DRAFT DECISION

CitiPower
Distribution Determination
2021 to 2026

Overview

September 2020

AUSTRALIAN
ENERGY
REGULATOR

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Executive summary

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set a maximum revenue that network businesses are allowed to recover from consumers in providing network services.

CitiPower owns and operates one of the five electricity distribution networks in Victoria and services around 330,000 customers in Melbourne's central business district and inner suburbs. On 31 January 2020, CitiPower submitted its proposal for the five year regulatory control period commencing 1 July 2021.

This draft decision sets out the amount of money CitiPower can recover from electricity customers for using its network over the regulatory control period.

We note that the unprecedented changes to the economic environment as a result of COVID-19 will have wide ranging impacts, which may cause aspects of CitiPower’s proposal to differ at the revised proposal stage. We base this draft determination on current information and best forecasts that can reasonably be made, but acknowledge that some proposals may need to change.

CitiPower can recover $1425.4 million ($ nominal) from its consumers to operate its network in the 2021–26 regulatory control period. This is 12.5 per cent lower than the revenue allowed for in our 2016–2020 final decision and leads to lower network charges for CitiPower’s consumers from the next regulatory control period.

The total revenue allowed in our draft decision is $178.7 million (or 11.1 per cent) less than the $1604.1 million ($ nominal) proposed by CitiPower.

The revenue we allow forms the distribution network component of retail electricity bills, making up about 20 per cent of a standard residential bill (25 per cent for small businesses).

We estimate that if this draft decision is implemented, compared to current charges, distribution network charges in the first year of the 2021–26 regulatory control period will drop by $60 (3.9 per cent) for residential consumers and $219 (3.7 per cent) for small business consumers, and thereafter increase by $3 (0.2 per cent) and $11 (0.2 per cent) per year respectively.

We estimate these bill impacts by calculating the average revenue per unit of energy charged to customers under our determination. We have adopted standard assumptions about the amount of energy used by customers and hold all other bill components constant.

These estimates may vary between our draft and final determinations following additional information provided in response to our draft decision. Further changes may occur during the subsequent annual pricing process. These changes may increase or decrease customer bills.

Customers' final bills may differ from the draft determination estimates because, for example:

- revised capital expenditure (capex) and operating expenditure (opex) estimates may be made in the final determination
- energy consumption forecasts may change
- the structure of tariffs may vary from the simple assumption of a constant amount for each unit of energy used
- a different rate of return may be made in the final determination reflecting updated market data
- the return on debt will be updated in each of years 2 to 5 of the 2021−26 regulatory control period
- revenue adjustments may be required to ensure compliance with the revenue cap
- penalties and rewards from the incentive schemes may be subtracted from or added to revenue
- adjustments to revenue may be required as a result of the transition in 2021 from a calendar to a financial basis for this determination. We expect that a true-up will be needed during the 2021−26 regulatory control period
- our forthcoming decision on the approach to estimating expected inflation will apply to the final determination
- approved network charges will include transmission charges and possible jurisdictional scheme charges.

In making this draft decision we have had regard to a range of sources including CitiPower's proposal, submissions received, as well as analysis undertaken and published by us.

Our draft decision finds CitiPower's proposal is not in the long term interests of consumers and substitutes forecasts for capex and opex. As noted above, a portion of the reductions to capex and opex forecasts are driven by the need to use updated evidence in light of current economic uncertainties resulting from COVID-19. CitiPower now has the opportunity to consider the latest economic data, engage with its consumers and put forward a revised proposal with updated information.

In making this draft decision, we note the following key themes:

- CitiPower's engagement with consumers
- poles and asset management
- ensuring consumers pay no more than necessary for safe and reliable services
- facilitating the emergence of Distributed Energy Resources
- network tariff reform proceeding in Victoria.

CitiPower's engagement with consumers

All five Victorian distributors made a concentrated effort to improve engagement with their customers and strive to better capture the diversity of their preferences. While each distributor approached this differently, all published an early draft of their regulatory proposal to gauge consumer views. We were encouraged to see these efforts to understand consumer preferences before the proposal has been finalised.

We were also encouraged to see the distributors coordinate their engagement on tariff structure statements in acknowledgement of the Victorian context and challenges advocates and representatives can face in finding resources to engage. The distributors collaborated on a series of forums to develop principles for their tariff strategies for small users as a basis to develop structures. Participating stakeholders included consumer representatives and advocates, community groups, the Victorian Government, and retailers. The consistent use of language and structured, focused points of engagement were noted in the generally supportive submissions we received from stakeholders.

Additionally CitiPower, Powercor and United Energy collaborated on a program called 'Energised 2021–26'. Through this program they engaged with 11,000 customers and stakeholders through around 2.5 million 'touch points'. Their business as usual engagement such as the Customer Consultative Committee and an Energy Futures Customer Advisory Panel (EFCAP) formed part of this engagement. This use of a range of approaches was considered a major strength by the AER's Consumer Challenge Panel (CCP17). Advancing consumer literacy to improve engagement was also acknowledged by the Victorian Community Organisations (VCO).

In submissions on CitiPower's engagement, CCP17 argued it was not particularly clear how the learnings from engagement had been applied, particularly in relation to the EFCAP. It noted that some members were frustrated as they could not see evidence of how their input had made a difference. The VCO also found that not all elements of engagement and its impact on the proposals had been transparently communicated. These are key considerations with respect to the weight we can place on the results of a distributor's consumer engagement when forming our draft decision. We invite CitiPower to clarify how this, and subsequent, engagement has been reflected in its revised proposal.

Poles and asset management

We consider CitiPower overstated its network risk in a number of its forecast capex projects and programs. This is evident in CitiPower's forecast pole replacement program. CitiPower sought to apply the findings from the Energy Safe Victoria (ESV) 2019–20 review of Powercor's wooden pole management practices, to its network. However, CitiPower does not face the higher network risks to Powercor. CitiPower's poles are in urban, low bushfire risk areas, so the consequences of failure are likely to be lower than for Powercor. Based on the information before us, we are not convinced a 511 per cent step up relative to its current spend in poles replacement is required. We note CitiPower's own risk assessment framework rated some of the proposed replacements as low risk. Stakeholders overwhelmingly showed a lack of support for CitiPower's forecast poles replacement expenditure (repex) for similar reasons.

Consistent with our previous decisions, we understand the importance of managing safety risk and therefore allowed funding to distributors to address these risks. But in this case, CitiPower did not provide sufficient evidence including economic analysis we typically receive from distributors, to support a forecast that is materially above its current period spend. Our substitute estimate was informed by the application of the CESS in the current period, where a material CESS reward indicates that a substitute estimate close to current period actual spend is a prudent and efficient level of capex over the forecast period in the absence of clear and well-documented external drivers of change in capex requirements.

Ensuring consumers pay no more than necessary for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a cornerstone of the regulatory determination process. We must assess whether a business' proposal is a reasonable and realistic forecast of how much money it needs for the safe and reliable operation of the network. It also involves encouraging distributors to explore how they can provide better services at lower cost through a range of incentive schemes.

CitiPower's forecast capex is 34 per cent higher than its current period spend. We have had regard to top down indicators (such as trend analysis, network health indicators and demand forecasts) which all point to a capex forecast that is overstated when checked against our bottom up review. We therefore did not accept CitiPower's forecast capex as it did not provide sufficient evidence to support a materially higher forecast than for its current period spend. Further, we consider that our alternative estimate, which is in line with current period spend, is sufficient for CitiPower to maintain its service levels, noting CitiPower performed well against network health indicators over the current period.

CitiPower underspent its current period capex allowance by 31 per cent,[1] for which it was awarded a capital expenditure sharing scheme (CESS) payment of $63.8 million. A number of stakeholders raised concerns about the operation of these incentive schemes. For example, CCP17 questioned distributors underspending in one period and then proposing capex increases in the following period. We are currently scoping a broad review of incentive schemes to address such concerns. In the meantime we would like to reassure stakeholders of the steps we are taking to support the appropriate operation of these schemes, particularly in relation to capex.

[1] The capex underspend for the 2016–20 regulatory control period includes actual capex for 2016 to 2019 and an estimate of capex for 2020. This is consistent with our post-tax revenue forward model (PTRM) and roll forward model (RFM).

Consistent with our standard approach, we reviewed the cost savings identified by CitiPower to assess whether these truly reflect reduced costs and not just deferral of costs between regulatory control periods. We did not find evidence that CitiPower's capex underspend was the result of deferrals of expenditures from the last regulatory control period that have now been included in our forecast capex. Further detail is included in section 2.4.

Facilitating the emergence of Distributed Energy Resources

As noted in the Issues Paper, facilitating the transition of the energy system is a key theme for this Victorian regulatory determination process. Various mechanisms can play a part, such as expenditure to physically accommodate greater exports, demand management initiatives and more cost reflective network tariffs to incentivise the efficient location of distributed energy resources (DER) to optimise use of the networks. We consider this work so important that we have made incentivising networks to become platforms for energy services a strategic objective in our regulation of networks. But it is imperative that these mechanisms are coordinated to ensure a coherent approach.

DER is no longer a marginal technology. This pattern will strengthen over the regulatory period with the Victorian Government's Solar Homes Program supporting the installation of 700,000 solar PV systems (for around one in four households) between 2018–19 and 2027–28. Networks are also preparing for the electric vehicle (EV) market and supporting charging infrastructure. While less developed than solar PV or battery storage systems, the EV market has the potential to provide significant network support.

We support CitiPower facilitating solar PV growth on its network, particularly in the context of the Victorian Government's Solar Homes Program, and have provided for this in our draft decision. Our decision provides for the Solar Homes Program while ensuring allowances are prudent. Accordingly, we have accepted CitiPower's expectations regarding the growth in solar PV uptake on its network (and associated export levels) and all of its DER related ICT investment. But we adjusted some assumptions underpinning its estimates of required expenditure for its solar enablement program. Specifically, we reduced the period over which benefits of the proposed projects are calculated and adjusted the timing of some investments to be consistent with the approach distributors, including CitiPower, undertake when investing in traditional capex. We also note that CitiPower's tariff strategy was not well linked to its DER strategy. We encourage a more unified approach in its revised proposal.

Network tariff reform proceeding in Victoria

We are encouraged by the Victorian distributors' efforts to progress network tariff reform in the 2021–26 regulatory control period. The distributors took on guidance from our 2017 decision and worked with customers to develop a unified approach for residential and small business customers in Victoria. This enabled distributors to move from opt-in to opt-out assignment to cost reflective network tariffs and allowed them to target the charging structures at periods of network constraints. They are also exploring pricing arrangements for DER such as electric vehicles and battery storage. Their efforts to explore appropriate price signals, including by considering stakeholder perspectives, indicate they are on the right track.

But we recommend the distributors build on this progress in their revised proposals. For small users, we advise the distributors to explore reassigning customers on legacy cost reflective tariffs to the new time of use and demand tariffs. Doing so would simplify the suite of network tariffs, improve the targeting of price signals for customers, and increase the magnitude of the customer base retailers are managing these signals for. For large users, distributors should offer choice of tariff structure, given those customers are more likely and able to face and respond to network tariff structures than smaller users. While the standard large user tariffs proposed are consistent with industry practice, offering optional tariffs would improve the matching of network tariffs to forward-looking costs at a more disaggregated level. Greater choice would also help emerging technologies to efficiently integrate into, and support the operation of the network.

Finally, distributors could do more to help customers understand the linkages between tariff strategies, tariff trials, DER and broader expenditure proposals. Linking tariff strategies for each tariff class with information and initiatives relating to demand management is also encouraged.

Change to the regulatory control period

In April 2019, the Victorian Minister for Energy, Environment and Climate Change indicated her intention to change the timing of the regulatory control period for electricity distribution networks from a calendar year basis to a financial year basis. We prepared this decision on the basis that the Victorian Government will enact legislation to change the commencement date of the next regulatory control period from 1 January 2021 to 1 July 2021.

The National Energy Legislation Amendment Bill 2020 (the Bill) currently before the Victorian parliament, provides for an extension of the current regulatory control period (1 January 2016 to 31 December 2020) by 6 months. Unfortunately the impact of external factors such as COVID-19 lockdown prevented the passage of the legislation and related Orders in Council prior to release of this decision. In a letter to the AER on 2 September 2020, the Minister reaffirmed the Victorian Government's commitment to change electricity and gas network regulatory periods from a calendar to financial year basis. The AER will publish the draft decisions for the five businesses for the next regulatory control period on this basis. It should be noted the draft decision was prepared under the expectation the legislation would be in place.

We separately assessed the total allowed revenue for CitiPower for the six month period from 1 January 2021 to 30 June 2021, based on the trend-forward approach outlined in our letter to the Victorian distributors in November 2019, our April 2020 Issues Paper, and the application of the 2018 Rate of Return instrument to the six month period. We set out our final approach to this assessment in a letter to CitiPower in August 2020.[2] Due to the delay in the passage of the legislation, we will not formally make a revenue decision for the relevant six-month period at this time.

We expect that the legislation and related Orders in Council, once in effect, will provide for a pricing proposal for the six month period. We will continue to work with distributors and the Victorian government to ensure any effects of this delay are minimised. We will provide further communication on the timing of the publication of our final decision for the six month period and the expected timing of our assessment of network tariffs shortly.

What are the next steps?

CitiPower now has the opportunity to consider our draft decision and submit its revised proposal and supporting material in December 2020.[3]

We will make our final determination by 30 April 2021.

Detailed explanations of factors informing our draft decision can be found in the overview section and attachments to this draft determination.

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2 AER letter to distributors August 2020, https://www.aer.gov.au/system/files/AER - Correspondence to CitiPower - Victorian EDPR and the six-month extension - 17 August 2020.pdf

3 The numbers in this draft determination may change in the final determination.

Invitation for submissions

In response to our draft decision, CitiPower now has the opportunity to submit a revised proposal for its next regulatory control period (2021–26) by 3 December 2020. Submissions on our draft decision and CitiPower's revised proposal are invited from interested stakeholders by 8 January 2021. We will consider and respond to all submissions received by that date in our final determination.

Submissions should be sent to: VIC2021-26@aer.gov.au

Alternatively, submissions can be sent to:

Kami Kaur
General Manager, A/g
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process.

Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication

(3) all non-confidential submissions will be placed on our website.[4]

4 For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy* (June 2014), which is available on our website: https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

Review timeline

The key milestones for our review of CitiPower’s regulatory proposal are set out below:

Milestone	Date
CitiPower submitted its proposal	31 January 2020
AER issues paper published	7 April 2020
Online Public forum on CitiPower's proposal	22 April 2020
Submissions on AER's issues paper and CitiPower's proposal closed	3 June 2020
AER draft decision published	30 September 2020
Public forum on draft decision	15 October 2020
CitiPower submits revised proposal	3 December 2020
Submissions on draft decision and revised proposal due	8 January 2021
AER final decision to be published	30 April 2021

Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to CitiPower for the 2021–2026 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents and 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

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme and demand management innovation allowance mechanism

Attachment 12 – Not applicable to this distributor

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Victorian f-factor incentive scheme

Contents

1 Our draft decision

Our draft decision would allow CitiPower to recover a total revenue of $1425.4 million ($ nominal) from its consumers from 1 July 2021 to 30 June 2026.

CitiPower is regulated using a revenue cap. Incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

Our draft decision for CitiPower determines the total revenue it can recover from consumers for the provision of common distribution services (standard control services (SCS)). This forms the basis of CitiPower's distribution tariffs for the 2021–26 regulatory control period. CitiPower's Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from consumers.

CitiPower also provides alternative control services (ACS), the costs of which are recovered only from users of those services, through a capped price on the individual service. These costs are considered separately to our building block determination.[5] Our draft decision sets out the prices CitiPower is allowed to charge consumers for the provision of ACS: ancillary network services, public lighting and metering. CitiPower has not proposed to provide any services on a negotiated basis in the 2021–26 regulatory control period.[6]

We have taken CitiPower’s consumer engagement into account in developing our draft decision. More information is provided at section 3.

1.1 What’s driving revenue?

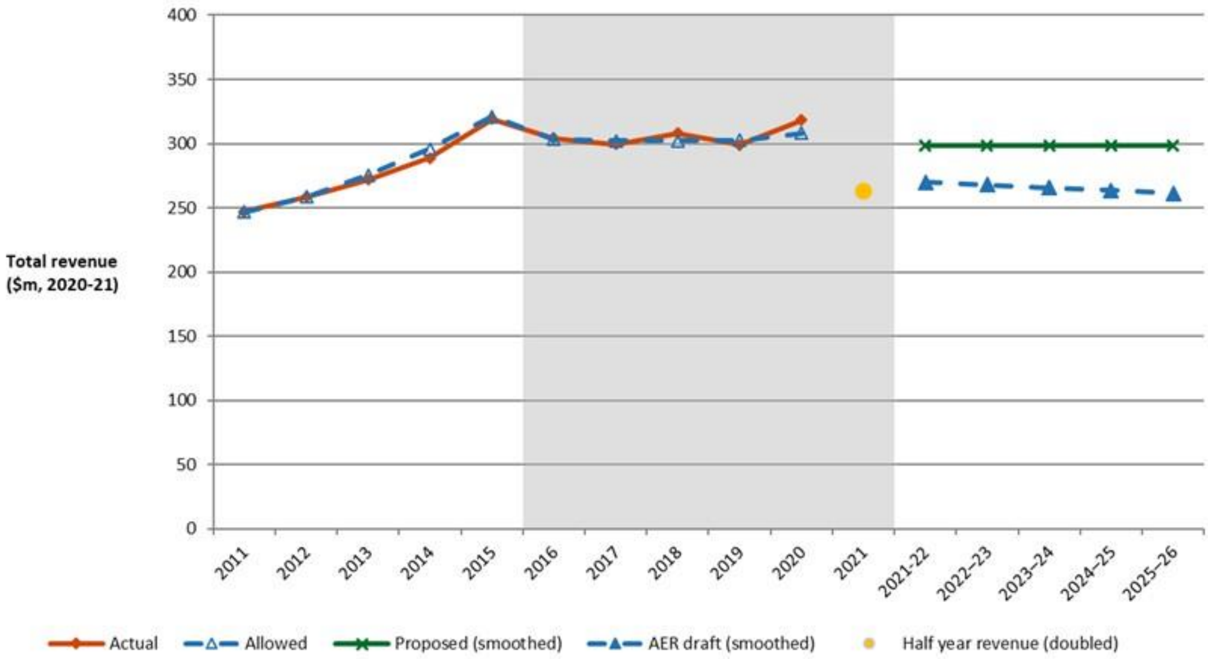
Revenue is driven by changes in real costs and inflation. We assess costs (such as capital and operating expenditure) in real terms (using 2020–21 as a common year) to reveal the underlying cost trends over a number of years or regulatory control periods. The numbers presented in this overview are in real 2020–21 dollars unless otherwise noted. Some aspects of our decision are presented in nominal terms to be consistent with the NER and to enable consumers to see the full impact of our determination inclusive of expected inflation.

The total revenue allowance in this 2021–26 draft decision is 12.5 per cent lower than the allowed revenue provided for in our 2016–20 final decision. Figure 1 shows real revenue decreases from 2020 levels by 15.2 per cent in the first year of the next regulatory control period. After that, CitiPower’s revenue allowance decreases by 0.8 percent per year.

5 We discuss alternative control services in Attachment 16 to this draft decision.

6 Our distribution determination for CitiPower includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because CitiPower has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2021–26 regulatory control period.

Figure 1 Revenue over time ($ million, 2020–21)



Source: AER analysis, smoothed revenue.

Figure 2 highlights the key drivers of CitiPower's allowed revenue for the 2021–26 regulatory control period. It illustrates that the largest driver of change is the return on capital building block. The nominal weighted average cost of capital (WACC) has decreased from around 6.11 per cent in the 2016–20 regulatory control period to 4.59 per cent for the 2021–26 regulatory control period.[7] Other reductions include:

- opex compared to the 2016–20 regulatory control period.[8]
- lower corporate tax amount, due to changes in our regulatory tax approach (following our recent tax review) and the 2018 rate of return instrument.[9]

The increase in the regulatory depreciation building block is largely driven by the small increase to the regulatory asset base (RAB) over the 2016–21 period.

The increase in the revenue adjustment is largely driven by positive incentive scheme payments over the 2021–26 regulatory control period, compared to negative efficiency

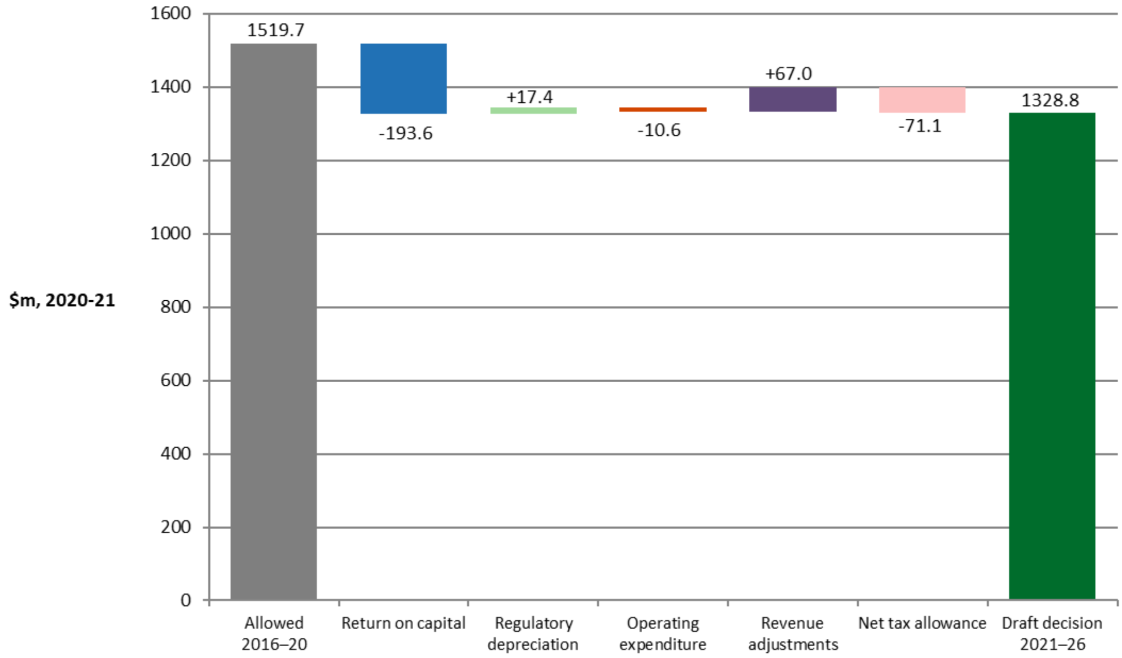
[7] The WACC is a nominal WACC unless stated otherwise. The real WACC is impacted to a similar degree. Please see section 2.2 for further details.

[8] Please see section 2.5 for further details.

[9] Please see section 2.6 for further details.

benefit sharing scheme (EBSS) payments and no CESS payments over the 2016–20 regulatory control period. [10]

Figure 2 Change in revenue from 2016–20 to 2021–26 ($ million, 2020–21)



Source: AER analysis.

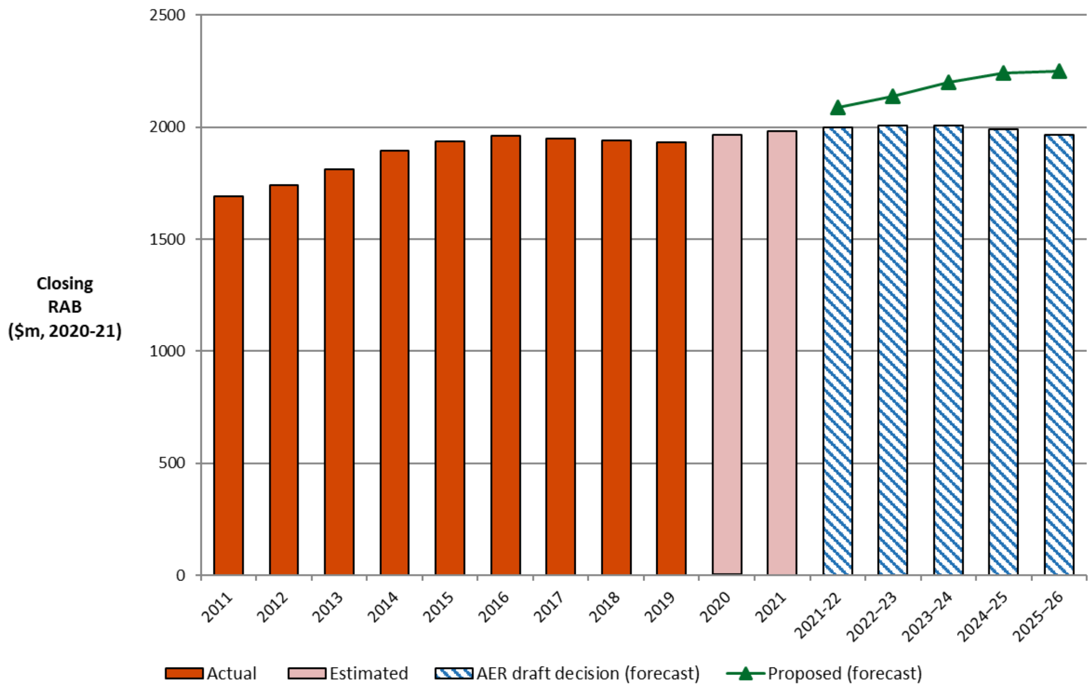
Note: Revenue adjustments include increments or decrements accrued under incentives schemes such as the CESS, EBSS, shared asset adjustments, and DMIAM.

Figure 3 compares our draft decision forecast RAB to CitiPower's proposed and actual RAB. This shows that CitiPower's regulatory asset base (RAB) is forecast to decrease by around 0.7 per cent in value over the 2021–26 regulatory control period, compared to a 1.6 per cent increase in the current 2016–20 regulatory control period.[11] This difference is mainly driven by lower forecast capex for the 2021–26 regulatory control period compared to capex incurred (and estimated) in the 2016–20 regulatory control period.

10 Please see section 2.7 for further details

11 Please see section 2.1 for further details.

Figure 3 Value of CitiPower's RAB over time ($ million, 2020–21)



Source: AER analysis.

1.2 Key differences between our draft decision and CitiPower's proposal

Our draft decision has determined total revenues of $1425.4 million ($ nominal) for the 2021–26 regulatory period. This is $178.7 million or 11.1 per cent lower than CitiPower's proposed $1604.1 million.

The biggest contributor to the difference between our draft decision revenue and CitiPower's proposal is the operating expenditures (opex). Our opex forecast of $462.9 million ($2020–21) is $99.9 million ($2020–21) or 17.8 per cent lower than CitiPower's proposed $562.8 million ($2020–21). The main drivers of this $99.9 million ($2020–21) difference is lower output and price forecasts due to the impacts of COVID-19 and not including a number of CitiPower's proposed step changes.

