DRAFT DECISION

Powercor
Distribution determination
2021 to 2026

Attachment 5
Capital expenditure

September 2020

AUSTRALIAN
ENERGY
REGULATOR

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Note

This attachment forms part of the AER's draft 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 draft decision.

The draft 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 11 – Demand management incentive scheme and demand management innovation allowance mechanism

Attachment 12 – Not applicable to this distributor

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Victorian f-factor incentive scheme

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5 Capital expenditure

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

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulations, and to maintain the safety, reliability, quality, security of its network (the capex objectives).[1]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[2] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (as required under the National Electricity Objective (NEO)).[3]

The *AER capital expenditure assessment outline* explains our and distributors' obligations under the National Electricity Law and Rules (NEL and NER) in more detail.[4] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives. Appendix A outlines further detailed analysis of our draft decision.

Total capex framework

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

Once the ex-ante capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs, the savings are shared with consumers in future regulatory control periods. This incentive-based framework recognises that distributors should have the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

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1 NER, cl. 6.5.7(a).

2 NER, cl. 6.5.7(c).

3 NEL, ss. 7, 16(1)(a).

4 AER, *Capex assessment outline for electricity distribution determinations,* February 2020.

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

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs. As noted previously, distributors may spend more or less than our forecast in response to unanticipated changes.

5.1 Draft decision

We do not accept Powercor's capex forecast of $2142.6 million.[5] We are not satisfied that its total net capex forecast reasonably reflects the capex criteria. Our substitute estimate of $1560.6 million is 27 per cent below Powercor's forecast. We are satisfied that our substitute estimate reasonably reflects the capex criteria. Table 5.1 outlines our draft decision.

Table 5.1 Draft decision on Powercor's total net capex forecast ($ million, $2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Powercor's initial proposal	516.0	496.9	411.3	367.3	346.9	2138.5
Forecast assessed[6]	497.0	527.2	407.9	363.2	347.3	2142.6
AER draft decision	332.9	398.6	312.5	269.1	247.6	1560.6
Difference ($)	-164.2	-128.5	-95.4	-94.1	-99.7	-581.9
Difference (%)	-33	-24	-23	-26	-29	-27

Source: Powercor's initial post-tax revenue model (PTRM), subsequent information request responses and AER analysis.

Note: Numbers may not sum due to rounding.

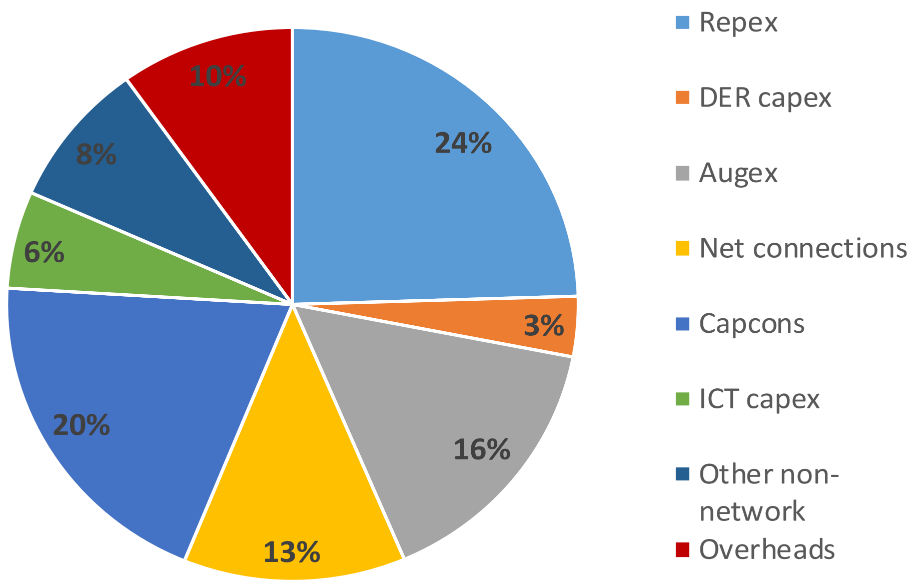
[5] All dollar amounts are presented in real $2020–21 unless otherwise stated.

[6] We have assessed a slightly higher forecast, as Powercor changed aspects of its initial proposal, including removing environmental repex and amending its rapid earth fault current limiter forecast.

5.2 Powercor's initial proposal

Powercor's capex forecast for the 2021–26 regulatory control period is $2142.6 million. This is 29 per cent higher than its actual capex of $1662.5 million over current regulatory control period.[7] Figure 5.1 outlines its initial capex forecast by capex driver. Figure 5.2 outlines Powercor's historical capex performance against its initial proposal.

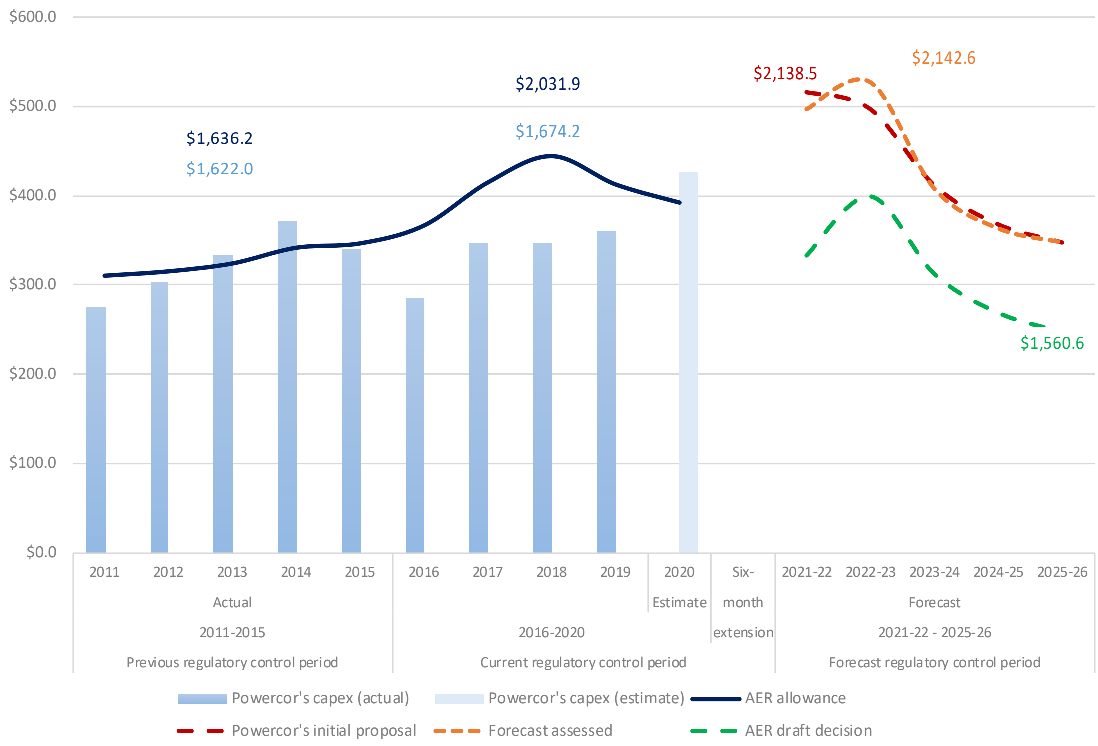
Figure 5.1 Powercor's initial total gross capex forecast



Source: Powercor's initial proposal and AER analysis.

7 In this attachment we compare forecast capex with actual capex in the current period; i.e. calendar year 2016 to 2019 pro-rated to five years. The impact of the COVID-19 pandemic and the derivation of calendar year 2020 estimate as the average of two financial year estimates creates uncertainty regarding the validity of the estimate.

Figure 5.2 Powercor's historical vs forecast capex snapshot ($ million, 2020–21)



Source: Powercor's initial proposal and AER analysis.

Note: The capex figures reported refer to five-year totals over a regulatory control period. The 2020 estimate has been included in this chart for indicative purposes. We have not used this estimate in our trend comparison.

5.3 Reasons for draft decision

We are not satisfied that Powercor's total capex forecast reasonably reflects the capex criteria. We are therefore required to set out a substitute estimate.[8] We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and forms part of an overall distribution determination that contributes to achieving the NEO to the greatest degree. In coming to our decision, we asked Powercor many questions across multiple information requests. Powercor was very receptive to our questions and in most cases provided useful responses within the requested timeframes. We acknowledge that our questions are likely to have presented additional resourcing challenges, particularly due to COVID-19, and appreciate Powercor’s cooperation and assistance.

We typically analyse a distributor's total capex forecast from a top-down perspective. This top-down review forms the starting point of our capex assessment to determine whether further detailed analysis is required, but is also used throughout our review

8 NER, cl. 6.12.1(3)(ii).

process to test the results of our bottom-up assessment. We apply both top-down and bottom-up reviews so that our decision is fully informed. In this case, we are not satisfied that Powercor's forecast capex is prudent and efficient under both reviews. From a top-down perspective, several metrics demonstrate that Powercor's forecast is not prudent and efficient:

- The capital expenditure sharing scheme (CESS) applies in the current regulatory control period. We place significant weight on Powercor's forecast capex being 29 per cent higher than its actual capex over the first four years of the current regulatory control period. In addition, its forecast is 30 per cent higher than its longer term actual capex trend, going back to the start of the 2011–2015 regulatory control period.
- Powercor's materially higher forecast relative to the current 2015 regulatory control period is combined with an underspend of approximately 15 per cent. This is reflected in its CESS payment of $65.9 million. This highlights that Powercor has demonstrated in the current regulatory control period that it can manage and maintain its network at a more efficient level.
- We observed limited top-down challenges to Powercor’s forecast. Powercor refers to top-down measures that it has considered, such as the replacement capital expenditure (repex) model. However, it does not appear to have made any adjustments to its forecast to account for these top-down measures or conducted sensitivity analysis to test its forecast. Energy Market Consulting associates (EMCa) raised similar concerns in its review.[9] EMCa also highlighted that Powercor did not provide any evidence of total capex prioritisation to address its highest risk areas first, which is likely to have led to an overstated forecast.[10]
- Most stakeholders did not support Powercor's initial capex forecast. The AER’s Consumer Challenge Panel (CCP17) submitted that the expenditure proposals required more detailed consideration and analysis.[11] The Energy Consumers Australia (ECA) submitted that affordability continues to be energy consumers’ number one priority, and overemphasising the reliability of electricity networks is not used to justify overinvestment and inappropriate price rises for consumers.[12] The Victorian Community Organisations (VCO) submitted that reducing network charges must be prioritised to ensure the affordability of an essential service for all Victorians. It stated that continued regulatory asset base (RAB) growth should be avoided to reverse the ongoing trend of rising electricity prices.[13] Figure 5.3 below outlines Powercor's long-term RAB trend and that our draft decision helps to slow Powercor's forecast RAB growth.

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[9] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 52.

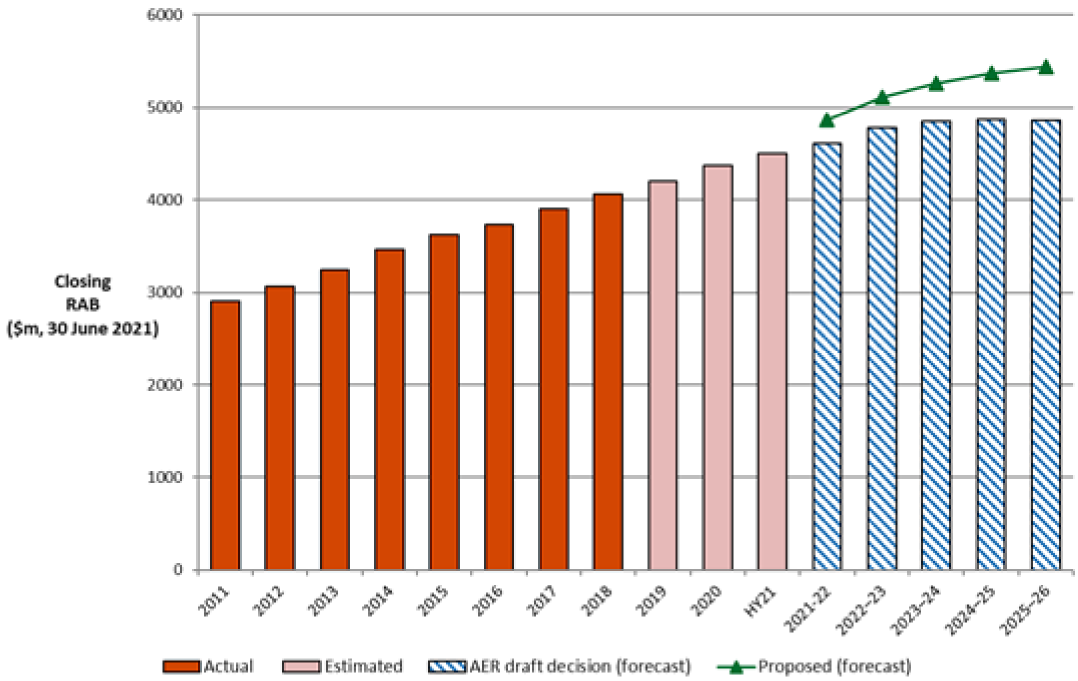
[10] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 31.

[11] CCP17, *Advice to the AER on the Victorian electricity distributors’ regulatory proposals, June 2020,* p. 3.

[12] ECA, *Victorian electricity distributors' regulatory proposals 2021–2026,* June 2020, p. 4.

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

Figure 5.3 Value of Powercor's RAB over time ($ million, 2020–21)



Source: AER analysis.

- Maximum demand, which is the key driver of augmentation expenditure (augex), has remained flat in Victoria over the last decade. Powercor has overstated its demand forecasts to support its augex proposals. In the past, Powercor has forecast strongly rising demand in its initial proposals for the previous and current regulatory control period forecasts, which did not eventuate. Powercor's continued optimistic forecast of rising maximum demand is predicated on a return to a strong relationship between gross domestic product (GDP) and demand, and was made prior to COVID-19. Key inputs have also been chosen or adjusted based on judgement rather than a neutral, evidence-based approach. We have applied the Australian Energy Market Operator's (AEMO's) latest demand forecasts because AEMO's recent demand forecast accuracy has been closer to actual demand and is widely accepted by industry and understood by stakeholders.
- Overall, improving system average interruption frequency index (SAIFI) measures and a reduction in fire starts indicate that Powercor's network performance is improving (except for wooden poles). This reflects Powercor's ability to effectively manage risk on its network. However, this is inconsistent with Powercor's submission narrative that it expects network risks to increase over the forecast regulatory control period, and therefore that an increase in expenditure is required. EMCa's review also highlighted that with the exception of wooden poles, there have been no material changes in Powercor's asset management practices.

To corroborate the outcomes of the top-down review, we thoroughly assessed the bottom-up material Powercor provided to support its capex forecast. Our bottom-up review confirmed the findings of our top-down assessment. In particular, Powercor did not provide convincing bottom-up evidence to support its forecast increase of 29 per cent compared with the current regulatory control period.

Table 5.3 summarises and appendix A outlines our detailed bottom-up assessment by capex driver, including how we have applied our assessment techniques and how we came to our position. Our assessment highlighted that Powercor's initial augex, repex, distributed energy resources (DER) capex, connections and information and communications technology (ICT) capex forecasts would not form a total capex forecast that reasonably reflect the capex criteria, taking into account the capex factors and the revenue and pricing principles. We had regard to the following considerations in forming our position:

- Powercor provided reasonable cost-benefit analysis for some projects and programs. However, there was a lack of supporting cost-benefit analysis, particularly options analysis, for several key projects and programs.
- In several cases, Powercor provided good models clearly setting out inputs and assumptions to support its forecast. However, often the model assumptions and inputs were either not explained, untested or overstated.
- For example, for Powercor’s forecast poles repex, Powercor has not provided sufficient information, specifically quantitative economic analysis to support its significantly higher forecast. We have had particular regard to the Energy Safe Victoria’s (ESV) 2019–20 findings and recommendations in its wood pole management review. Consistent with our previous decisions, we are acutely aware of the importance of funding for safety-related network risks. Therefore, our substitute estimate, which is a step-up from current regulatory control period replacement volumes, takes account of the longer term trend in pole replacement and includes a ‘back-log’ of poles replacement to bring Powercor to a sustainable level of poles replacement.
- For Powercor's DER integration capex, we are highly supportive of Powercor facilitating solar photovoltaic (PV) growth on its network. However, its solar enablement program forecast overstates what is necessary to deliver the Victorian Government’s Solar Homes program. Specifically, its analysis includes investments that would be more prudent to undertake in subsequent regulatory control periods.
- In addition, many stakeholders highlighted concerns with how Powercor valued solar PV exports in its modelling, suggesting the attributed value over the life of the investment did not consider there might be zero or negative benefits into the future and the proposal tended to overstate the value of solar export.[14] The final value of DER (VaDER) study report, due in early October 2020, will help to address some of these stakeholder concerns.

[14] DELWP, *Victorian Government submission on electricity distribution price review 2021–26,* May 2020, p. 2; CCP17, *Advice to AER on Victorian electricity distributors’ regulatory proposals,* June 2020, p. 106; EnergyAustralia, *Submission to VIC DNSP proposals,* June 2020, p. 1; EUAA, *EDPR submission,* June 2020, p. 11.

- We acknowledge the cost savings achieved due to Powercor's current regulatory control period transformation program, which contributed to both capex and opex efficiencies. However, these cost savings are not fully reflected in Powercor's capex forecast. EMCa and stakeholders including Origin Energy,[15] EnergyAustralia,[16] ECA[17] and CCP17[18] also raised this issue.

Table 5.2 outlines the capex amounts by driver that we have included in our substitute estimate of $1560.6 million. Table 5.3 summarises the reasons for our substitute estimate by capex driver. This reflects the way we have assessed Powercor's total capex forecast.

Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver. However, we use our findings on the different capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary.

15 Origin Energy, *Submission to Victorian electricity distributors' regulatory proposals,* June 2020, p. 6.

16 EnergyAustralia, *Victorian electricity distribution determinations 2021–26 – Regulatory proposals*, June 2020, p. 8.

17 ECA, *Victorian electricity distributors' regulatory proposals 2021–26,* June 2020, Attachment 1, p. 32.

18 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals 2021–26*, June 2020, p. 65.

Table 5.2 Capex driver assessment ($ million, $2020–21)

Driver	Powercor's initial proposal	Forecast assessed	AER draft decision	Difference ($)	Difference (%)
Repex[19]	694.7	677.6	426.1	-268.6	-39
DER capex	94.0	94.0	63.1	-30.9	-33
Augex[20]	395.3	416.5	276.8	-118.5	-30
Gross connections	864.5	864.5	738.3	-126.1	-15
ICT capex	151.7	151.7	133.4	-18.3	-12
Other non-network capex	227.5	227.5	224.7	-2.8	-1
Capitalised overheads[21]	264.9	264.9	218.5	-46.5	-18
Gross capex	**2692.7**	**2696.8**	**2080.9**	**-611.8**	**-23**
less capital contributions	528.6	528.6	494.7	-33.9	-6
less asset disposals	25.7	25.7	25.6	-0.1	0
Net capex	**2138.5**	**2142.6**	**1560.6**	**-577.8**	**-27**

Source: Powercor's initial PTRM, subsequent information request responses and AER analysis.

Note: Numbers may not sum due to rounding. Modelling adjustments are incorporated into each line item and relate to Powercor's consumer price index (CPI) and real price escalation assumptions.

Table 5.3 Summary of our findings and reasons

Issue	Findings and reasons
Total capex	Powercor has not provided sufficient information to demonstrate that its forecast capex is prudent and efficient. We have therefore substituted its forecast with a substitute estimate that better reflects the capex criteria. We invite Powercor to address our concerns in its revised proposal.
Repex	Powercor has not established that the proposed increase in its forecast repex is prudent and efficient. Powercor has either overstated its costs, benefits, or has not established the need of its proactive programs. Our substitute estimate is 8 per cent higher than its average actual repex over the current regulatory control period. This increased amount allows Powercor to address a 'backlog' of poles, which is the prudent and efficient repex required to stabilise and maintain the safety and reliability of its poles.

[19] The repex forecast assessed is lower than initially proposed as Powercor removed its environmental capex.

[20] The augex forecast assessed is higher than initially proposed because Powercor amended its REFCL proposal.

[21] Powercor's overheads forecast was immaterially different following its repex and augex forecast amendments.

Issue	Findings and reasons
DER capex	Powercor has adequately supported most aspects of its DER integration capex proposal. However, it has overstated its solar enablement program by including investments that would be more prudent to undertake in subsequent regulatory control periods. In addition, its net present value (NPV) analysis is conducted over 30 years. We are supportive of Powercor facilitating solar PV growth on its network. However, its forecast overstates what is necessary to deliver the Victorian Government's Solar Homes program.
Augex	Powercor has overstated its demand forecast and included inefficient cost estimates in its rapid earth fault current limiter (REFCL) proposal. Our traditional augex assessment is based on the historical augex Powercor has incurred over the current regulatory control period with flat maximum demand on its network. For REFCLs, we have conducted a detailed bottom-up assessment.
Connections capex	Powercor has not justified the increase in connections capex compared with historical expenditure under its current contributions policy. In addition, COVID-19 has affected construction activity, which is closely tied to connections. Our COVID-19 adjustment is based on a Housing Industry Association (HIA) dwelling forecast.
ICT capex	We have assessed recurrent ICT primarily through a top-down assessment. Top-down trend and benchmarking analysis reveals that Powercor's recurrent ICT capex forecast is likely to be overstated. Powercor has adequately supported most of its non-recurrent ICT capex forecast, except its customer enablement and intelligent engineering programs.
Other non-network capex	We accept Powercor's proposed other non-network capex forecast. Powercor's property capex forecast appears reasonable based on historical trend. Powercor's fleet forecast also appears reasonable based on its bottom-up fleet model and our benchmarking analysis.
Capitalised overheads	We have updated Powercor's base and trend component of its capitalised overheads forecast. We have also adjusted capitalised overheads for a lower level of forecast direct capex.
Modelling adjustments	Modelling adjustments relate to Powercor's CPI and real price escalation assumptions. We have updated Powercor's labour price growth to be consistent with our opex decision, as set out in Attachment 6.[22] In addition, consistent with our standard approach, we have assumed contract labour price growth in line with CPI only over the forecast period.

[22] AER, *Powercor distribution determination 2021–26 – Attachment 6 operating expenditure*, September 2020.

Issue	Findings and reasons
Asset disposals	Powercor did not include a forecast for the sale of used vehicles. Our draft decision includes a forecast for the sale of these assets.
Demand forecasts	Powercor's demand forecast is overstated, likely due to the way key variables have been applied as post-modelling adjustments rather than incorporated within its regression model. Powercor's past forecasts have materially overstated demand and its current forecasts do not adjust for the effects of COVID-19. We have adopted the AEMO's most recent demand forecasts for Powercor's network, which have historically been more accurate.

A Capex driver assessment

This appendix outlines our detailed analysis of Powercor's capex driver category forecasts for the 2021–26 regulatory control period. These categories are repex, DER integration capex, augex, connections capex, ICT capex, other non-network capex and capitalised overheads. All dollar amounts are presented in real $2020–21 unless otherwise stated.

We used various qualitative and quantitative assessment techniques to assess the different elements of Powercor's proposal to determine whether it reasonably reflects the capex criteria. More broadly, we seek to promote the NEO and take into account the revenue and pricing principles set out in the NEL.[23] In particular, we take into account whether our overall capex forecast will provide Powercor with a reasonable opportunity to recover at least the efficient costs it incurs to:

- provide direct control network services
- comply with its regulatory obligations and requirements.[24]

When assessing capex forecasts, we also consider:

- The prudency and efficiency criteria in the NER are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers to achieve the expenditure objectives.[25]
- Past expenditure was sufficient for the distributor to manage and operate its network in previous periods, in a manner that achieved the capex objectives.[26]
- The capex required to provide for a prudent and efficient distributor's circumstances to maintain performance at the targets set out in the service target performance incentive scheme (STPIS).[27]
- The annual benchmarking report, which includes total cost and overall capex efficiency measures, and considers a distributor's inputs, outputs and its operating environment.
- The interrelationships between the total capex forecast and other constituent components of the determination, such as forecast opex and STPIS interactions.[28]

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23 NEL, ss. 7, 7A and 16(1)-(2).

24 NEL, s. 7A.

25 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8–9.

26 AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

27 The STPIS provides incentives for distributors to further improve the reliability of supply only where customers are willing to pay for these improvements.

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

A.1 Repex

Repex must be set at a level that allows distributors to meet the capex criteria. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment determines that it is likely to fail soon or degrade in performance, such that it does not meet its service requirement and replacement is the most economic option[29]
- the asset does not meet the relevant jurisdictional safety regulations and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

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

A.1.1 Draft decision

We do not accept Powercor's repex forecast of $677.6 million.[30] Our substitute estimate is $426.1 million, which is 39 per cent lower than Powercor's forecast. We are satisfied that our substitute estimate forms part of a total capex forecast that meets the capex criteria.

