FINAL DECISION

CitiPower
Distribution Determination
2021 to 2026

Attachment 6
Operating expenditure

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to CitiPower for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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6 Operating expenditure

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

This attachment outlines our assessment of CitiPower's revised opex proposal for the 2021–26 regulatory control period.

6.1 Final decision

Our final decision is to accept CitiPower's total opex forecast of $476.7 million ($2020–21),[1] including debt raising costs, for the 2021–26 regulatory control period. We have tested CitiPower's updated revised proposal by comparing it to our alternative estimate of $473.7 million ($2020–21), which is generally consistent with CitiPower's updated revised proposal ($3.1 million ($2020–21), or 0.6 per cent, lower). We therefore consider that CitiPower's total opex forecast reasonably reflects the opex criteria.[2]

Our final decision opex forecast is:

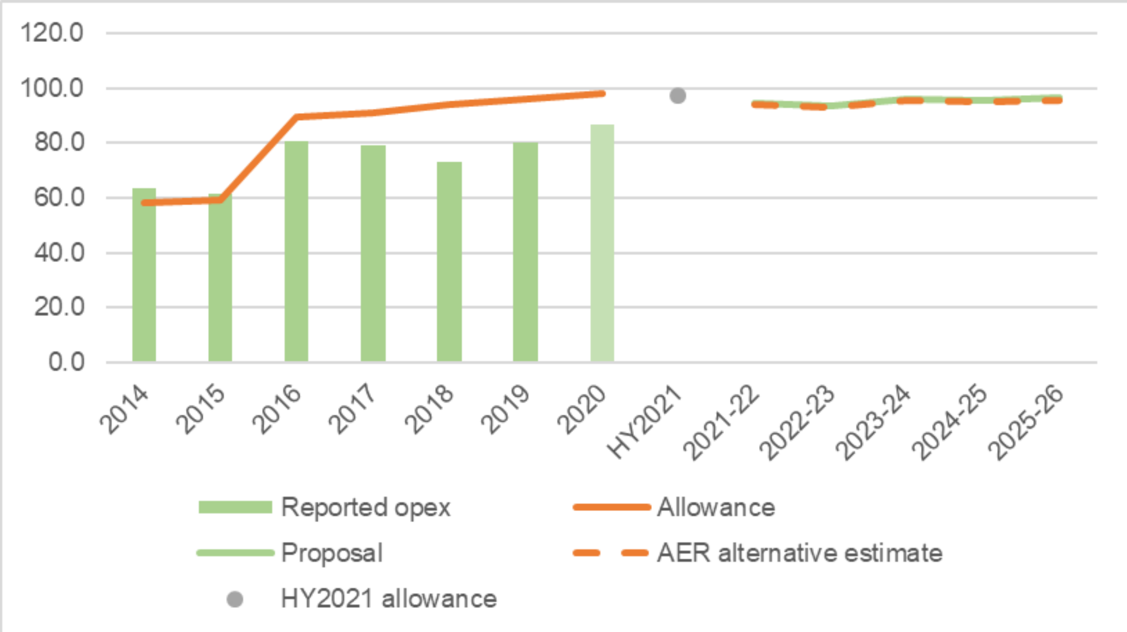
- $7.7 million (or 1.6 per cent) higher than the opex forecast we approved in our final decision for the 2016–20 regulatory control period
- $76.3 million (or 19.0 per cent) higher than CitiPower's actual (and estimated) opex in the 2016–20 regulatory control period
- $92.1 million (or 16.2 per cent) lower than CitiPower's initial proposal.

Figure 6.1 shows CitiPower's actual opex, our previous approved forecast, proposed opex for the next five years and our alternative estimate for the final decision.

1 CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex – update*, December 2020.

2 NER, cl. 6.5.6(c).

Figure 6.1 CitiPower's opex over time ($ million, 2020–21)



Source: CitiPower, *Revised Regulatory Proposal - 2021–26 - MOD 10.06 - Opex - update*, December 2020; AER, *Final Decision, CitiPower distribution determination 2021–26, Opex model*, April 2021; AER, *Final Decision, CitiPower distribution determination 2021–26, EBSS model*, April 2021; AER analysis.

Table 6.1 sets out CitiPower's revised proposal, its updated revised proposal (which we accept), and our alternative estimate.

Table 6.1 Comparison of CitiPower's revised opex proposal and our alternative estimate ($ million, 2020–21)

	CitiPower's revised proposal	Updated revised proposal	AER alternative estimate	Difference
Base (reported opex in 2019)	413.4	413.4	413.4	–
Base year adjustments	11.4	11.4	8.4	–3.0
Final year increment	17.8	17.8	19.7	1.9
Trend: Output growth	10.3	10.3	9.8	–0.5
Trend: Real price growth	5.8	5.8	5.7	–0.1
Trend: Productivity growth	–6.1	–6.1	–6.0	0.0
Step changes	13.9	13.9	13.2	–0.7
Net category specific forecasts	0.8	5.3	4.7	–0.6
Total opex (excluding debt raising costs)	**467.3**	**471.8**	**468.8**	**–3.0**
Debt raising costs	4.9	4.9	4.9	–0.0
Total opex (including debt raising costs)	**472.2**	**476.7**	**473.7**	**–3.1**

	CitiPower's revised proposal	Updated revised proposal	AER alternative estimate	Difference
Percentage difference to updated revised proposal				–0.6%

Source: CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex*, December 2020; CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex – update*, December 2020; AER, *Final Decision, CitiPower distribution determination 2021–26, Opex model*, April 2021; AER analysis.

Note: Numbers may not add up to totals due to rounding. The difference is between CitiPower's updated proposal and our alternative estimate. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance. Net category specific forecasts captures the net impact of removing these costs from the base year and re-forecasting as a category specific forecast for the 2021–26 regulatory control period.

The following key factors explain the differences in our alternative total opex forecast, compared to the updated revised proposal which we accept:

- For base adjustments, our alternative estimate is $3.0 million ($2020–21) lower than CitiPower's proposal as we have included a lower forecast for Advanced metering infrastructure (AMI) communications network adjustment.
- Our final year increment is $1.9 million ($2020–21) higher as we have updated for the latest inflation actuals and forecasts.
- Our rate of change is $0.6 million ($2020–21) lower than CitiPower’s proposal. For labour price growth, we have used more recent forecasts from Deloitte Access Economics. For output growth, we have updated output weights based on our 2020 Benchmarking Report.
- Opex related to step changes is $0.7 million ($2020–21) lower as we have made an efficiency adjustment to the proposed solar enablement expenditure.
- Net opex related to category specific forecasts is $0.6 million ($2020–21) lower as we have made an efficiency adjustment to the proposed Yarra Trams forecast.

6.2 CitiPower’s revised proposal

CitiPower used a ‘base-step-trend’ approach to forecast opex for the 2021–26 regulatory control period in its revised and updated revised regulatory proposals, consistent with our standard approach.

CitiPower proposed a revised total opex forecast of $472.2 million ($2020–21) for the 2021–26 regulatory control period. On 21 December 2020, CitiPower submitted an updated proposal where it proposed an updated total opex forecast of $476.7 million ($2020–21) to account for updates to its guaranteed service level (GSL) payments forecast and to include Yarra Trams pole relocation costs.[3]

[3] CitiPower, *Revised Regulatory Proposal – 2021–26 – Supplementary revised proposal submission*, December 2020.

In applying our base-step-trend approach to forecast opex for the 2021–26 regulatory control period, CitiPower:[4]

- used actual opex in 2019 as the **base** to forecast ($413.4 million ($2020–21))
- adjusted the base year expenditure to include forecast for activities which it considered are not fully reflected or should be removed in the base year expenditure ($11.4 million ($2020–21))
- added the final year increment from the base year of 2019 ($17.8 million ($2020–21))
- applied a rate of change (**trend**) comprising of:
    - real price escalation ($5.8 million ($2020–21))
    - output growth ($10.3 million ($2020–21))
    - and productivity (–$6.1 million ($2020–21))
- added forecast **step** changes for the 2021–26 regulatory control period ($13.9 million ($2020–21))
- added category specific forecasts for the 2021–26 regulatory control period ($5.3 million ($2020–21))
- added forecast debt raising costs ($4.9 million ($2020–21)).

