FINAL DECISION

Powercor
Distribution Determination
2021 to 2026

Overview

April 2021

AUSTRALIAN ENERGY REGULATOR

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AER reference: 63602

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. This final decision sets out the amount of money Powercor can recover from electricity consumers for using its network over the 2021–26 regulatory control period.

Powercor owns and operates one of the five electricity distribution networks in Victoria and services around 836 000 customers across the west of Victoria, from the edge of Melbourne to the border with South Australia. On 31 January 2020, Powercor submitted its regulatory proposal for the five year regulatory control period commencing 1 July 2021. On 3 December 2020, Powercor submitted a revised proposal based on our draft decision of 30 September 2020.

Powercor accepted many parts of our draft decision and demonstrated an ongoing commitment to consumer engagement in its revised proposal. A key area of difference between Powercor's revised proposal and our draft decision was the amount of capital expenditure (capex) it forecast for the next regulatory control period, particularly relating to its wood poles replacement program. In reaching our final decision we focused our efforts— including engaging extensively with Energy Safe Victoria's (ESV) and working collaboratively with Powercor— to arrive at a prudent and efficient capex forecast, such that consumers pay no more than necessary for safe and reliable power. The main issue we had with Powercor's revised operating expenditure (opex) proposal is that it raised bushfire liability insurance cost increases, an important issue. We worked collaboratively to determine an efficient forecast insurance premium amount and have included it in the opex we approved.

We are satisfied that the amount of money we have allowed Powercor to recover from consumers is no more than necessary to replace ageing infrastructure and operate its network in a safe and reliable manner in the long term interest of consumers.

Powercor can recover $3450.9 million ($ nominal) from its consumers over the 2021–26 regulatory control period. In real terms, this is 0.8 per cent lower than the revenue allowed for in our 2016–20 final decision and leads to lower network charges for Powercor's consumers from the next regulatory control period.

The revenue we allow forms the distribution network component of retail electricity bills, making up about 24 per cent of a standard residential bill (28 per cent for small businesses).

We estimate that Powercor's distribution network and metering charges in the first year of the 2021–26 regulatory control period will drop by $34 (2.2 per cent) for residential consumers and $107 (1.8 per cent) for small business consumers, relative to the charges in 2020. Thereafter, these charges are estimated to increase by $3 (0.2 per cent) and $14 (0.2 per cent) per year respectively.

Consumers have already benefited from our decision because a reduction in distribution network charges was passed through to Victorian consumers on

1 January 2021 with the introduction of the *National Energy Legislation Amendment Act 2020* (Vic) (NELA Act).[1] In making this final decision we updated a range of components that were used to calculate the lower distribution network charges that were passed on to consumers on 1 January 2021. In particular, we updated the rate of return to reflect movements in interest rates and our revised estimate of expected inflation. As a result of these updates, distribution network charges starting from 1 July 2021 will be 2.5 per cent higher than the distribution network charges starting 1 January 2021, but will still be lower than the distribution network charges that were in place in 2020. We still need to consider other factors that will impact the final distribution network charge that consumers and business pay – these will be considered when we assess Powercor's annual pricing proposal.[2]

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

Powercor's engagement with consumers

A key development of the 2021–26 determination has been the positive shift by the distributors in relation to improved consumer engagement.

In recognition of this evolution, in our draft decision, we developed a framework[3] to assess the consumer engagement activities of the Victorian distributors. This framework informed how we viewed this engagement in relation to the initial expenditure proposals and our overall assessment. Stakeholder submissions provided positive support and feedback on this approach and we plan to undertake further stakeholder consultation on the future design of the framework following completion of the Victorian reset.

We recognise that consumer engagement can take many different approaches and to assist in the final decision we have continued to refer to the framework as outlined in the draft decision, which provides a benchmark for the discussion and is replicated at appendix C. We acknowledge that each distributor approached engagement differently and CitiPower, Powercor and United Energy worked together across the three networks to achieve their consumer engagement program. In developing their proposal, they sought to learn about their customer's values and preferences.[4]

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1 The intention of the NELA was to change the timing of the regulatory control period for electricity distribution networks from a calendar year basis to a financial year basis, to align with other NEM states. We separately assessed the total allowed revenue for Powercor for the six month period from 1 January 2021 to 30 June 2021. See our final decision of 28 October 2020 at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powercor-determination-2021-26/aer-position#step-72922.

2 See Pricing proposals & tariffs webpage on the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs.

3 AER, *Draft decision, Powercor distribution determination 2021–26, Overview*, September 2020, Table 7, p. 42.

4 Through CitiPower, Powercor and United Energy's engagement program 'Energised 2021–26' they engaged with 11 000 customers and stakeholders through around 2.5 million 'touch points'. See AER, See AER, *Draft Decision – Powercor distribution determination 2021–26 Overview*, September 2020, p.4.

Our draft decision stated it was difficult to understand how consumer engagement learnings had influenced the initial proposals. We recognise that CitiPower, Powercor and United Energy have proactively responded to actively involve customers in the decision making process with the formation of their new Customer Advisory Panel (CAP). Ultimately, we maintained a bottom-up assessment of Powercor's capex, as supported by our initial top-down assessment, along with insufficient evidence from its customer engagement to persuade an alternative assessment. However, it does not prevent Powercor from spending from their aggregate capex on projects shown to be of value to its customers.

Consumer engagement models will continue to mature over time. Ongoing development of the framework will support businesses to develop proposals that are prudent and efficient, and demonstrate the express views and support of consumers.

Poles and asset management

We are acutely aware of the importance of achieving safety outcomes and the direct impact on consumers. Consistent with previous decisions on safety-related capex, we understand the importance of managing safety risk and therefore allowed funding to distributors to address these risks.

In coming to our position, we have taken into account Powercor’s circumstances including: ESV’s investigation into its wood pole management practices, Powercor’s efforts to improve its practices, as well as the higher risk of bushfires in rural Victoria relative to other regions.

We have engaged extensively with ESV in this process. Our engagement reflects our aligned focus of ensuring safe and reliable services for all Victorians. We look forward to our continued collaboration as ESV reviews all Victorian distributors’ pole management practices over 2021.

We concur with ESV's view that Powercor's wood pole inspection and management practices need to improve, and appreciate that a step up from current period spend is required. However, Powercor has not provided sufficient evidence to support its forecast of $200 million for wood pole replacement over the 2021–26 regulatory control period. Based on the information before us, we have concluded that its forecast materially overstates expenditure required to maintain the safety and reliability of Powercor's poles network.

Our final decision includes a higher wood poles forecast than our draft decision. Consistent with our draft decision, our forecast continues to account for Powercor’s actual pole failure rates and pole replacement, and allows for a “back-log” of pole replacement to bring Powercor to a sustainable level of pole replacement. It also takes into account stakeholder views that many of Powercor’s poles are approaching end-of-life.

We are satisfied that our substitute estimate provides sufficient replacement capital expenditure (repex) to allow Powercor to maintain safety and reliability. In particular, our substitute estimate will allow Powercor to replace a much higher proportion of its older, lower durability (class 3) poles compared with the current period. It is also within

ESV's ballpark range of what is required to provide confidence that sustainable safety outcomes will be delivered.

The decision we have reached on Powercor's wood pole forecast does not preclude Powercor from spending more than our forecast, given that we provide a total capex allowance for the regulatory period. Further, we recognise circumstances may change in which case mechanisms within our framework are available to ensure that the objective of safe and reliable services is maintained.

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.

Our final decision approved most of Powercor's revised expenditure proposal, the main element we did not approve was capex.

We have not accepted Powercor's revised total forecast capex of $1864.6 million which is 18 per cent higher than our draft decision and largely driven by replacement (wood poles), augmentation (Rapid Earth Fault Current Limiters (REFCL)) and connections capex categories. We did not accept forecasts for these categories in full. We undertook a detailed bottom-up assessment of the forecasts for these categories, as top-down metrics indicated that its total forecast may not be prudent and efficient. Our detailed bottom-up review also helped inform our substitute estimate.

We do not consider total forecast capex proposed by Powercor reasonably reflects prudent and efficient costs. Our substitute capex forecast of $1728.4 million is 6 per cent lower than Powercor's revised proposal. We are satisfied that our substitute capex forecast is sufficient for it to maintain the safety and reliability of its network. This is because our substitute capex forecast is in line with its current period spend. Our substitute estimate does not preclude Powercor from spending more or less on capex in aggregate or for the component programs.

Our final decision includes a further capital expenditure sharing scheme (CESS) adjustment of $4.7 million, bringing the overall adjustment to $14.6 million. This reduces Powercor's overall CESS benefit payment to $62.4 million. The further CESS adjustment comes about from the increase in allowance for backlog pole replacement. Our decision reduces the benefit to network from simply deferring an expenditure from one period to the next.

Our final decision accepts Powercor's updated revised total opex proposal of $1422.5 million ($2020–21). This is because it is not materially different to our alternative opex estimate of $1419.7 million ($2020–21). We acknowledge there is some uncertainty with future insurance premium forecasts, but believe businesses should be incentivised through our framework to achieve efficient outcomes and lower prices for consumers in subsequent periods by including these costs in the total opex forecast. Powercor provided a higher updated revised proposal with a step change of $67.7 million ($2020–21) for these future premium increases. We considered this was reasonable and have accepted it as a part of its total opex proposal. As a result we have not accepted the proposed insurance premium event nominated cost pass through for the 2021–26 regulatory control period.

Having reviewed an application by CitiPower, Powercor and United Energy, we determined that the annual payments made by the Victorian distributors to ESV is a jurisdictional scheme.[5] This final determination includes a decision on how Powercor is to report to the AER on its recovery of amounts for the scheme and on adjustments made in pricing proposals to account for over or under recovery. From the start of the 2021–26 regulatory control period ESV levy costs will be recovered through annual prices rather than the allowed (opex) revenue we set in our decision.

Transition of the energy system

Facilitating the transition of the energy system is a key theme for this Victorian regulatory determination process. Mechanisms such as expenditure to physically accommodate greater solar exports, tariff price signals and demand management initiatives can help. We consider the transition of the energy system so important that we have made incentivising networks to become platforms for energy services a strategic objective in our regulation of networks.

Powercor accepted our draft decision on the amount of capex required to facilitate and integrate distributed energy resources (DER) on its network. Our decision supports Powercor accommodating solar PV growth on its networks to achieve consumer expectations regarding the Victorian Government's Solar Homes program.

We have engaged extensively with stakeholders in the development of consistent DER integration expenditure guidelines. We published CSIRO and CutlerMerz's final value of DER (VaDER) methodology study in November 2020. However, the Australian Energy Market Commission (AEMC) recently published draft rule changes which have implications for our DER integration expenditure guideline, and which will delay its finalisation.[6]

Cost reflective network tariffs also have an important part to play in the energy transition by incentivising the location and use of DER to optimise benefits to consumers and networks.

We are encouraged by the Victorian distributors' efforts to progress network tariff reform during the 2021−26 regulatory control period. The distributors moved from

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5 See https://www.aer.gov.au/communication/aer-makes-determination-on-cpus-application-for-a-jurisdictional-scheme.

6 See https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources.

opt−in to opt−out assignment to the new default time of use tariff for consumers receiving a new meter or who upgrade their connection. By working collaboratively with their stakeholders[7] they developed small consumer tariff proposals with aligned, more targeted peak charging windows. We are also pleased to see the Victorian distributors reassigning small consumers on legacy cost reflective tariffs to new and more targeted default time of use tariff.

