energy market consulting associates

Powercor 2026 - 2031 Regulatory Proposal

REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON AUGEX, REPEX AND VEGETATION MANAGEMENT

Public Version

Report prepared for:

AUSTRALIAN ENERGY REGULATOR (AER)

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Preface

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be allowed for the prescribed distribution services of Powercor from 1st July 2026 to 30th June 2031. The AER's determination is conducted in accordance with its responsibilities under the National Electricity Rules (NER).

This report covers a particular and limited scope as defined by the AER and should not be read as a comprehensive assessment of proposed expenditure that has been conducted making use of all available assessment methods nor all available inputs to the regulatory determination process. This report relies on information provided to EMCa by Powercor. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AER and for the use of this report for any purpose other than the intended purpose. In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as an interpretation of the application of the NER or other legal instruments.

EMCa's opinions in this report include considerations of materiality to the requirements of the AER and opinions stated or inferred in this report should be read in relation to this over-arching purpose.

Except where specifically noted, this report was prepared based on information provided to us prior to 1 June 2025 and any information provided subsequent to this time may not have been taken into account. Some numbers in this report may differ from those shown in Powercor's regulatory submission or other documents due to rounding.

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABBREVIATIONS

Term	Definition
ACR	Automatic Circuit Recloser
ACS	Alternate Control Service
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plan
Augex	Augmentation expenditure
BAU	Business As Usual
BESS	Battery Energy Storage System
BST	Base-Step-Trend
CAP	Customer Advocacy Panel
CBA	Cost Benefit Analysis
CBRM	Condition Based Risk Management
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resources
CoC	Cost of Consequence
CPI	Consumer Price Index
CPU	CitiPower, Powercor and United Energy
DAPR	Distribution Annual Planning Report
DLA	Dielectric Loss Angle
DNSP	Distribution Network Service Provider
DSS	Distribution Substation
DTC	Distribution Transfer Capacity
DVM	Dynamic Voltage Management
EAR	Energy At Risk
EDCoP	Electricity Distribution Code of Practice
EFD	Early Fault Detection
ELCA	Electric Line Clearance Area
ESMS	Electricity Safety Management System
EUE	Expected Unserved Energy
EV	Electric Vehicle
HBRA	High Bushfire Risk Area

Term	Definition
ICT	Information Communication Technology
ISP	Integrated System Plan
LBRA	Low Bushfire Risk Area
LDC	Load Duration Curve
LGA	Local Government Area
LiDAR	Light Detection and Ranging
MEC	Major Electricity Company
MEDs	Major Event Days
NEM	National Electricity Market
NER	National Electricity Rules
next RCP	2026-2031
NPV	Net Present Value
NSP	Network Service Provider
PoE	Probability of Exceedance
PoF	Probability of Failure
RCP	Regulatory Control Period
REFCL	Rapid Earth Fault Current Limiter
repex	Replacement expenditure
RGCS	Remote Control Gas Switch
RIN	Regulatory Information Notice
RIT	Regulatory Investment Test
RP	Regulatory Proposal
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPS	Stand-Alone Power System
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Service
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
USE	Unserved Energy
VCR	Value of Customer Reliability
VER	Value of Emissions Reduction
VNR	Value of Network Resilience
VSL	Value of Statistical Life
WSC	Worst-Served Customer

Term	Definition
ZSS	Zone Substation

EXECUTIVE SUMMARY

Introduction and context

1. The AER has engaged EMCa to undertake a technical review of aspects of the replacement expenditure (repex), augmentation expenditure (augex) and opex step changes that Powercor has proposed in its regulatory proposal (RP) for the 2026-31 Regulatory Control Period (next RCP).
2. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed capex and opex allowances as an input to its draft determination on Powercor's revenue requirements for the next RCP.

Expenditure under assessment

Proposed repex

3. Powercor has proposed $1,491.5 million for repex in the next RCP. This represents a 47% increase from the $1,017.6 million that Powercor expects to incur in the current RCP.
4. We have been asked to review projects and programs with aggregate proposed capex of $1,038.8 million (or approximately 70%) of the proposed repex.

Proposed augex

5. Powercor has proposed $564.7 million for augex over the next RCP.
6. We have been asked to review projects and programs with aggregate proposed capex of $421 million and including an Electrification/CER project with proposed capex of $101 million. These projects comprise approximately 75% of Powercor's proposed augex.

Proposed opex step change for vegetation management

7. Powercor has proposed an opex step change for its vegetation management program of $232.9 million for the next RCP. Powercor proposes the opex step change to meet its compliance obligations commencing in the current period, and which is above that included in the base year opex of FY25.
8. We have assessed the proposed opex step change based on the same methodology applied to each of the Powercor, CitiPower and United Energy networks.

Assessment and findings

Assessment of governance, management and forecasting methods

9. In considering Powercor's expenditure governance, management and forecasting methodologies, we focus primarily on matters which we consider impact the forecast expenditure requirements that we have been asked to review, as detailed in the subsequent sections of this report.
10. We found that Victorian DNSPs' regulatory proposals, including Powercor, reflect changes impacting the industry; however, we found that the way in which each DNSP proposes to respond to these changes differs and which was a feature of our review.
11. In our review of the governance, management and forecasting methods that Powercor applied in determining its forecast expenditure, we found examples of the following issues:

- Powercor's initial submission lacked quality information
- Powercor's reliance placed on economic modelling outcomes was overstated and the conclusions that it drew from it were not always valid, and
- Cost estimates that were higher than an efficient level.

12. We saw evidence of many of these issues in the projects and programs that we were asked to review and have considered the implications of these findings in our determination of an alternate estimate of the forecast expenditure requirements. We understand that in determining an overall expenditure allowance for capex and opex, the AER will have regard to these matters more generally.

Assessment of proposed repex

Distribution lines-related programs are largely based on historical trend of condition, with proposed increases that are not sufficiently justified

13. The forecasts for Powercor's distribution lines related expenditure are largely based on the historical trends of defects, and not economic analysis as required under the AER guidance note. For poles, Powercor referred to a decay model as its counterfactual to demonstrate that the proposed volumes as indicated by the ESV direction notice for the current RCP are reasonable. For crossarms, the volumes are based on extrapolating the current find-rate of defects, and the bulk of the conductor forecast is based on a historical trend. The exception to the remainder of the distribution lines expenditure is for the proposed risk-based conductor expenditure, where Powercor has relied on economic models.

14. We did not find evidence of sufficient analysis of alternate replacement volumes or options to demonstrate that the forecast is prudent and efficient. We consider this is critical considering the uplift in expenditure that Powercor has proposed. Instead, we found that the programs are overstated. We arrived at this conclusion after considering the data that Powercor provided, including the impact of related programs.

15. For its risk-based programs we found issues with the modelling methods and assumptions that had been relied upon by Powercor, and which once adjusted for more reasonable assumptions result in reduction to the cost and/or benefits such that the project timing is not economic to implement in the next RCP.

Unit rates applied to distribution lines-related programs are higher than an efficient level

16. The increase in Powercor's proposed repex program is driven by increases in replacement volumes and by increases in assumed unit rates. Powercor refers to recent price uplifts, as well as ongoing inflationary pressure to explain the increases in unit rates. Our analysis of unit rates for the distribution lines related programs show that Powercor is, in general, the highest cost DNSP across the NEM. This is reflected in the historical costs and continues to be the case in its forecast unit costs.

17. We found examples where the unit cost for Powercor was similar to that of CitiPower, and others where Powercor was higher. Powercor did not explain the basis of its costs, nor explain why an urban/rural DNSP would have unit costs similar to or higher than a CBD/Urban DNSP. We also found examples of unit costs that Powercor in its response to our questions is not able to explain.

18. We consider that the unit rates that Powercor has assumed are, for the asset classes we reviewed, not reflective of an efficient cost.

Substation-related repex programs include a higher level of expenditure than is indicated by its models after adjustment for more reasonable methods and inputs

19. In general, Powercor provided models for its substation-related expenditure, however some had limited functionality. We asked for and were provided with additional models that assisted our ability to review the proposed projects and programs. Some of the models

continued to include hard-coded values, which limited our ability to understand the methods that Powercor has applied to derive these values in some cases.

20. Powercor's recent development of its risk quantification framework meant that it has placed greater emphasis on its economic models, and we reviewed this in some detail. We found issues with the modelling methods and input assumptions that Powercor has applied, for both its cost estimates and its benefit calculations. Once adjusted for more reasonable methods and inputs, we consider a portion of the proposed projects would be deferred to beyond the next RCP.

Cost estimates for discrete projects were similarly higher than an efficient level

21. We found evidence that some of Powercor's costs for its substation projects were higher than observed in other DNSPs and appeared to reflect materially higher rates than it had advised the AER for the current period, without sufficient justification.

Assessment of proposed augex

Demand-and non-demand driven projects/programs

22. In each of the projects/programs we were satisfied that there was a compelling need for Powercor to consider means of mitigating risk and or improving service levels.

23. Powercor presented a good range of options and in each case selected the option with the highest NPV. We consider that in each case the selected strategy was appropriate in responding to the identified need.

24. However, with the demand-driven projects, we have issues with the economic analyses, leading us to conclude that the proposed capex is overstated. Reasons vary between projects, but include:

- Input assumptions are not credible based on the information provided
- Inappropriate application of VCR, and
- Estimated cost is unreasonably high.

25. In the case of the non-demand-driven projects, our concern is with the extent of potential variance in cost and benefit assumptions. Powercor has recognised this issue and has, appropriately, recommended limited scope/pilot projects to enable testing of assumptions. We support this but consider in both cases that smaller pilot programs are warranted with sufficient time given in the next RCP to test results before contemplating broader investments.

The proposed CER – Customer-driven electrification project is not sufficiently justified

26. We are satisfied that forecast demand and the expected trend to electrification will tend to increase instances of voltage non-compliance over time. We also accept that Powercor will need to incur expenditure to ensure functional compliance in a dynamic system and we are directionally supportive of selective proactive augmentation to address under-voltages, offsetting reactive responses to complaints, where the latter is less cost effective.

27. However, we have significant concerns with Powercor's forecasting methodology that we consider has led to an overstatement of the expenditure that Powercor will require in the next RCP. We found issues with the modelling, and the use of input assumptions. These include the use of VCR to value energy served to customers at less than 216 volts which we do not consider to be a valid application of the VCR. The jump from two voltage complaints in FY24 to Powercor's forecast of 220 voltage complaints in FY27, is also not credible from the information provided and affects the assumed quantum of augmentation required.

Powercor has not sufficiently justified the scope of its proposed Bushfire Mitigation projects and programs

28. In our view Powercor has failed to adequately justify the level of expenditure for the REFCL reliability project and for the AFAP-driven projects, primarily because we consider the benefits claimed by Powercor to be overstated.

29. For the REFCL compliance project, Powercor has used a reasonable forecasting method for the majority of its proposed capex. However, for the Bendigo substation, we consider there are approaches that can reasonably defer augmentation to beyond the next RCP.

Assessment of proposed vegetation management opex step change

There has been no change to regulation obligations that apply to Powercor

30. We firstly considered whether the proposed step change met the requirement of the opex step change criteria for a change in regulatory obligations. Based on CPU's submission, there has been no change to its regulatory obligations. The electric line clearance requirements have not changed since the commencement of the current RCP, and CPU has not advised of any change to its electric line clearance obligations that are likely to positively or negatively impact the expenditure requirements in the next RCP.

31. However, LiDAR data used as part of improvements to vegetation management has identified a volume of spans to be treated that exceeds the current program to meet its compliance obligations.

Basis of forecast step change is likely to overstate the required expenditure

32. We reviewed the assumptions proposed by Powercor, and its modelling methods and found that:

- The ultimate size of the vegetation management program will likely be lower than Powercor has assumed after taking into account additional factors,
- Powercor has not sufficiently demonstrated that the proposed increases to its vegetation management costs are prudent, or that the unit cost assumptions are efficient. We base this on our own analysis of the historical and forecast costs incurred by the CPU businesses,
- Powercor has not correctly taken account of the BST forecasting method for opex in the calculation of the required step change, and
- Our benchmarking of Powercor's historical costs indicates that it is higher than other NEM DNSPs. CPU has not provided rationale for why it is incurring costs that are materially higher, why these higher rates are reflective of an efficient level or what measures are in place, or being put into place, to reduce the costs to an efficient level.

Adjustment for a range of uncertainty and efficiency factors is likely to reduce the need for an opex step change

33. We consider that whilst the CPU businesses are building capacity and capability to meet their compliance requirements, the opportunities for competitive forces to apply downward pressure on prices from the market are lessened. However, over time, we consider there should be opportunities for pricing to moderate, and then to improve. This is also supported by our own benchmarking analysis which indicates that Powercor is currently incurring costs that are materially higher than other NEM DNSPs, including other Victorian DNSPs, for reasons that Powercor is unable to explain.

34. We further consider that the program, once stabilised, offers Powercor an ability to reduce not only the costs but potentially the volume of spans to be treated through greater targeting of maintenance cutting practices. Powercor has not taken account of these potential efficiency factors.

35. Our analysis indicates that the need for additional opex is very sensitive to relatively small changes in the factors we identified, meaning that relatively small reductions to volume or costs (towards the benchmark cost) or increases in efficiency removed the need for the proposed step change.

Implications for expenditure allowances

Our approach

36. We were asked to consider an alternate expenditure forecast for the projects and programs that we reviewed based on the issues that we identified. Where a project was reasonably justified in accordance with the NER, we included this in our alternate expenditure forecast. In other cases, our proposed alternative expenditure forecast for the categories of expenditure we were asked to review involves one or more adjustments, to the extent that the adjustment factors formed the basis of Powercor's forecast and which we consider to be not justified or overstated.

37. Since the scope of our review did not in all cases comprise all projects within a 'category' of proposed expenditure, our alternative forecasts necessarily apply only to the aggregate of the projects within the scope of our review.

38. To the extent we found evidence of systemic issues in its application of governance, management and forecasting issues to the projects and programs that we reviewed, we have taken account of these in our proposed alternate forecast.

Alternative forecasts for reviewed projects

Powercor's proposed forecast for the repex projects that we reviewed is higher than a prudent and efficient level

39. We consider that a reasonable alternative forecast for the repex categories that we reviewed, would be between 25% and 35% less than Powercor has proposed.

Powercor's proposed forecast for the augex projects that we reviewed is higher than a prudent and efficient level

40. We consider that a reasonable alternative forecast for the projects within the augex categories that we reviewed, and which includes its proposed CER-related augex, would be between 40% and 50% less than Powercor has proposed.

Powercor's proposed vegetation management opex step change forecast is not a reasonable forecast of its requirements

41. We consider that Powercor will be able to achieve compliance in the next RCP with a level of expenditure that does not require an opex step change.

1 INTRODUCTION

The AER has asked us to review and provide advice on aspects of Powercor's proposed expenditures over the 2026-31 Regulatory Control Period (next RCP) relating to replacement expenditures (repex), augmentation expenditures (augex) and operating expenditures related to vegetation management. Our review is based on information that Powercor provided and on aspects of the NER relevant to assessment of expenditure allowances.

1.1 Purpose of this report

42. The purpose of this report is to provide the AER with a technical review of aspects of the expenditure that Powercor has proposed in its regulatory proposal (RP) for next RCP'

43. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed expenditures allowance as an input to its Draft Determination on Powercor's revenue requirements for the next RCP.

1.2 Scope of requested work

44. Our scope of work, covered by this report, is as defined by the AER. Relevant aspects of this are as summarised in Figure 1.1.

Figure 1.1: Scope of work covered by this report

Scope of work covered by this report

The scope of this review, as requested by the AER, covers the following.

- Capex (ex ante)
  - Repex (selected projects)
  - Augex (selected projects, including CER and electrification-related augex)
- Opex
  - Vegetation management step change

45. We cover our assessment of other aspect of Powercor's expenditures, including ICT and cybersecurity, in separate reports. In our ICT report, we also provide a wider assessment of CPU's proposed CER and electrification programs.

1.3 Our review approach

1.3.1 Approach overview

46. In conducting this review, we first reviewed the RP documents that Powercor has submitted to the AER. This includes a range of appendices and attachments to Powercor's RP and certain Excel models which are relevant to our scope.

47. We next collated several information requests. The AER combined these with information request topics from its own review and sent these to Powercor.

48. In conjunction with AER staff, our review team met with Powercor at its offices on 2 – 4 April 2025. Powercor presented to our team on the scoped topics, and we had the opportunity to engage with Powercor to consolidate our understanding of its proposal.

49. Powercor provided the AER with responses to information requests and, where they added relevant information, these responses are referenced within this review.

50. We have subjected the findings presented in this report to our peer review and Quality Assurance processes and we presented summaries of our findings to the AER prior to finalising this report.

1.3.2 Conformance with NER requirements

51. In undertaking our review, we have been cognisant of the relevant aspects of the NER under which the AER is required to make its determination and relevant AER Guidelines.

Capex Objectives and Criteria

52. The most relevant aspects of the NER in this regard are the 'capital expenditure criteria' and the 'capital expenditure objectives.' Specifically, the AER must accept the Network Service Provider's (NSP) capex proposal if it is satisfied that the capex proposal reasonably reflects the capital expenditure criteria, and these in turn reference the capital expenditure objectives.

53. The NER's capital expenditure criteria and capital expenditure objectives are reproduced in Figure 1.2 and Figure 1.3.

Figure 1.2: NER capital expenditure criteria

NER capital expenditure criteria

The *AER* must:

*(1) subject to subparagraph (c)(2), accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (**the capital expenditure criteria**):*

(i) the efficient costs of achieving the capital expenditure objectives;

(ii) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(iii) a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the capital expenditure objectives

Source: NER 6.5.7(c) Forecast capital expenditure, v230

Figure 1.3: NER capital expenditure objectives

NER capital expenditure objectives

(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to do each of the following ***(the capital expenditure objectives****):*

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services;

(4) maintain the safety of the distribution system through the supply of standard control services; and

(5) contribute to achieving emissions reduction targets through the supply of standard control services.

Source: NER 6.5.7(a) Forecast capital expenditure, v230

Opex Objectives and Criteria

54. The most relevant aspects of the NER in this regard are the 'operating expenditure criteria' and the 'operating expenditure objectives.' The NER's opex criteria and opex objectives are reproduced below.

Figure 1.4: NER operating expenditure criteria

NER operating expenditure criteria

*(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (****the operating expenditure criteria****):*

(1) the efficient costs of achieving the operating expenditure objectives;

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the operating expenditure objectives.

Source: NER 6.5.6(c) Forecast operating expenditure, v230

Figure 1.5: NER operating expenditure objectives

NER operating expenditure objectives

*(a) A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to do each of the following (**the operating expenditure objectives**):*

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services; and

(5) contribute to achieving emissions reduction targets through the supply of standard control services.

Source: NER 6.5.6(a) Forecast operating expenditure, v230

How we have interpreted the capex and opex criteria and objectives in our assessment

55. We have taken particular note of the following aspects of the capex and opex criteria and objectives:

- Drawing on the wording of the first and second criteria, our findings refer to efficient and prudent expenditure. We interpret this as encompassing the extent to which the need for a project or program or opex item has been prudently established and the extent to which the proposed solution can be considered to be an appropriately justified and an efficient means for meeting that need
- The criteria require that the forecast '*reasonably reflects*' the expenditure criteria and in the third criterion, we note the wording of a '*realistic expectation*' (emphasis added). In our review we have sought to allow for a margin as to what is considered reasonable and realistic, and we have formulated negative findings where we consider that a particular aspect is outside of those bounds
- We note the wording '*meet or manage*' in the first objective (emphasis added), encompassing the need for the NSP to show that it has properly considered demand management and non-network options
- We tend towards a strict interpretation of compliance (under the second objective), with the onus on the NSP to evidence specific compliance requirements rather than to infer them; and
- We note the word '*maintain*' in objectives 3 and 4 and, accordingly, we have sought evidence that the NSP has demonstrated that it has properly assessed the proposed expenditure as being required to reasonably maintain, as opposed to enhancing or diminishing, the aspects referred to in those objectives.

56. The DNSPs subject to our review have applied a Base Step Trend approach in forecasting their aggregate opex requirements. Since our review scope encompasses only proposed expenditure for certain purposes, we have sought to identify where the DNSP has proposed an opex step change that is relevant to a component that we have been asked to review. Where the DNSP has not proposed a relevant opex step change, then we assume that any opex referred to in documentation that the DNSP has provided is effectively absorbed and need not be considered in our assessment.

1.3.3 Technical review

57. Our assessments comprise a technical review. While we are aware of stakeholder inputs on aspects of what Powercor has proposed, our technical assessment framework is based on engineering considerations and economics.

58. We have sought to assess Powercor's expenditure proposal based on Powercor's analysis and Powercor's own assessment of technical requirements and economics and the analysis that it has provided to support its proposal. Our findings are therefore based on this supporting information and, to the extent that Powercor may subsequently provide additional information or a varied proposal, our assessment may differ from the findings presented in the current report.

59. We have been provided with a range of reports, internal documents, responses to information requests and modelling in support of what Powercor has proposed and our assessment takes account of this range of information provided. To the extent that we found discrepancies in this information, our default position is to revert to Powercor's RP documents as provided on its submission date, as the 'source of record' in respect of what we have assessed.

1.4 This report

1.4.1 Report structure

60. In section 2 we provide our observations on Powercor's application of its governance framework and forecasting methodology to the expenditure category, along with the derived forecasting inputs.

61. In the assessment sections 3 to 5 inclusive, we have presented our assessments for projects within our scope, respectively for:

- Proposed repex categories/projects
- Proposed augex projects
- Proposed vegetation management opex step change.

62. In each of these assessment sections we include:

- an overview of the proposed expenditure and a summary of Powercor's justification for that expenditure
- our assessment of individual expenditure categories and/or projects, and
- our findings for each expenditure category and the implications of these findings for the expenditure allowances determined by the AER in its Draft Determination.

63. We also provide the following appendices:

- Appendix A - CPU economic modelling issues specific to CPU's proposed electrification program
- Appendix B - Economic assessment methodology issues, and
- Appendix C - Powercor historical performance.

64. We have taken as read the considerable volume of material and analysis that Powercor provided, and we have not sought to replicate this in our report except where we consider it to be directly relevant to our findings.

1.4.2 Information sources

65. We have examined relevant documents that Powercor has published and/or provided to the AER in support of the areas of focus and projects that the AER has designated for review. This included further information at onsite meetings and further documents in response to our information requests. These documents are referenced directly where they are relevant to our findings.

66. Except where specifically noted, this report was prepared based on information provided by AER staff prior to 1 June 2025 and any information provided subsequent to this time may not have been taken into account.

67. Unless otherwise stated, documents that we reference in this report are Powercor documents comprising its RP and including the various appendices and annexures to that proposal.

68. We also reference responses to information requests, using the format IRXX QYY being the reference numbering applied by the AER to IRs and to specific Question numbers within that IR. Noting the wider scope of the AER's determination, the AER has also provided us with IR documents that it considered to be relevant to our review.

1.4.3 Presentation of expenditure amounts

69. Expenditure is presented in this report in $2025-26 real terms and includes real cost escalation, unless stated otherwise. In some cases, we have converted to this basis from information provided by the business in other terms.

70. While we have endeavoured to reconcile expenditure amounts presented in this report to source information, in some cases there may be discrepancies in source information provided to us and minor differences due to rounding. Any such discrepancies do not affect our findings.

2 REVIEW OF GOVERNANCE, MANAGEMENT AND FORECASTING METHODS

The focus of our assessment has been on the material changes to the governance and forecasting methods applied by Powercor in its determination of its expenditure requirements for the next RCP. Specifically, whether the changes made by Powercor are likely to have led to a higher or lower estimate of expenditure than would otherwise have been the case, for those items of expenditure we have been asked to review.

The extent to which the expenditure forecast requirements meet NER requirements is, in part, dependent on how its investment governance and management framework has been applied.

2.1 Introduction

71. In this section we provide some context from the historical performance of Powercor and make observations relating to the service performance and expenditure performance leading into the next RCP.

72. We then consider the materials provided by Powercor and how they align with the requirements as defined in the AER guidance materials. The extent to which we have a complete set of information to undertake our assessment is critical to a determination that the proposed expenditure is prudent and efficient.

73. We next consider whether Powercor has made any material changes to its governance arrangements during the current RCP, that have impacted its investment decision making and impacted either the nature or completeness of the information available to us. Following this we consider the governance, management and forecasting methods applied to the development of expenditure requirements for the next RCP, and whether these are likely to have led to a prudent and efficient forecast of requirements.

74. Our assessment of the governance, management and forecasting methods is not intended to be a comprehensive review, nor does it purport to represent all methods that Powercor has applied for the next RCP. Rather we focus primarily on matters which we consider impact the forecast expenditure requirements, detailed in the subsequent sections of this report.

2.2 Background and context

2.2.1 Summary

75. Common to our review of Victorian DNSPs, Powercor's expenditure incurred during the current RCP has differed from the allowance. Common drivers include the delay to the onset of demand compared with the forecast prepared at the time of the previous determination and also uplifts in the price of goods and services incurred during the current period. We comment on key reasons for the changes in expenditure profile and composition of the projects and programs that make up the expenditure profile in our assessment of the corresponding expenditure.

76. For the next RCP, Victorian DNSPs like other NSPs across the NEM are responding to macro-economic changes including transformation of the electricity system including

electrification of gas[1] and transport.[2] In Victoria there are specific policy settings that impact demand and are embedded into the demand forecasts that each of the NSPs have relied upon. By agreement with the AER, a separate review of the demand forecast is being undertaken by the AER. For this review, we rely on the demand forecast and assumptions prepared by and submitted with the DNSP regulatory proposal.

77. In Appendix C, we provide a summary of the historical trends in service delivery and expenditure as context for our review. The trends are based on published materials from the AER and ESV, which apply to each DNSP that we have been asked to review.

78. We have not been asked to consider the broader performance for each DNSP or take account of all factors that may be contributing to the service of expenditure performance indicated by these trends. We also recognise that the measures applied by the AER and ESV are not comprehensive or exhaustive, but act as context for our assessment of specific projects and programs.

2.2.2 General observations relating to service performance

79. We observe that Powercor's network performance has generally been improving, along with asset performance despite the impact of several major weather events across Victoria. For Powercor's network:

- Average reliability performance is generally improving, which suggest that Powercor's asset management process has maintained service levels,
- According to the safety regulator ESV, the number of all asset failure incidents and contact incidents are lower than the long-term average,
- Rate of line clearance non-compliance has recently improved, however the regulator is concerned by a worsening long-term trend,
- Network utilisation has been flat over the last 10 years, and remains higher than the DNSP average, and
- Voltage compliance has been well within the functional compliance limit set under the EDCoP.[3]

2.2.3 General observations relating to expenditure performance

80. Powercor's actual expenditure has historically tracked lower than the forecast expenditure. Issues such as increasing labour and material costs, and deferral of works that occurred during the current RCP also have implications for the forecast in the next RCP, and we consider the implications in the projects and programs that we have reviewed. For Powercor's network:

- Capex delivery performance is subject to a range of factors, with actual capex tracking more closely to forecast capex recently,
- Powercor expects the net capex to exceed the capex allowance for the current RCP, and
- Over the last 5 years, actual opex is slightly higher than forecast opex resulting in an overspend against the opex allowance.

1 In 2022, the Victorian Government published its Gas Substitution Roadmap that outlined the pathway to transition away from residential gas in Victoria, with the first key step being the ban on new residential gas connections from January 2024

2 The Victorian Government is committed to decarbonizing its road transport sector with the goal of achieving net-zero emissions by 2045

3 Victorian Electricity Distribution Code of Practice

2.3 Presentation of submission information

81. In this section we consider the degree to which Powercor has adhered to the expenditure assessment guidelines.

2.3.1 AER guidance on expectations

82. Drawing on the relevant parts of the Rules as detailed in section 1, and the guidance materials published by the AER, the AER has outlined four expectations of a network business' capital expenditure proposals in the Better Resets Handbook. These are:

- Top-down testing of the total capital expenditure forecast and at the category level,
- Evidence of prudent and efficient decision-making on key projects and programs,
- Evidence of alignment with asset and risk management standards, and
- Genuine consumer engagement on capital expenditure proposals.

