiPower's opex proposal from: CitiPower's Consumer Advisory Panel, Origin Energy, Victorian Greenhouse Alliances, and the Consumer Challenge Panel (CCP32).

Submissions did not raise strong issues related to CitiPower's opex proposal, and were generally supportive. Submissions noted the electrification effort currently taking place in Victoria, and particularly noted the impact on demand and the interactions with CER penetration on the networks.

4 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 74.

CCP32 queried whether some of CitiPower's step changes met the Better Reset Handbook requirements for a step change, but concluded the vegetation management and customer assistance step changes were likely consistent with government and community expectations.[5] CCP32 particularly noted the strong customer support for the vulnerable customer assistance step change.[6] The Greenhouse Alliance also recommended establishing a consistent methodology for CER expenditure proposals. It considered this would provide a more meaningful overview to consumers on these proposals.[7]

3.3 Reasons for draft decision

Our draft decision is to not accept CitiPower's total opex forecast of $586.1. million, including debt raising costs, for the 2026–31 regulatory control period. Our alternative estimate of $524.4 million is materially different from CitiPower's total forecast opex proposal ($61.7 million or 10.5% lower). Therefore, we are not satisfied that CitiPower's total opex forecast reasonably reflects the opex criteria, having regard to the opex factors.[8]

Table 3.1 sets out CitiPower's proposal, our alternative estimate that has informed this draft decision, and the difference between our alternative estimate and the proposal.

The main drivers for this difference are also set out in section 3.1 and we discuss each of the components of our alternative estimate, and our assessment of CitiPower's proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

3.3.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider CitiPower would need for the safe and reliable provision of network services over the 2026–31 period.

3.3.1.1 Proposed base year

CitiPower proposed a base year of 2024–25 and base year opex of $94.8 million.[9] This equates to $474.1 million over the five years of the next regulatory control period.

CitiPower's base year actual opex is $22.8 million, or 19.4%, lower than the forecast opex approved for that year and $2.0 million, or 2.2%, higher than the average actual opex over the period of 2021–22 to 2023–24.

CitiPower submitted that 2024–25 is the most suitable base year because it will be the most recent year where audited actual data will be available at the time of our final decision.[10]

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5 CCP32, *Submission – CitiPower electricity distribution proposal 2026–31*, May 2025, pp. 23–26.

6 CCP32, *Submission – CitiPower electricity distribution proposal 2026–31*, May 2025, p. 24.

7 Victorian Greenhouse Alliances, *Submission – Victorian electricity distribution proposals 2026–31*, May 2025, pp. 16–17.

8 NER, cl. 6.5.6(c)–(e).

9 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 75.

10 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 75.

While there will be year to year fluctuations in reported opex over the current regulatory period, due to the interaction with the EBSS, we do not generally have concerns with the choice of base year, provided we find CitiPower's opex in the base year to be efficient.

In our alternative estimate for the draft decision, we have updated the base opex amount for 2024–25 to $94.8 million, or $473.9 million over the next regulatory control period. This is because we have used the latest inflation values to convert the nominal amount into real terms. We have used the actual inflation for the year to August 2025, from the Australian Bureau of Statistics, and the Reserve Bank of Australia's (RBA) forecast of inflation for the year to June 2026, from its May Statement on Monetary Policy.[11] These inflation forecasts were not available at the time of CitiPower's initial proposal, and represent the best available forecast, because they are the most up-to-date information available at this time.

3.3.1.2 Efficiency of CitiPower's opex

As summarised in our Expenditure Forecast Assessment Guideline (the Guideline), our preferred approach for forecasting opex is to use a revealed cost approach. This is because opex is largely recurrent and stable at a total level. Where a distribution business is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations. However, we do not assume that the business's revealed opex is efficient. We examine the trend in opex and use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently historically and particularly in the base year.

We consider CitiPower's estimate of its opex in 2024–25 is not materially inefficient, as indicated by its opex trend over time and our benchmarking results. Accordingly, we have used CitiPower's estimated costs in 2024–25 to develop our alternative estimate.

In terms of the trend in opex, Figure 3.1 shows CitiPower's opex forecast for the next regulatory control period, its actual opex in previous regulatory control periods and our previous regulatory decisions.

Overall, CitiPower's opex has been historically lower than our approved forecast since 2015–16. CitiPower's estimated opex in the base year (2024–25) of $94.8 million is $22.8 million or 19.4% below the approved forecast opex for that year.

In line with our standard approach, we have used our benchmarking tools and other cost analysis to assess and establish whether CitiPower is operating relatively efficiently, both over time and in the base year. We conclude that CitiPower performs well compared to other networks and is not materially inefficient.

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11 Australian Bureau of Statistics (ABS), *Consumer Price Index, Australia, released on 30 July 2025* (accessed on 31 July 2025: https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release); Reserve Bank of Australia (RBA), *Statement on monetary policy*, *August 2024*, (accessed on 17 September 2025: https://www.rba.gov.au/publications/smp/2025/aug/outlook.html#3-5-detailed-forecast-information).

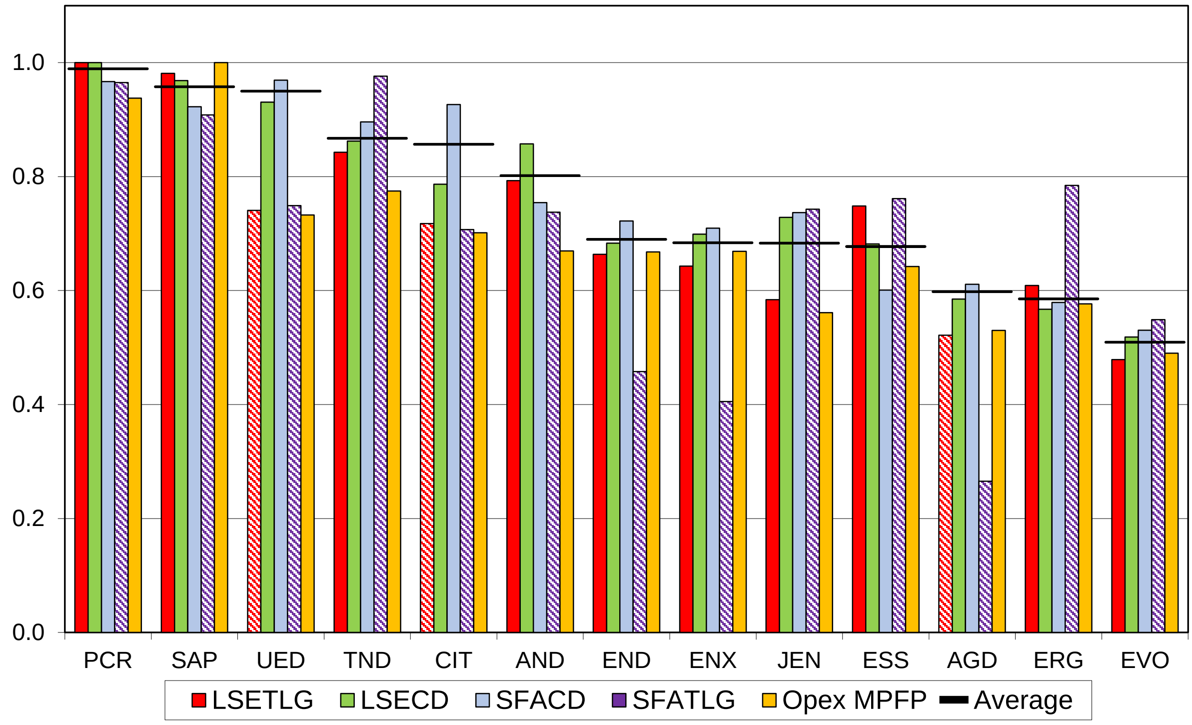
As set out in more detail in past decisions,[12] in assessing base opex efficiency, our standard approach is to benchmark a business's efficiency on the basis of its average efficiency over time (using a period-average efficiency score from our econometric opex cost function models). We consider that this is the appropriate place to start rather than initially looking at the efficiency of a single year (such as the base year) as this recognises that opex is generally recurrent, but with some degree of year-to-year volatility. Reflecting our conservative approach, we use a 0.75 benchmark comparison point (rather than 1.0) to assess the relative efficiency of distribution businesses.