We engaged rigorously with the electric vehicle (EV) sector and heard many different perspectives. We encourage EV charging station and energy storage proponents to engage with the Victorian distributors on tariff trials. We see trials as a valuable way of proving out new and innovative service models to inform future network tariffs.

Our view is that it is important that EV charging stations face cost reflective network tariffs to minimise new network investment that increases costs for all consumers. Consistent with our view, charging stations which install load limiting devices can access alternative cost reflective tariffs. Our final decision also makes clear, consistent with Victorian Government policy, that once small consumers with an EV are identified they must be assigned to a cost reflective network tariff.

We consider storage assets should both contribute to recovery of network costs commensurate with their network use and see cost reflective price signals to guide their operation. Our final decision on stand-alone grid scale storage connected to the Victorian networks is to assign such consumers according to the usual tariff classes unless they are only providing network support services. Regardless, ownership of storage assets should not affect tariff class assignment.

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[7] Which included retailers and jurisdictional government entities.

Note

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

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer Service Incentive Scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

1 Our final decision

Our final decision allows Powercor to recover a total revenue of $3450.9 million ($ nominal) from its consumers from 1 July 2021 to 30 June 2026.

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

Our final decision for Powercor 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 Powercor's distribution tariffs for the 2021–26 regulatory control period. Powercor's Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from consumers.

Powercor also provides alternative control services (ACS), the costs of which are recovered only from users of those services. These costs are considered separately to our building block determination.[8] Our final decision sets out the prices Powercor is allowed to charge consumers for the provision of ACS: ancillary network services, public lighting and total revenue for metering. Powercor has not proposed to provide any services on a negotiated basis in the 2021–26 regulatory control period.[9]

We have taken Powercor's consumer engagement into account in developing our draft decision. More information is provided in section 4.

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 National Electricity Rules (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 final decision is 0.8 per cent lower than the allowed revenue provided for in our 2016–20 final decision in real terms. Figure 1 shows real revenue decreases from 2020 levels by 6.4 per cent in the first year of the next regulatory control period. After that, Powercor's revenue allowance is steady with a smaller 0.1 per cent decrease per year.

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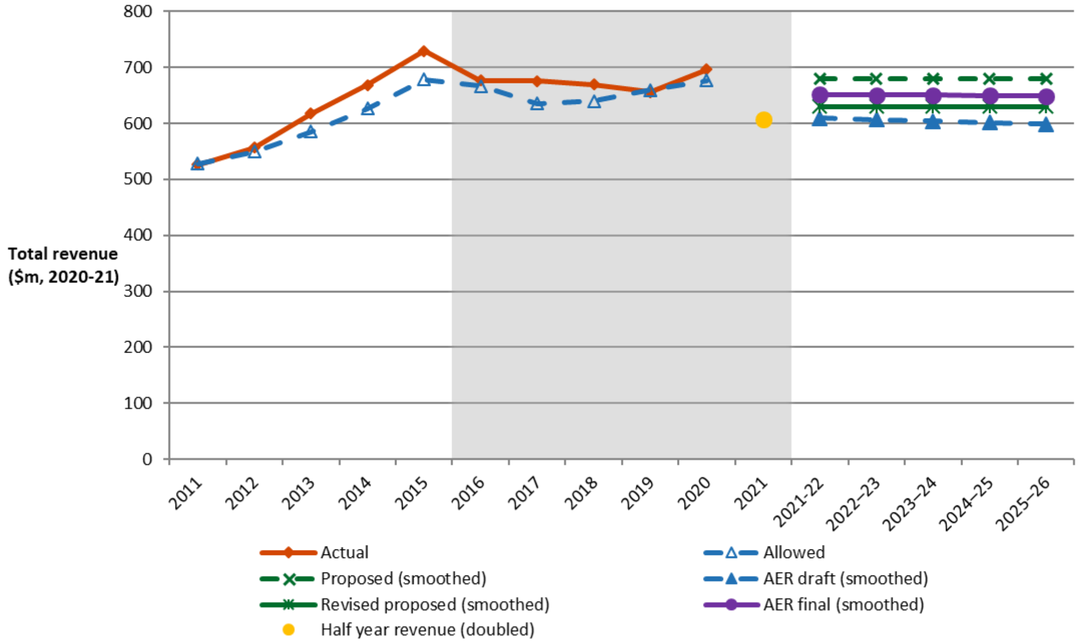
[8] We discuss alternative control services in Attachment 16 to this final decision.

[9] Our distribution determination for Powercor includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because Powercor 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.

Figure 2 highlights the key drivers of the change in Powercor's allowed revenue from the 2016–20 regulatory control period compared to what we expect in the 2021–26 regulatory control period. It illustrates that a large driver of change is the return on capital building block. The rate of return has decreased from around 6.11 per cent in the 2016–20 regulatory control period to 4.73 per cent for the 2021–26 period. As a result, the total cost of capital had reduced by $158.4 million.[10] In 2019, we reviewed how we calculate the cost of corporate tax and made changes to our approach to align with the latest rulings of the Australian Tax Office. This means we expect the tax allowance for Powercor will be lower than it was in the past. As a result, Figure 2 also shows a decrease in the cost of corporate tax building block of $177.7 million.[11] Other changes include:

- Increase to forecast regulatory depreciation by 28.8 per cent. Each year, Powercor builds new equipment to keep its network running. The cost of this new equipment is added to a cumulative total called the regulatory asset base or RAB. Over time, the cost of this equipment is paid back to Powercor through our depreciation. Because Powercor added new equipment to its network over the last five years, its RAB is increasing and so is its depreciation. Powercor's increase in depreciation is also affected by lower expected inflation over the 2021–26 regulatory control period.[12]
- Increase to revenue adjustments of $30.4 million. This is mainly driven by the application of CESS.

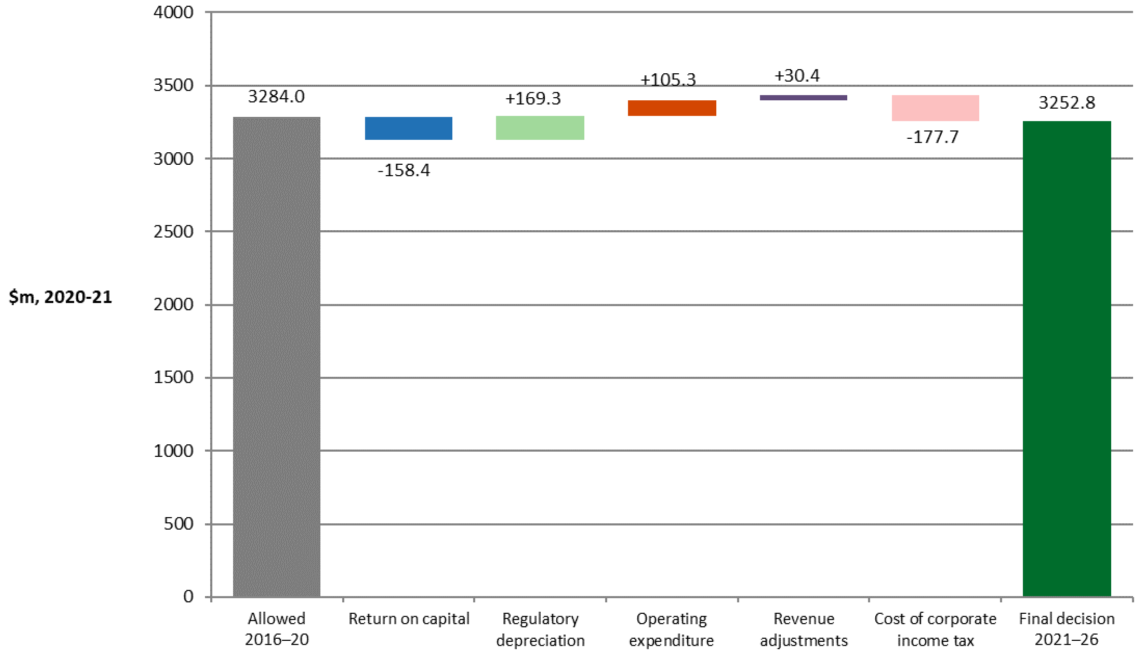
10 The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has decreased by a similar amount. Please see section 2.2 for further details.

11 Please see section 2.6 for further details.

12 Please see section 2.3 for further details.

- Increase to forecast opex compared to the 2016–20 regulatory control period, by 8.0 per cent.[13]

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



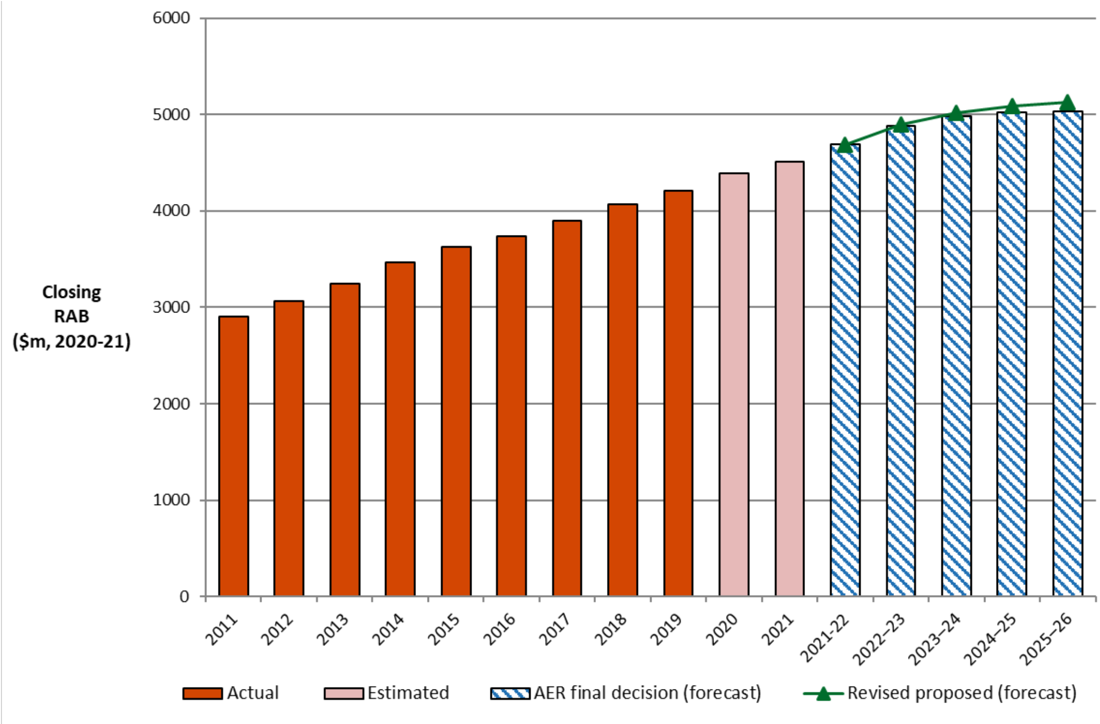
Source: AER analysis.

Figure 3 compares our final decision forecast RAB to Powercor's revised proposed and actual RAB. We carefully reviewed Powercor's proposal to increase its capital expenditure going forward and have reduced the forecast spend. Powercor's RAB is forecast to increase by around 11.5 per cent in real terms over the 2021–26 regulatory control period. In the previous 2016–20 regulatory control period, its RAB increased by 20.8 per cent.[14]

[13] Please see section 2.5 for further details. This comparison is based on converting 2016–20 forecast opex for inflation to 2020–21 dollar terms using lagged CPI.