83. In our technical review, we have regard to the first three of these expectations as they apply to the scope of our review and which target categories or sub-categories of capex. More specifically, expectation 2 includes demonstration of prudency and efficiency in its decision-making including by:

- Identification and evidence of the network need,
- Quantitative cost benefit analysis, demonstrating that customers are likely to receive a net economic benefit from the proposed scope and timing of the work, and
- Where relevant, evidence of fully accounted for capex-opex or other trade-offs.

84. These expectations are also accompanied by a range of guidelines to assist DNSPs, including the expenditure forecast assessment guidelines. With regard to the capital expenditure assessment approach, the expenditure forecast assessment guidelines emphasise the need for economic justification of the proposed expenditure:

> *'Where businesses do not provide sufficient economic justification for their proposed expenditure, we will determine what we consider to be the efficient and prudent level of forecast capex. In assessing forecasts and determining what we consider to be efficient and prudent forecasts we may use a variety of analysis techniques to reach our views.'*[4]

85. When considered together, and also drawing from relevant parts of other AER guidelines,[5] we interpret this to mean that the AER places material weight on demonstration of economic analysis to support the proposed expenditure. We have therefore sought evidence of the economic justification in our assessment.

2.3.2 AER guidance on information that is expected to support the regulatory proposal

86. This is further supported by the summary of information that is expected to accompany the regulatory proposal, whereby the guidelines state:

> *'We will require a range of data to support our assessment of total forecast capex. We expect DNSPs to submit regulatory proposals that include:*
>
> – *economic analysis demonstrating the forecast expenditure is prudent and efficient. This should include documentation and underlying data sufficient to support the economic analysis*
>
> – *reasons for costs for given expenditure categories and types of work differing from their historical expenditure*

4 AER Expenditure forecast assessment guidelines – Electricity distribution – October 2024

5 Including the asset replacement guidelines

– *explanations of trade-offs between capex and opex expenditure that show that the choices chosen (for example to undertake a capex IT program to reduce opex) are prudent and efficient. Firms will also need to demonstrate these choices are fully accounted for in capex and opex forecasts.'*[6]

2.3.3 Summary of information provided for its capex forecast

87. In terms of the scope of our review, we summarise the information that has been provided to support the forecast expenditure in Table 2.1 under the headings of evidence of need, and quantitative analysis.

Table 2.1: Summary of information provided

Expenditure category	Sub-category	Evidence of need	Quantitative analysis
Replacement capex	Volumetric	Summary business case (titled asset class overview) for each asset class summarising the need.	Largely based on the historical trends in defects model, and not economic analysis.
Replacement capex	Discrete projects	Summary business case (titled asset class overview) for each asset class summarising the need.	Economic analysis model for each project
Augmentation capex	Discrete projects	Summary business case for each project summarising the need	Economic analysis model for each project
Opex step change	Vegetation management	Summary business case	Cost model based on historical spend, and not economic analysis.

88. The information provided initially by Powercor was not conducive to a review in accordance with the capex assessment guidelines, as the models and supporting information were incomplete, or the workings and assumptions relied upon by Powercor were not transparent. We made numerous requests for the models and supporting information that Powercor had relied upon in preparing its expenditure forecast and we were subsequently provided with this information. We have taken account of this information in our review.

89. In some instances, we did not find that justification documentation that was provided to us was robust, and that areas of expenditure were largely unexplained, or not sufficiently supported by evidence of observed performance. We are aware that similar matters were raised during the previous determination process, and which indicates that these matters have not been adequately addressed.

90. Where Powercor has proposed to change the expenditure included in the submission from its initial proposal, we have made note of this in our assessment.

2.4 Assessment of governance arrangements and forecasting methods for the next RCP

91. Consistent with the overarching purpose, we focus primarily on matters which we consider impact the forecast expenditure requirements, detailed in the subsequent sections of this report.

[6] AER Expenditure forecast assessment guidelines – Electricity distribution – October 2024

2.4.1 Summary of material changes to the governance arrangements from the current RCP

92. In the context of the investment governance framework, forecasting methods and risk management approaches ('governance methods') we asked CPU to detail any changes to the governance methods applied by each of the DNSPs and in common during the current period, and that impact the development of the expenditure forecast for the next period. In its response, CPU referred to strengthening the role of stakeholder engagement:

> *'Strengthening the role of stakeholder engagement, including enhancing the governance and independence the Customer Advisory Panel, represents a material changes (sic) in the governance and external oversight of the development of our expenditure forecasts for the 2026–31 regulatory period.'*[7]

93. We consider that an effective stakeholder engagement process is critical to ensuring that the expenditure proposed by a DNSP meets the criteria and objectives of the NER. However, we have not been asked to assess the stakeholder engagement processes employed by CPU or the extent to which the proposed expenditure responds to feedback provided by stakeholders to CPU. Where we discuss stakeholder feedback, it is included to assist an understanding of what CPU has proposed.

94. CPU also refer to changes including the following updates:

   – *'our customer values work was refreshed to challenge/validate any changes in customer priorities*

   – *updated our value framework to reflect with AER values of VCR, and added the new AER values of VER and VNR for quantifying emissions reduction and resilience benefits*

   – *updated our value framework to reflect the Value of Statistical Life (VSL) data regularly published by the Department of the Prime Minister and Cabinet*

   – *updated and refreshed our ICT risk monetisation framework, as set out in PAL ATT 7.*02,' [8] and which is discussed in our companion report to the AER.

95. In addition to the updating of key input assumptions to its planning processes, we understand from our discussions with CPU, that its risk assessment framework was also updated to better align with a 'site-based' risk assessment as was previously deployed by United Energy. We discuss this further in our review of the relevant expenditure for the next RCP.

96. Notwithstanding the strengthening of stakeholder engagement in its governance arrangements, we concluded that Powercor's investment planning processes within our scope of review had not materially changed from the time of the previous determination by the AER.

2.4.2 Top-down review and portfolio optimisation

CPU has applied a top-down review of its forecast expenditure

97. We consider that application of a top-down review and portfolio optimisation are two critical methods in determining a prudent and efficient expenditure forecast.

98. The respective CPU regulatory proposals states that:

> *'The development of our expenditure forecasts also occurred through multiple expenditure iterations that progressively refined our investment portfolio. This process*

7 Powercor response to IR004 Question 2

8 Powercor response to IR004 Question 2

continually challenged and limited expenditure to those investments that deliver clear value for our customers. [9]

99. We requested that CPU describe the process and steps taken to refine the investment portfolio, and which we summarise in Table 2.2.

Table 2.2: Summary of CPU steps in regulatory proposal development

Step	Elaboration
Strategic framework	A key deliverable in the early works program was the development of a strategic framework for the 2026–31 regulatory proposals. This framework sought to identify the key strategic challenges that CPU need to 'get right' in its proposals.
Understanding service level expectations	In addition to the strategic framework, the development of CPU regulatory proposals was based on and supported by considerable effort to understand the service level expectations of its customers. This was particularly relevant in the context of relatively new issues, including electrification.
Expenditure iterations	The development of CPU expenditure forecasts occurred through multiple expenditure iterations that progressively refined our investment portfolio. The timing of these iterations was structured to support key milestones.

Source: Powercor – IR004 – general capex – 20250320 question 3

The portfolio review process has included three expenditure iterations

100. Powercor describes three expenditure iterations:[10]

- Preliminary iteration, December 2023
- Draft proposal, April 2024, and
- Regulatory proposal, December 2024.

101. In a further request, we asked for details of the three iterations and evidence of the investments removed from the forecast. The iterations are reproduced in Table 2.3.

Table 2.3: Summary of Powercor expenditure iterations

Category	Pre-draft proposal	Draft proposal	Regulatory proposal
Augmentation	531	527	546
Net connections	551	450	583
Replacement	1,418	1,288	1,416
ICT	236	305	301
Non-network assets (other)	322	376	267
Total	**3,058**	**2,946**	**3,112**

Source: Powercor response to IR012 question 1

102. We had expected to see demonstration of intermediate iterations, and evidence of the decision-making process being applied by the governance layers that demonstrate the movement up or down of the expenditure forecast in response to changing inputs or output scenarios.

103. CPU describes the process of challenge and review that it has applied as:

'The design of our iteration process meant that top-down assessments were considered throughout the development of our forecasts. All else equal, we consider challenging and refining key input assumptions is preferable to higher-level or arbitrary assessments at

9 Powercor Regulatory proposal 2026-31 – Part B – Explanatory statement, page 9

10 Powercor response to IR004 Question 3

> *total portfolio or category level (where it is more difficult to robustly understand the impacts of subsequent adjustments)'*[11]

104. We consider that effective top-down reviews go beyond this description to test for changes in service levels, risk and deliverability. Notwithstanding comments by CPU, its response describes the consideration of additional top-down considerations, including:

- Affordability
- Equity
- Deliverability
- Acceptability (to customers, regulators and government), and
- External review and challenge of assumptions (e.g. challenge by the CAP).

105. Often this includes a prioritisation or ranking of investments, and which may include ranking against differing criteria. CPU states that the '*prioritisation of investments included in our regulatory proposal were not assessed based on a consolidated whole-of-business portfolio*.'[12] Rather:

> *'the prioritisation of economic projects was determined through balancing bottom-up inputs and top-down principles (which are broader than just economic value) and repeatedly challenging these outcomes through internal and external governance processes. We consider this better recognise the varying drivers of the different projects (including stakeholder and customer service level expectations), the limited discretion associated with many of our proposed programs and the absence of a known financial constraint (such as an approved regulatory allowance, which may otherwise be used in our portfolio optimisation approach within a regulatory period).'*[13]

106. Whilst our scope of review did not extend to considering whole expenditure categories, for our purposes, we did not see evidence of how CPU had made the trade-offs to determine that the projects and programs it had included were reflective of a prudent and efficient expenditure forecast. Nor did we receive a satisfactory explanation as to why the current lower level of expenditure in the current RCP and the higher level in the next RCP are both considered to reflect prudent requirements, given the proposed step increase in proposed expenditure requirements.

The $560 million of projects removed from its forecast is offset by project additions

107. In its regulatory proposal, Powercor refers to $560 million of investments removed from the forecast expenditure. We asked Powercor to describe the nature of the investments removed from the forecast expenditure, and which we summarise as:[14]

- Refinement to project options (adoption of lower cost options)
- Updated demand forecasts, based on August 2024 and including lower forecasts for both CER and electrification
- Updated asset and cost data, and
- Reliance on the uncertainty framework, such as contingent projects and cost-pass through applications.

108. Powercor also provided a worksheet[15] that explained the basis of the claimed $560 million reduction and which comprised 30 individual projects with the vast majority associated with augex and repex projects. However, Powercor states that due to project additions, the reduction is not visible in the totals.

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11 Powercor response to IR004 Question 3

12 Powercor response to IR012, Question 2

13 Powercor response to IR012 Question 2 (and IR004)

14 Powercor response to IR004 question 3

15 Powercor - IR012 - Q1 - iteration changes

2.4.3 Activity forecasting methods

Repex activity forecasting

109. CPU has used a combination of forecasting methods for its repex requirements, including fault and inspection/defect-based replacement using historical trend, risk-based replacement making use of its quantified risk cost modelling and economic analysis.

Augex activity forecasting

110. Augex is typically forecast using bottom-up methods, as Powercor has done, and responds to specific drivers which may vary from one regulatory period to another.

111. CPU undertakes Network Planning in accordance with its Network Planning Framework, which sets out the process CPU follows to identify the need for physical and operational changes in the network over time. It is said by CPU to contribute to the network management objectives[16] described in its Network Planning Framework. The documents and content are consistent with what we would expect to see.

112. Powercor (with CitiPower, United Energy and consultants) has recently developed a Customer Electrification Forecasting Methodology and a SAPS methodology (a cost-benefit analysis) which it applied to derive forecast expenditure to respond to customer-driven electrification and to identify economically viable Stand Alone Power System (SAPS) opportunities within Powercor's Single Wire Earth Return (SWER) network, respectively. We consider the application of these methodologies in the relevant projects within our scope of review.

Opex step change forecasting

113. CPU has provided a bottom-up build of its vegetation management opex requirements, drawing from its historical expenditure as recorded in the RIN, and which it has used to determine the proposed opex step change with reference to a base year of FY25 to meet its compliance obligations.

2.4.4 Economic assessment

High level of reliance placed on model outcomes

114. CPU has placed significant emphasis on economic modelling of the proposed projects and programs as justification for proposed projects. In response to our questions surrounding management of uncertainty and preservation of option value, CPU stated that:

> *'All projects and programs included in our regulatory proposal are economically justified, and/or based on defect trends consistent with our revealed asset management practices. As noted above, our reference to least regrets indicates that while projects are economically justified, even if our modelling is wrong, it is likely these projects would otherwise be undertaken in the near future, such that investing now is a least or no-regrets action.'*[17]

115. Proposals that are economically justified and/or can be demonstrated as arising from a regulatory obligation are central precepts to the assessment of expenditure proposals under the NER. We have reviewed the basis of the proposals presented by CPU, including the economic models that CPU has relied upon.

We found instances where there was a lack of alignment of assessment periods

116. Risk cost assessment and economic modelling are crucial for determining the optimal timing of electricity infrastructure investments. Net Present Value (NPV) analysis serves as a

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16 Which relate to safety, reliability, asset management, compliance obligations, continuous improvement, and customers' input, interests, and needs.

17 Powercor response to IR004 Question 7

foundational tool in this process, enabling stakeholders to evaluate the financial viability and timing of investments under uncertainty.

117. Ensuring that the assessment periods for costs and benefits are the same in Net Present Value (NPV) analysis is crucial for obtaining an accurate and meaningful evaluation of an investment's economic viability. When costs and benefits are assessed over different timeframes, the comparison becomes inconsistent, potentially leading to misleading conclusions. For instance, if costs are projected over a 10-year period while benefits are considered over 15 years, the NPV calculation may understate the project's true value by not accounting for the full span of benefits. This misalignment can result in the rejection of potentially viable investments or the acceptance of less favourable ones. Therefore, aligning the assessment periods ensures that both costs and benefits are evaluated on equal terms, providing a more accurate representation of the investment's net value and aiding in sound decision-making.

118. In reviewing its economic modelling, we frequently encountered cases where Powercor had annuitised the capex using a value for the economic life that exceeded the period over which it had conducted its analysis. The PV of the annuitised capex was therefore less than the PV of the capex itself. As we show in Appendix B, this understates the PV of the proposed expenditure and introduces a bias that incorrectly boosts the project NPV, leading to selection of projects on economic grounds that would otherwise have a negative NPV, or bringing forward projects that would otherwise not have a favourable NPV until a later time.

Key modelling input assumptions impact the timing of expenditure requirements

119. In its regulatory proposal, CPU has updated its assumptions for final demand assumptions (e.g. incorporating most recent AEMO reports) and AER values, including VCR, CECV, VNR and VER. We have reviewed the models as presented and tested the sensitivity of the outcome to changes in these input assumptions.

120. We have not commented on demand forecasts. The AER has advised us that it will assess Powercor’s demand forecast separately and will consider our findings accordingly. However, we have, for demand-driven projects, commented on the sensitivity of the proposed projects’ optimal timing to negative variance in the demand forecast. Our ‘low demand case scenario’ is a demand forecast of 100% 50PoE rather than the 70%:30% weighted 50PoE/10PoE forecast used by Powercor for planning purposes.

121. We understand the forecast expenditure is based on the AER’s 2019 VCR study, escalated in accordance with the AER’s specified methodology. In the latest AER VCR study published in 2024, the values were materially changed including a reduction to the business customer VCR.

122. CPU has stated that it is yet to assess the impact of these changes but will consider these through the development of its revised regulatory proposal.

123. We have reviewed the potential impact of changes to the VCR assumption on the proposed expenditure for the next RCP and note that many of the substation VCRs appear to reflect a higher value of VCR than may be derived from AER’s most recent 2024 VCR study. We come to this view by application of the customer weightings that CPU has applied, and when applied to the latest value of VCR by customer, result in reduction to the VCR assumption used in the economic analysis. In our assessment of the proposed expenditure, we consider that the timing for some projects is deferred beyond the end of the next RCP.

124. In addition to the value used for VCR, for several of the augex programs within our scope, we found issues with:

- Other input assumptions, including apparent lack of correlation with RIN data, inappropriate application of the VCR, and
- Inappropriate benefit derivation, including benefit timing and benefit sources.

2.4.5 Cost estimation and cost forecasting

CPU has applied its cost estimation methodology

125. To assist our understanding of how CPU prepared its cost estimate for the projects and programs that it had proposed for the next RCP, we asked for a copy of the cost estimation methodology and/or procedure used to develop project cost estimates in the capex forecast. In its response, CPU provided a summary of its typical cost estimation process.[18]

126. In a follow-up request, we asked for the approved and documented cost estimation methodology and/or cost estimation standard and/or cost estimation procedure used to develop project cost estimates in the capex forecast. We would expect that this is a standard management system document that outlines the requirements, quality and accuracy of cost estimates that applied to projects and programs, treatment of costs and risk allowances to be included in project cost estimates. We were provided with a network project estimation process document that describes its standard cost estimation methodologies that it uses for business-as-usual project delivery purposes. [19]

127. The methodology nominates that final project cost estimates for major projects are based on P50 estimates, and do not include contingency amounts. The methodology is consistent with what we had expected to see. CPU referred to provisions for risk allowances for known risks, however we were not provided with evidence of the process to determining or quantifying the risk allowance, nor did we see evidence of its inclusion in the projects and programs we reviewed.

We did not see sufficient evidence to confirm the accuracy of the cost estimation process including via review processes

128. We also requested evidence of the estimation accuracy of a sample of projects delivered, and where available, any reviews of the estimating accuracy of projects. We were provided with a sample of eight projects totalling approximately $10 million.[20] We do not consider this sample representative of the capex program that allows any meaningful conclusions to be drawn.

129. As a part of our review of the proposed expenditure we considered the reasonableness of the cost estimates relied upon by Powercor for the specific projects and programs that we reviewed.

We found examples of costs that are higher than an efficient level

130. CPU refers to recent price uplifts, as well as ongoing inflationary pressure to explain the increases in unit rates that are included in its proposed expenditure.

131. Whilst we accept the current market conditions are adding cost pressures we sought to understand the reason for real increases in unit rates. We reviewed the unit cost information provided by CPU and found that the unit rates for volumetric programs appeared high. Based on our own benchmarking against RIN data, the unit costs for CitiPower and Powercor were at the high end of DNSPs across the NEM.

132. We also observed that the unit costs applied for cost estimates applied for discrete projects were also high. We review specific examples in the expenditure we have been asked to assess.

133. Powercor did not explain the basis of its costs, including being well above the benchmark cost when we would expect similar cost pressures to be present across other DNSPs, or comparable to CitiPower where we had expected to be a larger differential in costs.

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18 Powercor response to IR004

19 Powercor response to IR012 Question 6

20 Powercor - IR004 - Q11(b) - completed projects - public

2.4.6 Deliverability

The choice of delivery model will impact the delivered cost, and indicates that Powercor/CitiPower are amongst the highest cost providers

134. Powercor (and CitiPower), unlike many other DNSPs, is predominately using an in-house delivery model, supplemented by external delivery partners where required. Powercor and CitiPower consider that this blend of internal and external resourcing provides the flexibility to efficiently deliver its capital program and scale up to changes in the capital program as required.[21]

135. The decision to insource or outsource is strategic to the goals of the network business and should take into account multiple factors. Many DNSPs operate a combination of internal and external resources, with key minimum resourcing retained for strategic reasons. Where competitive markets exist, the costs of outsourced services are often lower.

136. Our benchmarking indicates that Powercor is amongst the highest cost providers.

137. Whilst benchmarking can provide a basis to compare across businesses or jurisdictions, it cannot capture the operating context of the businesses. Sourcing should however seek to provide maximum value to consumers, and one measure is the cost efficiency of the delivered services. Powercor (and CitiPower) should be able to demonstrate why its delivery arrangements reflect highest value to customers.

Powercor and CitiPower has taken some steps to lessen the delivery challenge

138. We asked CPU to confirm the steps that have been undertaken to confirm the deliverability of the proposed increase in capex forecast, particularly the increases in substation-related replacement. In its response, CPU referred to:

- The ability to scale up using a combination of in-house and external providers,
- Distribution line works - moderated forecasts for overhead conductor and network hardening (i.e. we did not propose all works that were identified as economic) and extended the compliance timeframe for our vegetation management program (as well as offering longer-term contracts to provide greater certainty for contractors to build resources), and
- Substation related works - staggered projects across the regulatory period, increased internal workforce and delivery partners capacity to seven companies, and established robust period contracts for key materials.

Powercor and CitiPower have demonstrated an ability to uplift the resource capacity in the past, and will be similarly required for the proposed program

139. CPU outlines broad actions it has taken to build capacity across its internal workforce, flexible external workforce, de-risking the procurement supply chain, and enabling resources in its Governance, forecasting and deliverability overview document, RIN 30. Whilst these are important elements of the deliverability of the portfolio of work and will contribute to CPU's ability to increase is delivery capacity, the description is not an assessment of the deliverability of the forecast expenditure, or changes in the composition of skills or project types.

140. We asked how Powercor and CitiPower had assured themselves of their delivery capability and capacity for the next RCP, at a total level and by resource type. For example, to understand the extent to which the deliverability assessment is informed by a resource and delivery strategy/plan and/or a workforce plan that identifies the current and future demand by work group and/or resource type, and which outlines strategies to address any gap including growing the internal or external workforce, and the steps to achieve this.

[21] PAL RIN 30 - Governance, forecasting and deliverability overview

141. Powercor's response[22] included an assessment of deliverability capacity for its forecast program of works, converted into an FTE equivalent, and based on the type of resource required to deliver different types of works. Similarly for substation related works, Powercor draws from its prior ability to increase its workforce size to complete the uplift in wood pole replacement and also the REFCL program.

142. Given the proposed increases that are proposed by Powercor, and across other DNSPs operating in the same resource market, we had expected a more granular assessment of the skills required, risks and strategies to address those risks and which we consider has likely been undertaken, but we did not see.

143. As a part of our assessment of the proposed expenditure for nominated projects and programs, we consider (if relevant) whether specific delivery risks are present and whether Powercor has taken sufficient account off these in its forecast of expenditure requirements.

2.5 Our findings and implications for our expenditure review

2.5.1 Summary of findings

Presentation of submission information

Lack of compelling information for our review

144. The Better Resets Handbook published by the AER nominates four expectations of a network business' capital expenditure proposal. [23]

- Top-down testing of the total capital expenditure forecast and at the category level,
- Evidence of prudent and efficient decision-making on key projects and programs,
- Evidence of alignment with asset and risk management standards, and
- Genuine consumer engagement on capital expenditure proposals.

145. Except for consumer engagement, which is beyond our scope of review, we find that Powercor's submission had not in all cases fully achieved the remaining three expectations.

Additional information was necessary to complete our review

146. Additional information was provided in response to our requests, and this was largely helpful. However, as explained in our assessment of the proposed expenditure, we found instances where the justification was insufficient to support the expenditure that was proposed. We expand on this further in our assessment of the expenditure proposed for each of the projects and program in the subsequent sections of this report.

147. The supporting information has focussed on the projects and programs that result in expenditure for the next RCP. Whilst supporting the expenditure, it does not in all instances allow interrogation of the broader planning and prioritisation processes, or confirmation that the business has adequately prioritised the highest risk / benefits areas for consumers.

Governance arrangements and forecasting methods

Large proportion of repex is based on inspection-based methods

148. A large proportion of proposed repex is not supported by economic analysis, rather relying on inspection- or condition-based methods. The absence of economic analysis does not assist with determining how the prudent and efficient replacement program has been

[22] Powercor response to IR012 Question 11

[23] AER. Better Reset Handbook - December 2021.

determined. Particularly where economic assessment methods have not been applied, we expected to see, and did not see, sufficient analysis of scenarios including alternate volumes to ascertain changes to the service / risk outcomes, as a means to demonstrate that the volumes included in the expenditure forecast were prudent and reasonable.

High level of reliance placed on model outcomes

149. CPU has placed significant emphasis on economic modelling of the proposed projects and programs. Proposals that are economically justified and/or can be demonstrated as arising from a regulatory obligation are central precepts to the assessment of expenditure proposals under the NER.

We found instances where the modelling methods applied by Powercor (and CitiPower) were flawed

150. Risk cost assessment and economic modelling are crucial for determining the optimal timing of electricity infrastructure investments. Net Present Value (NPV) analysis serves as a foundational tool in this process, enabling stakeholders to evaluate the financial viability and timing of investments under uncertainty. For example, we found that:

- Assessment periods for costs and benefits were not the same in Net Present Value (NPV) analysis and had led to an overstatement of the net economic benefit, and
- Lack of consideration of the economic timing with changes to input assumptions as part of its sensitivity analysis.

The economic analysis relies heavily on the input assumptions that Powercor (and CitiPower) have applied, but which are not always supportable

151. CitiPower and Powercor have continued to develop the asset risk assessment methods that they apply, including adoption of site-based risk assessment, based on work initially undertaken at United Energy which we consider is likely, if implemented with reasonable input assumptions, to improve the risk assessment and prioritisation for substation repex.

152. Across the capex and opex forecast that we reviewed, we found examples of unsupported input assumptions, including for both the estimation of costs and for benefits. For example, in the case of the electrification-driven capex we consider that Powercor’s use of VCR to attribute an economic cost to undervoltage supply considerably overstates this cost, leading to a considerable overstatement of the economic benefits of rectification.

153. We have reviewed the potential impact of changes to the VCR assumption on the proposed expenditure for the next RCP and note that many of the substation VCRs appear to reflect a higher value of VCR than may be derived from AER’s most recent 2024 VCR study. We come to this view by application of the customer weightings that CPU has applied, and when applied to the latest value of VCR by customer, result in reduction to the VCR assumption used in the economic analysis. In our assessment of the proposed expenditure, we consider that the timing for some projects is deferred beyond the end of the next RCP.

154. Some input assumptions adopted by Powercor has led to the development of a higher program of expenditure than is prudent. Adoption of more reasonable inputs results in deferral of some projects beyond the next RCP.

We found examples of cost estimates that are higher than an efficient level

155. Whilst we accept the current market conditions are adding cost pressures we sought to understand the reason for real increases in unit rates. Unit costs are higher than an efficient level when compared with peer Victorian DNSPs and across the NEM. We understand direct comparisons of costs can be problematic as they may not take account of all factors that contribute to the calculation of direct costs. However, when considered over time, we would expect that the costs should correlate, and where cost uplifts are incurred due to external factors beyond the control of the DNSP, they should be similarly incurred across all DNSPs. For Powercor and CitiPower, the unit costs for key programs for distribution lines,

and which make up a significant proportion of the proposed expenditure, are materially higher. CitiPower and Powercor do not provide an explanation for the higher costs.

156. Whilst Powercor (and CitiPower) have a cost estimation methodology in place, we did not see sufficient evidence of review processes.

157. For discrete projects, such as for substation asset replacement, we also found evidence of estimate that are higher than an efficient level. We also saw evidence of high opex costs in relation to vegetation management. We provide examples of these in our assessment of the associated expenditure.

Powercor (and CitiPower) has demonstrated an ability to uplift the resource capacity in the past, and will similarly be required for the proposed program

158. CPU outline broad actions it has taken to build capacity across its internal workforce, flexible external workforce, de-risking the procurement supply chain, and enabling resources. Whilst these are important elements of the deliverability of the portfolio of work and will contribute to CPU’s ability to increase is delivery capacity, the description is not an assessment of the deliverability of the forecast expenditure, or changes in the composition of skills or project types.

159. Given the proposed increases that are proposed by Powercor, and across other DNSPs operating in the same resource market, we had expected a more granular assessment of the skills required, risks and strategies to address those risks. We consider the extent to which Powercor has addressed the delivery risks in relation to the individual projects and programs as a part of our assessment of the associated expenditure.

160. The actual impact of the energy transition, and specifically increased pressure placed on the supply of key electricity sector resources across the state of Victoria remains uncertain. However, we consider that Powercor has taken reasonable steps to develop the required delivery capacity to deliver its proposed works program.

2.5.2 Implications for the expenditure forecast

161. We consider the implications of these findings in our review of the specific projects and programs in the subsequent sections of this report.

3 REVIEW OF PROPOSED REPLACEMENT EXPENDITURE (REPEX)

Powercor has proposed a material uplift in repex activity relative to the repex that it expects to incur in the current period, and which is above that included in the AER's final determination capex allowance. Key changes relate to Powercor's assessment of asset condition, introduction of new programs and increases to zone substation-based replacement activity.