Table 6.2 CitiPower's proposed opex ($ million, 2020–21)

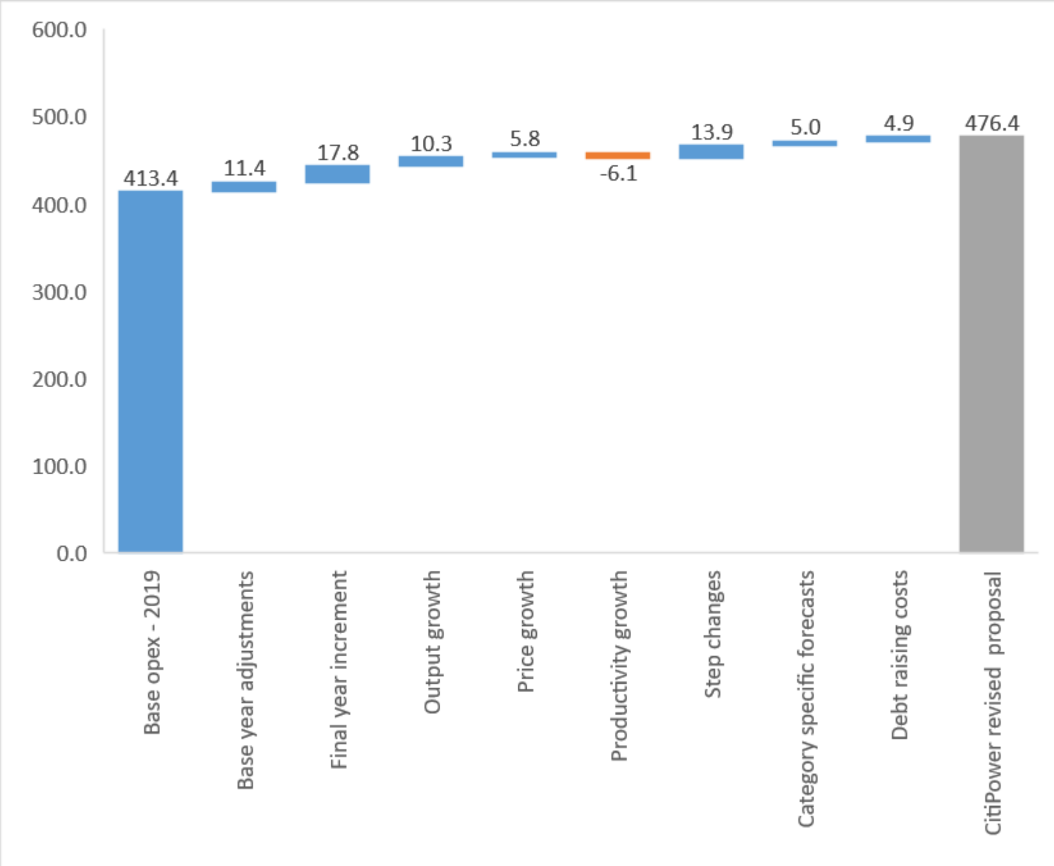
	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Total opex excluding debt raising costs	93.9	92.7	95.1	94.6	95.5	471.8
Debt raising costs	1.0	1.0	1.0	1.0	1.0	4.9
Total opex	**94.9**	**93.7**	**96.1**	**95.6**	**96.5**	**476.7**

Source: CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex – update*, December 2020.
Note: Numbers may not add up to totals due to rounding.

[4] CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex – update*, December 2020.

Figure 6.2 shows the different components in CitiPower's opex proposal.

Figure 6.2 CitiPower's revised opex forecast ($ million, 2020–21)



Source: AER analysis.

6.2.1 Stakeholder views

We received four submissions on CitiPower's 2021–26 regulatory proposal that raised issues about opex. At a high level, submissions were generally supportive of our draft decision noting concerns of productivity declines over time. Submissions provided commentary on various components of the revised proposals. We have taken these submissions, and any other concerns consumers identified, into account in developing the positions set out in this final decision. A summary of the opex issues raised in submissions is provided in table 6.3.

Table 6.3 Submissions on CitiPower's revised opex proposal

Stakeholder	Issue	Summary
AER Consumer Challenge Panel,	Base opex	The VCO suggested that a bottom-up sanity check may be useful in evaluating efficiency as all distributors, except United Energy, have experienced a decline

Stakeholder	Issue	Summary
sub panel 17 (CCP17), Ausgrid, Victorian Community Organisation (VCO), Energy Consumers Australia (ECA)		in productivity over time. Further, that distribution businesses have consistently under-spent their opex allowance, suggesting base opex is not efficient.[5] The CCP17 noted that based on the benchmarking results, CitiPower, Powercor and United Energy are the more efficient distribution businesses in Australia for all measures, whereas AusNet Services and Jemena have performed poorly.[6] Consultant for ECA, Spencer&Co expressed concerns about the benchmarking results. It considered the benchmarking results to be highly sensitive to inputs and that this presents risks when setting opex using these results.[7]
VCO	Trend	The VCO considered that to determine price growth the most recent data sources should be used (including the Victorian government's December 2020 estimates) and that the labour / materials weights should be the same across all businesses.[8] The VCO supported the AER's approach for developing output growth forecasts using updated information for the final decisions and to address the issues raised in the NERA and Frontier Economics reports.[9] It considered a detailed review of the forecast growth in outputs is required, including for customer numbers (connections), peak demand and energy throughput. It also sought consistency in approach across all businesses.[10] The VCO considered the 0.5 per cent per annum productivity growth forecast is too low.[11]
CCP17, VCO	Step Changes	The VCO supported the application of materiality as grounds for examining step changes, in particular the proposed Australian Energy Market Operator (AEMO) fees and Energy Safe Victoria (ESV) levy. It was generally supportive of the AER's decisions on the step changes in the draft decision.[12] The CCP17 also supported the application of materiality as a guide for determining if proposed step changes are prudent and efficient and discussed the issues raised by CitiPower, Powercor and United Energy in its revised proposal.[13]

5 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 15–16, 50–51 (Headberry Partners P/L).

6 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 54–57.

7 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 9 (Spencer&Co).

8 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 52 (Headberry Partners P/L).

9 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 52 (Headberry Partners P/L).

10 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 22 (Headberry Partners P/L).

11 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 52 (Headberry Partners P/L).

12 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 54 (Headberry Partners P/L).

13 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 57–59.

Stakeholder	Issue	Summary
VCO, ECA	ESV Levy	The VCO supported the AER draft decision that the ESV levy cost should be absorbed by the distribution businesses.[14] ECA generally supported the distribution businesses' position to include fees and charges levied by regulators in the price control mechanism. It considered these costs cannot controlled and that it is appropriate to pass the costs on to customers via price controls.[15]
CCP17, VCO, ECA	Solar/Future Grid	The CCP17 supported CitiPower, Powercor and United Energy's solar enablement step change with the caveat that these resources should be largely managed through automated network monitoring over time.[16] The VCO submitted that while some of CitiPower, Powercor and United Energy's counters to the AER's draft decision to reject their solar step change has some merit, CitiPower, Powercor and United Energy have not demonstrated any net benefit to the consumer.[17] Consultant for ECA, Spencer&Co, supported the AER's draft positions for the distribution businesses and recommends the AER review the CitiPower, Powercor and United Energy step change to satisfy itself that the cheapest opportunities for capacity expansion and distributed energy resource facilitation are not being overlooked.[18]
CCP17, ECA	GSL payments	The CCP17 contended allowing businesses to recover GSL payments does not incentivise improved services. It believed businesses should bear the costs for GSL payment categories they have control over (e.g. for late or missed appointments or delays to connections) and 30 per cent of the other payment categories. The CCP17 proposed that the AER actively review the extent to which GSL payments should be met by the business rather than passed to customers.[19]
ECA	Metering	Consultant for ECA, Spencer&Co, was supportive of a reallocation of metering costs where there is no metering competition, as it will make little difference to consumers.[20]
ECA	Yarra Trams	Consultant for ECA, Spencer&Co, was satisfied that the arrangement with Yarra Trams is in the interest of CitiPower's customers. Without access to shared infrastructure, costs to CitiPower's customers would be higher.[21]
ECA	Security of infrastructure	Consultant for ECA, Spencer&Co, stated the requirement to reverse this otherwise efficient decision is being externally imposed on CitiPower and

14 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 55 (Headberry Partners P/L).

15 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 18 (Spencer&Co).

16 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 111.

17 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 55 (Headberry Partners P/L).

18 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 13 (Spencer&Co).

19 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 64–67.

20 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 18 (Spencer&Co).

21 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 21 (Spencer&Co).

Stakeholder	Issue	Summary
		therefore, outside its control. It also considered this step change to be reasonable in the circumstances, particularly as it is based on tendered costs.[22]

6.3 Assessment approach

Our role is to form a view about whether to accept a business's forecast of total opex. Specifically, we must form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[23] In doing so, we must have regard to each of the opex factors specified in the National Electricity Rules (NER).[24]

If we are satisfied the business's forecast reasonably reflects the opex criteria, we must accept the proposed forecast.[25] If we are not satisfied, we must not accept the proposed forecast and must substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria.[26] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business' proposal, and the materiality of the difference. Further, we are required to consider interrelationships with the other building block components of our decision.[27]

As set out in our draft decision in detail, we generally assess a business' forecast total opex using a 'base-step-trend' approach, as summarised in Figure 6.3.[28]

22 Spencer&Co, Report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 21.

23 NER, cl. 6.5.6(c).

24 NER, cl. 6.5.6(e)

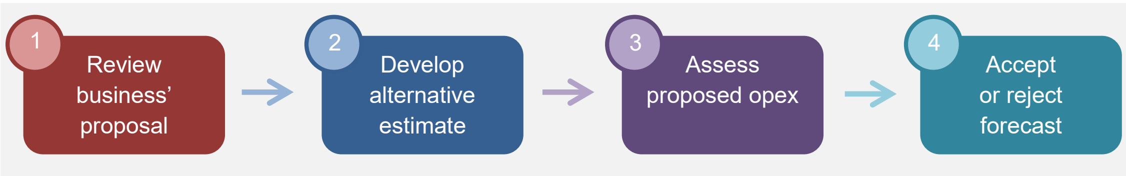
25 NER, cl. 6.5.6(c).