A.1.2 Powercor's initial proposal

Powercor initially proposed a forecast of $694.7 million. During the review process, Powercor withdrew its environmental repex and subsequently updated its repex forecast to $655.6 million. In our draft decision, we have assessed a higher repex ($677.6) due to the shift of expenditure from opex to capex.[31] To forecast repex, Powercor relied on different forecasting methodologies. It either relied on:

- historical defect-driven programs for high volume assets, such as pole top structures, service lines, conductors
- condition-based risk modelling (CBRM) to forecast some substation-related elements, such as transformers, switchboards and protection relays

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

[30] Powercor withdrew its environmental repex following the submission of its proposal. In our draft decision, the expulsion drop out (EDO) fuse replacement and minor repairs base adjustments have been shifted from operating expenditure (opex) to capex.

[31] The shift of minor repairs base adjustments and the EDO fuse replacement step-change.

- historical trends in volume and unit rates for its network fault program.

In addition, Powercor checked its repex forecast against the repex model threshold, albeit with different assumptions. We discuss our repex modelling approach, including engagement with Powercor on its repex modelling, in Appendix C.

A.1.3 Reasons for draft decision

We have applied several techniques to assess Powercor's proposed repex forecast, as well as considering stakeholder submissions. These techniques include:

- trend analysis
- repex modelling
- top-down and bottom-up assessments, including EMCa's technical review
- stakeholder submissions
- network health indicators.

After having regard to these factors, we are not satisfied that Powercor has sufficiently justified that its forecast repex is prudent and efficient. Overall, Powercor did not provide convincing evidence to demonstrate that a material step-up of 63 per cent relative to the current regulatory control period was warranted, particularly in light of a 33 per cent underspend. We have identified the following issues with its forecasting approach:

- In a number of instances, we found over-forecasting bias. Powercor forecast additional projects and programs that are likely to duplicate work already in Powercor's business-as-usual or recurrent historical repex. Powercor did not provide quantitative evidence to demonstrate a change in network conditions that would require an increase relative to the current regulatory control period. EMCa also observed the additional projects do not appear to have been considered within the prioritisation and optimisation processes of the governance and management framework.[32]
- For some asset groups, Powercor provided good models in support of its forecast, although this was not in the majority of cases. Its risk monetarisation model is an example where these models are consistent with our *Industry practice application note for asset replacement planning*.[33] However, we agree with EMCa that Powercor appears to overstate some risk assumptions, and it did not support some assumptions with evidence of historical failures and consequence costs.[34] Therefore, we are not convinced that Powercor's forecast repex to mitigate these risks is prudent and efficient.

[32] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 32.

[33] AER, *Industry practice application note for asset replacement planning*, January 2019.

[34] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 30.

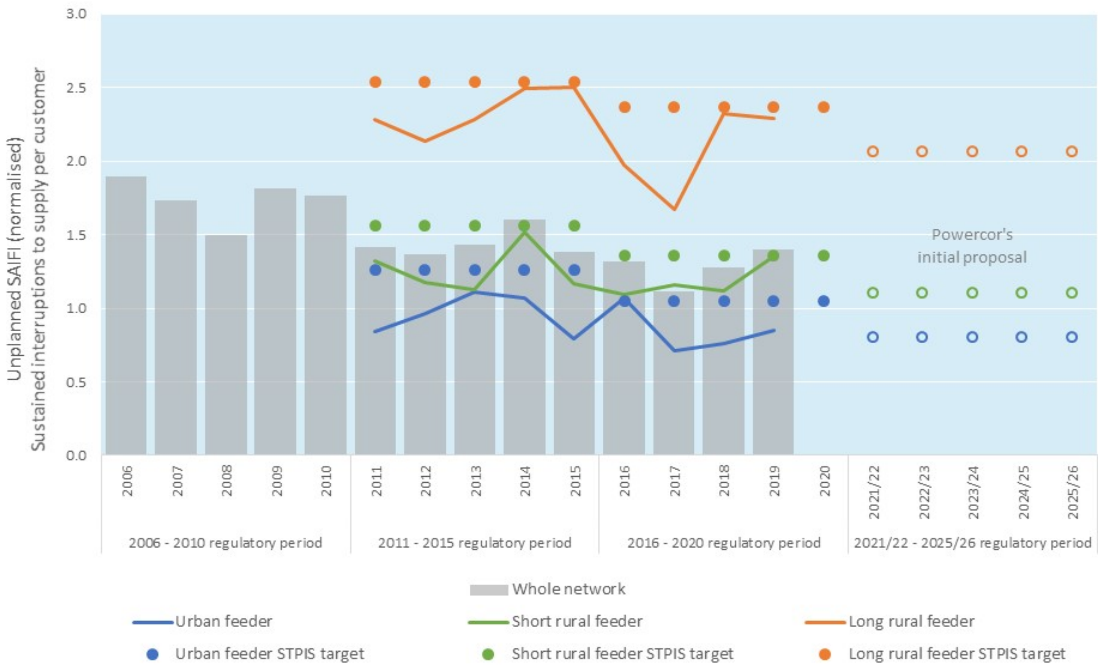
- Powercor did not support several of its forecast programs and projects with business cases, cost-benefit analysis or other quantitative supporting evidence. This was particularly the case for its poles, service lines and its EDO fuses forecasts. Inputs and parameters included in some supporting models were also unsubstantiated, untested or overstated.
- While we acknowledge the cost savings achieved due to Powercor's current regulatory control period transformation program, which contributed to both capex and opex efficiencies, these cost savings are not fully reflected in Powercor's repex forecast. This issue was similarly raised by EMCa.[35]
- A number of stakeholders, such as EnergyAustralia and VCO, questioned the increase in repex, particularly given the large underspend in the current regulatory control period.[36] VCO indicated, based on the historical trends, the proposed repex is likely to be higher than required and should be reduced.[37]
- We are not convinced that Powercor's forecast material increase relative to the current regulatory control period is required, given it has successfully managed and maintained its network, other than poles, over the current regulatory control period. Figure A.1 shows that Powercor outperformed its SAIFI targets in the first four years of the current regulatory control period (2016 to 2019), while underspending its capex regulatory forecast. These results provide us with confidence that, with the exception of poles repex, Powercor's revealed recurrent expenditure is likely to be reflective of its future repex requirements.

35 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 31.

36 EnergyAustralia, *Victorian electricity distribution determination 2021–26*, 3 June 2020, p. 9.

37 VCO, *Joint submission from Victorian community organisations - summary document*, May 2020, p. 4.

Figure A.1 Powercor's SAIFI performance over time from 2009 to 2026



Source: AER analysis.

Given our overall concerns with Powercor's proposed forecast, we have included a lower repex forecast in our substitute estimate of total capex. Our repex forecast is 8 per cent higher than Powercor's historical repex over the first four years of the current regulatory control period. We are satisfied our substitute estimate is sufficient for Powercor to meet its capex objectives.[38]

Trend analysis

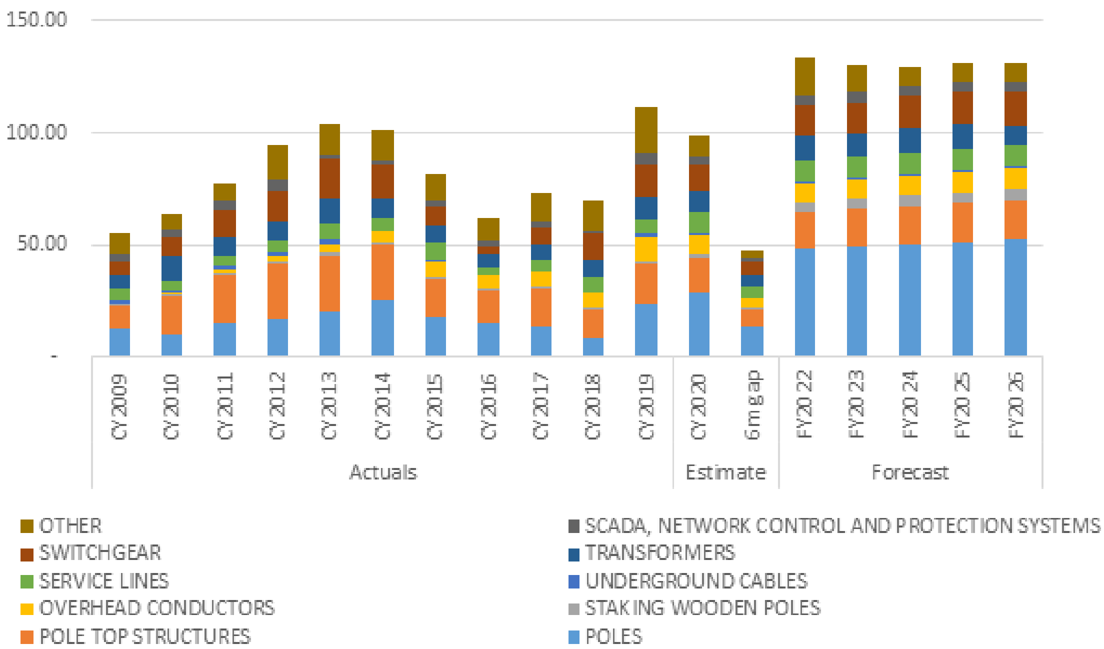
Powercor has included $677.6 million in its repex forecast, which makes up 24 per cent of its total gross capex forecast. Powercor’s proposal is 63 per cent above its historical spend between 2016 and 2019. In addition, Powercor achieved material efficiencies in the current regulatory control period with an underspend of approximately 33 per cent ($244 million) compared with its current regulatory control period regulatory forecast. To explain its underspend, Powercor referred to its 'world class' transformation program and the ESV exemption.[39] Powercor submits that its 'world class' program provided it the opportunity to apply technology innovations, renegotiate its contract

38 NER, cl. 6.5.7.

39 The exemption related to the $55.3 million capex that was included in Powercor's 2016–20 regulatory forecast. The ESV granted Powercor an exemption from correcting non-compliance clearances on overhead lines and from the installation of armour rods and vibration dampers on overhead lines in low bushfire areas (LBRA). Powercor, *Response to information request 54,* July 2020, p. 2.

arrangements, and establish a lean and efficient internal service delivery model.[40] Figure A.2 below shows Powercor’s long-term repex trend from 2009 to 2026.

Figure A.2 Repex trend from 2009 to 2026 ($ million, $2020–21)



Source: AER analysis.

Powercor’s forecast repex for the 2021–26 regulatory control period represents a significant increase over the current regulatory control period as well as over the longer term. The main driver of this increase is Powercor's poles program, which is a 216 per cent step-up relative to the current regulatory control period. Powercor submitted that its forecast poles repex was informed by the ESV's recommendations to achieve sustainable wood pole management practices. We discuss our findings on its poles forecast later in this attachment.

Repex modelling results

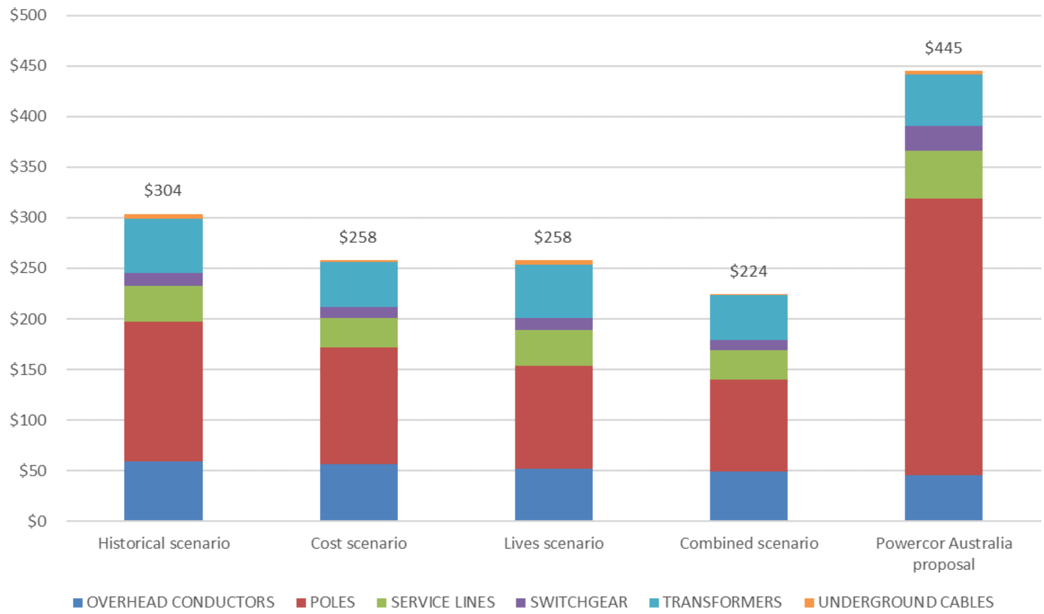
Consistent with our standard approach, we have tested Powercor’s asset categories and compared its repex forecast against the following four scenarios:

- Historical scenario – historical unit costs and calibrated expected replacement lives
- Cost scenario – comparative unit costs and calibrated expected replacement lives
- Lives scenario – historical unit costs and comparative expected replacement lives
- Combined scenario – comparative unit costs and comparative expected replacement lives.

[40] Powercor, *Response to Information Request #035 - EMCa questions following on-site*, 15 June 2020.

Figure A.3 below shows Powercor's proposed modelled repex compared with the four scenarios. Powercor's proposal of $445 million is $156 million higher than the repex model threshold.[41]

Figure A.3 Repex modelling results ($ million, $2020–21)



Source: AER analysis. See AER, *Draft decision repex model,* September 2020.

Figure A.3 shows that Powercor's modelled forecast for poles is significantly higher than the model predicts ($187 million), while service lines and switchgear are also higher than predicted. On the other hand, the model predicts that Powercor's forecast for overhead conductors, underground cables and transformers are likely to be reasonable. To support its proposal, Powercor has run the repex model, albeit with different assumptions. It acknowledged that the poles forecast is higher than the model predicts, but added that its risk monetisation and cost-benefit analysis are a more robust indicator of prudency and efficiency of its proposed investment than the repex model.[42]

In addition, Powercor acknowledged it supports the use of the repex model, particularly in situations where the historical asset management practices are stable over time. However, it flagged that its poles forecast is driven by a change to its pole asset management policies and therefore, in response to our issues paper, it cautioned stakeholders to consider the change in its asset management practices when comparing its forecast to the repex modelling results.[43] We have taken Powercor's

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41 The repex model threshold is the higher of the cost and lives scenario. However, we have had regard to both in this instance as both scenarios are $258 million.

42 Powercor, *Regulatory proposal 2021–26*, January 2020, p. 49.

43 CitiPower, Powercor and United Energy, *Response to AER's issues paper - Regulatory proposal 2021–26*, p. 27.

statements into consideration and have reviewed its supporting cost-benefit analysis and risk quantification in determining our substitute estimate.

Bottom-up considerations

In coming to a view of the prudency and efficiency, we have assessed the projects and programs that are included in Powercor's repex forecast. While we consider certain projects in determining our substitute estimate, we do not determine which programs or projects a distributor should or should not undertake. Once we set a forecast, it is up to Powercor to prioritise its total capex program given its circumstances, which are subject to change, over the course of the regulatory control period.

We have identified that the level of detail provided varied, with Powercor providing 47 per cent of business cases to support its repex forecast.[44] For other items, the level of detail provided was limited to a single line description in the supporting models provided. Below we discuss our assessments, findings and the basis of our substitute estimate for the programs and projects proposed. Our review has largely been categorised based on Regulatory Information Notices (RIN) classifications.

Fault program

Powercor proposed $74.6 million ($2020–21, excluding real cost escalation) to address network faults across multiple repex asset groups.[45] The forecast included repex for poles, pole top structures, transformers, service lines and switchgear assets. The network faults program did not include any forecast repex for overhead conductors and underground cables, as Powercor's modelling stated that the fault-related underground cables and overhead conductors contributed to its 'minor' repairs opex step-change.[46]

Powercor's forecast network fault expenditure used a trend-based approach for the forecast volumes, and an average approach for unit rates. For the volumes, Powercor calculated the average increase or decrease in volumes from 2011–12 to 2017–18 for each asset category, and then added this to the 2017–18 volume and each subsequent year to maintain a linear trend, increase or decrease, in forecast volumes. Powercor determined the forecast expenditure by multiplying these volumes by the average unit rate from 2014–15 to 2017–18 for each asset category—the unit rate is constant in the forecast period.

EMCa queried the trended volume approach, but Powercor's response did not sufficiently explain the rationale to support an increasing trend rather than a flat profile.[47] Powercor's response also identified a relatively flat historical expenditure for network faults. Considering this, we agree with EMCa's finding that:

44 Powercor, *Presentation to EMCa – Powercor regulatory proposal*, May 2020, p. 24.

45 Poles, pole top structures, transformers, service lines and switchgear.

46 Powercor, *MOD 4.11 – Network faults*, January 2020.

47 Powercor, *Response to information request 35*, June 2020, pp. 10–11.

> In the absence of better information, the level of expenditure associated with network faults is more likely to remain similar to historical levels, rather than an increasing trend as proposed.[48]

We tested the available data, including updated 2018–19 actual volumes from Powercor.[49] Based on our analysis, including EMCa's findings, we have derived an alternative approach to forecast network faults, which relies on the most recent actual volumes and unit rates, both from 2015–16 to 2018–19. Our alternative approach is more likely to reflect Powercor's needs over the forecast regulatory control period compared with its trended volumes.

In addition, we have identified that Powercor included trended volumes for public lighting fault capex within its network faults program. When we queried Powercor, it indicated that the works in question make the electricity supply safe following damage to public lighting assets (e.g. due to vehicles hitting a pole). Powercor's response does not sufficiently explain why these works are included in SCS capex. Therefore, we have excluded public lighting expenditure from the network faults program. Both changes result in a substitute estimate for networks faults of $62.8 million (excluding real cost escalation)[50], which is a reduction of 16 per cent.[51]

As the network faults program affects a number of asset groups, our substitute estimate on network faults flowed through to our analysis, including our substitute estimate for each of the affected asset groups.[52]

Poles – a modelled asset group

Powercor forecast $273.8 million for poles repex. This is an increase of $193.9 million, or 243 per cent, compared with actual repex in the current regulatory control period ($79.9 million).[53] Powercor submitted that its proposed forecast stems from the need to respond to community safety concerns, matters raised by ESV in its review of Powercor's asset management practices and to address recent deterioration in pole failure rates.[54] We acknowledge that some level of increase in wood poles volumes is justified.

We recognise ESV's review and subsequent recommendations to Powercor and appreciate the significance of these recommendations in managing safety risk. Consistent with our previous decisions, we are aware of the importance of maintaining

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48 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 43.

49 Powercor, *Response to information request 57*, July 2020.

50 Poles, pole top structures, service lines, switchgear and transformers.

51 The substitute estimate excludes the amount for underground cables and overhead conductors, which is discussed in the relevant sections.

52 Poles, pole top structures, transformers, service lines and switchgear.

53 Powercor's forecast for poles repex is 192 per cent higher than current regulatory control period when we include Powercor's 2020 estimate, which is higher repex than the previous four years.

54 Powercor, *PAL BUS 4.02 wood pole replacement program*, January 2020, p. 8.

safety risk and therefore have provided funding to distributors to address these risks where the costs were not grossly disproportionate to the risk reduction benefits.

However, in this case, Powercor has not provided sufficient evidence to support its forecast in full. Powercor has not demonstrated that its forecast is prudent and efficient. We have included $123.5 million for poles repex in our substitute estimate of total capex, which takes into account our substitute estimate on wood poles as well as the findings on fault program relating to pole volumes.

Powercor provided additional information on 7 August 2020, including updated failure rates. We are still reviewing this information and note that Powercor states that it is preparing cost-benefit analysis for its risk-driven volumes and updating its forecast to reflect outcomes of its enhanced pole calculator trial.

Wood poles – background

In March 2018, a wood pole failure in Powercor's network led to a bushfire that caused extensive property damage. Following the fires, community members escalated their concerns about Powercor's wood pole management practices to Members of Parliament. In response to the fires and community concerns, ESV investigated Powercor's management of its wood pole assets and concluded its current practices were inadequate to deliver sustainable safety outcomes.[55] ESV issued recommendations to Powercor to improve its pole management objectives, inspection practices, risk strategy and performance monitoring.[56]

Over the five years to 2018, Powercor's pole intervention volumes decreased as it found fewer poles assessed as unserviceable.[57] However, there was also a corresponding increase in the number of poles failures each year from 2016. In response to these events, Powercor made changes to its asset management practices in March 2019 and has proposed more substantial changes from July 2021.

Wood poles – forecast

Powercor forecast $256.4 million for wood poles repex, an increase of $189.1 million (281 per cent) compared with actual repex in the current regulatory control period ($67.3 million).[58] Wood poles make up 94 per cent of Powercor's total poles repex forecast. The wood poles forecast consists of:

- Condition-based interventions – 15,983 interventions. These are poles assessed as unserviceable through Powercor's inspection procedures.

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[55] ESV is the Victorian electricity safety regulator. Its role is to ensure ongoing compliance with Victorian safety legislation. It requires Victorian distributors to maintain documents that prescribe the business' approach to and governance of managing safety risk.

[56] ESV, *Powercor – Wood Pole Management, Sustainable Wood Pole Safety Management approach – Detailed Technical report*, December 2019.

[57] Interventions are either replacement or reinforcement (pole staking).

[58] Powercor's forecast for wood poles repex is 216 per cent higher than current regulatory control period when we include Powercor's 2020 estimate, which is higher repex than the previous four years.

- Visual inspections – 8,231 interventions. These are poles assessed as unserviceable through visual inspection (e.g. fungal or termite damage and visual defects).
- Risk-based replacements – 15,556 interventions. These are poles selected for proactive intervention as they are deemed higher risk by Powercor. They are in hazardous bushfire risk areas and assessed against Powercor's inspection criteria as serviceable but requiring additional monitoring

Powercor submitted that the identified need for the higher intervention volumes is:

> …to ensure our wood pole replacement program complies with all our existing safety obligations; supports our commitment to maintaining our reliability performance; and addresses community expectations of a sustainable approach to asset management.[59]

Trend analysis – wood poles

Figure A.4 shows the magnitude of the increase in forecast wood poles repex relative to historical trends and unassisted pole failure rates. Historically, poles repex increased between 2009 and 2014 and decreased to $6.8 million in 2018.

Pole failure rates were below Powercor's performance target of 17 failures over the period 2010 to 2015.[60] Since 2016, failure rates have exceeded the target in three out of four years. Powercor noted that 'the majority of these failures occurred in the northern region of Powercor in both serviceable and Added Control (AC) Serviceable poles averaging 52 years of age'.[61] We observe that the higher failure rates coincide with decreasing intervention volumes between 2015 and 2018 due to lower 'find-rates' of unserviceable or AC serviceable poles. ESV noted that 'the pole intervention volume is unsustainable'[62], and Powercor took measures to increase intervention volumes in March 2019. Most significantly, it increased the 'good wood' diameter threshold for unserviceable poles from 30mm to 35mm.[63]

The increase in 2019 actual and 2020 estimated repex reflects the changes made by Powercor to its asset management practices in March 2019. In September 2020, we wrote to Powercor regarding these changes.[64] We informed Powercor that the changes to its asset management practices would appear to be a distribution regulatory

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59 Powercor, *Wood pole replacement program*, January 2020, p. 8.

60 Performance target from ESV, *Powercor – Wood pole management, Sustainable wood pole safety management approach – Detailed technical report*, December 2019, p. 103.

61 ESV, *Powercor – Wood pole management, Sustainable wood pole safety management approach – Detailed technical report*, December 2019, p. 102.

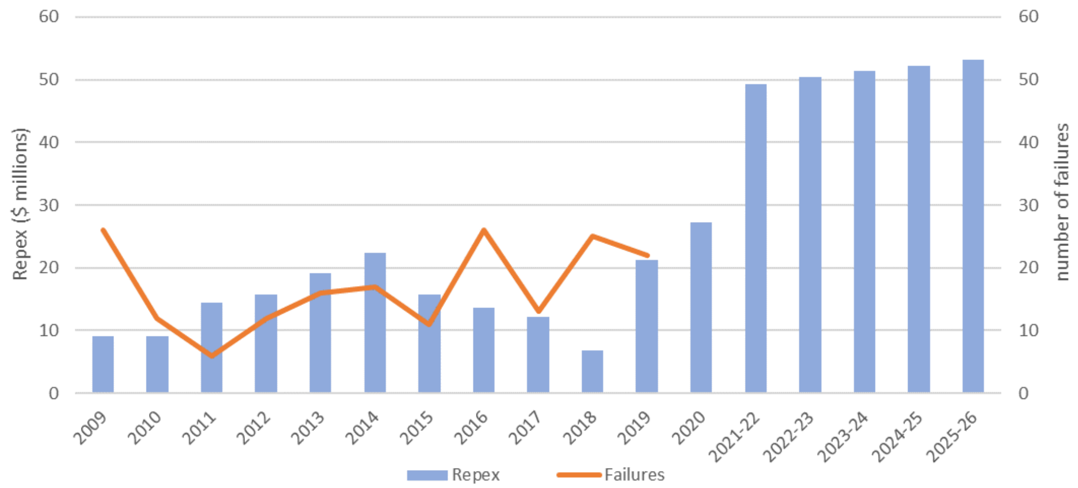
62 ESV, *Powercor – Wood pole management, Sustainable wood pole safety management approach – Detailed technical report*, December 2019, p. 102.