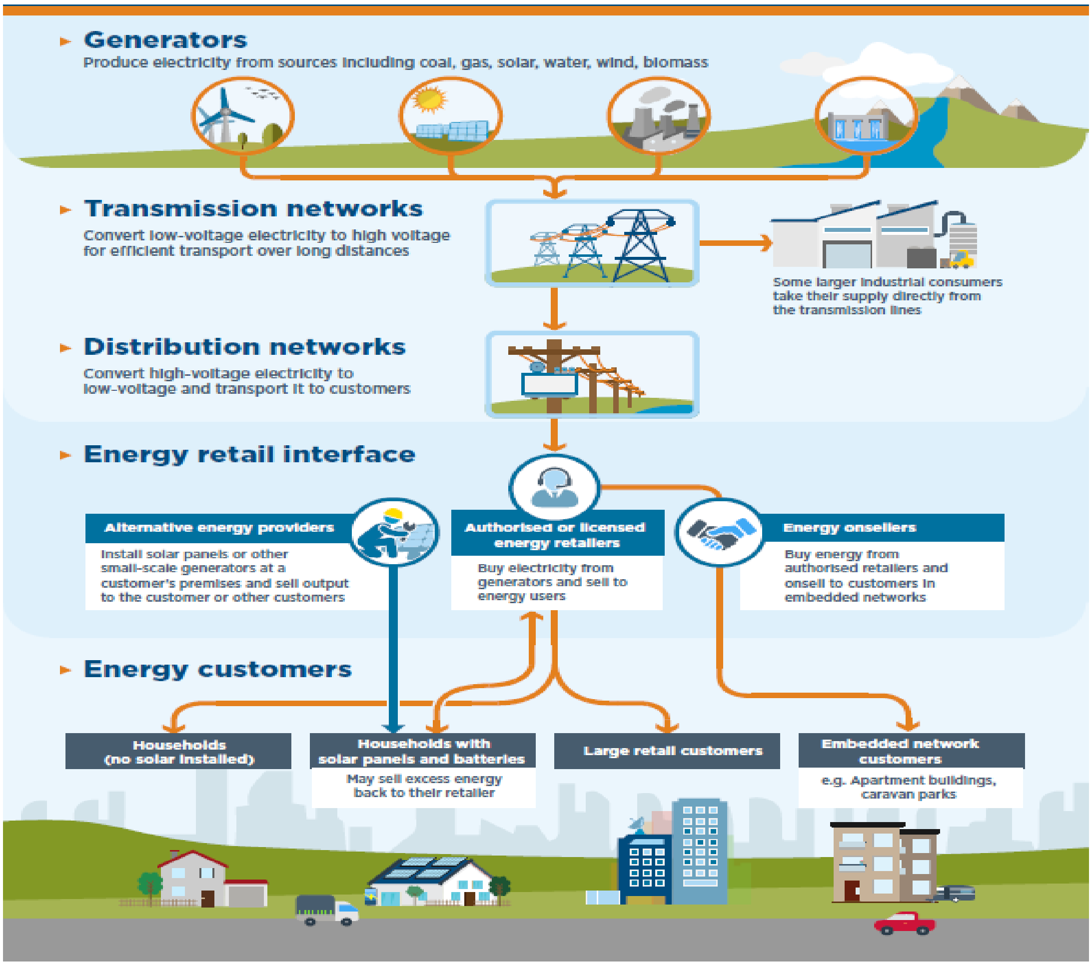
While CitiPower applied the 2018 rate of return instrument, the risk free rate and cost of debt are now both lower than at the time of submitting its proposal. As a result of this and the lower forecast RAB discussed below, the revenue for the cost of capital component is lower by $59.0 million ($ nominal) compared to CitiPower's proposal.

CitiPower has not sufficiently justified the prudency or efficiency of its proposed forecast capex of $1144.0 million ($2020–21). Our substitute capex forecast is $316.4 million ($2020–21) or 27.7 per cent lower than the proposal. This leads to a lower forecast RAB than CitiPower's proposal. The lower forecast RAB also contributes to our lower draft decision revenues through a lower return of capital and regulatory depreciation allowance.

1.3 Expected impact of our draft decision on electricity bills

CitiPower's distribution network SCS charges makes up around 20 per cent of the total residential and 25 per cent of the small business retail electricity bills paid by customers in CitiPower's area.[12] Our decision also covers charges for revenue-capped metering services (that form a part of ACS) and these costs are included in this estimated bill impact analysis.[13] Other components of the electricity bill include wholesale electricity costs, retail costs and environmental policy costs. Figure 4 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to customers by their chosen electricity retailer.

Figure 4 Electricity supply chain



Source: AER, State of the Energy Market, December 2018, p. 28.

12 Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 - Final decision*, 18 November 2019, p. 76; CitiPower, *2020 Pricing Proposal*, 22 October 2019, p. 5.

13 The metering costs referenced in the estimated bill impact analysis refer only to the revenue-capped type 5 and 6 (including. smart metering) services, and do not include any other price-capped metering services. For more information on metering services, see Attachment 16 – Alternative control services.

For this draft decision, we have estimated average distribution price impacts flowing from our revenue determination. These prices are indicative and will vary for a number of reasons. For example, any change in forecast demand will affect annual price updates. We have also not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

Table 1 shows the estimated average annual impact of our draft decision for the 2021–26 regulatory control period on electricity bills for residential and small business customers.

We estimate these impacts, while holding all other components constant. This approach isolates the effect of our draft decision on distribution network tariffs from other bill components. However, this does not imply that other components will remain unchanged across the regulatory control period.[14]

The final bill impact is likely to be affected by our final decision on any revisions made by CitiPower, changes in consumption, the return on debt, cost pass throughs, adjustments for under or over recovery and incentive schemes. The final outcome of our inflation review later this years and the Victorian Government's legislation on the 6 month extension period will also change the final bill impact. We note that due to the economic uncertainties and concurrent review of our methodology for estimating expected inflation there is potential for a larger-than-normal change between the draft and final decisions.

Under the draft decision we estimate that compared to current charges, the distribution network charges ($ nominal) in CitiPower's area:

- for an average residential consumer would:
    - reduce by $60 (3.9 per cent) in the first year of the 2021–26 regulatory control period
    - increase on average by $3 (0.2 per cent) for each of the remaining four years of the 2021–26 regulatory control period.
- for an average small business consumer would:
    - reduce by $219 (3.7 per cent) in the first year of the 2021–26 regulatory control period
    - increase on average by $11 (0.2 per cent) for each of the remaining four years of the 2021–26 regulatory control period.

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[14] It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since CitiPower operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2021–26 regulatory control period.

Table 1 Estimated contribution to annual electricity bills for the 2021–26 regulatory control period ($ nominal)

	2020	2021–22	2022–23	2023–24	2024–25	2025–26
AER draft decision						
Residential annual bill	1513[a]	1454	1456	1459	1462	1465
Annual change[c]		–60 (–3.9%)	3 (0.2%)	3 (0.2%)	3 (0.2%)	3 (0.2%)
Standard control services		–41	2	2	2	2
Metering		–19	1	1	1	1
Small business annual bill	5970[b]	5751	5762	5772	5783	5794
Annual change[c]		–219 (–3.7%)	11 (0.2%)	11 (0.2%)	11 (0.2%)	11 (0.2%)
Standard control services		–200	10	10	10	10
Metering		–19	1	1	1	1
CitiPower proposal						
Residential annual bill	1513[a]	1480	1485	1491	1496	1501
Annual change[c]		–33 (–2.2%)	5 (0.3%)	5 (0.4%)	5 (0.4%)	6 (0.4%)
Standard control services		–14	5	5	5	5
Metering		–20	1	1	1	1
Small business annual bill	5970[b]	5884	5907	5930	5954	5979
Annual change[c]		–86 (–1.4%)	23 (0.4%)	24 (0.4%)	24 (0.4%)	24 (0.4%)
Standard control services		–67	23	23	23	24
Metering		–20	1	1	1	1

Source: AER analysis; Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 - Final decision*, 18 November 2019, p. 76.

(a) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 - Final decision* and reflects the average consumption of 4000 kWh for residential customers in Victoria. This is then indexed by CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

(b) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 - Final decision* and reflects the average consumption of 20000 kWh for small business customers in Victoria. This is then indexed by CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

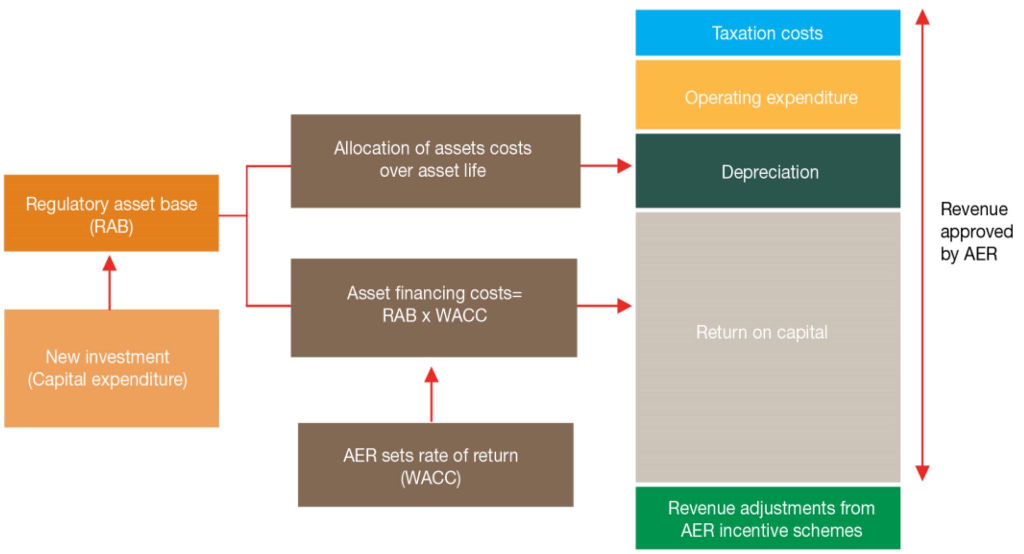
(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2020 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by CitiPower. Actual bill impacts will vary depending on electricity consumption and tariff class.

2 Key components of our draft decision on revenue

The total revenue CitiPower's proposed reflects its forecast of the efficient cost of providing network services over the 2021–26 regulatory control period. CitiPower's proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach to determining a total revenue allowance (see Figure 5) which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capital expenditure (capex) — the capex incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of incentive schemes, such as the EBSS and CESS that applied to CitiPower for the 2016–20 regulatory control period and the Demand Management Innovation Allowance Mechanism (DMIAM) allowance for 2021–26 (section 2.7).

Figure 5 The building block model to forecast network revenue



Source: AER, *State of the Energy Market*, December 2018, p. 28

We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework, which aims to promote the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our draft decision on CitiPower's distribution revenues for the 2021–26 regulatory control period is set out in Table 2.

Table 2 AER's draft decision on CitiPower's revenues for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Return on capital	90.9	90.7	89.9	88.6	86.6	446.6
Regulatory depreciation[a]	63.9	70.2	76.8	83.4	89.8	384.1
Operating expenditure[b]	94.0	96.2	99.0	102.2	105.7	497.0
Revenue adjustments[c]	18.6	15.4	10.7	10.0	14.5	69.1
Net tax allowance	4.3	6.8	5.5	6.5	6.6	29.8
Annual revenue requirement (unsmoothed)	271.7	279.3	281.9	290.7	303.1	1426.6
Annual expected revenue (smoothed)	**276.4**	**280.7**	**285.0**	**289.5**	**294.0**	**1425.4**
X factor[d]	n/a[e]	0.80%	0.80%	0.80%	0.80%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from EBSS, CESS, shared asset adjustments and DMIAM.

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) CitiPower is not required to apply an X factor for 2020–21 because we set the 2020–21 expected revenue in this decision. The expected revenue for 2021–22 is around 15.2 per cent lower than the estimated total annual revenue for 2020 in real terms, or 13.2 per cent lower in nominal terms after taking into account the escalation by half year CPI to allow comparison of the revenue from 1 July 2021 onwards.

In the sections below we discuss each component of our draft decision on CitiPower's revenue for 2021–26 in turn.

2.1 Regulatory asset base

The RAB is the value of assets used by CitiPower to provide regulated distribution services. The value of the RAB substantially impacts CitiPower's revenue requirement, and the price consumers ultimately pay. This makes it a key issue for many stakeholders. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

As part of our decision on CitiPower's revenue for 2021–26, we make a decision on CitiPower's opening RAB as at 1 July 2021. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block allowances.

We determine an opening RAB value of $1979.9 million ($ nominal) as at 1 July 2021 for CitiPower. This value is $33.5 million (or 1.7 per cent) lower than CitiPower's proposed opening RAB of $2013.4 million ($ nominal) as at 1 July 2021.[15] While we largely accept the proposed methodology for calculating the opening RAB, we made the following revisions to CitiPower's proposed inputs to the roll forward model (RFM):

- corrected the capex inputs for 2016–18 to be consistent with the values reported in the annual and economic benchmarking RINs for those years
- made a minor correction to the forecast straight-line depreciation for equity raising costs for 2017–20 to be consistent with the values in the 2020 return on debt update in the 2016–20 post-tax revenue model (PTRM)
- amended the estimated gross capex and customer contribution inputs for 1 January to 30 June 2021 to be equal to half of the total amount for the 2020–21 financial year as set out in the reset regulatory information notice (RIN)
- removed the 'Standard metering' and 'Supervisory cables' asset classes as the assets have effectively been fully depreciated. There is no new capex allocated to these asset classes during the 2021–26 regulatory control period
- amended the 2016 equity raising cost value to be consistent with the 2020 return on debt update in the 2016−20 PTRM
- updated the following inputs as newer information has become available since CitiPower submitted its proposal:
    - actual capex for 2019 reported in the annual RIN for that year

15 CitiPower, *CP MOD 10.01 – RFM 5.5 year 2016–21,* January 2020.

- actual inflation for the 6 month extension period of 1 January to 30 June 2021, reflecting the lagged CPI series
- forecast inputs for inflation, nominal WACC, equity raising costs and depreciation for the 6 month period of 1 January to 30 June 2021.

To determine the opening RAB as at 1 July 2021, we have rolled forward the RAB over the 2016–20 regulatory control period and a further roll forward for six months (the 1 January to 30 June period)[16] to arrive at a closing RAB value at 30 June 2021 in accordance with our RFM. This roll forward includes an adjustment at the end of the 2016–20 regulatory control period to account for the difference between actual 2015 capex and the estimate approved in the 2016–20 determination.[17] All other adjustments are applied as part of the final year adjustments at 30 June 2021 to establish the opening RAB value at 1 July 2021.[18]

Table 3 sets out the roll forward of CitiPower's RAB over the 2016–21 period.

Table 3 AER's draft decision on CitiPower's RAB for the 2016–21 period ($ million, nominal)

	2016	2017	2018	2019	2020[a]	2021[b]
Opening RAB	1762.9	1813.6	1820.0	1849.3	1879.9	1940.7
Capital expenditure[c]	126.2	90.7	103.9	108.4	154.2	68.6
Inflation indexation on opening RAB	26.6	18.6	35.2	38.4	29.9	23.7
Less: straight-line depreciation[d]	102.1	102.9	109.9	116.2	122.7	53.1
Interim closing RAB	1813.6	1820.0	1849.3	1879.9	1941.3	1979.9
Difference between estimated and actual capex in 2015					−0.5	
Return on difference for 2015 capex					−0.1	
Closing RAB as at 31 December 2020					1940.7	
Closing RAB as at 30 June 2021						**1979.9**

Source: AER analysis.