[14] Please see section 2.1 for further details.

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



Source: AER analysis.

1.2 Differences between revised proposal and final decision

The total revenue we are allowing in our final decision is $3450.9 million ($ nominal) for the 2021–26 regulatory control period. This is $68.7 million or 2.0 per cent higher than Powercor's revised proposal of $3382.2 million.

We have largely accepted Powercor's revenue proposal and the difference is due to us updating the proposed building block amounts using more recent information. Further while we have not accepted Powercor's proposed capex, the impact on revenue is not material from a short term perspective (*although in the longer term, our decision has wider consequences*).

The biggest contributor to the difference between our final decision revenue and Powercor's revised proposal is regulatory depreciation. Our estimate of the regulatory depreciation of $805.3 million is $88.9 million ($ nominal) or 12.4 per cent higher than Powercor's revised proposal estimate of $716.4 million ($ nominal). The main driver of this difference is the lower expected inflation which resulted from our inflation review. Our latest version of the post-tax revenue model (PTRM) (version 5) released in April 2021 amended the way we estimate inflation, in order to improve our estimation in periods of economic instability or sustained periods of low or high inflation.[15] Our final decision estimates expected inflation of 2.00 per cent, lower than Powercor's estimate of expected inflation of 2.37 per cent.

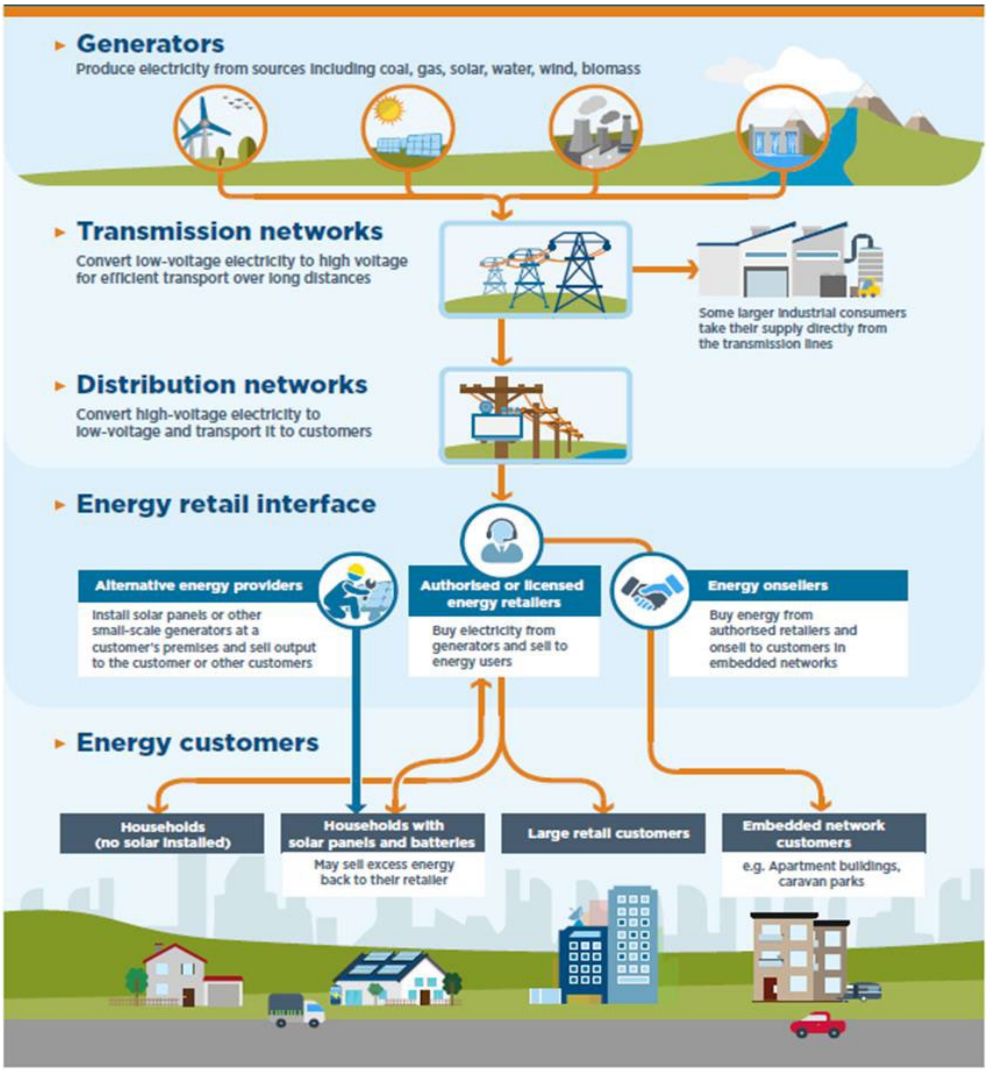
[15] AER, *Final position paper - Regulatory treatment of inflation*, December 2020, p. 6.

Based on evidence before us, we are not satisfied that Powercor's revised proposed forecast capex of $1836.3 million ($2020–21) reasonably reflect prudent and efficient costs. Our substitute capex forecast is $107.9 million ($2020–21) or 5.9 per cent lower than the revised proposal. This leads to a lower forecast RAB than Powercor's revised proposal.

1.3 Expected impact of our final decision on electricity bills

Powercor's distribution network SCS charges make up around 24 per cent of the total residential bill and 28 per cent of the total small business retail electricity bill. Our decision also covers charges for revenue-capped metering services (that form part of ACS) and these costs are included in this estimated bill impact analysis. 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.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our allowed revenue determination. These prices are indicative and might vary with changes in demand. Table 1 shows the estimated average annual impact of our final decision for the 2021–26 regulatory control period on electricity bills for residential and small business customers.

We estimate the expected impact on bills by varying the distribution charges in line with our 2021–26 final decision, while holding all other components constant. This approach isolates the effect of our final decision on distribution network tariffs from other parts of the bill. However, this does not mean that other components will remain unchanged across the regulatory control period.[16]

Under the final decision we estimate that compared to 2020 charges, the distribution network and metering charges ($ nominal) in Powercor's area:

- for an average residential consumer would:
  - reduce by $34 (2.2 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 $107 (1.8 per cent) in the first year of the 2021–26 regulatory control period
  - increase on average by $14 (0.2 per cent) for each of the remaining four years of the 2021–26 regulatory control period.

[16] It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since Powercor 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 Final decision						
Residential annual bill	1536[a]	1501	1504	1508	1511	1515
Annual change (per cent)[c]		–34 (–2.2%)	3 (0.2%)	3 (0.2%)	4 (0.2%)	4 (0.2%)
Standard control services		–21	3	3	3	3
Metering		–13	0	0	0	0
Small business annual bill	5816[b]	5710	5724	5738	5752	5766
Annual change (per cent)[c]		–107 (–1.8%)	14 (0.2%)	14 (0.2%)	14 (0.2%)	14 (0.3%)
Standard control services		–93	14	14	14	14
Metering		–13	0	0	0	0
Powercor revised proposal						
Residential annual bill						
Annual change (per cent)[c]	1536[a]	1489	1494	1498	1503	1508
Standard control services		–47 (–3.0%)	5 (0.3%)	5 (0.3%)	5 (0.3%)	5 (0.3%)
Metering		–31	5	5	5	5
Small business annual bill		–15	0	0	0	0
Annual change (per cent)[c]	5816[b]	5663	5683	5704	5725	5746
Standard control services		–153 (–2.6%)	20 (0.4%)	21 (0.4%)	21 (0.4%)	21 (0.4%)
Metering		–138	20	21	21	21

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*, 8 November 2019 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.

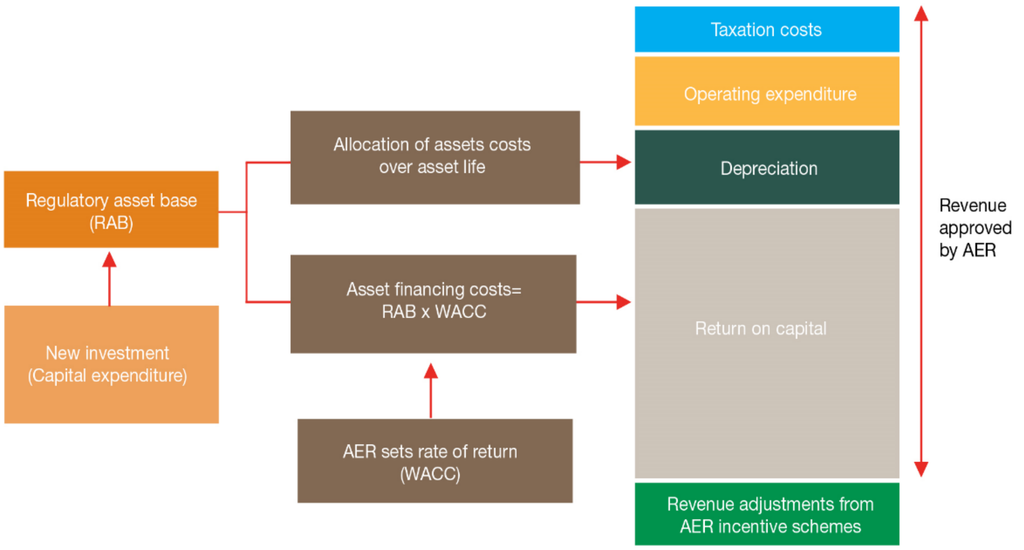
(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2020 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by Powercor. Actual bill impacts will vary depending on electricity consumption and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

2 Key components of our final decision on revenue

The total revenue Powercor's proposed reflects its forecast of the efficient cost of providing network services over the 2021–26 regulatory control period. Powercor's proposal, and our assessment of it under the National Electricity Law (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)
- capex — the capital expenditure 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 (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, and is consistent with the National Electricity Objective (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 final decision on Powercor's distribution revenues for the 2021–26 regulatory control period is set out in Table 2.

Table 2 AER's final decision on Powercor'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	213.4	217.1	221.2	220.2	216.3	1088.1
Regulatory depreciation[a]	137.9	150.4	163.2	171.4	182.4	805.3
Operating expenditure[b]	278.1	290.1	303.0	314.0	326.2	1511.3
Revenue adjustments[c]	16.7	9.2	4.4	6.8	13.2	50.4
Cost of corporate income tax	0.0	0.0	0.0	0.0	0.0	0.0
Annual revenue requirement (unsmoothed)	646.1	666.8	691.8	712.3	738.1	3455.0
Annual expected revenue (smoothed)	**664.5**	**677.1**	**689.9**	**703.0**	**716.4**	**3450.9**
X factor[d]	n/a[e]	0.10%	0.10%	0.10%	0.10%	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 the efficiency benefit sharing scheme (EBSS), the capital expenditure sharing scheme (CESS) and the demand management innovation allowance mechanism (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) Powercor is not required to apply an X factor for 2021–22 because we set the 2021–22 expected revenue in this decision. The expected revenue for 2021–22 is around 6.4 per cent lower than the approved total annual revenue for 2020 in real terms, or 4.5 per cent lower in nominal terms after taking into account the escalation by half year Consumer Price Index (CPI) to allow comparison of the revenue from 1 July 2021 onwards.

2.1 Regulatory asset base

The RAB is the value of assets used by Powercor to provide regulated distribution services. The value of the RAB substantially impacts Powercor’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 Powercor’s revenue for 2021–26, we make a decision on Powercor’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.