Our benchmarking results indicate that CitiPower has been amongst the more productive and efficient distributors in the National Electricity Market (NEM). Our recent 2024 Annual Benchmarking Report shows CitiPower continues to perform well, relative to other distribution businesses in the NEM.[13] In particular, as shown in Figure 3.3 for the 2006–23 period, CitiPower remains a benchmark comparator business, with an econometric model-average score across the 2006–23 period of 0.86 and the 2012–23 period of 0.74, which are, on average, above our benchmark comparison point of 0.75.

12 AER, *Final Decision Attachment 6 – Operating expenditure – Ergon Energy – 2025–30* Distribution determination revenue proposal, April 2025, p. 17.

13 AER*, 2024 Annual Benchmarking Report – Electricity distribution network service providers*, November 2024.

Figure 3.3 Econometric opex efficiency scores and opex MPFP, 2006–23

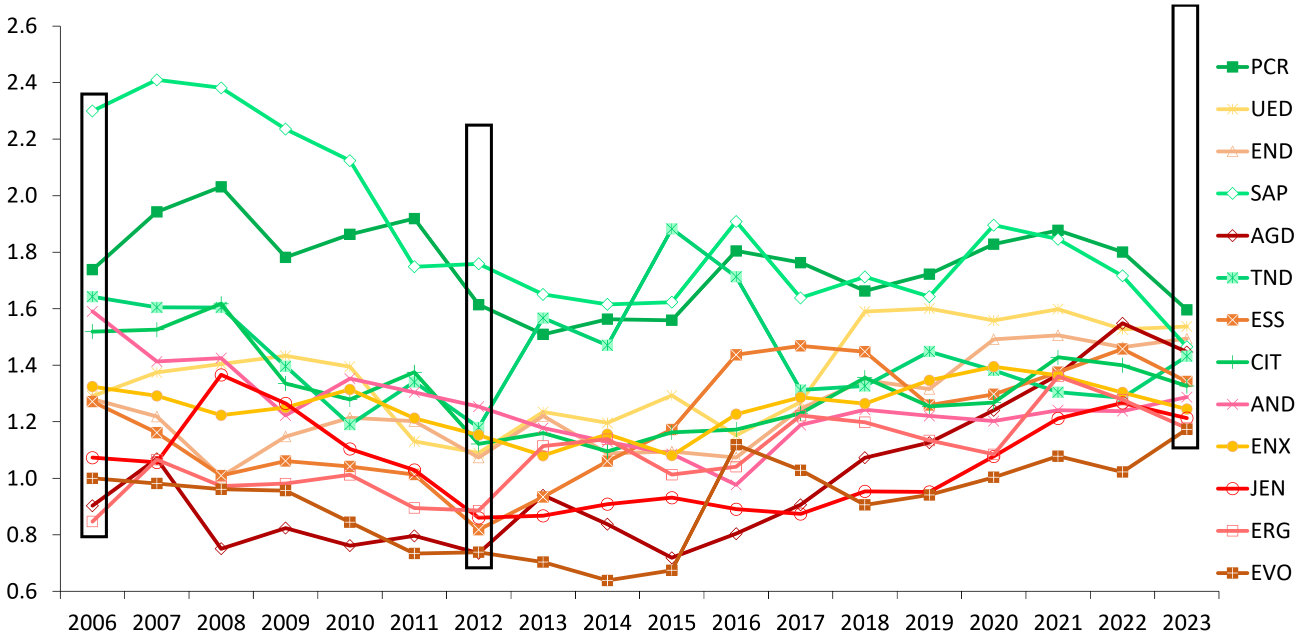


Source: Quantonomics; AER analysis.

Note: Columns with a hatched pattern represent results that violate the key property that an increase in output is achieved with an increase in cost. These results also do not reflect the impact of a range of material OEFs (see section 7). Opex MPFP scores for each DNSP are displayed for comparison and are not included in the calculation of the average efficiency score, which also excludes any results affected by monotonicity violations.

We also use productivity index number techniques to enable comparisons of productivity levels over time and between DNSPs. The multilateral total factor productivity (MTFP) index measures the total factor productivity of each business over time, whereas the opex and capital multilateral partial factor productivity (MPFP) indexes measure the productivity of opex or capital inputs respectively. Our opex MPFP efficiency results are also not adjusted for material operating environment factors. As shown in Figure 3.4, CitiPower has generally been mid-field among distribution businesses in opex MPFP throughout the period.

Figure 3.4 Individual DNSP opex MPFP indexes, 2006–23



Source: Quantonomics; AER analysis.

We consider that these results warrant the use of revealed costs in 2024–25 as the base year in our alternative estimate, as it provides a not materially inefficient base from which to form the 2026–31 period opex allowance.

3.3.2 Adjustments to base year opex

CitiPower proposed the following adjustments to its base year opex:[14]

- add $1.1 million for the increase in opex between the base year 2024–25 and the final year, 2025–26 (the final year increment). This is consistent with our standard approach and we have made the same adjustment in our alternative estimate. This increases our alternative estimate by $5.5 million over the 5 years of the 2026–31 period.
- add $0.2 million from the estimated final year opex for the removal of opex categories forecast separately. We have subtracted $0.05 million in our alternative estimate instead. This difference is because we have not removed the forecast change in opex associated with the Yarra Trams pole relocation project that was provided as a category specific forecast in the 2021–26 period. These costs will be forecast as capex in the 2026–31 period and are not provided as a category specific opex forecast. This also ensures these costs are treated consistently in the opex forecast and the EBSS (where CitiPower did not remove these forecast costs). This decreases our alternative estimate by $0.2 million over the 5 years (–$1.4 million compared to CitiPower).
- remove $0.4 million from the estimated final year opex for licence fees. These costs will be recovered as a jurisdictional scheme from 2025–26. We have made the same adjustment. This reduces our alternative estimate by $1.8 million over the 5 years of the 2026–31 period.

[14] CitiPower, *CP MOD 1.05 – Opex*, January 2025.

3.3.3 Rate of change

Having determined an efficient base year opex and estimated final year opex by adding a final year increment, we trend forward estimated final year opex to account for the forecast growth in prices, output and productivity over the regulatory control period. We refer to this as the rate of change.[15]

CitiPower largely applied our standard approach to forecast the rate of change, including:[16]

- **Price growth:** adopting our standard input price weightings of 59.2% labour and 40.8% non-labour. It forecast labour price growth using an average of forecasts of the growth in the wage price index (WPI) from BIS Oxford Economics (its consultant) and Deloitte Access Economics (our consultant, as a placeholder).
- **Output growth:** applying the output weights from our four econometric models, consistent with our standard approach. It applied these weights to its forecasts of the growth in its customer numbers, circuit length and ratcheted maximum demand.
- **Productivity growth:** using our 0.5% per year productivity growth forecast.

The rate of change proposed by CitiPower contributed $22.1 million, or 3.8%, to CitiPower's total opex forecast of $586.1 million. This equates to an average opex increase of 1.7% each year. We have included a rate of change that contributes $8.2 million, or 1.7%, to our alternative estimate of total forecast opex of $524.4 million. This equates to an average opex increase of 0.7% each year in our alternative estimate.

15 AER, Final decision – *Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, pp. 22–24.

16 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, pp. 76–77.

Table 3.2 Forecast annual rate of change in opex (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower proposal					
Price growth	0.9	0.5	0.6	0.7	0.7
Output growth	0.9	1.3	1.5	1.7	2.1
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**1.3**	**1.3**	**1.7**	**1.9**	**2.2**
AER alternative estimate					
Price growth	0.5	0.6	0.7	0.7	0.7
Output growth	0.4	0.4	0.4	0.7	0.9
Productivity growth	0.5	0.5	0.5	0.5	0.5
Rate of change	**0.4**	**0.4**	**0.6**	**0.9**	**1.0**
Difference	**–0.9**	**–0.8**	**–1.1**	**–1.0**	**–1.2**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER, *CitiPower 2026–31 – Distribution – Draft decision – Opex model*, September 2025; AER analysis.

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.3.3.1 Forecast price growth

CitiPower proposed average annual price growth of 0.7%, which increased its total opex forecast by $10.1 million. We have used real average annual price growth of 0.6% in our alternative estimate of total opex. This increases our total opex estimate by $8.7 million.

Both we and CitiPower forecast price growth as a weighted average of forecast labour price growth and non-labour price growth (real price growth rate of zero), using weights of 59.2% and 40.8% respectively.

Consequently, the key differences between our real price growth forecasts and CitiPower's are that:

- we have updated our labour price growth forecast to include more recent forecasts from our consultant Deloitte Access Economics
- we have not included a superannuation increase in 2026–27 in our labour price growth rates since the last superannuation guarantee increase is in 2025–26.