The AER has asked us to assess a subset of Powercor's proposed $1,491.5 million replacement capex for the next RCP, across most of its asset groups and which accounts for approximately 70% of the proposed repex.

Overall, we consider that the proposed repex of $1,038.8 million that we reviewed is not a reasonable forecast of its requirements and is materially overstated. This is for a number of reasons including insufficient justification for proposed increases, unsupported assumptions in its modelling and cost estimates that are higher than an efficient level.

We consider that a reasonable alternative forecast for the repex categories that we reviewed, would be between 25% and 35% less than Powercor has proposed.

3.1 Introduction

162. We reviewed the information provided by Powercor to support its proposed repex forecast, including a sample of projects and programs. We sought to establish the strategic basis for, and the reasonableness of the proposed repex for each of the identified projects and programs that we were asked to review. Forecast expenditure in the next RCP is reflective of a step increase from the historical expenditure that Powercor has incurred and is expected to incur in the remainder of the current RCP.

163. To the extent that Powercor has explained the dependencies across each of the projects and programs included in its forecast repex we have referred to this in our assessment. We present our assessment using the asset groups included in the RIN. In many cases, our scope did not extend to all projects and programs included in the RIN asset group or take account of the apportionment of repex between projects and programs and the RIN asset groups. We refer to the information we have relied upon in our analysis in the sections that follow.

164. We first summarise and compare the proposed expenditure for the next RCP with its historical actual and estimated expenditure in the prior and current RCPs and relate our scope of review to the proposed repex by RIN asset group.

3.2 What Powercor has proposed

3.2.1 Proposed repex

Summary of proposed repex

165. Powercor has proposed $1,491.5 million for repex in the next RCP as shown in Table 3.1. This represents a 47% increase from the $1,017.6 million that Powercor expects to incur in the current RCP.

Table 3.1: Powercor proposed and current actual/estimate repex by RIN asset group- $m, real FY2026

Asset group	Total RCP	2026-27	2027-28	2028-29	2029-30	2030-31	Total next RCP
Poles & Staking	**475.0**	123.6	124.2	125.0	125.9	126.8	**625.5**
Pole top	**206.2**	49.7	52.7	52.4	54.8	56.0	**265.7**
Overhead conductors	**20.7**	24.0	24.2	18.8	18.9	19.0	**104.9**
Underground cables	**23.7**	10.9	11.0	11.2	11.2	11.2	**55.5**
Service lines	**49.1**	9.0	13.0	17.1	11.0	13.9	**64.1**
Transformers	**82.1**	25.9	26.2	26.3	25.6	23.6	**127.6**
Switchgear	**133.0**	34.1	32.2	34.7	35.2	34.9	**171.1**
SCADA, network control & protection system	**6.9**	8.7	8.6	16.0	8.3	8.1	**49.7**
Other	**21.1**	6.0	5.7	5.4	5.4	5.0	**27.4**
Total	**1,017.6**	**291.9**	**297.7**	**306.8**	**296.5**	**298.6**	**1,491.5**

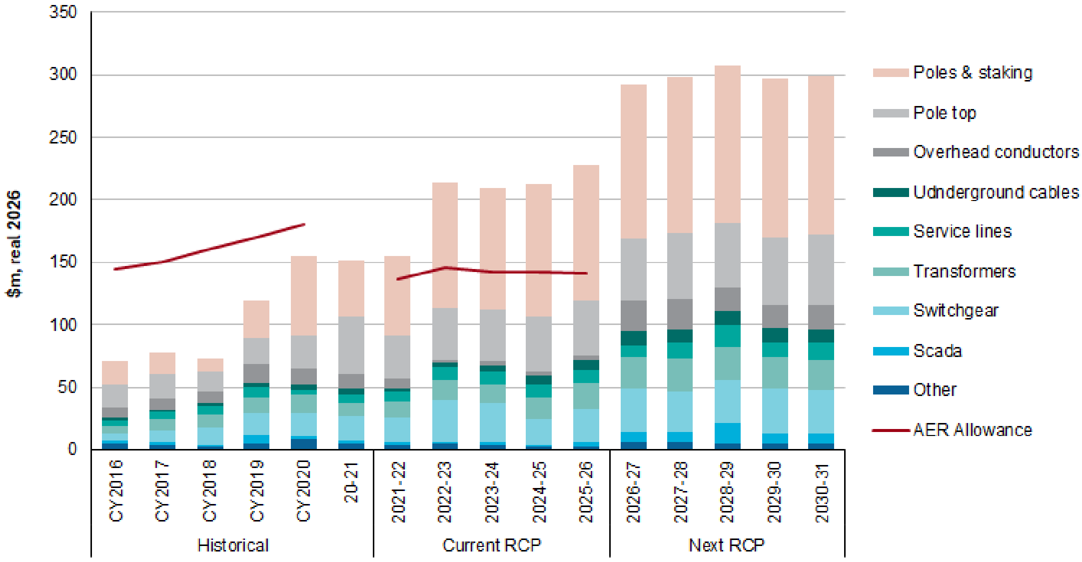
Source: EMCa table derived from Powercor RIN Workbook 1 – Forecast template – Jan2025 and its annual RIN

166. Powercor has proposed large increases to several asset groups namely poles, conductor and substation asset replacement.

Historical trend

167. In Figure 3.1 we show the historical and forecast repex by RIN asset group reported in the RIN. We also include the AER repex allowance excluding approved cost-pass through amounts.

Figure 3.1: Powercor proposed repex compared with current and historical - $m, real FY2026[24]



Source: Powercor RIN Workbook 1 – Forecast template – Jan2025 and its annual RIN[25]

168. As shown in Figure 3.1, Powercor expects to materially overspend its repex compared with the allowance in the current period - particularly for poles and pole-top structures. Powercor explains the overspend as being the result of the following factors:

- rising input costs, and
- increasing expenditure consistent with a longer-term trend of increasing asset replacements of high-volume distribution assets, which is reflective of the characteristics of the underlying asset populations.

169. We looked for evidence of the rising input costs, and the impact on Powercor relative to other DNSPs. In terms of increasing expenditure requirements, we are guided by the requirement of the NER, specifically to assess whether the proposed increases are prudent and efficient, and justified as economic.

Comparison of regulatory periods

170. In Figure 3.2 we show the average annual repex by asset group for the last three five-year periods. We observe that the annual average repex has been steadily increasing over this period, with an increase from approximately $100 million per year to $200 million per year in the current period then a further proposed increase to $300 million per year. The largest increases relate to distribution line assets.

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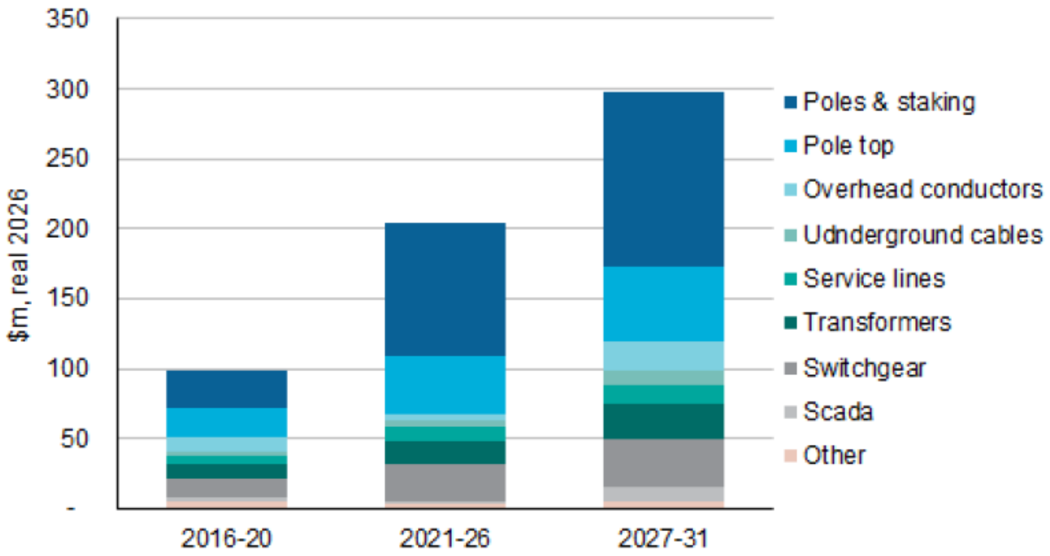
24 The AER allowance for the current RCP includes cost pass through amounts of $130.3m ($2026)

25 The chart represents the data reported in the RIN and as supplied to us by the AER. We observed some gaps in the historical data, e.g. no staking in historical expenditure for years 2015-2017 and 2020

Figure 3.2: Comparison of average annual repex across regulatory periods - $m, real FY2026



Source: EMCa derived from Powercor RIN Workbook 1 – Forecast template – Jan2025 and its annual RIN

171. As shown in Figure 3.1 and Figure 3.2, there has been a step increase in repex across the last two regulatory periods, and which applies to most asset groups. The largest increases are associated with the switchgear and underground cables asset groups.

3.2.2 Inclusion of additional bushfire mitigation programs

172. Powercor has included a number of projects in its repex forecast from its bushfire management program as shown in Table 3.2. We consider each of these as a part of our assessment of the respective expenditure category.

173. The bushfire mitigation projects included as augex are included in our assessment in section 4.

Table 3.2: Powercor bushfire mitigation projects - $m, 2026 (excluding escalation)

Project	Asset group	Forecast Total
Repex		
Minimising bushfire risks from bare 22kV conductors	Overhead conductors	10.5
Minimising bushfire risks from HV wooden crossarms	Pole top structures	24
Sub- total repex		**34.5**
Non-demand driven augex		
Maintain REFCL compliance	-	94.6
Maintain REFCL reliability[26]	-	12.5
Minimising bushfire risks from SWER lines[27]	-	13
Minimising bushfire risks in Horsham supply area[28]	-	18.4
Sub-total augex		**138.5**
Total		**172.9**

Source: EMCa table derived from PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public, Table 1

26 Included as a part of Minimising bushfire risk (augex) in the capex model

27 Included as a part of Minimising bushfire risk (augex) in the capex model

28 Also referred to as 'Non-mandated REFCL' in the capex model

3.2.3 Summary observations

174. Powercor has been increasing the level of repex it has forecast to incur across the last three regulatory periods, with a step increase corresponding with the next RCP.

175. Powercor expects to incur a higher level of repex than was included in the AER's Final Determination, driven by estimated step increases in the final years of the current period. Powercor attributes the overspend to increases in the cost of delivering its repex program – labour and materials. The forecast overspend remains subject to Powercor's ability to deliver on its estimated expenditure, albeit it is comparable to the latest year of actual costs.

3.2.4 EMCa's scope of repex review

176. Of the $1,491.5.1 million that Powercor has proposed for repex in the next RCP, our scope relates to $1,038.8 million (or approximately 70%) as shown in Table 3.3.

Table 3.3: Repex within EMCa's scope by RIN asset group - $m, real FY2026

Asset group	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Poles	109.2	109.8	110.5	111.3	112.1	**552.9**
Pole top	49.7	52.7	52.4	54.8	56.0	**265.7**
Overhead conductor	23.4	23.5	18.2	18.3	18.4	**101.9**
Transformer	8.3	8.6	8.5	8.3	5.3	**38.9**
Switchgear	4.5	4.7	9.3	9.2	9.3	**37.1**
SCADA, network control & protection system	6.2	5.9	11.2	3.6	3.7	**30.6**
Other	2.2	2.2	2.5	2.6	2.2	**11.7**
Total	**203.5**	**207.4**	**212.6**	**208.1**	**207.2**	**1,038.8**

Source: EMCa table derived from Powercor SCS capex model

177. We consider the project and programs that comprise this expenditure in the sections that follow.

3.3 Assessment of repex

3.3.1 Poles

What Powercor has proposed

178. The scope for our assessment for the Poles asset group is shown by asset category in Table 3.4, and which excludes some pole repex that we understand is associated with the proposed resilience program and which is not within our scope.

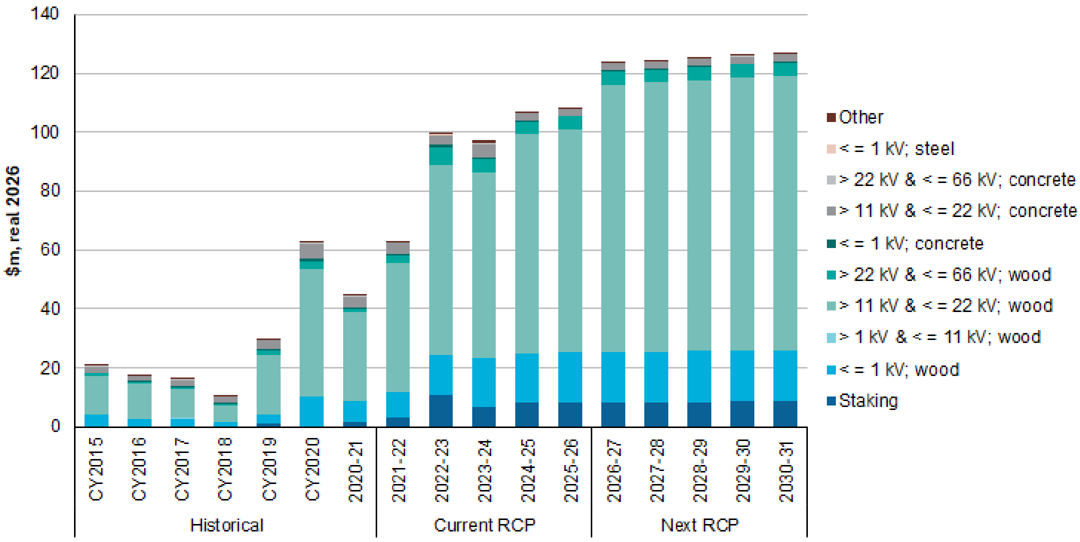
Table 3.4: EMCa scope of Powercor's proposed pole repex - $m, real FY2026

Poles	2026-27	2027-28	2028-29	2029-30	2030-31	Total
HV pole replacement	83.4	83.8	84.4	85.0	85.6	**422.2**
LV pole replacement	17.4	17.5	17.6	17.7	17.9	**88.1**
Pole reinforcement	8.4	8.5	8.5	8.6	8.6	**42.6**
Total	**109.2**	**109.8**	**110.5**	**111.3**	**112.1**	**552.9**

Source: EMCa table derived from Powercor SCS capex model

179. The total poles repex proposed by Powercor is $625.5 million for pole replacement and reinforcement. The historical and forecast repex is shown in Figure 3.3.

Figure 3.3: Historical and forecast Pole intervention repex - $m FY2026

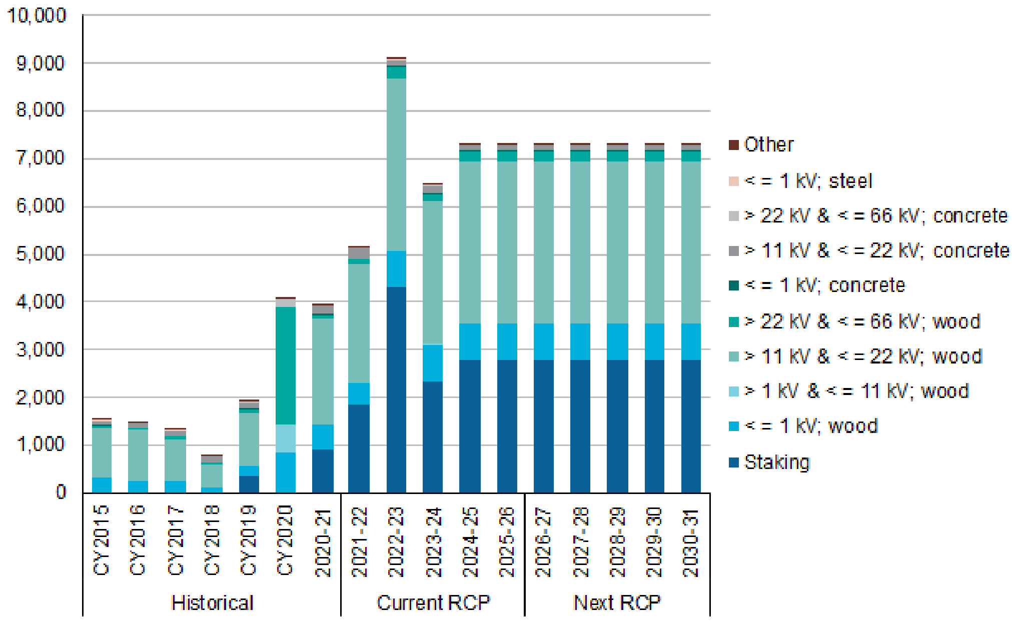


Source: EMCa derived from RIN

180. The proposed historical and forecast intervention volumes are shown in Figure 3.4. We observe a large spike in intervention volumes in 2022-23, which we understand is associated with implementing the increase in pole interventions arising from the ESV direction to treat a higher volume of poles.

181. The spike in 2022-23 is largely driven by increases in pole staking volumes as shown in Figure 3.3.

Figure 3.4: Historical and forecast pole intervention volumes[29]



Source: Source: EMCa derived from RIN

182. We observe a mismatch between the proposed expenditure and the intervention volumes. We understand that a proportion of the proposed expenditure for poles is designated as resilience-driven, and that this contributes to the higher repex for the next RCP, however we do not observe a corresponding step increase to the intervention volumes over the same

29 Staking not present in historical RIN data

period – the intervention volumes are flat. We have not been asked to review the resilience driven expenditure.

Assessment

Model provided with submission is opaque

183. In its submission, Powercor included a wood pole management model that converted its inspection data into annual decay rates which were used to predict future measured condition and subsequent serviceability. The model included a forecast intervention volume of 80,637.[30] We were not able to derive the replacement volume that Powercor had included in its proposal from this model. We asked Powercor to explain how the proposed intervention volume had been determined.

184. In response to IR013, we understand that the model was used as a comparison to the replacement volumes indicated by the ESV direction that applied in the current period, and not as we had first understood - as a basis for the proposed replacement volume. Powercor explained that the model included 8 years of data, with the proposed replacement volumes from the counterfactual model indicated in Table 3.5.

Table 3.5: Summary of Powercor's proposed condition-based intervention volumes, using decay modelling

Intervention criteria	Number of poles (8 years of data)	Percent included for 2026-31	2026-31 poles pa	2026-31 poles
Unserviceable	21,702	100%	2,713	13,564
AC serviceable P3 and criticality ≥ 3	16,012	100%	2,002	10,008
Double staked in HBRA	2,180	100%	273	1,363
Serviceable P4, HBRA, SWT <75 and age ≥ 50	40,743	47%	2,394	11,968
Total for wood pole condition intervention	**80,637**		**7,380**	**36,902**

Source: EMCa derived from Powercor - IR013 - Q2 - poles forecast data

Forecasting method is based primarily on condition-based interventions and aligned with commitments to ESV established in the current RCP

185. Powercor has included a lower volume of 6,932 pa or 34,660 in total over the next RCP in its proposal based on Powercor's Bushfire Mitigation Plan as shown in Table 3.6. This aligns with the replacement volumes included in the ESV direction that applies in the current RCP. In addition, Powercor has added fault interventions and concrete pole replacements based on a five-year historical average.

[30] PAL MOD 4.11 - wood pole condition counterfactual - Jan2025 – Public

Table 3.6: Build-up of pole intervention program

Intervention type	Poles pa	2026-31 poles	Source
Average annual wood pole measured condition and observable defect interventions	6,932	34,660	Powercor Bushfire Mitigation Plan (required by ESV)
Average annual fault interventions	221	1,105	Historical 5-year average
Average annual concrete pole replacements	132	660	Historical 5-year average
Total	**7,285**	**36,425**	
Wood pole reinforcements	2,777	13,885	
Pole replacements[31]	4,508	22,540	
Total	**7,285**	**36,425**	

Source: Derived from Powercor's response to IR013

186. In response to our request to explain how the proposed intervention volumes had been determined, Powercor stated that its model was used to establish the envelope to which historical and forecast replacements were compared:

> *'As shown in the counterfactual tab in the model attached in response to Q2 [Powercor - IR013 - Q2 - poles forecast data], our historical volumes are within the 'envelope' established by this counterfactual, giving further confidence to our proposal to maintain historical volumes and intervention practices.*
>
> *As presented in our regulatory proposal, our counterfactual analysis also showed the profile of projected condition-based interventions out to FY41. This indicates future levels of intervention volumes that would be beyond our capacity to deliver and gives support to the timing of our proposed intervention forecast.'*[32]

At a total level, an increase to the number of pole interventions compared with historical practices is reasonable

187. We consider that the uplift in pole intervention volumes included in the ESV direction notice relative to the historical practice has not been completed, as it applies to the full five-year period of the current RCP. Having commenced within the current RCP, the full inspection cycle will not be completed until after the next RCP has commenced.

188. Moreover, arresting a decline in pole performance evidenced by increasing defects and unassisted pole failures typically requires an increase in interventions (above historical trend) over more than one inspection cycle and which spans more than one regulatory period. Maintaining an uplift in intervention volumes, as Powercor has proposed, is reasonable.

189. This is supported by decay modelling that indicates a higher replacement volume, indicative of a higher rate of deterioration, than is indicated by the volumes included in the ESV direction notice.

190. However, other than this single reference point, we did not see sufficient evidence that Powercor had tested the intervention volumes to understand the differences in risk/benefit to consumers, such as by considering scenarios. The logical extension would be to monetise the risk/benefit associated with each scenario to establish a case for the preferred scenario. As established in section 2, we consider that this is a requirement of justification for repex included in AER guidance materials.

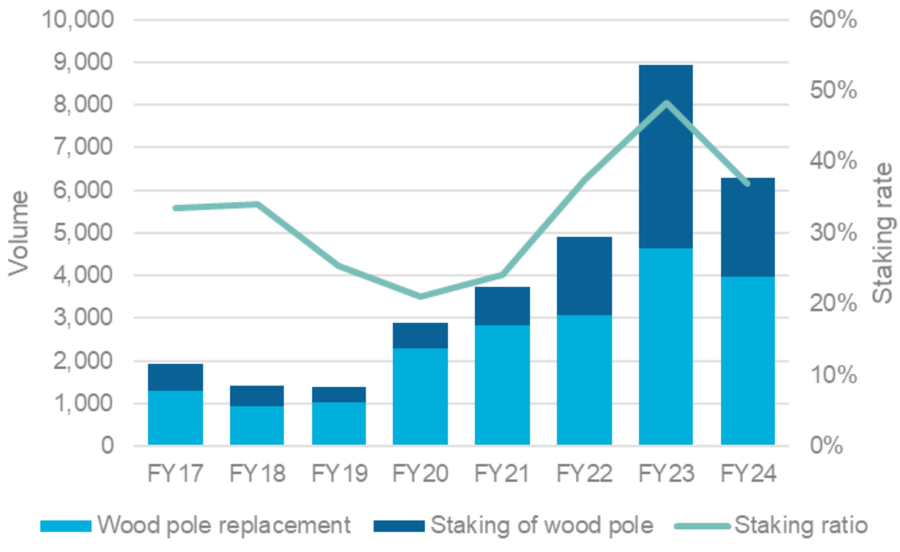
31 Including 660 concrete pole replacements

32 Powercor response to IR013, Question 5

Proposed staking ratio is consistent with recent levels

191. Based on the proposed intervention volumes, the effective staking rate (excluding the faults and concrete poles) is approximately 40%. We show the historical staking rate in Figure 3.5, which indicates a more recent increase in staking following adoption of the intervention volumes included in the ESV direction.

Figure 3.5: Historical staking rate



Source: Derived from Powercor's response to IR013, Powercor - IR013 - Q2 - poles forecast data

192. In a response to our questions, Powercor stated that its staking rates are lower than in the CitiPower network:

> *'Relative to our Powercor network, higher staking rates are generally possible in CitiPower for the following reasons…'*[33]

193. The reasons for the differences between Powercor and CitiPower are reasonable; the staking ratio is based on the split of intervention volumes nominated in its BMP and are consistent with the application of the ESV's direction notice. We consider that a staking rate of this order is reasonable and compares well to industry peers as a low-cost solution to de-risk the network.

Powercor states that it has removed potential overlap between the condition-based program and resilience program

194. Powercor states that it has removed the overlaps between its proposed bushfire resilience program and the condition-based replacement program, and which results in a $2.0 million reduction in the bushfire resilience program. Powercor also states that it has similarly reduced its flood resilience program by $1.1 million.

195. We have not been asked to review the resilience programs to confirm how this has been applied by Powercor.

Derivation of unit rates for submission result in increases to unit rates

196. In its regulatory proposal, Powercor states that:

33 Powercor response to IR013, Question 4

'Our forecasts also reflect a volume-weighted average of our most recent unit rates derived from our audited RIN data. These rates have increased throughout the current regulatory period relative to those set out in the AER's final determination.' [34]

197. We asked Powercor to demonstrate how it had derived the unit rates that apply to the forecast repex requirements, including for poles. We have been able to reproduce the volume weighted average of the unit rates applied by Powercor for the 3 years ending FY24 included in its response.[35] However, we found that the analysis was volume weighted using an average of replacement volumes for the period FY22 to FY24, applied to a unit rate in FY24 only. We asked Powercor to explain the basis of this decision, where an average unit rate is typically applied to avoid the potential distortions in any single year. Powercor stated:

'In the prevailing market, where input costs have been increasing above CPI, using an average across multiple years would immediately result in unit rates lower than what we are currently incurring today. Using the most recent year of data provides us the opportunity to recover our efficient costs, consistent with the capital expenditure criteria.

Further, there is no indication that rates from suppliers, including for materials, labour or contracts will decrease, particularly in the context of local and global energy transition where demand will remain high. Additionally, unit rates are reflecting increasing costs of business associated with growing traffic management requirements and other compliance factors; the extent of these are not reflected in historical rates and therefore would be under-represented in longer averaging periods.

We also note that for high-volume assets (such as poles and pole-tops), using a single year of data still correlates to a significant sample size.'[36]

198. Whilst we accept the current market conditions are adding cost pressures, and that these may not be evident in longer term averages, we also did not see sufficient evidence that the unit cost in a single year is not in itself driving up the assumed unit cost. We sought to understand the reason for real increases in unit rates for wood poles.

Unit rates are also above those submitted to AER for recent cost-pass through application

199. Given the recency of the cost-pass through application by Powercor for its proposed uplift in wood pole replacement, we considered the unit rates included in that submission with those proposed for the next RCP. We also observed that Powercor had provided evidentiary support for its unit rates at that time, and which reflected an increase above its historical rates. We asked Powercor to explain the change in unit rates from those included in the cost pass-through application, including updated information from wood pole management contractors that supports the proposed unit rate for wood pole replacement and reinforcement.

200. Powercor only addressed the question in part, and did not provide a similar level of information to that which it had previously provided to the AER to support its proposed unit rate increases:

'Real increases in unit rates for wood poles since our cost pass through application have been driven by separate increases across each of labour, materials and contracts. For example:

- *real labour rate increases reflect the impacts of enterprise bargaining agreements (EBAs) with the Electrical Trade Union of Victoria and the Australian Services Union collectively. While the impact of the headline wage growth escalation in these EBAs has been consistent with inflation over recent years, changes in corresponding allowances (e.g. dual-trade, leadership loading), progression opportunities (e.g. pay*

[34] Powercor Regulatory Proposal 2026-31 - Part B - Explanatory Statement - Jan2025, page 52

[35] Powercor response to IR004 Question 11 (c) – unit rates

[36] Powercor response to IR012, Question 7

point increases associated with qualifications) and changes to works practices have driven additional cost

- *labour cost increases have also been driven by an increasing proportion of external labour, with external rates typically more expensive than equivalent internal labour*
- *materials prices have increased, with the average cost to procure a wood pole increasing by 58 per cent and concrete poles by 19 per cent from FY21*
- *traffic management industry reforms launched in February 2022 have led to ~30 per cent cost increases, driven by more rigorous training requirements under a nationally consistent training framework for traffic management personnel.1 The reforms also required more stringent site safety and operational requirements, increasing the amount of traffic personnel required*
- *civil contract costs have increased, in particular those associated with non-destructive digging and equipment hire (e.g. crane and excavator hire have increased 23 per cent on a per hour basis). At the same time, the proportion of jobs requiring civil works has grown (i.e. 58 per cent in FY24 compared to 46 per cent in FY21).*

With respect to contracts used for the purpose of our pass-through application, these have expired and have not been renewed.'[37]

201. We accept that Powercor has been subject to cost increases, including those indicated in its response, however we are unable to ascertain the reason for the large differences apparent in its historical costs and which underpin its forecast. We also did not see sufficient evidence that Powercor has sought to minimise the cost increases, or to explore resourcing strategies and/or delivery models that seek to lower the costs to consumers.