26 NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

27 NEL, s. 16(1)(c).

28 Our base–step–trend approach is also set out in our expenditure guideline. See AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–24.

Figure 6.3 Our opex assessment approach



1. Review business' proposal

We review the business' proposal and identify the key drivers.

2. Develop alternative estimate

Base — We use the business' opex in a recent year as a starting point (revealed opex). We assess the revealed opex (e.g. through benchmarking) to test whether it is efficient. If we find it to be efficient, we accept it. If we find it to be materially inefficient, we may make an efficiency adjustment.

Trend — We trend base opex forward by applying our forecast 'rate of change' to account for growth in input prices, output and productivity.

Step — We add or subtract any step changes for costs not compensated by base opex and the rate of change (e.g. costs associated with regulatory obligation changes or capex/opex substitutions).

Other — We include a 'category specific forecast' for any opex component that we consider necessary to be forecast separately.

3. Assess proposed opex

We contrast our alternative estimate with the business' opex proposal. We identify all drivers of differences between our alternative estimate and the business' opex forecast. We consider each driver of difference between the two estimates and go back and adjust our alternative estimate if we consider it necessary.

4. Accept or reject forecast

We use our alternative estimate to test whether we are satisfied the business' opex forecast reasonably reflects the opex criteria. We accept the proposal if we are satisfied.

If we are not satisfied the business' opex forecast reasonably reflects the opex criteria we substitute it with our alternative estimate.

6.3.1 Interrelationships

In assessing CitiPower's total forecast opex we took into account other components of its proposal and our determination, including:

- the efficiency benefit sharing scheme (EBSS) carryover—the level of opex used as the starting point to forecast opex (the final year of the current regulatory control period (2016–20)) should be the same as the level of opex used to forecast the EBSS carryover. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years

- the operation of the EBSS in the 2016–20 regulatory control period, which provided CitiPower an incentive to reduce opex in the base year
- the impact of cost drivers that affect both forecast opex and forecast capital expenditure (capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex,
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block,
- concerns of electricity consumers identified in the course of CitiPower's engagement with consumers.

6.4 Reasons for final decision

Our final decision is to accept CitiPower's total opex forecast of $476.7 million ($2020–21),[29] including debt raising costs, for the 2021–26 regulatory control period. This is because our alternative estimate of $473.7 million ($2020–21) is not materially different ($3.1 million ($2020–21), or 0.6 per cent, lower) than CitiPower's updated revised total opex forecast proposal. Therefore we consider that CitiPower's total opex forecast satisfies the opex criteria.[30]

We discuss the components of our alternative estimate below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that CitiPower would need for the safe and reliable provision of electricity services over the 2021–26 regulatory control period.

For our final decision we have used base opex of $82.7 million ($2020–21) for each year of the 2021–26 regulatory control period or $413.4 million ($2020–21) over five years to form our alternative estimate.

6.4.1.1 Base year

Consistent with its initial proposal, and our draft decision, CitiPower's revised proposal used 2019 as the base year for opex.[31]

Our position has not changed since the draft decision and we consider 2019 is an appropriate base year as it is representative of the base opex required for the next regulatory control period. We also note that, due to the interaction with the EBSS, we

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29 CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex – update*, December 2020.

30 NER, cl.6.5.6(c).

31 CitiPower, *Revised Regulatory Proposal 2021–26*, December 2020, p. 115.

are generally indifferent to the choice of base year of a distribution business, provided we find its opex efficient.

6.4.1.2 Efficiency of base opex

As outlined in section 6.3, and in our *Expenditure Forecast Assessment Guideline*, our standard approach for forecasting opex is to use a revealed cost approach.[32] 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.

Analysis of CitiPower's revealed costs, as shown in figure 6.1, show a relatively stable trend in CitiPower's opex over current regulatory control period, and opex has been below our approved forecast for this period.

However, we do not rely on the a priori assumption that the business's revealed opex is efficient. We use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently.

As set out in more detail in our draft decision, 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 and opex multilateral partial factor productivity (MPFP) 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.[33] Reflecting our conservative approach, we use a 0.75 comparator point (rather than 1.0) to assess the relative efficiency of distribution businesses.

In our draft decision, we observed that our benchmarking results showed that CitiPower has consistently been amongst the most productive and efficient distributors in the National Electricity Market (NEM) over the last twelve years.[34] Our recent *2020 Annual Benchmarking Report*, published after the draft decision, shows CitiPower continues to perform well, relative to other distribution businesses in the NEM.[35] In particular, CitiPower remains a benchmark comparator business, with an average model score across the 2006–19 period of 0.88 and the 2012–19 period of 0.83, which is above our benchmark comparison point of 0.75. We also observe that CitiPower:

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32 AER, *Expenditure forecast assessment guideline,* November 2013.

33 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 23.

34 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 23–25.

35 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2020, pp. 21–22.

- is second[36] in terms of 2006–19 period-average multilateral total factor productivity (MTFP) which measures the relationship between total output and total input (that is, capital assets and opex).
- is second overall in terms of opex efficiency when measured using our econometric models and opex MPFP[37] over the periods 2006–19 and 2012–19.[38]
- performed well for various total cost and cost category partial performance indicators (PPIs) over the four year period 2015–19. The exceptions are average maintenance opex per circuit kilometre and average emergency response opex per circuit km where it was one of the poorer performers.[39]

We consider that these results warrant the use of revealed costs in 2019 for base opex in our alternative estimate, as it provides an efficient base from which to form the 2021–26 regulatory control period opex allowance.

As in the draft decision, we continue to recognise the potential impact that varying capitalisation practices (the use and/or reporting of opex versus capital) among the businesses may be having on the opex above benchmarking scores. This is an area of ongoing work, and is an issue that we intend to explore further in the context of the *2021 Annual Benchmarking Report.* For the purposes of this final decision, we have re-run the sensitivity analysis for CitiPower described in the draft decision, namely:

- Applying CitiPower's opex/capital ratios as an adjustment to its econometric benchmarking scores, reflecting the relative difference in opex/capital used and reported by CitiPower, as compared to other distribution businesses. We have updated our analysis to use the benchmarking results from the *2020 Annual Benchmarking Report* and to make the adjustments for opex/capital ratio differences using the approach we have set out in the Jemena final decision.[40]
- Replicating our benchmarking efficiency analysis using a backcast of opex under distribution businesses' current cost allocation methodologies (CAMs), including CitiPower's opex under its 2016 CAM. We have updated our analysis to use the benchmarking results from the *2020 Annual Benchmarking Report*.

This sensitivity analyses continues to indicate that CitiPower's historical and base year opex is not materially inefficient.

The base year opex we use in our alternative estimate is $82.7 million ($2020–21) which is consistent with CitiPower's revised proposal. This figure has been updated from the draft decision to reflect the updated inflation forecast for the year ending June

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36 AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2020, p. 21.

37 MPFP examines the productivity of opex and capital inputs in isolation. Opex MPFP considers the productivity of the distributor's operating expenditure.

38 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2020. pp. 32–33.

39 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2020. pp. 34–43.

40 See AER, *Final Decision, Jemena 2021–26, Attachment 6, Operating expenditure*, April 2021, section 3.1.4.2 and Appendix C.

2021 in the Reserve Bank of Australia's February 2021 *Statement on monetary policy.*[41]

6.4.1.3 Final year increment

Our standard practice to estimate final year opex is to add the difference between the opex forecast for the final year of the preceding regulatory control period and the opex forecast for the base year to the amount of actual opex in the base year.[42] As a result of the six month extension to the current regulatory control period, we have updated our final year increment calculation in our alternative estimate by exchanging the opex forecast for the final year of the preceding regulatory control period with the annualised half year 2021 forecast.

6.4.1.4 Base adjustments

Advanced metering infrastructure (AMI) communications network

Consistent with our draft decision,[43] our alternative estimates includes a base adjustment of $1.0 million ($2020–21) for the reclassification of AMI communications network costs.

Table 6.4 Reclassification of AMI communication costs ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower's revised proposal	0.7	0.7	0.7	0.7	0.7	**3.7**
AER final decision	0.2	0.2	0.2	0.2	0.2	**1.0**
Difference	–0.5	–0.5	–0.5	–0.5	–0.5	**–2.6**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision,[44] we did not consider the meter power quality data volumes proposed by CitiPower to allocate AMI communications network costs between standard control services (SCS) and alternative control services (ACS) were justified. CitiPower proposed an allocation of 88.0 per cent for SCS and 12.0 per cent for ACS based of the proportion of AMI meter data collected for SCS purposes relative to ACS purposes. Our draft decision alternative estimate included an estimate of

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41 Reserve Bank of Australia, *Statement on monetary policy*, February 2021.