(a) Based on estimated capex provided by CitiPower. We expect to update the RAB roll forward for actual capex in the final decision.

16 The additional roll forward for 6 months is due to the decision by the Victorian government to change the timing of the annual Victorian electricity network price changes to financial year basis from calendar year basis. This change means the current regulatory control period of 2016–20 is extended by 6 months and the next regulatory control period will commence on 1 July 2021.

17 The end of period adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2016–20 determination.

18 This includes re-allocation for accelerated depreciation purposes associated with solar enablement distribution transformers. Please see section 4.4.2 of attachment 4 for details.

(b)	The half year period of 1 January to 30 June 2021. Based on estimated capex provided by CitiPower. We expect to update the RAB roll forward with a revised capex estimate in the final decision, and true-up the RAB for actual capex at the next reset.
(c)	Net of disposals and capital contributions, and adjusted for actual CPI and half-year WACC.
(d)	Adjusted for actual CPI. Based on forecast capex.

We determine a forecast closing RAB value as at 30 June 2026 of $2210.4 million ($ nominal) for CitiPower. This is $320.9 million or 12.7 per cent lower than CitiPower's proposed closing RAB value of $2531.3 million ($ nominal).[19] Our draft decision on the forecast closing RAB value reflects the amended opening RAB as at 1 July 2021, and our draft decisions on the expected inflation rate (attachment 3), forecast depreciation (attachment 4) and forecast capex (attachment 5).[20]

Table 4 sets out our draft decision on the forecast RAB values for CitiPower over the 2021–26 regulatory control period.

Table 4 AER's draft decision on CitiPower's RAB for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26
Opening RAB	1979.9	2045.5	2102.3	2152.1	2187.9
Capital expenditure[a]	129.5	127.0	126.6	119.2	112.3
Inflation indexation on opening RAB	47.0	48.6	49.9	51.1	51.9
Less: straight-line depreciation	110.9	118.8	126.7	134.5	141.8
Closing RAB	**2045.5**	**2102.3**	**2152.1**	**2187.9**	**2210.4**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the PTRM, the capex includes a half-year WACC allowance to compensate for the six month period before capex is added to the RAB for revenue modelling.

We accept CitiPower's proposal that the forecast depreciation approach is to be used to establish the opening RAB at the commencement of the 2026–31 regulatory control period.[21] We consider this approach is consistent with our *Framework and approach* paper.[22] It is also consistent with the capital expenditure incentive objective in that it will provide sufficient incentives for CitiPower to achieve capex efficiency gains over the 2021–26 regulatory control period.

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19 CitiPower, *CP MOD 10.02 - PTRM 2021–26*, January 2020.

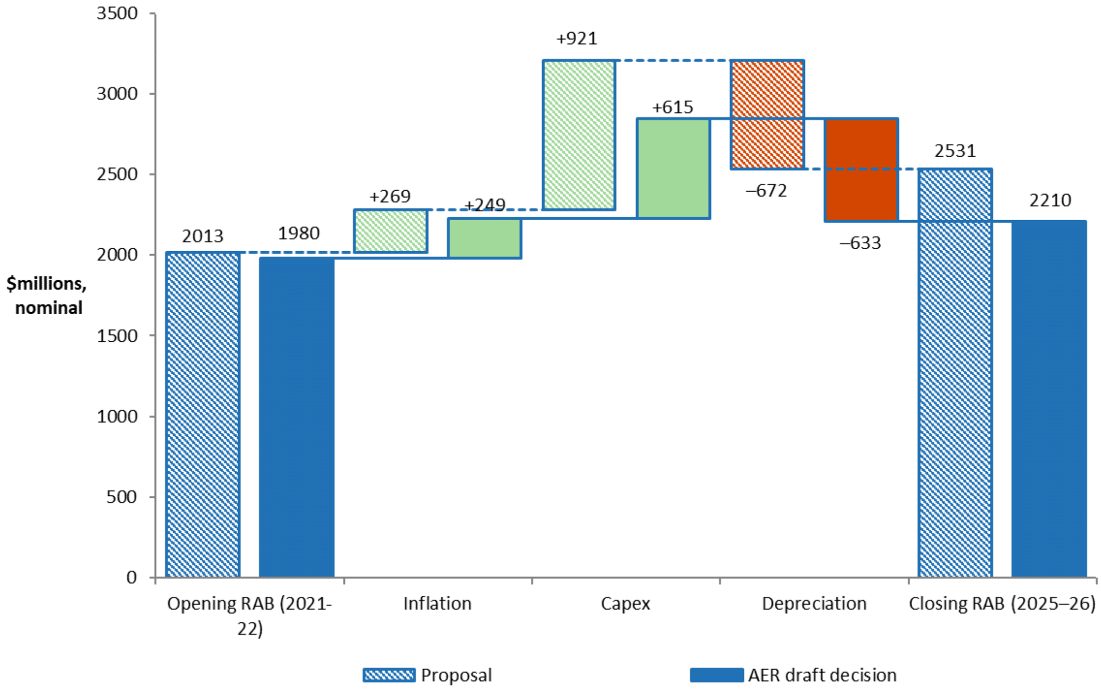
20 Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our draft decision on the forecast RAB also reflects our amendments to the rate of return for the 2021–26 regulatory control period (attachment 3).

21 NER, cl. 6.12.1(18). CitiPower, *Regulatory proposal 2021–2026*, January 2020, p. 130.

22 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 12.

Figure 6 shows CitiPower's proposal and our draft decision RAB over the 2021–2026 regulatory control period.

Figure 6 CitiPower's proposal and AER's draft decision RAB ($ million, nominal)



Source: AER analysis.

Further detail on our draft decision regarding the RAB is set out in attachment 2.

2.2 Rate of return and value of imputation credits

The return each business is to receive on its RAB (the 'return on capital') is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.

An accurate estimate of the rate of return is necessary to promote efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

The Victorian Government is intending to move the Victorian electricity distribution network service providers from a calendar year regulatory period to a financial year regulatory period.[23] This entails a 6 month extension to the current regulatory period (2016–20) through to June 2021 then a 5 year regulatory control period starting on 1 July 2021.[24]

We are required by the National Electricity Law (NEL) to apply a rate of return instrument—the current 2018 Rate of Return Instrument (2018 Instrument)—to estimate an allowed rate of return.[25] However, the 2018 Instrument was developed on the basis of consecutive 12-month regulatory years, and does not contemplate an intervening 6 month extension period when moving from calendar years to financial years. This is important for the calculation of the trailing average portfolio return on debt under the Instrument. The 2018 Instrument also did not contemplate the nomination of averaging periods for a 6 month extension period.

The Victorian Government intends to enact the change to a financial year regulatory period through the National Energy Legislation Amendment (NELA) Bill. By the time of this draft decision, the Bill has not been passed. In a letter to the AER on 2 September 2020, the Minister reaffirmed the Victorian Government's commitment to change electricity and gas network regulatory periods from a calendar to financial year basis. We anticipate that we will be able to apply a modified 2018 instrument in the final decision on this basis.[26]

Subject to the passing of the NELA Bill and relevant Orders in Council, application of a modified 2018 Instrument in this draft decision would estimate a placeholder allowed rate of return of 4.59 per cent (nominal vanilla) which will be updated for our final decision on the averaging periods.[27] We note CitiPower's proposal has also accepted the application of these modifications to the 2018 Instrument.[28]

Our calculated rate of return, in Table 5, will apply to the first year of the 2021–26 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with a modified 2018

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[23] Victorian Government, *Letter re: Intention to change the timing of annual Victorian network price changes*, April 2019, available at https://www.aer.gov.au/system/files/VIC%20DELWP%20letter%20to%20AER%20re%20intention%20to%20change%20the%20timing%20of%20annual%20Victorian%20network%20price%20changes%20-%20April%202019_0.pdf

[24] The 6 month extension period was labelled as the 'mini-year' when we consulted on modifications to the 2018 Rate of Return Instrument.

[25] NEL, Part 3, division 1B. AER, *Rate of return instrument*, December 2018, available at https://www.aer.gov.au/networks-pipelines/guidelinesschemes-models-reviews/rate-of-return-guideline-2018/final-decision

[26] Hon Lily D'Ambrosio MP, *Letter re: Reaffirming commitment to change the timing of Victorian network pricing*, 2 September 2020.

[27] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision. NGL, Chapter 2, Part 1, division 1A; NEL, Part 3, division 1B.

[28] Citipower, *Regulatory Proposal 2021–2026*, January 2020, p. 125.

Instrument to use a 10-year trailing average portfolio return on debt that is rolled-forward each year.

Subject to the passing of the NELA Bill and relevant Orders in Council, our draft decision is to accept CitiPower's proposed risk free rate averaging period[29] and debt averaging periods because they would comply with conditions proposed for a modified 2018 Instrument.[30]

Table 5 Draft decision on rate of return (% nominal)

	AER final decision (2015–20)	CitiPower's proposal (2021–26)	AER draft decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	2.48%	1.32%	0.93%[a]	
Market risk premium	6.5%	6.1%	6.1%	
Equity beta	0.7	0.6	0.6	
Return on equity (nominal post–tax)	7.0%	4.98%	4.59%	Constant (%)
Return on debt (nominal pre–tax)	5.51%	4.65%	4.59%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.11%	4.79%	4.59%	Updated annually for return on debt
Expected inflation	2.32%	2.4%	2.37%	Constant (%)

Source: AER analysis; CitiPower, *Regulatory proposal 2021–2026*, January 2020.

[a] Calculated using a placeholder averaging period of the month of June 2020.

[b] Calculated using a placeholder averaging period of the month of June 2020.

Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

[29] This is also known as the return on equity averaging period.

[30] See AER, *Rate of return instrument*, December 2018, cll. 7–8, 23–25, 36; Parliament of Victoria, *National energy legislation amendment bill 2020*, June 2020; and AER, *Draft decision, CitiPower draft determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, September 2020.

Our draft decision is to accept the method used in CitiPower's proposal which uses an annual rate of 8.1 basis points per annum (bppa).[31] We have considered this annual rate and found our alternative benchmark estimate (8.1 basis points) is similar to CitiPower's proposal.

We accept CitiPower's proposal to use our approach to estimate equity raising costs.[32] Using this approach, CitiPower forecast $4.66 million equity raising costs.[33] We have updated our estimate for this regulatory control period based on the benchmark approach using updated inputs. This results in equity raising costs of $1.43 million.

Imputation credits

Subject to the passing of the NELA Bill and relevant Orders in Council, our draft decision is to apply a gamma of 0.585 as provided in the 2018 Instrument.[34] CitiPower's proposal has adopted a value of 0.585 which is consistent with this.[35]

Inflation

CitiPower proposed to apply our current approach to estimate expected inflation. Our draft decision estimate of expected inflation is 2.37 per cent for the regulatory control period. Each Victorian distributor's proposal noted concerns with our current approach to estimating expected inflation. We are currently undertaking a review into the treatment of inflation in our regulatory framework, including the method likely to result in the best estimate of expected inflation. The final outcomes of this review are expected in December 2020, with a draft position to be published in early October. The draft position will provide guidance on the potential impact of alternative methods of estimating expected inflation. If we consider a different method for estimating expected inflation should be adopted, we intend to commence the consultation process under the NER for amending the PTRM. We expect to apply amendments to the PTRM (if any) in our final determination for each of the Victorian distributors in April 2021, unless a rule change proposal is required.

2.3 Regulatory depreciation (return of capital)

Regulatory depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). CitiPower invests capital in large assets to provide electricity network services to its consumers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from consumers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance. The regulatory depreciation allowance is

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31 Citipower, *Regulatory Proposal 2021–2026*, January 2020, p. 126.

32 Citipower, *Regulatory Proposal 2021–2026*, January 2020, p. 127.

33 Citipower, CP MOD 10.02 - PTRM 2021–26 - Jan2020 - Public.

34 See Parliament of Victoria, *National energy legislation amendment bill 2020*, June 2020; AER, *Rate of return instrument*, December 2018

35 Citipower, *Regulatory Proposal 2021-2026*, January 2020, p. 128.

the net total of the straight-line depreciation less the inflation indexation adjustment of the RAB.

Our draft decision on CitiPower's revenue for 2021–26 includes a regulatory depreciation amount of $384.1 million ($ nominal). This is $19.0 million (4.7 per cent) lower than CitiPower's proposal.

We adopt the same approach to regulatory depreciation as CitiPower, including its proposed standard asset lives which determine how quickly an asset class is removed from the RAB. We also accept CitiPower’s proposal to apply the year-by-year tracking approach, subject to minor changes to its depreciation tracking model.

CitiPower proposed accelerated depreciation of $8.0 million for certain existing PVC grey services and solar enablement distribution transformers. CitiPower considers that these assets will become redundant over the 2021–26 regulatory control period and therefore should be fully depreciated by this time. We accept the principle that asset that are replaced or no longer used before their expected life otherwise indicates can be subject to accelerated depreciation. However, in this case we require adjustment to both the way the residual value of the different assets in question are calculated. We consider the quantum of replacement is lower than proposed. For the PVC grey services we do not accept the stated need for replacement at all. For the solar enabled distribution transformers, we consider the appropriate ‘scrapping rate’ of these assets is significantly lower than proposed and a large proportion of these assets can therefore be redeployed on the network. We also require adjustment to the unit rates used to determine the value of the assets in question. As a result of these changes, we have accepted accelerated depreciation of $1.0 million of existing assets over the 2021–26 regulatory control period.

We have also made determinations on other components of CitiPower’s proposal that in turn impacts the forecast regulatory depreciation. Reductions to the opening RAB (attachment 2) and forecast capex (attachment 5) lead to a $39.7 million reduction in straight-line depreciation. Offsetting this, our decision on the indexation of the RAB is $20.7 million lower than the proposal. This is largely due to the lower forecast RAB and applying a lower expected inflation rate in this draft decision (attachment 3).

Further detail on our draft decision regarding depreciation is set out in attachment 4.