Table 3.3 compares our forecast labour price growth with CitiPower's proposal.

Table 3.3 Forecast labour price growth (%)

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower proposal					
Deloitte Access Economics	0.8	0.7	0.8	1.1	1.1
BIS Oxford Economics	1.2	1.0	1.3	1.3	1.2
Average	**1.0**	**0.9**	**1.0**	**1.2**	**1.1**
Superannuation guarantee increases	0.5	–	–	–	–
Average, including super guarantee	**1.5**	**0.9**	**1.0**	**1.2**	**1.1**
AER's alternative estimate					
Deloitte Access Economics	0.7	0.9	1.1	1.1	1.0
BIS Oxford Economics	1.2	1.0	1.3	1.3	1.2
Average	**0.9**	**0.9**	**1.2**	**1.2**	**1.1**
Overall difference	**–0.6**	**0.1**	**0.1**	**–0.0**	**–0.0**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; Deloitte Access Economics, *Labour price growth forecasts*, 30 July 2025, p. 10; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

We will receive updated WPI forecasts prior to our final decision. We will use these to update our labour price growth forecasts in the final decision.

3.3.3.2 Forecast output growth

CitiPower proposed average annual output growth of 3.3%, which increased its proposed opex forecast for the 2026–31 regulatory control period by $19.3 million. We have forecast average annual output growth of 0.5%. This increases our alternative estimate of total opex by $6.6 million, which is $12.6 million less than CitiPower's proposal.

Customer numbers growth

We are not satisfied that CitiPower's forecast growth rates for customer numbers reflect a realistic expectation. We have used the customer number forecast in Table 3.4.

Table 3.4 Forecast growth in customer numbers, %

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower proposal	2.0	1.9	1.9	1.9	1.8
AER alternative estimate	1.0	0.9	0.9	0.9	0.9
Difference	**–1.0**	**–1.0**	**–1.0**	**–1.0**	**–0.9**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

CitiPower used population growth, taken from *Victoria in Future 2023*, to forecast customer numbers growth. It stated that customer numbers growth was correlated to population growth.[17] While customer numbers growth is correlated to population growth, the relationship is not one for one in CitiPower's network area, as shown in Figure 3.5. Historically, customer numbers have grown by 0.48% when population has grown by 1% (this excludes the years from 2020, which were impacted by COVID). We have corrected forecast customer numbers to reflect this relationship.

Figure 3.5 Historic customer numbers growth and population growth, %

Source: CitiPower, AER analysis.

Circuit length growth

We are satisfied that CitiPower's forecast growth in circuit length, as set out in Table 3.5, reflects a realistic expectation. This forecast is consistent with the circuit length forecast CitiPower provided in its reset RIN and is similar to actual growth rates in recent years.

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17 CitiPower, *Response to information request IR023*, 5 May 2025, p. 2.

Table 3.5 Forecast growth in circuit length, %

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower proposal	0.1	0.1	0.1	0.1	0.1
AER alternative estimate	0.1	0.1	0.1	0.1	0.1
Difference	**–**	**–**	**–**	**–**	**–**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Ratcheted maximum demand growth

We are not satisfied that CitiPower's forecast growth rates for ratcheted maximum demand reflect a realistic expectation. We have used the ratcheted maximum demand forecast in Table 3.6.

Table 3.6 Forecast growth in ratcheted maximum demand, %

	2026–27	2027–28	2028–29	2029–30	2030–31
CitiPower proposal	0.3	1.2	1.9	2.4	3.3
AER alternative estimate	–	–	–	0.9	1.2
Difference	**–0.3**	**–1.2**	**–1.9**	**–1.5**	**–2.1**

Source: CitiPower, CP MOD 1.05 – Opex, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

The maximum demand forecasts that CitiPower used in its opex model were different to those that CitiPower included in its reset RIN.[18] We asked CitiPower why it did not use the demand forecast in its reset RIN and it stated that it used its actual maximum demand in 2023–24 escalated by the forecast growth rates in its reset RIN, plus half the L.E.K. Consulting forecast of new data centre capacity over 2027–31.[19] It did not provide a reason for doing this.

We engaged Baringa to review CitiPower's maximum demand forecasts and it noted that CitiPower had treated the L.E.K. Consulting data centre demand forecasts inconsistently across its forecasts. Baringa considered CitiPower's approach of only including data centres that are committed and contracted in the maximum demand forecasts in its reset RIN was reasonable. Baringa considered that data centres that are yet to be contracted should be excluded from the forecasts.[20] We agree that there is insufficient certainty to include the

18 Specifically, we use non-coincident maximum demand, 50% PoE, forecast at the transmission connection point in MW.

19 CitiPower, *Response to information request IR023*, 5 May 2025.

20 Baringa, *Distribution demand forecast assessment, Review of CitiPower's 2026–31 regulatory proposal*, July 2025, pp. 8–9.

L.E.K. Consulting data centre demand forecasts in the maximum demand forecasts, and have not included them in the forecast ratcheted maximum demand used to forecast opex.

We also have concerns with how CitiPower included non-data centre block loads, which we consider double counts loads captured in the trend and other components of the modelling. The block load register provided by CitiPower included blocks that are substantially lower than the loads of large customers. It may be appropriate to include a block at a particular asset (for example, at the feeder level). But when forecasting demand at the system level this load may be captured by the trend growth factor (such as population growth or economic growth). We are not satisfied that CitiPower sufficiently accounted for the potential overlap between block loads and other components of the modelling for system-level demand because it was limited to population-driven block loads. Baringa raised similar concerns, noting that the approaches to block loads at the spatial level compared to the system level, and how they reconcile to each other, was unclear.[21]

We invite CitiPower to update its maximum demand forecast in its revised proposal.

3.3.3.3 Forecast productivity growth

CitiPower proposed average productivity growth of 0.7% per year, which decreased its total opex by $7.2 million. We have forecast the same average productivity growth rate, which reflects our standard approach.[22] This decreases our alternative opex estimate by $7.2 million over the 2026–31 regulatory control period.

3.3.4 Step changes

In developing our alternative estimate for the draft decision, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the Guideline, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider does not already include the proposed cost for such items and they are required to meet the opex criteria.[23]

CitiPower's proposal included 6 step changes totalling $75.3 million or 14.8% of its proposed total opex forecast.[24] These are shown in Table 3.7 along with our alternative estimate for the draft decision, which is to include step changes totalling $27.8 million. This is $47.6 million lower than CitiPower's proposal. While we consider these step changes to be prudent, we are not satisfied they reflect an efficient level of expenditure, hence our lower estimate in most cases. We discuss our assessment of each step change below.

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21 Baringa, *Distribution demand forecast assessment, Review of CitiPower's 2026–31 regulatory proposal*, July 2025, p. 33.

22 AER, *Final decision – Forecasting productivity growth for electricity distributors*, March 2019.

23 AER, *Final decision – Expenditure Forecast Assessment Guideline – Electricity Distribution*, October 2024, pp. 24–25.

24 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement*, January 2025, p. 77.

Table 3.7 CitiPower's proposed step changes and the AER's alternative estimate ($million, 2025–26)

Step change	CitiPower proposal	AER alternative estimate	Difference
Customer assistance package	6.8	–	–6.8
Vegetation management	33.6	8.7	–24.9
CER integration	12.3	9.4	–2.9
Cloud services	11.2	1.2	–10.0
ICT modernisation	11.6	8.6	–3.0
Fleet electrification	–0.2	–0.2	–
Total step changes	**75.3**	**27.8**	**–47.6**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.

3.3.4.1 Customer assistance package

CitiPower proposed $6.8 million (1.2% of forecast opex) for its customer assistance package, which aims to improve services to customers experiencing vulnerability.[25] The package combines five programs, as follows:[26]

- Energy care ($0.7 million)
- Community energy fund ($1.6 million)
- Vulnerable customer assistance program ($2 million)
- Energy advisory services ($0.7 million)
- First Peoples program ($1.9 million).

Based on our review, we have included a lower amount of $4.0 million for this step change in our alternative estimate of total opex. This is 41% lower than CitiPower's proposal. We have also treated this step change as a category specific forecast. Our alternative forecast of annual costs is provided in the category specific forecast section 3.3.5.3.

25 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, p. 5.