42 AER, *Expenditure forecast assessment guideline,* November 2013. pp. 22–23.

43 AER, *Draft Decision*, *CitiPower 2021–26, Attachment 6, Operating expenditure***,** September 2020, p. 29.

44 AER, *Draft Decision*, *CitiPower 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 29; AER, *Draft Decision, CitiPower 2021–26, Attachment 16, Alternative Control Services,* September 2020, pp. 33–38, 41–43.

AMI communications network costs based on an allocation of 25.0 per cent for SCS and 75.0 per cent for ACS.

CitiPower's revised proposal reproposed allocating 88.0 per cent of its AMI communications network costs from ACS to SCS based on the findings of an independent review conducted by Operational Technology Solutions.[45] The review assessed which network management activities require AMI meter data and the frequency and population size of AMI meter data required to deliver these activities.

Based on our assessment of the information provided by CitiPower, we do not consider that the AMI meter power quality data volumes proposed by CitiPower for network management activities are required. For our alternative estimate, we have maintained our draft decision position to allocate AMI communications network costs based on an allocation of 25.0 per cent for SCS and 75.0 per cent for ACS. Further details, including the reasons for our maintaining our approach, are set out in Attachment 16 - Alternative control services.

Emergency recoverable works

Consistent with our draft decision,[46] our final decision is to include a base adjustment of $1.1 million ($2020–21) in our alternative estimate for the reclassification of emergency recoverable works.

Table 6.5 Emergency recoverable works ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower's revised proposal	0.2	0.2	0.2	0.2	0.2	**1.1**
AER final decision	0.2	0.2	0.2	0.2	0.2	**1.1**
Difference	–	–	–	–	–	**–**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that the proposed reclassification of emergency recoverable works as SCS was consistent with our *Framework and Approach* paper.[47] We also considered the costs proposed by CitiPower were reasonable because they were based on historical actual costs incurred.[48]

45 CitiPower*, 2021–26 Revised Proposal – Supporting document ATT37 – OTS AMI data for network management*, December 2020, p. 3.

46 AER, *Draft Decision*, *CitiPower 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 28–29.

47 AER, *Final Framework and Approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 26–27.

48 AER, *Draft Decision*, *CitiPower 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 29.

CitiPower's revised proposal accepted our draft decision position.[49] We have included this base adjustment in our alternative estimate, updating the costs to account for the latest inflation forecasts.[50]

Wasted truck visits

Consistent with our draft decision,[51] our final decision is to include a base adjustment of $2.0 million ($2020–21) in our alternative estimate for the reclassification of wasted truck visits.

Table 6.6 Wasted truck visits ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower's revised proposal	0.4	0.4	0.4	0.4	0.4	**2.0**
AER final decision	0.4	0.4	0.4	0.4	0.4	**2.0**
Difference	–	–	–	–	–	**–**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that the proposed reclassification of wasted truck visits for network faults that turn out to be due to faults on the customer's side of the meter was consistent with our *Framework and Approach* paper.[52] We also considered the costs proposed by CitiPower were reasonable as they were based on historical actual costs incurred.[53]

CitiPower's revised proposal accepted our draft decision.[54] We have included this base adjustment in our alternative estimate, updating the costs to account for the latest inflation forecasts.[55]

Repair works

Our final decision is to include a base adjustment of $10.2 million ($2020–21) in our alternative estimate to account for costs related to the reclassification of repair works from capex to opex over the 2021–26 regulatory control period. This differs from our draft decision, where we did not include the proposed costs in our alternative estimate.

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49 CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 121.

50 Reserve Bank of Australia, *Statement on monetary policy*, February 2021.

51 AER*, Draft Decision*, *CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 28.

52 AER*, Final Framework and Approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 32.

53 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 28.

54 CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 121.

55 Reserve Bank of Australia, *Statement on monetary policy*, February 2021.

Table 6.7 Reclassification of minor repairs ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower's revised proposal	2.1	2.1	2.1	2.1	2.1	**10.6**
AER final decision	2.0	2.0	2.0	2.0	2.0	**10.2**
Difference	–0.1	–0.1	–0.1	–0.1	–0.1	**–0.4**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In the draft decision[56] we did not include in our alternative estimate a base adjustment of $20.5 million ($2020–21) to reclassify minor repair works as opex, as proposed by CitiPower.[57] We agreed with our consultant EMCa's assessment that:

- CitiPower did not provide a clear auditable definition to distinguish when a repair is capex or opex
- CitiPower's minor repairs costs, claimed to be based on actual historical costs, were not consistent with either historical information in its recast RIN or aggregated unitised project cost information.

In its revised proposal[58] CitiPower proposed a base adjustment of $10.6 million ($2020–21) reclassifying from capex to opex repair works resulting from either asset faults of identified asset defects. CitiPower's revised proposal is $9.9 million ($2020–21) lower than its original proposal of $20.5 million ($2020–21) reflecting CitiPower's revised granular approach to better identify jobs that are more appropriately classified as repairs rather than asset replacement. The proposed repair works base adjustment amount of $10.6 million ($2020–21) is the five-year historical average of repair works costs.

We requested that CitiPower provide further information to support the revised proposed expenditure costs to be reclassified due to the significant difference in the methodology and granularity of the data provided for reclassification in its revised proposal compared to its initial proposal. CitiPower's response explained the reasons for variations in repair works cost estimates, and provided a report setting out a detailed description of repair works to be reclassified as opex by repair categories and historical unitised data to demonstrate volumes of works and unit rates.[59] CitiPower also engaged Deloitte to undertake a limited assurance engagement audit review which concluded 'nothing has come to our attention that causes us to believe that the "financial information" of CitiPower included within the Tables does not present fairly, in

56 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 26–28.

57 CitiPower, *2021–26 Regulatory Proposal*, January 2020, p. 106.

58 CitiPower*, Revised Regulatory Proposal 2021–26*, December 2020, p. 121.

59 CitiPower, *Information Request #067 – Reclassification of Minor Repairs*, December 2020.

all material respects, in accordance with the Basis of Preparation'.[60] CitiPower considered the repair categories presented and the proposed expenditure amounts should be treated as opex because they were only for repair works and did not extend the life of, or create a new asset.[61]

We reviewed the repair categories provided by CitiPower to assess whether they represent only repair works that do not extend asset lives or create new assets. Our review concluded this was the case for all categories, except for zone sub switchyard lighting, and it is appropriate to classify these categories as opex. We do not consider that zone sub switchyard lighting should be classified as opex because, while the work would not extend the life of a zone substation, it would replace the existing end of life lighting asset, or improve zone substation lightning asset function and performance.

Accordingly, we consider it is appropriate to include in our alternative estimate a base adjustment for repair works which includes all of the repair categories proposed by CitiPower with the exception of zone sub switchyard lighting. Consistent with EMCa's advice for the draft decision on how to forecast minor repairs costs for United Energy,[62] we consider the use of a five-year historical average is reasonable. Based on the information responses and Deloitte's audit review, we are satisfied the historical cost information provided by CitiPower can be used to estimate repair works costs for the 2021–26 regulatory control period.

Our alternate estimate includes a base adjustment of $10.2 million ($2020–21) for the reclassification of repair works from capex to opex. This includes all of the repair costs proposed by CitiPower except for zone sub switchyard lighting.

ESV levies

Our final decision is to remove ESV levies from base opex in our alternative estimate as they will be recovered via the price control mechanism over the 2021–26 regulatory control period following our decision on 19 March 2021 to approve the ESV levy as a jurisdictional scheme.[63] This is consistent with CitiPower's updated revised proposal, which removed ESV levy costs from base opex.[64]

Table 6.8 ESV levy ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower's revised proposal	–1.2	–1.2	–1.2	–1.2	–1.2	**–5.9**
AER final decision	–1.2	–1.2	–1.2	–1.2	–1.2	**–5.9**
Difference	–	–	–	–	–	**–**

60 CitiPower, *Revised Regulatory Proposal 2021–26, ATT55 Reclassification of Repairs,* December 2020.

61 CitiPower, *Information Request #067 – Reclassification of Minor Repairs*, December 2020.

62 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, pp. 221.

63 AER*, Determination on CPU jurisdictional scheme request*, March 2021.

64 CitiPower*, Revised Regulatory Proposal – 2021–26 – APP08 – L–factor additions*, December 2020, p. 6.

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

CitiPower's initial proposal sought a step change for expected increases in ESV levies over the 2021–26 regulatory control period. Our draft decision did not include this proposed step change in our alternative estimate because:[65]

- base opex already reflects the cost of meeting existing regulatory obligations, including the obligation to pay the ESV levy
- changes in specific costs should be managed within:
    - the existing base as the cost of other projects or programs decline. A rise in a single cost category is not sufficient to justify a step change, and/or
    - the rate of change forecast which escalates base opex to capture real increases in input prices and output growth (net of productivity growth).