Unit rates do not benchmark well amongst peers

202. The historical unit rates reported by Powercor are higher than we had expected for many distribution lines assets.

203. In Table 3.7, we show the range of wood pole unit rates, comprising the majority of the forecast expenditure for 2024, being the year used by Powercor in its derivation of unit rates for the next RCP.

[37] Powercor response to IR012, Question 8

Table 3.7: Comparison of 2024 unit rates (staking and replacement) - $m FY2026

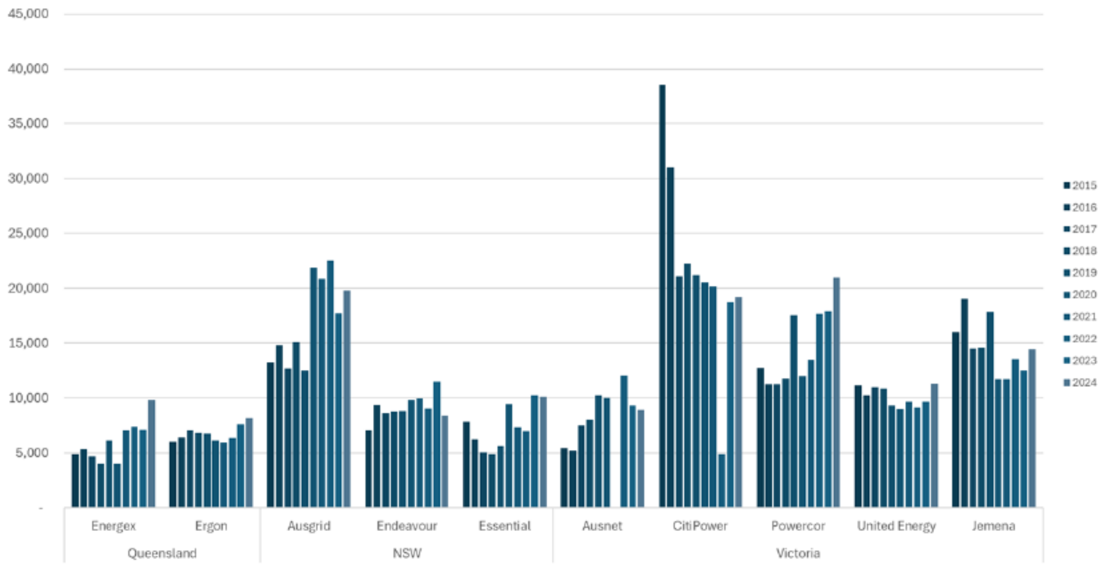
2024 unit rates	Pole staking	<=1kv ;wood	>11kv&<=22kv; wood	>1kv&<=11kv; wood
Non-Victoria				
Ausgrid	1,521	19,785		20,049
Endeavour	1,071	8,434	8,433	8,449
Energex	1,307	9,840		7,092
Ergon	1,647	8,184	9,277	9,277
Essential	1,364	10,108	8,424	9,266
Average	**1,382**	**11,270**	**8,711**	**10,827**
Victoria				
AusNet	1,182	8,929	12,691	3,628
CitiPower	1,419	19,223	30,638	18,470
Jemena		14,413	17,829	18,622
Powercor	2,913	20,969	21,102	20,161
United Energy	1,210	11,283	18,190	18,483
Average	**1,681**	**14,964**	**20,090**	**15,873**
Representative efficient unit cost	**1,315**	**14,973**	**18,010**	**18,525**

Source: EMCa derived from historical RIN

204. In Table 3.7, we have also produced the simple average of costs across the Victorian DNSPs. We also derived from this data a reference cost by excluding outliers for Victorian DNSPs (by removing highest and lowest unit costs), and if Powercor was not already excluded for this reason, excluding Powercor's cost, to determine a representative efficient cost. Powercor is above these costs for all wood pole types.

205. In Figure 3.6 we show the historical trend of costs across all NEM DNSPs for LV wood pole replacement.

Figure 3.6: Historical trend of LV wood pole replacement unit cost – all NEM DNSPs, $ FY2026



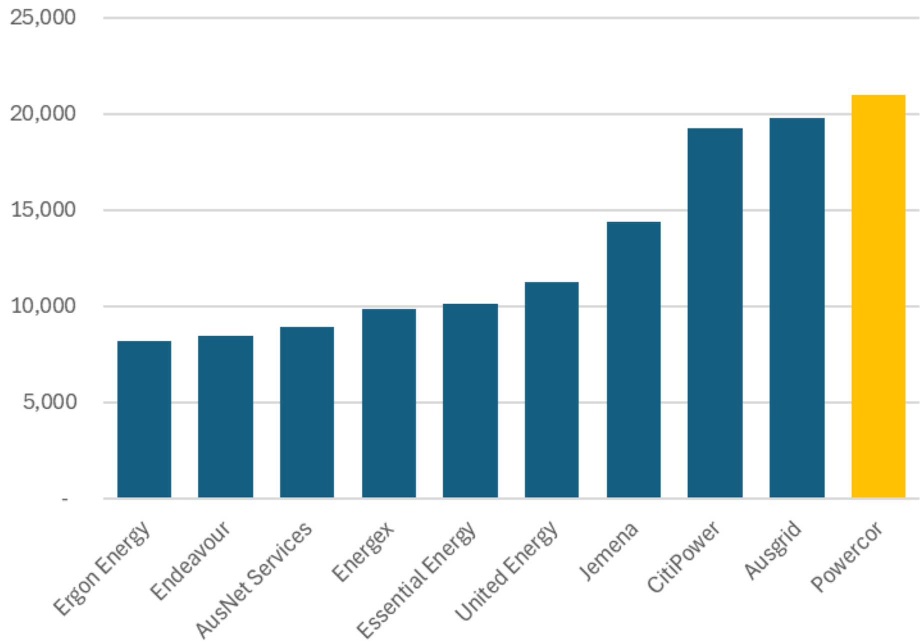
Source: Source: EMCa derived from RIN

206. As can be seen from this graph, Powercor's costs have trended up significantly since 2020. Whilst we had expected to see some price increases resulting from factors such as COVID, and global supply chain issues these trends are not reflected consistently across the DNSPs. This casts doubt on the reasons for the price increases reported by Powercor. These same trends are also not present for CitiPower, which shows a generally decreasing cost over the same period.

207. Of most concern is the most recent costs, which are similar in magnitude to the costs reported by CitiPower which is a CBD/urban network and which we would expect to incur higher costs on average than Powercor. In these most recent years, and which Powercor has used as the basis for its forecast, Powercor is materially above the costs reported by other Victorian DNSPs and NEM DNSPs more generally.

208. In Figure 3.7 we show the most recent actual cost for LV pole replacement recorded in the RIN. Powercor is shown to have incurred the highest cost, above DNSPs which may be subject to additional costs associated with inner urban/CBD locations including CitiPower and Ausgrid. Powercor was not able to explain to us the reasons for its much higher unit costs than comparable DNSPs.

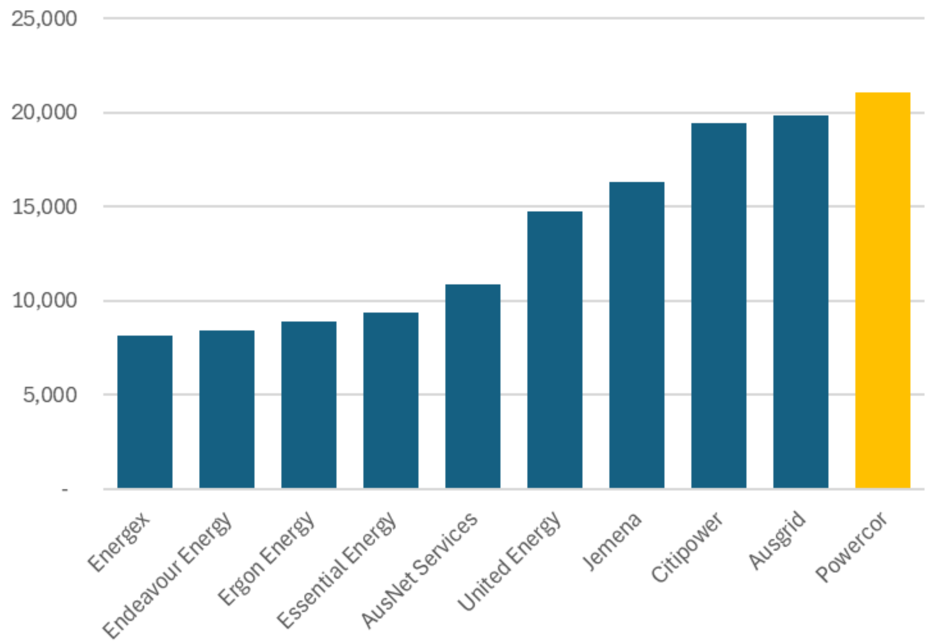
Figure 3.7: Recent actual LV wood pole replacement unit cost, $ FY2026



Source: Source: EMCa derived from RIN

209. In Figure 3.8, we generated a volume weighted wood pole unit cost (comprising 1kV, 11kV and 22kV wood poles replacements) based on the most recent 2024 actual costs. Whilst the order of some DNSPs were interchanged, the DNSPs incurring the highest unit costs did not, with the highest being Powercor.

Figure 3.8: Volume weighted 1kV, 11kV and 22kV wood pole replacement unit cost, $ FY2026

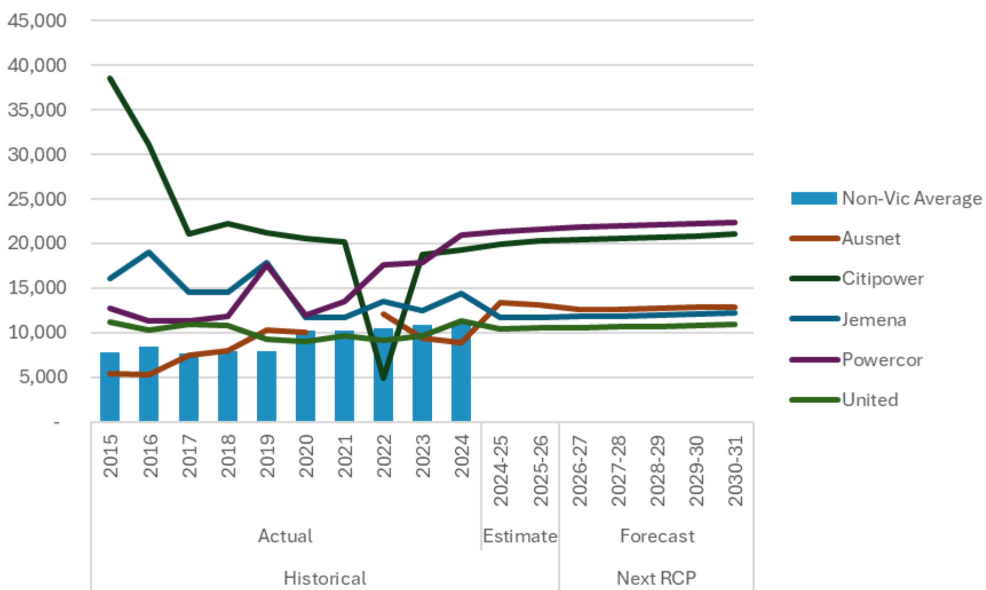


Source: Source: EMCa derived from RIN

210. The unit rates reported by Powercor are materially above those being incurred by other DNSPs and cannot be considered as reflective of an efficient cost. We accept that more recent cost increases may increase costs above historical trends, however this should be evident in the costs of other DNSPs both in Victoria and across the NEM. Rather it appears that Powercor and CitiPower have higher historical costs, and which may reflect higher cost structures, and which are reflected in higher forecast costs.

211. In Figure 3.9, we show the historical unit rate for a LV wood pole for Victorian DNSPs using information from the RIN to understand whether there were any common factors contributing to the cost.

Figure 3.9: Historical LV pole replacement unit rate - $ FY2026



Source: EMCa derived from RIN

212. This trend is evident for most asset categories, where Powercor (and CitiPower) are clear outliers for unit costs when compared to Victorian DNSPs. Powercor (and CitiPower) are also outliers across the NEM.

213. We observe significant volatility in the average unit cost of these activities, impacted by COVID-19 and changes in reporting from CY to FY which could impact the accuracy of the information. Post this period we would expect to see average unit rates become less volatile, notwithstanding that the composition of activities remains. We would expect differences between as-incurred and as-commissioned to be minimal due to the volumetric nature of these assets.

214. Post 2020-21 we observe all costs adopted a slight upward trend, which suggests costs are increasing above inflation:

- Pole top replacement and staking of wood poles exhibit a slight upward trend as above,
- Whereas the increases evident for pole replacement are much more exaggerated, and continue to increase year on year, and
- Conductor replacement costs vary year on year within a band of costs, following a slight upward trend.

215. Also evident is the increases to unit rates for Powercor, particularly in a period for wood pole replacement where increased volumes should have resulted in realisation of greater economies of scale. Whilst other Victorian DNSPs have not experienced the uplift in replacement volumes, they similarly have not incurred nor are forecast to incur material uplifts in unit costs.

Pole staking unit rates are much higher than its peers

216. For pole staking, we typically see rates around $1,500 per pole, as this activity is predominantly outsourced by DNSPs. Powercor’s rate significantly exceeds this amount.

217. In response to our enquiries on pole-related unit costs, Powercor stated:

> *‘We currently contract out pole reinforcement works, with typical costs of around $1,200–$1,500. This rate is not consistent with reported RIN data for Powercor, and we are further investigating the driver of this difference.’*[38]

218. We consider that the rate reported by Powercor is in line with our expectations, and indicative of an efficient cost. However, the higher unit rate of approximately $3,000 per pole has been applied in the determination of its forecast repex for the next RCP.

Findings

219. We consider that the proposed poles repex is overstated.

220. Following receipt of a new forecast model, we were able to confirm that the proposed pole intervention volumes are based on the ESV direction notice, and which compare favourably with Powercor’s decay modelling. Given that Powercor is part-way through implementing the higher intervention volumes indicated by the ESV direction notice in the current period, we consider it reasonable that this volume of interventions will need to be maintained in the next RCP to address the issues identified by ESV.

221. Powercor’s proposed staking rates are consistent with recent levels, as indicated under the ESV direction notice and are reasonable.

222. However, we consider that the unit rates applied by Powercor are higher than an efficient level.

[38] Powercor’s response to IR012 response part II question 9

3.3.2 Pole top structures

What Powercor has proposed

223. The scope for our assessment for the Pole top structures asset group is shown by asset category in Table 3.8, and which aligns to the RIN.

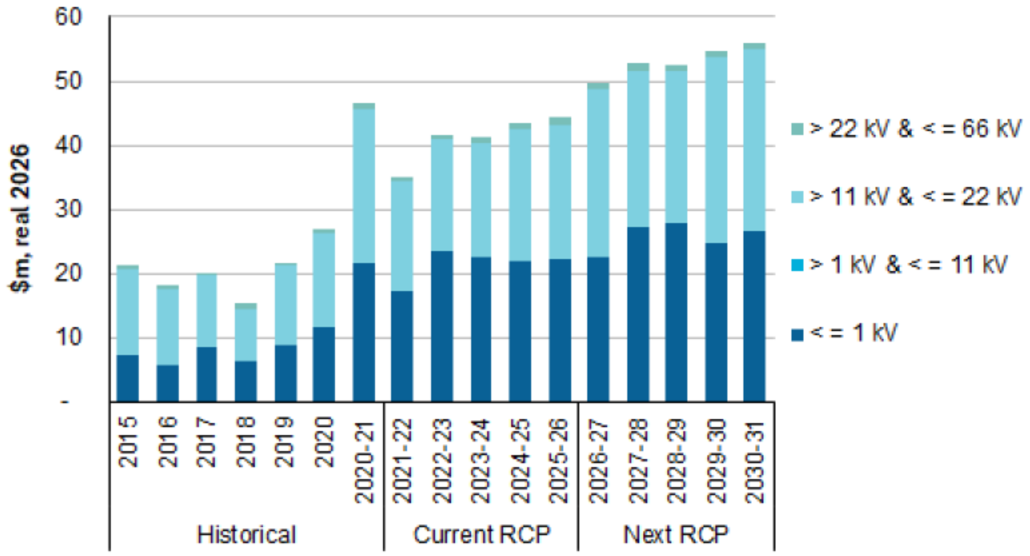
Table 3.8: EMCa's scope of Powercor proposed pole top repex - $m, real FY2026

Pole top	2026-27	2027-28	2028-29	2029-30	2030-31	Total
HV pole top replacement	22.2	20.3	19.6	25.1	24.1	**111.2**
LV pole top replacement	22.6	27.4	27.8	24.7	26.8	**129.3**
HBRA HV wooden cross-arm replacements	5.0	5.0	5.0	5.1	5.1	**25.2**
Total	**49.7**	**52.7**	**52.4**	**54.8**	**56.0**	**265.7**

Source: EMCa table derived from Powercor SCS capex model

224. The total poles repex proposed by Powercor is $265.7 million for pole top structure replacement. The historical and forecast repex is shown in Figure 3.10. The increases for the next RCP relate to both an increase in volumes (shown below in Figure 3.11) and unit rates.

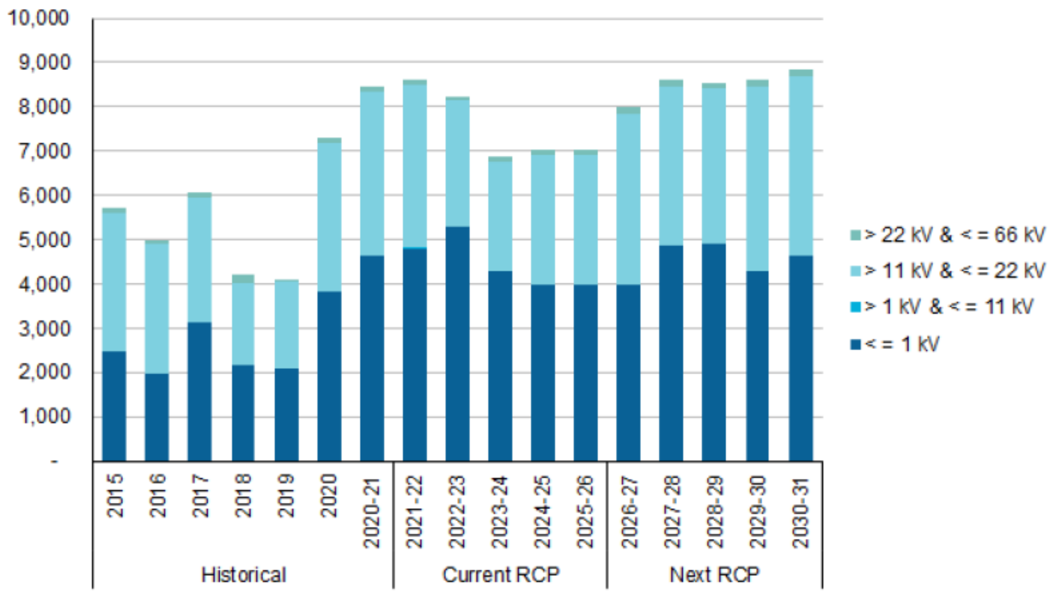
Figure 3.10: Historical and forecast pole top structure repex - $m, FY2026



Source: EMCa derived from RIN data

225. In Figure 3.11 we show the asset replacement volume for pole top structures from the RIN. Powercor has proposed an increase to the replacement volumes in the next RCP. This is primarily due to the inclusion of the HBRA program, and after removal of this the volumes are similar.

Figure 3.11: Historical and forecast pole top structure replacement volume



Source: EMCa derived from RIN data

Assessment

Forecasting method is based primarily on Powercor's cyclic inspection program and historical find rate

226. Powercor provided a single model for its HV HBRA crossarm replacement program, however this did not include the basis for the proposed volume of replacements for the remainder of its program. We asked Powercor to explain how it derived its forecast replacement volumes, which we understood were a combination of fault and corrective forecasts, as well as one risk-based sub-program (HV HBRA crossarms).

227. In response to our request for information,[39] Powercor provided a distribution lines model which detailed the calculations it had relied upon. The forecasting method and volumes are summarised in Table 3.9, including the volumes from the HBRA crossarm model.

Table 3.9: Derivation of proposed crossarm replacement volumes

Program	Driver	Forecast method	Total for next RCP
HV pole top replacement	Corrective	Historical average	12,077
	Faults	Historical average	3,085
LV pole top replacement	Corrective	Historical average	18,970
	Faults	Historical average	3,677
HV HBRA	Risk-based	Risk model	4,761
Total			**42,570**

Source: Derived from Powercor response to IR013, distribution lines volume forecast model

228. The analysis undertaken by Powercor for corrective and fault-based replacement is based on its historical data:

- Defect analysis is based on historical inspection volume by region, multiplied by the forecast defect find rate which remains flat from 2023/24 to 2030/31. The forecast defect

39 Powercor response to IR013

find rate is determined as the 3-year average defect find rate from the available data, being the period 2020/21 to 2022/23.

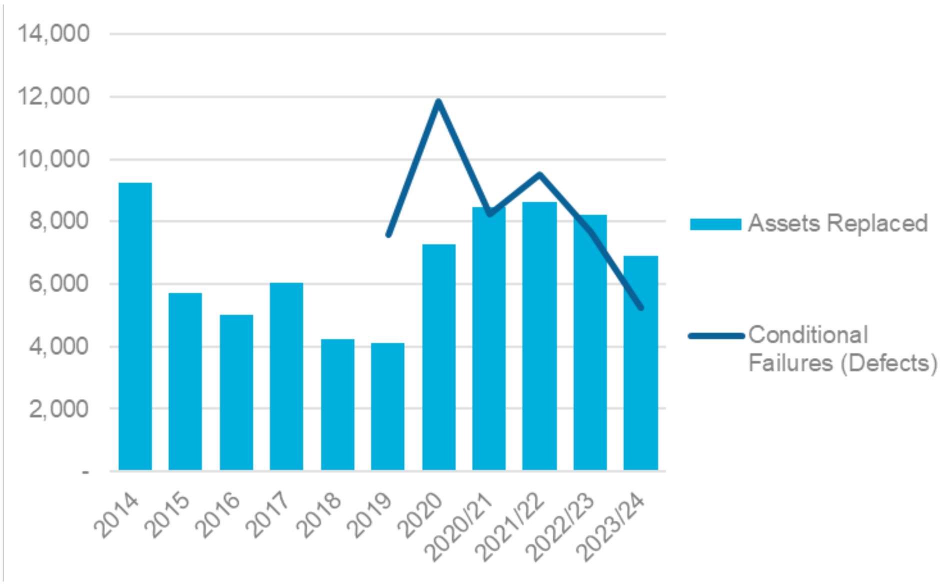
- Fault-based replacement based on the average of five years historical data to 2023/24

229. Unsurprisingly, the historical data leads to a similar forecast replacement volume to the volume that Powercor has historically incurred, adjusted for inspection variability. We would have expected that Powercor had updated its forecasting method to include the latest completed year, being 2023/24 for its defect-based forecast.

Powercor has not adequately taken account of the impact of related replacement programs nor the declining defect trend

230. The defects and failure information provided by Powercor indicates a declining trend. We show the declining defects in Figure 3.12 with a similar downward trend observed in unassisted failures.

Figure 3.12: Trend of defects and failures for crossarms



Source: EMCa analysis of IR005 Q3 historical data

231. Based on the above trends, we would have expected that Powercor would have made a downward adjustment to the number of crossarms being replaced in its crossarm replacement program compared with historical practices. The historical find rate, which includes data points reflective of a higher failure and defect volume than Powercor has been incurring, is likely to inflate the forecast replacement volume. Moreover, we see no adjustment for the increase in pole replacement that has occurred, and which would have contributed to a higher number of crossarms being replaced.

Uplift in crossarms replacement includes increase to risk-based program in HBRA, which is reasonable

232. Powercor has provided a separate model for the proposed risk-based replacement of crossarms in HBRA.[40]

233. The proposed program includes the incremental replacement of 952 crossarms per year, increasing the annual replacement volumes from 1,749 to 2,701 crossarms. This is based on 4,761 crossarms planned for the 2031-36 period (based on current annual replacement volumes), brought forward to the next RCP.

234. We have reviewed the model and consider that the incremental bushfire benefit of $12.7 million (with an effective benefit to cost ratio of 4.6) is sufficient to justify the decision to

40 PAL MOD 4.16 – HV wooden crossarms (bushfire) – Jan 2025

bring forward this work. However as noted below, we have concerns regarding the unit rates that have been assumed.

Information provided does not support proposed expenditure for crossarms

235. We were unable to determine the proposed expenditure based on the provided unit rates in this response. Instead, the proposed expenditure is more closely aligned with the application of unit rates provided in response to our information request, as shown in Table 3.10.

Table 3.10: Comparison of crossarm replacement unit rates, $2026

	HV HBRA replacement cost	Volume forecast model	FY24 actual	Unit rates model[41]
HV cross arm replacement	5,015	5,192	7,162[42]	6,959
LV crossarm replacement	n/a	7,184	5,248	5,417

Source: EMCa derived from IR013, HBRA model and analysis of RIN

236. Whilst there may be minor variances between the sources due to the calculation methods applied, we observe material differences in the sources of data provided by Powercor. For example, the models provided as being the basis of the forecast volumes have lower HV crossarm rates than LV, however the information based on RIN data has this relationship inverted.

Unit rates do not benchmark well amongst peers

237. As detailed in our assessment of poles, the historical unit rates reported by Powercor are higher than we had expected for many distribution lines assets.

238. In Table 3.10 we showed the range of crossarm unit rates incurred by DNSPs across the NEM in 2024, being the year used by Powercor in its derivation of unit rates for the next RCP.

239. In Table 3.11, we have also produced the simple average of costs across the Victorian DNSPs and also the reference cost by excluding outliers for Victorian DNSPs (to remove highest and lowest unit costs), and if Powercor is not already excluded, excluding Powercor to determine a representative efficient cost.

41 Volume weighted unit rates

42 Based on 22kV only

Table 3.11: Comparison of 2024 unit rates - $m FY2026

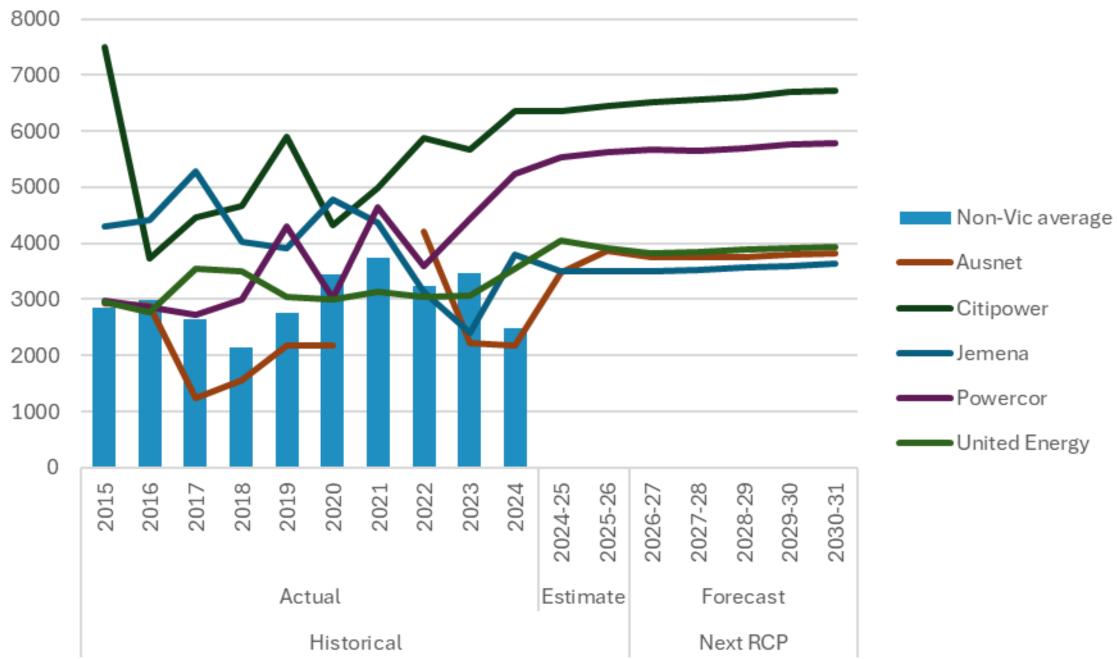
2024 unit rates	<=1kv	>11kv&<=22kv
Non-Victoria		
Ausgrid	3,941	3,941
Endeavour	2,312	3,854
Energex	4,489	2,519
Ergon	4,064	-
Essential	1,679	1,761
Average	**3,297**	**2,415**
Victoria		
AusNet	2,176	2,807
CitiPower	6,364	9,640
Jemena	3,798	5,094
Powercor	5,248	7,162
United Energy	3,550	3,776
Average	**4,227**	**5,696**
Representative efficient unit cost	**3,674**	**4,435**

Source: EMCa derived from historical RIN

240. This analysis is the same as provided in our assessment of poles repex, and like for poles, we find that the unit rates for crossarms reported by Powercor are materially above that being incurred by other DNSPs. Accordingly, these rates cannot be considered as reflective of an efficient cost. We accept that more recent cost increases will increase costs above historical trends, however this should be evident in the costs of other DNSPs both in Victoria and across the NEM. Rather it appears that Powercor and CitiPower have higher historical costs, and which may reflect higher cost structures, and which are reflected in higher forecast costs.