Our final decision is to determine an opening RAB value of $4514.5 million ($nominal) as at 1 July 2021 for Powercor. This amount is $17.6 million (or 0.4 per cent) higher than Powercor's revised proposed opening RAB of $4496.9 million ($nominal) as at 1 July 2021.[17] While we largely accept the proposed methodology for calculating the opening RAB, we made the following revisions to Powercor's proposed inputs to the roll forward model (RFM):

- Amended the 2020 capex estimate, which was provided by Powercor subsequent to the revised proposal.
- Amended inputs for the six month 2021 period for the nominal rate of return and equity raising costs.

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 the six month 2021 period[18] 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.[19] All other end of period adjustments are applied at 30 June 2021 to establish the opening RAB value at 1 July 2021.[20] Table 3 sets out the roll forward of the RAB to the end of the 2016–21 period.

Table 3 AER's final decision on Powercor's RAB for 2016–21 period ($ million, nominal)

	2016	2017	2018	2019	2020[a]	2021[b]
Opening RAB	3307.0	3453.2	3646.3	3871.7	4089.2	4332.0
Capital expenditure[c]	282.0	336.0	350.4	355.7	411.5	233.5
Inflation indexation on opening RAB	50.0	35.3	70.5	80.4	65.1	52.8
Less: straight-line depreciation[d]	185.7	178.3	195.5	218.6	229.7	103.8
Interim closing RAB	3453.2	3646.3	3871.7	4089.2	4336.1	4514.5
Difference between estimated and actual capex in 2015					–3.2	
Return on difference for 2015 capex					–0.9	
Closing RAB as at 31 December 2020					4332.0	
Opening RAB as at 1 July 2021						**4514.5**

Source: AER analysis.

[17] Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 64.

[18] The additional roll forward for six 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 six months and the next regulatory control period will commence on 1 July 2021.

[19] The adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2016–20 determination.

[20] These end of period adjustments are applied at the end of the final year of the roll forward period which in this case is 30 June 2021. For Powercor this includes reallocation for accelerated depreciation purposes associated with Rapid Earth Fault Current Limiters (REFCL) program and other assets.

(a) Based on estimated capex provided by Powercor. We will true-up the RAB for actual capex at the next reset.

(b) The six month 2021 period of 1 January to 30 June 2021. Based on estimated capex provided by Powercor. 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.

Note: Summation of entries may not equal totals due to rounding.

For this final decision, we determine a forecast closing RAB value at 30 June 2026 of $5557.5 million ($nominal) for Powercor. This is $204.3 million (or 3.5 per cent) lower than Powercor's revised proposal of $5761.8 million ($nominal). Our final decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2021, and our final decisions on the expected inflation rate (attachment 3), forecast depreciation (attachment 4) and forecast capex (attachment 5).[21] Table 4 sets out our final decision on the forecast RAB values for Powercor over the 2021–26 regulatory control period.

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

	2021–22	2022–23	2023–24	2024–25	2025–26
Opening RAB	4514.5	4782.3	5081.6	5286.1	5436.7
Capital expenditure[a]	405.7	449.7	367.7	322.0	303.2
Inflation indexation on opening RAB	90.3	95.6	101.6	105.7	108.7
Less: straight-line depreciation	228.1	246.0	264.8	277.1	291.1
Closing RAB	**4782.3**	**5081.6**	**5286.1**	**5436.7**	**5557.5**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the post-tax revenue model (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 are satisfied that the use of a forecast depreciation approach in combination with the application of the CESS and our other ex post capex measures are consistent with the capex incentive objective.[22] Further, this approach is consistent with our draft decision, Powercor's initial proposal and our *Framework and approach.*[23]

Figure 6 shows the key drivers of the change in Powercor's RAB over the 2021–26 regulatory control period for this final decision. Overall, the closing RAB at the end of

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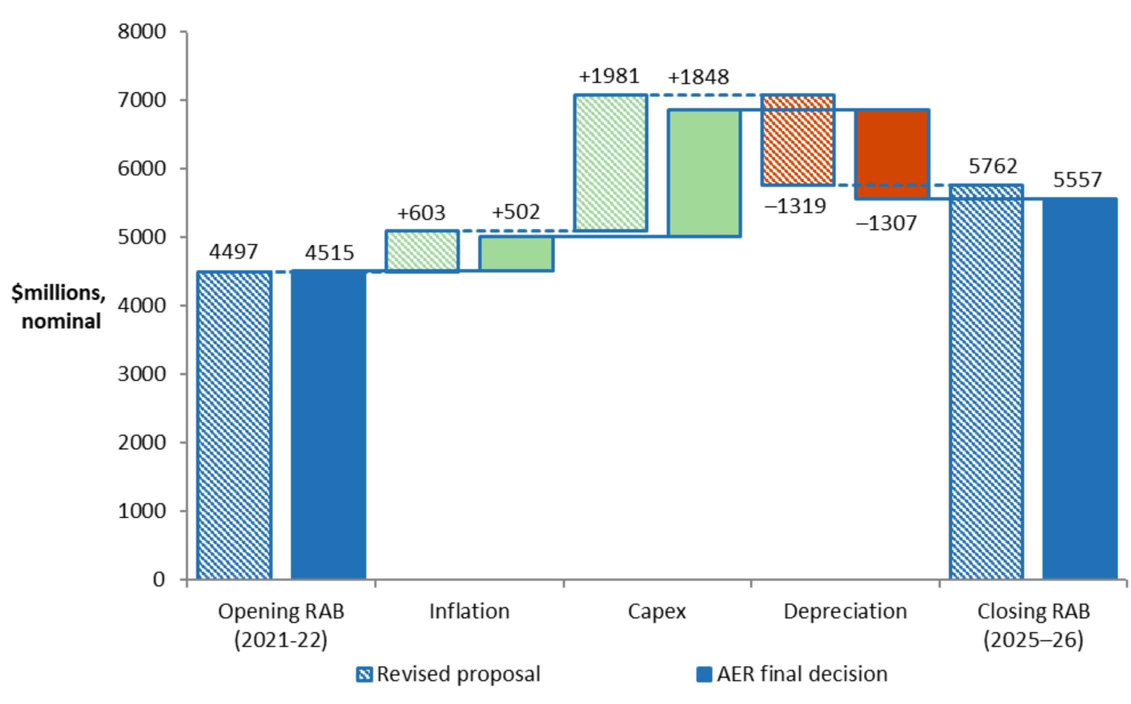
21 Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our final decision on the forecast RAB also reflects our amendments to the rate of return for the 2021–26 regulatory control period (section 2.2 of the Overview).

22 Our ex post capex measures are set out in the capex incentive guideline, AER, *Capital expenditure incentive guideline for electricity network service providers,* November 2013, pp. 13–19 and 20–21. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

23 AER, *Draft decision: Powercor distribution determination 2021 to 2026, attachment 2 – Regulatory Asset Base*, September 2020, p. 19; Powercor, *Revised regulatory proposal 2021–26*, 03 December 2020, p. 69; AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy – Regulatory control period commencing 1 January 2021,* January 2019, pp. 83–85.

the 2021–26 regulatory control period is forecast to be 23.1 per cent higher than the opening RAB at the start of that period, in nominal terms. The approved forecast net capex increases the RAB by 40.9 per cent, while expected inflation increases it by 11.1 per cent. Forecast depreciation, on the other hand, reduces the RAB by 29.0 per cent.

Figure 6 Powercor's actual, revised proposed and AER final decision RAB ($ nominal)



Source: AER analysis.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

Further detail on our final 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.

We are required by the NEL to apply a rate of return instrument—the current 2018 Rate of Return Instrument (2018 Instrument)—to estimate an allowed rate of return.[24]

The Victorian Government has moved the Victorian distributors from a calendar year regulatory control period to a financial year regulatory control period.[25] This entails a six month extension to the current regulatory control period (2016–20) through to June 2021, then a five year regulatory control period starting on 1 July 2021.[26] Our 2018 Instrument needs to be applied from 1 January 2021—that is, to the six month extension period as well as the following five financial years which form the 2021–26 regulatory control period. Some amendments to the 2018 Instrument were needed to accommodate the additional six month period. The Victorian government enabled these amendments through the NELA Act[27] and therefore, we apply modified 2018 Instruments to both periods.[28] [29]

Application of a modified 2018 Instrument in this final decision estimates an allowed rate of return of 4.73 per cent (nominal vanilla) for the five year regulatory control period commencing 1 July 2021. We note Powercor's proposal and revised proposal also applied these modifications to the 2018 Instrument.[30]

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 Instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year.

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24 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

25 *National Energy Legislation Amendment Act 2020* (Vic).

26 The six month extension period was also labelled as the 'mini-year' when we consulted on the modifications to the 2018 Rate of Return Instrument.

27 *National Energy Legislation Amendment Act 2020*.

28 *National Energy Legislation Amendment Act 2020*.

29 For the six month extension period instrument see: AER, *Modified rate of return instrument for the Victorian electricity distribution networks during the extension period of 1 January 2021 to 30 June 2021*, 27 October 2020; For the instrument to apply to the 2021–26 regulatory control period, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

30 Powercor, *Regulatory Proposal*, January 2020, p. 143; Powercor, *Revised Proposal*, December 2020, pp. 65, 69.

Table 5 AER's final decision on Powercor's rate of return (percentage, nominal)

	AER draft decision (2021–26)	Powercor's revised proposal (2021–26)	AER final decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	0.93%[a]	0.93%	1.38%[c]	
Market risk premium	6.1%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	4.59%	4.59%	5.04%	Constant (%)
Return on debt (nominal pre–tax)	4.59%[b]	4.59%	4.52%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.59%	4.59%	4.73%	Updated annually for return on debt
Expected inflation	2.37%	2.37%	2.00%	Constant (%)

Source: AER analysis; Powercor, *Revised Regulatory Proposal 2021–26*, December 2020, p. 69; Powercor, *Revised Regulatory Proposal 2021–26*, *MOD 10.02, PTRM 2021–26 March 2021*, March 2021.

[a,b] Calculated using a placeholder averaging period.

[c,] Calculated using an averaging period of 2 January 2021 to 29 March 2021.

[d] Final decision return on debt is calculated using the proposed and accepted debt averaging period.

Our final decision is also to accept Powercor's proposed risk free rate averaging period[31] and debt averaging periods because they comply with conditions in a modified 2018 Instrument.[32] These were submitted with its initial regulatory proposal and we specify the debt averaging periods in confidential appendix A to attachment 3.

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.

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

[32] For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*); see also AER, *Final decision, Powercor distribution determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, April 2021.

We note Powercor proposed to use our approach to estimate 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 zero equity raising costs.

Our final decision is to accept the method used in Powercor's revised proposal which uses an annual rate of 7.91 basis points per annum.[34] We have considered this annual rate and found our alternative benchmark estimate (7.96 basis points) is similar to Powercor's proposal.

Imputation credits

Our final decision is to apply a gamma of 0.585 as provided in a modified 2018 Instrument.[35] Powercor's revised proposal adopted a value of 0.585.[36]

Inflation

We estimate an expected inflation of 2.0 per cent based on the approach adopted in our final position paper from our 2020 inflation review.[37][38] Powercor accepted the inflation rate in the draft decision but expected the value to be updated for the outcome of the inflation review.[39]

True up for six month extension period

We applied placeholder averaging periods in our final decision for the six month extension period of 1 January 2021 to 30 June 2021.[40] This was due to the unanticipated delay in the passing of the NELA Act, and to facilitate our pricing process – the nominated (and accepted) averaging periods would not have finished in time to allow practical estimation of the final rate of return (based on the accepted averaging periods).