63 'Good wood' or 'sound wood' is the amount of remaining wood (unaffected by rot/decay or termite attack) in the wood pole annulus. The good wood gives the pole its structural strength.

64 AER, letter of inquiry, *Re: Compliance with the Regulatory Investment Test for Distribution – change in pole replacement practice*, 21 September 2020.

investment test (RIT-D) project under the NER. We invited Powercor to inform us about its proposed RIT-D process for its proposed changes from July 2021.

Figure A.4 Powercor's historical and forecast wood poles repex and interventions



Source: Powercor's RIN data and asset class strategy - poles and towers, December 2019. 2009 and 2010 failure are estimated from ESV data.

Note: Interventions means the sum of replacements and staking.

Concerns with Powercor's wood poles forecast

Powercor has not provided compelling evidence to demonstrate that its forecast is prudent and efficient. We have several concerns with Powercor's forecasting methodology. EMCa also reviewed Powercor's poles repex forecast and concluded that, based on the information provided, it did not consider that the forecast expenditure is representative of a prudent and efficient level. It noted that Powercor has established a reasonable basis for increasing the volume of wood pole treatments above its historical levels but noted various concerns with Powercor's forecasting methods. We highlight the following:

- Powercor did not provide quantified cost-benefit analysis. Without risk-based cost benefit analysis, it is not apparent what level of risk Powercor is trying to mitigate, and what intervention volumes are required to achieve these targets. EMCa made the same observation, noting that the selection of the level of risk reduction is not justified, and there was insufficient analysis of the intervention volumes in terms of failure rates and risk outcomes. We therefore do not have confidence that Powercor's forecast is prudent and efficient.

- After raising this with Powercor, it told us that it is now developing economic analysis for its risk-based and sustainability components of its forecast.[65] We will have regard to this new information in our final decision.

- It is not clear how Powercor's proposal will address the identified concerns with its wood poles. EMCa noted that Powercor's business cases do not describe how it has addressed an increasing failure rate and corresponding risk of lower durability poles (class three strength poles) in its proposed intervention volumes.
- Powercor's options analysis is inadequate in that it does not explore feasible solutions or has gaps in its analysis.
  - Powercor has proposed to improve asset monitoring, training and auditing of inspectors, more frequent inspections and improvements to its inspection practices in response to ESV's recommendations. We expect these changes will lead to significant improvements to Powercor's pole management. However, Powercor does not discuss these changes in its options analysis, including their impact on required intervention volumes.
  - Powercor's preferred option is to 'implement proposed enhancements to our pole calculator and serviceability index'. It submits that 'this approach will employ best practice techniques to assess pole condition and the probability and consequences of asset failure'.[66] However, these changes contribute to only 40 per cent of forecast volumes. Powercor has not explained why its forecast visual inspection-based volumes is significantly higher than current levels or why the additional risk-driven volumes are required.
  - Powercor dismisses an option to maintain the status quo plus additional interventions to maintain average asset age, because 'an asset management approach that is focused on the average age of the pole population is unlikely to optimise the safety and cost outcomes for our customers'.[67] While we agree that age is not a good indicator of asset condition, and may not lead to efficient investment outcomes, we query why Powercor has chosen an alternative option that is significantly more costly than to maintain an age-based approach.
- Powercor used a 'simulation' of its new enhanced pole calculator to forecast intervention volumes.[68] This bottom-up forecasting methodology is untested and includes parameters that are unsubstantiated or overstated.
  - Powercor stated that it commenced field testing of its enhanced pole calculator in August 2020 and the test is scheduled to conclude in December 2020.[69] We will have regard to these findings in our final decision.

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65 Powercor, *CitiPower, Powercor and United Energy pole replacement programs*, August 2020, p. 3.

66 Powercor, *PAL BUS 4.02 wood pole replacement program*, p. 23.

67 Powercor, *PAL BUS 4.02 wood pole replacement program,* p. 23.

68 The pole calculator is the algorithm that Powercor uses to assess pole condition. Powercor proposed an "enhanced" calculator for the forecast period. The primary differences from the current version is the introduction of a wood fibre strength variable and tip load calculation in accordance with AS7000 Overhead line design.

- Our inspection of the results finds that the enhanced pole calculator predicts relatively high interventions of class 1 poles, which are higher durability and on average younger than Powercor's class 3 population. Conversely, it predicts relatively low intervention numbers for Powercor's ageing, lower durability class 3 poles. These results are the opposite of what we expect and raises questions about the validity of the simulation outcomes.
- Powercor does not explain how it has set its serviceability threshold for the enhanced pole calculator. The enhanced pole calculator assesses a significantly higher volume of poles as requiring intervention compared with the existing pole calculator. Therefore, it is not clear whether the intervention volumes predicted represent prudent volumes. We expect Powercor to quantify or otherwise demonstrate that this revised risk level is reasonable and efficient.
- Powercor uses a 100 per cent pole load utilisation for poles in the highest risk bushfire areas, instead of the industry-standard 80 per cent. This assumption leads to overstated risk and forecast intervention volumes that are unlikely to be efficient.

- The visual inspection forecast is based on outputs from the enhanced pole calculator simulation and is forecast to increase significantly. However, there is no reason why fungal or termite attacks (the primary drivers of visual inspection condemnation) should increase in the forecast period. Instead, it is likely that condemnations due to visual inspection will be relatively constant over time.
- The inclusion of the proactive risk-driven interventions is not likely to be prudent. Powercor's enhanced pole calculator assesses these poles as serviceable but Powercor proposed to replace or reinforce them over the forecast period. As noted by EMCa, we found that there is no risk-based cost-benefit analysis or other adequate supporting material to justify intervention of these serviceable poles.
- We agree with EMCa that Powercor has not sufficiently demonstrated that it seeks to moderate the expenditure. This includes moderation with the top-down review methods it describes in its business case, with an estimate of the forecast outcomes in terms of network risk, or assessing the relationship with what appears to be improving network performance measures.[70]

On balance, Powercor has not satisfied us that its forecast for wood poles repex is prudent and efficient. On account of the very large increase compared with current regulatory control period repex, we expect Powercor to support its forecast with evidence-based cost-benefit analysis. We also have concerns with Powercor's use of the enhanced pole calculator to estimate intervention volumes because it is untested. We will have regard to the results of Powercor's field testing, due in December 2020, in our final decision.

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[69] Powercor, *CitiPower, Powercor and United Energy pole replacement programs*, August 2020, p. 4.

[70] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 53.

Stakeholder submissions

Stakeholders held mixed views on Powercor's forecast poles repex. Most support an increase in interventions where there is evidence of a need to address safety issues. CCP17 supported Powercor 'revising its pole and powerline maintenance strategies and improving the 'on the ground' safety assessment of poles'.[71] However, it also notes the imperative to address pole safety issues immediately and asks if the forecast 'can be demonstrated to be prudent, efficient and consistent with peers, and no more'. It also asks Powercor to 'consider reinvesting some or all of the CESS benefit towards its pole and powerline safety programme, with customers not perceiving that they may be 'paying twice"'.[72]

Spencer&Co (for Energy Consumers Australia) supports 'an increase in pole replacement if there is evidence that the asset management system has been lacking…However, given the level of expenditure and the low levels of pole failure to date, we ask that the AER review the modelling to assure itself that the parameters have been correctly applied'. It also notes that Powercor has not considered the interrelationships with REFCL capex.[73]

The VCO 'are not convinced that the faster rates of wood poles is warranted' and submit that Powercor has not 'provided sufficient argument' for the forecast increase to poles repex.[74] ESV 'supports the Powercor case for increased levels of intervention'.[75] The Victorian Government submits it 'supports (Powercor's proposal) to increase pole replacement' but 'network management activities undertaken to reduce risk as far as practicable need to be at an acceptable cost to consumers'.[76]

Substitute estimate

We are not satisfied that Powercor's forecast is prudent and efficient and have included in our substitute estimate $123.5 million for total poles repex (table A.1). This is 55 per cent lower than Powercor's forecast and 46 per cent higher than its actual poles repex for the current regulatory control period.

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71 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals 2021–26*, June 2020, p. 87.

72 CCP17, Advi*ce to the AER on the Victorian electricity distributors' regulatory proposals 2021–26*, June 2020, p. 88.

73 Spencer&Co*, Report to Energy Consumers Australia – A review of Victorian distribution networks regulatory proposals 2021–26,* June 2020, p. 20.

74 Victorian Community Organisations, *2021–26 Victorian EDPR*, May 2020, p. 45.

75 ESV, *Submission in response to AER issues paper – Victorian electricity distribution determination 2021 to 2026*, May 2020, p. 3.

76 DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 5.

Table A.1 Breakdown of our substitute estimate for poles repex ($ million, $2020–21)

	Draft decision
Wood poles	111.2
Non-wood poles	12.3
Total	**123.5**

Source: AER analysis.

Our substitute estimate on total poles includes adjustments to non-wood poles (such as concrete and steel poles) consistent with the methodology outlined in the network faults program above. We are satisfied that our substitute estimate, in conjunction with the asset management improvements recommended by ESV, will provide Powercor with sufficient capex to maintain the safety and reliability of its pole assets.

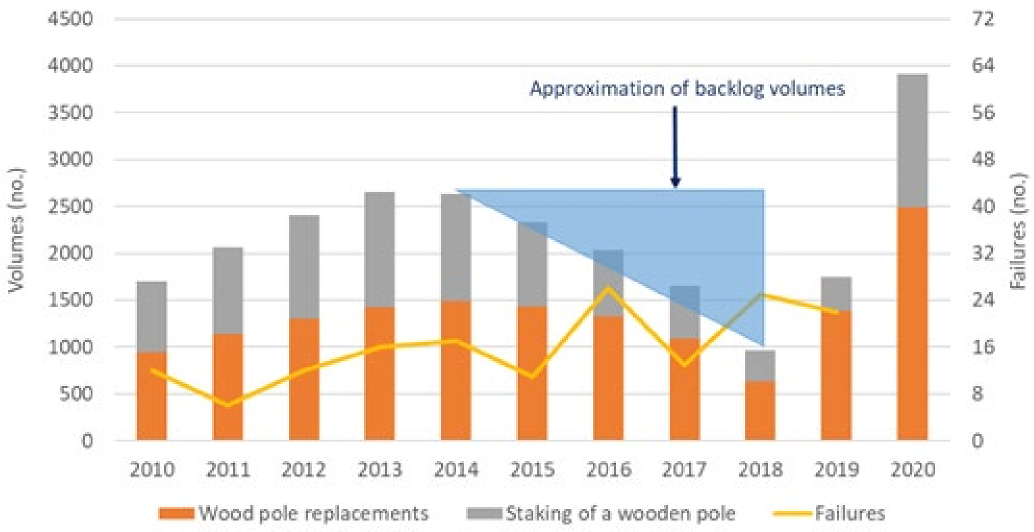
Substitute estimate on wood poles

Our substitute estimate for wood poles takes into account Powercor's historical repex and failure rates, and acknowledges the need to address a 'backlog' of poles requiring intervention due to Powercor's inadequate historical wood pole inspection practices.

Our approach was to analyse Powercor's failure rates from 2009 to 2019 (see figure A.5). We observed that over the period 2010 to 2015 failure rates were relatively low and stable compared with the period from 2016 to 2018. At the same time, intervention volumes were generally higher than in 2016 to 2018. This indicates that these volumes may represent a sustainable intervention level at which Powercor adequately managed wood pole failure rates. Therefore, we took Powercor's 2,660 intervention volumes in 2013 (the highest volumes over the 2010 to 2015 period) as the 'base level' volume for each year of the forecast regulatory control period. We consider that the base level volume is adequate for Powercor to maintain the safety and reliability of its wood poles population.

In addition to our base level volumes, we also include a further 3,669 poles for the forecast regulatory control period. This represents a conceptual 'back-log' of volumes that were not completed in 2014–18 when compared with our base level volumes (illustrated in figure A.5). We consider that these additional volumes were required to maintain network performance and therefore represent outstanding volumes that Powercor has a likely need to address in the forecast regulatory control period. We have not included Powercor's actual 2019 and estimated 2020 volumes in our backlog because these volumes (2,832 per year) exceed the base level volume (2,660 per year). Finally, we applied an average of staking rates over the period 2010–18. This is a conservative estimate (40 per cent) and is lower than Powercor's forecast staking rate of 42 per cent.

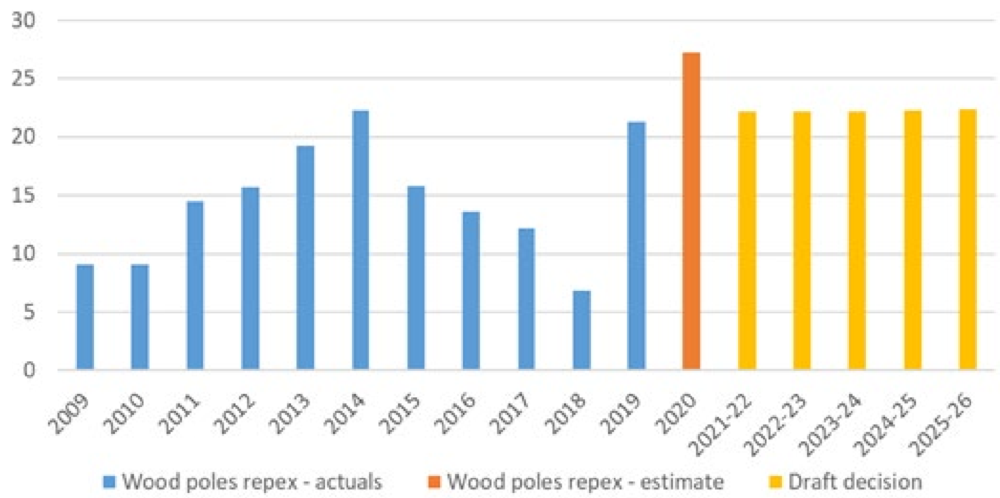
Figure A.5 Historical interventions showing backlog of volumes in the current regulatory control period



Source: AER analysis and RIN data.

Figure A.6 shows that our substitute estimate is around 37 per cent higher than Powercor's current regulatory control period actual and estimated repex, and around 32 per cent higher than its annual average actual and estimated repex over the last ten years to 2020.

Figure A.6 Powercor's historical wood poles repex vs draft decision



Source: Powercor's RIN data and AER analysis.

We tested our substitute estimate against the repex model results. The repex model, which has regard to Powercor's asset age profile, predicts a maximum of $82.4 million for wood poles over the forecast regulatory control period.[77] The repex model's output reflects Powercor's previous asset management practices, which the ESV observed to be unsustainable in maintaining the safety of its network. For this reason, we included the 'backlog' volumes in our substitute estimate. After we add in our additional 'backlog' volumes, the repex model predicts a maximum of $106 million for wood poles repex. This is broadly in-line with our substitute of $111.2 million. We are satisfied that our substitute estimate of $111.2 million for wood poles is sufficient capex to maintain the safety and reliability of Powercor's pole assets.

Switchgear – modelled and unmodelled components

Powercor forecast $71 million for switchgear replacement.[78] The assessed forecast is 52 per cent higher than its current regulatory control period expenditure. Powercor's switchgear asset group is divided into unmodelled and modelled components.[79] Our assessment has identified that Powercor has not established that its forecast is prudent or efficient. Therefore, we have substituted an estimate of $52.8 million, which is 13 per cent higher than its current regulatory control period expenditure.

Switchgear – unmodelled

As part of forecast repex, Powercor included $35.3 million for high-voltage (HV) switches, including EDO fuses and surge arrestors.[80] It has also proposed an opex step-change of $11.1 million to proactively replace all its EDO fuses. We, EMCa and stakeholders such as Spencer&Co[81] and the CCP17[82], do not agree with the proposed classification of the EDO fuse replacements. We do not accept the proposed opex step-change for the reasons set out in Attachment 6 of this draft decision. We have shifted it to repex and assessed it along with Powercor's proposed unmodelled switchgear. Our assessment of HV switches is included below.

HV switches – proposed as repex

Powercor's proposed repex to replace its HV switches includes replacement of its existing fleet of EDO fuses and surge arrestors. To forecast HV switches, Powercor relied on the average of its actual volumes and unit rates from 2014 to 2018. Powercor

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77 The lives scenario predicts $82.4 million for wood poles over the forecast period, whereas the cost scenario predicts $76.4 million.

78 The amount is higher than originally forecast, as it includes the reclassified EDO fuse step-change, which we did not accept is of an operating nature.

79 The modelled component is included in the repex model results presented earlier.

80 The amount is included in switchgear "other" in the reset RIN. Powercor, *Workbook 1 – Regulatory determination*, January 2020.

81 Spencer&Co, *Report to Energy Consumers Australia – A review of Victorian Distribution Networks Regulatory Proposals 2021–26*, May 2020, p. 20.

82 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, June 2020, p.55.

has not provided convincing evidence as to why its forecast units are higher than current period actual unit rates, particularly as they do not take into account the efficiency benefits that Powercor has achieved between 2016 and 2019.

On balance, the overall forecast amount is in-line with current regulatory control period repex and based on Powercor's existing performance. EMCa considered that it is appropriate to maintain similar levels of replacement to those Powercor has historically undertaken.[83] We accept Powercor's forecast for HV switches and included the $33.9 million[84] in our substitute estimate of total capex.

HV switches – EDO fuse replacement in ELCA and HBRA areas – proposed as opex

The proactive EDO fuse replacement project is made up of $8.8 million to replace this type of fuse in the electric line construction area (ELCA) and $2.2 million to progressively replace these fuses in the high bushfire risk area (HBRA).[85] The ESV has indicated its support for progressively replacing EDO fuses in hazardous bushfire risk areas to arrest any increase in fire starts which may be caused by EDO fuses.[86]

EMCa reviewed the underlying justification of the program and identified a number of input assumptions that are likely to overstate the risk cost:[87]

- the absence of moderating factors to account for the probability of a failure causing a fire, the probability of its occurrence on a total fire ban day, and the likelihood that an unsuppressed fire resulting in a catastrophic consequence.
- the likelihood of catastrophic consequence is unsubstantiated through the use of actual data, and appears higher than the reported fires contained in the ESV 2019 safety report.

In addition to EMCa's concerns, Powercor's proposed pro-active program did not have regard to the volume of EDO fuses replaced in its recurrent-historical repex. Powercor replaced 9,895 EDO fuses between 2014 and 2018,[88] as part of its HV switches category under "other" switchgear. The forecasting of a proactive program, without taking into account its existing on-going replacement program, contributes to the systemic over-forecasting bias, which we have observed throughout the review process.

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83 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 77.

84 The amount takes into account the impact of real cost escalation and CPI.

85 Electric Line Construction Areas (ELCA) in the Electricity Safety (Bushfire Mitigation) Regulations 2013 (Amended Bushfire Mitigation Regulations) were implemented in Victoria on 1 May 2016. ELCAs are considered to have a higher value of consequence from a potential fire compared to the remainder of HBRA, measured as the value of economic and social cost in an event of a major fire. As such, ELCAs have more stringent standards with regards to the construction of electric lines. See Powercor, BUS 9.04 – EDO replacement, January 2020.

86 ESV, *Submission in response to the AER issues paper – Victorian electricity distribution determination 2021–2026,* May 2020.

87 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 223.

88 Powercor, *Response to information request 57,* July 2020.

We also observed that Powercor's cost-benefit analysis, underpinning the EDO replacement, applies a disproportionality factor of 6 for property damage. Consistent with the principles outlined in our replacement expenditure application note[89], disproportionality factors do not apply to property damage, but only to the uncertainty associated with safety risk, mainly fatalities – a separate consequence category. If the property risk cost estimate is adjusted to remove the application of the disproportionality factor, the cost of the project materiality exceeds the risk cost.

We have solved for the efficient project cost that mitigates the revised risk cost (without the application of a disproportionality factor of 6 for property damage). This results in a proactive EDO fuse replacement in the ELCA that is 43 per cent lower than proposed. The other input assumptions, as noted in EMCa's report, while contributing to an overstated risk cost for the ELCA, are less material and therefore we have not made any further adjustments to the risk modelling. Our substitute estimate, based on an adjustment to the risk modelling, of $5.1 million, allow Powercor to proactively replace EDO fuses within the ELCA.

For the proposed fuse replacements within the HBRA, consistent with EMCa's findings, when we adjusted the input assumptions in the proposed modelling,[90] the project cost exceeds the risk costs, therefore, the proposed amount is not prudent or efficient. We have not solved for or included any additional proactive component for the replacement of EDO fuses in the HBRA in our substitute estimate. We are satisfied that the combined amount for all EDO fuse expenditure of approximately $39.1 million provides Powercor with sufficient expenditure to manage its risks within all its service areas, including the ELCA and HBRA, over the forecast period.

Switchgear – modelled

Powercor proposed $24.7 million ($2020–21) for its modelled switchgear for the forecast regulatory control period. In this modelled component, Powercor has included one business case and cost model to support $6.9 million ($2020–21) for its HV caution refer operator (CRO) air-break switches out of the proposed $24.7 million. No further documentation or justification for the remainder of its modelled switchgear forecast was included. We have a number of concerns with Powercor's forecast repex for modelled switchgear:

- there is a lack of supporting quantitative documentation and analysis to justify the majority of the proposed increase in expenditure
- Powercor's forecast is 104 per cent higher than the repex model ($12.1 million).

We and EMCa consider a component of the forecast, the CRO-tagged interrupters, is likely to be reasonable. On the other hand, EMCa has indicated that Powercor has not sufficiently demonstrated that its non-Gevea switch forecast represents a prudent

89 AER, *Industry practice application note for asset replacement planning,* January 2019.

90 Powercor, *PAL MOD 9.06 - EDO HBRA risk*, January 2020.

replacement. Powercor has not provided options analysis, a business case nor economic analysis to justify the need for the project.[91]

Based on information before us, Powercor has not justified the prudency or the efficiency of its total modelled switchgear component of repex. Therefore, we have determined a substitute estimate of $13.6 million, which is in line with Powercor's revealed costs, and takes into account our findings on fault repex. We are satisfied that our substitute estimate is sufficient to maintain the quality, safety and reliability of its network as it is in-line with the repex modelling outcomes for the modelled switchgear component.[92]

Transformers – a modelled asset group

Powercor forecast $51.0 million for its transformers repex, which is an increase of 32 per cent from its actual average repex between 2016 and 2019. The forecast is generally in line with the repex model output for transformers repex.[93]

The majority of the forecast, approximately 61 per cent, relates to distribution transformers replacement - a subset of the fault program. In addition, Powercor included three zone substation transformer replacement programs, two at Robinvale, one at Warrnambool and one regulator replacement at Inglewood. These are forecast at $10.2 million and represents 19 per cent of its total transformer forecast. Powercor has acknowledged that the three transformers zone substation replacements have been deferred from the current regulatory control period.

Powercor noted that its approach to forecasting its zone substation transformer replacements is based on a risk monetisation model, and the probability of the assets failing is a function of its underlying condition and health index of the asset. Powercor provided risk monetisation models to support its forecast replacements.

EMCa has reviewed the underlying data, including the risk monetisation models. Based on a sensitivity analysis of the input assumptions, EMCa concluded that replacements are likely to be reasonable.[94] Therefore, we are satisfied that the proposed replacements are prudent. While we have concerns with the forecast unit costs, particularly that the forecast unit costs are higher than other distributors, any reduction based on unit costs for the three units is immaterial in the context of the overall repex forecast.

Based on the information before us, we have included $46.7 million for transformers repex in our substitute estimate, which includes all the proposed zone substation replacements and the regulator, but includes an adjustment for distribution

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91 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 77.

92 The repex model predicts between $11.2 million and $12.1 million based on the cost and lives scenario respectively.

93 The cost scenario predicts $45 million for transformer repex, whereas the lives scenario predicts $52 million for transformer repex.