26 CitiPower, *CP MOD 8.03 – Opex step changes,* January 2025.

Table 3.8 Customer assistance step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	1.3	1.4	1.4	1.4	1.4	6.8
AER alternative estimate	–	–	–	–	–	–
Difference	**–1.3**	**–1.4**	**–1.4**	**–1.4**	**–1.4**	**–6.8**

Source: CitiPower, *CP MOD 1.05 – Opex,* January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Assessment

We have had regard to CitiPower's consumer engagement in our assessment of the customer assistance package. We note that the customer assistance package was developed with input from, and is strongly supported by, both customers and CitiPower's Consumer Advisory Panel (CAP). For example, the CAP submitted:

> We are particularly pleased about increases in the regional and rural supply program and the customer assistance package, as well as the commitment to create a vulnerability strategy with an emphasis on partnerships with community organisations who already support people in vulnerable circumstances.[27]

The CAP emphasised that CitiPower should adopt a partnership-based approach, underpinned by a vulnerability strategy, and focus on areas where it is uniquely positioned to have the greatest impact in assisting vulnerable customers on its network.[28] We agree these are important factors in considering whether the proposed costs are prudent, efficient, and provide incremental benefits to consumers.

Vulnerable customer costs do not, however, meet our standard step change categories (new regulatory obligations, a capex/opex trade-off or a material change in an external market factor). However, we recognise these programs represent new incremental costs (not covered by base/trend opex) and we have provided for similar costs in other recent determinations on the basis of strong customer support and our assessment of each proposal. We also note CCP32's view that:

> strong customer support, along with regulator and government expectations, are close enough to meeting step change criteria for this proposal to be actively considered.[29]

We have assessed each proposed program separately, based on the cost breakdown provided by CitiPower in its step change model, as well as the objectives of each program outlined in the proposal. We set out our conclusions on each program which forms part of the overall vulnerable customer package step change below. The key considerations we have

27 CPU Customer Advisory Panel – *Submission – CitiPower electricity distribution proposal 2026–31*, April 2025, p.ii.

28 CPU Customer Advisory Panel – *Submission – CitiPower electricity distribution proposal 2026–31*, April 2025, p. 3, 26–27, 32.

29 CCP32, *Submission – CitiPower electricity distribution proposal 2026–31*, May 2025, p. 25.

had regard to in our assessment are whether the proposed programs align with a partnership-based approach to assisting vulnerable customers, are not duplicative of existing programs or costs, and reflect activities where a distribution network is specifically or uniquely well placed to assist.

We consider that vulnerable customer package costs should be treated as a category specific forecast, however, rather than an opex step change. This treatment is consistent with our approach in recent determinations, and means incurred costs will not be automatically rolled into base opex. We also consider a review of the outcomes of these programs, with ongoing input and oversight from consumers, is warranted.

Energy care

CitiPower proposed $0.7 million for its Energy Care program[30], which aims to provide information and training sessions to community support workers, as well as in-person electricity literacy for vulnerable customers.[31]

We have included part of CitiPower's proposal where we consider costs align with CAP's recommendation to focus on partnerships with other organisations, and areas where CitiPower is uniquely positioned to assist. Our alternative estimate is $0.2 million, covering community support worker training and one supporting employee.

Based on our review, we have not included the remaining costs associated with delivering direct energy literacy services, as we are not satisfied that these costs are prudent and efficient, given the existence of similar in-person, phone-based, and web-based programs.[32]

Community energy fund

CitiPower proposed $1.6 million for its Community Energy Fund program,[33] which aims to provide funding for initiatives such as community batteries and solar hubs. The program proposes to fund six (unspecified) projects annually, with any unused funds to be returned to customers.[34]

Based on our review, we have not included this program in our alternative estimate, as it appears duplicative of similar initiatives already provided for, or supported by, other existing programs and bodies from time to time.[35]

Additionally, we note there is no clear mechanism under the NER to ensure unspent funds are returned to customers, creating a risk of increased costs if suitable projects are not identified. As a result, we are not satisfied this program is prudent or efficient.

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30 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

31 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, p. 5.

32 For example: Energy Assistance Program, Anglicare-EAP ,Useful tools on Energy Made Easy | Energy Made Easy.

33 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

34 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, p. 6.

35 For example: 100 Neighbourhood Batteries Program Grants.

Vulnerable customer assistance program

CitiPower proposed $2 million for its Vulnerable Customer Assistance Program,[36] which aims to assist vulnerable customers and communities in transitioning away from gas appliances by reducing fees for necessary fuse or phase upgrades, and by developing a vulnerability strategy.[37]

We have included this program in our alternative estimate, as we consider CitiPower to be uniquely positioned to provide these services and there is evidence of consumer support that the program aligns with the intent of the Game Changer and other reforms to reduce barriers and enhance outcomes for vulnerable customers.

However, we also note that CCP32 considered customer engagement on the program details to be limited, with a greater focus on general customer views.[38] While the fuse upgrade component of the program is well detailed in the proposal, other cost categories are not well explained,[39] and it is unclear from the information available whether the CAP or consumers generally support the full scope and cost of the program.

Therefore, while we have included this program, we encourage CitiPower to further engage with the CAP and other consumers to confirm consumers are aware of and support the detailed costs of this program.

Energy advisory service

CitiPower proposed $0.7 million for its Energy advisory service program,[40] which aims to provide discounted or waived fees for bespoke data requests and advice for community groups. CitiPower proposed that any unspent funds be returned to customers.[41]

Based on our review, we have not included this program due to the following key concerns:

- bespoke data requests are not a new service, and it is unclear why discounted services have not been offered previously, especially given a significant opex underspend in the current regulatory period. Minor additional costs can likely be managed within base and trend opex growth.
- while the proposal focuses on discounted data services; cost breakdown also includes existing services and a web hub, which appears to overlap with the CER Data Visibility initiative, raising potential double-counting issues.[42]
- there is no clear mechanism to ensure unspent funds are returned to customers.

36 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

37 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, pp. 6–7.

38 CCP32, *Submission – CitiPower electricity distribution proposal 2026–31*, May 2025, pp.10–11.

39 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

40 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

41 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, p. 7.

42 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

First Peoples program

CitiPower proposed $1.9 million for its First Peoples program[43] to improve energy access through initiatives such as energy literacy sessions delivered through community engagement by First Peoples, and a $500 annual rebates for over-60s to help offset heating and cooling costs.[44]

We have included this program based on the strong support from the First Peoples advisory committee (FPAC) and its alignment with the AER's Game Changer intent.

However, we also note a relatively high proportion of administrative costs (over 40.0%) associated with delivering the service.[45] We have included this program as a placeholder, but encourage further consultation with FPAC to evidence support for the benefits of the program relative to administrative costs.

Conclusion

The following table summarises CitiPower's proposal for its customer assistance package, our alternative estimates, and draft decisions for each program.

Table 3.9 Customer assistance package draft decision summary ($million, 2025–26)

Program	Proposal	Alternative Estimate	Draft Decision	Comment
Energy Care	0.7	0.2	Partially accepted	Accept costs for partnership delivery and areas of unique positioning, avoiding duplication
Community Energy Fund	1.6	–	Not accepted	CitiPower not uniquely positioned to provide this service. Overlap with other organisations
Vulnerable Customer Assistance Program	2.0	2.0	Accepted	Accept as a placeholder; encourage CitiPower to confirm CAP support detailed program costs
Energy Advisory Service	0.7	–	Not accepted	Not a new service; potential double-counting with CER Data Visibility program
First Peoples Program	1.9	1.9	Accepted	Accept as a placeholder; seek further evidence that FPAC supports net benefits of program
Total	**6.8**	**4.0**	**41% reduction**	

43 CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

44 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, pp. 9–12.

45 CitiPower, *CP BUS 8.02 – Customer assistance package*, January 2025, p. 12.

3.3.4.2 Vegetation management

CitiPower proposed a $33.6 million step change (5.7% of forecast opex) for increased vegetation management costs.[46] We have included a step change of $8.7 million for vegetation management in our alternative estimate of total opex. We consider CitiPower's total base opex, and the rate of change, do not provide sufficient opex for CitiPower to comply with its electric line clearance obligations in the 2026–31 period. However, we consider CitiPower's proposed amount for this step change is not justified on the available information. This view is based on our own analysis, which aligns with, and is supported by, EMCa's advice.

Table 3.10 Vegetation management step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	5.7	6.5	7.0	7.1	7.2	33.6
CitiPower's amended forecast	5.2	6.6	6.7	6.8	6.9	32.1
AER alternative estimate	1.2	2.1	1.8	1.8	1.8	8.7
Difference	**–4.5**	**–4.4**	**–5.3**	**–5.3**	**–5.4**	**–24.9**

Source: CitiPower, *CP MOD 1.05 – Opex*, January 2025; CitiPower, *Response to information request IR017*, 22 April 2025; AER analysis.