We have calculated the updated rate of return for the extension period based on the nominated and accepted averaging periods, and in accordance with the modified six-month instrument and the Order in Council. We determine that the difference with the placeholder rate of return will be recovered through the C-factor as noted in our control mechanisms attachment.

2.3 Regulatory depreciation (return of capital)

Depreciation is the amount provided so capital investors recover their investment over the economic life of the asset (return of capital). Powercor invests capital in large assets to provide electricity network services to its consumers. The costs of these

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33 Powercor, *Revised Regulatory Proposal 2021–26*, *MOD 10.02, PTRM 2021–26 March 2021*, March 2021.

34 Powercor, *Revised Regulatory Proposal 2021–26*, *MOD 10.02, PTRM 2021–26 March 2021*, March 2021.

35 For the modified application of the 2018 instrument to the regulatory control period 2021–26, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

36 Powercor, *Revised Regulatory Proposal 2021–26*, December 2020, p. 69.

37 AER, *Final position, Regulatory treatment of inflation*, December 2020.

38 See our latest version of the PTRM (version 5) released in April 2021; AER, *Final position, Regulatory treatment of inflation*, December 2020.

39 Powercor, *Revised Regulatory Proposal 2021–26*, December 2020, p. 67.

40 For example, see: AER, *Final decision Powercor six-month extension – variation decision*, October 2020, pp. 11–12.

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.

In deciding whether to approve the depreciation schedules submitted by Powercor, we make determinations on the indexation of the regulatory asset base (RAB) and depreciation building blocks for Powercor's 2021–26 regulatory control period.[41] The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our final decision is to determine a regulatory depreciation amount of $805.3 million ($ nominal) for Powercor for the 2021–26 regulatory control period. This amount represents an increase of $88.9 million (or 12.4 per cent) to the $716.4 million ($ nominal) in Powercor's revised proposal.[42] It is $94.7 million (or 13.3 per cent) higher than the regulatory depreciation amount determined in the draft decision. This significant increase is driven by our review of lower expected inflation which resulted from our inflation review. This lower expected inflation (amongst other things) impacts the indexation component of the regulatory depreciation allowance.

In coming to this decision:

- We accept Powercor's revised proposed straight-line method to calculate the regulatory depreciation, which is consistent with our draft decision.
- We accept Powercor's revised proposal to continue with the year-by-year tracking approach to implement straight-line depreciation of existing assets, consistent with our draft decision. However, we have updated the inputs in the depreciation model for 2020 capex and the forecast equity raising costs and nominal rate of return inputs for the six month 2021 period, consistent with the RFM.
- We accept Powercor's revised proposed asset classes and standard asset lives, which are consistent with our draft decision. We have amended the equity raising costs standard asset life consistent with our standard weighted average approach.
- We accept the inclusion of the new asset class of 'Accelerated depreciation assets' proposed by Powercor. However, we have updated the value of existing assets reallocated into this new asset class from the 'Distribution system assets' class. This is because we have amended some of the unit rates and volumes used in the calculations for this final decision. These amendments have increased the value of Powercor's accelerated depreciation to $30.3 million which is an increase of $0.8 million compared to the draft decision amount of $29.5 million.

The difference in our final decision and the revised proposed regulatory depreciation is largely due to the following determinations on related parts of our decision:

- expected inflation over the 2021–26 regulatory control period (attachment 3)

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41 NER, cll. 6.12.1, 6.4.3.

42 Powercor, *Revised regulatory proposal – MOD 10.02 - PTRM 2021–26,* 03 updated 24 March 2021.

- forecast capex (attachment 5) including its effect on the projected RAB over the 2021–26 regulatory control period.[43]

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

2.4 Capital expenditure

Capex refers to the investment in assets to provide network services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. Capex is added to Powercor'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 final decision on Powercor's total net capex is to not accept its revised proposal of $1836.3 million for the 2021–26 regulatory control period.[44] We are not satisfied that Powercor's revised total capex proposal reasonably reflects prudent and efficient costs. Our final decision includes a total capex forecast of $1728.4 million, which is 6 per cent below Powercor's revised capex forecast and 8 per cent below the forecast we assessed.[45]

Powercor accepted several aspects of our draft decision, reducing its forecast capex by 14 per cent relative to its initial proposal. Figure 7 compares our final decision on total capex with Powercor's initial and revised proposals, as well as our draft decision and its historical capex spend.

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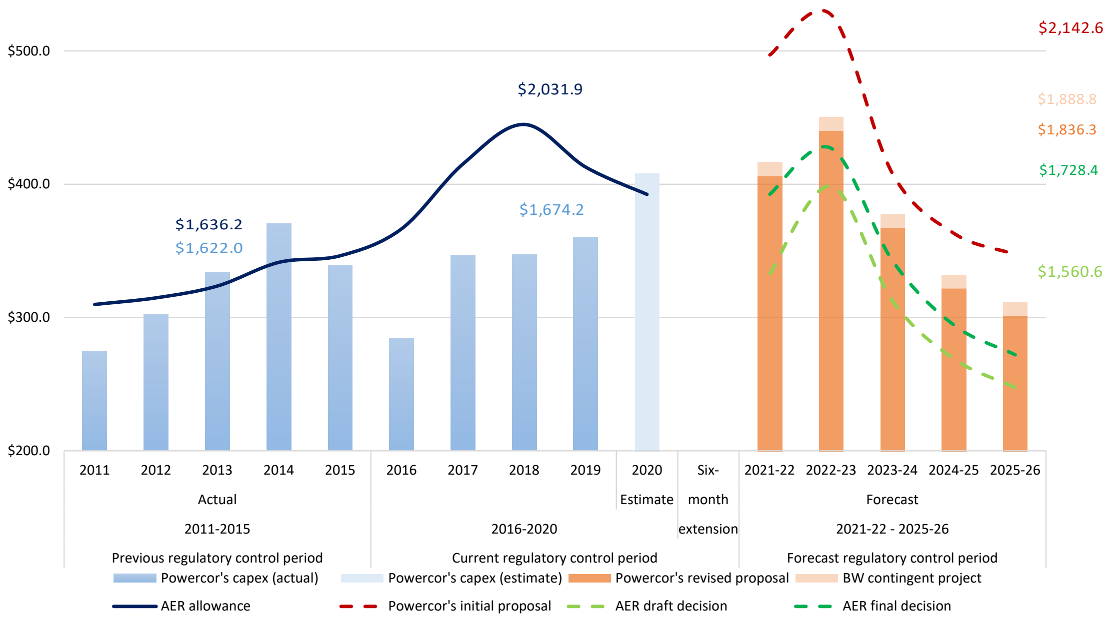
43 Capex enters the RAB net of forecast disposals and capital contributions. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our final decision on the RAB (attachment 2) also reflects our updates to the WACC for the 2021–26 regulatory control period.

44 All dollar amounts are presented in real $2020–21 unless otherwise specified.

45 We assessed a slightly higher forecast, as we considered Powercor's Ballarat West contingent project as forecast capex.

Figure 7 Powercor's historical vs forecast capex snapshot ($ million, 2020–21)



Source: Powercor's revised 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.

While we acknowledge Powercor's efforts to reconsider its forecast in light of the concerns raised about its initial proposal in our draft decision, we would encourage it and other distributors to include more substantiated capital expenditure requirements in its initial proposal. Powercor's initial forecast was 28 per cent above its current period actual capex, with insufficient evidence to support its forecast in full. For the AER to have confidence that a distributor's forecast reasonably reflects efficient and prudent costs, we expect initial proposals to be supported by quantitative business cases and reflect genuine engagement with its customer base.

In coming to our final decision, we asked Powercor questions on its revised proposal. Powercor was receptive to our questions and provided responses within requested timeframes. Our final decision is higher than our draft decision as Powercor provided sufficient evidence to satisfy us that parts of its revised forecast are prudent and efficient.

Our final decision provides a capex allowance that is slightly above Powercor's current period spend. We are satisfied that this capex allowance is sufficient for Powercor to maintain its service levels. However, our decision does not preclude Powercor from changing the mix of capex projects and programs it has proposed for this review or from spending more than its capex allowance. Our regulatory framework recognises that circumstances may change over the course of the regulatory control period and that a distributor may need to reallocate capex to manage its risks.

Overall, we note the following:

- For its wood pole forecast, Powercor has not provided sufficient information to support its forecast in full. While we have not accepted its wood pole forecast, we acknowledge Powercor's efforts in developing tools and processes towards better understanding the condition of its poles. In coming to our position on wood poles, we were cognisant of community concerns around safety outcomes. Our final decision wood pole forecast is higher than our draft decision, as it takes into account stakeholder comments that we have particular regard for the age of Powercor's wood poles. Our forecast pole volume interventions is also within ESV's ballpark range of what is required to achieve sustainable safety outcomes for the Victorian community. We look forward to continue collaboration with ESV as it reviews the remaining Victorian distributor's pole management practices.

- We included an amount of capex in its draft decision forecast capex for the Ballarat West REFCL project ($25.9 million). However citing uncertainty in stakeholder expectations, Powercor reproposed the project as a contingent project in the revised proposal. Although we recognise there may be some uncertainty associated with the project, we are satisfied that Powercor will be required to undertake capex in the 2021–26 regulatory control period to meet its REFCL compliance obligation and the associated costs are sufficiently certain for them to include in the capex forecast. For this reason, we have included this project as part of our capex forecast rather than a contingent project. In assessing the updated cost information provided by Powercor, we consider there are several alternative options to the $52 million project Powercor proposed to meet its obligations. We have based our forecast on our draft decision amount of $26 million, which we consider reasonably reflects prudent and efficient costs. We note that this alternative capex estimate will also allow for several other viable alternatives.
- We reviewed Powercor's methodology for calculating capital contributions and found that it was not consistent with the NER requirements. In consultation with Powercor, we calculated an alternative capital contribution amount in a manner that aligns as closely as possible with its acceptable current practice and is consistent with the NER requirements. This resulted in a $46 million increase in capital contributions leading to a corresponding decrease in the net connections capex that is included in our total capex forecast.
- Powercor's initial augmentation expenditure forecast included a project to upgrade power line capacity in part of its network – specifically to upgrade single wire earth return (SWER) feeders in Tyrendarra, Strathdownie, Cape Bridgewater and Gorae West to three-phase supply. Powercor did not repropose this project in its revised proposal. However, we received over 80 submissions from local consumers, businesses, councils and industry organisations supporting the project.

  While we acknowledge the strong support from the local community, the submissions did not evidence broader market benefits of the project for Powercor customers or provide sufficient evidence to support the assertions about the power supply in the region. In addition, consumer groups did not comment on this project, nor did Powercor's CAP. Many submissions requested Victorian Government assistance to fund the upgrade, which we understand is available under co-funding and grant programs at the state level.

Further detail on our final decision regarding capex is set out in attachment 5.