241. In Figure 3.13, we show the historical unit rate for a LV crossarm replacement for Victorian DNSPs compared with the average across non-Victorian DNSPs using information from the RIN to understand whether there were any common factors contributing to the cost.

Figure 3.13: Historical LV crossarm replacement unit rate - $ FY2026



Source: EMCa derived from RIN

242. This trend is evident for most asset categories, where Powercor (and CitiPower) are clear outliers for unit costs when compared to Victorian DNSPs. Powercor (and CitiPower) are also outliers across the NEM.

Findings

243. We consider that the proposed pole top structure repex for crossarm replacement is overstated. Powercor has not adequately taken account of the impact of related replacement programs or declining defect trends and which lead it to a higher replacement volume than is prudent. Also, the unit rates applied by Powercor are higher than an efficient level.

3.3.3 Overhead conductor

What Powercor has proposed

244. The scope for our assessment for the Conductor asset group is shown by asset category in Table 3.12, and which closely aligns with the RIN total of $104.9 million.[43]

43 We did not seek an explanation of the difference, and it was beyond our scope.

Table 3.12: EMCa's scope of Powercor proposed overhead conductor repex - $m, real FY2026

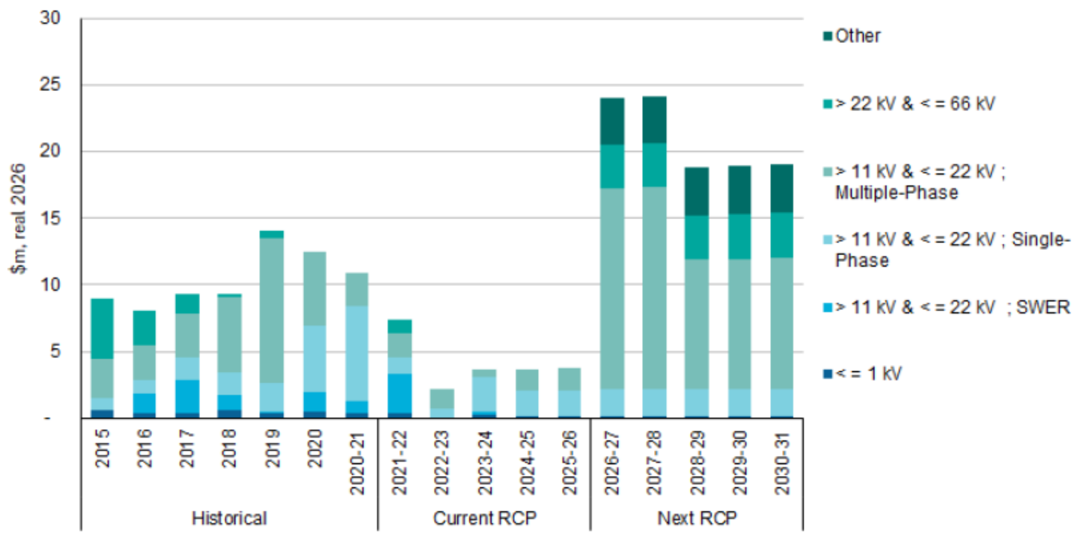
Overhead conductor	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Defective conductor	10.7	10.8	10.8	10.9	11.0	**54.2**
Risk-based 66kV replacement	3.3	3.3	3.4	3.4	3.4	**16.8**
Risk-based HV conductor replacement	0.4	0.4	0.4	0.4	0.4	**2.1**
Bare 22kV conductor bushfire mitigation	5.5	5.5	0.0	0.0	0.0	**10.9**
Conductor clearance rectification from LIDAR	3.5	3.5	3.5	3.6	3.6	**17.8**
Total	**23.4**	**23.5**	**18.2**	**18.3**	**18.4**	**101.9**

Source: EMCa table derived from Powercor SCS capex model

245. Powercor states[44] that it has included an additional amount from the allocation of works undertaken as part of other asset replacements (e.g. replacement of pole mounted distribution transformers and switchgear typically result in minor associated overhead conductor works). This allocation is not shown above, and once added, reconciles to the total of $104.9 million.

246. The historical and forecast repex for overhead conductors is shown in Figure 3.14.

Figure 3.14: Historical and forecast overhead conductor repex - $m FY2026



Source: EMCa derived from RIN

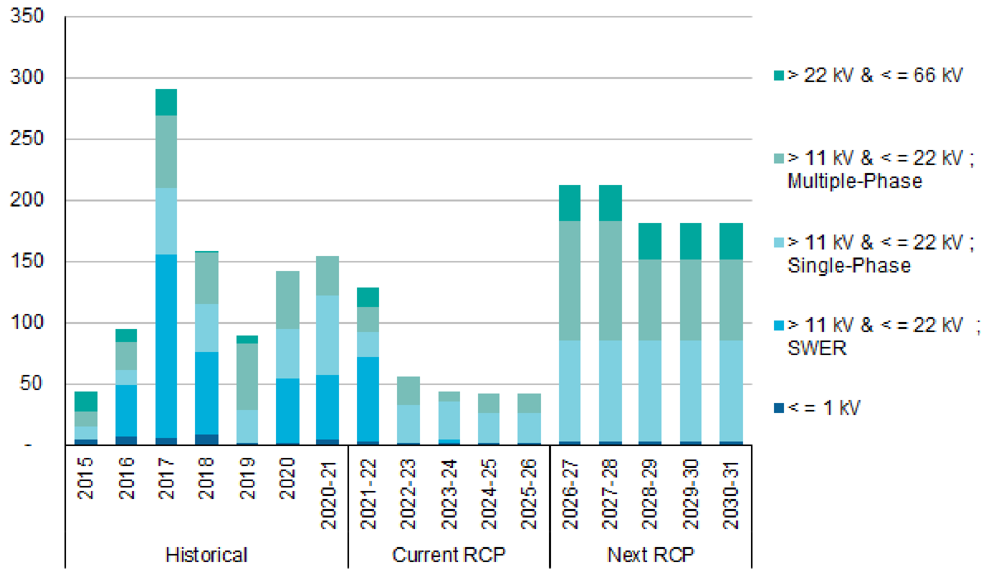
247. We observe large increases in conductor replacement proposed for the next RCP, particularly at 22kV and 66kV operating voltages. We consider this aligns with the introduction of the new programs shown in Table 3.12 The increases for the next RCP relate both to an increase in volumes (shown below in Figure 3.11) and to unit rates.

248. We associate the increase to the 'other' asset category with the conductor clearance rectification program.

249. In Figure 3.15 we show the asset replacement volumes proposed. We have excluded the conductor clearance program as it was added to the RIN using number of defects, and the 340 defects proposed to be rectified per year resulted in a distortion of the proposed volumes which otherwise are expressed in km. However, after removal of the conductor rectification program, Powercor is proposing a material increase to conductor replacement from approximately 50km p.a. to almost 200km p.a.

44 ASSET CLASS OVERVIEW – OVERHEAD CONDUCTORS page 15

Figure 3.15: Overhead conductor replacement volumes excluding conductor rectification



Source: EMCa derived from RIN

Assessment

Powercor has proposed an uplift in conductor replacement driven by the introduction of its proposed risk-based programs

250. In its Overhead conductor business case (BUS 3.11) Powercor states that its high priority defects are increasing, and that forecasts of condition indicate that in the absence of any intervention before 2031, approximately 45% of its covered conductor will have a modelled condition rating associated with a higher risk of failure. Powercor did not provide the modelling used to generate this forecast.

251. Powercor also refers to long-term replacement volumes of approximately 135km. From the RIN, more recent replacement volumes are less than 50km, whereas volumes prior to 2021-22 approached the average referred to by Powercor. Powercor has not explained the reasons for reduced volumes prior to the commencement of the next RCP.

252. Powercor goes on to describe the driver of the step increase that it proposes for the next RCP as being due to the introduction of its risk-based programs, and by implication not due to its condition-based program.

Powercor's forecasting methods vary by driver

253. Powercor's forecasting method is separated as follows:

- Faults (not forecast separately)
- Condition / defect: defective conductor program (which includes faults)
- Risk-based: comprising
  - replacement of 66kV radial lines to address the risk of 66kV conductor failure causing station black and supply interruption to customers
  - replacement of aged and deteriorated polyphase HV conductors to address HV conductor failure risk
  - targeted replacement of bare, non-REFCL protected 22kV conductors in hazardous bushfire risk areas (HBRA) as part of its bushfire mitigation program.

254. Powercor has provided three models, however the condition /defect and faults models were not provided, though they cover the majority of the forecast expenditure:

- MOD 4.08 Conductor replacement

- MOD 4.09 Conductor rectification based on LiDAR
- MOD 4.10 66kV radial lines, and
- MOD 4.17 Minimise risk from 22kV conductor (bushfire).

255. In response to our request for information,[45] Powercor provided a distribution lines volume forecast model which detailed the calculations it had relied upon. The forecasting method and volumes are summarised in Table 3.13.

Table 3.13: Composition of conductor replacement program

Program	Capex model project/investment	Driver	Forecast method	Total for next RCP
Defective and fault-based conductor replacements	Defective conductor	Corrective condition	Historical average	740
Replacement of aged and deteriorated HV conductor	Risk-based HV conductor replacement	Risk	Historical average	18
Rectification of clearances based on LIDAR	Conductor clearance rectification from LIDAR	Compliance	Defect rate	n/a[46]
Replacement of 66kV radial lines	Risk-based 66kV replacement	Supply risk	Risk model	148
Replacement of bare HV conductor bushfire mitigation	Bare 22kV conductor bushfire mitigation	Bushfire risk	Risk model	62

Source: BUS 4.03 Table 6

256. The proposed defective conductor program at 147km pa appears much higher than the long-term average indicated by the RIN. The addition of the risk-based programs results in a further increase to 193km pa for the next RCP.

257. We show how the conductor replacement has changed between the current and next RCP in Table 3.14.[47] For the next RCP, we observe increases to the 22kV and 66kV asset categories contributed by increase to the condition-based program and risk-based programs.

Table 3.14: Historical and forecast average annual conductor replacement volume by asset category (km)

Average annual replacement volume	2021-2026	2026-2031
< = 1 kV	2	3
> 11 kV & < = 22 kV ; SWER	14	-
> 11 kV & < = 22 kV ; Single-Phase	26	83
> 11 kV & < = 22 kV ; Multiple-Phase	17	78
> 22 kV & < = 66 kV	3	30
Total	**63**	**193**

Source: EMCa derived from RIN

258. The proposed program is also higher than the 7-year average included in Powercor's distribution line forecast model of approximately 120km, and which aligns with statements in the business case of the average replacement volume of 120km pa from 2015.

45 Powercor - IR013 - distribution lines volume forecast model

46 Volumes associated with its compliance-driven conductor clearance program are not forecast on a per-km basis. Instead, these are reported in the reset RIN under the 'other' conductor category.

47 The change from calendar year to financial year reporting makes the comparisons prior to the current RCP problematic

AMP identifies targeted replacement of HV conductors based on condition

259. In its asset management plan,[48] Powercor nominated four options to manage its HV bare conductor, selecting option 4:

- Option 1: Run assets to failure.
- Option 2: Continue condition-based preventative maintenance (current practice)
- Option 3: Continue condition-based preventative maintenance (current practice), with additional 3-yearly inspection using high resolution drones in targeted high-risk areas
- Option 4: Implement risk-based proactive replacement (proactively replace highest risk - Network Safety & Network Reliability)

260. A summary NPV analysis is presented (but not supplied for our review) that appears to support option 4 with a total PV from its modelling for option 4 exceeding $690 million. We consider below the benefits for each of the risk-based programs as presented by Powercor.

Assessment of defective and fault-based conductor replacements

Proposed replacement volumes are not reflective of more recent replacement volumes, and once adjusted reduce the size of the program

261. As noted above, the distribution lines volume forecast model[49] provides the forecast replacement volume based on historical average. The model provided indicates 737km based on an average replacement volume of 121km pa and which we consider closely approximates the volume included in the business case of 740km.

262. Our review of the model and the business case confirms the use of a 5-year historical average to determine the defect and fault replacement volumes. However, Powercor has applied the sample period up to and including 2022 rather than to 2024 (being the most recent actual data) as it has done for other assets. Powercor has not explained this decision.

263. From Powercor's data, the conductor related failures were shown to be increasing from 2019, however more recent data indicates the trend of failures has flattened, with an increasing trend for high priority defects.

264. We show the historical replacement data relied upon by Powercor in Figure 3.16. We consider that the more recent 5-year actual data is more reflective of Powercor's current replacement volume, and more likely to reflect the network performance.

265. After adjustment, the forecast replacement volume reduced from 737km to 498km over the next RCP. At approximately 100km p.a., the forecast replacement volume would still represent an increase relative to the most recent actuals of 2023-24. When considered alongside the additional replacement volume included in the proposed risk-based programs, the reduced volume is likely to provide a reasonable estimate of replacement requirements.

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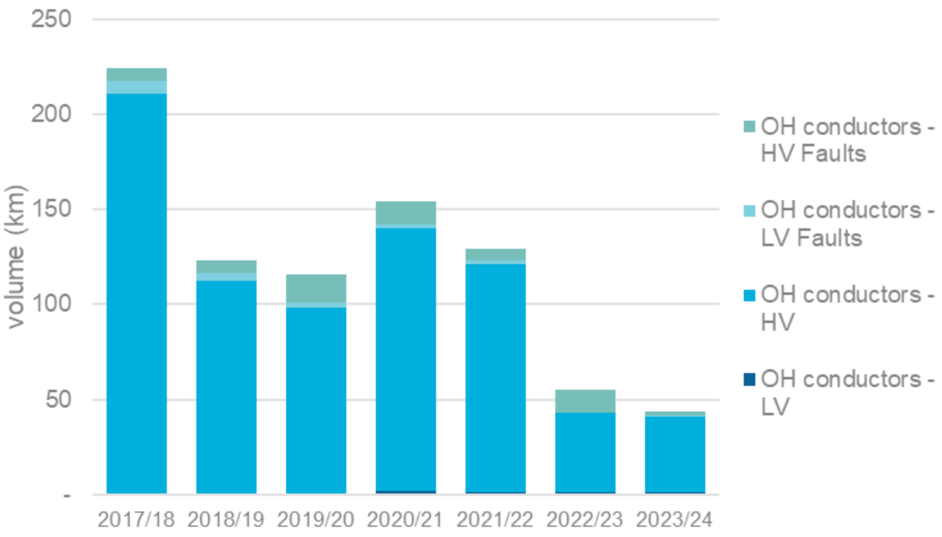
48 Powercor - IR005 - Q2(a) - AMP - overhead conductor - public

49 Powercor - IR013 - Q6 - distribution lines volume forecast model

Figure 3.16: Historical conductor replacement volume



Source: EMCa derived from IR013 Q6 distribution lines volume forecast model

The information provided does not support the proposed unit rates, however when compared against the RIN are within a reasonable range

266. We were unable to reproduce the proposed expenditure based on the unit rates supplied in Powercor's distribution volume forecast model, which included unit rates for condition and fault-based replacement separately. Instead, the proposed expenditure is more closely aligned with the application of the average unit rates provided in response to IR004.

267. Based on Powercor's response to IR004 we observe that the unit rates of LV conductor replacement are much higher than for HV, and that single phase is higher than three phase and SWER. Whilst this may be explained in part by a higher volume of pole mounted assets being replaced for LV poles and some synergies for longer lengths of HV conductor, the relationships are not as we expected.

268. We expect that this is due to the use of FY24 only, and when we review the relationship in prior years it aligns to what we had expected, and which does not make a material difference to the volume weighted unit rate.

269. Absent the published unit rates for the condition-based program that reconcile to the forecast expenditure, we rely on the rates generated from the RIN and which include the proposed risk-based programs. We consider that the unit rates across the conductor replacement program are within a reasonable range.

Powercor explained why it has not made top-down adjustments

270. We asked Powercor if had applied any top-down adjustments to take account of other programs included in its proposed capex program. In response to our information request, Powercor stated that:

> *'As part of challenging our overhead conductor intervention forecast, we reviewed our forecast against the remainder of our replacement and augmentation portfolios to identify and remove any overlaps. Specifically, we assessed our risk-based conductor replacements against the following programs:*
>
> – our *proposed single-wire earth return (SWER) intervention program, which includes the installation of early fault detection and replacement of some bare SWER with covered conductor*
>
> – *our broader regional and rural SWER upgrade program*

> – *the targeted replacement of bare, non-REFCL protected 22kV conductors in hazardous bushfire risk areas (HBRA).*
>
> *As we are not proposing any risk based SWER replacements as part of our overhead conductor replacement program, there are no overlaps with the above SWER replacement programs. Similarly, we found no overlap with our program to replace bare, non-REFCL protected 22kV.'* [50]

271. We are satisfied with Powercor's explanation that there are no identified material overlaps with other parts of its capex program.

Assessment of conductor clearance rectification from LiDAR

Powercor has identified non-compliant sites based on its application of LiDAR

272. In its Overhead conductor business case (BUS 3.11) Powercor describe the introduction of light detection and ranging (LiDAR) technology to replace its ground-based vegetation inspection practices. In 2023, Powercor expanded its use of LiDAR to identify non-compliant conductor clearances.

273. At the time, Powercor identified 4,400 sites that had become non-compliant.

Staged approach to rectification is reasonable

274. Powercor refers to adoption of a 10 to 15-year rectification program that will target 340 of the highest-risk sites per annum. Based on the original 4,400 identified sites, a rectification program of 340 sites per annum requires 12.9 years to complete. Excluding any allowance for new sites, this is within the nominated window.

275. Powercor states that the program has been discussed with the safety regulator ESV during the development of its regulatory proposal. We consider that adoption of a staged rectification program over multiple regulatory periods, addressing the highest risk sites first, is a reasonable approach.

276. We are unable to verify whether this is a continuation of an existing program as we have not been provided with evidence of current activity or expenditure as this program is not identified in the RIN or capex model.

The number of sites requiring rectifications is likely to be reasonable

277. We asked Powercor for a copy of its 10-year plan, which we understood to include a prioritised list for addressing the identified clearance defects. In its response, Powercor stated that:

> *'During 2023 we conducted a LiDAR inspection that found a high volume of sites (~49,000) had potentially become non-compliant with AS 7000:2016 over time. Further validation on around 3,000 of these sites confirmed that around 9 per cent are non-compliant. This validation percentage was extrapolated across the full potential defect sample, indicating approximately 4,400 sites will likely require rectification.* [51]

278. We were also provided with a spreadsheet with the raw inspection data for the full sample of potential non-compliant sites based on its 2024 LiDAR data. Powercor states that the more recent data did not impact the scale of the proposed program.

279. Based on representations made by Powercor, we consider this is a reasonable estimate of the required activity. More accurate forecasts are likely to be possible once the program has been operational for a few years.

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50 PAL BUS 4.03 – Overhead conductors – Jan2025 – Public, page 14

51 Powercor response to IR013

Powercor select from a range of reasonable options to address the identified non-compliance

280. Powercor has provided a model[52] that summarises the costs of its three options, with its preferred approach based on:

- ground clearance issues with pole replacements (52 per cent)
- re-stringing (38 per cent)
- pole top upgrades (6 per cent), and
- other solutions (4 per cent).

281. The model outlines the assumed percentage of clearance issues, and the cost of each solution aligns with the deployment of solutions as outlined above. The assumed costs are reproduced in Table 3.15

Table 3.15: Assumed costs for conductor replacement $ FY2026 (excl cost escalation)[53]

Conductor clearance rectification solution	Estimated cost to implement per site
Restringing/Re-Sagged	$7,590
Pole Top Augmentation (Raiser Bracket, Crossarm)	$7,000
Pole Replacement/New Pole	$17,288
Other (LV retirement etc)	$7,590
Spreader installation	$1,767

Source: PAL MOD 4.09 - conductor rectification based on LiDAR - Jan2025

282. Based on our review of pole and crossarm costs, the costs assumed for this program also exhibit similar issues relative to the costs of other DNSPs, and which impact where those solutions have been applied.

An estimate of poles replaced under the wood pole replacement program has been excluded

283. Powercor has made an allowance to ensure that poles that are replaced under the wood pole replacement program are not included in the costs of this program. It has assumed that 64% of poles identified for replacement to correct clearance issues will have their costs included under the clearance program as they are less than 50 years old and not replaced under the wood pole replacement program. We are not able to validate this number, however some provision is reasonable.

Assessment of risk-based 22kV replacement

284. Powercor refers to this program as the risk-based 22kV program and Replacement of aged and deteriorated HV conductors. The program is described in Appendix C of its asset class strategy.[54]

285. Powercor outlines the increasing HV conductor high priority defects and proportion of assets with a higher-risk asset condition rating also increasing.

Powercor assessed options including use of EFD

286. The installation of EFD was not recommended based on NPV. Powercor also states that:

52 PAL MOD 4.09 - conductor rectification based on LiDAR - Jan2025

53 The model does not specify the dollars that have been applied. Based on the total of $3.0 million pa, we assume that the costs are expressed in FY2026 excluding escalation

54 PAL BUS 4.03 – Overhead conductors – Jan2025 – Public

'installing EFDs on aged and deteriorated conductors will increase costs and is impractical as these conductors will eventually need to be replaced.'[55]

Powercor expects to increase its volume of conductor replacement, however, proposes a small volume in the next RCP

287. In its asset class strategy Powercor states that the identified need is:

'…to move toward more sustainable intervention volumes to prudently manage deliverability and safety factors associated with an increasingly high volume of aged and deteriorated polyphase HV conductor.'[56]

288. We are concerned by statements that indicate an uplift in replacement volumes that are not linked to a compliance obligation, condition factors or economic analysis. However, we found that Powercor had developed an economic model based on calculation of the energy at risk in the event of a conductor failure. Despite identifying a large portion of conductor sections as being economic to replace using this model, Powercor has not relied on this model to develop its forecast expenditure.

289. We asked Powercor to describe the criteria applied to determine the proposed volume for conductor replacement, which differs materially from both the long-term average conductor replacement of approximately 120km per annum and the economic assessment results which Powercor stated shows replacement of a much larger volume to be economic.

290. In its response, Powercor stated that it considered higher replacement volumes:

'.. intervention volumes for the replacement of aged and deteriorated HV conductor that more closely aligned with our economic analysis were considered, but were not proposed in the [sic] due to deliverability and affordability considerations for our customers. These considerations were undertaken in the context of both our overall replacement program, as well as within our conductor replacement program.

The characteristics of our overhead conductor population are such that we expect to need to increase replacement volumes over multiple regulatory periods. For the 2026–31 regulatory period we have proposed to prioritise radial sub-transmission lines due to the number of customers potentially impacted and high-priority ground clearance rectifications due to compliance risks. These are additional to business-as-usual interventions driven by faults and identified defects.'[57]

291. To better understand the relationship between this program and the condition-based conductor replacement program, we asked Powercor to indicate how it has determined the prudent scope and timing of the proposed replacement volume for the next RCP, including by consideration of alternate replacement volumes. Powercor stated that

'The scope of our proposed replacement volumes were determined based on deteriorated asset condition and deliverability. For the risk-based programs, we used cost benefit analysis to select a subset of the assessed conductors for replacement. Programs typically have equal annual volumes of replacements throughout the program.

The timing for fault and corrective programs are based on historical data, with risk-based programs based on the optimal timing methodology detailed below.'[58]

292. The methodology for the risk-based 22kV replacement program assessed 12,243km of overhead HV conductor with deteriorated condition, with 8,376km identified as economic to replace. However, further assessment of the optimal timing by Powercor indicated that

55 PAL BUS 4.03 – Overhead conductors – Jan2025 – Public, Table 12

56 PAL BUS 4.03 – Overhead conductors – Jan2025 – Public, page 25

57 Powercor response to IR013 Question 13

58 Powercor response to IR013 Question 9

529km of this conductor was likely to be economic to replace in the 2026–31 regulatory period.

293. Powercor proposes replacing 18km of this volume in the next RCP from this analysis, stating that:

> *'Alternative (i.e. higher) intervention volumes were considered, but were not proposed in the context of our overall conductor replacement program due to deliverability and affordability considerations for our customers.'*[59]

294. Also stating that:

> *'We recognise that this volume is low in isolation, but we have taken a cautious approach for the 2026–31 regulatory period to increase overhead conductor volumes incrementally (and with recognition to the other proposed risk-based interventions). We consider this also provides an opportunity for the impacts of electrification to be observed more fulsomely, and to inform future capacity needs as well as like-for-like replacements. In any event, these volumes will need to escalate significantly in future regulatory periods.'*[60]

295. Powercor provided a new version of its conductor model in response to our questions, which included assessment of the replacement timing for each conductor section. Powercor states that its replacement timing was determined when benefits in each year exceed the annualised capex for the conductor section, and within the regulatory period. We determined that the model indicated 979 sections, equivalent to 456kms.

296. We were not able to determine the relationship between the 529km of conductor that Powercor had deemed to be economic to replace in the next RCP, and other parts of the proposed replacement program including its risk-based conductor program.

297. As Powercor had not relied on its economic model, we did not review the modelling methods and inputs in detail.

Assessment of risk-based 66kV overhead line replacement

Powercor has identified 10 substations exposed to station black for loss of radial line

298. In Appendix B of its Asset class overview,[61] Powercor states that the identified need is to manage the risk of loss of electricity supply to customers from the ten substations supplied by radial 66kV lines, given a failure of the line will result in station black.

Powercor has proposed a prioritised list of conductor sections to be replaced

299. Powercor considered a range of options comprising a combination of capex and opex options and proposes risk-based replacement of sections of its radial 66kV lines to reduce the likelihood of line failure.

300. The options were assessed individually for each of the 414 radial line sections across the 10 zone substations, and conductor sections where the analysis yielded a positive NPV were included in the proposed program. Powercor proposes replacement of 46 of the 414 radial line sections at a NPV of $55 million, comprising:

- Cohuna (CHA) zone substation – 13 of the 20 sections are economic to replace
- Charam (CHM) zone substation – 9 of the 55 sections are economic to replace
- Charlton (CTN) zone substation – 24 of the 139 sections are economic to replace.

301. The line sections vary in age from 60 to 68 years for CHA, 70 years for CTN and 88 years old as of 2024 for CHM.

59 Powercor response to IR013, Question 9

60 Powercor response to IR013, Question 9

61 PAL BUS 4.03 – Overhead conductors – Jan2025 – Public

302. The options detailed in the business case were not explored in the provided model.[62]

Model indicates a slightly lower volume of work than has been proposed, however Powercor proposes to include additional volume by proximity

303. We observed that the model generated a slightly lower volume of conductor identified for replacement. We asked Powercor to explain the difference:

> *'This analysis indicates the optimal timing of four of these 46 line sections may occur beyond the 2026–31 regulatory period. These sections are on the 66kV line supplying our CHM zone substation and have a total length of 6.7km.*
>
> *Notwithstanding the above, we consider replacing these lines is prudent in the 2026–31 regulatory period given the following:*
>
> *• these conductors are 88 years old and deteriorated, thus replacing these four line sections will reduce station black risk at CHM zone substation*
>
> *• the replacement volume of these four line sections is relatively low (only 6.7km)*
>
> *• bundling these four line section replacements together with the replacement of the other five economic line sections on the 66kV radial line supplying CHM zone substation is likely to be more efficient.'*[63]

304. This is likely to be a reasonable strategy, given that Powercor is targeting the remaining sections that are 88 years old, likely to be experiencing similar condition issues and that the modelled timing is within a few years of the proposed works.