In its revised proposal, CitiPower proposed to recover the ESV levies through the price control mechanism. It stated it is an unavoidable cost, outside of its control and not captured by the rate of change.[66]

The VCO's submission was supportive of our draft decision and considered the ESV levy increases should be absorbed by the businesses.[67] However, ECA's consultant Spencer&Co, supported moving the ESV levy into the price control mechanism, on the basis that these fees are outside the control of the business.[68]

On 25 February 2021, CitiPower, Powercor and United Energy submitted an application to request that the AER determine the ESV levy is a jurisdictional scheme.[69] We considered that the ESV levy meets the jurisdictional scheme criteria, and we determined that ESV levy is a jurisdictional scheme.[70] Further details are in our decision.[71] In this distribution determination, we have also made a decision on how CitiPower and the other Victorian businesses are to report to the AER on its recovery of the jurisdictional scheme amounts for the scheme and on the adjustments to be made to pricing proposals to account for over and under recovery.[72] As a result of the ESV levy becoming an approved jurisdictional scheme for CitiPower, the scheme

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65 AER*, Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, pp. 55–57.

66 CitiPower*, Revised Regulatory Proposal 2021–26 – APP08 – L–factor additions,* December 2020, pp. 6–9.

67 Victorian Community Organisations*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals,* January 2021, p. 55 (Headberry Partners P/L).

68 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 18 (Spencer&Co).

69 CitiPower. Powercor and United Energy, *Jurisdictional scheme determination request,* February 2021.

70 NER, cll. 6.18.7A(n) and 6.18.7A(x).

71 AER*, Determination on CPU jurisdictional scheme request*, March 2021.

72 NER, cl, 6.12.1(20) and AER, *Final decision, CitiPower distribution determination 2021–26 – Overview*, April 2021, Appendix A; AER, *Final decision, CitiPower distribution determination 2021–26, Attachment 14 Control mechanisms*, April 2021, Appendix D.

amounts are recovered via the price control mechanism, and therefore we have removed such costs from total opex in our alternative estimate.

We note that while the ESV levy meets the jurisdictional scheme criteria, we consider from a policy perspective there is a strong case for such costs to remain in base opex. The reasons for this are:

- While they are costs which may be outside the control of the distributor, neither opex nor the EBSS within our framework distinguishes between controllable and uncontrollable costs. As stated in our explanatory statement for the EBSS,[73] to do so would weaken the incentive framework and there is no compelling reason to share the cost of uncontrollable events between consumers and the distributor differently to all other costs faced by the distributor. Uncontrollable costs present both upside and downside risks to distributors, with any material risks able to be managed via pass-through events and contingent projects. So while levies and licence fee costs may be largely out of the control of businesses, this should not preclude them from being included in our total opex forecast and subject to the EBSS.
- While we recognise that licence fee and levy costs may be volatile, our top down approach looks at total opex. As explained in our assessment approach in the draft decision[74] 'even if disaggregated opex categories have high volatility, the total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year to year—to the extent they do not offset each other—by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.'
- Increasing the number of items included in the price control mechanism makes it difficult for consumers to know how much tariffs will change year to year if they are subject to numerous adjustments.

CitiPower's revised proposal also sought to recover changes in expected Australian Energy Market Operator (AEMO) fees through the price control mechanism for similar reasons it outlined in its revised proposal for ESV levies.[75]

On 26 March 2021, AEMO published its final report on *Electricity Fee Structures* which determined that distributors will not be charged participant fees for the next fee period.[76] As a result of AEMO's final report there is no need to include these fees in the price control formula.

[73] AER, *Explanatory statement, Efficiency benefit sharing scheme, November 2013,* pp. 19–21.

[74] AER*, Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 16.

[75] CitiPower, *2021–26 Revised Regulatory Proposal – APP08 – L–factor additions*, December 2020, pp. 6–9.

[76] AEMO, *Final Report and Determination, Electricity Fee Structures,* March 2021, p. 5.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[77]

In its revised proposal, CitiPower applied our standard approach to forecasting the rate of change. Specifically it:

- **Output growth:** adopted the output weights, measures and vales we used in our draft decision.[78]
- **Price growth:** adopted our input price weightings of 59.2 per cent labour and 40.8 per cent non-labour and an average of Wage Price Index (WPI) price growth forecasts from Deloitte and BIS Oxford Economics for labour price growth.[79]
- **Productivity growth:** adopted our productivity growth forecast of 0.5 per cent per year.[80]

The rate of change proposed by CitiPower contributes $10.0 million ($2020–21), or 2.1 per cent, to CitiPower's revised proposal total opex forecast of $476.7 million ($2020–21). This equates to opex increasing on average by around 0.8 per cent each year in the next regulatory control period.[81]

We have included a rate of change that on average increases opex by around 0.7 per cent each year in our alternative estimate. We have set out in table 6.9 CitiPower's updated revised proposal and our alternative estimates of each component of the rate of change. We have set out the reasons for our forecast below.

We received one submission, from the VCO, relating to the rate of change. It generally supported our approach to forecast the rate of change in our draft decision, specifically how we accounted for the impact of COVID 19. The VCO stated that we should apply the same approach across all the Victorian businesses.[82] We have considered this submission in making our final decision.

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77 AER, *Expenditure forecast assessment guideline*, November 2013, pp. 23–24.

78 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

79 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122; CitiPower, *Revised Regulatory Proposal – 2021–26, MOD 10.06, Opex*, December 2020.

80 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

81 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

82 Victorian Community Organisations*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals,* January 2021, p. 52 (Headberry Partners P/L).

Table 6.9 Forecast rate of change, per cent

	2021–22*	2022–23	2023–24	2024–25	2025–26
CitiPower's revised proposal					
Price growth	0.5	0.3	0.4	0.6	0.8
Output growth	0.5	0.8	0.9	0.9	0.9
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	**0.6**	**0.6**	**0.8**	**1.0**	**1.2**
AER final decision					
Price growth	0.5	0.4	0.4	0.4	0.6
Output growth	0.5	0.8	0.9	0.9	0.8
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	**0.6**	**0.7**	**0.8**	**0.8**	**0.9**
Overall difference	**–0.0**	**0.1**	**–0.1**	**–0.2**	**–0.2**

* The rate of change for 2021–22 reflects nine months' worth of growth in price, output and productivity to account for the extension of the current regulatory control period by six months to transition the timing of the regulatory control period for Victorian electricity distribution networks from a calendar year basis to a financial year basis. We discuss the reasons for this in our draft decision.

Source: CitiPower, *Revised regulatory proposal – 2021–26, MOD 10.06, Opex*, December 2020; AER analysis.

6.4.2.1 Forecast price growth

We have included forecast average annual real price growth of 0.4 per cent in our alternative opex estimate. This compares to CitiPower's proposed average annual price growth of 0.5 per cent.[83] This increases our alternative estimate of total opex by $5.7 million ($2020–21), instead of $5.8 million ($2020–21) as proposed by CitiPower.

Our real price growth forecast is a weighted average of forecast labour price growth and non-labour price growth:

- To forecast labour price growth we use the forecast of growth in the WPI for the Victorian electricity, gas, water and waste services (utilities) industry. Specifically, we have used an average of forecasts from our consultant Deloitte and the BIS Oxford forecasts submitted by CitiPower. In our draft decision we did not use the BIS Oxford forecasts submitted by CitiPower with its regulatory proposal because we considered they did not account for the COVID–19 pandemic or the legislated

[83] CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

changes to the superannuation guarantee.[84] The revised BIS Oxford forecasts submitted by CitiPower now account for both of these issues.[85]

- Both we and CitiPower applied a forecast non-labour real price growth rate of zero. This is consistent with our draft decision and CitiPower's initial and revised proposals.[86]
- We applied benchmark input price weights of 59.2 per cent and 40.8 per cent for labour and non-labour, respectively. These are the weights we use for our econometric modelling in our annual benchmarking report.[87] This is consistent with our draft decision and CitiPower's revised proposals.[88]

Consequently, we and CitiPower have applied the same approach to forecast price growth. The only differences between our real price growth forecasts and CitiPower's is that we have:

- used more recent forecasts of WPI growth from Deloitte[89]
- adjusted BIS Oxford Economics' WPI growth forecast for 2021–22 to reflect the growth between the average WPI value for the first six months of calendar year 2021 and the average value for the 2021–22 financial year. This is to account for the shift from calendar years to financial years and is the same approach we adopted for the draft decision.[90]

6.4.2.2 Forecast output growth

We have included forecast average annual output growth of 0.8 per cent in our alternative opex forecast. This increases our alternative estimate of total opex by $9.8 million ($2020–21) instead of $10.3 million ($2020–21) as proposed by CitiPower. The difference between us and CitiPower is due to updating output weights, which we discuss below.

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84 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 31.

85 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

86 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 31; CitiPower, *2021–26 Regulatory proposal*, January 2020, p. 107; CitiPower, *Revised Regulatory Proposal – 2021–26, MOD 10.06, Opex*, December 2020.

87 Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights,* 18 May 2020, p. 8.

88 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 31–32; CitiPower, *Revised Regulatory Proposal – 2021–26, MOD 10.06, Opex*, December 2020.

89 Deloitte Access Economics, *Wage Price Index forecasts*, 1 April 2021, p. xiii.

90 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 44.

CitiPower also included an average annual output growth forecast of 0.8 per cent in its revised proposal.[91] This reflects a change from the approach it adopted to forecast output growth in its initial proposal.