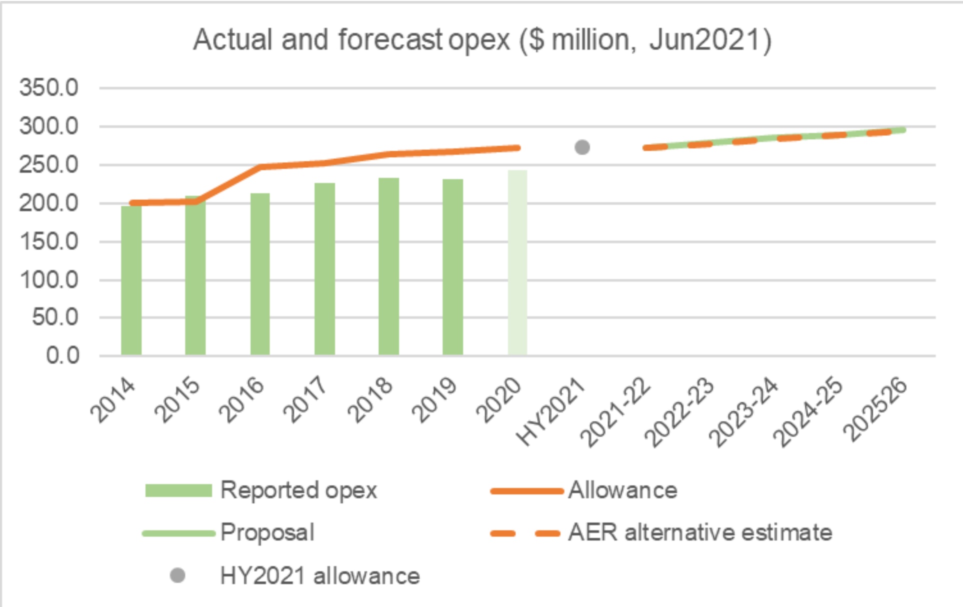
2.5 Operating expenditure

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

Our final decision is to accept Powercor's total opex forecast of $1422.5 million, including debt raising costs, for the 2021–26 regulatory control period. This is because our alternative estimate of $1419.7 million is not materially different than Powercor's updated revised total opex forecast proposal. Therefore we consider that Powercor's total opex forecast reasonably reflects the opex criteria.[46]

Figure 8 shows Powercor's opex forecast for the next five years, which is increasing by $274.7 million or 23.9 per cent relative to its actual (and estimated) opex in the current regulatory control period.

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



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

We applied (as did Powercor) our top down base-step-trend approach to forecast increasing opex for the 2021–26 regulatory control period. This consists of:

- Starting with reported opex in 2019 as the opex base, which is lower than the forecast we set for the current regulatory control period, and we consider is reasonable as it is not materially inefficient.
- Escalating base opex to account for forecast changes in price growth, output growth and productivity over the next regulatory control period, which we consider is reasonable and consistent with our standard approach.
- Adding a number of base adjustments, step changes and category specific forecasts. The most significant step change proposed is for increasing insurance premium costs over the 2021–26 regulatory control period. Other increases include

46 NER, cl.6.5.6(c).

costs to meet new security of critical infrastructure obligations, obligations or capex / opex trade-offs such as those for REFCL testing and maintenance, five minute meter requirements, IT cloud, solar enablement and reclassification of categories of repair works from capex to opex. We have assessed these and consider they are prudent and efficient. These additions are a key driver for forecast opex being higher than historical levels.

We have set out the reasons for our final 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 zero for Powercor in the 2021–26 regulatory control period. This is consistent with our draft decision and Powercor's revised proposal.

We expect Powercor to incur a forecast tax loss over the 2021–26 regulatory control period.[47] We have determined that $257.0 million in tax losses as at 30 June 2026 will be carried forward to the 2026–31 regulatory control period where it can be used to offset future tax liabilities. The forecast tax loss arises because of Powercor's forecast tax expenses will exceed its revenue for tax assessment purposes over the 2021–26 regulatory control period. This is mostly due to the implementation of our findings from the 2018 *Review of the regulatory tax approach*, where the introduction of immediate expensing of capex and diminishing value method of tax depreciation have resulted in a significant increase of forecast tax depreciation.

For this final decision, we have:

- reduced the forecast immediately expensed capex for tax purposes from $945.8 million to $800.1 million ($2020–21)[48]
- increased the revised proposed opening tax asset base (TAB) value as at 1 July 2021 by $62.3 million to $4048.3 million[49]
- accepted Powercor's revised proposal on the standard tax asset lives for all of its asset classes, consistent with our draft decision
- updated Powercor's remaining tax asset lives as at 1 July 2021 to reflect our amendments to the opening TAB value
- accepted Powercor's revised proposal to change the tax treatment for gifted assets to be consistent with a recent ruling by the Full Federal Court of Australia[50] made after the draft decision

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47 A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carried forward over to future regulatory control periods to offset future taxable income until the tax loss is fully exhausted.

48 All else equal, a lower immediately expensed capex amount will increase the cost of corporate income tax because it reduces the tax expense.

49 All else equal, a higher opening TAB value will increase the tax depreciation, a component of the tax expense, and lower the cost of corporate income tax.

50 Federal Court of Australia, *Victoria Power Networks Pty Ltd v Commissioner of Taxation [2020] FCAFC 169*, 21 October 2020.

- not accepted Powercor's revised proposal to change the tax treatment for large embedded generators by directly charging for the tax cost associated with their connections.

Further detail on our final decision on corporate income tax is set out in attachment 7.

2.7 Revenue adjustments

Our final decision on Powercor's total revenue also includes a number of adjustments:

- **Efficiency benefit sharing scheme (EBSS)** – Powercor accrued EBSS carryovers totalling –$12.1 million ($2020–21) from the application of the EBSS in the 2016–20 period. This is the same carryover amount Powercor included in its revised proposal. 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. Consumers benefit from improved efficiencies through lower forecast opex in subsequent periods. Attachment 8 sets out our final decision on Powercor's EBSS.
- **CESS** – Powercor has accrued rewards under the CESS we applied in the current 2016–20 regulatory control period to incentivise Powercor 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, Powercor out-performed our capex forecast, and our final decision is to approve a CESS revenue increment amount of $56.3 million ($2020–21). This amount is lower than our draft decision forecast of $65.9 as it reflects updated Consumer Price Index, weighted average cost of capital, actual and deferred capex.
- **Demand management innovation allowance mechanism (DMIAM)** – Table 6 sets out the DMIAM allowance for Powercor for the 2021–26 regulatory control period, based on the final PTRM for Powercor. The DMIAM aims to encourage distribution businesses to find investments that are lower cost alternatives to investing in network solutions.

Table 6 AER's final decision on the DMIAM ($ million, real 2020—21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
DMIAM	0.69	0.69	0.70	0.71	0.71	3.51

Source: AER analysis.

Section 4 sets out our final decision on the incentive schemes that apply to Powercor over the next regulatory control period.

3 Powercor's consumer engagement

A significant development in the preparation of proposals for the Victorian Electricity Distribution 2021–26 regulatory control period, has been the improvement in consumer engagement approaches undertaken by the distributors. Stakeholders have commented favourably on the observed improvement in consumer engagement across all Victorian distributors.[51] As a result of this advancement, we developed a framework[52] for assessing the Victorian distributor's consumer engagement activities, which we published in our draft decision.[53]

The framework sought to provide increased transparency around our assessment of consumer engagement outcomes and how this has influenced our decisions on expenditure forecasts. It was developed, based on our observations on the quality of engagement, to represent a range of considerations we thought clearly demonstrated if consumers had been genuinely engaged during development of proposals.[54] The Framework, in its current form, represents a high threshold a distributor would need to meet – among other things – should it be seeking to submit a proposal that is 'capable of acceptance'. Used in conjunction with our technical analysis, the framework allowed us to place weight on the outcomes of the engagement activities undertaken by each distributor to assist in providing an overall assessment of expenditure proposals. In response to a number of submissions[55], this final decision also provides further clarity on the use of the framework in our decision making process. Noting that while we take the quality of consumer engagement, and the extent to which proposals are influenced by consumer preferences into account, it does not displace our technical assessment under the NER. The assessment of consumer engagement under the framework can however, inform the depth of technical assessment required.

Stakeholder submissions on our draft decision supported the framework[56], as a tool in our kit, along with the further development of our approach to consumer engagement.[57]. We also recognise there may be other elements of engagement which are also worthy of inclusion as our assessment approach develops.[58] As a result, we

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51 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 6-42; CCP17, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, p.10; Department of Environment, Land, Water and Planning, *Victorian Government submission on the electricity distribution price review 2021–26*, May 2020, p. 2; EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 6

52 See Table 7: AER, *Draft decision, Powercor distribution determination 2021–26, Overview - September 2020*, p. 41.

53 AER, *Draft decision, Powercor distribution determination 2021–26, Overview - September 2020*, p. 41.

54 AER, *Draft decision, Powercor distribution determination 2021–26, Overview - September 2020*, p. 40.

55 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 7; VCO, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, p. 12; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12, 14.

56 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 2.; 3-4, CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 6-42; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 8; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12.

57 Op cit.

58 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 6-42; EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 3-4;

plan to take any further development of the framework in full consultation with stakeholders, outside of the Victorian reset process. However, to maintain consistency of our assessment of the Victorian distributor's consumer engagement in this final decision, we have continued with the approach outlined in our draft decision.

3.1 Clarifying the role of consumer engagement in our assessment process

Some stakeholders have expressed concern that an assessment of high quality consumer engagement may lead to a decreased level of technical assessment. In particular, the Energy Users Association of Australia and Victorian Community Organisations (VCO) submissions suggested that successful participation in a New Reg process could lead to a network business getting a 'rails run', with less detailed regulatory scrutiny.[59]

The NER outlines that we must have regard to consumer concerns, and be satisfied that expenditure forecasts we approve reasonably reflect prudent and efficient costs. One of the factors that we must have regard to is the extent to which the capex and opex forecasts address consumer concerns identified throughout distributors' engagement with its customers.[60] However, this must be balanced against other capex and opex factors, including that we must have regard to distributors' actual and expected capex and opex in preceding regulatory periods[61], and whether the forecasts are consistent with any relevant incentive schemes.[62] In undertaking our reviews, we apply a number of bottom-up and top-down assessment techniques. Our technical analysis makes use of a range of measures, none of which are used deterministically in isolation. The quality of a distributor's consumer engagement informs the nature of our technical assessment but does not displace it.

3.2 An assessment of consumer engagement

In our assessment of consumer engagement in the development of proposals for the 2021–26 regulatory control period, we recognise that each distributor has approached consumer engagement differently.

CitiPower, Powercor and United Energy worked together on a common strategy to engage with their customers in the development of regulatory proposals for the three networks. The initial proposal outlined its 'Energised 2021–26' program, which consulted on a broad range of topics, across a diverse cross-section of the combined customer base. While this approach was considered a major strength[63], in our draft

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ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 9; CitiPower, Powercor and United Energy, *Revised Regulatory Proposal – 2021–26* - December 2020, p. 26; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 12-13.

59 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 1; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12.

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

61 NER, cl. 6.5.7(e)(5) and 6.5.6(e)(5).

62 NER, cl. 6.5.7(e)(8) and 6.5.6(e)(8).

63 See VCO, *Submission on the Victorian EDPR revised proposals and draft decision 2021–26*, January 2021 – p 12 where they note that the CitiPower, Powercor and United Energy program was the most successful in testing priorities of different sectors within their base.

decision we concluded that this engagement was not clearly reflected in how it influenced their proposals.[64] Our draft decisions noted that, in addition to our top-down technical assessments, outcomes from Powercor's consumer engagement process was not sufficient to persuade us that a more thorough bottom-up analysis was not warranted. Further, that the increased expenditure forecasts should be accepted in the face of this bottom-up analysis.[65]

In response to our draft decision, we acknowledge that Powercor has taken on board our comments and the feedback of stakeholders regarding their engagement. For example, Powercor noted that while it believed its engagement had been 'broad and comprehensive' it also listened to stakeholder feedback to reshape their program to include a smaller panel, comprised of experienced members representing a cross section of customers across society.[66] This led to the establishment of its CAP[67], which will also become part of their business as usual engagement with customers. [68] The CAP delved into "marque programs" and topics of engagement with the intent to provide feedback on reducing the revised proposal spending in line with customer preferences by testing the programs through informed discussions.[69]

In providing this assessment, we recognise that the limited timeframe, between the draft decision and submission of the revised proposals presented challenges for distributors to address all elements of our framework.