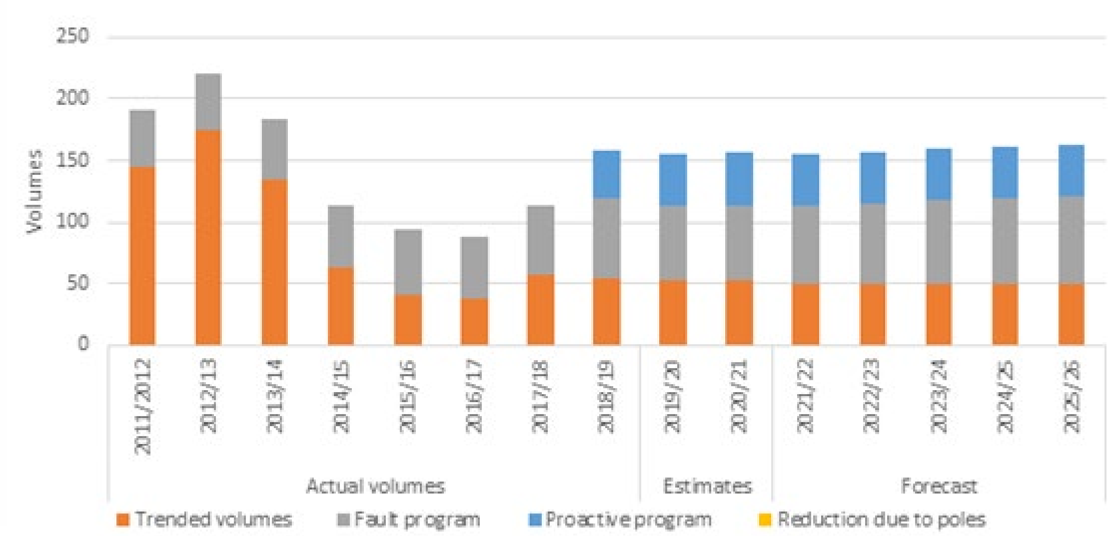
94 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 74.

transformers replacement, in line with our findings on the fault program. We are satisfied that the amount is sufficient for Powercor's requirements as it is $8 million higher than its average historical repex over 2016 to 2019.

Service lines – a modelled asset group

Powercor proposed $47.6 million for service lines repex over the forecast regulatory control period. This is an 82 per cent step-up from its service lines repex between 2016 and 2019. It is also 52 per cent higher than what the repex model predicts for its existing service lines population. In terms of forecasting methodology, Powercor has built up its service lines replacement volumes based on four components. First, it used an historical trended approach, which includes historical volumes and historical unit rates. Second, it took into account a forecast for service lines faults in its network, which was based on historical trends. Third, it included a proactive program for a range of service lines issues that require proactive replacement in addition to its historical trend approach. Fourth, it included a negative adjustment to take into account efficiencies of replacing its service lines along with increased pole replacement volumes. Figure A.7 below shows the breakdown of Powercor's forecast volumes over time.

Figure A.7 Powercor's components of its forecast service line volumes compared to historical volumes



Source: AER analysis

We have reviewed the programs, inputs and assumptions that are relied on. Based on the information before us, Powercor has not justified the increase in its service lines repex relative to its current regulatory control period spend for the following reasons:

- Powercor has not provided any cost-benefit analysis or risk monetisation to support the proactive component of its service lines replacement (such as the PVC grey, Veranda access or neutral screen testing programs). EMCa also came to the same finding.[95] In the absence of this information, there is insufficient evidence that there is a need to undertake this replacement or that the benefit of a proactive program exceeds the risk costs.
- Powercor has forecast its service lines using a number of different bottom-up methodologies, with no top-down adjustment to ensure its bottom-up projects do not overlap. For example, Powercor is forecasting to replace a specific type of service line (PVC grey), a service line with a known defect, by using a ratio of defect find rate as a percentage of the total population.[96] However, it has not considered its business-as-usual repex over the current regulatory control period is likely to include PVC grey replacements. The two methodologies together, without taking into account the synergies, are likely to overstate the volume of replacements required over the forecast period.
- Powercor's forecast unit costs are 19 per cent higher than its historical unit costs, but it did not provide evidence to explain this step-up in unit costs. EMCa came to the same conclusion.[97]

EMCa's review also concluded that Powercor has not justified the extent of the proposed increase to its forecast expenditure for the service lines repex category. In addition to our concerns, EMCa identified that:

- Powercor has experienced a decreasing or constant trend in fire starts, asset failures, and reportable incidents involving the public, which does not support the need for a step increase in replacement volumes.[98]
- Powercor has not adequately demonstrated that a forecast based on historical trended volumes would be insufficient to meet its safety obligations, if prioritised based on a highest risk service lines.
- Powercor's assumptions for the proactive component are based on a single year of replacement data. Even though Powercor relies on recent data as justification for its assumptions, EMCa noted the following:

> Powercor's replacement volumes for PVC grey service lines were extrapolated from elevated levels of replacement that occurred in 2018, which were the order of four to five times the replacement levels that occurred prior to and following this period…. Use of more recent replacement data is positive, however insufficient without other corroborating evidence that the incurred replacement levels are directed at addressing an elevated level of safety risk, systemic issues, or defects. Also, that this replacement volume should be

95 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 66.

96 Powercor, *PAL MOD 4.06 - Lines replacement,* January 2020.

97 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 66.

98 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 65.

undertaken in addition to the underlying level of defect driven replacements that are forecast based on other methods.[99]

Based on the information above, including EMCa's findings, Powercor did not establish that its proposed service lines is prudent and efficient. We have included a substitute estimate of $27.6 million, which does not include the proactive projects and incorporates our findings on the service lines elements of Powercor's fault related capital. We are satisfied that the amount is sufficient for Powercor to maintain the safety and reliability of its network as demonstrated in its performance, as it is 5.4 per cent above its service lines repex from 2016 to 2019.

Underground cables and overhead conductors – modelled asset groups

Powercor has forecast $48.9 million for both its underground cables and overhead conductors repex over the forecast regulatory control period. In addition, Powercor proposed a base adjustment to opex, which equates to $20.8 million for minor repairs of underground cables and overhead conductors.[100] It submitted that the amount was incorrectly capitalised in the current regulatory control period and the nature of the work is that of repair and does not extend the life of the asset. Therefore, it has also provided us a recast RIN to ensure that its historical capex removes the impact of minor repairs.

Based on the information before us, including advice from EMCa, we do not accept the base adjustment in the opex forecast. We discuss our reasons for this decision in Attachment 6 of this draft decision. We have shifted the amount to repex and have assessed it against the capex criteria. We discuss our findings on the reclassified minor repairs repex and originally proposed repex below.

Minor repairs repex

The information before us indicates that the proposed amount is not prudent or efficient. Table A.2 shows the proposed breakdown of the base adjustment that amounts to approximately $18.8 million ($2020–21, excluding the impact of opex rate of change) of expenditure over the forecast regulatory control period.

[99] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 66.

[100] The figure includes the impact of opex rate of change. See Powercor, *MOD10.06 – Opex model*, January 2020.

Table A.2 Components of the proposed minor repairs base adjustment ($ million, $2020–21)

Asset group	Description	Minor repairs – total expenditure
Underground	Cable termination/joint replacements	0.6
Underground	Single-wire earth return (SWER) iso earth repairs	1.7
Major plant	Zone substation switchyard lighting refurbishment	0.8
Major plant	Transformer oil regeneration	0.2
Overhead	Overhead conductor repairs	5.9
Underground	Underground cable repairs	9.6
Total		**18.8**

Source: CP MOD 10.06 – Opex model. The numbers presented exclude the opex rate of change.

As shown in table A.2, in addition to activities that relate to works on cables and conductors, Powercor has included miscellaneous refurbishment type activities for other assets (such as transformers and switchyard lighting) as part of its minor repairs forecast. The inclusion of these activities duplicates what is already included in other repex categories. For example, Powercor has forecast approximately $5.2 million for transformer-related refurbishment as well as unplanned plant replacement as part of 'other repex'.[101]

Powercor has not explained why it has included amounts beyond what is already included in its repex forecast. This is consistent with the over-forecasting bias that is systemic in its forecasting methodology. In addition, there is no evidence that Powercor has in fact removed these activities from historical repex during the process of recasting its RIN.[102] Therefore, we have not included any non-cable or non-conductor expenditure in our substitute estimate of total capex.

We also have a number of concerns regarding the prudency and efficiency of the underground cables and overhead conductors expenditure. Powercor has not provided any supporting justification for its proposed expenditure. It did not provide any cost-benefit analysis, business cases or risk monetisation models to demonstrate that the proposed amount is prudent and efficient.

[101] Powercor, *PAL MOD 4.09 - Plants and Stations,* January 2020.

[102] The evidence before us indicates that Powercor has only recast the overhead and underground asset groups. AER analysis of Powercor, Workbook 2 - New historical CAT, January 2020, Public and the Category Analysis RINs.

Further, while Powercor claims that its proposed amount is representative of its historical incurred expenditure, we found no evidence of this. Powercor has not been able to provide any historical information, unitised volume and unit cost information that supports its proposed amount. EMCa made the following observation:

> Powercor's claim that its proposed amount of $3.8m per year (in $2020–21 terms) results from its analysis of such repair costs in 2019. However, it was not able to provide the individual repair volume and cost information that forms the basis of this claimed amount. Rather, it was able to account for only around $1.6m in this way. Powercor was also unable to account for its historical recast of minor repairs on the basis of volume and unit cost information, from which it is reasonable to infer that this is not how Powercor undertook its expenditure 'recast'.[103]

In the absence of cost-benefit analysis and historical incurred expenditure that supports its forecast, we are not satisfied that Powercor's forecast for minor repairs repex is prudent and efficient. Our substitute estimate is based on Powercor's historical data, in particular the historical data for fault repex, for underground cables and overhead conductors.[104] Our substitute estimate is based on our alternative approach for forecasting fault repex. It relies on the simple average of historical volumes and the average unit rates between 2016 and 2019, which results in a substitute estimate of $9.8 million ($2020–21, excluding the impact of real cost escalation).[105]

As-proposed repex

Powercor included $45.7 million for its overhead conductors repex and $3.3 million for its underground cables repex. We have assessed the repex component of the total underground cables and overhead conductors expenditure based on the standard repex assessment approach, namely having regard to:

- The repex model, which was calibrated with data on a like-for-like basis,[106] and indicates that the forecast for both asset groups was lower than the model predicted. We have placed lower weight on the repex model in this instance, due to the reclassification of minor repairs back to repex. In coming to our final decision, we will re-run the repex model results, depending on Powercor's revised proposal and its position on minor repairs.

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103 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 219.

104 In its proposal, Powercor indicated that it has excluded underground cables and overhead conductors from its forecast fault program due to the reclassification of minor repairs. See, Powercor, *MOD 4.11 – Network faults*, January 2020.

105 We excluded the proposed rate of change forecast from our substitute estimate for capex, consistent with our standard approach for capex forecasting.

106 We relied on recast RIN data as the basis of input to the repex model. The recast RIN series is historical series that took into account the impact of the reclassification of minor repairs from capex to opex

- Reasoning for the forecast for underground cables and overhead conductors being 18 per cent and 44 per cent, respectively, higher than the historical actual repex over the current regulatory control period.[107]
- EMCa's advice that there are a number of concerns with the forecast, particularly around over-forecasting bias and a unit cost that is higher than efficient.

In addition, for total expenditure, we sought to understand the impact of our substitute estimate on minor repairs plus the as-proposed repex, when compared with the historical incurred repex (on a like-for-like basis) from a top-down perspective. We have identified the following:

- Forecast overhead conductors of $49.4 million is $7.2 million above the historical incurred expenditure ($42.1 million) over the current regulatory control period.
- Forecast underground cables of $9.4 million is $1.0 million below its historical incurred expenditure ($10.4 million) over the current regulatory control period.

For overhead conductors, Powercor has not provided any cost-benefit analysis to demonstrate that its forecast for overhead conductors is prudent and efficient. In particular, over the current regulatory control period, Powercor had a regulatory obligation, as mandated by the ESV, which required it to proactively remove all non-metallic screened HV aerial-bundled cable in HBRA by 2018, which has been completed.[108]

Based on the information before us, as there is no regulatory obligation in the forecast regulatory control period of a similar nature, as such, a forecast that is in-line with, or lower than, historical may be a better reflection of Powercor's requirements moving forward. Therefore, we are not satisfied that an overhead conductors repex forecast that is higher than historical repex is required over the forecast regulatory control period. We have included $42.2 million in our substitute estimate, which is in line with historical repex on overhead conductors repex between 2016 and 2019.

For underground cables, while we have the same concerns around the lack of bottom-up justification and the forecast unit costs, given the total forecast for cables is below Powercor's revealed recurrent repex, we are satisfied that $9.3 million represents prudent and efficient costs.[109]

Pole top structures – unmodelled asset group

Powercor forecast $85.4 million for its pole top structures repex. It is a minor increase from its current regulatory control period actuals. Powercor has relied on trended volumes and historical unit rates from 2014 to 2018 to build its forecast requirements over the forecast regulatory control period. Powercor also added volumes to take into

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107 We have based our trend analysis on a like-for-like bases, namely the trend analysis compared the reset RIN to the recast RIN (as provided) as part of Workbook 3, See Powercor, Workbook 3 - Recast CAT - January 2020.

108 Powercor, *Bushfire Mitigation Plan - Electricity Safety (Bushfire Mitigation) Regulations 2013*, 14 April 2020, public, p. 41.

109 The substitute estimate incorporates the impact of CPI changes and real cost escalation.

account its fault related capital and it forecast a negative volume adjustment to take into account its increased replacement of poles. The main driver for replacement is the asset condition based on inspection and/or asset failure.[110]

Powercor has not provided sufficient reasoning for an increase in its pole top structure volumes. In addition, it has not provided a business case nor supporting documentation. However, from our review of the supporting documentation, Powercor has assumed a growth rate in its fault related expenditure. EMCa also noted that Powercor has not justified the extent of the proposed increase for pole top structures repex as the:

- increased expenditure from the current regulatory control period is not explained
- proposed reduction included to account for increase in proposed pole replacement program is likely to be insufficient.[111]

We have observed that Powercor's forecast unit costs are lower than its historical unit costs. Despite the lack of justification for the increase in volumes, on balance, the total pole top structures repex is a minor step-up from its historical repex over the current regulatory control period. Therefore, we have not made any additional adjustments for the increase in volumes apart from a single adjustment to reflect our findings on Powercor's fault related expenditure. We are satisfied that $81.7 million for pole top structures reasonably reflects prudent and efficient costs, as it is in line with its actual pole top structures repex over the current regulatory control period.

Protection repex – an unmodelled asset group

Powercor proposed $23.8 million for replacing secondary protection and control assets at zone substations, which is 74 per cent higher than its repex over the current regulatory control period. This program consists of a number of replacement projects, primarily focused on protection relays and remote terminal unit replacements. Powercor indicated that asset condition as the dominant driver of its proposed replacement. Powercor provided the output of its CBRM as supporting justification for its forecast.[112]

EMCa reviewed this program and highlighted:

- Documents provided by Powercor[113] do not provide sufficient justification for the proposed forecast expenditure, including how the replacement projects were

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[110] Powercor RIN016.

[111] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 57.

[112] Powercor, *Response to Information Request #035 - CBRM HI and POF summary - supplementary response*, public, 17 June 2020.

[113] Powercor provided an expenditure model which includes a list of projects with forecast repex. Powercor has also provided protection and control asset class strategy. Powercor, *Response to information request #017 - protection and control asset class strategy*, 12 May 2020.

selected or how the level of expenditure is reflective of a prudent and efficient level.[114]

- Powercor has not demonstrated the relationship between its CBRM tool and its forecast expenditure, to determine how it has arrived at a prudent level of replacement for this category. EMCa noted that the model produces a probability of failure and what appears to be an assessment of network performance consequence from failure of the protection assets.[115] It is not evident from the model, or from the information provided, how Powercor has used this information, if at all, in producing its expenditure forecast.[116]
- Even though Powercor has established the need for some level of increase of its supervisory control and data acquisition (SCADA) network control and protection replacement program, the extent of the proposed increase and the timing of replacement projects has not been demonstrated with the information provided.[117]

Based on the information before us, including advice from EMCa, Powercor has not justified that its forecast expenditure for SCADA, network control and protection repex, is prudent and efficient. Our substitute estimate is $13.7 million, which is consistent with its average historical repex over the 2016–2020 regulatory years. We will have regard to any additional justification that Powercor provides in its revised proposal when we make our final decision.

Other repex – unmodelled

Powercor forecast $53.6 million in other repex, which is a 24 per cent decrease from its historical repex. This category includes a number of assets that do not fit in any other repex categories and are non-recurrent in nature. The largest component of Powercor’s ‘other’ repex is a $35.7 million program that Powercor refers to as a bushfire mitigation program.

Bushfire mitigation program

The bushfire mitigation program is made up of the sub-projects shown in table A.3. Powercor has labelled this expenditure Victorian Bushfire Royal Commission capex, and referenced their inclusion in the Bushfire Mitigation Plan (BMP) and the Electricity Safety Management Scheme (ESMS), subject to AER assessment. We acknowledge that the intent of these projects is to minimise risk as far as reasonably practicable, as per the policy intent of the BMP and the ESMS.[118] However, Powercor has not

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114 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 81.

115 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 82.

116 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 82.

117 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 82.

118 Bushfire Mitigation Plan states that its policy is "To minimise the risk of fire starts from its electrical assets as far as reasonably practicable by complying with legislative and regulatory requirements, whilst allowing flexibility within the business to encourage innovation, continuous improvement and the efficient use of resources". Powercor, *Bushfire Mitigation Plan – Electricity Safety (Bushfire Mitigation) Regulations 2013*, June 2020.

provided any evidence or justification as to how the majority of the projects below reduce the risks as far as reasonably practicable.

Table A.3 Breakdown of the bushfire mitigation program ($ million, $2020–21)

Project name	Capex (without real escalations)
Early fault detection	2.7
Replace wood cross arms in ELCA's	3.2
Replace low-voltage (LV) fuse switch disconnectors (FSDs) in ELCAs	3.7
Replace LV fused overhead line connector boxes (FOLCBs) in ELCAs	5.0
Technology developments and research partnerships (annual program)	2.1
Mitigating REFCL reliability impacts	13.0
Cross arm and insulator replacement	6.3
Total	**35.8**

Source: Powercor, *PAL MOD 6.09 – Bushfire Safety*, January 2020, Public.

The largest sub-project is the mitigating REFCL project, which is approximately $13.0 million. The project aims to address a decline in customer reliability where Powercor is required to install a REFCL device, by replacing traditional automatic circuit reclosers (ACRs) not compatible with REFCL technology with smart ACRs.

Our review of the Powercor's cost-benefit analysis demonstrates that the program is purely reliability driven, rather than bushfire (or safety) driven, as previously classified by Powercor. The program takes into account the values of customer reliability as the main cost of consequence. Powercor confirmed the program is reliability driven in response to an information request.[119] After reviewing the business case and the cost-benefit analysis provided, we are satisfied that the mitigating REFCL program is prudent and efficient, as it addresses a reliability issue. Additionally, EMCa indicated that the project is benefit positive and reasonable[120], and a number of stakeholders such as CCP17 and ECA support this program.

While we have included the mitigating REFCL program in our substitute estimate, Powercor has not established that the remaining $22.8 million included under the ‘bushfire mitigation’ program banner is prudent or efficient for the following reasons:

- The proposed expenditure seems to be above and beyond what is included in ‘base repex’, namely the recurrent repex over the current regulatory control period. This is consistent with EMCa’s overall observation that Powercor proposed

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119 Powercor, *Response to information request 13 – REFCL reliability and service lines,* 30 April 2020.

120 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, pp. 87–88.

additional expenditure without taking into account the interdependencies between projects and what is already in its recurrent repex.

- Our substitute estimate for overhead conductors and pole top structures repex, which is around $123.9 million, is sufficient for Powercor to address any cross-arm or overhead conductor expenditure that form the majority of the sub-projects above.
- There was no cost-benefit analysis or risk quantification provided to support this expenditure. Similarly, ECA's consultant Spencer&Co observed that Powercor did not take into account all its existing expenditure on bushfire mitigation (on REFCL) when proposing this additional amount.

EMCa has identified similar concerns around a lack of cost-benefit analysis and risk quantification.[121] EMCa concluded that Powercor has not justified the proposed forecast repex. In addition to our concerns, EMCa identified that Powercor did not demonstrate that existing asset replacement programs were prioritised and considered in conjunction with the forecast program, to deliver bushfire mitigation benefits associated with bushfire mitigation expenditure. Absent demonstration that a review has been undertaken, together with an economic test of benefits, there is potentially a duplication of asset replacement work, incurring higher expenditure than efficient.[122]

Based on the information above, including EMCa's findings, Powercor has not established that its proposed expenditure in other repex is prudent and efficient. Our substitute estimate of $28.6 million excludes the proactive component of the bushfire mitigation program with the exception of the mitigating REFCL impact project.

A.2 DER integration capex

DER includes solar PV, energy storage devices, electric vehicles (EVs) and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that are placed on networks.

DER integration expenditure addresses increasing DER penetration on the network. This includes managing voltage within safety standards and allowing solar customers to dynamically export back onto the grid. DER integration capex includes:

- augmenting the network to physically provide greater solar PV export capacity
- ICT capex to develop greater visibility of the LV network and manage changes being driven by technological developments (batteries and EVs).

A.2.1 Draft decision

[121] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 87.

[122] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 87.

Powercor has not demonstrated that its initial DER integration capex forecast is prudent and efficient. We have included $63.1 million for this category in our substitute estimate of total capex, which is $30.9 million (33 per cent) lower than Powercor's initial proposal.

A.2.2 Powercor's initial proposal

Powercor's initial DER integration capex forecast includes the following programs:

- solar enablement (augex) – augmenting distribution transformers to increase capacity
- digital network (ICT capex) – ICT capex technology upgrades
- digital network devices (augex) – targeted rollout of network devices to facilitate the two programs above
- LV supply quality (augex) – business-as-usual augex required to maintain supply quality
- dynamic voltage management system (DVMS) (ICT) – enables remote and dynamic voltage adjustment.

For this draft decision, these programs have been grouped together to form the DER integration capex category. The relevant forecasts have also been subtracted from Powercor's respective augex and ICT capex forecasts, ensuring the forecasts are not double counted and the total net capex amounts reconcile.

A.2.3 Reasons for draft decision

Powercor has adequately supported most aspects of its DER integration capex proposal. However, Powercor has overstated its solar enablement program by including investments that would be more prudent to undertake in subsequent regulatory control periods. In addition, Powercor has not fully explained how its solar enablement program interrelates with other aspects of its DER integration capex forecast, particularly its digital network program, as well as its tariff structure statement proposal. Stakeholders such as CCP17 raised similar concerns.[123]

Solar enablement

Powercor stated that it proposed this program because it is forecasting a large increase in solar PV penetration during the forecast regulatory control period.[124] This is expected to cause localised network voltages to rise, which may cause solar inverters to trip off as a safety measure that prevents the solar PV system from producing and exporting.[125] Powercor is also forecasting an associated solar enablement step change

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123 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 105.

124 Solar customers as a proportion of total customers.

125 Powercor, *Solar enablement business case,* January 2020, p. 4.

($6.2 million), which includes tapping and an ongoing compliance program. Transformer tapping is an operational practice that helps to regulate network voltages. Our opex decision (Attachment 6) outlines further detail.

We are supportive of Powercor facilitating solar PV growth on its network. However, its forecast overstates what is necessary to deliver the Victorian Government's Solar Homes program. Specifically, its analysis includes investments that would be more prudent to undertake in subsequent regulatory control periods. Secondly, the solar enablement program business case uses a 30-year NPV analysis period, unlike the standard 20-year NPV period Powercor uses for other repex and augex projects.

Though a departure from our approach to date, we think capex required to increase DER export capacity can be considered standard control services and is consistent with the capex objectives. In assessing the solar enablement program, consistent with EMCa's advice, we have been guided by two principles: timeliness and proportionality. Considering timeliness ensures that investments are undertaken as they are needed and not before they are required. Considering proportionality requires that, given the substantial amount of network augmentation proposed, possible lower cost solutions are exhausted and each augmentation is individually justified.

EMCa stated that considering these principles will help facilitate the most appropriate actions being taken to accommodate distributed solar and to enable customers to achieve the benefits of their own investments.[126] As a result, overall our draft decision better reflects the costs needed for customers to export energy and ensures that customers are not overcharged.