In its initial proposal, CitiPower proposed that we forecast output growth using only the output weights from the results of our two Cobb Douglas econometric models.[92] In our draft decision we outlined reasons why we considered all five of our economic benchmarking models should be used.[93] CitiPower adopted the approach we used in our draft decision in its revised proposal.[94]

In our draft decision we stated that we would update the output weights to reflect the results from all five of our economic benchmarking models in the *2020 Annual Benchmarking Report*, which we published in November 2020.[95]

For this final decision, we have used the updated weights derived from the *2020 Annual Benchmarking Report* to forecast our alternative estimate of forecast opex. As set out below, in addition to updating these weights to reflect the results in the most recent benchmarking report, we have also considered the appropriate weights to use in response to feedback received as a part of the Victorian resets. In summary, we have forecast output growth by:

- Calculating the growth rates for three outputs (customer numbers, circuit line length and ratcheted maximum demand). This is a change from our draft decision where we also used energy throughput. CitiPower used the output measures we used for our draft decision, including energy throughput.[96]
- Calculating four weighted average overall output growth rates for these three outputs using the output weights from four of the five models presented in our *2020 Annual Benchmarking Report* (see table 6.10). We did not use the opex MPFP model for this final decision. We discuss the reasons for this below.
- For our translog models, calculating the elasticities at the full sample mean. For our draft decisions we calculated the elasticities at the Australian sample mean, which is the approach CitiPower also adopted in its revised proposal. We discuss the reasons for this change in approach below.
- Averaging the four model-specific weighted overall output growth rates.

The output weights that we have used in our alternative estimate for the final decision are set out in table 6.10.

91 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

92 CitiPower, *2021–26 Regulatory Proposal*, January 2020, pp. 110–112.

93 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 38–43.

94 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

95 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 38–39.

96 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

Table 6.10 Output weights, per cent

	Cobb-Douglas SFA	Cobb-Douglas LSE	Translog LSE	Translog SFA	Average	Draft decision average
Customer numbers	50.9	63.3	49.5	59.3	55.7	52.5
Circuit length	14.9	16.4	16.6	14.2	15.5	20.7
Ratcheted maximum demand	34.2	20.3	33.9	26.5	28.7	25.1
Energy throughput	–	–	–	–	–	1.7

Source: Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, 13 October 2020, pp. 149–151; AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 38.

Note Numbers may not add up to 100 per cent due to rounding. Energy throughput is only used in the opex MPFP model.

The difference between our output growth forecasts and CitiPower's updated revised proposal is due to us:

- updating output weights to reflect our 2020 annual benchmarking results as stated in the draft decision[97]
- not using the opex MPFP output weights and consequently not including energy throughput in forecasting our output growth (see below)
- using output weights from the translog opex cost function with data normalised by the full sample means (see below).

The difference between CitiPower's updated revised proposal output growth forecast and ours because of these changes is immaterial.

CitiPower accepted our draft decision on the forecast growth of the individual output measures and we have maintained them in developing our alternative estimate.[98]

Exclusion of opex MPFP weights from our alternative output growth forecast

Our standard approach to forecast output growth has been to calculate the average output growth across all of the benchmarking models we have published in our most recent annual benchmarking report. For our draft decision, this was four econometric methods (two Cobb-Douglas (CD SFA and CD LSE) and two translog (TLG SFA and

97 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 38–39.

98 CitiPower, *Revised Regulatory Proposal 2021–26*, December 2020, p. 122.

TLG LSE)) and one using the partial productivity index number method (opex MPFP).[99] In its revised proposal as part of the Victorian distribution resets, Jemena and its consultant, CEPA, submitted that it was inappropriate to use the opex MPFP output weights for the purpose of trending opex forward because they reflect drivers of total cost, not relationship between output and opex.[100] CitiPower, Powercor and United Energy also raised concerns with using the opex MPFP weights, although they did use them in their revised proposals.[101]

We agree that we should not include the opex MPFP weights in determining our forecast of output growth because they reflect drivers of, and relationship with total cost, not necessarily opex. This is consistent with our consultant Economic Insights' view.[102] Consequently, we have not used the output weights from this model, or energy throughput as an output measure, in this final decision (opex MPFP benchmarking is the only model that includes this output).

Translog cost function weights

For this final decision, we have calculated the Translog elasticities at the full sample mean. In our draft decision, we calculated the output weights from the translog opex cost function models at the Australian average output level, rather than at the average output levels of all distributors in the international sample.[103] We adopted this approach in response to concerns raised by Frontier Economics in a report submitted with CitiPower's, Powercor's and United Energy's initial proposals.[104] Frontier Economics contended the output elasticities (used to determine the output weights) should be evaluated at output levels that reflect the operating characteristics of Australian distributors.

Our consultant, Economic Insights agreed there was some merit in calculating the output weights from the translog opex cost function models at the Australian average output level.[105] However, in its *2020 Benchmarking report*, Economic Insights advised against making this change until there has been sufficient opportunity to review the performance of the translog models. The inclusion of additional data from 2019 raised

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99 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 38.

100 CEPA, *AERs opex benchmarking a review of the impact of capitalisation and model reliability*, December 2020, p. 27; Jemena, *Revised Regulatory Proposal – 2021–26, Attachment 05–01, Operating expenditure*, December 2020, p. 26.

101 CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122.

102 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 5.

103 AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 42–43.

104 Frontier Economics, *Review of econometric models used by the AER to estimate output growth*, 5 December 2019, pp. 16–18.

105 Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 20.

a number of monotonicity violation concerns with the Australian distributors.[106] We agree with this advice and we will continue to monitor the performance of our translog cost function as part our ongoing benchmarking development.[107]

6.4.2.3 Forecast productivity growth

Consistent with our draft decision, we have forecast annual productivity growth of 0.5 per cent.[108] This reduces our alternative estimate of total opex by $6.0 million ($2020–21). CitiPower also adopted an annual productivity growth forecast of 0.5 per cent in its revised proposal, consistent with its initial proposal.[109]

6.4.3 Step changes

In its revised proposal, CitiPower reproposed four of the eight step changes from its initial proposal (some with minor adjustments).[110]

Table 6.11 summarises the step changes CitiPower included in its initial and revised proposals, our draft decision and our alternative estimate for the purpose of the final decision. In its revised proposal, CitiPower's step changes total $13.9 million ($2020–21).

We have included $13.2 million ($2020–21) for four step changes in our alternative estimate for the final decision. We have examined each step change on its own merit and whether the proposal meets the intent of what step changes should reflect as set out in the *Expenditure Forecast Assessment Guideline*.[111]

Table 6.11 CitiPower's step change proposals and our alternative estimate ($ million, 2020–21)

Step change	CitiPower initial proposal	AER draft decision	CitiPower revised proposal	AER alternative estimate for Final Decision	Difference
Yarra trams pole relocation	14.4	–			
Security of critical	14.4	13.4	8.9	8.8	–0.0

[106] Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 13.

[107] For more detail about issues on the performance of the translog cost function of our benchmarking analysis, see: Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 34.

[108] AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 44.

[109] CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 122; CitiPower, *2021–26 Regulatory proposal*, January 2020, p. 113.

[110] CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 123–124.

[111] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

Step change	CitiPower initial proposal	AER draft decision	CitiPower revised proposal	AER alternative estimate for Final Decision	Difference
infrastructure					
EPA regulations change	6.1	withdrawn			
IT cloud solutions	2.3	2.2	2.2	2.2	–0.0
5 minute settlement	1.9	1.8	1.8	1.8	–0.0
Financial year RIN	1.8	–			
ESV levy	1.5	–			
Solar enablement	1.3	–	1.0	0.4	–0.7
Total step changes	**43.6**	**17.3**	**13.9**	**13.2**	**–0.7**

Source: CitiPower, *2021–26 Regulatory proposal*, *January 2020, pp. 99, 102*; AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 45; CitiPower, *Revised Regulatory Proposal – 2021–26*, December 2020, p. 112; CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex*, December 2020; CitiPower, *Revised Regulatory Proposal – 2021–26 – MOD 10.06 – Opex – updated*, December 2020; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

The following sections sets out the reasons for our alternative estimate of each step change.

6.4.3.1 Solar enablement

Our final decision is to include a step change of $0.4 million ($2020–21) for solar enablement in our alternative estimate. This differs from our draft decision to not include this step change in our alternative estimate.[112]

Table 6.12 Solar enablement ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower revised proposal	0.3	0.2	0.3	0.1	0.1	**1.0**
AER final decision	0.1	0.1	0.1	0.0	0.0	**0.4**
Difference	–0.2	–0.2	–0.2	–0.1	–0.1	**–0.7**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

[112] AER, *Draft decision, CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, pp. 57–59.

Note: Numbers may not add due to rounding. Differences of ‘0.0’ and ‘–0.0’ represent small variances and ‘–‘ represents no variance.