We observe that Powercor's engagement with its CAP appears genuine and the distributors used the panel's expertise in the revised proposal.[70][71] A number of "marquee programs" that the CAP engaged on included, customer enablement, poles management and forecasting for COVID-19.[72] However, the CAP did not engage deeply on the total revised proposal package. The Consumer Challenge Panel, sub-panel 17 (CCP17) also noted this point, but concluded that while the CAP did not have an opportunity to review the revised proposals 'as a whole', they did not see it is a significant shortcoming.[73] In contrast, the VCO, noted in their submission that CitiPower, Powercor and United Energy were the most successful in engaging with 'different sectors within their base'.[74] The engagement of the CAP, can be seen as an important complementary function to the broad engagement already undertaken.

64 AER, *Draft Decision – Powercor distribution determination 2021–26 Overview*, September 2020, p. 4.

65 AER, *Draft Decision – Powercor distribution determination 2021–26 Overview*, September 2020, p. 53-54.

66 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, pp. 8, 12

67 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 8.

68 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 12

69 CitiPower, Powercor and United Energy have provided their CAP with detailed information packs to equip its members to allow for a deep and meaningful discussion. For an example see Powercor's supporting attachments provided by their consultant Forethought Customer Engagement and CAP supporting documents.

70 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 14.

71 ' Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 17: CAP member Dean Lombard, noted the openness of the engagement, with CitiPower, Powercor and United Energy 'sharing key Information and having frank discussions with members about the issues at hand and the alternative approaches to them.

72 See Powercor - *Revised Regulatory Proposal - 2021–26 - Att 14 - CAP - Meeting 1 Minutes 2020, Att 20 - CAP - Meeting 2 Minutes, Att 27 - CAP - Meeting 3 Minutes 2020,* December 2020.

73 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26* - January 2021, p 3.

74 VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26* - January 2021, p. 13.

Powercor has provided greater explanation in their revised proposal documents, including sign-post tables outlining the engagement undertaken since submission of its initial proposal. It also outlined the feedback it received from stakeholders and how its engagement for the revised proposal had been more targeted, including their collaboration with the CAP.[75] Energy Consumers Australia's (ECA's) consultant, Spencer&Co, were satisfied that the revised proposals 'adequately linked customers views to the outcomes proposed.'[76] We acknowledge the improvement that Powercor undertook to clearly identify the elements of its revised proposal that were shaped by discussions with its CAP. Given the limited timeframe, this may have contributed to the targeted discussions driven largely by Powercor on its "marquee programs", which limited consumers influence to other significant aspects of its revised proposal.

Powercor's revised proposal largely accepted the main elements of our draft decision which are discussed further in Sections 2.4 (capex) and 2.5 (opex). The CCP17 acknowledged that significant engagement was undertaken on issues including wood pole replacement, customer service schemes and future networks, however flag that a potential opportunity was missed to present a revised proposal as a whole, which included the contingent projects and new activities.[77] Powercor's revised proposal capital investment forecast was 17 per cent higher than our draft decision. The CCP17 noted they were 'pleased with many aspects of Powercor's revised proposal, which with the exception of wood pole replacement and contingent projects, is much more in line with historical spend.'[78]

Significant stakeholder engagement has occurred in relation to pole management. Powercor appreciated the value of discussing this issue with its stakeholders, given the large percentage of total forecast and the increase in historical levels of investment.[79] This continued engagement included a facilitated workshop by Forethought[80], and with its CAP,[81] as well as workshops with Powercor, ourselves, ESV, the CCP17 and DELWP to discuss Powercor's forecasting tool (the enhanced pole calculator). The CCP17, VCO and ECA all provided submissions on this issue and supported the ongoing work being done to address Powercor's asset replacement needs.[82] Our analysis and decision is discussed further at section 2.4.

We received a large number of submissions from consumers supporting Powercor's regional upgrade of SWER feeders in Tyrendarra, Strathdownie, Cape Bridgewater and Gorae West to three-phase supply. Powercor noted its disappointment of our draft determination to reject its proposed upgrade, however Powercor has failed to provide

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75 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26* January 2021, p 42-43. See also Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, pp.18-23.

76 ECA, Spencer&Co report - *Submission and attachment on the Victorian EDPR Revised Proposal and Draft Decision 2021–26 - 20* January 2021, p.6.

77 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26* -January 2021, p. 111.

78 CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26* -January 2021, p 112.

79 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 52.

80 See Powercor, *ATT07 - Forethought, Asset Replacement, summary stakeholder feedback* – October 2020.

81 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 52.

82 See CCP17, *Submission on the Victorian EDPR Revised Proposal and Draft Decision 2021–26,* January 2021, pp.113-116, VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26* - January 2021,p 20 and ECA - *Submission and attachment on the Victorian EDPR Revised Proposal and Draft Decision 2021–26 - 20* January 2021, p. 11.

sufficient evidence to demonstrate its engagement with customers discussing proposed approaches to this issue. The supporting submissions received do not refer to any engagement they have had with Powercor. Potentially their concerns could have been addressed by deeper engagement by Powercor with all its customers, earlier in the proposal process.[83] In addition, many stakeholder submissions requested that the Victorian Government help fund the upgrade of SWER lines to three-phase feeders. Reasons for our decision are discussed further at section 2.4.

CitiPower, Powercor and United Energy have acknowledged they are continuing to learn and improve their engagement approach.[84] We acknowledge the significant work undertaken following the draft decision with the initiative of the CAP however, there is still further work that can be done by Powercor to demonstrate that its customers are consistently understood and considered in its decisions.

Overall, while we have undertaken a more thorough bottom-up analysis of Powercor's proposal, we are confident that the consumer engagement undertaken since our draft decision with their CAP demonstrates progress towards establishing the proof points set out in our framework.

83 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 90.

84 Powercor, *Revised Regulatory Proposal - 2021–26*, December 2020, p. 12.

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 Powercor 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 STPIS
- the Customer Service Incentive Scheme (CSIS)
- the demand management incentive scheme (DMIS) and allowance (DMIAM)
- the f-factor scheme.

Once we make our decision on Powercor's 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 control 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. Our final decision makes a further CESS adjustment of $4.7 million compared to our draft decision. This is to account for changes in Powercor's age profile and the consequential increase in deferred interventions. Powercor's deferred capex included in our substitute capex forecast satisfies the three criteria set out in the Better Regulation CESS guidelines that allow the AER to make an adjustment to a distributors' CESS reward. In particular, we found Powercor's capex underspend in the current period to be material, its deferred capex also to be material and our substitute forecast to be materially higher than it would have been had the deferred capex not been included in our substitute forecast.[85] Protection against over forecasting 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. All Victorian distributors accepted our draft decision to apply the DMIS and DMIAM. We acknowledge that the Local Government Response expressed its concern that the full DMIAM allowance has been approved for Jemena, CitiPower and Powercor, without justification or evidence of the types of activities that

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

will be undertaken.[86] While we acknowledge this concern, we consider that the DMIAM research and development works have the potential to deliver long-term savings to consumers. The scheme has an in-built control framework to ensure that only those expenditures that meet the tests prescribed by the scheme will be approved. Any unspent DMIAM allowance will be returned to the consumers.

Our final decision is to apply the DMIS and the DMIAM to Powercor for the 2021–26 regulatory control period, without any modification. Our draft decision reasons form part of this final decision.

The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. Our final decision is to apply our national STPIS version 2.0 (November 2018) to Powercor for the 2021–26 regulatory control period. We will not apply the guaranteed service level component to Powercor as the existing jurisdictional arrangements will continue to apply. We will not apply the STPIS telephone answering target and incentive rate to Powercor in the next regulatory control period because the distributor has opted to apply our CSIS in the revised proposal. However, Powercor should continue to report on the telephone answering parameter in the next regulatory control period. Attachment 10 sets out our final decision on Powercor's STPIS.

Our final decision is to apply CitiPower, Powercor and United Energy’s proposed CSIS design. The proposed scheme replaces the current STPIS telephone answering parameter with a more holistic incentive that addresses its customer’s preferences, as identified through a genuine and thorough engagement process. The performance targets are based on historical performance, with the revised revenue adjustment formula ensuring that incentives and penalties are commensurate to the value identified by customers. The scheme has been approved by CitiPower, Powercor, United Energy’s CAP, and external stakeholders have also expressed support for the scheme in submissions. For each businesses, we the total revenue at risk for customer service performance will be 0.5 per cent of total revenue.

Our final decision is that each of the EBSS, CESS, STPIS, CSIS, DMIS and DMIAM should apply to Powercor for the 2021–26 regulatory control period.

Our final decision also includes how the f-factor scheme is applied to Powercor in the 2021–26 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. [87] The 2016 Order was amended by the F-factor Scheme Amendment Order 2020. We have made an f-factor scheme determination for Powercor under the F-Factor Scheme Order in respect of the 2021–26 regulatory control period, as detailed in attachment A of our draft decision. Our final decision is to make revenue adjustments for Powercor in accordance with the F-Factor Scheme Order by way of an annual adjustment through the "I-factor" component in the control mechanism, as specified in attachment 14 of the final decision. We discuss our final decisions on each incentive scheme in attachments 8 to 12.

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[86] LGR, prepared by Victorian Greenhouse Alliance, *Submission to the AER Victorian Electricity Distribution Price Review 2021–26, Local Government Response to the AER’s Draft Determination,* December 2020, p. 10.

[87] *Victoria Government Gazette, G 51*, 22 December 2016, p. 3239.

5 Tariff structure statement

Powercor's 2021–26 proposal includes the second iteration of its tariff structure statement (TSS). Its current TSS applies from 1 January 2016 to 30 June 2021.[88]

The requirement on distributors to prepare a TSS arises from significant reforms to the rules governing distribution network pricing. These reforms aim to:

- help distributors provide better price signals to retailers to reflect what it costs to use the network
- manage future expectations for retailers, distributors and consumers by providing guidance on distributors' tariff strategy
- help the transition to more cost reflecting pricing.

Distributors do not directly charge end customers. Rather, distributors charge retailers for the network services provided to end customers. Retailers can then decide how best to pass on these price signals to end customers.

A TSS applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning and reassigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor takes to setting tariffs in pricing proposals.[89] It is accompanied by an indicative pricing schedule.[90] A TSS provides consumers and retailers with certainty and transparency in relation to how and when network prices will change.

While an indicative pricing schedule must accompany the TSS, Powercor's tariffs for the entire 2021–26 regulatory control period are not set as part of this determination. Rather, tariffs for 2021–22 will be subject to a separate approval process that takes place in May 2021, after this final revenue determination in April 2021. Tariffs for the following four years will also be approved on an annual basis in May of each year.