2.4 Capital expenditure

Capex—the capital costs and expenditure incurred to provide network services—mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. Capex is added to CitiPower's RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision on CitiPower's revenue includes a total net capex forecast of $567.3 million ($2020–21) for the 2021–26 regulatory control period. This is 29 per cent lower than CitiPower's updated forecast (‘forecast assessed’) of $799.7 million ($2020–21).[36]

Figure 7 illustrates the change in CitiPower's capex over time. CitiPower's forecast is a 41 per cent step up from its historical actual capex.[37] It also underspent by 31 per cent relative to its current period allowance.

Our draft decision allows for a capex allowance that is line with CitiPower's current period spend. Our substitute estimate is 0.6 per cent above CitiPower's actual capex over the 2016–2019 regulatory years. The application of the CESS in the current period, and a material CESS reward indicates that a substitute estimate close to current period actual spend is a prudent and efficient level of capex over the forecast period. We are satisfied that this capex allowance is sufficient for CitiPower to maintain its services level, particularly as CitiPower performs well on a number of network health indicators over the current period. In coming to our draft decision, we asked CitiPower many questions across multiple information requests. Citipower was very receptive to our questions and in most cases provided useful responses within the requested timeframes. We acknowledge that our questions are likely to have presented additional resourcing challenges, particularly due to COVID-19, and appreciate Citipower's cooperation and assistance.

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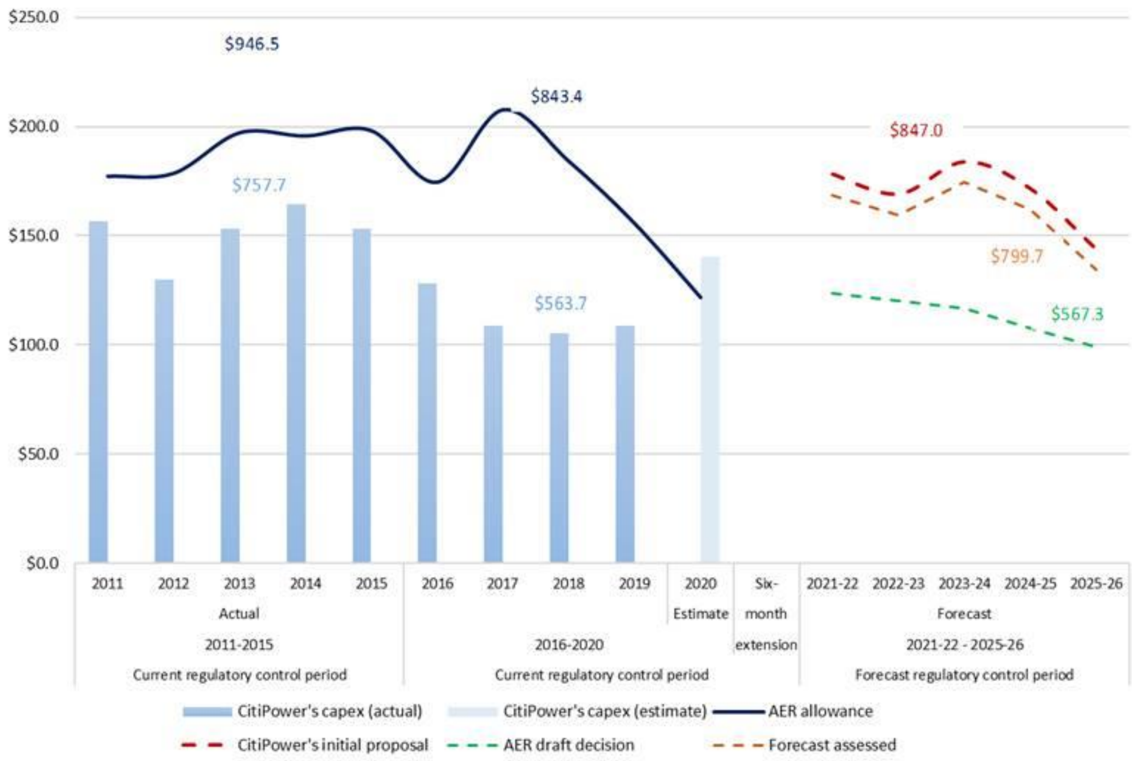
36 CitiPower's initial proposal included $847 million for net capex. It subsequently withdrew its proposed environmental capex program. The forecast assessed of $799.7 million takes into account CitiPower’s updates as well as the shift of expenditure from opex to capex.

37 We compare forecast capex with actual capex in the current period; i.e. calendar year 2016 to 2019 pro-rated to five years.

Figure 7 CitiPower's proposal, current period capex and the draft decision ($ million, 2020–21)



Source: CitiPower's initial proposal and AER analysis.

Note: The capex figures reported refer to five-year totals over a regulatory control period. The 2020 estimate has been included in this chart for indicative purposes. We have not used this estimate in our trend comparison. Forecast assessed takes into account CitiPower's updates to its capex forecast, as well as the shift of expenditure from opex to capex.

We typically analyse a distributor's total capex forecast from a top-down perspective. This top-down review forms the starting point of our capex assessment to determine whether further detailed analysis is required, but is also used throughout our review process to test the results of our bottom-up assessment. We apply both top-down and bottom-up reviews so that our decision is fully informed. In this case, we are not satisfied that Citipower's forecast capex is prudent and efficient under both reviews.

From a top-down perspective, several metrics demonstrate that Citipower's forecast is not prudent and efficient:

- The CESS applies in the current period. We therefore place significant weight on Citipower's forecast capex being 41 per cent higher relative to its actuals over the current period. This forecast is also 26 per cent higher relative to its actual spend over the longer term (10 year trend).
- Citipower's materially higher forecast relative to current period spend was combined with an underspend of 31 per cent. We acknowledge the efficiencies Citipower has achieved as reflected in its CESS reward of $63.8 million. This

highlights that Citipower has demonstrated in the current period that it can manage and maintain its network at a more efficient level.

- We found, as did EMCa, that Citipower's network performance is improving. Citipower successfully outperformed both its SAIFI targets over the first four years of the current period while underspending its capex allowance. This provides us confidence that CitiPower's current period capex is a reasonable forecast to address its network requirements over the RCP. We are therefore satisfied that our substitute estimate which is in line with current period spend will provide Citipower with sufficient funding to meet its capex objectives under the NER.
- Most stakeholders did not show support for CitiPower's forecast capex. CCP17, the VCO, and Spencer & co (for the ECA) questioned CitiPower's assumption that it has the same network risk as Powercor, given that it does not operate in high bush risk areas and does not appear to have issues with its wood pole inspection practices.
- Energy Consumers Australia (ECA) and Victorian Community Organisations (VCO) noted that affordability continues to be energy consumers' number one priority and encouraged us to question the justification of the proposed investments.[38]
- We observed little evidence of top-down challenges to its forecast. For instance, while CitiPower refers to top-down measures such as the repex model, it has not made any modifications or undertaken any sensitivity analysis to demonstrate how it has taken these top down measures into account. Similarly, it appears that CitiPower did not consider the synergies between its repex and augex forecasts, which would likely overstate its requirements moving forward. EMCa also highlighted that Citipower did not provide any evidence of total capex prioritisation to address highest risk areas first, which is likely to have led to an overstated forecast.
- Maximum demand, which is the key driver of augex, has remained flat in Victoria over the last decade. CitiPower has overstated its demand forecasts to support its augex proposals. In the past, CitiPower has forecast strongly rising demand in its initial proposals for the previous and current regulatory period forecasts, which did not eventuate. CitiPower's continued optimistic forecast of rising maximum demand is predicated on a return to a strong relationship between GDP and demand, and was made prior to COVID-19; key inputs have also been chosen or adjusted based on the consultant's judgement rather than a neutral, evidence based approach. We have applied AEMO's latest demand forecasts because AEMO's recent demand forecast accuracy has been closer to actual demand and is widely accepted by industry and understood by stakeholders.

Given our concerns with the outcomes of the top-down review, we thoroughly assessed the bottom-up material Citipower provided to support its capex forecast. Our bottom-up review confirmed the findings of our top-down assessment. In particular,

[38] Victorian Community Organisations, *2021–26 Victorian EDPR,* May 2020, p. 1.

Citipower did not provide sufficient bottom-up evidence to support the significant increase compared with the current period. In summary, our bottom-up review identified the following and we invite CitiPower to address our concerns in its revised proposal:

- CitiPower provided good models clearly setting out inputs and assumptions to support its forecast. However, we came to the same conclusions as EMCa that often the model assumptions and inputs were either not explained, untested, or overstated.
- While CitiPower provided reasonable cost benefit analysis for some projects and programs, there was a lack of supporting cost benefit analysis, particularly options analysis, for other asset projects and programs in the regulatory proposal. For instance, CitiPower did not provide economic analysis in support of its forecasted wood poles repex of $58.8 million[39] despite the 511 per cent step up from its current period spend.
- We acknowledge that Citipower's underspend resulted from the significant cost savings it achieved due to transformation program. However, these cost savings are not fully reflected in the forecast period, and therefore not passed or shared with consumers. This issue was similarly raised by EMCa.
- In a number of instances, Citipower did not provide quantitative evidence to demonstrate a change in network conditions that would require a forecasted step up relative to current period. For example, CitiPower proposed a number of pro-active replacement programs in addition to business as usual repex but it did not provide any risk modelling or cost benefit analysis to show that additional funds would be of net benefit to consumers and therefore required over and beyond its existing expenditure.
- For CitiPower's DER integration capex, we are supportive of CitiPower facilitating solar PV growth on its network. However, its solar enablement program forecast overstates what is necessary to deliver the Victorian Government's Solar Homes program. Specifically, its analysis includes investments that would be more prudent to undertake in subsequent regulatory periods.
- Most CitiPower customers supported a reasonable level of export constraint but the network must be prepared to accommodate more solar and ensure these constraints are not excessive. In response to the initial proposal, most stakeholders were supportive of investment by networks to integrate a greater level of PV export.[40] However, several stakeholders highlighted concerns with how CitiPower

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[39] CitiPower's initial proposal included an amount of $66.5 million for poles repex. In response to an information request it subsequently revised its forecast to $58.8 million. CitiPower, Information request 032 – Q11, 17 June 2020.

[40] Victorian Community Organisations, *2021–26 Victorian EDPR,* May 2020, p.4, Local Government Response, *2021–26 Victorian EDPR, May 2020,* p.30, Origin Energy, *Submission to Victorian electricity distributors' regulatory proposals,* June 2020, p.3, Vector Limited, *2021–26 Victorian EDPR,* June 2020, p.4, DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 2.

valued solar PV exports in its modelling, suggesting the attributed value over the life of the investment did not consider there might be zero or negative benefits into the future and the proposal tended to overstate the value of solar export.[41] More specifically, the VCO called for a standard approach for valuing exported generation that reflects the expected changes in the value of DER exports over time.[42]

- Similar concerns about a lack of consistency across distributors in valuing the benefits associated with investing in DER integration were raised in response to the AER's consultation paper on Assessing DER Integration Expenditure.[43] In response, the AER and ARENA commissioned the value of DER (VaDER) study earlier this year.[44] CSIRO and Cutler-Merz were engaged to conduct a study into potential methodologies for valuing DER and have extensively engaged with stakeholders, including Citipower, as part of the study.
- The final report of the VaDER study is due to the AER in early October 2020, which will help to address some of the stakeholder concerns outlined above. We will publish the final report as soon as practicable. We will then consider the report's recommendations and formally implement them as we consider appropriate as part of the AER's DER integration expenditure guideline, now due for completion in 2021. Given the extensive stakeholder engagement in forming the VaDER study's recommendations, we anticipate that consumers will expect Victorian distributors to prepare their revised proposals in the spirit of these recommendations.

We have set out the reasons for our draft decision on capex in more detail in Attachment 5.

2.5 Operating expenditure

Opex is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services. Forecast opex is one of the building blocks we use to determine CitiPower's total regulated revenue requirement.

CitiPower initially proposed a total opex forecast of $568.8 million ($2020–21) for the 2021–26 period. On 15 May, CitiPower submitted an updated proposal[45] where it proposed an updated total opex forecast of $562.8 million ($2020–21) to account for

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41 DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 2; CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 106; Energy Australia, *Submission to VIC DNSP proposals,* June 2020, p. 1; EUAA, *EDPR submission,* June 2020, p. 11.

42 Victorian Community Organisations, *2021–26 Victorian EDPR,* May 2020, p. 10.

43 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/initiation.

44 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/consultation

45 CitiPower, *CitiPower, Powercor and United Energy - Amendments to operating expenditure step changes and capital programs*, 15 May 2020.

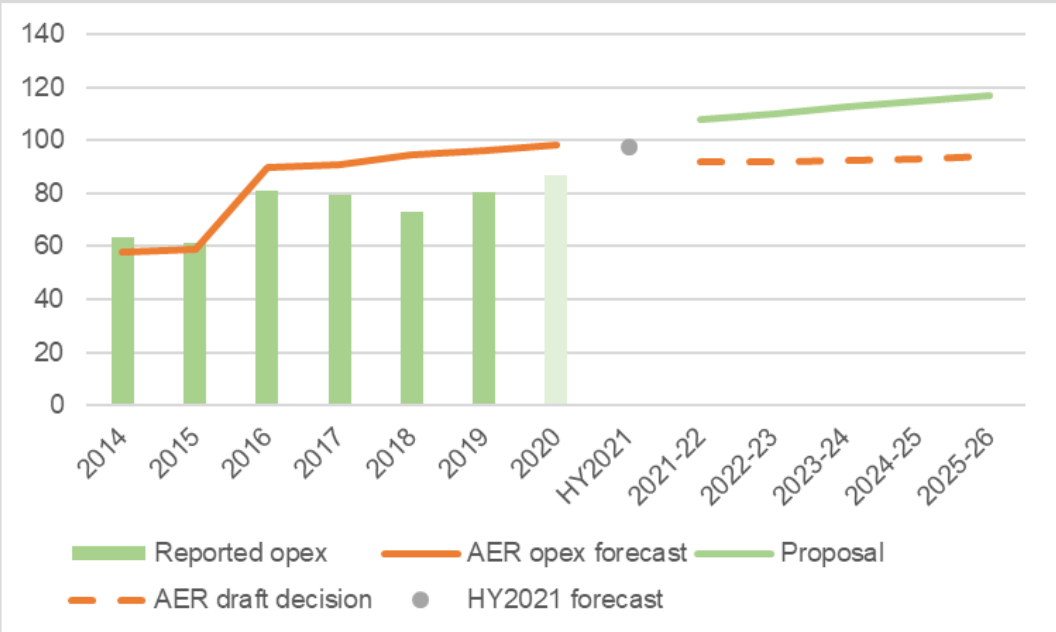
changes in circumstances since the proposal was submitted. Opex represents 37.7 per cent of CitiPower's total revenue proposal.[46]

Our draft decision is to include our alternative total opex forecast of $462.9 million ($2020–21) in CitiPower's allowed revenue for the 2021–26 period. This is $99.9 million, or 17.8 per cent, lower than CitiPower's updated total opex forecast of $562.8 million ($2020–21).[47]

Our draft decision opex forecast is also $6.2 million (or 1.3 per cent) lower than the opex forecast we approved in our final decision for the 2016–20 regulatory period and $62.4 million (or 15.6 per cent) higher than CitiPower's actual (and estimated) opex in the 2016–20 regulatory period.