In our draft decision, we did not include the proposed $1.3 million ($2020–21) step change in our alternative estimate to tap down distribution transformers to remove voltage constraints, and to undertake a monitoring and compliance regime to improve compliance of inverter settings. This was for two key reasons:[113]

- Based on advice from our consultant, EMCa, we were not satisfied CitiPower had explored other potential cost-effective options to proactively ensure correct inverter settings are applied to address non-compliance.
- We agreed with our consultant, EMCa, that while the proposed tapping activities and volume are prudent and reasonable, it did not consider CitiPower’s unit cost of $1959 ($2020–21) is efficient, concluding that an efficient unit cost for tapping would be under $1000 ($2020–21). Based on EMCa’s advice, we adjusted CitiPower’s tapping costs from $0.7 million ($2020–21) to $0.3 million ($2020–21) or $0.4 million ($2020–21) depending on whether a unit cost of $865 or $1000 is used. Our draft decision considered these costs to be immaterial and should be managed within CitiPower’s total forecast opex.

In its revised proposal, CitiPower adjusted its proposal from $1.3 million ($2020–21) to $1.0 million ($2020–21) for this step change. It submitted:[114]

- A revised unit cost of $1535 (down from $1959 in CitiPower’s initial proposal), which is consistent with United Energy’s rate. CitiPower considered this rate as efficient and reflects the rate agreed to following a competitive tender process with United Energy’s provider, Zinfra;[115] and
- Its monitoring and compliance program, as it considered the only other alternative means to ensure compliance is costly augmentation.[116]
- Additionally, CitiPower’s revised proposal raised concerns that it was inappropriate to not include step changes in our alternative estimate on the basis of materiality in our draft decision.[117] CitiPower contended this approach in the draft decision was not consistent with the NER, which does not stipulate a materiality threshold in the opex criteria. Further, CitiPower considered that the proposed step change

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[113] AER, *Draft decision CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020 pp. 57–59.

[114] CitiPower, *Revised Regulatory Proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, p. 17.

[115] CitiPower, *Revised Regulatory Proposal 2021–26 – Supporting document BUS 9.06 – Other step changes*, December 2020, pp. 9, 14.

[116] CitiPower, *Revised Regulatory Proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, p. 16.

[117] CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 114.

represents an efficient capex/opex trade-off, and the rate of change fails to adequately capture the increasing growth in distributed energy resources.[118]

For the final decision, we have included $0.4 million ($2020–21) in our alternative estimate to undertake tapping activities at the downward adjusted cost of $1000 per unit. The reasons for this are:

- Our review of the scope of work statement included in Zinfra's $1535 unit cost found it included 'surveying, installing and removing power quality loggers, phase balancing and tap changing'.[119] This indicates CitiPower's proposed unit cost is a blended unit rate which also includes other types of work such as voltage surveys and phase rebalancing work. As the proposed step change only includes tapping activities, we consider the unit rate cost should be adjusted to account for this.
- Based on advice from EMCa for our draft decision,[120] we consider a unit cost for tapping of $1000 is reasonable.

Consistent with our draft decision, we do not consider that CitiPower's monitoring and compliance program is prudent and efficient. CitiPower has not been able to justify that the proposed solution is the most cost effective option to address non-compliance of solar installations. CitiPower submitted that it 'had not modelled a complete cost-benefit analysis of ensuring compliance'.[121]

We did not include this amount in our draft decision on the basis that we considered it immaterial.[122] For clarity, when we consider materiality in the context of step change assessments, what we mean is whether the costs of the step change are double counted in other elements of the opex forecast.[123] In light of the concerns raised by CitiPower in relation to materiality, we have re-considered whether this step change should be included in our alternative estimate. We have included this step change in our alternative estimate on the basis that output growth does not fully account for growing distributed energy resources, and in these circumstances it may be appropriate to allow a step change for distributed energy resources management.[124]

Therefore for the final decision we have included an adjusted step change of $0.4 million ($2020–21) for solar enablement in our alternative estimate.

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118 CitiPower, *Revised Regulatory Proposal 2021–26 – Supporting document BUS 9.06 – Other step changes,* December 2020, pp. 4–5.

119 United Energy, *Information request 68, Q–3,* 7 January 2021, p. 3.

120 AER, *Draft decision CitiPower distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 58.

121 CitiPower, *Information request 70, Q–2,* 7 January 2021, p. 2.

122 AER, *Draft decision CitiPower distribution determination 2021–26, Attachment 6 Operating expenditure,* September 2020 p. 59.

123 AER, *Expenditure forecast assessment guideline,* November 2013. p. 24.

124 AER*, Draft decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 58.

6.4.3.2 IT cloud solutions

Consistent with our draft decision,[125] our final decision is to include a step change of $2.2 million ($2020–21) for the migration of a number of ICT applications to cloud hosting in our alternative estimate.

Table 6.13 IT cloud ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower revised proposal	0.3	0.3	0.5	0.6	0.6	**2.2**
AER final decision	0.3	0.3	0.5	0.5	0.5	**2.2**
Difference	0.0	0.0	0.0	0.0	0.0	**0.0**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.
Note: Numbers may not add due to rounding. Differences of ‘0.0’ and ‘–0.0’ represent small variances and ‘–‘ represents no variance.

In our draft decision, we concluded that the IT cloud proposal was an efficient capex-opex trade-off and the lowest cost option to meet their ICT infrastructure needs.

CitiPower’s revised proposal accepted our draft decision position.[126] We have included this step change in our alternative estimate, updating the costs to account for updated inflation forecasts and our forecast of price growth for the final decision.

6.4.3.3 Security of critical infrastructure

Consistent with our draft decision,[127] our final decision is to include $8.8 million ($2020–21) for compliance with new critical infrastructure requirements in our alternative estimate. This is less than the $13.4 million ($2020–21) included in our draft decision alternative estimate step change.

Table 6.14 Security of critical infrastructure ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower’s revised proposal	2.4	1.7	1.7	1.5	1.5	**8.9**
AER final decision	2.4	1.7	1.6	1.5	1.5	**8.8**
Difference	0.0	0.0	–0.0	–0.0	–0.0	**–0.0**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.
Note: Numbers may not add due to rounding. Differences of ‘0.0’ and ‘–0.0’ represent small variances and ‘–‘ represents no variance.

125 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, pp. 49–52.
126 CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 118.
127 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, pp. 48–49.

In our draft decision we were satisfied CitiPower is subject to new regulatory obligations which require them to comply with critical infrastructure system and data control requirements.[128] CitiPower is expected to transition to compliance in accordance with the work plan approved by the Australian Government.[129]

We also noted that we expect CitiPower to update its forecast in its revised proposal following the results of a competitive tender process to ensure the step change forecast reflects the most cost-efficient option. CitiPower's revised proposal included an updated step change amount in its revised proposal of $8.9 million ($2020–21).[130] This was a reduction of $5.5 million ($2020–21) compared to the forecast included in the initial proposal. We have examined the updated cost information and consider CitiPower have provided sufficient documentation to demonstrate it has undertaken market testing. On this basis, it is reasonable to include the proposed step change amount in our alternative estimate.

We have also updated the step change amount to account for the latest inflation forecasts and our forecast of price growth for the final decision.

6.4.3.4 Five minute settlement

Consistent with our draft decision,[131] our final decision is to include $1.8 million ($2020–21) in our alternative estimate.

Table 6.15 Five minute settlement ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower revised proposal	0.2	0.3	0.4	0.4	0.5	**1.8**
AER final decision	0.2	0.3	0.4	0.4	0.5	**1.8**
Difference	0.0	–0.0	–0.0	–0.0	0.0	**–0.0**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that the proposal was prudent to meet the five minute settlement rule published by the Australian Energy Market Commission (AEMC) on 28 November 2017[132] and made minor adjustments to the proposed cost to align with our rate of change decision.[133]

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128 AER, *Draft Decision, CitiPower 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 48.

129 CitiPower, *Regulatory proposal 2021–26,* January 2020, p. 100.

130 CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 124.

131 AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 52.

132 AEMC, *National Electricity Amendment (Five Minute Settlement) Rule 2017, Rule determination,* 28 November 2017.

133 AER, *Draft Decision*, *CitiPower 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 52–54.

CitiPower's revised proposal accepted our draft decision position.[134] We have included this step change in our alternative estimate, updating the costs to account for updated inflation forecasts and our forecast of price growth for the final decision

6.4.4 Category specific forecasts

We have included two expenditure items, debt raising costs and GSL payments, in our alternative estimate of total opex which we did not forecast using the base-step-trend approach.

6.4.4.1 GSL payments

We have included GSL payments of $0.1 million ($2020–21) as a category specific forecast in our alternative estimate. This is consistent with CitiPower's revised proposal[135] and is $0.2 million ($2020–21) lower than our draft decision.[136]

The Essential Services Commission of Victoria (ESCV) concluded its review of the consumer protection framework in the Electricity Distribution Code on 16 November 2020. The final decision included updates to the GSL scheme.[137] Notably, there have been changes to the value of payments, payment thresholds and the introduction of exclusions for major event days. We stated in our draft decision that we would update our forecast of GSL payments in this final decision to reflect the revisions made to the GSL scheme by the ESCV.[138]

In its amended revised proposal, CitiPower removed the GSL payments it incurred in 2019 from its base opex. It then added a category specific forecast for GSL payments equal to the average of the GSL payments it would have incurred in 2015 to 2019 had the new scheme been in place in those years.[139] We consider this is a reasonable way to forecast the impact of the changes to the scheme. This approach yields a forecast lower than the placeholder amount CitiPower initially included in its revised proposal.[140]

We note that AusNet Services proposed a 'transitional amount' in addition to its forecast of GSL payments. AusNet Services stated that from 2015 to 2019, it made significant GSL payments for events that were outside of its control. Due to the changes to the GSL scheme, many of these payments were excluded from its backcast payments and thus not included in AusNet Services' forecast GSL payments for the 2021–26 regulatory control period.