The timing indicated in the model suggests the program occurs within the next RCP

305. Whilst the proposed program is spread evenly across the RCP, the outcome of the model indicates that the conductor sections are identified for replacement in 2026-27, which on the basis of Powercor's assumptions suggests it is already economic to undertake this work. We looked into the assumptions further and identified that the proposed 46 line sections are of ACSR construction and varied from 65 to 87 years old with a current HI assessed to be >8 (out of the total 50 line sections of ACSR construction).

Some conductor sections have very high HI leading to high PoF, largely driven by age of the conductor

306. We observed that the model included a service life of 60 years, which indicated that at the assessment year Powercor recorded an initial HI of 5.5 and applied a scale factor referred to as a reliability factor (RF) of between 1.64-1.65, increasing the HI from 5.5 to >8 for any conductor exceeding 60 years. This suggests to us that the model is driven by age rather than condition.

307. We tested these assumptions against the failure and defect data, and found that according to Powercor's AMP, HV ACSR had a low failure rate of 0.4 per 1,000kms. From our reading of the AMP, the key areas of concern for HV conductor failure appeared to be related to Cu and Steel construction, and not ACSR.

> *'Over the last 10 years, about 66% of overhead conductor failures occurred in HV network with steel conductor accounting for 46% of total HV conductor failures.'*[64]

308. The AMP does highlight the age of the 66kV conductors, with 26% of ACSR conductor circuits over 65 years old but not its condition or performance. In terms of performance, there is limited information pertaining to issues with ACSR at 66kV. The key issues primarily

62 PAL MOD 4.10 - 66kV radial lines - Apr2025 - Public

63 Powercor response to IR013

64 Powercor - IR005 - Q2(a) - AMP - overhead conductor – public, page 17

relate to Cu and Steel conductors. Therefore, the origins of the program to replace 66kV lines are not evident in the strategy.

309. We did not see evidence that the method used to determine forecast HI values and PoF was calibrated to existing failures. Based on our assessment of the model, we aggregated the PoF in 2024 to determine the cumulative failures per 1,000km and found that this figure far exceeded the stated failures.

Methodology has weaknesses, which underscores need for calibration

310. Powercor appears to have applied the CNAIM methodology as developed by distribution network operators in Great Britain,[65] adopting many of the default values determined by the methodology. However, we are concerned that the method may not be adequately calibrated to Powercor's experience, and it may include factors that drive a higher HI and PoF than are reasonable.

311. We have seen the CNAIM methodology applied in Australian DNSPs previously, and typically with the use of Weibull parameters. According to EA technology,

> *'The CNAIM is consistent with many of the principles and recommendations in the IPAN [Industry Practice Application Note for Asset Replacement Planning]. CNAIM is a regulatory reporting and benchmarking tool and is not required to be used for individual asset replacement or refurbishment justification.'*[66]

312. We understand that the CNAIM has become the starting point for development of some CBRM models. The CNAIM states:

> *'The use of the exponential curve results in an escalating acceleration effect once assets reach a high Health Score. For assets that are approaching end of life, this can result in a run-away effect in the forecast future PoF, which would not reflect the deterioration that would be observed in real life.*
>
> *The cause of the runaway effect is due to the imperfect match of the selected curve once the asset reaches high values of health and hence resultant PoF. To minimise the potential for overstatement of the forecast future PoF, an Ageing Reduction Factor is introduced to modify the asset's rate of deterioration. This slows down the Ageing Rate of the asset by flattening the exponential curve especially (although not exclusively) where the Health Score is greater than 5.5.'*[67]

313. We consider that applying correction factors may bias the rate of degradation and should wherever possible be measured against other techniques.

314. Despite the use of an 'ageing' factor, the CNAIM operates on a 0-15 scale for HI. The impact of a health score up to 15 is unclear given that CBRM practices generally cap the HI scale at 10 with values of 7.0-7.5 triggering replacement planning.

315. Nonetheless Powercor has linked its calculation of HI to an estimated PoF, which it in turn uses to calculate its risk cost.

316. The CNAIM allows for the application of an additional Reliability Modifier to be applied at individual DNO's discretion to the Current Health Score of those assets. This would be the case if the individual DNO believes there would be a materially different PoF than would be expected for a typical asset within the same Asset Category with the same Health Score. This would possibly be because of generic issues that affect health/reliability associated with: (i) the make and type of the asset, and (ii) the construction of the asset (e.g. material used, or treatment applied).

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65 DNO Common Network Asset Indices Methodology, v2.1

66 https://eatechnology.com/australia/resources/blogs/asset-management/ipan-vs-cnaim/

67 DNO Common Network Asset Indices Methodology, page 38 viewed at https://www.ofgem.gov.uk/sites/default/files/docs/2021/04/dno_common_network_asset_indices_methodology_v2.1_final_01-04-2021.pdf

317. The Reliability modifier includes the Reliability Factor (RF) which is a multiplication factor applied in the calculation of the Current Health Score, with a default value of 1.0.

318. Powercor uses as a combination of factors including tension, vibration fatigue and buffeting turbulence fatigue to develop its RF. Our reading of Powercor's AMP, and our experience suggests that the leading causes of conductor failure are more typically related to corrosion and weather. Whereas vibration is the leading cause of connection failures. The basis for the use of these factors in derivation of a RF is therefore not clear to us.

319. Our reading of the application of the RF in the CNAIM, limits the combination of factors when applying the Maximum and Multiple Increment (MMI) technique and would lead to a lower RF than Powercor has proposed.

320. In our view, this underscores the need to calibrate any model to observed experience, and where possible experience or methods employed by others across the industry.

Adoption of more reasonable inputs will likely reduce the scope of the proposed replacement

321. Notwithstanding the identified risk of conductor failure of radial connected substations, this is inherent in the design. Powercor's program relies on its economic analysis and robustness of the assumptions that this analysis has relied upon. We consider that the modelling has likely overstated some of the assumptions that lead to its high PoF rates.

322. In response to our information request, we were provided with a model[68] that Powercor relied upon to generate the PoF values for this project. We were able to modify the RF values which generate a PoF series, materially reducing the identified replacement volumes.

323. We also identified other potential factors, including

- Service life for ACSR is assumed to be 60 years, being younger than other construction types, which has the result of increasing the modelled HI for these sections
- The values of energy at risk were hard-coded and we were not able to confirm these, as were the VCRs. We consider that like other projects this may be sensitive to changes in the assumed VCR given more recent updates by the AER.

324. We consider there is sufficient uncertainty in the modelling to alter the outcome that Powercor has relied upon for this project.

Assessment of minimising bushfire risks from bare 22kV conductors

325. Powercor also refers to this project as Minimising bushfire risks from bare non-REFCL protected 22kV conductors in HBRA, and also Bare 22kV conductor bushfire mitigation.

326. In Appendix D of its supporting business case,[69] Powercor states that the lack of REFCL protection on bare 22kV conductors in its HBRAs represents a significant bushfire risk. Powercor states that the identified need for the proposed project to replace 62km of bare overhead conductor in HBRA is to minimise as far as practicable the potential for fire starts associated with these conductors.

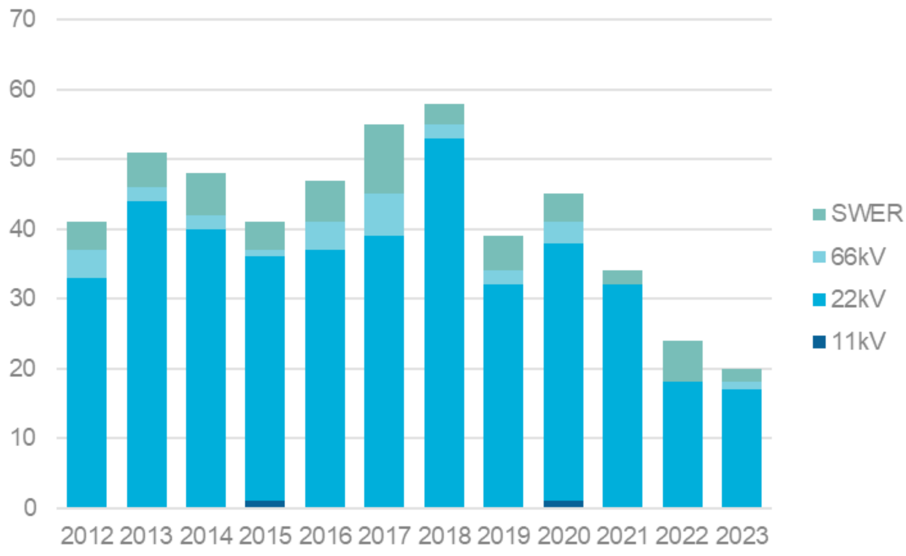
Number of fire starts are declining

327. Powercor states that 22kV lines are the leading cause of HV conductor fire incidents, accounting for 83 per cent of all HV conductor-related fires. We asked Powercor for the data that supports the statements around fire starts. Whilst the response confirmed that fire starts are dominated by 22kV volage lines, the number of fire starts has been declining since 2020 as shown in Figure 3.17.

68 Powercor - IR013 - Q8 - PoF 66kV conductor

69 PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public

Figure 3.17: Historical fire starts by voltage



Source: EMCa derived from IR005 Q5(b) HV conductor fire starts

328. We were not able to determine the cause of the fire starts from this data, to ascertain the percentage that can be attributed to causes which may be addressed through conductor replacement. Powercor states that the leading causes include insulator leakage and vegetation, both of which are addressed by the solution to replace bare conductor with covered conductor.

329. The declining trend of fire starts may be for a number of reasons including interventions made by Powercor to reduce the fire risk or other factors.

Basis for determining the proposed volume of conductor replacement is reasonable

330. We understand that the conductor targeted for replacement is associated with the highest bushfire risk lines. To help us better understand the basis for selecting the installation of 62km of covered conductor on bare non-REFCL protected 22kV conductors in HBRA, we asked Powercor to provide an explanation of the risk criteria applied to determine the bushfire risk. The criteria applied to determine bushfire risk are consistent with that applied for all potential investments under Powercor's AFAP procedure.

331. Powercor stated that the bushfire risk values are obtained from the outputs of the bushfire risk model (BRM), which are input (hard coded) into the business case NPV model.

332. The selection of the 62km of bare 22kV conductor on non-REFCL protected lines within HBRA was based on the following steps:

- the bushfire risk model was used to determine and extract the bushfire risk per pole for the network and mapped to all 22kV overhead bare conductor sections
- the mapped data was then filtered to 22kV overhead bare conductor sections on non-REFCL protected lines within HBRA, and disproportionality factors were applied
- the risk reduction for the installation of covered conductor was determined by assessing the effectiveness of covered conductor (control) as rated against the identified risk causes (with the effectiveness criteria and ratings independently validated by GHD). This results in a bushfire risk reduction of 63.5 per cent
- cost benefit analysis was undertaken based on the cost to install the new covered conductor and the risk reduction per conductor section
- the sections were ranked from highest to lowest present value, from which the sections with a positive value and where conductor age was 50 years or greater. In total this added to ~62km of conductor replacements, and

- the annual bushfire risk associated with the 62km of conductor was summated ($853,135) and entered into PAL MOD 4.17.

333. We were not provided with evidence of this process; however, the process appears logical. We have reviewed the economic model where the 62km is an input along with the bushfire risk value. Based on these inputs, the project generates positive economic value.

334. Whilst Powercor considered additional options including deployment of EFD technology which it considered also for its SWER program (including in our assessment of bushfire mitigation augex), and combinations of covered conductor and EFDs it has determined that the installation of covered conductor only has the highest net benefits. Powercor has selected the prudent option.

Bushfire risk projects aligned with broader application of its AFAP procedure

335. Powercor states that the criteria applied to determine bushfire risk are consistent with that applied for all potential investments under its AFAP procedure. For example, where the primary driver of an initiative is harm risk reduction (e.g. bushfire risk) and that harm benefit is greater than 50 per cent of the total benefit (including the use of disproportionate factors), they are considered as AFAP harm reduction projects and assessed as follows:

- where the investment has a PVR>1; the combination of harm reduction benefits and other investment benefits exceed the project cost, and this is treated as mandatory and project timing is accepted, and
- where the investment has a PVR<1; the project cost exceeds the harm reduction and other investment benefits, and the project is deferred until or if the risk increases to a time that it exceeds the PVR >1 threshold.

336. Powercor states that the development of its AFAP projects follows the AFAP risk mitigation investment assessment procedure and which was reviewed for Powercor by GHD.

337. Powercor has followed a common procedure for valuing bushfire risk, and which we consider is reasonable.

Cost estimates within a reasonable range

338. The unit rate assumed for covered conductor was $152,000 per km ($2023).

339. We asked Powercor to explain the basis for the cost estimates included for this project. Powercor stated that the cost estimate for the installation of covered conductor was based on the costs from completed overhead bare conductor replacement projects, then increased for the expected additional costs required for multi-phase covered conductor (such as additional material and labour costs associated with installing covered conductor and the installation of surge arrestors). This was undertaken as Powercor did not have sufficient history of covered conductor installation at the time.

340. We consider this is a reasonable approach for establishing its estimated cost.

Findings

341. We consider that the proposed conductor repex is overstated.

342. We find aspects of the program are reasonable including minimising bushfire risks from bare 22kV conductors, and risk-based 22kV replacement programs. Similarly, the approach adopted for conductor clearance rectification from LIDAR program is reasonable.

343. For the defective and fault-based conductor replacements we found that the proposed replacement volumes are not reflective of more recent replacement volumes and once adjusted, would reduce the size of the program from 737 to 498km.

344. We found issues in the modelling approach adopted by Powercor in its assessment of the proposed risk-based replacement of 66kV lines. When more reasonable inputs are adopted, the scope of the proposed risk-based replacement of 66kV lines to be completed in the next RCP would be less than Powercor has proposed.

3.3.4 Transformers

What Powercor has proposed

345. The scope for our assessment for the Transformer asset group is shown by asset category in Table 3.16, and which excludes some Transformer repex.

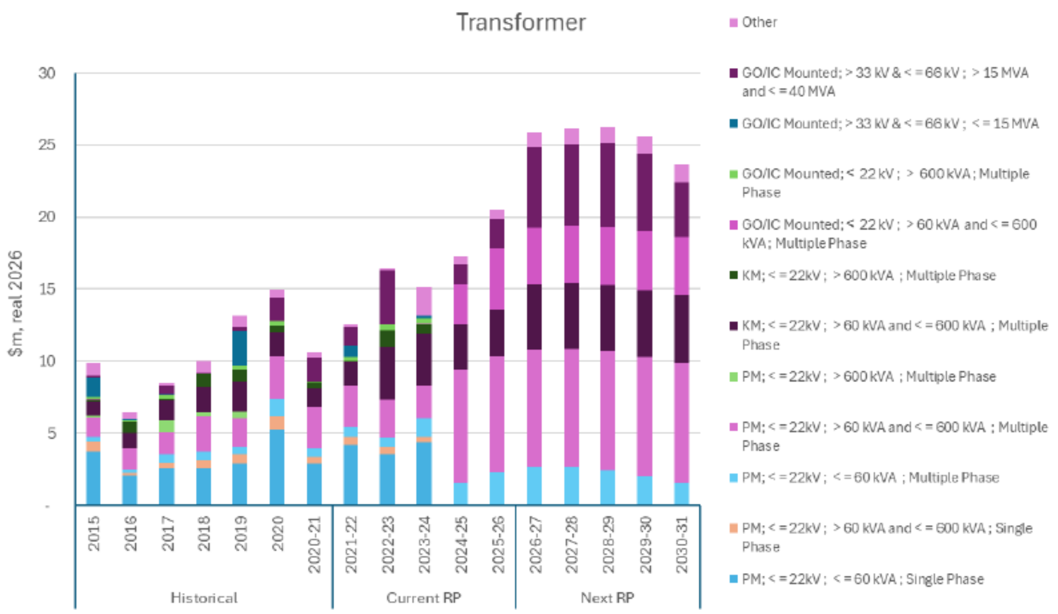
Table 3.16: EMCa's scope of Powercor's proposed transformer repex - $m, real FY2026

Transformer	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Minor station works	0.9	1.0	0.8	1.1	0.8	**4.4**
Transformer refurbishment	1.8	1.9	1.9	1.9	1.9	**9.3**
ZSS transformer replacement	5.6	5.7	5.8	5.3	2.7	**25.1**
Total	**8.3**	**8.6**	**8.5**	**8.3**	**5.3**	**38.9**

Source: EMCa table derived from Powercor SCS capex model

346. In Figure 3.18 we present the historical and forecast expenditure for the substation asset group in the RIN. Expenditure reported in the transformer asset group in the RIN will differ from the project-based expenditure, as major plant replacement works (such as transformer replacements) are allocated across multiple RIN asset categories to reflect the nature of the work undertaken.

Figure 3.18: Historical and forecast transformer repex $m FY2026



Source: EMCa derived from RIN

347. We observe increases to pole mounted and ground mounted 60-600kV transformers estimated in 2024-25, and which continue at these higher levels into the next RCP. In addition, Powercor is proposing a material increase to its 66kV transformer replacement volume in the next RCP compared to the historical trend.

Assessment of transformer replacement program

Three transformer replacements are proposed for the next RCP

348. Powercor has included transformer replacements at Cohuna, Mooroopna, and Shepparton North substations as described in its Asset class strategy document (BUS 4.08).

349. A summary of the three transformer sites is included in Table 3.17.

Table 3.17: Summary of proposed transformer replacement projects ($m, real 2026) – excluding escalation

Substation	Summary of need	Preferred option	Forecast expenditure	NPV	Completion year
Cohuna (CHA) zone substation	Transformers are 62 years old and at end of life, key components past design life, with failing main tank seals. T2 in worse condition and assessed for replacement	Replace	8.0	1.0	2027-28
Mooroopna (MNA) zone substation	Transformers are nearly 50 years old and approaching end of life, key components past design life, with failing main tank seals. T1 in worse condition and assessed for replacement	Replace	8.3	1.0	2028-29
Shepparton North (SHN) zone substation	Transformers are 42 years old and close to end of life. T2 in worse condition and assessed for replacement	Replace	7.5	0.7	2030-31

Source: EMCa derived from PAL BUS 4.08 - Zone substation transformers - Jan2025 - Public

Powercor has relied solely on its economic analysis for transformer replacement

350. We asked Powercor for any major changes to the management of its substation transformer assets over the last 10 years (if any). Powercor stated:

> *'we now consider the station as a system, rather than on an asset-by-asset basis. This approach has a greater emphasis on the consequence associated with asset failure rather than the likelihood (as a function of condition). Further, the Environmental Protection Act (2017) requires us to manage assets in such a way to minimise harm to the environment 'as far as reasonably practicable', driving investments during the current regulatory control period to mitigate and contain power transformer oil leaks'* [70]

351. We also requested copies of condition reports. Powercor stated that for zone substation assets, whilst its program considers condition, it is not driven by condition—for example:

> *'Interventions are driven by risk associated with the substation as a system, not on a singular asset basis. This is deemed the most appropriate for zone substations, which have time-varying levels of redundancy throughout the year, and inter-dependencies.*
>
> *condition is included where risk is identified to prioritise assets within the substation. A detailed condition assessment is not necessarily required for this approach, and a comparative assessment of the condition of key components (e.g. bushings, OLTC and winding) is generally sufficient to determine prioritisation, which we have considered in our forecast*
>
> *our risk modelling uses low failure rates and probability functions based on historic data, which are benchmarked against industry statistics. Where there is a particularly serious condition issue identified with an asset that would create a significant failure risk increase which would materially increase the likelihood of failure, this is typically treated not via replacement, but our routine maintenance and repair processes.'* [71]

[70] Powercor response to IR005

[71] Powercor response to IR005 question 2

352. For the transformers included in the proposed capex, we were not provided with additional supporting information that demonstrated that the transformers were at end-of-life as Powercor has claimed. Our analysis has therefore focussed on the economic analysis that has been provided, and which Powercor has used to support the proposed program.

Risk methodology applied for its replacement projects appears reasonable

353. Given the proposed increase in substation transformer repex, we asked Powercor how the asset condition risks were managed in the current RCP (2021-26) and the prior RCP (2016-2021), and how this was categorised in the historical capex. In its response Powercor provided an overview of key changes to its methodology:

> *'During the 2016–21 regulatory period, zone substation asset replacement was primarily prioritised using health index (HI) ratings generated from the original CBRM models. In 2018, the investment framework evolved to incorporate load index (LI), acknowledging that asset deterioration alone does not always justify immediate replacement. Assets with high HI but low LI were assessed as lower priority.*
>
> *This approach introduced a more holistic view of risk, optimising investment timing and enabling the network to direct funding toward higher-benefit areas. It also marked the start of a shift away from isolated condition scoring to risk-informed planning.*
>
> *Leading into the 2021–26 regulatory period, a new generation of CBRM models was developed for transformers, switchboards, and circuit breakers. These models were integrated into risk monetisation frameworks, allowing the network to better quantify asset risk and make economically defensible investment decisions.'*[72]

354. We consider that the evolution of the risk methodology outlined by Powercor is reasonable.

355. Powercor has develop a Parallel risk model[73] using this methodology which it uses to determine the risks for each asset at each substation, which are then input into each of the economic models for each site.

356. The methodology to determine its failure probabilities, and risk monetisation is as described in the Asset risk quantification guide:

> *'The preferred methods to assess the likelihood of a common-cause failures is the Multiple Greek Letter model. This is one of the most used Common-cause failure (CCF) - factor model in the 2-asset case).'*[74]

357. For each transformer, the risks are made up of unserved energy, safety, unplanned replacement risk, unplanned fault risk and environmental risk. The primary risk cost is Unserved energy following failure of the transformer, then environmental risk.

Options analysis does not consider transformer life extension

358. In its asset class strategy, Powercor define the refurbishment of a transformer as:

> *'Refurbish the transformer if the transformer has not been recently refurbished. This may entail oil treatment, painting/repairs to the main tank, and other minor component replacement as required but does not include any OLTC or oil replacement.'* [75]

359. However, Powercor's options analysis does not consider its refurbishment option as providing life extension, as we would have expected. Our understanding was confirmed in the onsite discussion, that the alternate to replacement was limited in scope. A life extension option, if proven to be feasible for the transformer fleet, may provide Powercor

72 Powercor response to IR005 question 2

73 PAL MOD 4.06 - Parallel risk model - Jan2025 - Public

74 PAL ATT 4.01 - Asset risk quantification guide - Jan2025 - Public

75 PAL BUS 4.08 - Zone substation transformers - Jan2025 - Public

with ability to manage increasing transformer risk and stage transformer replacements in future years.

360. We reviewed the AMP provided in response to our information request, which considered the credible options for transformer management. One of the options was to defer replacements, coupled with investment in targeted refurbishment and risk-mitigation measures (option 3). Powercor states that the option is technically possible, however refurbishment is most effective at mid-life where equipment is showing signs of deterioration. Based on its assessment of the current age profile, Powercor concluded that many of the oldest assets would not benefit from refurbishment works, so the residual risk for these transformers would still be high. This is a reasonable assumption for transformers that are in a deteriorated condition.

Adjustment for more reasonable input assumptions is likely to lead to deferral of the proposed replacement projects

361. We have reviewed the calculation of the Energy at Risk included in Powercor's Parallel risk model and consider this provides a reasonable estimate. To calculate the unserved energy, Powercor multiplies the Energy at risk by VCR, which is determined for each site.

362. We have not been provided with the customer weightings for calculation of the VCR applied in its unserved energy calculation. The values indicated in Table 3.18, and consideration of the geography of the areas, suggests a higher weightage to business and/or agricultural customers. In the latest AER VCR study published in 2024, the values were materially changed including a reduction to the business customer VCR and also the agricultural customer VCR. When the new VCR figures are adopted for the customer base applicable for these sites, we consider that the proposed timing of replacement for each of the nominated substation sites would be deferred relative to what Powercor has proposed.

Table 3.18: Summary of VCR assumed for the proposed transformer replacement projects

Substation		Location	VCR ($2023)
CHA	Cohuna	Rural	48.01
MNA	Mooroopna	Rural	48.58
SHN	Shepparton North	Rural	47.13

Source: EMCa analysis of transformer models

363. The aggregate environmental risk is a hard-coded value and which we understand is similar to the values developed as a part of Powercor's environmental management program. We consider that this is not a reasonable estimate of the environmental risk, as discussed in a subsequent section of our assessment.

364. For the CHA site, the site monetised environmental risks are given as $176,250 pa, with T2 having a leak rate of >300L per year and which is a significant driver of risk cost for this project. As discussed in our assessment of the transformer environmental management program below, we consider that the risk costs are not formed on a reasonable basis and if removed for this project, would result in deferral of the replacement project. However, Powercor's description of the issues at this site suggest that remediation is required under one of its programs.

Alignment of the assessment periods results in reductions to the calculated NPV

365. The calculation of costs and benefits are not reviewed on the same basis. Specifically, the capital costs associated with the transformer replacements are annualised over a life of 50 years, and which decreases the costs considered for the assessment period of 20 years. Adjustments to align the assessment periods results in reductions to the NPVs that are

already small in value, to the point that the nominated sites are not economic to proceed in the next RCP.[76]

Cost estimates for substation projects appear high

366. Powercor has provided cost estimates for each of its replacement projects in response to our information request. These are provided at a high level – comprising project management, design and construction (primary, secondary and civil). We note that the AER flagged a concern with the high costs of its proposed substation replacement projects in the current period.

367. The lack of granularity does not allow for detailed review, other than to note that the costs appear high. The proportion of project management costs for these projects also appears high, in the range of 14-15% and 18-20% of the total cost for switchboard projects.

368. At a total level, we observe that the costs for projects undertaken at rural substations for Powercor are similar to those in CBD/urban areas for CitiPower, where we had expected to see a greater differential in costs, with the CBD sites being higher.

Table 3.19: Range of substation replacement costs, $m, 2026

Activity	CitiPower	Powercor
Transformer replacement	6.2 (VM) 7.2 (AR) 8.5 (NC)	8.3 (MNA) 8.0 (CHA) 7.5 (SHN)
Switchboard replacement	15.3 (VM) 8.7 (AR) 8.1 (RD, NC)	9.0 (KYM) 8.7 (MNA, NKA, PLD, WBL)

Source: EMCa derived from information provided by Powercor and CitiPower

369. In its final decision for the current period, the AER stated that '*the proposed transformer unit costs for a new build zone substation are high relative to benchmarked new zone substation builds for AusNet Services and Jemena.*' [77] Also, that '*Powercor had not supported this relative difference in costs and has not identified any specific site conditions that would warrant additional costs to a typical installation.*'[78]

370. We do not have access to the information relied on by AER in making this determination. But the costs included for the next RCP by Powercor are similar to the costs for CitiPower and are not adequately explained.

371. We compared the transformer replacement costs proposed to be incurred in AusNet's network, which range from $3.1 – $4.4 million, which is much lower than forecast by Powercor (and CitiPower).

Assessment of transformer environmental management program

Powercor has established the program based on its risk-cost modelling

372. In addition to its proposed transformer replacements, Powercor has included a program to address identified oil leaks at its zone substation sites. Powercor described this as '*a risk-based approach to complying with the Environmental Act and have significantly increased our investment in this area across a range of network-related activities.*'[79]

373. Powercor has submitted a model[80] that identifies 25 transformers where it considers that the cost to address the risk is lower than its assessment of the risk-cost, identified as a benefit

[76] We describe this issue more generally in Appendix B

[77] AER Attachment 5: Capital expenditure | Final decision – Powercor 2021–26, page 5-38

[78] AER Attachment 5: Capital expenditure | Final decision – Powercor 2021–26, page 5-38

[79] PAL BUS 4.08 - Zone substation transformers - Jan2025 – Public, page 17

[80] PAL MOD 4.04 - Transformer refurbishment - Jan2025 - Public

to cost ratio >1. The program spans the current and next RCP, with 15 transformers proposed for replacement on environmental grounds in the next RCP.