Figure 8 shows CitiPower's actual opex, our previous approved forecast in the current regulatory control period along with its proposed opex for the next regulatory control period and our draft decision.

Figure 8 CitiPower's opex over time ($ million, 2020–21)



Source: CitiPower, *2021–26 Regulatory proposal – Supporting document RIN001 – Workbook 1 – Reg determination*, January 2020; CitiPower, *2021–26 Regulatory proposal – Supporting document 10.02 – Opex model (updated)*, May 2020; AER, *Draft Decision, CitiPower distribution determination 2021–26, Opex model*, September 2020; AER, *Draft Decision, CitiPower distribution determination 2021–26, EBSS model*, September 2020; AER analysis.

Table 6 sets out CitiPower's proposal, including updates it submitted, our alternative estimate for the draft decision and key differences.

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46 CitiPower, *2021–26 Regulatory proposal – Supporting document 10.02 - PTRM 2021–26 (updated)*, May 2020.

47 Including debt raising costs.

Table 6 Comparison of CitiPower's proposal and our draft decision on opex ($ million, 2020–21)

	Citipower proposal	Updated proposal	AER draft decision	Difference
Base (reported opex in 2019)	434.7	434.7	413.4	–21.3
Base year adjustments	26.8	26.8	4.0	–22.9
Final year increment	19.7	19.7	17.8	–1.9
Trend: Output growth	25.2	25.2	10.0	–15.2
Trend: Real price growth	20.7	20.7	0.9	–19.9
Trend: Productivity growth	–7.2	–7.2	–5.9	1.2
Step changes	43.6	37.6	17.3	–20.3
Category specific forecasts	0.0	0.0	0.7	0.7
Total opex (excluding debt raising costs)	563.7	557.6	458.0	–99.6
Debt raising costs	5.2	5.2	4.8	–0.3
Total opex (including debt raising costs)	568.8	562.8	462.9	–99.9
Percentage difference to proposal				–17.8%

Source: CitiPower, *2021–26 Regulatory proposal – Supporting document 10.06 - Opex model,* January 2020; CitiPower, *2021–26 Regulatory proposal – Supporting document 10.06 - Opex model (updated),* May 2020; AER analysis.

Note: Numbers may not add up to totals due to rounding. The difference is between CitiPower's proposal and our draft decision.

The following factors have contributed to our lower alternative total opex forecast:

- We used 2019 for base year opex in developing our alternative estimate as our assessment of revealed cost data and benchmarking techniques found that CitiPower has been relatively efficient over time.[48] CitiPower was amongst the top two in terms of opex efficiency when measured using our econometric models. [49] We have updated for actual 2019 reported opex which was not available at the time the proposal was submitted, which lowers our alternative estimate compared to CitiPower's proposal by $21.3 million ($2020–21).
- For base adjustments, our alternative estimate is $22.9 million ($2020–21) lower than CitiPower's proposal. The main driver of this difference is we have not included the proposed reclassification of replacement expenditure on faults and minor repairs as opex.

48 See Attachment 6 for a fuller description of our economic benchmarking and base opex assessment.

49 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2019. pp. 29–30.

- With the exception of forecasting labour price growth, we have used our standard approach to trend opex forward over the next five years. For labour price growth, we have used a forecast prepared by Deloitte Access Economics rather than the standard approach of averaging two forecasts as this is the only forecast available which factors in the impacts of COVID-19. For the final decision we will consider updating the rate of change forecast using our standard approach provided the necessary forecasts are available.
- We forecast the rate of change for CitiPower over the next five years is on average 0.5 per cent each year. This is lower than CitiPower's proposed 2.4 per cent per year. This primary driven by lower output and price growth forecasts, which in large part reflect the impacts of COVID-19 on forecast customer numbers and wage price growth. This lowers our alternative estimate compared to CitiPower’s proposal by $33.9 million ($2020–21).
- We generally only include step changes where we are satisfied there are efficient costs associated with new regulatory obligations or capex/opex tradeoffs and these costs are not already captured in base opex or through our trend forecast. We have included three of the eight step changes (five minute settlement, IT cloud solutions and security of critical infrastructure) proposed by CitiPower but have reduced some of the proposed amounts based on our efficiency assessment. We did not include five of the step changes as they were either withdrawn (Environment Protection Act Amendment), had costs which were immaterial or captured by trend (solar enablement, financial year RIN, Energy Safe Victoria levy) or did not have a legitimate driver (Yarra Trams pole relocation). This lowers our alternative estimate compared to CitiPower’s proposal by $20.3 million ($2020–21)

We have set out the reasons for our draft decision on opex in more detail in attachment 6. Our opex model, which calculates our alternative estimate of opex, is available on our website.

2.6 Corporate income tax

We determine an estimated cost of corporate income tax of $29.8 million ($ nominal) for CitiPower in the 2021–26 regulatory control period. This represents a decrease of $6.9 million compared to CitiPower's proposal of $36.6 million ($ nominal).

The key reasons for the decrease is due to our:

- reduction to the return on equity, which is influenced by our adjustments on other building block components (attachments 2, 3 and 5)
- reduction in customer contributions (attachment 5).

Further, in this draft decision we have:

- increased the proposed forecast immediately expensed capex
- adjusted the proposed opening tax asset base (TAB) as at 1 July 2021, including amendments and updates for actual and estimated capex and a reallocation for accelerated tax depreciation consistent with the accelerated depreciation approach for the RAB.

We accept CitiPower's proposed standard tax asset lives for all of its existing asset classes and we have amended the standard tax asset life for CitiPower's new 'In-house software' asset class. The proposed standard tax asset lives are broadly consistent with the tax asset lives prescribed by the Commissioner for taxation in Australian Tax Office (ATO) taxation ruling 2020/3 and/or are the same as the approved standard tax asset lives for the 2016–20 regulatory control period.

We also accept CitiPower's proposed weighted average method to calculate the remaining tax asset lives as at 1 July 2021. This method is a continuation of the approved approach used in the 2016–20 regulatory control period and applies the approach as set out in our RFM.

Our adjustments to the return on capital (attachments 2, 3 and 5) and the regulatory depreciation (attachment 4) building blocks affect revenues, which in turn impacts the tax calculation. The changes affecting revenues are discussed in attachment 1.

Further detail on our draft decision regarding the corporate income tax is set out in attachment 7.

2.7 Revenue adjustments

Our draft decision on CitiPower' total revenue also included a number of adjustments:

- EBSS — CitiPower accrued EBSS carryovers totalling $0.4 million ($2020–21).[50] This is $8.3 million ($2020–21) higher than –$7.9 million ($2020–21) proposed.[51] The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users.
- CESS — CitiPower has accrued rewards under the CESS we applied in the current 2016–20 regulatory control period to incentivise CitiPower to undertake efficient capex throughout the period. The CESS rewards efficiency gains and penalises efficiency losses, each measured by reference to the difference between forecast and actual capex. In the 2016–20 period, CitiPower out-performed our capex forecast, and our draft decision is to approve a CESS revenue increment amount of $63.8 million ($2020–21).
- Shared assets — Distributors, such as CitiPower, may use assets to provide both the SCS we regulate and unregulated services. These assets are called 'shared assets'. If the revenue from shared assets is material, ten per cent of the unregulated revenues that a distributor earns from shared assets will be used to reduce the distributor's revenue for SCS. For this draft decision, we determine a revenue adjustment of $1.5 million ($2020–21) to be shared with customers across the 2021–26 regulatory control period.

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[50] Includes accrued EBSS carryovers for the HY2021 period

[51] Includes accrued EBSS carryovers for the HY2021 period

- DMIAM — an allowance of $2.07 million ($2020–21) has been has been applied to CitiPower over the 2021–26 regulatory control period. The DMIAM aims to encourage distribution businesses to find investments that are lower cost alternatives to investing in network solutions.

Section 4 sets out our draft decision on the incentive schemes that might apply to CitiPower over the next regulatory control period.

3 CitiPower's consumer engagement

The National Electricity Objective focuses our work on the long-term interest of consumers[52] and we think including consumers in the development of proposals is the best way to deliver this. Genuine, high quality engagement with consumers helps distributors better understand consumers' preferences and experiences and tailor their proposals to align with consumers' long-term interests. The Rules also require us to consider the extent to which elements of the proposals address relevant concerns identified during the distributor's engagement with consumers.[53]

We value the work of the distributors to constructively engage with consumers when preparing their draft proposals. They all acknowledged the diversity within their consumer base in terms of the manner in which they engage with the network, as well as the linguistic, cultural and demographic characteristics that influence this engagement. The interactions between the distributors' senior management (including board members) and the engagement initiatives also suggested the distributors were keen to hear what their consumers had to say.

We used the results of each distributor's consumer engagement to inform our draft decisions. High quality consumer engagement can take a range of forms and we encourage distributors to consider which approach best suits them and consumers in their network. The best approach to take may depend on the nature of a distributor's consumer base and the issues of importance to those consumers.

Regardless of the approach taken, we believe that proposals which have been developed with the influence of consumers, and their preferences, are more likely to be in the long-term interests of consumers than those which have not. Taking this into account, the elements outlined in Table 7 represent a range of considerations that we think can clearly demonstrate whether consumers have been genuinely engaged in the development of the proposals.

The elements of consumer engagement which informed how we viewed this engagement and the weight we were able to place on the outcomes in our consideration of the regulatory proposal are summarised in Table 7. The rest of this section discusses our assessment of each distributor's engagement against this framework. These elements are intended to show how our thinking has evolved since our 2013 Consumer Engagement Guideline but are not intended to provide a fixed view. Our framework will continue to evolve as distributors' models of consumer engagement mature over time.

52 NEL, s. 16(1)(a).

53 NER, cl. 6.5.6(e)(5A) and 6.5.7(e)(5A).

Table 7 Framework for considering consumer engagement

Element	Examples of how this could be assessed
Nature of engagement	• Consumers partner in forming the proposal rather than asked for feedback on distributor's proposal • Relevant skills and experience of the consumers, representatives, and advocates • Consumers provided with impartial support to engage with energy sector issues • Sincerity of engagement with consumers • Independence of consumers and their funding • Multiple channels used to engage with a range of consumers across a distributor's consumer base
Breadth and depth	• Clear identification of topics for engagement and how these will feed into the regulatory proposal • Consumers consulted on broad range of topics • Consumers able to influence topics for engagement • Consumers encouraged to test the assumptions and strategies underpinning the proposal • Consumers were able to access and resource independent research and engagement
Clearly evidenced impact	• Proposal clearly tied to expressed views of consumers • High level of business engagement, e.g. consumers given access to the distributor's CEO and/or board • Distributors responding to consumer views rather than just recording them • Impact of engagement can be clearly identified • Submissions on proposal show consumers feel the impact is consistent with their expectations

Proof point	• Reasonable opex and capex allowances proposed
	  ○ In line with, or lower than, historical expenditure
	  ○ In line with, or lower than, our top down analysis of appropriate expenditure
	  ○ If not in line with top down, can be explained through bottom up category analysis

Nature of engagement

For the purpose of engagement, CitiPower, Powercor and United Energy operated an overarching engagement program developed to support the three networks, noting that when differences were identified measures were taken to engage further or differently with customers and stakeholders as required.[54] We have not undertaken a formal audit against the IAP2 spectrum. However, from the information provided it would appear that CitiPower's proposal is broadly consistent with the consult or involve end of the spectrum.

Their initial plan outlined their engagement from January 2017 to July 2019, culminating with the submission of proposals. This plan was extended in May 2019 to reflect the intention of the Victorian Government to extend the previous regulatory control period (2016–20) to coincide with 1 July 2021 price changes.

CitiPower, Powercor and United energy highlighted the key milestones of its four-phase principle based engagement plan, including the opportunities to engage and review customer feedback in its Stakeholder Engagement Plan.[55] Their engagement stated that they deliberately focused on 'grass roots' customers and their three-year plan encompassed 2.5 million 'touch points' and 11 000 direct engagements with customers.[56]

CitiPower, Powercor and United Energy outlined in their engagement plan that they recognised the need for a dedicated advisory panel and established the EFCAP to provide a collaborative platform that represented the perspectives of their customers.[57] The EFCAP comprised of 11 members with a diverse representation of customer and stakeholders. These members represented:

- energy market, policy, regulation or planning
- consumer advocacy
- residential, small business, commercial, industrial or vulnerable customers
- sustainability, renewables or distributed energy.[58]

CitiPower, Powercor and United Energy state that the EFCAP was critical to advise on: customer and stakeholder views were being fully considered; the effectiveness of the engagement activities and whether feedback was reflected in their draft proposal;

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54 CitiPower, APP 01 Stakeholder Engagement, January 2020, p 4; Powercor, APP01 Stakeholder Engagement, January 2020, p.4; United Energy, APP01 Stakeholder Engagement, January 2020, p.5.

55 CitiPower, Powercor and United Energy, *Att069 Regulatory reset stakeholder engagement plan 2021–25*, pp. 10–12.

56 CitiPower, Powercor and United Energy, *Response to the AER's issues paper regulatory reset 2021–26*, April 2020, pp. 6, 14.