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

CitiPower's proposal

CitiPower stated that in recent years it has introduced helicopter mounted LiDAR technology to inspect its electricity lines for compliance against its obligations under the Electricity Safety (Electric Line Clearance) Regulations. Prior to using LiDAR, it relied on visual inspections. It stated that using LiDAR provides increased accuracy and precision that has shown previously unidentified non-compliance. It stated it needs increased opex (as a step change) to address this non-compliance.[47] Of note, Jemena and AusNet, which are subject to the same regulations, did not proposed similar step changes for vegetation management.

In response to an information request, CitiPower provided an amended forecast of its vegetation management step change to reflect more up to date information.[48] We have based our assessment on this more recent forecast.

Stakeholder engagement on the vegetation management step change

CitiPower stated that it designed its regulatory proposals with Victorian electricity consumers in mind and had consulted on this step change with its consumer advisory panel (CAP). It stated that the CAP was supportive of it receiving additional expenditure to comply with its safety related regulatory obligations, and in turn minimise bushfire risk.

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46 CitiPower, *CP MOD 1.05 – Opex*, January 2025.

47 CitiPower, *CP ATT 8.02 – Vegetation management step change*, January 2025, pp. 2–4.

48 CitiPower, *Response to information request IR017*, 22 April 2025.

CCP32, however, stated that if the need for increased opex was due to CitiPower underspending consistently over recent years, and needing to get back to forecast levels, then this would not be a reason for a step change. Otherwise, it considered a step change may be appropriate, subject to the appropriate level being considered by the AER.

The Victorian Greenhouse Alliances considered that the DNSPs should be required to implement more frequent pruning cycles, to reduce unnecessary destruction of mature trees.

CitiPower's regulatory obligations

CitiPower's regulatory obligations are set by the *Electricity Safety Act 1998*, and the Electricity Safety (Electric Line Clearance) Interim Regulations 2025. The Code of Practice for Electric Line Clearance is a schedule to the Regulations.

There has been no substantive change to the Electric Line Clearance Regulations or the Code of Practice in the 2021–26 control period. The current Regulations are due to expire on 25 June 2026. We are not expecting the new regulations to include any material changes from the existing regulations or the Code of Practice.

Although there has been no substantive change to the regulations, CitiPower argued that it is subject to a new regulatory obligation. It states that it is now using LiDAR technology to inspect vegetation clearances and this is identifying non-compliance that it was not able to identify previously. Once it identifies non-compliance, it must address that non-compliance. CitiPower stated that this has the effect of increasing the standard of compliance.[49]

As required under the Regulations, CitiPower prepared and submitted to Energy Safe Victoria, a management plan in September 2021 outlining how it will comply with the Code. CitiPower noted that the Regulations require that it 'must not contravene a requirement of the management plan if the management plan is approved by Energy Safe Victoria'. Consequently, CitiPower stated that once its management plan was approved by ESV it became a regulatory obligation.[50]

Regardless of whether the management plan itself is a regulatory obligation we are satisfied that CitiPower must meet all the requirements of its plan. Accordingly, the forecast total opex we approve must be sufficient for CitiPower to meet all the requirements in its approved management plan, as well as its regulatory obligations under the relevant Act, Regulations and Code of Practice.

CitiPower also noted that collectively, CitiPower, Powercor and United Energy have been subject to four ESV prosecutions since 2019, as well as a large number of fines. It stated that this reflects the higher standard of compliance now required.[51]

49 CitiPower, *CP ATT 8.02 – Vegetation management step change*, January 2025, p. 10.

50 CitiPower, *CP ATT 8.02 – Vegetation management step change*, January 2025, p. 10.

51 CitiPower, *CP ATT 8.02 – Vegetation management step change*, January 2025, p. 11.

EMCA's assessment

We engaged EMCa to provide an expert view on CitiPower's proposed vegetation management step change. EMCa was satisfied that LiDAR data has identified additional cutting is required for CitiPower to meet its obligations. Key points from EMCa were:[52]

- indications from data provided by CitiPower that the LiDAR program has identified a smaller vegetation management program than what CitiPower has proposed
- EMCa's alternative estimated cutting for 2024–25 maintains the size of the current program, and when combined with a smaller total volume to achieve compliance, results in a reduced total vegetation management expenditure
- inadequate justification for the proposed uplifts in contractor liaison costs
- unit rates are amongst the highest in Victoria, and higher than revealed costs, without sufficient justification
- relatively new application of LiDAR technology and spatial analytics, which amongst other things will require several years to be refined, including updating of the vegetation management systems to establish a stable vegetation management program. Once stabilised, this can be expected to enable efficiencies to be realised which are not currently included in the forecast of opex requirements. EMCa considers these efficiencies can be material.

EMCa concluded that CitiPower requires a materially lower increase in opex than it has proposed. It considered that additional opex of $8.7 million would provide the efficient additional opex CitiPower would require to comply with its vegetation management obligations in the 2026–31 period.

Our assessment of CitiPower's vegetation management step change

EMCa's findings are broadly consistent with our own analysis. We found several flaws in CitiPower's modelling that make it difficult to justify its proposed opex required for this step change based on available information. We also have some concern that the proposed step change may be inconsistent with the intended opex incentive framework.

Overall, we have considered whether CitiPower's base year expenditure, plus the rate of change, is sufficient for it to comply with its regulatory obligations. CitiPower's proposed base year is 2024–25.

We have assessed CitiPower's vegetation management from both a top-down and bottom-up assessment. In terms of our top-down assessment, we looked at CitiPower's vegetation management costs over time. We also looked at how CitiPower's vegetation management opex compared to its Victorian peers, who operate under the same regulatory framework.

CitiPower appears to have reduced its vegetation management opex over the decade from 2013, but it is highly volatile

We show CitiPower's vegetation management opex from 2009 in Figure 3.6. CitiPower's vegetation management obligations increased following the Black Saturday bushfires in

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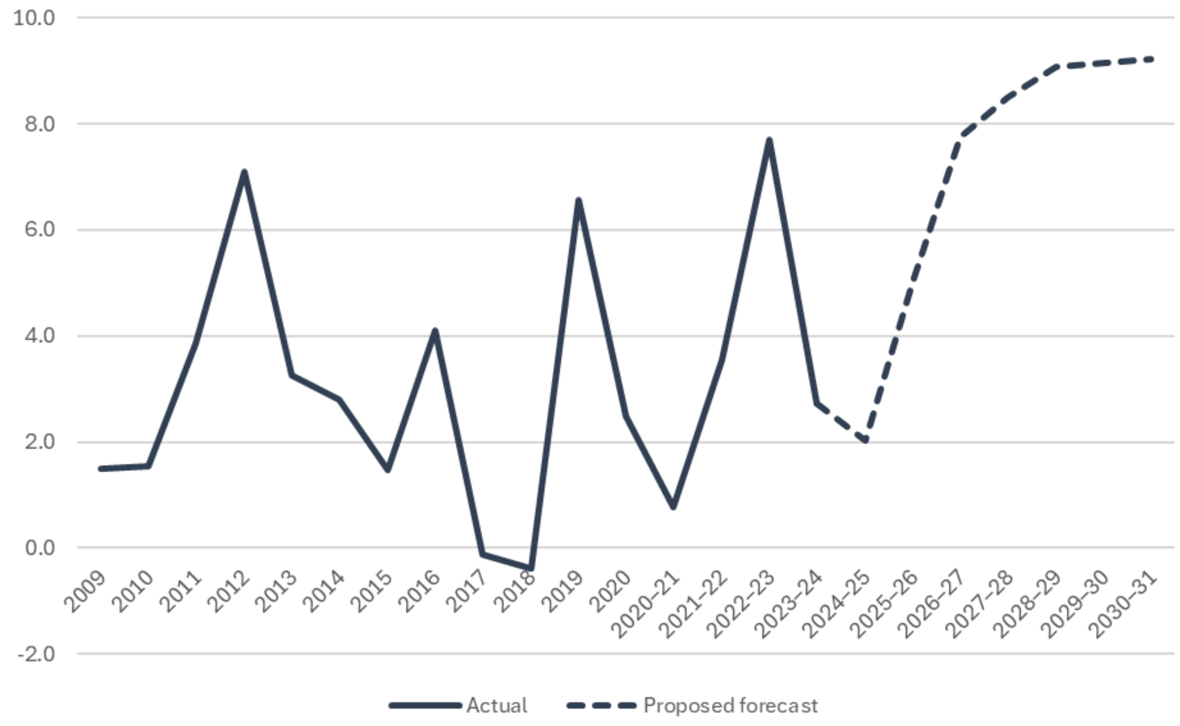
52 EMCa, *CitiPower 2026–2031 Regulatory Proposal, Review of certain aspects of proposed expenditure on augex, repex and vegetation management*, September 2025, pp. 105–108.