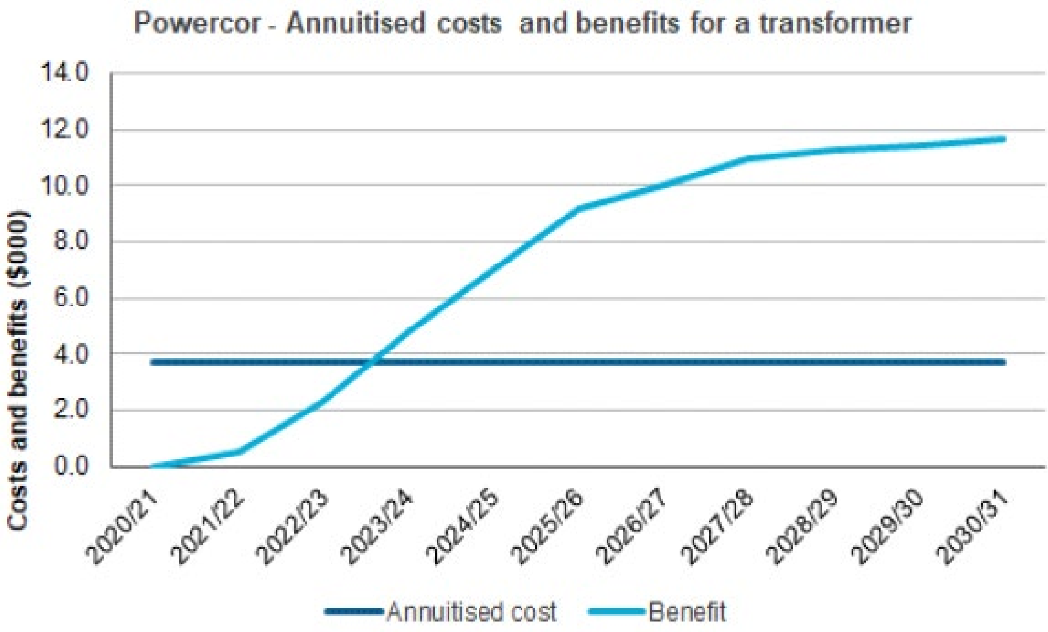
Timeliness – Optimal investment timing

EMCa's review of Powercor's solar enablement program identified that distribution transformer upgrades that would be more prudent to undertake in subsequent regulatory control periods have been included in Powercor's initial proposal. Powercor sought to determine a time profile for its proposed expenditure as the year when the cost-benefit analysis model first produces a positive NPV. This is erroneous and also inconsistent with the method Powercor (and other distribution businesses) apply in seeking to determine the appropriate timing for other augex projects.

The applied approach brings forward augmentations when they are still uneconomic, but have a positive NPV only because its forecast of distant future positive net benefits is offsetting the still negative net benefits within the forecast period. The standard approach is to identify when the annual benefits exceed the annual costs, in this case represented by the annuitised cost of the upgrade being considered. EMCa's analysis highlighted that the net benefits to customers are far smaller if these augmentations are undertaken before this time. Figure A.8 below outlines an example of this analysis and highlights that the optimal investment timing for this specific transformer is 2023–24.

[126] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 133.

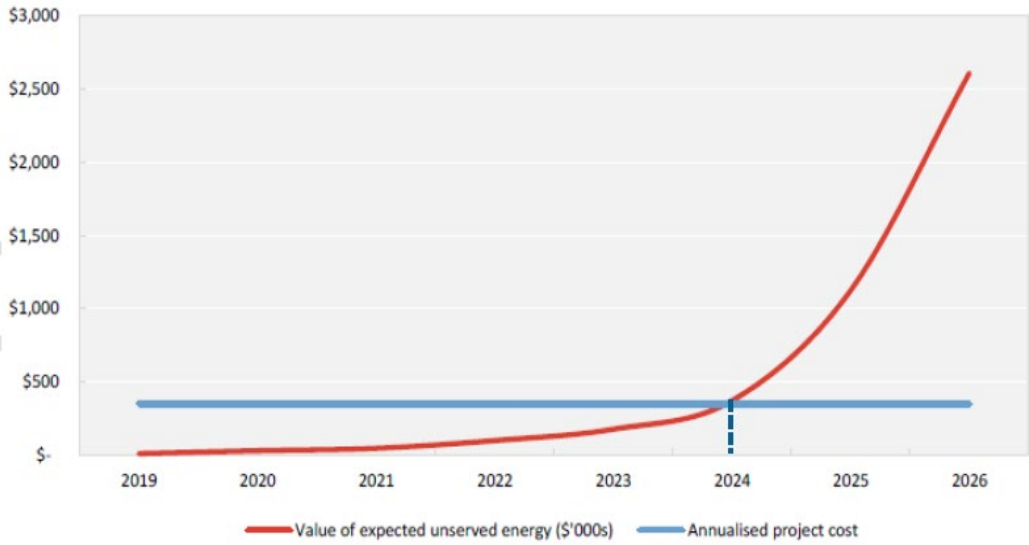
Figure A.8 Annuitised costs and modelled benefits of one transformer upgrade ($000, $2020–21)



Source: EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 150.

Figure A.8 highlights that the annual benefits of this distribution transformer upgrade are not expected to exceed the annualised costs until 2023–24. This type of analysis is consistent with how some distributors propose and we typically assess repex and traditional augex proposals. Figure A.9 below outlines the analysis Powercor undertook for its Bacchus Marsh supply area augex project. It used this approach to ascertain the optimal timing of each of its traditional augex proposals but has not done so for DER.

Figure A.9 Powercor's assessment of the energy not served vs the annualised option project cost ($000, $2020–21)



Source: EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 113.

EMCa applied the same analysis approach to all proposed distribution transformers. Conducting the analysis of the proposed 30-year period produces 662 transformers that are economic to upgrade in the forecast regulatory control period, compared with Powercor's proposal of 1,026 transformers. In other words, 364 of the proposed transformers have an optimal investment timing trigger point, i.e. where the expected benefits exceed the expected costs, outside the forecast regulatory control period (2026–27 or later). Therefore, EMCa's analysis highlights that it is not prudent and efficient to upgrade these transformers in the forecast regulatory control period.

To further support this position, EMCa conducted both NPV analysis and optimal investment timing analysis for a sample of distribution transformers. EMCa's NPV analysis showed that the upgrades should be triggered around the same time as determined by the optimal investment timing analysis method. In other words, the net benefit is low if the upgrade is done prematurely, but increases significantly if the timing is deferred. In addition, EMCa's analysis shows that if the upgrade is deferred even further beyond this point, the net benefit reduces, which further supports the assertion that the selected timing is optimum.

Proportionality – NPV analysis period

Powercor's solar enablement business case is based on a 30-year NPV analysis. Standard approaches to this type of analysis for other augex and repex projects use a 20-year NPV period. EMCa noted that Powercor had not adequately considered the uncertainty inherent in justifying capex based on a 30-year model of assumed PV export benefits.[127] EMCa advised that using a 20-year NPV period aligns with Powercor's cost-benefit analysis approach for its augex and repex programs.

Powercor stated that a 30-year analysis period is appropriate because uncertainty had already been factored into its analysis by using conservative assumptions for forecast PV uptake and installed inverter capacity.[128] However, this response indicates that Powercor has not placed weight on the potential for battery technology to develop and consumer behaviour to change in response to cheaper and developing technologies.

Powercor also submitted that shortening the NPV analysis period would require the time over which assets are depreciated to be shortened as well.[129] However, we do not agree with this assertion. There are many examples of other expenditure where the economic analysis period does not align with the depreciation life. For example, the standard approach to conduct NPV analysis is generally over 20 years, including for repex and augex. However, these assets are not depreciated over 20 years. For example, Powercor's distribution system assets have a standard life of 51 years. In addition, Powercor's ICT assets have a standard life of six years, but the economic analysis is not conducted over this same period.

EMCa's review also came to the same conclusion. EMCa did not agree that the NPV analysis period must equal the depreciation life of the relevant asset. EMCa stated that:

> Low-voltage assets may well have economic lives of 45 years or more and are typically depreciated accordingly. Similarly, we would expect that an LV asset that is installed as part of an LV augmentation, whether for solar enablement purposes or for other reasons, would have a similar expected life in service.
>
> The question at issue here is not the life of the asset itself, but the analysis period for which it is reasonable to consider benefits to justify the augmenting the existing low-voltage network, in this case, for solar enablement purposes. This requires consideration of a reasonable forecasting horizon, within which a reasonable estimate of costs and benefits can be made.[130]

Other considerations

Powercor conducted forums, surveys, a deep dive workshop, and published and consulted on an options paper to develop options for enabling solar. It contends that customer feedback from these engagement activities was pivotal in shaping its approach and noted that its customers can tolerate reasonable constraints but the network must be prepared to accommodate more solar and ensure these constraints are not excessive. However, CCP17 submitted that the way the investment proposal

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127 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 133–135.

128 Powercor, *Response to information request 44,* July 2020, p. 9.

129 Powercor, *Response to information request 46,* July 2020, p. 11.

130 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 136.

was presented to customers may have led to Powercor overstating customers' expectations.[131]

Powercor concluded that allowing some (reasonable) level of solar constraint and removing it when the cost of continuing to allow the constraint outweighs the cost of removing was the only option that is capable of maximising the net benefits of solar. A key component of this assessment is the value Powercor attributes to the additional solar proposed to be added to its network.

Many stakeholders highlighted concerns with how Powercor valued solar PV exports in its solar enablement modelling:

- The Victorian Department of Environment, Land, Water and Planning (DELWP) submitted that the Victorian Government is committed to helping Victorians take control of their energy bills, create jobs and take strong and effective action on climate change via the Solar Homes program, and Powercor's proposed solar enablement program will support the delivery of its program over the forecast period.[132] However, DELWP acknowledged that assessing the proposed investment is challenging due to lack of agreed methodology and limitations of transparency in assumptions and approaches.[133]
- CCP17 submitted that the assumed value of rooftop solar exports used in the modelling does not consider that over the life of the investment there might be zero or negative pool prices.[134]
- EnergyAustralia submitted that that there are some aspects in the treatment of DER that warrant closer attention, particularly the value of solar export, and noted that generally the DER integration proposals tended to overstate the value of solar export.[135]
- Energy Users' Association of Australia (EUAA) stated that the value of DER may be overstated, highlighting that in both South Australia and Queensland in the last twelve months, at times in the middle of the day increased solar PV can have no value or a negative value with the incidence of negative pool prices increasing.[136]
- VCO supported a standard approach for valuing exported generation that reflects the expected changes in the value of DER exports over time.[137]

Similar concerns were raised in response to our consultation paper on Assessing DER Integration Expenditure,[138] in addition to a lack of consistency across distributors in

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131 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 106.

132 DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 2.

133 DELWP, *Victorian Government submission on the electricity distribution price review 2021–26,* May 2020, p. 3.

134 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 106.

135 EnergyAustralia, *Submission to VIC DNSP proposals,* June 2020, p. 1.

136 EUAA, *EDPR submission,* June 2020, p. 11.

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

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

valuing the benefits associated with investing in DER integration. In response, we and the Australian Renewable Energy Agency commissioned the VaDER study earlier this year.[139] The Commonwealth Scientific and Industrial Research Organisation and Cutler-Merz were engaged to conduct a study into potential methodologies for valuing DER and have extensively engaged with stakeholders, including Powercor, as part of the study.

The final report of the VaDER study is due to us in early October 2020, which will help to address some of the stakeholder concerns outlined above. We will publish the final report as soon as practicable. We will then consider the report's recommendations and formally implement them as we consider appropriate as part of our DER integration expenditure guideline, now due for completion in 2021. Given the extensive stakeholder engagement in forming the VaDER study's recommendations, we anticipate that consumers will expect Victorian distributors to prepare their revised proposals in the spirit of these recommendations.

Substitute estimate

Our substitute estimate conducts the optimal investment timing analysis discussed above over a 20-year analysis period, rather than the 30-year period that Powercor proposed. This is consistent with our standard assessment approaches for more traditional types of expenditure, such as repex and augex. This approach reduces the number of distribution transformers that are economic to upgrade in the forecast period from 1,026 to 570 and contributes $35.3 million[140] to our substitute estimate of total capex (compared with Powercor's forecast of $63.5 million).

Digital network

Powercor's DER integration capex forecast includes a digital network program. It outlined that its network is going through a large transformation. It has good visibility of its high-voltage network, but changing customer requirements such as demand management programs and electric vehicle and battery uptake require it to develop greater visibility of its low-voltage network.[141] Powercor expects this program will allow it to manage the network more efficiently in real-time, through better forecasting, monitoring and diagnosis and eventually through automation.[142]

The listed benefits of its digital network program are promoting electric vehicle uptake, optimising load control of customer appliances, enhancing cost-reflective pricing, detecting electricity theft, proactively managing asset failures, avoiding overblown fuses, looking after vulnerable customers and keeping customers safe.[143] Powercor

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

140 This amount is before real price escalation changes have been taken into account.

141 Powercor, *Digital network business case,* January 2020, p. 4.

142 Powercor, *Digital network business case,* January 2020, p. 3

143 Powercor, *Digital network business case,* January 2020, p. 5.

proposes to implement more advanced technological capabilities and extend its advanced metering infrastructure (AMI) coverage to type 1-4 contestable metering customers (large customers) and unmetered supply customers in a targeted rollout.

CCP17 acknowledged that a level of investment is needed to establish a data gathering and analytics capability to explore some of the benefits identified. However, it questioned why Powercor could not draw reasonable advantages regarding energy theft, customer energy profile modelling and EVs charging analysis from its existing systems, noting that Victorian customers have already spent a significant amount on advanced metering at most customer supply points.[144]

Therefore, CCP17 submitted that it did not support the digital network programs because other simpler and less costly alternatives exist to achieve similar outcomes; many expectations of customer acceptance of these initiatives are untested; the benefits to customers are not clear, are over a long time period subject to exogenous factors that may or may not change.[145]

EMCa's review highlighted that digital network may have merit but that the investments may be premature for the forecast regulatory control period. EMCa noted the needs analysis for real-time data to support digital network has not been fully justified.[146] EMCa considered that the claimed positive net benefit is strongly dependent on benefit streams continuing for ten to 20 years and there is considerable uncertainty in these benefit streams beyond 10 years.[147]

However, Powercor has provided quantified benefits for its digital network program to improve the capabilities regarding EVs uptake, cost-reflective pricing and customer appliance load control. As highlighted above, these aspects were not accounted for in the distributors' solar enablement proposals. We consider it would not be reasonable to highlight that Powercor had not accounted for these considerations in its solar enablement program, but then materially reduce the complementary ICT proposals that aim to facilitate these capabilities.

While we agree with EMCa's assessment and stakeholder submissions that highlighted that the digital network programs may be marginally overstated, we consider it is more critical for Powercor to account for the capabilities outlined above, particularly EVs uptake and cost-reflective pricing, in its revised solar enablement proposal.

Therefore, we have included Powercor's initial digital network forecast ($16.4 million) in our substitute estimate of total capex. As noted above, Powercor has flagged that it intends to reconsider the intended outcomes and output measures of its DER

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144 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 100.

145 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 100.

146 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 154.

147 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 156.

integration capex forecast, and test alternative options in light of additional stakeholder engagement on the proposal.

A.3 Augex

The need to build or upgrade the network to address changes in demand and network utilisation typically triggers augex. The need to upgrade the network to comply with quality, safety, reliability and security of supply requirements can also trigger augex.

A.3.1 Draft decision

Powercor has not demonstrated that its augex forecast is prudent and efficient, due to overstating forecast demand and including inefficient cost estimates in its REFCL proposal. We have included an augex forecast of $276.8 million in our substitute estimate of total capex.

For traditional augex, this is based on our alternative forecast for flat maximum demand, and the historical augex Powercor has incurred over the current regulatory control period with flat maximum demand on its network. For REFCLs, we have incorporated efficient cost estimates for several aspects of Powercor's REFCL forecast.

As noted above in section A.2, we have included Powercor's solar enablement, LV supply quality and digital network devices programs in the DER integration capex category. These programs are therefore excluded from the numbers and analysis presented below.

A.3.2 Powercor's initial proposal

Powercor initially proposed $395.3 million in augex. It subsequently amended its REFCL proposal and the augex forecast we have assessed is $416.5 million. We have divided this into the following categories, based on the different drivers involved and whether the expenditure is recurrent or non-recurrent:

- $152.8 million for traditional augex
- $198.7 million for REFCL and bushfire-related augex
- $65.0 million for other augex.

A.3.3 Reasons for draft decision

Traditional augex

The major projects proposed in this category are:

- Tarneit supply area ($20.6 million)
- Surf Coast supply area ($73.5 million, including REFCLs)
- Bacchus Marsh supply area ($7.7 million)
- HV feeder program ($16.0 million).

Powercor identified growing maximum demand as a key driver of the need for these projects.

Powercor also proposed $42.5 million for 94 smaller projects not supported by business case analysis. Based on descriptions Powercor provided, 54 per cent of capex for these smaller projects is driven by forecast demand growth, leaving the remainder driven by other requirements (such as regulatory compliance).[148]

Powercor proposed a largely demand-driven increase of 63 per cent compared with 2016–19 actuals, as shown in figure A.10. As discussed in appendix B (forecast demand), Powercor's maximum demand forecasts are materially overstated. Stakeholders also expressed concern at the risk that overstated demand forecasts could lead to overbuilding or windfall CESS benefits, including after accounting for the effects of COVID-19.[149]

We have adopted AEMO's 2019 transmission connection point forecasts as our alternative demand forecast. AEMO is forecasting maximum non-coincident demand to remain flat, as has broadly been the case over the current period. We therefore do not accept that the increase Powercor has forecast is justified.

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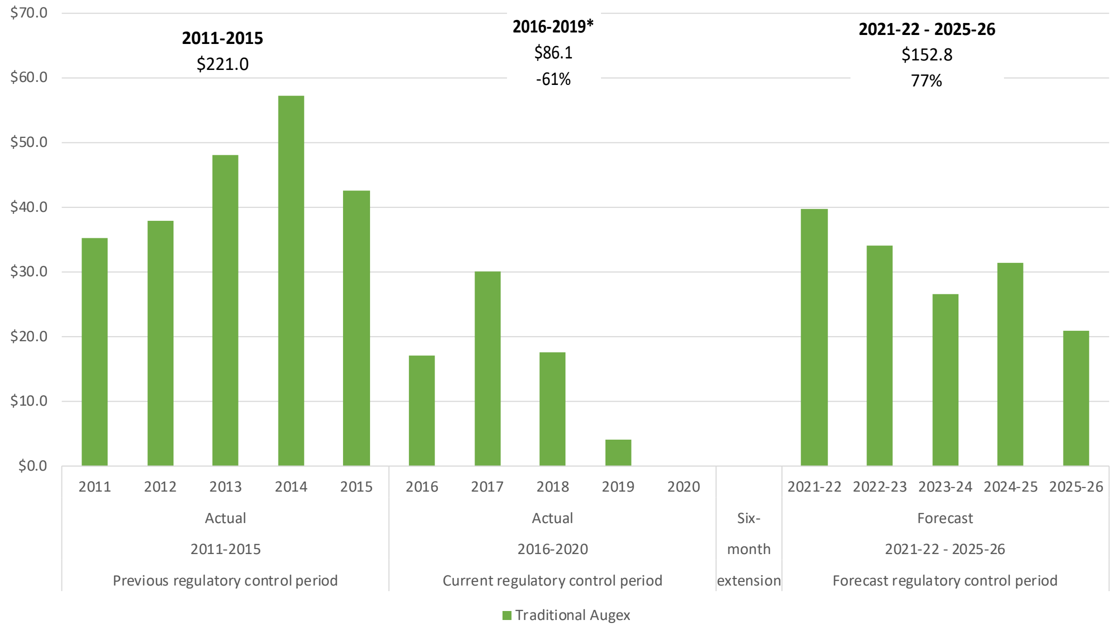
[148] Powercor, *Information request 14 – Q3*, April 2020, pp. 1–2.

[149] Victorian Community Organisations, *2021–26 Victorian EDPR,* May 2020, p. 4; CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals 2021–26,* June 2020, pp. 59–62; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals,* May 2020, p. 3.

Figure A.10 Powercor's historical vs forecast traditional augex ($ million, $2020–21)



Source: AER analysis based on Powercor RIN data.

Note: Traditional augex excludes other assets for historicals, and excludes other assets, DER capex and the upgrading regional supply project over the forecast period. The 2016 to 2019 amount has been prorated to a five-year period and no estimate was made for 2020 or the six-month gap.

For our substitute estimate, where we reasonably expect maximum demand to grow (or not grow) at a similar rate as historically, and there are no significant new compliance obligations, the need for traditional augex in the future is fundamentally the same as historically. Therefore, we have treated Powercor's traditional augex as a recurrent category where revealed costs are a reasonable estimate of future costs.

To apply this approach, for calendar years 2016–19, we have included all augex reported in Powercor's RIN except 'other assets'.[150] This produces a substitute forecast for non-DER traditional augex of $93.9 million, compared with Powercor's forecast of $152.8 million. This substitute does not rely on apportioning our alternative demand forecasts to the zone substation level and assessing the need for individual projects. For 28 per cent of augex in this category, Powercor did not supply business cases, and

150 To validate this comparison, we asked Powercor to clarify how it has accounted for other categories of augex historically. Powercor stated that the 'other assets' category of its RIN data includes augex that was 'bushfire related' and 'communications and SCADA related'. This is consistent with the way Powercor has categorised its forecast augex, as it has used separate models for bushfire augex and communications augex, and these two models account for all forecast 'other assets' augex. Powercor, *Information request 58 – Q5 Historical and Forecast Augex Drivers*, July 2020, pp. 4–5.

EMCa found there was not sufficient evidence to support this part of Powercor's forecast.[151] This further supports the use of a top-down approach for this category.

Nevertheless, we sought to check the reasonableness of our forecast through bottom-up analysis for the projects for which we had sufficient information. To do this, we reconciled Powercor's original bottom-up zone substation forecasts to AEMO's 2019 forecasts at the terminal station level, by changing forecasts for all zone substations connected to each terminal station by the same ratio each year. This is similar to the procedure Powercor describes for reconciling its bottom-up zone substation forecasts to its top-down terminal station forecasts.[152]

For zone substations where Powercor forecasts a need for demand-driven augex to begin in a given year, we took the demand forecast in that year as the threshold for augmentation. We then calculated which projects met this threshold during the forecast regulatory control period, based on our substitute zone substation demand forecasts. This led to reductions of $63.1 million for the 87 per cent of expenditure we could assess, which is greater than our substitute estimate based on historicals ($58.9 million in reductions).

However, although our substitute demand forecasts are usually lower, this is not the case at every geographical level. Our demand forecasts could therefore imply the need for new projects Powercor has not forecast and we have not examined this. On the other hand, we have included significant capex for non-demand driven projects in our bottom-up substitute without assessing it individually. On balance, we consider our bottom-up analysis supports our top-down forecast.

EMCa assessed projects in this category primarily from an engineering perspective. It was not within EMCa's scope to assess Powercor's demand forecasts, as we consider AEMO's demand forecasts are robust inputs to our assessment. EMCa's demand forecasting sensitivity analysis was limited to adjusting for one consideration: whether to use a blend of POE10 and POE50 forecasts (as Powercor and AEMO do) or a POE50 forecast only.[153] Our substitute demand forecasts based on AEMO's forecasts involve more significant changes. While it allows for geographical differences in rates of demand growth, and therefore positive growth in some locations, it forecasts essentially no change in maximum demand across Powercor's network.

REFCLs

Powercor proposed $198.7 million for REFCL augex for bushfire mitigation obligations.[154] Following the Victorian Bushfires Royal Commission in 2009, legislative amendments were introduced to mandate the installation of technologies to reduce the

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151 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 92.

152 ENEA, *Top-down and bottom-up forecasts reconciliation,* February 2020.

153 Implicitly, our alternative zone substation forecasts retain Powercor's blended method, assuming the ratio of POE50 to POE10 forecasts remains constant.

154 On 13 July 2020, Powercor amended its REFCL forecast from $177.4 million.

likelihood of bushfire starts from electrical equipment faults.[155] These amendments place regulatory obligations to achieve certain technical requirements (referred to as 'required capacity') at 22 of Powercor's zone substations.[156] A REFCL is a technology installed at zone substations used to achieve the required capacity to reduce the risk of faulted powerlines starting bushfires.

In the current regulatory control period, AusNet Services and Powercor each submitted a contingent project application in three tranches. Through the contingent project process, most of the zone REFCL augex has been approved but the distributors have proposed additional capex for maintaining compliance at the tranche one and two sites that have been completed or are due for completion in 2021. The ongoing compliance expenditure is to address network capacitive current that is expected to exceed the REFCL capacity at some zone substations in the forecast regulatory control period and to maintain the required capacity to comply with the regulations.

Powercor's proposed REFCL augex is divided into three programs plus remaining contingent project expenditure. The first program is $62.9 million for ongoing compliance at eight zone substations from tranches one and two. The second program is $48.6 million for compliance at the Waurn Ponds zone substation, which also involves installing REFCLs at a new Torquay zone substation. The third program is $50.8 million for compliance in North Western Geelong, which involves constructing a new zone substation in Gheringhap as an alternative for the Corio and Geelong zone substations.[157] There is also $36.3 million remaining from the contingent project but we have not assessed this capex given it has already been assessed in the contingent project process.[158]

Our draft decision for REFCL augex is to include $145.5 million, which is $52.1 million (or 26 per cent) lower than Powercor's proposal. We have assessed the REFCL forecast from a bottom-up approach, while still considering the total REFCL amount. The prudency criteria has been satisfied because of the regulatory obligation. However, we are not satisfied that Powercor's forecast reasonably reflects efficient costs. Table A.4 summarises our expenditure adjustments, with more detailed reasoning set out below.