57 CitiPower, APP 01 Stakeholder Engagement, January 2020, p 17; Powercor, APP 01 Stakeholder Engagement, January 2020, pp. 17–18; United Energy, APP 01 Stakeholder Engagement, January 2020, p 18.

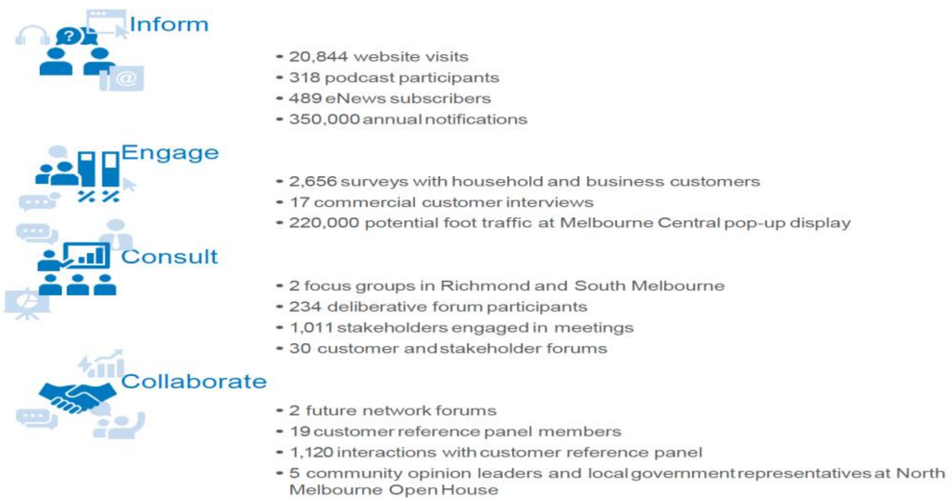
58 CitiPower, APP 01 Stakeholder Engagement, January 2020, p 17; Powercor, APP 01 Stakeholder Engagement, January 2020, pp. 17–18; United Energy, APP 01 Stakeholder Engagement, January 2020, p 18.

provide feedback to inform their decision making; and share information to other interested stakeholders.[59]

CitiPower, Powercor and United Energy's held deliberative approaches in their Energy Network Future Forum's in both phase one and two to inform the development of their possible future energy drivers.[60] Members from their Customer Consultative Committee, the EFCAP, and other electricity industry stakeholders joined these forums.[61] In the phase two, April 2019 forum, they outline that they used the unprompted priorities from customers identified through phase one to continue testing and refining the possible future scenarios.[62] The distributors commissioned Woolcott Research to support their engagement as independent facilitators. This included facilitating and providing reports on how customers responded to the topics for consultation. For example, in relation to solar exports and demand response they noted consumers wanted the solution adopted 'to be equitable and benefit a diverse range of customers... (and) that solutions may be different for each of the three networks and should be discussed separately'.[63]

CitiPower, Powercor and United Energy have outlined a high-level their engagement, and the variety of channels utilised with their stakeholders in Figure 9.

Figure 9 CitiPower, Powercor and United Energy Engagement Journey



Source: CitiPower, Powercor, United Energy, Overview paper, January 2020, p. 20.

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[59] CitiPower, APP 01 Stakeholder Engagement, January 2020, p 17; Powercor, APP 01 Stakeholder Engagement, January 2020, pp. 17–18; United Energy, APP 01 Stakeholder Engagement, January 2020, p 18.

[60] CitiPower, APP 01 Stakeholder Engagement, January 2020, p 17; Powercor, APP 01 Stakeholder Engagement, January 2020, pp. 17–18; United Energy, APP 01 Stakeholder Engagement, January 2020, p 18.

[61] CitiPower, APP 01 Stakeholder Engagement, January 2020, p 17; Powercor, APP 01 Stakeholder Engagement, January 2020, pp. 17–18; United Energy, APP 01 Stakeholder Engagement, January 2020, p 18.

[62] CitiPower, APP 01 Stakeholder Engagement, January 2020, p 23; Powercor, APP 01 Stakeholder Engagement, January 2020, pp. 23; United Energy, APP 01 Stakeholder Engagement, January 2020, p 24

[63] Woolcott Research, *CitiPower Attachment 74, Future Networks Forum – April 2019*, January 2020, p 6.

We acknowledge that CitiPower, Powercor and United Energy have done extensive work in reaching customers in order to gain a clearer understanding of the values of a diverse customer base. This has occurred across multiple channels and ‘touch points’ and investment in this degree of activity suggests a sincere level of engagement from the distributors. For example, CCP17 noted that they had no major issues with the consumer engagement and that they were pleased that ‘the reports from Woolcott do not paint a picture of perfect understanding of customers.’[64]

Breadth and depth

CCP17 commented that CitiPower, Powercor and United Energy delivered ‘a set of well-presented readable documents’ that enabled stakeholders to understand business drivers for the regulatory control period (2021–26) and the businesses responses to those drivers. [65]

CCP17 submission also noted that CitiPower, Powercor and United Energy’s consumer engagement that was undertaken enabled them to look at issues from a customer perspective.[66] CCP17 also attended many of the events held and considered the EFCAP an especially useful approach, which was well implemented. However they noted that the learnings developed from the EFCAP process over the last 12 months have not been clear and seemed to have reduced in its advisory capacity.[67] CCP17 highlighted:

> Some EFCAP members were clearly frustrated because they were participating in order to “make a difference” for customers but could not see evidence of that. EFCAP members requested more frequent (monthly meetings) so that they could provide an advisory role, but this did not eventuate. EFCAP met a total of three times during 2018, and the impact of the businesses’ activities remain unclear.[68]

The VCO joint submission also recognised the extensive engagement program undertaken by CitiPower, Powercor and United Energy.[69] The VCO noted that while there had been a different approach to their engagement, the results still returned

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64 CCP17, *Progress report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021–2025 Regulatory Reset,* 27 March 2019, p.19.

65 CCP17, *Comments on the CitiPower, Powercor and United Energy Draft Regulatory Proposals (draft plans)*, July 2019, p.4.

66 CCP17, *Submission on the Victorian Electricity Distributors’ Regulatory Proposals for the Regulatory Determination 2021–26,* June 2020, pp.24–25.

67 CCP17, *Submission on the Victorian Electricity Distributors’ Regulatory Proposals for the Regulatory Determination 2021–26,* June 2020, p.25.

68 CCP17, *Submission on the Victorian Electricity Distributors’ Regulatory Proposals for the Regulatory Determination 2021–26,* June 2020, p.26.

69 Victorian Community Organisations, *Submission on the Victorian Electricity Distributors’ Regulatory Proposals for the Regulatory Determination 2021–26,* May 2020, p.14.

direct benefits to customers, resulting in new or changed programs or processes, for example with an energy literacy programs for vulnerable customers.[70]

The VCO compared the result of engagement across all five Victorian distributors and noted varying results in key areas – such as the value of reliability, safety and affordability. They observed that CitiPower, Powercor and United Energy found no difference between the three networks in these areas. The VCO suggest different research approaches are likely to have an impact on findings, as demonstrated by different outcomes by other distributors, and suggest that results should inform, rather than determine the proposal process.[71]

Consumers were clearly consulted on a broad range of topics. However, this was often at a high level with the issues and agendas guided by the distributor's staff. While we appreciate the use of Woolcott Research to support the distributor's engagement, we are not aware of independent resources being made available to consumers to assist in supporting their decision making and engagement.

Clearly evidenced impact

CitiPower, Powercor and United Energy outlined in their engagement plans that they used initial customer feedback to identify unifying values across all three networks. These values included:

- safe and maintained networks, with reliable supply
- affordability of supply that lowers bills and is fair
- services that provide customer choice regarding information and communication of supply and discounts, incentives and program to support bill reductions
- a sustainable network.[72]

CitiPower outlines that these values and on-going feedback were incorporated and applied to their proposal. The following is a sample of examples where this was outlined throughout the proposal:

- The retirement of Port Melbourne assets to be moved to the Westgate zone substation, combined with an upgrade at the Westgate substation, which received overwhelming support from customers.[73]

[70] Victorian Community Organisations, *Submission on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* May 2020, p.14.

[71] Victorian Community Organisations, *Submission on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* May 2020, p.15.

[72] CitiPower, *APP 01 Stakeholder Engagement, January 2020*, p. 22; Powercor, *APP 01 Stakeholder Engagement, January 2020*, January 2020; p.22; United Energy, *APP 01 Stakeholder Engagement, January 2020*, January 2020, p.23.

[73] CitiPower, *Regulatory Proposal 2021–26*, January 2020, pp. 70–71.

- 65 per cent of customers were interested in accessing real-time data and under three-quarters of residents would use this data to seek rebates or savings, supporting the ongoing work of CitiPower's customer enablement program.[74]
- Affordability was a key concern for customers, including commercial and industrial customers. CitiPower assert that their proposal provides value for money, while maintaining reliability for its customers with a $38 reduction for residential customers and $119 reduction for small business customers over the regulatory control period (2021–26).[75]

Another element raised in CitiPower, Powercor and United Energy's proposal is the commitment to remove 95 per cent of solar constraints for customers. The example given being that Powercor customers would be paying a similar increment on their bill compared with AusNet Service's customers, however receiving better outcomes.[76] This investment in solar enablement is supported by customers who have said that preparation should be made for a future driven by increased solar, batteries and electric vehicles.[77] CCP17 in their draft review, encouraged all three distributors to ensure that in the context of supporting the export of energy by customers with DER, they are 'very cognisant of defining the value of these investments to all customers, including the majority who do not invest in DER capability.'[78]

We received limited submissions from stakeholders drawing out specific elements in relation to CitiPower, Powercor and United Energy's assessment of the integration of this engagement in developing its proposals. We weren't always able to identify how consumer views were incorporated in their proposals. The VCO highlighted that CitiPower, Powercor and United Energy 'prepared their draft and initial proposal in line with customer response to their own nominated contestable investment proposals (which were, established internally and not made public)'.[79]

The LGA submission did provide a positive example where the distributors demonstrated listening to feedback provided by stakeholders throughout their engagement process. They noted that at the Future Networks Forum (April 2019) many of the topics discussed were unpopular with attendees, covering issues such as proposals to enable solar exports, demand response programs, and incentives to

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[74] CitiPower, *Regulatory Proposal 2021–26*, January 2020, p. 85.

[75] CitiPower, *Regulatory Proposal 2021–26*, January 2020, p. 119

[76] CCP17, *Submission on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* June 2020, p.28.

[77] CitiPower, *APP 01 Stakeholder Engagement, January 2020*, p. 63; Powercor, *APP 01 Stakeholder Engagement, January 2020*, January 2020; p.73; United Energy, *APP 01 Stakeholder Engagement, January 2020*, January 2020, p.91.

[78] CCP17, *Comments on the CitiPower, Powercor and United Energy Draft Regulatory Proposals (draft plans)*, July 2019, pp, 12, 20, 27.

[79] Victorian Community Organisation, *Submission on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, May 2020, p. 14.

encourage customers to shift their energy load to off-peak periods.[80] The LGA gave credit to the distributors for responded to stakeholder concerns as they subsequently revised their approach to DER enablement with the release of an updated options paper for consultation. The LGA believe this has resulted in a 'DER pricing proposal more closely aligned with the pricing proposed by other distributors and broadly supported by customers'.[81]

We recognise the work that has gone into shaping the engagement process. However, we have been unable to clearly identify the elements of the proposal that were shaped by consumer preferences. This has lessened the weight which the AER has been able to give to the consumer engagement process in this draft determination. Although we believe there are still many opportunities for the revised proposals to outline and clarify how this engagement specifically shaped elements of their proposals.

Proof point

Once we have considered the nature, scope, and impact of the consumer engagement, our final step is to consider whether the outcome of this engagement as presented by CitiPower is in the long-term interest of consumers. We do this by undertaking our standard process. We compare the allowances proposed by CitiPower with those our established models and approaches suggest represent alternative estimates. If the proposal is aligned with or below these estimates we are able to have greater confidence that the results of the consumer engagement is in the long-term interest of consumers.

CitiPower is proposing materially increased expenditure. As outlined in sections 2.4 (capex) and 2.5 (opex) we do not consider CitiPower provided enough evidence that increasing allowances above the historical level would be in the long-term interest of consumers. The outcomes of CitiPower's consumer engagement process have not persuaded the AER that a more thorough bottom up analysis is not warranted, or that the increased expenditure forecasts should be accepted in the face of this bottom up analysis.

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80 LGA, *Submission on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, June 2020, updated August 2020, p. 41.

81 LGA, *Submission on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, June 2020, updated August 2020, p. 41.

4 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination we've discussed in section 2, to encourage CitiPower to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

The incentive schemes that might apply to an electricity distribution network as part of our decision are:

- the opex EBSS
- the capital CESS
- the service target performance incentive scheme (STPIS)
- the customer service incentive scheme
- the demand management incentive scheme (DMIS) and allowance (DMIAM)
- the f-factor scheme.

Once we make our decision on CitiPower' revenue cap, it has an incentive to provide services at the lowest possible cost, because its returns are determined by its actual costs of providing services. Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. If networks reduce costs to below our forecast of efficient costs, the savings are shared with its consumers in future regulatory periods through a lower opex allowance and a lower RAB.

We understand the strong concerns of stakeholders that the CESS not only rewards efficiency gains but also over forecasting and deferral of capex. The current CESS guideline includes protections against material deferrals that have been triggered for some elements of Powercor's proposal[82] but not for CitiPower. Protection against over forecasting of capex lies in the rigorous assessment of proposed capex.

The DMIS and the DMIAM provide businesses an incentive to undertake efficient expenditure on non-network options relating to demand management research and development in demand management projects that have the potential to reduce long-term network costs.

The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to

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82 AER, *Draft Decision, Powercor Distribution Determination 2021–26, Attachment 9 Capital Expenditure Sharing Scheme*, September 2020.

businesses to maintain and improve service performance and not by simply cutting costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years.