2009. CitiPower's actual opex is volatile and varies significantly from year to year. This includes reporting negative vegetation management opex in 2017 and 2018. It is not clear that CitiPower's vegetation management opex has increased to address the non-compliance that became apparent when it began using LiDAR to inspect vegetation clearances.

CitiPower's forecast vegetation management opex for the 2026–31 period is 108% more than its actual and estimated vegetation management opex for the 2021–26 period, and 245% more than the 2016–2020 period.

Figure 3.6 CitiPower's vegetation management opex ($million, 2025–26)



Source: CitiPower, *Annual RINs, Table 2.1.2*; CitiPower, *Response to information request IR017*, 22 April 2025.

CitiPower appears to be spending more on vegetation management than its Victorian peers

We understand that AusNet Services and Jemena have not been subject to similar enforcement actions. Given this, we have looked to see how the vegetation management opex of the five Victorian distributors compare. We compared CitiPower's unit rate (vegetation management opex divided by the number of maintenance spans) to the other Victorian distributors. We found that CitiPower's unit rate has shown significant volatility and has risen significantly in recent years. This significant increase in unit rates was driven by both an increase in CitiPower's total vegetation management opex, and a decrease in the number of maintenance spans. We found that by 2023–24 CitiPower has the second highest unit rate after Powercor.

EMCa compared CitiPower to both its Victorian peers, and the other distributors in the wider NEM.[53] EMCa found that CitiPower was among the highest cost businesses for vegetation

[53] EMCa, *CitiPower 2026–2031 Regulatory Proposal, Review if certain aspects of proposed expenditure on augex, repex and vegetation management*, September 2025, pp. 98–102.

management, and did not appear to be undertaking the work at an efficient cost. It considered that this was indicative of a program that is progressing towards compliance and has not been optimised.[54] EMCa also considered that CitiPower had not justified the further increases in its unit rates that it included in its forecast vegetation management costs.[55]

Our bottom-up assessment shows that CitiPower has significantly overstated the opex required to comply with its regulatory obligations

In addition to this top-down analysis, we also looked closely at the model CitiPower used to forecast its vegetation management step change. We have significant concerns with several of the underlying assumptions. The model forecasts the number of spans to be cut each year. This included both regular maintenance cuts and the cutting required when vegetation is found within the minimum clearance space.

As noted by EMCa, CitiPower proposed a volume of cutting that is similar to what its LiDAR program identified as necessary in 2024. CitiPower provided information showing that had it completed its full program of maintenance cuts in 2024, and cleared all spans that were found to have vegetation in the minimum clearance space, it would have needed to do 11,245 cuts. CitiPower proposed to increase the number of cuts from its actual cut count of 4,873 in 2024 to 11,442 from 2027–28.

We consider that CitiPower's proposed 11,442 cuts is higher than can be justified on the information available for three reasons. Firstly, CitiPower's modelling approach double counts a small number of cuts in both its base and uplift forecasts. Second, the number of cuts CitiPower will need to do each year will likely reduce once it achieves compliance because this volume likely includes a backlog of non-compliant spans. Third, CitiPower's cutting volumes vary significantly from year to year and 2024 does not appear to be a typical year. We discuss these issues in greater detail below.

CitiPower double counted cuts in its base and uplift volumes

CitiPower forecasts the volume of cuts it will need to do by forecasting a base volume plus an 'uplift'. As discussed above, it forecasts the uplift based on its cutting volumes for 2024, when it completed 4,873 cuts. But to forecast the base volume it used its estimated volume for 2025, which is 5,070. This double counts 197 cuts.

CitiPower has assumed that the number of spans with vegetation inside the minimum clearance space will not improve from the high level of 2024

CitiPower assumed that the number of non–compliant spans it will have in the 2026–31 period will not improve from what it was able to achieve in 2024. This is despite also forecasting an increase in the number of maintenance spans it will cut, which should reduce the number of non-compliant spans that need rectifying.

CitiPower forecast cut volumes for the 2026–31 control period based on the 'total' cuts in 2024, the sum of cuts made and 'remaining' cuts. We have concerns this will likely overstate the number of cuts that will be required once compliance is achieved because 2024 appears

[54] EMCa, *CitiPower 2026–2031 Regulatory Proposal, Review if certain aspects of proposed expenditure on augex, repex and vegetation management*, September 2025, p. 98.

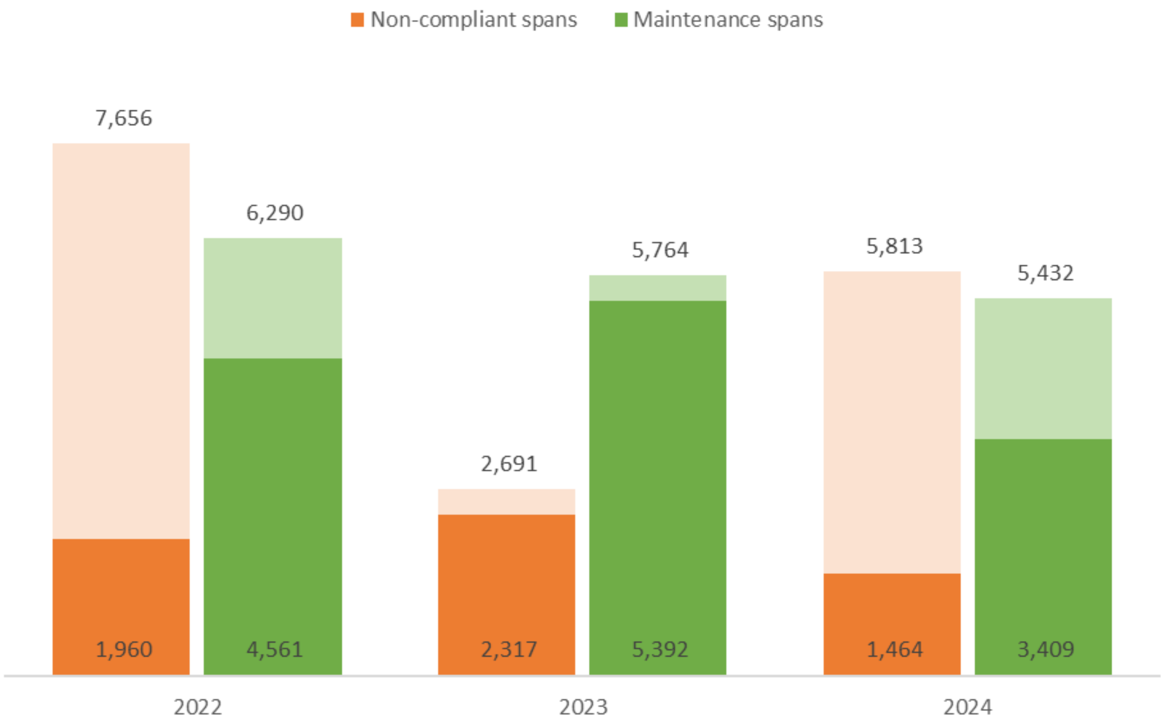
[55] EMCa, *CitiPower 2026–2031 Regulatory Proposal, Review if certain aspects of proposed expenditure on augex, repex and vegetation management*, September 2025, p. 98.

to include a backlog of non-compliant spans. To test this, we compared the ratio of cuts to rectify non-compliant spans to maintenance cuts. In 2024, the total number of non-compliant spans (cut and remaining) was 107% of its total maintenance cuts (cut and remaining). We Would expect this to reduce significantly once CitiPower achieves compliance. By way of comparison, we note that for Powercor, in its high bushfire risk areas, the total number of non-compliant spans (cut and remaining) was equal to 35% of its maintenance cuts (cut and remaining) in 2024.