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155 *Electricity Safety (Bushfire Mitigation) Regulations 2013* (Vic), *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017* (Vic) and *Electricity Safety (Bushfire Mitigation Duties) Regulations 2017* (Vic).

156 Achieving required capacity involves reducing the voltage and current on faulted power lines as defined in the *Electricity Safety (Bushfire Mitigation Duties) Regulations 2017*, regulation 7.

157 An allowance for Geelong was provided in tranche two. The proposed augex for Corio was removed with the amended proposal.

158 NER cll. 6.5.7 (f)–(j)

Table A.4 Summary of REFCL adjustments ($ million, $2020–21[159])

Description	Forecast
Benchmarking labour hours consistent with tranche three final decision	-6.0
Removed duplicated expenditure: contracts and GFN labour	-5.6
Transformer expenditure	-4.2
Asset resilience	-8.3
Distribution communications	-3.4
Removal of Geelong tranche two allowance already provided	-19.0
Total adjustments	-46.6
Difference in real price escalation	-5.6
Total adjustments including real price escalation	-52.1

Source: AER analysis.

Note: Numbers may not sum due to rounding.

In making our draft decision, we have not been able to account for all recent information request responses from Powercor due to timing of the amended proposal and our subsequent information requests. We will consider this information with the revised proposal.

Benchmarking labour hours reduces capex by $6.0 million

We benchmarked Powercor's REFCL capex proposal consistent with the approach in our tranche three final decision.[160] This involved benchmarking labour hours for surge arrestors, ground fault neutralisers (GFN), and design and procurement. Consistent with tranche three, labour hours were capped to five hours per surge arrestor site ($1.8 million reduction) and 1,600 hours per GFN ($2.3 million reduction).

For design and procurement, we benchmarked the hours for Ballarat West against Gheringhap as they are both greenfield sites with similar site characteristics, GFN requirements, 66 kV line works and 22 kV feeder works. This results in a reduction of the design hours from 18,048 to 9,438, corresponding to a reduction of $1.8 million. Powercor's proposal indicates the proposed estimates for Ballarat West are high level. We requested further scoping information for Ballarat West but Powercor indicated this is not yet available.[161] Therefore, we consider this is a reasonable benchmark in the absence of further justification.

159 Direct costs excluding real price escalation.

160 AER, *Final decision – Powercor contingent project application – REFCL T3,* January 2020, pp. 43–44, 47–48.

161 Powercor, *Information request 11 and 11a,* April 2020.

Duplication of contracts and GFN labour expenditure reduces capex by $5.6 million

We compared the tranche three contingent project cost model with the models provided in the proposal and found consistent unit rates for expenditure items after adjusting for inflation. However, Powercor included an additional $3.5 million of contracts expenditure associated with primary plant for nine zone substations. We queried Powercor on these additional costs and it confirmed that this expenditure was inadvertently duplicated in the process of disaggregating some cost components compared with the tranche three cost model.[162]

Similarly, Powercor included an additional expenditure component for GFN labour compared with the tranche three cost model. Powercor also confirmed that this was inadvertently duplicated in preparing the cost model and subsequently removed this, reducing the forecast by $2.1 million.

We have removed $19.0 million for the allowance already provided for Geelong

Consistent with our intended treatment described in the tranche three final decision, we have removed $19.0 million of capex from the proposed capex for the Gheringhap zone substation.[163] Without this reduction, we would have otherwise needed to make a CESS adjustment as we consider the capex is for the same purpose as described below. In May 2020, Powercor received an exemption for undertaking REFCL works at Corio and Geelong.[164] The exemption is conditional on undertaking the required works at an alternative zone substation with the five required 22 kV feeders from Corio and Geelong transferred to this zone substation. In July 2020, Powercor amended its REFCL capex proposal to remove Corio from the forecast and add the new preferred option of a new zone substation near Gheringhap.

Powercor received an allowance for Geelong in the current regulatory control period through contingent project tranche two. The abovementioned exemption removes the need to undertake REFCL works at Geelong. In our tranche three final decision released in January 2020, we indicated our intended treatment that the capex for a proposed alternative solution to Corio and Geelong would be net of the allowance already provided for Geelong.[165] We have not changed our position and have netted off the allowance for Geelong. Comparing the original capex proposed for Geelong ($19.0 million) and Corio ($29.0 million) against the capex for Gheringhap ($49.3 million), the capex of either option is aligned. It would not be appropriate to

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162 Powercor, *Information request 65a,* August 2020.

163 AER, *Final decision – Powercor contingent project application – REFCL tranche three,* January 2020, pp. 35–36. Powercor originally considered a zone substation in the vicinity of Bannockburn (as referred to in the tranche three final decision) but considered Gheringhap was a more efficient option that also addresses future demand growth.

164 Victorian Government, *Order in Council for Powercor exemption of section 120W of the Electricity Safety Act 1998,* May 2020, pp. 1014–1015, www.gazette.vic.gov.au/gazette/Gazettes2020/GG2020G021.pdf.

165 AER, *Final decision – Powercor contingent project application – REFCL tranche three,* January 2020, pp. 35–36.

include the full amount for Gheringhap considering the allowance already provided for Geelong. Therefore, we maintain removing $19.0 million from the proposed forecast.

Transformer expenditure for greenfield sites appears overstated by $4.2 million

Powercor has proposed the construction of two zone substations at Ballarat West and Gheringhap, both requiring two 25/33 MVA transformers. The cost of this appears overstated by $4.2 million. Powercor's proposed installed cost for two transformers is $4.5 million (or $2.25 million per transformer). Our internal engineering advice is that around $1.2 million is the efficient installed cost for a single transformer of this size range at a greenfield installation.

We asked Powercor for further justification of the proposed labour hours of 5,200 per transformer. It based its labour hours on a recent brownfield transformer installation.[166] However, brownfield works have additional costs that are not applicable to a greenfield site and thus overstate the labour hours and cost required. We have adjusted the labour hours to reflect a total installed cost for the two transformers of $2.4 million.

Insufficient justification for efficiency of $8.3 million for asset resilience

Powercor proposed $8.3 million for asset resilience for the Waurn Ponds supply area for testing and replacing underground cables and ring main units that are incompatible with REFCL operation. The information provided has not sufficiently justified the expenditure in terms of the volumes and unit rates. For example, it is unclear how Powercor has accounted for cable characteristics (type and installation date for targeting testing) and the presence of isolating substations in determining the total underground cable length that is subject to resilience testing and possible replacement.

Although capex for resilience may be required, Powercor has not provided sufficient information to assess the efficiency. Given the large proposed expenditure for this item, we consider more information is required in the revised proposal to support the proposed testing volumes, replacement rates and unit rates. This information will assist in justifying the efficiency.

Insufficient justification for efficiency of $3.4 million for distribution communications

Due to the timing of the amended REFCL proposal and subsequent information requests, we have not been able to fully assess the efficiency of the proposed $3.4 million for distribution communications at Gheringhap. We are not satisfied the proposed expenditure is efficient. We requested additional supporting information, which identified the expenditure is for 22 kilometres of overhead fibre optic cable. In response to our questions, Powercor added a further $2.6 million for distribution

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166 Powercor, *Information request 65,* July 2020.

communications at Ballarat West.[167] We have not considered this in our draft decision and will consider it in the revised proposal.

Other augex programs

Powercor proposed other augex programs including an upgrading regional supply program, network communications device upgrades and other technology upgrades. EMCa's review highlighted that Powercor had not provided compelling supporting information to justify some of this communications augex forecast.[168] We encourage Powercor to include further supporting information including business cases and cost models for these aspects of its forecast in its revised proposal.

Consistent with our alternative control services (ACS) capex draft decision, we have reallocated a proportion of Powercor's proposed network communications expenditure to ACS capex. Powercor allocated 100 per cent of its 3G shutdown network communications program to SCS capex. However, as outlined in our ACS metering draft decision (Attachment 16), some 3G shutdown capex should be allocated to ACS metering. The 3G systems that are being replaced are used to backhaul bulk data from AMI meters. This data is used for both metering and standard control network services. Therefore, this cost should be shared between SCS and ACS. Based on our analysis, we have allocated 80 per cent of this program to SCS capex and the remaining 20 per cent to ACS capex.

Similarly, Powercor allocated 88 per cent of its annual communication devices program to SCS capex. Our ACS metering analysis has determined that this allocation should be 25 per cent SCS capex and 75 per cent ACS capex. Our substitute estimate of total capex is consistent with these reallocations. Further analysis of these reallocations can be found in Attachment 16 of this draft decision.

Upgrading regional supply

Powercor’s augex forecast includes an upgrading regional supply program. It stated that current regional electricity infrastructure in Victoria’s south west is not meeting customer needs, but targeted regional investment can result in significant economic and community benefits.[169] It is proposing to upgrade the existing single phase feeders to three phase supply. Powercor identified the following benefits:

- reducing capacity constraints, enabling existing dairy farms and support industries to expand
- attracting new investment and converting lower value grazing land into dairy farms
- improving land utilisation for existing and new farms through better irrigated land

167 Powercor, *Information request 65,* August 2020.

168 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, pp. 123–124.

169 Powercor, *Upgrading regional supply business case,* January 2020, p. 3.

- supporting regional communities.[170]

Powercor's business case indicates a highly focused benefit for four dairy farms in south-west Victoria. However, the costs of the upgrading the regional supply project are socialised across all customers. It does not appear to consider whether the individual farms should pay for some or all of the project through capital contributions. EMCa's review highlighted that Powercor's economic analysis is not consistent with the RIT-D requirements and its project is not prudent.[171] EMCa also outlined that the analysis conflates gross regional product with economic benefit, ascribing the benefits of the project entirely to electricity supply enhancement.[172]

CCP17 appreciated the community-based approach underpinning the initiative to upgrade regional areas supplied by single-wire earth return (SWER) systems. However, it noted it could not support the proposal, stating that all beneficiaries – customers, the State Government and Powercor – should make reasonable contributions to the cost of the upgrade. CCP17 noted that the costs should not be borne by electricity consumers alone and that this investment could create a precedent for SWER retirements in many other areas in Victoria.[173] Spencer&Co also noted concerns about whether all customers should pay for the upgrade proposed in this project.[174]

We also received submissions from the Wannon Branch United Dairy Farmers group and four other local dairy farmers in the area that broadly support the proposed augex project. These submissions supported upgrading to three phase power and eradicating SWER lines. The submissions noted that currently this is a limitation to productivity and future economic growth in the region. On balance, while we acknowledge the concerns of stakeholders in support of this program, whom will receive a direct benefit from this investment, we agree with the majority of stakeholder submissions and EMCa and do not think that all Powercor customers should pay for this project. Powercor has overvalued the benefits to Powercor customers and the project is not prudent and efficient. Therefore, we have not included Powercor's upgrading regional supply project in our substitute estimate of total capex

A.4 Connections capex

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet new customer demand.

A.4.1 Draft decision

170 Powercor, *Upgrading regional supply business case,* January 2020, p. 14.

171 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 107.

172 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 106.

173 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, p. 89.

174 Spencer&Co, *Advice to ECA on Victorian submissions,* June 2020, p. 13.

We do not accept Powercor's connections and capital contributions forecasts, as it has not justified the increase compared with historical expenditure under its current contributions policy. In addition, COVID-19 has since affected construction activity, which is closely tied to connections.

The forecast we have included in our substitute estimate of total capex adjusts gross connections down by 15 per cent to $738.3 million and customer contributions down by 6 per cent to $494.7 million. This is based on historical expenditure under Powercor's current customer contributions policy, adjusted for COVID-19 based on a HIA dwelling forecast.

A.4.2 Powercor's initial proposal

Powercor proposed $864.5 million for gross connections and $528.6 million for capital contributions. For high-volume connections (typically residential and smaller connections), Powercor forecast volumes initially based on their average by type between 2015–16 and 2018–19, then applied growth rates for construction activity taken from the Australian Industry Construction Forum for regions in its network. It similarly averaged unit rates by type between 2015–16 and 2018–19.

For 'low-volume' connections, Powercor used a combination of 'bottom-up build' and 'historical average' methods. Powercor has forecast contributions, gifted assets and rebates based on 2016–17 to 2018–19 averages. It stated it used this shorter period due to the change in its connections contributions policy from July 2016.

A.4.3 Reasons for draft decision

For categories where historical unit rates and volumes are key inputs to a forecast, it is important to select appropriate years from which to calculate these averages. Generally, selecting a different range of years over which to calculate gross connections and customer contributions is unlikely to be appropriate, or at least requires justification. Otherwise, 'cherry picking' from different samples to arrive at a higher forecast is possible.

Powercor's decision to limit the years used to calculate its capital contributions until after its policy changed is reasonable. Since its customer contributions increased materially after the policy change, including earlier data would bias its net connections forecast downwards.

However, Powercor has not justified its decision not to use the same range of years to calculate average volumes and gross connections unit rates. Even when broken down by category, unit rates and volumes are an average across connections with different requirements. So from year to year, these averages can move due to essentially random fluctuations. Using the same periods for averaging for gross connections and customer contributions means that the same projects are used as samples for both.

Unit rates from closer to the forecast period will also generally be more reflective of future unit rates, especially if a trend is evident. Average unit rates across high-volume connections declined by 4 per cent per year on average over the period Powercor used.[175]

Powercor has also used an estimate (financial year 2018–19) as part of the average used to form its forecast. Powercor's estimate of overall net connections in this year exceeds net connections in all previous years in the graph presented.[176] We now have actuals for these years and we typically check estimates once actuals are available.

To test the materiality of these issues, we compared Powercor's average yearly forecast net connections (prior to real escalation) with average yearly net connections between calendar years 2016 and 2019. To address the effect of Powercor's different connections policy prior to July 2016, we weighted the 2016 data by half (noting excluding 2016 entirely would have produced a lower average). We used calendar year data as Powercor's financial year RINs are consistent with having been averaged between calendar years, rather than having been calculated directly.

Powercor's net connections forecast is 21 per cent higher based on this comparison. This indicates Powercor's choice of years for averaging purposes has a material effect on its forecast. For these reasons, we do not accept Powercor's high-volume connections and capital contributions forecasts prior to the effects of COVID-19.

Powercor's forecasts were also made prior to COVID-19. The virus has strongly affected the construction industry, and is likely to continue to reduce activity due to its effect on net migration and overall output.

To produce a substitute estimate that estimates both COVID-19 effects and uses more appropriate years as the basis for averaging, we have first adopted the yearly average for gross connections and capital contributions from calendar years 2016 to 2019, with 2016 data weighted by half, for every year of the forecast period. We have then applied a COVID-19 adjustment to this historicals-based forecast, based on HIA forecasts released in April 2020. We have used these forecasts as they provide a Victoria-specific forecast and extend one year into the forecast period.[177]

To estimate the effects of the virus over 2021–22, we compared forecast dwelling starts with actual yearly dwelling starts prior to COVID-19 over the current period (calendar years 2016 to 2019). This gives a ratio of 0.58. This is an approximate measure of the forecast effects of the virus, as this is the major factor the HIA sought to account for in producing these forecasts. We then applied this ratio to the yearly averages for gross connections and capital contributions described above for financial year 2021–22. This results in a further 8 per cent reduction to both forecasts.

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175 This takes unit rates by Powercor's function codes, weighted by average volumes between 2015–16 and 2018–19.

176 Powercor, *Regulatory proposal 2021–26*, January 2020, p. 53.

177 Housing Industry Association, *HIA Housing Forecasts – April 2020 COVID–19 Update*, April 2020.

The virus is also likely to affect low-volume connections due to its effect on economic activity. Powercor has used a bottom-up build to forecast some of these projects, which needs to be reconsidered. As we do not have sufficient information to assess COVID-19 effects for each project, we have combined low-volume and high-volume connections together for the purposes of our substitute forecast based on historicals and a COVID-19 adjustment.

Currently, the duration of the main consequences of COVID-19 are highly uncertain. The Reserve Bank of Australia's August statement on monetary policy assumes international border restrictions will ease from the middle of 2021 in its baseline scenario.[178] Net migration and construction activity will likely then take time to recover. This indicates it is reasonable to assume the effects of COVID-19 on construction will have ended by July 2022. Therefore, for years after 2021–22, we have not adjusted our historicals-based substitute estimate.

The combined effect of these adjustments reduces gross connections by 15 per cent to $738.3 million and capital contributions reduces by 7 per cent to $494.7 million. For our final decision, we would incorporate any new information that materially affects the forecast, including:

- revised forecasts provided by Powercor in its revised proposal
- updated construction forecasts for Victoria (including those that would allow us to distinguish effects by type of connection)
- any actual 2020 capex data from Powercor
- updated information about the likely length of the pandemic.

A.5 ICT capex

ICT refers to all devices, applications and systems that support business operation. ICT expenditure is categorised broadly as either replacement of existing infrastructure for reasons due to end of life, technical obsolescence or added capability of the new system or the acquisition of new assets for a business need.

A.5.1 Draft decision

We do not accept that Powercor's initial ICT capex forecast of $151.7 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included $133.4 million for this category in our substitute estimate of total capex, which is $18.3 million (12 per cent) lower than Powercor's initial proposal.

[178] Reserve Bank of Australia, *Statement on monetary policy*, August 2020, Section 6 (Economic Outlook).

A.5.2 Powercor's initial proposal

Powercor’s initial proposal includes an ICT capex forecast of $151.7 million, which is split into $115.7 million in recurrent ICT and $36.0 million in non-recurrent ICT. Table A.5 summarises Powercor's initial proposal and our draft decision. As noted above in section A.2, we have included Powercor's digital network and solar DVMS programs in the DER integration capex category. These programs are therefore excluded from the numbers and analysis presented below.

Table A.5 Draft decision on Powercor's ICT capex forecast ($ million, $2020–21)

Category	Initial proposal	Draft decision	Difference ($)	Difference (%)
Recurrent ICT	115.7	103.4	-12.3	-11
Non-recurrent ICT	36.0	30.0	-6.0	-17
Total ICT capex	**151.7**	**133.4**	**-18.3**	**-12**

Source: AER analysis.

Note: Numbers may not sum due to rounding.

A.5.3 Reasons for draft decision

We have had regard to all the information before us, including EMCa’s independent review and stakeholder submissions. We received several submissions that raised questions or concerns about Powercor’s ICT capex, including from ECA, CCP17 and Origin Energy. The submissions noted that:

- the benefits were not always clear and opex benefits/savings appeared relatively low
- the duplication of retailer provided services should not be included within regulated revenue.

Consistent with the approach outlined in our ICT expenditure assessment guideline, we have assessed recurrent ICT capex separately to non-recurrent ICT capex.[179]

Recurrent ICT

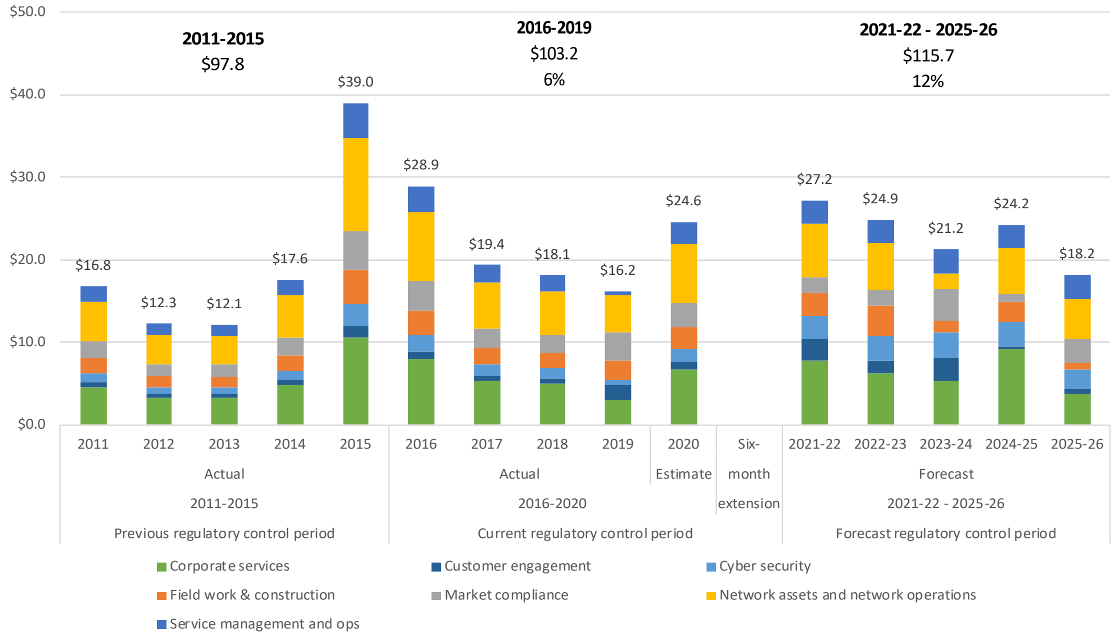
We have assessed this aspect of the forecast primarily through a top-down assessment. This is because historical costs are a likely indicator of future costs for this ICT capex category given the recurrent nature of these investments. We also had regard to benchmarking analysis of recurrent ICT total expenditure (totex) to assess Powercor’s recurrent ICT capex forecast.

[179] AER, *ICT capex assessment review*, May 2019.

Top-down assessment

Given the recurrent nature of these investments, historical costs are a likely indicator of future costs for this category of ICT capex. Powercor's historical expenditure for each recurrent ICT program shows that its total forecast expenditure is 12 per cent higher than current regulatory control period expenditure for these programs. Its forecast is also slightly higher than its longer term trend, as highlighted in figure A.11. From a top-down perspective, Powercor's recurrent ICT capex appears to be a slightly overstated forecast of the prudent and efficient costs for this capex category.

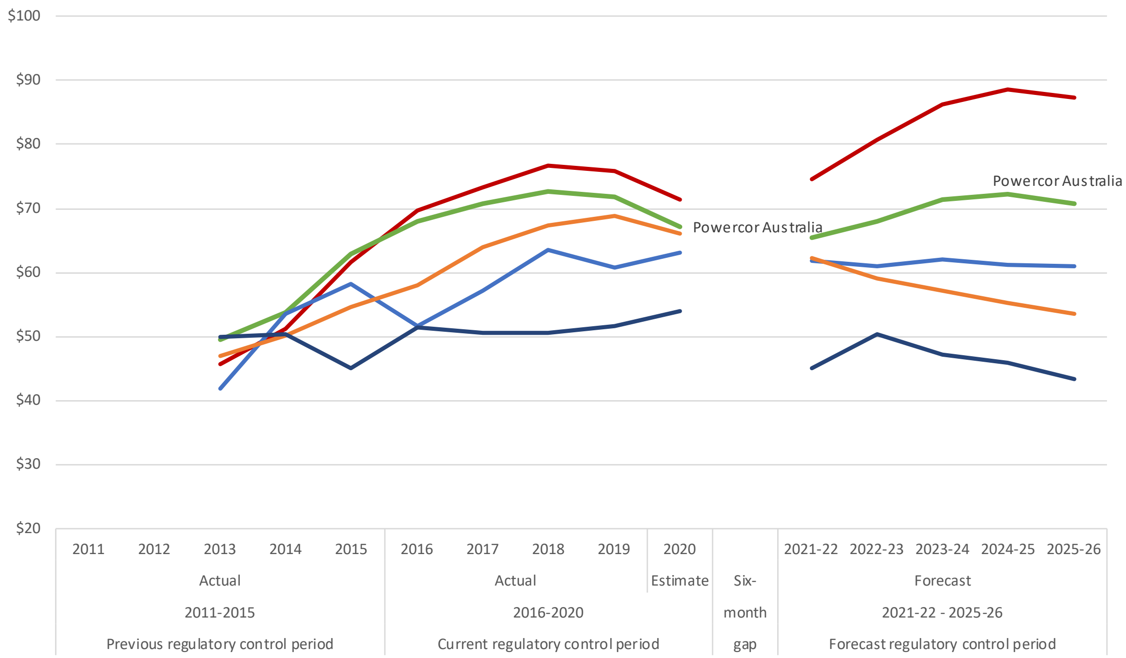
Figure A.11 Powercor's historical vs forecast recurrent ICT snapshot ($ million, $2020–21)



Source: Powercor's initial proposal and AER analysis.

Note: The four years of actual data from the current period (2016–19) have been prorated to a five-year period. The capex figures reported refer to five-year totals over a regulatory control period.