To accompany the STPIS we have established the CSIS to try and capture how well the distributor is meeting customer preferences. The intention is for this to replace the 0.5 per cent of revenue tied to the telephone answering parameter under the STPIS. As a new small scale incentive scheme, it is up to the distributor to formally propose to us how they intend to apply the scheme. We have not yet received a proposal from CitiPower, but understand they are still considering whether to apply for this scheme.

Our draft decision is that each of the EBSS, CESS, STPIS, DMIS and DMIAM should apply to CitiPower for the 2021–26 regulatory control period. Whether or not we need to make a decision on the CSIS will be contingent on if we receive a formal proposal.

Our draft decision also includes how the f-factor scheme is applied to CitiPower in the next regulatory control period. The f-factor scheme is prescribed by the Victorian Government's "f-factor scheme order 2016" to reduce the risk of fire starts by network assets.[83] We will continue to adopt our current approach to give effect of the outcomes of the scheme as an "I-factor" component within the price control formula.

We discuss our draft decisions on each incentive scheme in attachments 8 to 11. Our draft decision on the f-factor scheme is discussed in attachment A.

83 http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf

5 Tariff structure statement

The requirement on distributors to prepare a tariff structure statement arises following significant reforms to the rules governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- providing better price signals to retailers to reflect what it costs to use the networks to supply electricity at different times
- transitioning to greater cost reflectivity while engaging with customers, customer representatives, and retailers to consider the impacts of tariff changes on customers
- managing future expectations for retailers, energy service providers and customers by providing guidance on distributors' tariff strategy.

It is important to note that distributors charge retailers for the network services provided to end-customers. There is no obligation on retailers or energy service providers to pass the network tariff structure through to their end-customers. The structure of retail offers should be determined by retailers responding to consumer preferences and competitive pressures.

Network tariff reform aims to help distributors charge retailers in a manner which more closely reflects the cost of providing electricity network capacity to their end customers. Retailers can then decide how best to manage these price signals which may include "insurance-style" flat rate offers and non-price measures such as well targeted demand management initiatives. If customers are well placed to respond to these price signals, retailers may pass through the structures and reward customers for helping to manage the commercial risk.[84] But at present, it is more common for retailers to pass through the cost reflective network tariff structures to large business customers, than for residential or small business customers.

The tariff structure statement must set out a number of matters. These include tariff classes, proposed tariffs and the structures and charging parameters, and the approach to setting tariff levels in each year of the regulatory control period. [85] The policies and procedures it will use to assign customers to tariffs, or reassign customers from one tariff to another must also be outlined.

In this determination we decide the structure of tariffs that will form the basis of annual pricing proposals throughout the regulatory control period.[86] We are also required to decide the policies and procedures for assigning or re-assigning customers to tariff classes.[87] While an indicative pricing schedule must accompany the tariff structure

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84 See our recently published Retailer Engagement Report on the Network Tariff Reform webpage

85 NER, cl. 6.18.1A.

86 NER, cl. 6.12.1(14A).

87 NER, cl. 6.12.1(17).

statement, the tariff levels for each tariff for each year of the 2021–26 regulatory control period are not set as part of this determination.[88]

Tariffs for the regulatory year commencing 1 July 2021 will be subject to a separate approval process in May 2021, after we have made our final revenue determination in April 2021. Tariffs for the next four years will also be approved on an annual basis.[89]

We commend the Victorian distributors for their work to engage with stakeholders in a series of forums to help develop a state-wide proposal for the small user components of their TSSs. Similar to our recent decisions on we have given weight to both the involvement of consumers in developing these proposals, as well as the supportive submissions we have received.[90] In forming our views for this draft decision we have also taken into account the Victorian Department of Environment, Land, Water & Planning’s submission which strongly encourages us to broadly accept these elements.[91]

Our draft decision broadly supports the direction of these proposals. Particularly as the distributors have generally met the expectations we set out in our final decision for the first round of TSS (2017–20). At that time we encouraged the Victorian distributors to move from opt-in to opt-out tariff assignment to cost reflective tariffs to increase the pace at which network tariff reform progresses. We also urged the Victorian networks to refine their tariff structures to include more targeted peak period charging windows. The Victorian distributors have also generally adopted strategies we have encouraged within our determinations for other networks, such as discounting their cost reflective tariffs relative to the flat rate option.[92]

However, we have concerns that some aspects of the proposed TSS do not comply with the pricing principles set out in the NER.[93] We require:

- greater clarity around the interlinkages between distributed energy initiatives, including tariff trials, and the tariff strategies for the 2021–26 regulatory period
- consideration of interactions between emerging distributed energy technologies, such as batteries and electric vehicles, and proposed tariff structures
- refining the charging windows for large user tariffs to more closely reflect periods of network constraint for each distributor
- responses to large businesses' requests for greater choice in network tariff structures as large users generally have network structures passed through.

In attachment 19 we have therefore set out a series of changes that we consider necessary for us to approve the Victorian distributors' TSS proposals.

88 NER, cl. 6.8.2(d)(1).

89 NER, cll. 6.18.2 and 6.18.8.

90 For example, see our Final Decision for SA Power Network's TSS for the 2020–25 regulatory control period

91 DELWP, Submission on Tariff Structure for the Victorian Electricity Distribution Proposal 2021–26, June 2020

92 For example see our Final Decision for Essential Energy's TSS for the 201924 regulatory control period

93 NER, cl. 6.18.5.

6 The National Electricity Law and Rules

The NEL and NER provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the NEO:[94]

> "…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[95] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long-term interests of consumers.[96] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[97]

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that is likely to contribute to the achievement of the NEO to the greatest degree.[98]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[99] These are set out in appendix A and the relevant attachments. In coming to a decision that contribute to the achievement of the NEO, we have considered interrelationships of the constituent components of our draft decision in the relevant attachments. Examples include:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark

94 NEL, s. 7.

95 NEL, section 16(1)(a)

96 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

97 Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

98 NEL, s. 16(1)(d).

99 NER, 6.12.1

efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3 and 7).

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[100] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account.[101]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long-term interests of consumers.[102] A particular economically efficient outcome may nevertheless not be in the long-term interests of consumers, depending on how prices are structured and risks allocated within the market.[103] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree than others would. For example, we consider that:

- the long-term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[104]
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where consumers are making more use of the network than is sustainable leading to safety, security and reliability concerns.[105]

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

101 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

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

103 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

104 NEL, s. 7A(7).

105 NEL, s. 7A(6).

A Constituent decisions

Our draft decision on CitiPower's distribution determination for the 2021–26 regulatory control period includes the following constituent components:

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the AER's draft decision is that the classification of services set out in Attachment 13 will apply to CitiPower for the 2021–26 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's draft decision is not to approve the annual revenue requirement set out in CitiPower building block proposal. Our draft decision on CitiPower's annual revenue requirement for each year of the 2021–26 regulatory control period is set out in attachment 1 of the draft decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve CitiPower's proposal that the regulatory control period will commence on 1 July 2021. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve CitiPower's proposal that the length of the regulatory control period will be 5 years from 1 July 2021 to 30 June 2026.
The AER did not receive a request for an asset exemption under clause 6.4.B.1 (a) (1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's draft decision is not to accept CitiPower's proposed total forecast capital expenditure of $847 million ($2020–21). Our draft decision therefore includes a substitute estimate of CitiPower's total forecast capex for the 2021–26 regulatory control period of $567.3 million ($2020–21). The reasons for our draft decision are set out in attachment 5.
In accordance with clause 6.12.1(4)(ii) of the NER and acting in accordance with clause 6.5.6(d), the AER's draft decision is not to accept Citipower’s proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $562.8 million ($2020–21). Our draft decision therefore includes a substitute estimate of Citipower total forecast opex for the 2021–26 regulatory control period of $462.9 million ($2020–21) including debt raising costs and exclusive of DMIAM. The reasons for our draft decision are set out in attachment 6 of the draft decision.
CitiPower did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the 2018 Rate of Return Instrument (to be modified subject to the passing of relevant Victorian legislation), the AER's draft decision is that the allowed rate of return for the 2021–22 regulatory year is 4.59 per cent (nominal vanilla) as set out in attachment 3 of the draft decision. The rate of return for the remaining regulatory years 2022–26 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) of the NER and the 2018 Rate of Return Instrument (to be

Constituent decision
modified subject to the passing of relevant Victorian legislation), the AER's draft decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in section 2.2 of this draft decision overview.
In accordance with clause 6.12.1(6) of the NER, the AER's draft decision on CitiPower's regulatory asset base as at 1 July 2021 in accordance with clause 6.5.1 and schedule 6.2 is $1979.9 million ($ nominal). This is discussed in attachment 2 of the draft decision.
In accordance with clause 6.12.1(7) of the NER, the AER's draft decision is to not accept CitiPower's proposed corporate income tax of $36.6 million ($ nominal). Our draft decision on the estimate of CitiPower's corporate income tax is $29.8 million ($ nominal). This is discussed in attachment 7 of the draft decision.
In accordance with clause 6.12.1(8) of the NER, the AER's draft decision is to not approve the depreciation schedules submitted by CitiPower. Our draft decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in attachment 4 of the draft decision.
In accordance with clause 6.12.1(9) of the NER the AER makes the following draft decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme (customer service incentive scheme) is to apply: • We will apply version 2 of the EBSS to CitiPower in the 2021–26 regulatory control period. This is discussed in attachment 8 of the draft decision. • We will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to CitiPower in the 2021–26 regulatory control period. This is discussed in attachment 9 of the draft decision. • We will apply our Service Target Performance Incentive Scheme (STPIS) to CitiPower for the 2021–26 regulatory control period. This is discussed in attachment 10 of the draft decision. • We will apply the DMIS and DMIAM to CitiPower for the 2021–26 regulatory control period. This is discussed in attachment 11 of the draft decision. • Whether or not we need to make a decision on the customer service incentive scheme (CSIS) will be contingent on whether we are formally provided with a proposed scheme from CitiPower in the near future.
In accordance with clause 6.12.1(10) of the NER, the AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft determination including attachments.
In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's draft decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for CitiPower for any given regulatory year is the total annual revenue calculated using the formula in attachment 14, which includes any adjustment required to move the DUoS unders and overs account to zero. This is discussed in attachment 14 of the draft decision.

Constituent decision

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's draft decision on the form of the control mechanism for alternative control services is to apply a revenue caps for type 5 and 6 metering (including smart metering) services and price caps for all other services. The revenue cap for Citipower's type 5 and 6 metering (including smart metering) services for any given regulatory year is the total annual revenue for type 5 and 6 (inc. smart metering) services calculated using the formula in attachment 14, which includes any adjustment required to move the metering unders and overs account to zero. . This is discussed in attachment 14 of the draft decision.

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

In accordance with clause 6.12.1(14) of the NER, the AER's draft decision is to apply the following nominated pass through events to CitiPower for the 2021–26 regulatory control period in accordance with clause 6.5.10:

- Terrorism event
- Insurance coverage event
- Natural disaster event
- Insurer credit risk event
- Retailer insolvency event

These events have the definitions set out in Attachment 15 of the draft decision.

In accordance with clause 6.12.1(14A) of the NER, the AER's draft decision is to not approve the tariff structure statement proposed by CitiPower. This is discussed in attachment 19 of the draft decision.

In accordance with clause 6.12.1(15) of the NER, the AER's draft decision is that the negotiating framework as proposed by CitiPower will apply for the 2021–26 regulatory control period. This is discussed in attachment 17 of the draft decision.

In accordance with clause 6.12.1(16) of the NER, the AER's draft decision is to apply the negotiated distribution services criteria published in February 2020 to CitiPower. This is discussed in attachment 17 of the draft decision.

In accordance with clause 6.12.1(17) of the NER, the AER's draft decision on the procedures for assigning retail customers to tariff classes for CitiPower is set out in attachment 19 of the draft decision.

In accordance with clause 6.12.1(18) of the NER, the AER's draft decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of CitiPower' regulatory control period as at 1 July 2026. This is discussed in attachment 2 of the draft decision.

Constituent decision
In accordance with clause 6.12.1(19) of the NER, the AER's draft decision on how CitiPower is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 14 of the draft decision.
In accordance with clause 6.12.1(20) of the NER, the AER's draft decision is to require CitiPower to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the draft decision.
In accordance with clause 6.12.1(21) of the NER, the AER's draft decision is to not approve the connection policy proposed by CitiPower. Our draft decision is to amend CitiPower' proposed connection policy as set out in attachment 18 of the draft decision.
In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the “f-factor scheme order 2016”,[106] the AER's draft decision is to apply the f-factor incentive payments/penalties as a part of the "I-factor" adjustment to the annual revenue requirement calculation formula.

[106] http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf, Victoria Government Gazette, G 51 22 December 2016, p. 3239.

B List of submissions

We received 21 public submissions in response to CitiPower's revenue proposal. These are listed below:

Submission from	Date received
AGL Energy Limited	3 June 2020
CCP17	10 June 2020
Department of Environment, Land, Water & Planning	2 June 2020
Department of Environment, Land, Water & Planning – specific submission on TSS	2 June 2020
Electric Vehicle Council	3 June 2020
EnergyAustralia	3 June 2020
Energy Consumers Australia	16 June 2020
Energy Safe Victoria	3 June 2020
Energy Users' Association of Australia	10 June 2020
Evie Networks	3 June 2020 and 17 August 2020
Local Government Response (prepared by Eastern Alliance for Greenhouse Action)	27 May 2020
Origin Energy	2 June 2020
Red Energy / Lumo Energy	19 June 2020
Vector Limited	3 June 2020
Victorian Community Organisations (prepared by Brotherhood of St Laurence, Renew, Victorian Council of Social Service)	3 June 2020
Allan Campbell	1 June 2020
Bernie Free	2 June 2020
Oonagh Kilpatrick	3 June 2020
Sarah Campbell	3 June 2020
Wannon Branch United Dairy Farmers	3 June 2020

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATO	Australian Tax Office
augex	augmentation expenditure
CAM	cost allocation method
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP 17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
CoS	classification of service
CPI	consumer price index
DRP	debt risk premium
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
Distributor/DNSP	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ERP	equity risk premium
F&A	framework and approach
MRP	market risk premium
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective

Shortened form	Extended form
NER or the rules	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
TSS	tariff structure statements
VCO	Victorian Community Organisations
WACC	weighted average cost of capital