Overlap between the environmental management program and transformer replacement program

374. We identified that the proposed sites included in CHA T2, which we understand is also proposed to be replaced.

Quantification of base risk cost is not correct

375. Powercor has calculated the risk cost, as the base risk value multiplied by a series of modifiers which we understand have the objective of reflecting a higher consequence arising from loss of oil to the environment (e.g. proximity to water bodies). This is also explained in Powercor's risk assessment quantification guide.[81]

376. We have identified several issues with the methodology. The base risk value is stated as the value of oil at $129.30 ($2023) per litre, which is then multiplied by volume of oil lost p.a. In our opinion, the risk cost should reflect the combination of probability, likelihood and consequence values that seek to reflect the cost to the local environment. This value also differs from the risk assessment methodology, and which uses a value based on 1/2000th of the value of a statistical life-year (VSLY) which we also consider is not correct. Using a risk cost equivalent to the cost of topping up the oil is the same as the current operational cost.

Modifiers are not allocated correctly

377. The modifiers are not scaled in accordance with the risk assessment methodology:

- Depth to ground water source is a factor that varies from 1 to 3, however the factor of 3 is only used for depth to ground water of 5 (not 1,2,3 or 4). This is not intuitively correct, as the higher risk would be to groundwater sources closer to the surface
- The distance modifier is also not intuitively correct, as risk increases with distance from water source – it should be the other way around
- Bunding modifier is typically set to 1, therefore it is not used, and
- PCB modifier is set to 1 or 5 - 5 when PCBs are present and which would have a higher environmental cost, so it is directionally consistent but does not apply to the selected transformers for the next RCP.

378. If all modifiers are set to their maximum, the aggregate impact is to increase the risk value by 75. We checked to see how sensitive the modelling was to the modifiers by resetting them all to 1. In doing so the program did not materially change.

Consequence costs are not developed on a reasonable basis

379. The AER's guidance note on Asset replacement planning for environmental consequences states:

> *'This refers to the environmental consequence to the surrounding community, ecology, flora and fauna arising from the failure of an asset. Notable environmental consequences are bushfire or contamination (e.g. oil leakage). The monetised value of the consequence typically considers costs for: • property loss; • damages for personal injury or loss of livelihood; • deemed loss to the natural environment; • clean-up or remediation; • any other related costs (which must be reasonably likely to be incurred and adequately justified).'*[82]

380. Powercor has not made a reasonable attempt to quantify the consequence for this program. For example, this could have been estimated based on the extent of potential contamination

[81] PAL ATT 4.01 - Asset risk quantification guide - Jan2025 - Public

[82] D19-2978 - AER -Industry practice application note Asset replacement planning - 25 January

(litres released/spilled) and which links to the clean-up cost and compliance/enforcement costs under the Environmental Protection Act 1994 for water contamination.

The cost to address loss of oil, referred to as its environmental management cost per transformer is not consistent across its program

381. The assumed cost per transformer is $530k ($2023) in this program, however in the transformer replacement options analysis the cost is $500k ($2023).

Some of the sites have high volume oil discharge and require action

382. Some of the sites identified by Powercor had annual loss of oil as being >300L. We understand that Powercor has a maintenance program to address this oil loss, however this level of oil loss appeared high to us.

383. We understand that Powercor has an existing program to address high risk sites in the current period, and it would be reasonable that additional high-risk sites are remediated into the next RCP. If the leaks are as bad as stated, and the cost of oil is as has been assumed, then some projects are self-funding, in that the cost of refurbishment is recovered within 1 year though savings in the cost of oil replacement. However, we suspect this is not the case, and that it is reasonable to include the high-risk sites in the next RCP for remediation.

Assessment of minor station works

384. From the submission we were unable to determine the scope of works included in these programs, or to which repex asset groups they were likely allocated to. We identified a single statement in the Asset Class strategy document, being:

> *'We forecast our unplanned interventions predominately based on historical average of the previous five years. These typically comprise minor station works.'*[83]

385. We requested Powercor to provide a justification statement identifying the need, scope, timing and to provide the supporting economic analysis for the minor station works repex, and miscellaneous plant and stations repex. These projects totalled $16.1m.

386. In its response, Powercor stated:

> *'These categories of investment reflect unplanned and reactive works, typically driven by emerging defects, operational issues, or site-specific condition risks that cannot be reliably forecast at an asset or component level. For example, they include the following:*
>
> – *minor station works include bushing replacements, cooling tower pipe and valve replacements and single 66kV CB replacements*
> – *miscellaneous plant and stations repex includes CVT replacement, control cable duct replacement and transformer Buchholz switch replacements.*
>
> *The nature of these works varies in any given year, but have been incurred historically and will arise across the 2026–31 regulatory period. Given the variability in these works, forecasts are based on a simple historical average of annual expenditure over the previous four-year period. This approach provides a representative basis for future requirements, and aligns with internal capital planning practices for comparable expenditure types.'*[84]

387. We acknowledge the need for unplanned reactive works in zone substations, including on the assets included in Powercor's response. Whilst we have not been provided with the historical data relied upon to calculate the historical average, given the expenditure proposed for this program, we consider that the program proposed by Powercor is reasonable.

83 PAL BUS 4.08 - Zone substation transformers - Jan2025 - Public

84 Powercor response to IR013

Findings

388. We consider that the proposed substation transformer repex is materially overstated.

389. For the proposed transformer replacements, we were not provided with additional supporting information that demonstrated that the transformers were at end-of-life as Powercor has claimed. Our assessment has therefore focussed on the economic analysis that has been provided, and which Powercor has used to support the proposed program. We found that adjustment for more reasonable input assumptions is likely to lead to deferral of some of the proposed replacement projects beyond the next RCP.

390. For the transformer environmental program, we did not find that the program has been sufficiently justified. We understand that Powercor has an existing program to address high risk sites in the current period, and it would be reasonable to undertake a smaller program targeting high-risk sites in the next RCP.

391. Inclusion of the reactive program for substation assets is reasonable.

3.3.5 Switchgear

What Powercor has proposed

392. The scope for our assessment for the switchgear asset group is shown by asset category in Table 3.20, and which excludes some switchgear repex.

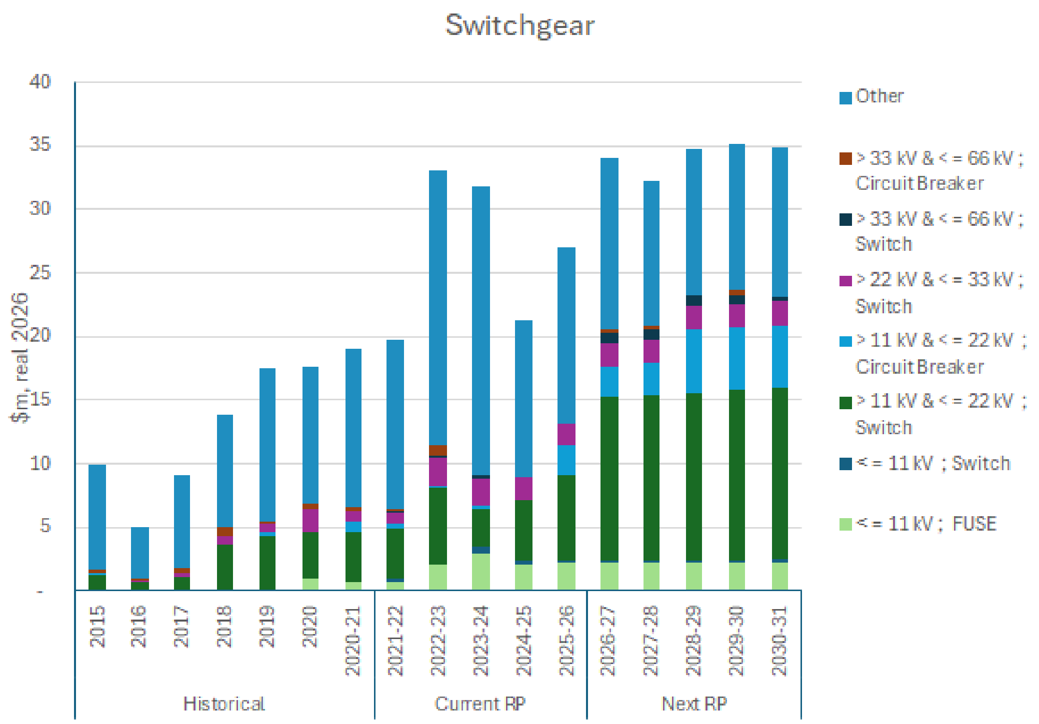
Table 3.20: EMCa's scope of Powercor proposed switchgear repex - $m, real FY2026

Switchgear	2026-27	2027-28	2028-29	2029-30	2030-31	Total
ZSS switchboard replacement	4.5	4.7	9.3	9.2	9.3	**37.1**

Source: EMCa table derived from Powercor SCS capex model

393. In Figure 3.19 we present the historical and forecast expenditure for the switchgear asset group in the RIN. Expenditure reported in the switchgear asset group in the RIN will differ from the project-based expenditure, as major plant replacement works (such as transformer replacements) are allocated across multiple RIN asset categories to reflect the nature of the work undertaken.

Figure 3.19: Historical and forecast switchgear repex $m FY2026



Source: EMCa derived from RIN

394. We observe increases to the replacement of 22kV switchgear (switches and CBs) in the next RCP. It is not clear from this chart how much of that is associated with distribution versus substation switchgear. However, if we isolate 22kV CBs, which are typically associated with switchboard replacement projects, we see a large increase compared with the historical trend.

Assessment of switchboard replacement program

Five switchboard replacements are proposed for the next RCP

395. Powercor has included switchboard replacements at Kyabram, Portland, Numurkah, and Mooroopna substations in addition to the completion of a project commenced in the current RCP at Warrnambool substation as described in its Asset class strategy document.[85]

396. The original model provided with the submission did not provide details for each of the substation sites. We asked for a replacement model, which was provided.[86] We summarise each of the switchboard projects, drawing from output of the modelling, in Table 3.21.

---

85 PAL BUS 4.09 - Zone substation switchgear - Jan2025 - Public

86 Powercor - IR013 - Q14a - PAL MOD 4.05 - Transformer rebuild - Apr2025 - public

Table 3.21: Summary of proposed switchgear replacement projects ($m, 2006)

Substation	Summary of need	Preferred option	NPV	Completion year
Warrnambool (WBL) zone substation	• Built in 1948 • legacy lack of sectionalisation introduces risk of station black in the event • safety risk with brown-pin type insulators • Protection relays close to end of service life • Control building deteriorated and beyond design life	replace the 22kV switchgear and relays in a new building	18.7	2026-27
Kyabram (KYM) substation	• Built late 1940s • legacy lack of sectionalisation introduces risk of station black in the event • safety risk with brown-pin type insulators • Protection relays well beyond service life • Control building deteriorated, hazardous material and beyond design life	replace the 22kV switchgear and relays in a new building	11.6	2028-29
Portland (PLD)	• Built early 1960s • legacy lack of sectionalisation introduces risk of station black in the event • safety risk with brown-pin type insulators • Protection relays well beyond service life • Control building deteriorated, hazardous material and beyond design life	replace the 22kV switchgear and relays in a new building	3.4	2029-30
Numurkah (NKA)	• Built 1960s • legacy lack of sectionalisation introduces risk of station black in the event • safety risk with brown-pin type insulators • Protection relays well beyond service life • Control building deteriorated	replace the 22kV switchgear and relays in a new building	2.4	2030-31
Mooroopna[87] (MNA)	• Built early 1960s • legacy lack of sectionalisation introduces risk of station black in the event • Protection relays well beyond service life • Control building deteriorated, hazardous material and beyond design life • Located in 1 in 100-year flood zone	replace the 22kV switchgear and relays in a new building	2.1	2031-32

Source: EMCa analysis of transformer rebuild model

397. The NPV results included in the above table are based on the modelling provided. We found that the NPV results included in the asset class strategy document did not align with the model. The completion year is based on the timing of the proposed capex in the regulatory proposal, as the modelling included all projects commencing in 2026-27.

[87] transformer replacement is also proposed at this site

Powercor has relied solely on its economic analysis for switchboard replacement

398. We asked Powercor for any major changes to the management of its substation switchgear assets over the last 10 years (if any). Powercor stated:

> *'we now consider the station as a system, rather than on an asset-by-asset basis. This approach has a greater emphasis on the consequence associated with asset failure rather than the likelihood (as a function of condition)'*[88]

399. We also requested copies of condition reports. Powercor stated that for zone substation assets, whilst its program considers condition, it is not driven by condition, as was the case for substation transformers.[89]

400. For the switchboards included in the proposed capex, we were not provided with additional supporting information that demonstrated that the switchgear is at end-of-life as Powercor has claimed. Our analysis has therefore focussed on the economic analysis that has been provided, and which Powercor has used to support the proposed program.

401. In the asset class strategy, this is explained as:

> *'For the 2026–31 regulatory period, our focus is rural 66/22kV zone substations that are susceptible to station 'black' in the event of a fault or plant failure at the zone substation. This stems from a lack of sectionalisation, which is a legacy issue from the original construction of the substations. Consequently, these zone substations have a higher risk in case of a failure as they do not possess a level of redundancy typically expected for such substations.* [90]

Asset risk methodology applied for its replacement projects appears reasonable

402. Given the proposed increase in substation switchboard repex, we asked Powercor how the asset condition risks were managed in the current RCP (2021-26) and the prior RCP (2016-2021), and how this was categorised in the historical capex. In the response to our assessment of the proposed transformer repex, Powercor stated that for switchboards:

> *'Switchboard prioritisation has similarly evolved. Online PD monitoring and DLA testing were introduced to improve condition intelligence, which in turn supported a more targeted selection of investment candidates (e.g. LQ and B switchboards).*
>
> *In addition, augmentation and operational network reconfiguration replaced the need for certain replacement projects. For example, multiple CitiPower substations were decommissioned and offloaded to adjacent stations, allowing aged assets to be retired.'*[91]

403. We consider that the evolution of the risk methodology outlined by Powercor is reasonable.

Powercor considers a range of sources of risk

404. Switchboards are modelled as a collective arrangement of multiple busses and modelled using an approach[92] applicable to systems with designed redundancy.

405. Powercor has identified risks from the following sources:
   - *'Insulators are the most common causes of failure within outdoor switchyards. Existing brown-pin type insulators in a zone substation from the 1960s are beyond their design life. They fail catastrophically, creating shrapnel that can damage plant and injure any personnel in the vicinity. Our failure rates are modelled based on*

88 Powercor response to IR005

89 Powercor response to IR005 question 2

90 PAL BUS 4.09 - Zone substation switchgear - Jan2025 - Public

91 Powercor response to IR005 question 2

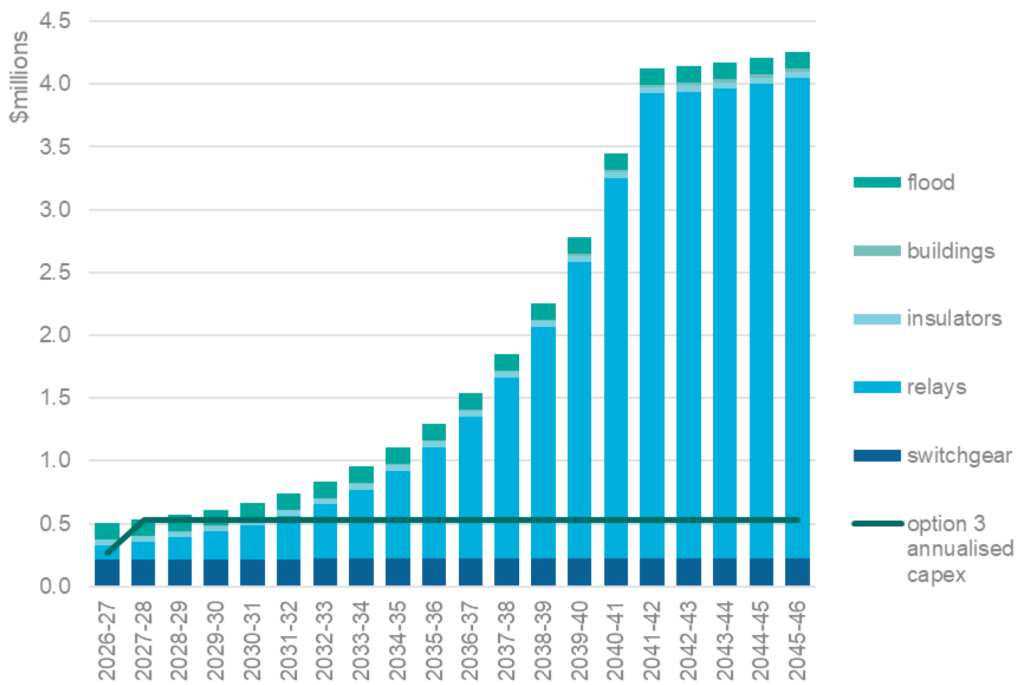
92 Described as MooN, meaning it provides M-out-of-N redundancy

recent performance, with the consequences of failure including energy at risk of a bus outage and safety risks.

- *Relays Some of our relays in rural zone substations are well beyond their service life. Relay risks were assessed as per the methodology set out in the relay asset class overview.*
- *Control cables – Based on original installation. These cables can pose safety risks to our staff due to deteriorated insulation and tripping hazards with cable trenches in the switchyard, such as due to missing trench covers. The energy at risk due to control cable failure has been calculated based on the annual probability of failure, outage duration, demand forecast and the VCR of the zone substation*
- *Buildings - Many of our rural zone substation control buildings are well past their service life and showing visible signs of deterioration, containing hazardous building materials. The annual probability of building failure was underpinned by the Weibull curve of historical failures based on building age.*
- *Floods - Three of our rural zone substations are located within the existing 1-in-100 year flood zone, and although protected by Levies flood events have resulted in supplies being interrupted. Quantification is based on VNR, the probability a flood will impact the zone substation, zone substation demand and historical flood outage duration.* [93]

406. The largest source of risk is associated with its relays, as a hard-coded input from its relay model. We were not able to review the calculation of the relay risks. A sample of Powercor's forecast for the risk cost stack for WBL substation is provided in Figure 3.20.

Figure 3.20: Example of the risk cost stack for WBL substation ($2023)



Source: EMCa analysis of Powercor - IR013 - Q14a - PAL MOD 4.05 - Transformer rebuild - Apr2025 – public

407. Given the impact of the relay-related risks to the economic assessment of these projects we were not able to ascertain whether the methods that have been applied by Powercor are reasonable.

93 Adapted from PAL BUS 4.09 - Zone substation switchgear - Jan2025 - Public

Cost information is not consistently represented in Powercor's models

408. We asked for evidence of the cost estimates for the ZSS rebuild costs for each of the substations and compared them with the costs that Powercor had included in its model (refer to Table 3.22).

Table 3.22: ZSS rebuild cost estimates ($m, 2026 unescalated)

Substation	Cost estimate	Economic model (highest NPV option)	Economic model (preferred option)
WBL	8.7	10.9	10.9
KYM	9.0	6.4	11.2
PLD	8.7	6.4	10.9
NKA	8.7	6.4	10.9
MNA	8.7	10.9	10.9
Total	**43.8**	**41.0**	**54.8**

Source: IR013 – Q14b – zone substation replacement works

409. At a total level, after adjusting for the timing of projects, the cost estimates in $2026 shown in Table 3.22 align with the regulatory proposal. However, in its model the costs included for the preferred options do not. We also found issues with the calculations, namely:

- The calculation of net benefits is based on the present value (PV) of annualised costs. As discussed in our review of the transformer replacements, the costs are modelled over the life of the asset which includes switchboard and buildings over 50 years, and which differs from the benefits over 20 years. This understates the capex and overstates the net benefits.
- The model appears to treat the input cost as $2023 and escalates these for the purpose of the annualised capex, whereas in reporting the capex Powercor assumes the inputs are in $2026.

410. However, if we assume that the lower cost estimates provided by Powercor are accurate, this should lead to an increase in the net benefits, all else being equal.

We did not see evidence of optimal timing

411. In addition to the modelling errors we describe above, we did not see evidence of the optimal timing of these replacements, as all replacements were assumed to be undertaken in 2026-27.

412. For KYM, PLD and NKA, the option with the highest NPV (option 2 – replacement of relays and building) was not selected as the preferred option as it was not deemed to address the station black risk identified at these sites. Hence, the preferred option is to simultaneously replace the 22kV switchgear and relays in a new building (option 3), with this option having the second highest NPV.

413. From our discussion at the onsite meeting with Powercor representatives, we understand this is primarily due to the efficiency associated with the coincident delivery of the works at these rural substations. On the basis that the net benefits are positive, and similar in magnitude, this is likely to be a prudent option.

414. However, as we found in our assessment of the transformer projects, we also found that the switchboard replacement projects were sensitive to changes to VCR. Given we were not able to review the largest source of risk, being relays, and that the consequence relies on the application of VCR we consider that the project timing may be similarly impacted. Specifically, when the new VCR figures are adopted for the customer base applicable for these sites, we consider that the proposed timing of replacement for each of the nominated substation sites would be deferred, with some beyond the end of the next RCP.

Findings

415. We consider that the proposed substation switchgear repex is materially overstated.

416. Our assessment has focussed on the economic analysis that has been provided in support of Powercor's switchboard replacement program. We found that adjustment for more reasonable input assumptions, applied to the switchgear projects as we have done for the transformer projects, is likely to lead to deferral of some of the proposed replacement projects beyond the next RCP.

3.3.6 SCADA, network protection and control system

What Powercor has proposed

417. The scope for our assessment for the SCADA, protection and control asset group is shown in Table 3.23, and which excludes some related repex.

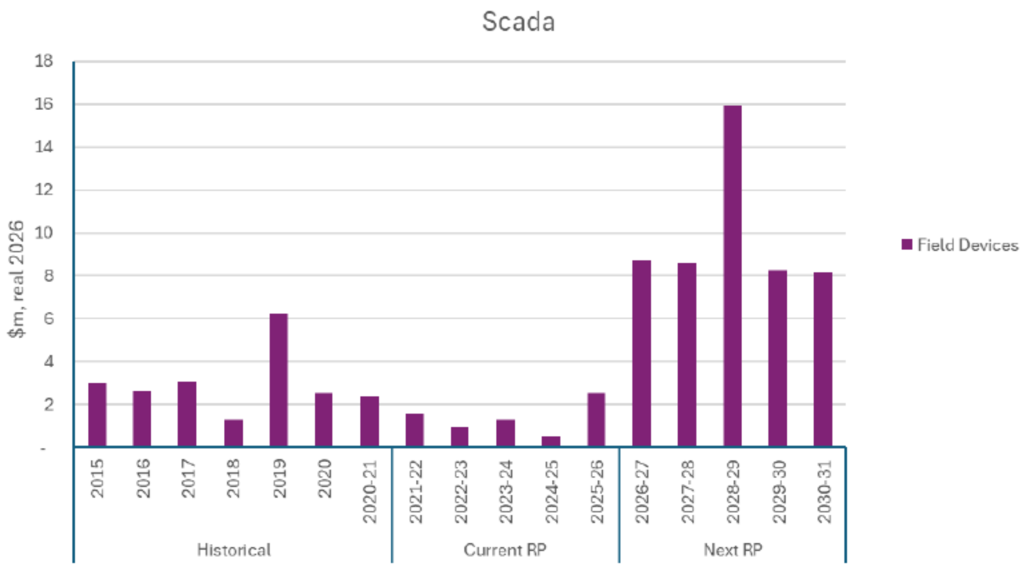
Table 3.23: EMCa's scope of Powercor proposed SCADA, protection and control system repex - $m, real FY2026

SCADA, protection and control	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Relay replacements	5.4	4.6	9.9	2.9	3.0	**25.7**
Secondary defects, batteries and chargers	0.7	1.3	1.4	0.7	0.7	**4.9**
Total	**6.2**	**5.9**	**11.2**	**3.6**	**3.7**	**30.6**

Source: EMCa table derived from Powercor SCS capex model

418. In Figure 3.21 we present the historical and forecast expenditure for the SCADA asset group in the RIN. Expenditure reported in the switchgear asset group in the RIN will differ from the project-based expenditure, as major plant replacement works (such as transformer replacements) are allocated across multiple RIN asset categories to reflect the nature of the work undertaken.

Figure 3.21: Historical and forecast SCADA, network control and protection repex, $m FY2026



Source: EMCa derived from RIN

419. We observe significant increases in the next RCP from the historical spend.

Assessment

Powercor has forecast an increase in defects and failure of its protection fleet

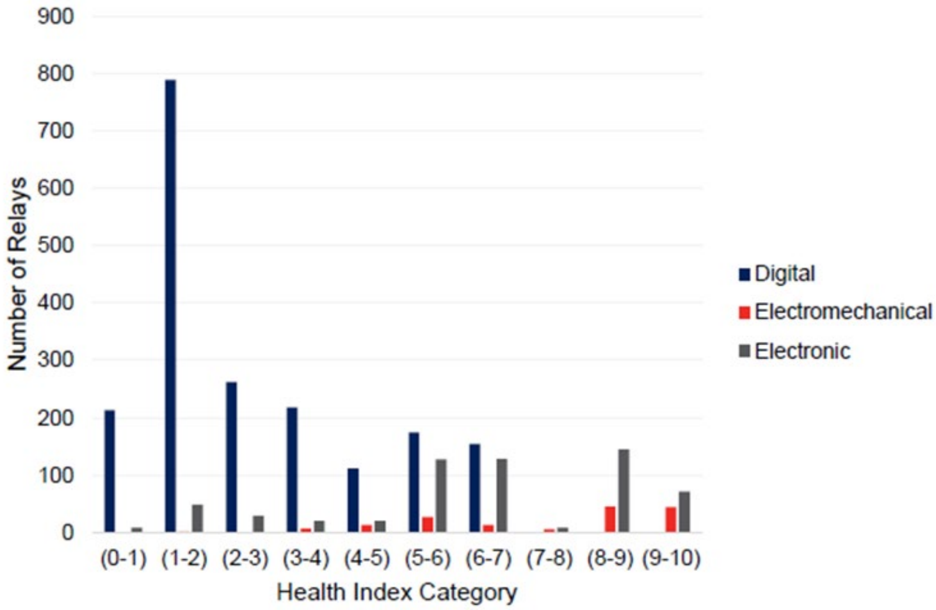
420. Based on its assessment of condition of its asset population, Powercor states that the increasing nature of defects and failures being experienced is expected to continue increasing. The issues relate primarily to its digital relay fleet.

421. The challenges listed by Powercor include the age profile of the protection fleet:

> *'The age profile of CitiPower and Powercor's protection devices indicates that there is a large volume of relays, especially electromechanical and electronic relays, that will likely require replacement over the next ten years. This will require additional specialist resources for protection design, replacement and for testing and commissioning.'* [94]

422. Powercor takes account of the underlying condition of its fleet of relays using CBRM, which we consider as part of its proposed planned replacement program. The results of its CBRM are shown in Figure 3.22.

Figure 3.22: Current HI for relay population



Source: CitiPower - IR007 - Q2(a) - AMP - protection and control – public provided by CitiPower and which also relates to Powercor's assets

423. The results of the current HI indicate a small population of relays, predominantly electronic type, already identified at the top end of the CBRM HI range.

Unplanned replacement program is reasonable

424. Described in the asset class strategy as unplanned interventions, and listed in the capex model as Secondary defects, batteries and chargers, Powercor describes this program as follows:

> *'Unplanned interventions in response to defects and failures are expected to occur on a consistent basis with recent history. As such, we forecast unplanned intervention expenditure based on an historical average of the previous five years.'* [95]

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94 CitiPower - IR007 - Q2(a) - AMP - protection and control – public provided by CitiPower and which also relates to Powercor's assets

95 PAL BUS 4.10 – Protection and control – Jan2025 – Public, page 9

425. Powercor has not explained the expenditure profile, which does not follow a historical average, but looks as though it includes specific programs.

426. We have not been provided any further information in support of this program. We expect that DNSPs will require provision for an unplanned program, and applying a historical trend approach is reasonable. This is supported by a slight upward trend in High priority defects, and we note that failures have been increasing over the last five years.

Planned relay replacements are proposed for twelve substations

427. Powercor is undertaking relay replacements as part of zone substation replacement. Powercor has provided a business case for the risk-based and unplanned relay replacement projects.