CitiPower's cut volumes vary significantly from year to year

We show CitiPower's cut volumes in Figure 3.7, which shows the number of cuts made and the number of remaining uncut spans. We separately show maintenance cuts and cuts to rectify non-compliant spans. We can see the number of cuts made and cuts remaining vary significantly from year to year. The darker shaded columns in the stacks represent the cuts made. The lighter shaded columns reflect the spans that remained uncut at the end of the year.

Figure 3.7 Spans cut and remaining, 2022 to 2024



Source: CitiPower, *Response to information request IR017*, 22 April 2025; AER analysis.

Of note, CitiPower had significantly less non-compliant spans in 2023 and fewer spans remained uncut at the end of the year than for 2024.

To address the significant variance from year to year, EMCa used an average of 2023 and 2024 to forecast its recommended vegetation management costs for CitiPower. On this basis it considered a reasonable estimate of the volume of spans cut each year to be 9,850.

We also note that in some years the number of non-compliant spans reduced by more than CitiPower's rectification cut volumes. This is the case in 2023. CitiPower ended 2022 with 5,696 non-compliant spans. In 2023 it reported 2,317 rectification cuts and ended the year with 374 non-compliant spans. This suggests that CitiPower used its maintenance cutting to address vegetation in the minimum clearance space. If this is the case, using the number of remaining non-compliant spans as the basis to forecast the number of rectification cuts may overstate the number of total cuts required.

We note that for Powercor and United Energy we have seen the number of non-compliant spans in HBRA areas reduce significantly in 2025, although we haven't yet seen the full year of data. Given this, we will take CitiPower's performance in 2025 into account in our final decision and we expect CitiPower to update its forecast in its revised proposal with the latest available information.

Contractor liaison costs

CitiPower included an additional $480,000 per year for the salaries of new staff that it stated it needs to manage its contractors.[56]

As noted by EMCa, the costs for contractor liaison are already included in the base year expenditure and the increase in volumes appears to be met with the same contractors. Like EMCa, we are not satisfied that CitiPower has provided sufficient justification for this increase. We consider that there is sufficient opex in CitiPower's base opex, and the rate of change, for it to manage its contractors.

CitiPower did not account for the impact of the rate of change on base year expenditure

CitiPower calculated its proposed step change as the difference between its forecast of vegetation management costs in a given year and the amount it estimated for the base year (2024–25). In forecasting its vegetation management costs it accounted for forecast price growth. However, in calculating the step change it did not account for the application of the rate of change to base year opex. This, in effect, double counts the impact of the rate of change on CitiPower's vegetation management base year opex.

We have used the step change value recommended by EMCa as a placeholder

We have used an alternative estimate of efficient costs for this step change of $8.7 million. This is the value recommended by EMCa. It calculated this based on:

- reducing the proposed volume of cutting to reflect the total cutting that CitiPower would have required in 2023 and 2024 to do all its maintenance program and cut all spans with vegetation in the minimum clearance space. EMCa used an average of two years to address the significant variation in CitiPower's cutting volumes from year to year.
- reducing the proposed unit rates
- removing the proposed hazard tree costs due to lack of justification
- assuming CitiPower achieves efficiencies once its new inspection and cutting program is well established.

We consider this is the best estimate available to use as a placeholder in the draft decision. We consider, however, that the volumes estimated by EMCa may be more than that required by CitiPower. We note that on average across 2023 and 2024, CitiPower's total rectification

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[56] CitiPower, *CP ATT 8.02 – Vegetation management step change*, January 2025, p. 15.

cuts (cut and remaining) were 76% of its full maintenance program. For Powercor, its total rectification cuts in its HBRA areas were only 35% of its total maintenance cuts. This suggests that once CitiPower achieves compliance, the volume of non-compliant spans it will need to cut could be less than the volumes estimated in EMCa's forecast.

We expect CitiPower will consider all the concerns raised above, and those raised by EMCa in its report, in preparing its revised proposal.

CitiPower's proposed step change may not share efficiency gains and losses symmetrically

Since 2010, the Electricity Safety (Electric Line Clearance) Regulations, and the underlying Code of Practice, have not changed significantly. In that time CitiPower has not increased its opex to the level that CitiPower now considers it needs to comply with those obligations. Under the opex incentive framework, CitiPower retains incremental efficiency gains (and losses) for 6 years. This means that if CitiPower reduces its ongoing level of opex its revenue (forecast opex and EBSS carryovers) doesn't reduce to the lower level until 6 years later. In this way CitiPower benefited from not increasing its vegetation management opex for six years. If we provide a step change for CitiPower to comply with its vegetation management obligations, it will not need to wait six years for its revenues to increase to the level it needs to comply with its regulatory obligations.

One of the opex factors we must have regard to when deciding whether forecast opex meets the opex criteria is whether the opex forecast is consistent with any incentive scheme that applies. Consequently, we must have regard to the EBSS when considering forecast opex.

In implementing the EBSS we must have regard to the desirability of both rewarding distributors for efficiency gains and penalising distributors for efficiency losses. Consistent with this, we consider that the opex incentive framework should operate in a symmetric way. That is, CitiPower should be penalised for any additional costs it needs to incur to meet its regulatory obligations in the same way it has been rewarded for not increasing its opex to a level that would allow it to meet those obligations.

However, while the NER requires us to have regard to the EBSS, we must ensure the forecast opex is sufficient for CitiPower to comply with all its regulatory obligations. We cannot reject a step change on the grounds it should be paid for by EBSS rewards. That said, both the *Expenditure forecast assessment guideline* and the EBSS allow for non-recurrent efficiency gains in the base year.

We are considering whether CitiPower's failure to maintain compliance with its vegetation management obligations constitutes a non-recurrent efficiency gain. We would welcome stakeholders' views on this issue. If we were to consider the additional opex required to comply with vegetation management obligations was a non-recurrent efficiency gain, then the additional opex would be recognised in the EBSS. This would penalise CitiPower for the additional opex it needs to incur to meet its regulatory obligations in the same way it has been rewarded for not increasing its opex to a level that would allow it to meet those obligations.

3.3.4.3 Consumer Energy Resource (CER) integration step changes

We have included $9.4 million for CER integration in our alternative estimate of total forecast opex for the draft decision. This is $2.9 million less than the amount proposed by CitiPower and reflects that we are not satisfied that the full proposed costs are prudent and efficient.

Table 3.11 CER integration step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	0.8	2.7	2.7	3.0	3.2	12.3
AER alternative estimate	0.6	2.0	2.0	2.3	2.5	9.4
Difference	**–0.2**	**–0.7**	**–0.7**	**–0.7**	**–0.7**	**–2.9**

Source CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

CitiPower proposed $12.3 million (2.1% of forecast opex) for CER integration to support its broad CER strategy, which it considered it requires to meet an evolving network undergoing a fundamental energy transition.[57]

CitiPower submitted this change is driven by factors including: a customer-led change to the interaction with energy services (such as CER), the government's net-zero commitment, growing renewable generation and battery deployment, and the anticipated electrification of transport and gas.[58] CitiPower further submitted that although the CER and electrification investments will come at some cost to customers in the short-term, these will be materially outweighed by the resulting benefits in the long-term.[59] CitiPower's CER integration step change broadly consists of 3 key programs:

1. Flexible services ($9.4 million) – investments to transition from static CER controls to flexible CER operation and management
2. Non-network procurement platform ($1.6 million) – development of a non-network marketplace
3. Network data visibility ($1.3 million) – development of a customer portal.

The above programs also relate to investments proposed in CitiPower's capital expenditure proposal. We have jointly assessed this proposal, including through the information provided in the respective business cases and models for the 3 programs, the responses received to our information requests, and information obtained through an onsite workshop. We also engaged EMCa to provide technical advice on the prudency and efficiency of the proposed expenditure for both opex and capex.

We provide details on each of these programs, our assessment and the reasons for our decisions of CitiPower's respective programs (both opex and capex), in **Attachment 2** of this

57 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, pp. 14, 19–30; CitiPower, *CP MOD 8.03 – Opex step changes,* January 2025.

58 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, pp. 19–20.

59 CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, pp. 14.

draft decision. In summary, we have included costs, as proposed, for the flexible services program.

3.3.4.4 Cloud services and ICT modernisation step changes

We have included $9.8 million (combined) for the Cloud services *and* ICT modernisation & new capabilities step changes in our alternative estimate of total forecast opex for the draft decision. This is $13.0 million less than the combined amount proposed by CitiPower and reflects that we are not satisfied that the full proposed costs and programs are prudent and efficient.

We have combined these two step changes as they largely reflect the recurrent (ICT modernisation and new capabilities) and non-recurrent (cloud services) costs of the same program.