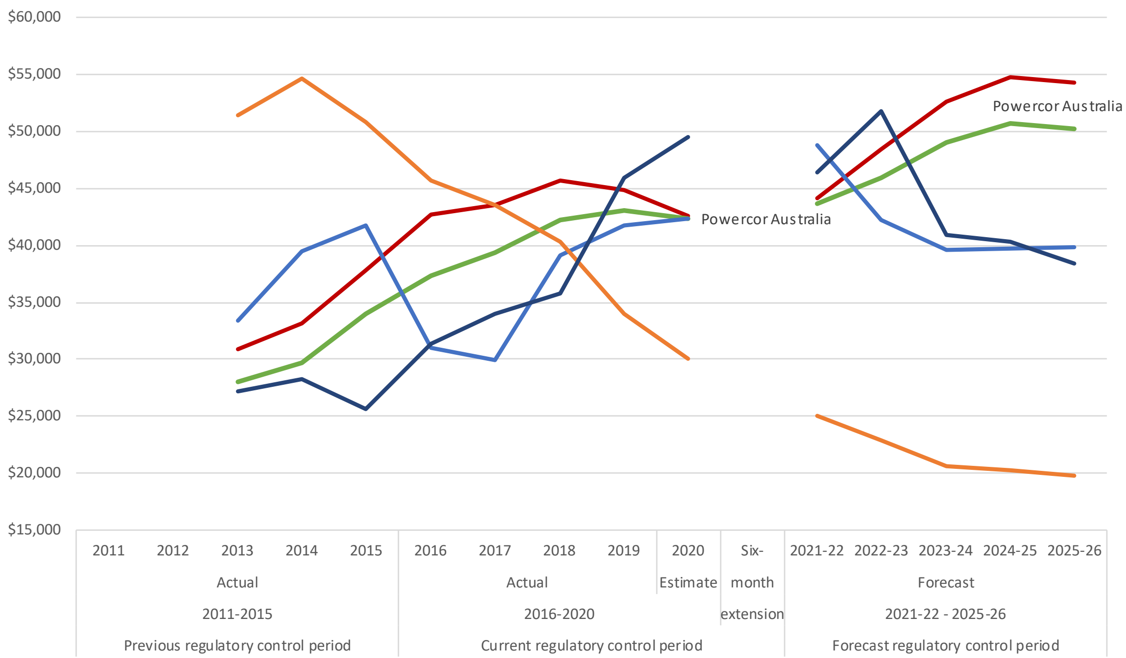
Figure A.12 Victorian ICT benchmarking – Recurrent ICT totex per customer ($ million, $2020–21)



Source: AER analysis.

Note: Data presented is a five-year moving average.

Figure A.13 Victorian ICT benchmarking – Recurrent ICT totex per end user ($ million, $2020–21)



Source: AER analysis.

Note: Data presented is a five-year moving average. End user refers to network employees that use these devices.

Figure A.12 highlights Powercor’s actual recurrent ICT totex per customer ranged from $50 to $72 between 2013 and 2019, and is just above $70 for the forecast regulatory control period. This places Powercor at the upper end of the five Victorian distributors for this metric both in terms of historical revealed expenditure and forecast expenditure.

Figure A.13 illustrates Powercor's actual recurrent ICT totex per end user has increased sharply from 2013 to 2019. Since 2017, the five Victorian distributors have spent between approximately $30,000 and $45,000 in ICT totex per end user. Powercor’s forecast places it towards the higher end compared with the other distributors, particularly by the end of the forecast regulatory control period.

Based on our top-down trend and benchmarking analysis, we have conducted a more detailed bottom-up assessment of a sample of Powercor's recurrent ICT programs and projects. EMCa also reviewed a sample of recurrent ICT business cases.

Bottom-up assessment

EMCa identified that Powercor’s forecast is reasonable for all elements other than the cloud infrastructure and network management programs. Powercor indicated that it will jointly undertake these programs with CitiPower. EMCa’s analysis therefore applies to the total expenditure for each program across the two distributors.

For the cloud infrastructure program, EMCa stated that Powercor’s proposed strategy is sound. EMCa noted that the capex-opex trade-off for the preferred option is adequate. However, EMCa found that Powercor did not adequately justify its proposed capex for refreshing and growing its remaining on-premise infrastructure.[180] It noted that Powercor’s forecast expenditure is approximately $15 million higher than its most recent three years of capex. Therefore, EMCa concluded that the capex for the preferred option 2 is overstated and should be lower than proposed.

For the network management program, EMCa stated that Powercor’s proposed frequency of upgrades and refreshes are unlikely to be prudent and efficient. EMCa’s concerns relate to annual network data processing and four EDNAr refreshes in five years.[181] It believes that the frequency of system upgrades (not refreshes) is excessive and that the value of each upgrade may not be realisable.[182] EMCa recommended that a slightly lower forecast than the proposed amount would represent an efficient level of expenditure.

Our trend and benchmarking analysis, along with EMCa’s bottom-up concerns, indicate that Powercor’s recurrent ICT forecast is likely to be slightly overstated. We have applied a top-down adjustment to the forecast. Our substitute estimate is

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180 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 178.

181 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 181.

182 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 180.

consistent with Powercor's actual recurrent ICT capex from the current regulatory control period.

Non-recurrent ICT

Powercor has not justified its $36.0 million forecast for non-recurrent ICT capex. Our substitute estimate does not include Powercor's customer enablement program and adjusts the forecast for its intelligent engineering program. We have not identified any material issues in Powercor's remaining non-recurrent ICT programs.

We reviewed the information Powercor provided in support of its non-recurrent ICT capex forecast, including the business cases and cost-benefit models. Where required, we have sought further information from Powercor through information requests. We have also had regard to the findings of EMCa from its bottom-up review.

Customer enablement

Powercor proposed to implement apps and other data platforms that will facilitate customer communication in relation to network services such as connections and outages ($4.6 million). The program also aims to facilitate customers understanding of their energy usage.[183] We sought to identify if the proposed investment was likely to be prudent and efficient, providing a positive expected value to consumers.

The first claimed benefit provides an additional means of accessing information in relation to network connections. While we consider this relevant, convenience is the only additional value the proposed app is likely to provide. In addition, the added value is likely to be quite low, as it may be slightly more convenient to use the app than using the identical web page facility.

The second claimed benefit provides improved availability and customer access to information. Given energy retailers already provide their customers with access to information on their energy usage, this benefit duplicates services that are inefficient in a monopoly network context. EMCa also does not consider that real-time data is required to extract the claimed benefits and therefore does not consider Powercor has fully justified the proposed costs of this project. EMCa concluded that some of the benefits could be achieved through a combination of price signals through tariff reform and third-party providers.[184]

The third claimed benefit provides a reduction in call centre time. As consumers already have access to these same services through the web page, the choice of an app would not make a material difference to calls. Powercor's approach to valuing savings in customer time through the use of these additional services overstates customer benefits. Powercor used an apportioned time saving between using an app versus a website and the average consumer wage rate as a proxy. The time saved

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183 Powercor, *Customer enablement business case,* January 2020, p. 4.

184 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 154.

from using an app compared with a website is likely to be immaterial[185] and the use of the average consumer wage rate as a proxy for enquiry time overvalues the time customers invest in following up a connection or outage enquiry.

Red Energy and Lumo Energy submitted that providing competitive services or duplicating services already provided by energy retailers must not form part of the revenue cap or regulated services provided. They considered that duplicating these costs across networks and retailers is not in the long-term interests of consumers.[186]

Based on our assessment, stakeholder submissions and EMCa's analysis, we do not consider that Powercor has established that its customer enablement program is prudent and efficient. Any realised benefits are likely to be insignificant. Once these benefits are removed, Powercor's preferred option becomes NPV negative. Therefore, we have not included this program in our substitute estimate of total capex.

Intelligent engineering

Powercor proposed a program to correctly map its network assets against physical earth with the use of the Global Positioning System (GPS) ($4.6 million). It explained coordinates between its own assets are correct, but because they are not correctly mapped to GPS, the discrepancy can result in higher costs and higher risk of safety incidents by working around its underground assets.[187] It stated the benefits of this program are:

- conflating its geospatial information system (GIS) records to the physical earth
- introducing a master data management system
- enhancing map insights
- improving dial before you dig (DBYD) accuracy and access to information.[188]

EMCa stated it has concerns the benefits of this project may be overstated because Powercor could not necessarily have 100 per cent confidence in the revised mapping. However, it considers it is prudent for Powercor to remap the network, and noted that these issues appear to be of such significance that there is a case for undertaking some of this work in the current regulatory control period rather than waiting until the forecast regulatory control period.[189] Powercor responded to this query in an information request that there is no work underway on this project in the current period.[190]

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185 We think the difference in time spent on an app versus a website is relatively immaterial given the frequency with which customers would actually use either interface.

186 Red Energy and Lumo Energy, *Victorian electricity distribution determination 2021 to 2026,* June 2020, p. 1.

187 Powercor, *Intelligent engineering business case,* January 2020, p. 4

188 Powercor, *Intelligent engineering business case,* January 2020, p. 4.

189 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 162.

190 Powercor, *Response to information request 23*, May 2020, p. 3.

However, we do not think the inclusion of the DBYD application is prudent and efficient under preferred option 2. Consistent with our concerns regarding the customer enablement program, we consider this app may only provide a degree of convenience over an identical web page facility. In addition, an official DBYD application already exists, which suggests that it is not the role of a monopoly network to duplicate an application, particularly if it is only applicable to a few Victorian electricity networks. We do not have material concerns with option 1, which excludes the DBYD application. Based on EMCa's advice, we recognise Powercor's proposal to remap its network is prudent and efficient. We have therefore included the capex forecast under option 1 for intelligent engineering in our substitute estimate of total capex.

CCP17 and Spencer&Co both submitted that although the program would streamline internal business operations, it was unclear how Powercor had taken these savings into account in its forecast.[191] Powercor explained that it had not incorporated the expected savings into its opex forecast, but it had not included some additional opex costs it expects to incur through the digital network program in its forecast.[192] The two operational benefits, first from intelligent engineering and second the additional cost of the digital network program not included in Powercor's forecast, are comparable. We have therefore not made an adjustment for this in our draft decision.

Other non-recurrent ICT programs

Powercor has justified its other non-recurrent ICT programs – systems applications and products (SAP) S/4 HANA, five-minute settlement and cyber security ($26.8 million), which we have included in our substitute estimate of total capex. AusNet Services and Jemena have similar proposals, and other distributors outside Victoria have required similar SAP upgrades and increasing cyber security requirements, including SA Power Networks, Ausgrid and TasNetworks. We are also satisfied the Australian Energy Market Commission's decision to delay commencing the five-minute settlement rule by three months will not materially affect the proposed program.[193]

Stakeholder submissions on these programs were limited. CCP17 suggested that we consider the economies of scale and customer impact of the proposed parallel upgrade by CitiPower, Powercor and United Energy to SAP S/4 HANA. We are satisfied that the proposed capex for each of the three programs is efficient. Powercor explained that the cost breakdown for the SAP S/4 HANA upgrade was developed by internal staff with expertise in the SAP systems implementation.[194]

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191 CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals,* June 2020, pp. 79, 93; Spencer&Co, *Advice to ECA on Victorian submissions,* June 2020, p. 22.

192 Powercor, *Response to information request 29*, June 2020, pp. 5–6.

193 Australian Energy Market Commission, *Rule determination: National electricity amendment (delayed implementation of five minute and global settlement) rule 2020*, July 2020, p. i.

194 Powercor, *Response to information request 30,* June 2020, pp. 4–5.

EMCa concluded that based on the number of SAP modules and the organisational business process complexity and migration from a legacy SAP platform to a modern SAP platform, the proposed implementation cost for a single instance for the preferred option is reasonable.[195] Powercor also provided evidence that 90 per cent of recent ICT projects have been delivered within budget and underspends that have occurred have not been substantial.[196]

A.6 Other non-network capex

Other non-network capex includes property, fleet, plant, tools and equipment. Property expenditure relates to the maintenance, refurbishment and optimisation of offices, operational depots, warehouses, training facilities and other specialist facilities. The indirect costs associated with property assets have been assessed as part of overheads and the costs below refer to 'direct' capital costs only.

Fleet includes expenditure for purchasing new vehicles and related items, including mounted plant. This can be divided between light fleet (passenger and light commercial vehicles) and heavy fleet (elevated work platforms, crane borers and other heavy commercial vehicles).

A.6.1 Draft decision

We accept Powercor's proposed other non-network capex forecast. Powercor's property capex forecast appears reasonable based on historical trend. Powercor's fleet forecast also appears reasonable based on its bottom-up fleet model and our benchmarking analysis.

A.6.2 Powercor's initial proposal

Powercor proposed $227.5 million in other non-network capex for the forecast regulatory control period. Property and fleet are the two largest components of this forecast, with a small amount also forecast for tools and equipment. Powercor's fleet, tools and equipment forecasts are based on historical actual capex over the current regulatory control period, as it expects these requirements to remain constant.[197] Powercor's property capex includes:

- $79.2 million to upgrade and build depots to maintain operating standards. This is due to aging facilities that have unsafe work conditions, insufficient capacity and an inability to service customer growth.
- $30.2 million for a facilities security upgrade to address increasing concerns of theft and unauthorised access. This involves new fencing, enhanced security and monitoring.

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[195] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 168.

[196] Powercor, *Response to information request 23,* May 2020, pp. 1–2.

[197] Powercor, *Regulatory proposal 2021–26*, January 2020, p. 109.

- $4.5 million for building compliance.

A.6.3 Reasons for draft decision

Property

Powercor's underlying assumptions overstate the benefits of the proposed programs. In addition, its modelling does not adequately quantify the risks outlined. However, the overall property capex forecast appears reasonable based on historical trend.

Top-down assessment

Powercor’s property forecast is 10 per cent below its actual and estimated property capex over the current regulatory control period.

Powercor undertook significantly more property capex than it forecast, which we approved ($27.5 million) in the current regulatory control period. The works it undertook in the current regulatory control period relate largely to seven new or refurbished depots.

We consider Powercor’s forecast is largely a continuation of this property program. With the CESS in place, we can be reasonably satisfied that Powercor incurred efficient capex. Given Powercor’s material total capex underspends in the current regulatory control period and its overspending on property capex. This indicates that Powercor considered these works to be important. Using a historical trend approach is consistent with our previous Powercor determination.

Bottom-up assessment

Although we are satisfied our top down assessment indicates Powercor's forecast below historical trend is a reasonable input into our substitute capex forecast, we have identified several issues with Powercor's property proposal.

We engaged EMCa to examine the business cases for each of Powercor’s property capex. EMCa reviewed the cost benefit analysis provided by Powercor in response to our information requests.

For the facilities upgrade project, EMCa considered Powercor did not provide evidence to support the assumptions used in its cost benefit analysis and it is likely to have overstated the risk. For example, Powercor's assumptions imply deaths or serious injury rate of 1.6 per year but did not present evidence to support these risks.[198]

However, EMCa has found that the project remains NPV positive after adjusting the assumptions. EMCa also noted the depots component which accounts for 38 per cent

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[198] EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 197.

of the project costs are likely to duplicate costs that would be included in Powercor's recent and proposed depot upgrades.[199]

EMCa also assessed each of the five depots and adjusted the cost benefit analysis to better take into account productivity, safety risk and customer service.[200] EMCa found that the do nothing option had the highest NPV at Brooklyn and Echuca. However, EMCa noted that Powercor’s business case does justify some works would be required at these sites.[201]

We agree with EMCA's assumptions and findings. Although we are accepting Powercor's property forecast, we consider the concerns outlined above and in the EMCa report warrant consideration in Powercor's revised proposal.

Fleet

Powercor has supported its historical expenditure based forecasts with a bottom-up fleet model. Its replacement policies are broadly in line with our benchmarks for efficient service lives. Therefore, Powercor's fleet capex forecasts are reasonable.

However, Powercor stated that it did not explicitly forecast disposals from the sale of new vehicles and did not explain how fleet disposals had been accounted for implicitly.[202] Accordingly, we have applied a substitute estimate for fleet disposals of $23.0 million, which is based on SA Power Networks' disposals values by vehicle type that we have applied to Powercor's bottom-up fleet model. This fleet disposal amount accounts for the majority of our draft decision asset disposals amount of $25.6 million.

A.7 Capitalised overheads

Overhead costs include business support costs not directly incurred in producing output, and shared costs that the business cannot directly allocate to a particular business activity or cost centre. The Australian Accounting Standards and the distributor's cost allocation methodology determine the allocation of overheads.

A.7.1 Draft decision

We are not satisfied that Powercor's capitalised overheads forecast of $264.9 million would form part of a total capex forecast that reasonably reflects the capex criteria. We have included an amount of $218.5 million in our substitute estimate of total capex. We are satisfied that our substitute estimate would form part of a total capex forecast that reasonably reflects the capex criteria.

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199 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 198–205.

200 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, p. 201.

201 EMCa, *Review of aspects of Powercor's regulatory proposal 2021–26*, September 2020, pp. 212.

202 Powercor, *Response to information request 14 – Q7*, April 2020, p. 5.

A.7.2 Powercor's initial proposal

Powercor forecast $264.4 million in capitalised overheads for the forecast regulatory control period. It applied a base step trend methodology to arrive at its forecast, which involved:

- adopting its 2018 standard control capitalised overheads as the base year
- step increases in the base year to reflect its forecast opex rate of change for the forecast period.

A.7.3 Reasons for draft decision

To arrive at our substitute, we have adjusted the overheads to reflect our lower substitute estimate of direct capex, our updated estimate for the base year and our substitute for Powercor’s rates of change. The net effect of these adjustments results in a substitute estimate of capitalised overheads that is $46.5 million (18 per cent) lower than Powercor's forecast.

Adjusting for our lower estimate of direct capex

Reductions in Powercor's forecast expenditure reduce the size of its total overheads. Our assessment of Powercor's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct expenditure contained in Powercor's proposal.

It follows that we would expect some reduction in the size of Powercor's capitalised overheads. Some of these costs are relatively fixed in the short term and therefore not correlated to the size of the expenditure program. However, we maintain that a portion of overheads should vary in relation to the expenditure.

As a result, in the absence of alterative information and consistent with our previous determinations, we have adopted a 75 per cent fixed and 25 per cent variable ratio to adjust overheads.

Other adjustments

We have also amended Powercor’s model to adjust the base year from 2018 to the average of the overheads expenditure between 2016 and 2019. The average reflects a more accurate representation of current regulatory control period overheads as it is less affected by annual variation. We then substituted the forecast rates of change used to escalate the overheads to maintain consistency with our forecast of Powercor’s opex rate of change. Our opex decision (Attachment 6) outlines further detail.

B Forecast demand

Maximum demand forecasts are fundamental to a distributor's forecast capex and opex, and to our assessment of that forecast expenditure. This is because we must determine whether the capex and opex forecasts reasonably reflect a realistic expectation of forecast demand for SCS.[203] Therefore, reasonable demand forecasts based on the most current information are important inputs to ensuring efficient levels of investment in the network. This section sets out our decision on Powercor's forecast network maximum demand for the forecast period.

B.1 Draft decision

We are not satisfied that Powercor's demand forecasts reasonably reflect a realistic expectation of demand over the forecast regulatory control period. We consider AEMO's 2019 Transmission Connection Point forecasts for Powercor's network are reasonable, based on currently available information.

B.2 Powercor's initial proposal

Powercor's consultant, the CIE, has forecast growth in non-coincident maximum demand of 2.2 per cent per year between 2021 and 2026. Powercor has used this to forecast its demand-driven augex projects, after reconciling them with its bottom-up zone substation forecasts. Powercor's RIN includes a different set of demand forecasts that are significantly higher.

The CIE's top-down forecasts are based on a combination of modelling using variables such as income per person, electricity prices, population, temperature and air-conditioning uptake, and post-modelling adjustments for the effects of solar PV, electric vehicles, battery storage, other forms of distributed generation and energy efficiency.[204]

The CIE produced these for each terminal station separately. Independently, Powercor forecast maximum demand at each of its zone substations. Powercor then adjusted these bottom-up forecasts to reconcile with the CIE's top-down terminal station forecasts. Powercor used these reconciled zone substation forecasts to determine the need for demand-driven augmentation, as summarised in Figure B.1 below.

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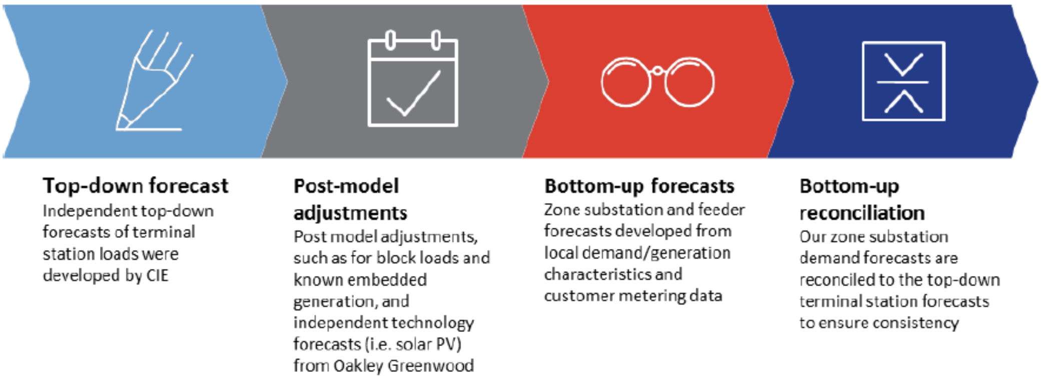
203 NER, cll. 6.5.6(c)(1)(iii) and 6.5.7(c)(1)(iii).

204 CIE, *CitiPower and Powercor maximum demand forecasts*, March 2019 p. 10; Oakley Greenwood, *Post-model adjustments for terminal station forecasts*, December 2018, p. 3.

Figure B.1 Powercor's demand forecasting approach



Source: Powercor, *Regulatory proposal 2021–26,* January 2020, p. 90.

B.3 Reasons for draft decision

We are not satisfied that Powercor's demand forecasts are reasonable based on:

- specific assumptions and methods used in Powercor's demand forecasts
- historical demand trends
- a comparison of results with AEMO's 2019 Transmission Connection Point forecasts
- Powercor's past demand forecasting performance compared with AEMO's
- the need to account for COVID-19 effects.

Consumers have expressed concern at overstated demand forecasts leading to windfall CESS benefits and the potential for this to reoccur.[205] We share these concerns and have looked at Powercor's demand forecasts in detail.

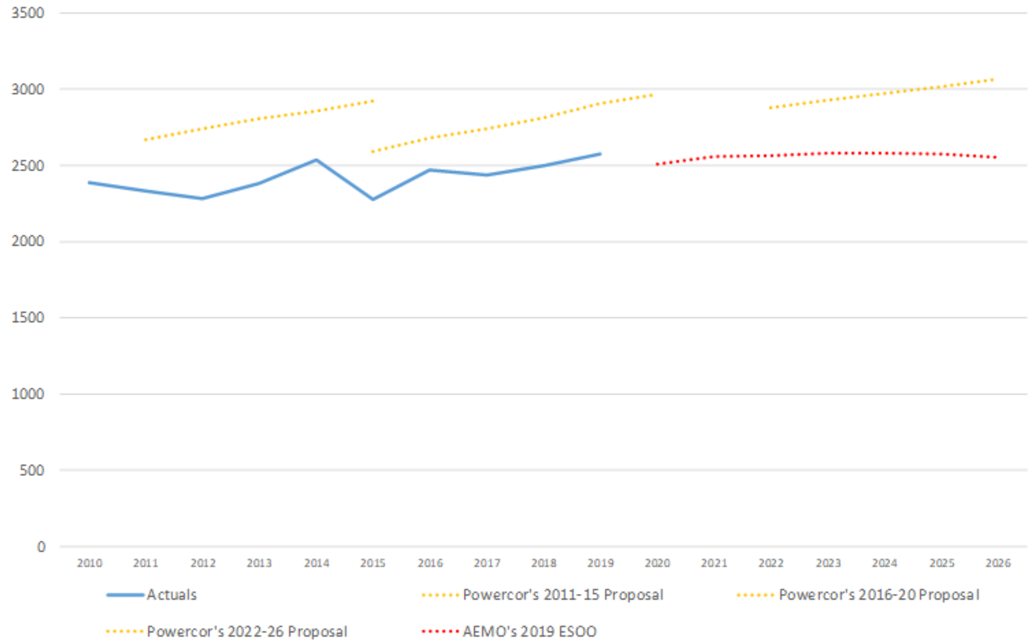
Traditionally, the key driver of augex has been growing maximum demand. However, since 2008 system peak demand has remained relatively flat in Victoria and other states except Queensland.[206]

As shown in Figure B.2, Powercor forecast strongly rising maximum demand in its 2011–16 proposal and its 2016–20 proposal. In both cases, this increase did not eventuate.

205 Victorian Community Organisations, *2021–2026 Victorian EDPR,* May 2020, p. 4; CCP17, *Advice to the AER on the Victorian electricity distributors' regulatory proposals 2021–26,* June 2020, pp. 59–62; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals,* May 2020, p. 3.

206 AER, *State of the Energy Market*, July 2020, pp. 71–72.

Figure B.2 Powercor's historical and forecast maximum non-coincident demand (MW, POE50)[207]



Source: AER analysis.