Our final decision is to amend Powercor's TSS by:

- requiring stand-alone (grid scale) storage face network price signals to guide their operation and contribute to the cost of operating and maintaining the electricity distribution networks they use
- specifying electric vehicles owners, once they are identified by the relevant network, will no longer have access to flat tariffs
- clarifying retailers can request tariff reassignment from distributors to help optimise their portfolios while consumers retain control over their retail offer
- reducing the minimum chargeable demand for its HV customers from 1000 kVA to 500 kVA and sub-transmission customers from 10 000 kVA to 5000kVA
- permitting it modifies its sub-transmission pricing structure to remain unchanged until the AER's final decision on Australian Energy Market Operator's Designated pricing proposal charges pricing methodology in Victoria

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[88] The regulatory control period (1 January 2016 to 31 December 2020) was extended by six months. Refer to the Executive Summary above for an overview of changes to the regulatory control period.

[89] NER, cl. 6.18.1A(a).

[90] NER, cl. 6.18.1A(e).

- providing greater detail on tariff trials in the first year of the regulatory control period.

These amendments complement the changes Powercor already made to align with our draft decision. These changes include:

- reassignment of residential consumers on legacy time of use, flexibility and demand tariffs to the new time of use or demand equivalent
- increasing the peak to off-peak ratio of the residential time of use tariffs to maintain the established ratios which incentivise consumers to respond
- adopting United Energy's incentive peak demand component into its large user tariff structure with transitional arrangements to help consumers adjust
- providing greater clarity about continued access for consumers with consumption under 160 MWh a year but demand greater than 120 kVA to a zero demand tariff structure
- refining large user peak charging windows to more closely target network conditions
- provided further flexibility to allow large customers to be reassigned to the small business tariff class
- providing greater clarity on how its tariff strategy aligned with DER integration and demand management initiatives

On large customer tariff choice, our final decision is to allow Powercor to:

- not offer large user tariff choice at this time given the tight timelines between our draft decision and its revised proposal, as well as its intention to trial new large customer tariffs during the 2021–26 regulatory control period.

On energy storage, we consider batteries should contribute to recovery of network costs and should face network price signals to guide their operation. This will retain consistency with other National Electricity Market jurisdictions given the absence of new rules or policy direction between our draft and final decisions. If the asset falls into a particular tariff class, it should be assigned to the same network tariffs as other customers in that tariff class, whether owned by a distributor, its affiliate or a third party. We have amended Powercor's TSS to reflect this position. To the extent batteries are used for network support they will remain exempt from network tariffs.

We note the AEMC has foreshadowed its intention to consult with stakeholders on efficiently integrating distributed energy resources and that charging arrangements may be considered more generally in the context of the Energy Security Board reforms. The Victorian distributors have also committed to trialling new tariffs for energy storage over the 2021–26 regulatory control period.

Attachment 19 of this final decision provides detailed reasons for our decision on Powercor's TSS.

6 Other price terms and conditions

In this section, we consider the other aspects of our determination. These may be described as the terms and conditions of our determination that cover how Powercor must set its prices. This includes the classification of services and the framework for Powercor's negotiated services.

6.1 Classification of services

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

In its revised proposal, Powercor accepted our draft decision on the classification of the services it provides.[91] Our final decision is to retain the classification structure and the services list as published in our draft decision for Powercor.[92] The list of classified services Powercor will provide for 2021–26 is set out in attachment 13 to this decision.

6.2 Negotiating framework and criteria

In our draft decision, we approved Powercor's proposed distribution negotiating framework for the 2021–26 regulatory control period.[93] We did not receive any objections or submissions on our draft decision. Our final decision is to approve Powercor's negotiating framework. The distribution negotiating framework that will apply to Powercor for the period of this determination is set out in attachment A. We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[94] Our final decision is to retain the NDSC that we published for Powercor in September 2020[95] for the 2021–26 regulatory control period. The NDSC gives effect to the negotiated distribution services principles.[96]

6.3 Connection policy

In our draft decision, we did not approve Powercor's proposed connection policy for the 2021–26 regulatory control period. We modified Powercor's connection policy nominated in its original proposal, to the extent necessary to enable it to be approved in accordance with the rules.

Powercor accepted the majority of the changes we made to its initially proposed connection policy. However, it did not accept the threshold level for what size new

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[91] Powercor, *Revised Regulatory proposal, 2021–26* - December 2020, p. 135.

[92] AER, *Draft decision Powercor distribution determination 202–-26*, Attachment 12 Classification of services, September 2020. The services list can be found in Attachment A

[93] AER *Draft decision Powercor distribution determination 2021–26*, September 2020, Attachment 17, p, 17-4

[94] NER, cl. 6.12.1(16).

[95] AER, *Draft decision Powercor distribution determination 2021–26*, September 2020, Attachment 17, p, 17-4

[96] NER, cl. 6.7.1.

connections needs to contribute the upstream cost in addition to the network extension cost set in the draft decision. Powercor also proposed a new change to its original proposal to include the tax liability to the capital contribution for large embedded generator connections.

We do not agree to these proposed changes, because:

- Powercor's proposed threshold is not consistent with our Connection Charge Guideline published under the NER, 100A 3 phase supply.
- Powercor did not consult with the relevant stakeholders regarding the proposed change to include tax liability to the capital contribution for large embedded generator connections, since such change will result in a step change to its existing practice.

The approved connection policy for Powercor's 2021–26 regulatory control period is appended to attachment 18 of our final decision.

7 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:[97]

> "…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.[98] 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.[99] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[100]

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.[101]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[102] 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 final 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 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).

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97 NEL, s. 7.

98 NEL, section 16(1)(a)

99 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.

100 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.

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

102 NER, 6.12.1

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.[103] 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.[104]

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.[105] 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.[106] 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.[107]
- 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.[108]

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

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

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

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

107 NEL, s. 7A(7).

108 NEL, s. 7A(6).

A Constituent decisions

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the classification of services set out in Attachment 13 will apply to Powercor for the 2021–26 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is not to approve the annual revenue requirement set out in Powercor building block proposal. Our final decision on Powercor's annual revenue requirement for each year of the 2021–26 regulatory control period is set out in Attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve Powercor'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 final decision is to approve Powercor's proposal that the length of the regulatory control period will be five 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 final decision is not to accept Powercor's proposed total forecast capital expenditure of $1836.3 million ($2020–21). Our final decision therefore includes a substitute estimate of Powercor's total forecast capex for the 2021–26 regulatory control period of $1728.4 million ($2020–21). The reasons for our final decision are set out in Attachment 5.
In accordance with clause 6.12.1(4)(i) of the NER and acting in accordance with clause 6.5.6(c), the AER's final decision is to accept Powercor’s proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $1422.5 million ($2020–21). The reasons for our final decision are set out in Attachment 6.
In accordance with clause 6.12.1(4A) of the NER, the AER’s final decision to not accept the contingent projects (Ballarat West zone substation and conductor replacement project) proposed by Powercor. The reasons for our final decision are set out in Attachment 5.
In accordance with clause 6.12.1(5) of the NER and the modified 2018 Rate of Return Instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs set out in the Order in Council made under section 16VE of the amended National Electricity (Victoria) Act 2005 (Vic), the AER's final decision is that the allowed rate of return for the 2021–22 regulatory control year is 4.73 per cent (nominal vanilla) as set out in Attachment 3 of the final 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 modified 2018 Rate of Return Instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs set out in the Order in Council made under section 16VE of the amended National Electricity (Victoria) Act 2005 (Vic), the AER's final 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 final decision Overview.

Constituent decision

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on Powercor's regulatory asset base as at 1 July 2021 in accordance with clause 6.5.1 and schedule 6.2 is $4514.5 million ($ nominal). This is discussed in Attachment 2 of the final decision.

In accordance with clause 6.12.1(7) of the NER, the AER's final decision on the estimate of Powercor's corporate income tax is zero dollars for each regulatory year of the 2021–26 regulatory control period. This is discussed in Attachment 7 of the final decision.

In accordance with clause 6.12.1(8) of the NER, the AER's final decision is to not approve the depreciation schedules submitted by Powercor. Our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in Attachment 4 of the final decision.

In accordance with clause 6.12.1(9) of the NER the AER makes the following final 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 Powercor in the 2021–26 regulatory control period. This is discussed in Attachment 8 of the final decision.
- We will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Powercor in the 2021–26 regulatory control period. This is discussed in Attachment 9 of the final decision.
- We will apply our Service Target Performance Incentive Scheme (STPIS) to Powercor for the 2021–26 regulatory control period. This is discussed in Attachment 10 of the final decision.
- We will apply the customer service incentive scheme (CSIS) to Powercor for the 2021–26 regulatory control period. This is discussed in Attachment 12 of the draft decision.
- We will apply the DMIS and DMIAM to Powercor for the 2021–26 regulatory control period. This is discussed in the overview of the final decision.

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

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Powercor for any given regulatory year is the total annual revenue calculated using the formulae 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 final decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply a revenue cap for type 5 and 6 metering (including smart metering) services and price caps for all other services. The revenue cap for Powercor'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 formulae 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 final decision.

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In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is that Powercor 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 final decision.

In accordance with clause 6.12.1(14) of the NER, the AER's final decision is to apply the following nominated pass through events to Powercor 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 final decision.

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

In accordance with clause 6.12.1(15) of the NER, the AER's final decision is that the negotiating framework as proposed by Powercor will apply for the 2021–26 regulatory control period. This is discussed in section 6.2 of this final decision overview and the negotiating framework is in Attachment A of this final decision.

In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria published in our draft decision, in September 2020, to Powercor. This is set out in section 6.2 of this final decision overview.

In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning and reassigning retail customers to tariff classes for Powercor is set out in Attachment 19 of the final decision.

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

In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how Powercor is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the 2021–26 regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges is to set this out in its annual pricing proposal. The method to report recovery of the charges and account for the under or over recovery of designated pricing proposal charges is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(20) of the NER, the AER's final decision on how Powercor is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the 2021–26 regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges is to set this out in its annual

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pricing proposal. The method to report recovery of the charges and account for the under or over recovery of jurisdictional scheme amounts is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to not approve the connection policy proposed by Powercor. Our final decision is to amend Powercor' proposed connection policy as set out in Attachment 18 of the final decision.

In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the “f-factor scheme order 2016”,[109] the AER's final decision is to apply the f-factor incentive payments/penalties as a part of the "I-factor" adjustment to the calculation of the total annual revenue requirement using the formulae in Attachment 14 of the final decision.

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109 See 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 public submissions from the following stakeholders on our draft decision and Powercor's revised proposal:

Stakeholder
AGL
Ausgrid
Brotherhood of St Laurence, Renew, Victorian Council of Social Service
Consumer Challenge Panel (CCP) 17
Electric Vehicle Council
Energy Users Association of Australia
EnergyAustralia
Evie Networks
Firm Power
Groundline Engineering
Jemena Electricity Networks People’s Panel
Origin Energy
Victorian Greenhouse Alliances

We also received over 80 public submissions from stakeholders related to Powercor's proposed upgrade of existing single phase feeders to three phase supply in the Tyrendarra, Strathdownie, Cape Bridgewater and Gorae West regions. These are available on our website in full.[110]

[110] See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powercor-determination-2021-26/revised-proposal#step-74723.

C Consumer engagement framework

The following table represented the framework outlined in our draft decision for considering consumer engagement.[111]

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

[111] AER, *Draft decision, Powercor distribution determination 2021–26, Overview*, September 2020, Table 7, p. 42.

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
CPI	consumer price index
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
NEL	National Electricity Law
NELA	National Energy Legislation Amendment Act 2020 (Vic)
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
repex	replacement expenditure
RFM	roll forward model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital
VCO	Victorian Community Organisations