Table 3.12 Cloud services step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	1.5	3.8	2.3	2.6	1.0	11.2
AER alternative estimate	0.2	0.1	0.2	0.4	0.2	1.2
Difference	**–1.2**	**–3.7**	**–2.1**	**–2.2**	**–0.8**	**–10.0**

Source CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Table 3.13 ICT modernisation step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	–0.2	1.0	3.0	3.7	4.1	11.6
AER alternative estimate	0.2	1.0	1.9	2.6	2.9	8.6
Difference	**0.4**	**0.0**	**–1.1**	**–1.1**	**–1.2**	**–3.0**

Source CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

CitiPower proposed these step changes (3.9% of forecast opex) for additional opex to support new ICT investments, and for the reclassification of cloud services from capex to opex, consistent with the change in accounting treatment.[60] The costs relate to the following programs:

1. Cyber security ($5.6 million) – investment to maintain prudent cyber maturity and protection
2. Enterprise resourcing planning and billing systems (10.8 million) – to upgrade its current systems reaching end-of-life and to achieve convergence across its related businesses

[60] CitiPower, *Regulatory Proposal 2026–31 – Part B – Explanatory Statement,* January 2025, p. 81; CitiPower, *CP MOD 8.03 – Opex step changes*, January 2025.

3. Infrastructure refresh ($3.2 million) – to transition to cloud-based services
4. Market interface technology enhancements (MITE) ($3.1 million) – for AEMO compliance-driven reforms.

The above programs also relate to investments proposed in CitiPower's capital expenditure proposal. We have jointly assessed this proposal, including through the information provided in the respective business cases and models for the 4 programs, the responses received to our information requests, and information obtained through an onsite workshop. We also engaged EMCa to provide technical advice on the prudency and efficiency of the proposed expenditure for both opex and capex.

We provide details on each of these programs, our assessment and the reasons for our decisions of CitiPower's respective programs (both opex and capex), in **Attachment 2** of this draft decision.[61] In summary, we have included costs, as proposed, for the cyber security and infrastructure refresh projects, and a lower amount for the MITE project.

3.3.4.5 Fleet electrification

CitiPower proposed a negative step change of –$0.2 million related to fleet electrification. CitiPower stated this was in response to an expected reduction in its vehicle operating costs due to its proposed electric vehicle transition program.

Consistent with our capex position, which has accepted CitiPower's fleet electrification program, we have included this step change in our alternative estimate, without any adjustments. More detail can be found in **Attachment 2** of this draft decision.

Table 3.14 CitiPower's fleet electrification step change ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	–	–0.03	–0.04	–0.04	–0.05	–0.16
AER alternative estimate	–	–0.03	–0.04	–0.04	–0.05	–0.16
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.3.5 Category specific forecasts

CitiPower's proposal included three category specific forecasts, which were not forecast using the base-step-trend approach. These were for:

- its proposed Innovation fund ($2.9 million),
- GSL payments ($0.3 million), and
- debt raising costs ($6.5 million).

[61] AER, *Attachment 2 – Capital expenditure – Draft decision – CitiPower distribution determination 2026–31*, September 2025.

Additionally, as mentioned in section 3.3.4.1, we have reclassified CitiPower's customer assistance program step change ($4.0 million – our lower amount) as a category specific forecast in our alternative estimate.

3.3.5.1 Innovation fund

We have included $0.5 million for the innovation fund in our alternative estimate of total forecast opex for the draft decision. This is $2.4 million less than the estimate proposed by CitiPower, and reflects that we are not satisfied that the full proposed costs and programs are prudent and efficient.

Table 3.15 Innovation fund ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	0.7	0.7	0.5	0.5	0.5	2.9
AER alternative estimate	0.1	0.1	0.1	0.1	0.1	0.5
Difference	**–0.6**	**–0.6**	**–0.4**	**–0.4**	**–0.4**	**–2.4**

Source CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

CitiPower proposed $2.9 million (0.5% of forecast opex) for a network innovation fund, which it submitted will ensure it continues to keep pace with changes underway in the energy market and to meet the expectations placed on networks in this environment.[62] It submitted that without explicit innovation funding, new approaches and the associated benefits are unlikely to be realised, particularly for customer focused innovation programs. It therefore considered its innovation allowance will deliver projects that will contribute long term customer value.[63]

CitiPower proposed 12 individual projects, broadly grouped into 3 categories:

1. assisting the energy transition
2. improving customer experiences
3. developing sustainable networks.

The above programs contain corresponding capital expenditure. We have jointly assessed the above programs with CitiPower's capital expenditure proposal, including through the information provided in its initial proposal and through responses to our information requests.

CitiPower also proposed a 'use it or lose it' arrangement, by where they would return any funds not spent during the 2026–31 period to customers via a revenue adjustment.[64] We consider the innovation fund does not satisfy the criteria for a revenue adjustment under the NER (clause 6.4.3.(b)(5)) because it is not listed as an allowable revenue increment

62 CitiPower, *CP BUS 9.01 – Innovation allowance*, January 2025, p. 9.

63 CitiPower, *CP BUS 9.01 – Innovation allowance*, January 2025, p. 12.

64 CitiPower, *CP BUS 9.01 – Innovation allowance*, January 2025, p. 12.

application. Therefore, our decision does not include the ‘use it or lose it arrangement’, where any unspent funds are returned to customers.

We provide more details on each of these programs, our assessment and the reasons for our decisions (both opex and capex), in **Attachment 2** of this draft decision. [65]

3.3.5.2 Guaranteed service level (GSL) payments

CitiPower also included a category specific forecast for GSL payments of $0.3 million in its proposal. These are payments CitiPower makes to customers who experience reliability less than the specified performance thresholds in the Electricity Distribution Code. We have made one adjustment to the forecast we have included in our alternative estimate. CitiPower increased the GSL payments by 15% in the expectation that the Essential Services Commission (ESC) will update the GSL payment rates, which it typically does every 5 years. The ESC, however, has not updated the GSL scheme. We will update the GSL payment amounts in our final decision to reflect any amendments the ESC makes to the scheme prior to the final decision.

We also note that the proposed forecast of GSL payments was calculated using an estimate of outages for 2024–25. We expect that CitiPower will update the forecast in its revised proposal using actual outage data for 2024–25.

Table 3.16 GSL payments ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	0.06	0.05	0.05	0.05	0.05	0.27
AER alternative estimate	0.05	0.05	0.05	0.05	0.04	0.23
Difference	**–0.01**	**–0.01**	**–0.01**	**–0.01**	**–0.01**	**–0.03**

Source CitiPower, *CP MOD 1.05 – Opex*, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

3.3.5.3 Customer assistance package

As discussed in section 3.3.4.1, we have reclassified CitiPower’s proposed customer assistance package step change ($6.8 million) as a category specific forecast for our lower alternative estimate of $4.0 million.

[65] AER, *Attachment 2 – Capital expenditure – Draft decision –CitiPower distribution determination2026–31*, September 2025.

Table 3.17 Customer assistance package ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	–	–	–	–	–	–
AER alternative estimate	0.8	0.8	0.8	0.8	0.8	4.0
Difference	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**4.0**

Source CitiPower, *CP MOD 1.05 – Opex, January 2025*; AER analysis.

3.3.5.4 Debt raising costs

We have included debt raising costs of $6.2 million in our alternative estimate. This is $0.4 million less than the estimate proposed by CitiPower.

Table 3.18 Debt raising costs ($million, 2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
CitiPower proposal	1.2	1.3	1.3	1.4	1.4	6.5
AER alternative estimate	1.2	1.2	1.3	1.3	1.2	6.2
Difference	**0.0**	**–0.0**	**–0.1**	**–0.1**	**–0.1**	**–0.3**

Source CitiPower, CP MOD 1.05 – Opex, January 2025; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides consistency with the forecast of the cost of debt in the rate of return building block. This is the basis for our alternative estimate in Table 3.18. We used our standard approach to forecast debt raising costs.

Shortened forms

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
capex	capital expenditure
CCP32	Consumer Challenge Panel, sub-panel 32
CPI	consumer price index
CTP	customer technology program
DMIAM	demand management innovation allowance (mechanism)
DNSP	distribution network service provider
distributor	distribution network service provider
EBM	emergency backstop mechanism
EBSS	efficiency benefit sharing scheme
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
FTE	Full Time Employee
GSL	guaranteed service levels
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NPV	net present value
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
repex	replacement expenditure
RIN	regulatory information notice
SCS	standard control services