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[134] CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 118.

[135] CitiPower, R*evised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020.

[136] AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 60.

[137] ESCV, *Electricity Distribution Code review – customer service standards, Final decision,* 16 November 2020.

[138] AER, *Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 60.

[139] CitiPower, *Revised Regulatory Proposal 2021–26 – Supplementary revised proposal submission,* December 2020, p. 2.

[140] CitiPower, *Revised Regulatory Proposal 2021–26,* December 2020, p. 124.

We consider a 'transitional amount' is only required when there is both a change in the scheme and there were abnormal events in the averaging period used to forecast GSL payments.[141]

We asked CitiPower if it considered it required a 'transitional amount' and it stated that it did not.[142] We have reviewed CitiPower's outages both at the customer level, and at the feeder level, and are satisfied that the outages on CitiPower's network over the period 2015 to 2019 reflect normal conditions. Consequently, we agree that a 'transitional amount' is not necessary in CitiPower's circumstances.

6.4.4.2 Yarra Trams pole relocation

Our final decision is to include $4.3 million ($2020–21) in our alternative estimate to account for costs related to pole-top assets and conductors on poles that Yarra Trams forecasts to replace or relocate over the 2021–26 regulatory control period. This differs from our draft decision to not include the proposed costs (as a step change) in our alternative estimate.[143]

Table 6.16 Yarra Trams ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
CitiPower revised proposal	1.5	0.4	1.9	0.6	0.4	**4.9**
AER final decision	1.4	0.3	1.7	0.5	0.3	**4.3**
Difference	–0.1	–0.1	–0.2	–0.1	–0.1	**–0.6**

Source: CitiPower, *Revised Regulatory Proposal 2021–26 – MOD 10.06 – Opex*, December 2020; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we did not include the proposed $14.4 million ($2020–21) step change in our alternative estimate for two key reasons:

1) we did not agree that such costs should be recovered through a step change as the costs appeared non-recurrent in nature
2) we had concerns around the efficiency of the proposed blended costs.[144]

In its revised proposal, CitiPower proposed $4.9 million ($2020–21) for Yarra Trams relocation costs and also re-categorised the cost as a category specific forecast as opposed to a step change.[145] Under the existing agreement with Yarra Trams, the two

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[141] AER, *Final Decision, AusNet Services 2021–26, Attachment 6, Operating expenditure*, April 2020, section 6.4.4.1.
[142] CitiPower, *Information request 71, Q–1,* 11 January 2021, p. 1.
[143] AER*, Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 46.
[144] AER*, Draft Decision, CitiPower 2021–26, Attachment 6, Operating expenditure,* September 2020, pp. 46–48.
[145] CitiPower*, Revised Regulatory Proposal 2021–26 – Supplementary revised proposal submission,* December 2020, p. 2.

parties can hold assets on each other's poles free of charge but are required to cover the costs to remove and relocate any assets on the poles. CitiPower's revised proposal is $9.6 million ($2020–21) lower than its original proposal, following updates to the number of forecast poles that Yarra Trams plan to relocate over the 2021–26 regulatory control period, as well as the blended cost estimated for the relocation of each pole-top asset.

ECA stated in its submission that based on the information provided, it was satisfied that the arrangement with Yarra Trams is in the interest of CitiPower's customers as without access to shared infrastructure, costs to CitiPower's customers would be higher.[146]

Our final decision is to include CitiPower's Yarra Trams pole relocation as a category specific forecast in our alternative estimate with an adjustment to the assumed blended cost leading to a lower forecast. We are satisfied with CitiPower's proposal to categorise such costs as a category specific forecast for the 2021–26 regulatory control period. We view this is appropriate given the proposed expenditure represents a one-off increase and addresses the concerns raised by stakeholders that such costs are not recurrent.[147] In CitiPower's revised proposal, it provided historical data from 2018 and 2019 in relation to the costs per project associated with pole top asset relocations and also provided details as to whether the projects were low or high complexity. Our adjustment relates to the assumed cost that is applied for pole relocation works over the 2021–26 period. CitiPower used the weighted average cost from all historical data to form a blended cost (based on 73 per cent projects being low complexity) that it applied to all poles in the next regulatory control period. We have calculated two average costs for both low and high complexity projects and applied each separately depending on the complexity of the project (of which 98.6 per cent were low complexity) for the next regulatory control period.

As a result, this leads to a minor decrease to the blended cost proposed by CitiPower and the estimated forecast we have included in our alternative estimate.

6.4.4.3 Debt raising costs

We have included debt raising costs of $4.9 million ($2020–21) in our alternative estimate. This is $0.04 million ($2020–21) less than the $4.9 million forecast ($2020–21) proposed by CitiPower.[148]

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. We consider the appropriate approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a

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[146] Energy Consumers Australia, *Submission and attachment on the Victorian EDPR Revised Proposal and Draft Decision 2021–26,* January 2021, p. 21 (Spencer&Co).

[147] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, p. 54.

[148] CitiPower, *Regulatory proposal 2021–26*, January 2020 p. 124.

single year. This provides for consistency with the forecast of the cost of debt in the rate of return building block.

We used our standard approach to forecast debt raising costs which is discussed further in Attachment 3 – Rate of Return, of this final decision.[149]

6.4.5 Assessment of opex factors

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the opex criteria under the NER, we have regard to the opex factors.[150]

We attach different weight to different factors when making our decision to best achieve the National Electricity Objective. This approach has been summarised by the AEMC as follows:[151]

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.17 summarises how we have taken the opex factors into account in making our final decision.

Table 6.17 Our consideration of the opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark opex that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark opex that would be incurred an efficient provider during the forecast period, necessarily provides a different focus. This is because it requires us to construct the benchmark opex that would be incurred by an efficient provider for that particular network over the relevant period. We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to form a holistic view on the efficiency of CitiPower's proposed total forecast opex compared to the benchmark efficient opex that would be

149 AER, *Draft decision, CitiPower distribution determination 2021–26 – Attachment 3 – Rate of return,* September 2020, pp. 9–12.

150 NER, cl. 6.5.6(e).

151 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Rule Determination*, 29 November 2012, p. 115.

Opex factor	Consideration
	incurred over the relevant regulatory control period.
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of CitiPower's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is efficient such that it can be relied on as the basis for forecasting required opex in the forthcoming period.
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	This factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[152] Based on the information provided by CitiPower in its proposal and the CCP17's advice, we consider that CitiPower's opex forecast was developed with the influence of its consumers. We have examined the issues raised by consumers in developing our alternative estimate of opex which includes expenditure to address consumer concerns such as CitiPower's consumer advisory panel supporting a conservative approach in forecasting growth due to the impact of COVID-19.[153]
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering CitiPower's proposed step changes. For instance we considered whether a step change for IT cloud is an efficient capex/opex trade-off. We considered the relative capex and opex costs for proposed solutions in considering this step change. We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above we considered capex/opex trade-offs in considering CitiPower's proposed step changes. Some of our assessment techniques examine opex in isolation — either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs. Further, we considered the different capitalisation practices of the service providers' and how this may affect opex performance under benchmarking.

152 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Rule Determination*, 29 November 2012, pp. 101, 115.

153 CitiPower, *Revised Regulatory Proposal 2021–26*, December 2020, p. 21.

Opex factor	Consideration
Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to CitiPower's opex in the 2016–21 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our estimate of base opex consistently in applying the EBSS and forecasting CitiPower's opex for the 2021–26 regulatory control period.
The extent the opex forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers. In our assessment we have not identified any such arrangements.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We have not identified any opex project in the forecast period that should more appropriately be included as a contingent project.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be particularly significant in reaching our final decision. We note that CitiPower considered network augmentation as an alternative in the context of its proposed solar enablement step change.
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	In having regard to this factor, we must identify any regulatory investment test (RIT-D) submitted by the business and ensure the conclusions of the relevant RIT-D are appropriately addressed in the total forecast opex. CitiPower did not submit any RIT-D project for its distribution network.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify CitiPower of any other opex factor.

Source: AER analysis.

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
CAM	Cost Allocation Method
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CPI	Consumer Price Index
distributor	distribution network service provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
ESCV	Essential Services Commission Victoria
ESV	Energy Safe Victoria
GSL	guaranteed service level
MPFP	multilateral partial factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
RBA	Reserve Bank of Australia
SCS	standard control services
utilities	electricity, gas, water and waste services
VCO	Victorian Community Organisations
WPI	Wage Price Index