Powercor's consultant, the CIE, has again forecast strong growth in maximum demand compared with historical trends. From summer 2015–16 until 2018–19, AEMO's weather corrected non-coincident actuals show average annual growth of 1.1 per cent (POE50). The CIE forecast demand growth at over double this rate for 2020–21 until 2025–26, which is an increase of 2.2 per cent per year.[208]

To forecast its opex, Powercor has included maximum demand forecasts in its RIN that are higher still (shown in figure B.2 above). We asked Powercor to clarify why its RIN forecasts exceeded the CIE's. It stated that the CIE's forecasts did not account for all demand in its network, but did not show how it had quantified these differences to arrive at its higher forecasts.[209] Powercor's proposal does not discuss this large discrepancy. Powercor should have transparently identified and supported the large difference between these forecasts initially, and its response to our information request is inadequate to justify any increase in its demand forecast above those produced by regression modelling. The remainder of our decision focuses on the CIE's forecasts, which Powercor used to forecast its capex.

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207 The forecasts are based on the higher maximum demand forecasts Powercor included in its RIN. CIE, *Maximum Demand Forecasting for CitiPower and Powercor – 2015 update*, July 2015, p. 52; Powercor, *2011–15 regulatory proposal*, p. 40; AEMO, *Transmission Connection Point forecasts for Victoria*, November 2019.

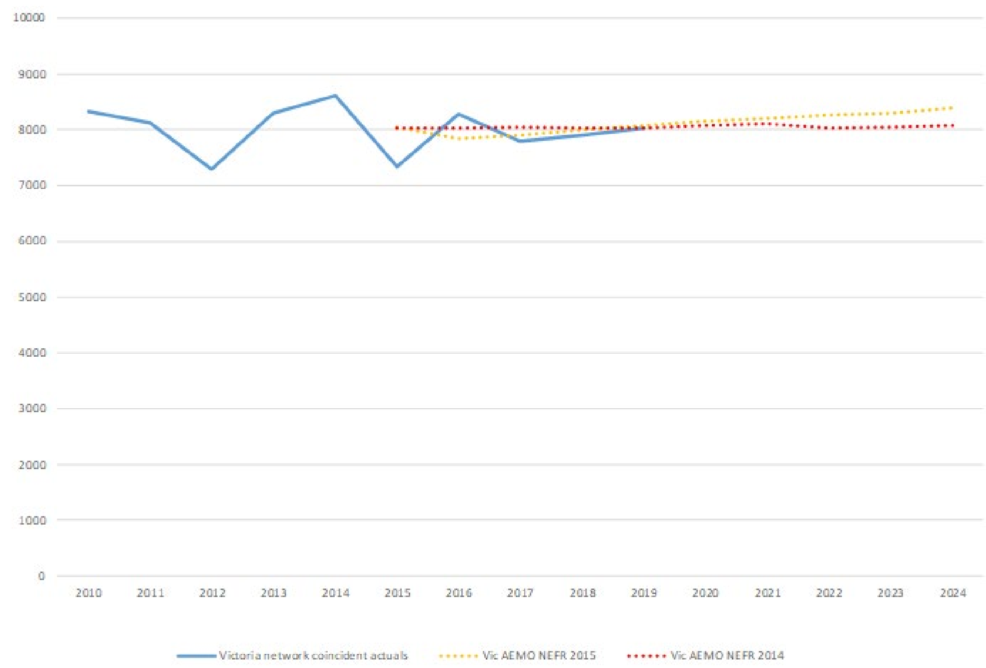
208 This is based on the demand forecasts produced by Powercor's consultant, CIE that are the basis for its augex forecasts. Powercor stated higher forecast demand in its reset RIN.

209 Powercor, *Response to information request 58,* July 2020, p. 1.

The CIE's forecasts use econometric regression modelling. Typically, regression modelling is sensitive to choices made by the researcher. Therefore, internal consistency alone may not be sufficient to establish that a forecast reasonably reflects a realistic expectation of demand. A forecast involving a substantial increase compared with historical trends also needs to be justified by comparing its results with any other authoritative forecasts, and where there are material differences, clearly demonstrate why the chosen methods and assumptions are superior. We have also given weight to the accuracy of past forecasts.

We consider AEMO's Transmission Connection Point forecasts should be the main basis for comparison. For transmission planning, the NER mandates AEMO’s role in producing demand forecasts and it has no strong incentive to under- or over-forecast. AEMO also consults widely with stakeholders in producing its forecasts through its standing Forecasting Reference Group. In contrast to the CIE's forecasts, AEMO's 2019 forecasts are for flat non-coincident maximum demand in Powercor's network over the forecast period: a decline of 0.01 per cent per year. AEMO's forecasts for Victoria that were available during the previous decision process have proven relatively unbiased. This is shown in figure B.3 below.

Figure B.3 AEMO’s historical forecasts vs actuals in Victoria (MW, network peak, POE50)



Source: AEMO national electricity forecasting reports 2014 and 2015; AEMO transmission connection point forecasts 2019; AER analysis.

In the previous regulatory control period, Powercor forecast 2.7 per cent average annual maximum demand growth in its draft proposal, which it reduced to 2.6 per cent in its revised proposal. AEMO's 2013 forecasts were for 0.3 per cent average annual growth, which it increased to 1.5 per cent average annual growth in 2014. AEMO's

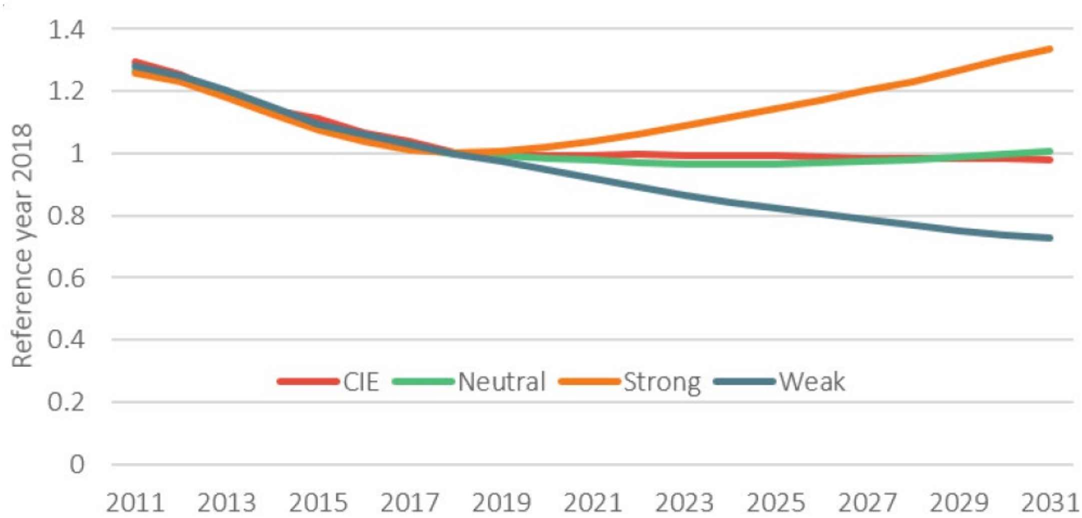
2013 and 2014 forecasts were broadly consistent with actual maximum demand growth so far (1.1 per cent per year, weather corrected). Powercor's revised forecasts have exceeded weather corrected maximum demand growth by 8 per cent overall.

We asked Powercor to explain why it considers its forecasts for the forecast regulatory control period superior to AEMO's. Powercor criticised AEMO's forecasts for failing to adequately consider bottom-up drivers of demand growth. In this respect, Powercor's modelling differs from AEMO's in two ways. First, the CIE ran its regressions at the terminal station level, whereas AEMO starts from the state level and allocates demand growth between terminal stations. Second, Powercor has produced bottom-up demand forecasts at the zone substation level.

Methodologically, there is no strong reason to prefer regressions performed at the terminal station level compared with the whole state level. Indeed, in aggregate, results from regressions at a smaller geographical level can be less reliable, as random variations tend to 'smooth out' over a larger area. Regarding Powercor's zone substation level forecasts, Powercor's own demand forecasting method appropriately depends on reconciling its bottom-up zone substation forecasts to its top-down terminal station forecasts, which take precedence.

Bottom up, we have used Powercor's forecasts at the zone substation level to produce an alternative set of demand forecasts that reconcile to AEMO's (as discussed in section A.3). Therefore, Powercor has not demonstrated that its forecasts are superior to AEMO's on methodological grounds. Demand by customers is a key output from the modelling, which is illustrated in figure B.4 below. This highlights how the CIE's scenario is for the historical decline in demand per customer to end relatively rapidly.

Figure B.4 Powercor's long-term trends of demand per inhabitant for different scenarios (reference year in 2018)



Source: ENEA Consulting, Load forecasting documentation, December 2018, p. 11, provided by Powercor in information request 44.

We also examined specific methods and assumptions used by the CIE. We found the following issues:

- Powercor's post-modelling adjustments assume a different average solar PV system size (4kW) than for its solar enablement business case (5kW). Although Powercor states that the effect of this difference is likely to be immaterial, it has not demonstrated this and it did consider the effect sufficiently material to update its proposed DER augex.[210]
- The modelling assumed EVs charging would take place at the network peak to a greater extent than is assumed in AEMO's ‘worst case scenario’.[211] Our draft tariff structure statement decision is for EVs owners to be subject to time of use tariffs, which will incentivise charging at non-peak times.
- The CIE has ‘cherry picked’ out negative income elasticity coefficients where its regression has found these in some geographical areas, based on its belief that GDP growth and demand must always be positively related. This is not a neutral, evidence-based approach. GDP growth and demand growth have generally diverged in Australia, so it is plausible there is no longer a strong underlying relationship between the two.[212] Manually overriding negative income elasticities with positive ones introduces an upwards bias to forecast demand.
- The CIE did not remove historical block loads before running its regressions, due to difficulties in identifying them. It also did not weight forecast block loads for probability of occurrence. This can bias forecasts upwards.[213]

Structurally, the key difference between the CIE's approach and AEMO's is that the CIE uses variables such as economic growth, population and price in its regression model, whereas AEMO's 2019 terminal station forecasts fit curves based on historical trends (after weather correction).

While in principle regression modelling based on underlying drivers of demand can be a reasonable approach, its success depends on specifying the model correctly, to incorporate all significant drivers. The poor historical performance of all Victorian distributors' demand models indicates that a key variable or variables are missing, such as energy efficiency, solar PV uptake or reduced industrial consumption.

While Powercor has sought to address this using post-modelling adjustments, these do not necessarily appropriately correct for the error introduced by model misspecification. For solar PV uptake, the CIE reported that incorporating this variable within the model improved its explanatory power.[214] However, it nevertheless chose to rely on post-modelling adjustments because it found evidence of omitted variable bias, which it identified as likely due to excluding energy efficiency from the model. In general,

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210 Powercor, *Response to information request 1,* Q 3 (a), March 2020, pp. 6–7.

211 Powercor, *Response to information request 1,* Q 3 (b), March 2020, p. 7.

212 AER, *State of the Energy Market*, July 2020, pp. 71–72.

213 Powercor stated that it only included committed future loads. However, this does not quantify the degree of commitment: the probability of a committed future load going ahead will still generally be less than certainty. Powercor, *Response to information request 1,* Q 2 (f), p. 6.

214 CIE, *CitiPower and Powercor maximum demand forecasts*, March 2019, pp. 18–19.

evidence that one variable should have been included is not good grounds to exclude another. Instead, either a suitable proxy should be found for any significant omitted variables or an alternative approach adopted.

In the absence of a model likely to be well-specified, AEMO's forecasts are likely to be more accurate. AEMO's 2020 state-wide forecasts do not first regress demand on variables such as GDP growth and prices, and then account for effects such as solar PV and energy efficiency afterwards. Instead, for residential demand, they model the effect of all variables on demand per customer as part of a single process.[215] This is less likely to cause misspecification bias.

Moreover, given the relationship Powercor's demand model uses between demand and GDP growth, even if we were to accept its method as reasonable, it would need to update its forecasts for the effects of COVID-19. Powercor has indicated that it is working on revisions to its demand forecasts to take account of these effects.

AEMO's 2020 Victoria-wide forecasts are for an initial decline in maximum demand due to COVID-19, and then flat maximum demand over the forecast regulatory control period.[216] Overall, maximum demand declines by 0.5 per cent per year until 2025–26 (compared with average maximum demand between 2015–16 and 2019–20), which is similar to its 2019 transmission connection point forecasts.

Hence, using AEMO's approach (which does not depend as strongly on GDP as an input), COVID-19 does not sufficiently affect demand across Victoria to change our conclusions for opex and capex. This reduction may be conservative, as AEMO's central scenario models COVID-19 as a temporary shock, rather than assuming a permanent effect due to lower migration and population growth. We will also consider AEMO's final transmission connection point forecasts due in November as part of our final decision, as these will provide data for each network separately.

[215] AEMO, *Electricity demand forecasting methodology information paper*, August 2020, pp. 27–28.

[216] AEMO, *2020 Electricity Statement of Opportunities*, August 2020, p. 106.

C Repex modelling appendix

This attachment describes the general repex modelling assumptions for the Victorian distributors and details specific adjustments for Powercor during our engagement. Inputs and outputs of the model, including the NEM median data are published alongside this decision.[217] Further detail on our repex modelling approach is detailed in the repex model outline.[218]

General repex modelling approach for all Victorian electricity distribution determinations

Our assumptions on the most representative calibration period and the conversion from financial year to calendar year are consistently applied for all Victorian distributors.

Transition from calendar year to financial year

The Victorian regulatory control periods are transitioning from a calendar to financial year basis. We have relied on as reported calendar year as our input data.[219] To estimate and compare the forecast repex requirements in financial year basis, we have taken the average of the 2021 and 2026 calendar years, along with the full calendar year forecasts for 2022, 2023, 2024 and 2025. This approach ensures that we capture a distributor's most recent replacement practices via its most recent actual reported and audited information.

Calibration period

The calibration period refers to the historical time period used to analyse a distributor's historical replacement practices.[220] For the Victorian electricity distribution determinations, we have relied on the four most recent calendar years (2016 to 2019 inclusive) as our calibration period. Due to the six-month transition from calendar year basis to financial year basis, we have four full years of current regulatory control period data available for the draft decision.

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217 AER, *Draft decision – Powercor distribution determination – Repex Model*, September 2020.

218 AER, *Repex model outline for electricity distribution*, February 2020.

219 Data reported as part of the annual category analysis RINs.

220 The time period that is most representative of a distributor's expected future repex requirements is selected as the calibration period. In doing so, we have regard to changes in legislative obligations or other factors that may affect our analysis or a distributor's historical replacement practices. AER, *Review of repex modelling assumptions,* December 2019, p. 7.

Specific modelling adjustments for Powercor – review of proposal

After reviewing Powercor's proposal and supporting documentation, including the Powercor's consultant report on repex modelling,[221] we have made further adjustments to our standard modelling approach.

Service lines

Powercor’s category analysis RIN contained a reporting anomaly in which service lines expenditure, volumes, and age profile were not reported under a single asset category.[222] To obtain a complete data set for service lines, an adjustment was made to combine the two sets of data together.

Powercor reported its historical service lines volumes in kilometres, instead of number of customers/spans. In line with GHD’s review of Powercor's repex model inputs, we converted the volumes into meters, and divided by the average length of a customer line length (22 meters) to obtain an estimate of the number of customers.[223] We invite Powercor to re-adjust its reported service lines units of measurement in the 2021–26 regulatory control period RINs to be consistent with other distributors.

Recast data

Powercor proposed to reclassify ‘minor repairs’ from capex to opex as it noted that the reclassification better reflects the nature of the work.[224] The reclassification affected a number of categories within the underground cables and overhead conductors asset groups. It was reflected in its recast RINs.[225] No other asset groups' volumes or expenditure were recast.

To forecast repex, while excluding the impact of ‘minor repairs’, we have relied on the recast category analysis RIN as the basis of the input expenditure and volumes for the underground cables and overhead conductors asset groups. Even though our draft decision did not accept the reclassification of minor repairs from repex to opex, we have not adjusted the input data for this draft decision repex model. In coming to our final decision modelling approach, we will have regard to Powercor's revised proposal and its position on minor repairs.

Overhead conductors

Powercor does not have an age profile for 22kV single-phase conductors, despite these assets existing in its network and RIN data indicating expenditure over the

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221 Powercor, *PAL ATT097 – GHD – Repex modelling review*, December 2019.

222 Powercor reports its service line age profile under ‘Service lines; other’, and its historical replacement expenditure and volumes as ‘Service lines; <=11kv; residential; simple type”.

223 Powercor, *PAL ATT097 – GHD – Repex modelling review,* December 2019, p. 17.

224 Powercor, *Regulatory proposal 2021–26*, January 2020, pp. 124–125.

225 Powercor, RIN003 – *Workbook 3 – Recast CAT,* January 2020; Powercor, *RIN001 Workbook 1 – Reg determination,* January 2020.

calibration period. Powercor stated it has a combined age profile for both single phase and multi-phase assets. To reflect Powercor's combined age profile, we have included expenditure and volumes of single phase conductors into the multi-phase.

Specific modelling adjustments for Powercor – engagement with Powercor

During the review process, we have engaged with Powercor on its repex model inputs through a number of information requests and meetings. In July 2020, we provided Powercor its preliminary repex modelling outputs. In response, Powercor questioned some of the repex modelling assumptions and provided us an alternative view on some of the repex model input data and assumptions. We discuss Powercor's questions, suggestions and our response below.

Transformer repex

Powercor submitted that it had not replaced large zone substation transformers during the calibration period. Therefore, it submitted that its historical unit cost for its 66 kV transformers is not an accurate representation of its forecast unit cost.[226] It argued that similar to CitiPower, a post-modelling adjustment should be applied.

After reviewing and considering the information before us, we have not made any post-modelling adjustments for Powercor's historical unit rates. Powercor is a large network with a recurrent replacement profile for its entire transformer asset group. The issues observed in the CitiPower network, namely the lumpiness of repex for smaller networks, do not apply to Powercor. As such, we have not made any post-modelling adjustments for specific categories within the transformer asset group.

Other repex

We excluded 'other' asset categories from the repex model,[227] because of the heterogeneity of the reported assets within those categories and the inability to adequately obtain consistent sets of historical and NEM median data. This approach is in-line with previous decisions, where unique assets, or assets that cannot be benchmarked, are excluded from the modelling.

Powercor submitted that the exclusion of these assets compromises the usefulness and the accuracy of the repex analysis, diminishes the coverage of a key regulatory tool, and adopts the principle of the 'lowest common denominator'. Powercor submitted that its preferred approach is to model the 'other' asset categories, while relying on the distributors' own calibrated historical performance, given that there are readily available asset information.

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[226] Powercor, *AER repex model – Preliminary results – CP PAL and UE questions*, August 2020, p. 1.

[227] If an asset is a common asset in the NEM, but due to data reporting issues, it is not reported in the distributors CA RIN over the calibration period, we may utilise similar assets' unit costs and estimated replacement lives as a substitute for missing data.

We considered Powercor's submission but have maintained our modelling approach of excluding unique assets. Our approach ensures the integrity of the comparative analysis, where the model tests a consistent set of asset categories. The repex model benchmarks a distributor's asset unit costs and calibrated lives against the median unit cost and calibrated life of each asset across the NEM. This comparison function is key to testing the prudency and efficiency of proposed modelled repex. The exclusion of unique assets ensures that asset categories that cannot be meaningfully compared with other distributors are not included in the repex modelling threshold.

It is important to note that irrespective of whether a particular asset category is considered modelled repex or unmodelled repex, we expect distributors to provide robust cost-benefit analysis to support their repex forecasts. Our consideration of Powercor's bottom-up, including cost-benefit, analysis is discussed in appendix A.

D Ex-post prudency and efficiency review

We are required to provide a statement on whether the roll forward of the RAB from the previous regulatory control period contributes to the achievement of the capital expenditure incentive objective.[228] The capex incentive objective is to ensure that, where the RAB is subject to adjustment in accordance with the NER, only expenditure that reasonably reflects the capex criteria is included in any increase in the value of the RAB.[229]

As the Victorian distribution network service providers are moving from calendar regulatory control years to financial regulatory control years, this ex-post assessment will apply to the 2014, 2015, 2016, 2017, 2018 and 2019 calendar regulatory years. The NER require that the last two years of the current regulatory control period are excluded from past capex ex-post assessment. The ex-post prudency and efficiency will exclude calendar regulatory control year 2020 and the first half of calendar regulatory control year 2021.[230]

The NER states that we may only make a determination to reduce inefficient past capex if any one of the following requirements is satisfied:

- The distributor has spent more than its capex allowance (the 'overspending' requirement).
- The distributor has incurred capex that represents a margin paid by the distributor, where the margin referable to arrangements that, in our opinion, do not reflect arm's length terms (the 'margin' requirement).
- Where the distributor's capex includes expenditure that should have been treated as opex (the 'capitalisation' requirement).[231]

D.1 Draft decision

We are satisfied that Powercor's capital expenditure over the regulatory control years 2014 to 2019 should be rolled into the RAB.

D.2 Reasons for draft decision

We have reviewed Powercor’s capex performance for the regulatory years from 2014 to 2019. This assessment has considered Powercor’s actual capex relative to the regulatory forecast provided and the incentive properties of the regulatory regime for a distributor to minimise costs. Powercor’s incurred total capex is below its forecast for each of those regulatory years.

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228 NER, cl. 6.12.2(b).

229 NER, cl. 6.4A(a).

230 The first half of the calendar year will be considered a regulatory year for the purpose of this review.

231 NER, cl. S6.2.2A(b) to (i).

We have also had regard to some measures of input cost efficiency as published in our latest annual benchmarking report.[232] We recognise that there is no perfect benchmarking model, but our benchmarking models are robust measures of economic efficiency and we can use this measure to assess and compare a distributor's efficiency.

The results from our most recent benchmarking report highlights that Powercor remained the fourth most efficient distributor out of the thirteen NEM distributors with a multilateral total factor productivity (MTFP) score of 1.161 for 2018[233], which is a 3.6 per cent decrease from its 2017 MTFP value. While this provides relevant context, we have not used our benchmarking results in a determinative way for this capex draft decision, including in relation to this ex-post prudency and efficiency review. Based on our review, we consider that the 'overspending' and 'margin' requirements are not satisfied.[234]

For the 'capitalisation' requirement, Powercor has informed us that it had incurred capex of approximately $11.6 million in the current regulatory control period that should have been classified as opex.[235] It submitted that the reclassification better reflects the nature of the work as the costs are incurred to maintain the age of the asset, and do not result in the creation of a new asset. [236]

Our draft decision has not accepted the reclassification of ‘minor repairs’ from capex to opex, as Powercor has not established that that these works are, in fact, of operating nature.[237] Therefore, the reclassification of 'minor repairs' has not met the ‘capitalisation’ requirement.

For the reasons set out above, we are satisfied that the entirety of Powercor’s capex in the regulatory control years from 2014 to 2019 should be rolled into the RAB.

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232 AER, *Annual benchmarking report: Electricity distribution network service providers*, November 2019.

233 Economic Insights, *Economic benchmarking results for the Australian Energy Regulator’s 2019 DNSP annual benchmarking report*, October 2019, p. 17.

234 NER, cl. S6.2.2A(c)

235 AER analysis of recast RIN as compared with the category analysis RIN.

236 Powercor, *Regulatory proposal 2021–2026*, January 2020, p. 124.

237 AER, *Powercor distribution determination 2021–26 – Attachment 6 operating expenditure,* September 2020.

Shortened forms

Shortened form	Extended form
AC	added control
ACRs	automatic circuit reclosers
ACS	alternative control services
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	advanced metering infrastructure
augex	augmentation expenditure
BMP	Bushfire Mitigation Plan
capex	capital expenditure
CBRM	condition-based risk modelling
CCP17	AER’s Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CRO	caution refer operator
CPI	consumer price index
DBYD	Dial Before You Dig
DELWP	Department of Environment, Land, Water and Planning
DER	distributed energy resources
DVMS	dynamic voltage management system
EDO	expulsion drop out
ELCA	electric line construction area
EMCa	Energy Market Consulting associates
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EUAA	Energy Users' Association of Australia
EVs	Electric vehicles
GDP	gross domestic product
GFN	ground fault neutralisers
HBRA	high bushfire risk area

Shortened form	Extended form
HIA	Housing Industry Association
HV	high-voltage
ICT	information and communications technology
LV	low-voltage
MTFP	multilateral total factor productivity
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	net present value
opex	operating expenditure
PTRM	post-tax revenue model
PV	photovoltaic
RAB	regulatory asset base
REFCL	rapid earth fault current limiter
repex	replacement capital expenditure
RIN	regulatory information notice
RIT-D	distribution regulatory investment test
SAIFI	system average interruption frequency index
SAP	systems applications and products
SCADA	supervisory control and data acquisition
SCS	standard control services
STPIS	service target performance incentive scheme
SWER	single-wire earth return
totex	total expenditure
VaDER	Value of DER
VCO	Victorian Community Organisations