428. Powercor's asset class strategy states:

> *'For the 2026–31 regulatory period, therefore, our risk-based approach to relay interventions will continue to address individual high-risk relays. By replacing approximately 14% of the relay population in the next regulatory period, the risk by 2031 is reduced by approximately 42% (relative to the base case). Residual risk, however, will remain higher than risk levels prevailing today.*
>
> *This approach prioritises the replacement of high priority assets over full zone substation replacements and minimises long-term costs to customers.* [96]

429. In the asset class strategy, Powercor has included relay replacement at 12 substations.

430. Powercor included a relay replacement model, including CBRM data, however this was limited to the 12 projects that it proposed to undertake. We could therefore not review how Powercor assigns risk or identified priority projects from its population of relays.

Risk-based assessment has been derived from CBRM

431. From 2021, Powercor's assessment of the proposed relay replacements has been derived using CBRM. As a result, most of the current period projects incorporate the Health Index (HI) component. Moving to CBRM has integrated monetised risk assessments.

432. On review of the included model, the high-priority relays identified for replacement using CBRM are indicated by a manual flag as shown in Table 3.24. Whilst these projects aligned with the submission, we were not able to review the underlying criteria that led to the identification and timing for these projects.

[96] PAL BUS 4.10 – Protection and control – Jan2025 – Public

Table 3.24: Replacement decision based on CBRM data for protection relays

Substation	TRUE	FALSE	Total
AC	28	10	38
BAN	18	47	65
DDL	28	6	34
ECA	8	18	26
FDN	12	2	14
GCY	40	1	41
MLN	20	38	58
SA	61	6	67
SHL	4	29	33
SHN	31	5	36
TYA	16		16
WBE	45	13	58
Total	**311**	**175**	**486**

Source: EMCa analysis of PAL MOD 4.07 - relay replacement - Jan2025 - Public

433. To understand the criteria that may have been applied, we considered the future HI at year 2034 and reviewed the relationship between future HI and whether the relays were include for replacement as shown in Table 3.25.

Table 3.25: Summary of replacement flags by HI value

HI	TRUE	FALSE
<5.5	2	98
5.5-6	1	2
6-7	1	17
7-8	15	6
8-9	13	15
9-10	26	10
10-15	199	24
15-20	43	3
20+	11	-
Total	**311**	**175**

Source: EMCa analysis of PAL MOD 4.07 - relay replacement - Jan2025 - Public

434. We observe a reasonable level of correlation between HI and relays selected by replacement. However, only those substations targeted for replacement were included in the model. This did not allow for review of how the relay population is being managed across Powercor's network, and whether the targeted approach had been applied in a uniform way. Only considering a subset, provides a lower level of confidence.

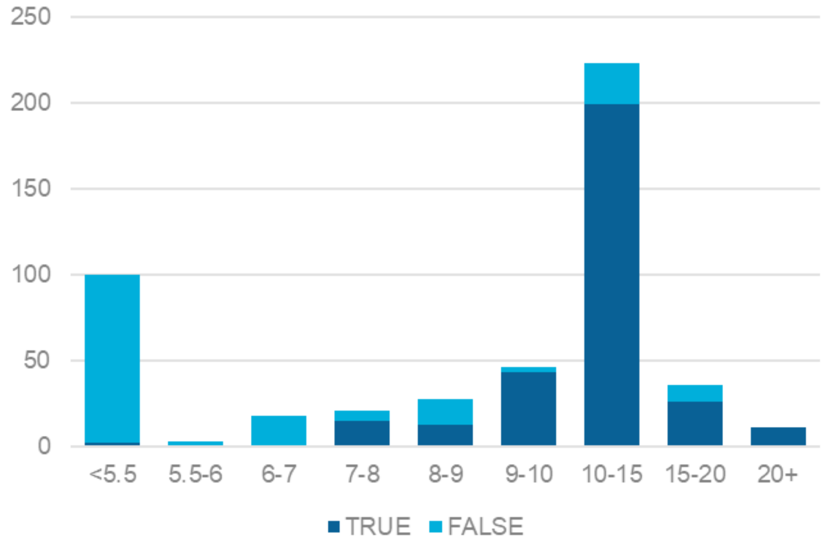
435. We make the following observations:

- HIs extend well beyond 10, which is typically a cap, to beyond 20. Without information to explain this, this tends to cast a level of doubt on the index and specifically what measure of HI is deemed to represent a trigger for replacement planning and/or at end of life, and
- A proportion of relays with a HI in the high range (considered above 7) that are not targeted for replacement. Whilst this may be explained by other projects or retirement of these systems, the absence of a criteria or explanation of the replacement decision did not assist our review. As noted above, adopting HI values that extend beyond 20,

suggests to us that a measure of 7 being a high range is too low, on the basis that it would not apply in the same way as it does for HI values with a cap of 10.

436. When we compare the current and future HI values determined from its CBRM models, we observe that there is significant increase in HI over this period as shown in Figure 3.23, with the largest population of relays in the HI range of 10-15, and a proportion of these not targeted for replacement. Powercor does not explain the relationship between HI values and replacement decisions.

Figure 3.23: Targeted relay replacements indicated by TRUE, versus future (2034) HI value



Source: EMCa analysis of PAL MOD 4.07 - relay replacement - Jan2025 - Public

Lack of transparency of derivation of risk costs assumed in the analysis

437. The risk costs are hard-coded and therefore we were unable to review them. We observe that the largest risk cost was associated with network performance and we presume is likely linked to an estimate of the Energy at Risk valued at VCR. For other programs included in the capex forecast we have observed an impact to the program through application of the updates to VCR and we expect that this program will be similarly impacted.

Powercor has limited its option analysis to do now, or do later

438. Powercor's analysis does not consider the optimal timing, and for the projects it has selected based on CBRM it has not considered whether to replace the assets in the next RCP or the subsequent RCP. It does this by modelling the replacement timing as spread across the next RCP (option 2), or in a single year in FY33 (option 3). The results of Powercor's analysis are shown in Table 3.26.

Table 3.26: Comparison of options

	Option 2 Net benefit	Option 2 timing	Option 3 Net benefit	Option 3 timing	Variance benefit	Variance timing (years)
AC	8.6	FY27	8.3	FY33	0.3	6
BAN	8.7	FY28	8.6	FY33	0.1	5
DDL	10.9	FY27	10	FY33	0.9	6
ECA	5.2	FY30	5.1	FY33	0.1	3
FDN	2.5	FY29	2.4	FY33	0.1	4
GCY	11.7	FY29	11.3	FY33	0.4	4
MLN	5.3	FY30	5.2	FY33	0.1	3
SA	22.5	FY29	22.0	FY33	0.5	4
SHL	0.5	FY31	0.4	FY33	0.1	2
SHN	8.3	FY31	8.1	FY33	0.2	2
TYA	8.0	FY29	7.5	FY33	0.5	4

Source: PAL BUS 4.10 – Protection and control – Jan2025 – Public

439. Whilst the model was provided to us with an assessment period of 22 years, the results did not align with the business case. We were, however, able to align the results when a longer assessment period of 28 years (coinciding with the design life) was selected.

440. In Powercor's NPV calculation, the assessment period for the included capex and benefits is not aligned, leading to the capex being understated. Once corrected, the NPV is lower.

441. The variance in benefit between the alternate timing for some of the projects is small. We consider that some of the projects would be marginally more positive by proceeding in the current RCP, particularly those towards the end of the period. If the benefits were to be less than estimated in this model, or the capex higher, the economic timing would move into the next period.

442. Whilst the age, serviceability and obsolescence of its protection relay population is captured in its CBRM model, it is producing results which don't align with a managed fleet of assets. We have been unable to determine whether Powercor has reasonably prioritised replacement across its fleet of relays, based on an assessment of relay-related risk, or if that risk had been reasonably determined.

Findings

443. We consider that the proposed SCADA, network control and protection repex is overstated.

444. We expect that DNSPs will require an allowance for some form of unplanned program, and applying a historical trend approach for such a program is a reasonable approach.

445. For its proposed planned relay replacement program, we did not find sufficient justification for the risk costs that Powercor has assumed in its analysis. We also found results of its CBRM modelling which, when combined with its economic analysis, indicate to us that Powercor, acting prudently, would be likely to undertake a smaller program than it has proposed in the next RCP.

3.3.7 Other repex

What Powercor has proposed

446. The scope for our assessment for the other repex asset group is shown in Table 3.27.

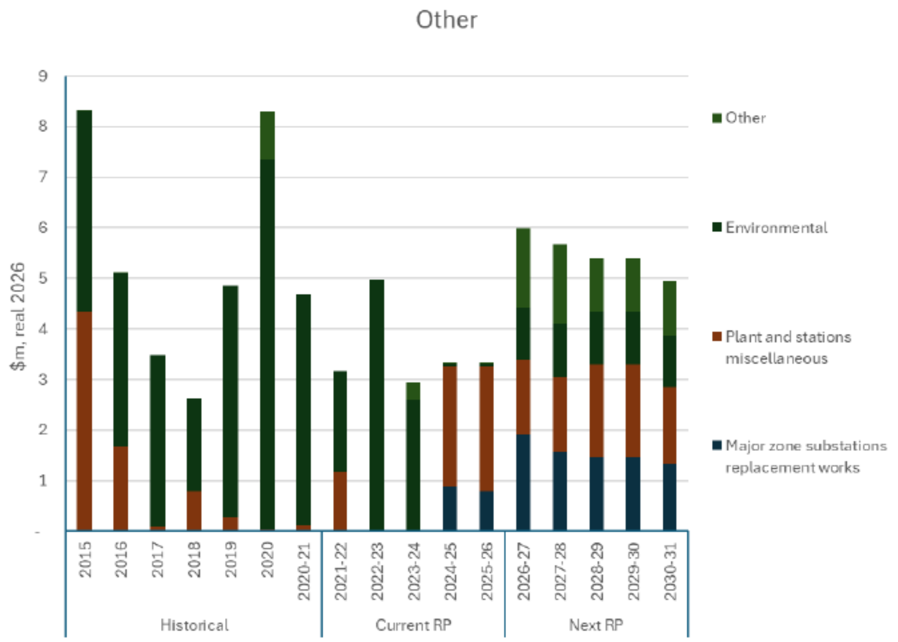
Table 3.27: EMCa's scope of Powercor proposed other repex - $m, real FY2026

Other	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Miscellaneous plant and station	2.2	2.2	2.5	2.6	2.2	11.7

Source: EMCa table derived from Powercor SCS capex model

447. In Figure 3.24 we present the historical and forecast expenditure for the Other repex asset group in the RIN. As can be seen in this table, the Miscellaneous Plant and Station expenditure that we have been asked to review, is only part of the wider 'other' category.

Figure 3.24: Powercor's proposed other repex - $m FY2026



Source: EMCa derived from RIN

448. On review of the RIN data, we see that the miscellaneous plant and stations repex included as a part of the 'other repex' asset group is highly variable.

Assessment of miscellaneous plant and station

449. As outlined in its response to our questions relating to its proposed substation transformer repex, Powercor describes this category as follows:

> *'These categories of investment reflect unplanned and reactive works, typically driven by emerging defects, operational issues, or site-specific condition risks that cannot be reliably forecast at an asset or component level. For example, they include the following:*
>
> – *minor station works include bushing replacements, cooling tower pipe and valve replacements and single 66kV CB replacements*
>
> – *miscellaneous plant and stations repex includes CVT replacement, control cable duct replacement and transformer Buchholz switch replacements.*
>
> *The nature of these works varies in any given year, but have been incurred historically and will arise across the 2026–31 regulatory period. Given the variability in these works, forecasts are based on a simple historical average of annual expenditure over the previous four-year period. This approach provides a representative basis for future*

requirements, and aligns with internal capital planning practices for comparable expenditure types. [97]

450. Whilst we acknowledge the need for unplanned and reactive works in zone substations, including on the assets included in Powercor's response, we consider that this response is unsatisfactory. We consider that Powercor is required to demonstrate that its forecast is prudent and efficient, and which would extend to providing the historical data to validate the basis of its forecast. However, we were not provided such evidence from Powercor.

Findings

451. We did not see sufficient justification for inclusion of the proposed expenditure for miscellaneous plant and station expenditure in the next RCP. We consider that Powercor will require an allowance for unplanned / reactive projects that are not able to be accurately forecast given the variability of the underlying activities. For this reason, we typically see the 'other repex' category forecast based on a historical average at the aggregate level, and deviations from this historical average supported by justification of new project expenditure.

3.4 Findings and implications for proposed repex

3.4.1 Summary of findings

General

452. Powercor has proposed a repex forecast that is 111% above the repex included in the capex allowance for the current RCP and 47% above the repex that it expects to incur in the current RCP. Powercor refers to increasing defects and unit costs as the key drivers for this proposed increase.

453. We have been asked by the AER to consider approximately 70% of the proposed repex by Powercor across a range of asset groups, split between distribution lines related expenditure (poles, crossarms and conductor) and substation related expenditure (transformers, switchgear, SCADA and Other). The AER nominated specific projects and programs from Powercor's capex model for our review. Our findings relate to the projects and programs included in our review.

454. The information provided initially by Powercor was not conducive to a review in accordance with the capex assessment guidelines, as the models and supporting information were incomplete. We made numerous requests for the models and supporting information that we considered that Powercor had relied upon in preparing its expenditure forecast and were subsequently provided with this information. We have taken account of this information in our review.

Distribution lines-related programs

455. The forecasts for its distribution lines related expenditure are largely based on the historical trends of defects, and not economic analysis as required under the AER guidance note. For poles, Powercor referred to a decay model as its counterfactual to demonstrate that the proposed volumes as indicated by the ESV direction notice for the current RCP are reasonable. For crossarms, the volumes are based on extrapolating the current find-rate of defects, and the bulk of the conductor forecast is based on a historical trend. The exception to the remainder of the distribution lines expenditure is for the proposed risk-based conductor expenditure, where Powercor has relied on economic models.

456. We did not find evidence of sufficient analysis of alternate replacement volumes or options, to demonstrate that Powercor's forecast is prudent and efficient. We consider that evidence of robust analysis of this nature is critical considering the uplift in expenditure that Powercor has proposed. Instead, we found a lack of, or deficiencies in, the analysis that Powercor had

[97] Powercor response to IR013 Question 15

relied on, and which leads to our finding that Powercor's proposed repex for its distribution lines-related program is overstated.

457. For its risk-based programs we found issues with the modelling methods and assumptions that Powercor had relied upon and which, once adjusted for more reasonable assumptions, result in reduction to the cost and/or benefits such that the economic timing results in a smaller program in the next RCP than Powercor has proposed.

Unit rates

458. The increase in Powercor's repex program is driven by increases in replacement volumes and unit rates. Powercor refers to recent price uplifts, as well as ongoing inflationary pressure to explain the increases in unit rates. Our analysis of unit rates for the distribution lines related programs show that Powercor is, in general, the highest cost DNSP across the NEM. This is reflected in the historical costs and continues to be the case in its forecast unit costs.

459. We found examples where the unit cost for Powercor was similar to that of CitiPower, and others where Powercor was higher. Powercor did not explain the basis of its costs, nor explain why an urban/rural DNSP would have unit costs similar to or higher than a CBD/Urban DNSP. We also found examples of unit costs that Powercor in its response to our questions is not able to explain.

460. We consider that the unit rates that Powercor has assumed are not reflective of an efficient cost.

Substation-related expenditure

461. Powercor provided models for its substation-related expenditure, however the functionality was limited. We asked for and were provided with additional models that assisted our ability to review the proposed projects and programs. Some of the models continued to include hard-coded values, which limited our ability to understand the methods that Powercor has applied to derive these values in some cases.

462. Powercor's recent development of its risk quantification framework meant that it has placed greater emphasis on its economic models, and we reviewed this in some detail. We found issues with the modelling methods and input assumptions that Powercor has applied, and once adjusted for more reasonable methods and inputs, we consider that a portion of the proposed projects would be deferred to beyond the next RCP.

463. Powercor's submission focussed on the projects and programs that it has proposed, and therefore we were not able to determine if the issues that we found were similarly present in other parts of the program, or that other projects became economic in the next RCP.

464. We found evidence that some of Powercor's costs for its substation projects were higher than observed in other DNSPs and appeared to reflect higher rates than it had advised the AER for the current period.

Additional observations

465. Powercor has proposed a number of projects and programs that are directly related to, and in some cases, requirements of its bushfire mitigation plan and electric line clearance obligations. These plans are shared with and accepted by the safety regulatory ESV.

466. Powercor also refers to future reviews by ESV that may have a bearing on its asset management plans in the future. Our review is based on a reasonable interpretation of Powercor's current obligations.

3.4.2 Implications for proposed capex allowance

467. We have been asked to review projects with aggregate proposed capex of $1,039 million. These projects comprise part of Powercor aggregate proposed repex of $1,492 million.

Alternative forecast methodology

468. For each of the seven categories of expenditure that we were asked to review, we consider that Powercor's proposed capex is not a reasonable forecast of its prudent and efficient expenditure requirements for the next RCP. Our proposed alternative forecast for these categories involves one or more of the following adjustments, to the extent that it formed the basis of Powercor's forecast and which we consider to be not justified or overstated:

- Adjustment to the volume of work
- Adjustment to the unit cost basis for the proposed forecast
- Adjustment to the timing of the proposed expenditure, resulting in deferment beyond the end of the next RCP
- Adjustment based on synergies with other work not otherwise accounted for
- Adjustments to correct modelling issues and/or unsupported or incorrect model input assumptions, and
- Adjustment to align the forecast with historical spend, where an ongoing level of expenditure represents a reasonable default assumption and where the proposed increase was not otherwise justified.

Alternative forecast of expenditure

469. We consider that a reasonable alternative forecast for the repex categories that we reviewed, would be between 25% and 35% less than Powercor has proposed.

470. We stress that our advice on an alternative forecast relates only to the categories of expenditure within the scope of our review and does not necessarily have any implication for repex that was not within the scope of our review.

4 REVIEW OF PROPOSED AUGMENTATION EXPENDITURE (AUGEX)

Powercor has proposed a material uplift in augex activity relative to the augex that it expects to incur in the current period, and which is above that included in the AER's final determination capex allowance for this period. This includes the introduction of programs in response to Powercor's assessment of electrification/CER-related drivers.

The AER has asked us to assess a subset of Powercor's proposed $565 million augmentation capex for the next RCP. The AER has asked us to review three demand-driven projects, two non-demand driven projects, and three bushfire mitigation projects, which together account for approximately 75% of Powercor's total proposed augex.

We consider that Powercor's proposed augex of $421 million for the projects that we reviewed is materially overstated. This is for a number of reasons, but which primarily relate to unsupported assumptions in the cost-benefit analyses that overstate the economic benefits.

We consider that a reasonable alternative forecast for the projects within the augex categories that we reviewed, would be between 40% and 50% less than Powercor has proposed.

4.1 Introduction

471. We have been asked by the AER to assess eight of Powercor's augmentation projects/programs submitted in its Proposal for the next RCP.

472. We reviewed the information provided by Powercor to support each of the projects and programs and as necessary asked clarifying questions, both in writing and at a face-to-face meeting with Powercor representatives. We sought to confirm the need, quantum, and optimal timing of each project that we were asked to review.

473. In the sections that follow, we identify the projects we have been asked to review from Powercor's full list, and then we present our assessment of the individual projects.

4.2 What Powercor has proposed

4.2.1 Proposed augex

474. As shown in Table 4.1, Powercor proposes augmentation capex of $564.7 million over the next RCP.

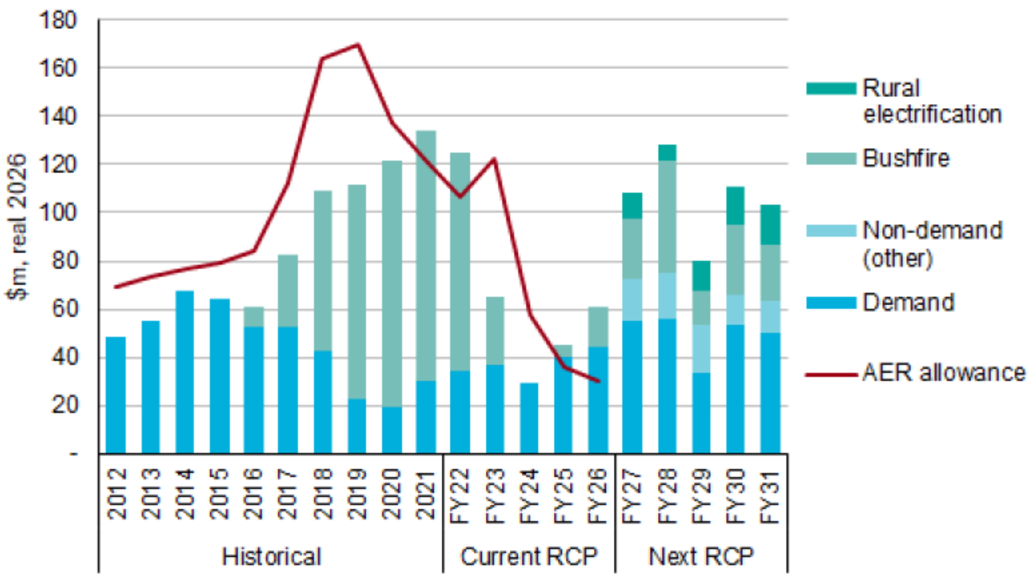
Table 4.1: Powercor proposed augex by driver - $m, real FY2026

Proposed Augex by Driver	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Demand	64.1	53.5	38.5	65.9	68.0	**290.1**
Non demand	21.1	31.0	30.1	19.1	15.6	**116.9**
Bushfire mitigation	26.1	47.9	14.4	30.1	24.6	**143.1**
Resilience	0.3	3.6	3.6	3.5	3.6	**14.6**
Total	**111.6**	**136.0**	**86.6**	**118.7**	**111.7**	**564.7**

Source: EMCa table derived from Powercor SCS capex model

475. Figure 4.1 shows a comparison between Powercor's forecast and historical augex. We note that Powercor has underspent the AER allowance by a considerable margin in the previous RCP and expects to do so again in the current RCP. The forecast for the next RCP represents a significant increase in augex from the current RCP, due primarily to a combination of Powercor's proposed programs for rural electrification and for demand-driven augex (which includes proposed augex for CER/electrification).

Figure 4.1: Powercor proposed augex compared with current RCP and historical by driver - $m, real FY2026



Source: EMCa derived from Powercor response to IR#006

4.2.2 EMCa's Scope of Augex Review

476. The AER has asked us to assess the projects/programs listed in Table 4.2, which at $421 million in total represents 75% of the total forecast augex. We provide our assessment of each project in the subsequent sections.

Table 4.2: EMCa's scope of Powercor proposed augex by driver - $m, real FY2026

Augex by Driver	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Demand						
Customer-driven electrification[98]	9.5	21.4	15.5	25.2	29.0	100.6
Regional and rural supply	11.0	7.6	13.1	16.2	17.5	65.4
Western growth corridor expansion	32.4	15.5	8.8	20.3	15.9	93.0
Subtotal	**52.9**	**44.5**	**37.4**	**61.7**	**62.5**	**259.0**
Non demand						
Stand-alone power systems	0.0	0.8	0.9	0.9	1.4	3.9
Worst served customer program	0.9	6.0	6.0	2.2	0.0	15.1
Subtotal	**0.9**	**6.8**	**6.9**	**3.1**	**1.4**	**19.0**
Bushfire mitigation						
Minimising bushfire risk	6.7	10.9	4.3	4.3	0.0	26.2
Non-mandated REFCL	0.0	0.0	0.0	9.5	9.6	19.1
REFCL compliance	19.4	37.0	10.1	16.3	15.0	97.8
Subtotal	**26.1**	**47.9**	**14.4**	**30.1**	**24.6**	**143.1**
TOTAL	**79.8**	**99.2**	**58.7**	**94.9**	**88.4**	**421.0**

Source: EMCa table derived from Powercor SCS capex model

4.3 Assessment of demand driven augex

4.3.1 What Powercor has proposed

477. Table 4.3 shows two of the programs within our scope for demand-driven augex. (We review Powercor's proposed customer-driven electrification program in section 4.5)

Table 4.3: EMCa's scope of Powercor proposed demand augex - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Regional and rural supply	11.0	7.6	13.1	16.2	17.5	**65.4**
Western growth corridor expansion	32.4	15.5	8.8	20.3	15.9	**93.0**
Total	**43.4**	**23.1**	**21.9**	**36.5**	**33.4**	**158.4**

Source: EMCa table derived from Powercor SCS capex model

Expressions of demand forecast

478. In our assessments, we refer to three forms of maximum demand forecast:

- 50PoE which is our acronym for 50% probability of exceedance
- 10PoE which is our acronym for 10% probability of exceedance, and
- Weighted demand forecast which is for Powercor's blend of 70% 50PoE and 30% 10PoE used in its cost benefit analysis models (CBA, also referred to as NPV models).

4.3.2 Regional and rural supply

What Powercor has proposed

479. Powercor proposes an 'economic SWER upgrade' program based on upgrading 606km of the 21,300km of single wire earth return lines (SWER) in its network at a cost of $65.4

98 Customer driven electrification is reviewed as an augex CER project, in section 4.5

million, as shown in Table 4.4. Powercor has selected individual projects from its economic assessment with claimed positive net benefits and optimal timing within the next RCP. The economic benefits are derived from three sources:

- avoided energy at risk from thermal and voltage constraints,
- avoided SWER failure, and
- bushfire reduction.

Table 4.4: Powercor proposed regional and rural supply program ($m, real FY2026)

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Regional and rural supply	11.0	7.6	13.1	16.2	17.5	**65.4**

Source: EMCa table derived from Powercor SCS capex model

Assessment

Powercor identifies multiple drivers for the program

480. Powercor's business case identifies the following drivers for upgrading power supply to customers currently supplied by SWER lines and relative to urban customers:

- Lower supply capacity
- Poor voltage performance
- Lower reliability
- Export restrictions
- Deteriorating conductor condition.
- Customer feedback.

481. In summary, in addition to the familiar and persistent issues with supply reliability and power quality from SWER lines due to their characteristics, Powercor's business case is founded on a response to its assessment that SWER lines have limited capacity to support 'electrification' and the adoption of renewable technologies.

Powercor refers to regulatory framework shortcomings and the Victorian Government strategies regarding rural and remote electrification

482. Powercor identifies that the existing regulatory framework requires that expenditure such as proposed here for rural and regional customers needs to be justified by *'…assessing the value of energy at risk and comparing it against the cost of applicable upgrades to reducing the value of energy at risk.'*[99] This is a narrow view, because there are other potential sources of benefit which Powercor can and does draw upon in its economic analysis, as discussed below. Nonetheless, it is the case that the cost of SWER upgrades is challenging to justify with the prevalent low customer density (and therefore relatively low energy at risk). Powercor goes on to say that:

> *'…this approach does not recognise the impact of increasing customer reliance on electricity in an electrified future, particularly for customers outside dense urban areas. The regulatory framework is incomplete because there is no guidance on minimum service standards to support fully electrified homes. Without this guidance, equity is not adequately considered in the regulatory framework.'*[100]

483. As discussed below, Powercor has sought to address the matter of equity by valuing 'import risk' using VCR, as well as incorporating the value of avoided export curtailment and reduced bushfire risk from its proposed SWER network upgrades.

99 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 7

100 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 7

484. Powercor also advises that it has been participating in a government policy review (comprising Commonwealth and Victorian Governments) to identify barriers for enabling electrification and renewable generation in regional and rural areas, with a focus on SWER networks: '*[t]he results of this study are expected to inform both Commonwealth and Victorian network policy direction and future programs.*[101]

485. It may be the case that within the next RCP, a policy underpinning measures that DNSPs are required to consider for enabling rural electrification and renewable generation will be released. However, in the interim, the current regulatory framework remains the basis for our assessment.

Powercor assessed four options for improving supply capacity and service levels to a subset of SWER customers

486. Powercor's business case[102] presents four options assessed against the identified need:

- Base case: maintain status quo, which is to rely on existing asset management practices such as maintenance and replacement on condition – so no cost would be incurred under this program
- Option 1: Limited SWER upgrades (to 3 phase) selected from the 'high value sites' across its network as determined by its economic analysis with a targeted spend of $45 million
  - 422 km of SWER upgraded adding 3.5MVA capacity across 33 lines and benefiting 971 customers at a cost of $46k per customer on average
- Option 2: economic SWER upgrades (to 3 phase) with all sites with positive net benefit included at a cost of $65.4 million
  - 606km of SWER upgraded adding 4.8MVA of capacity across 44 lines benefiting 1,310 customers at a cost of $50k per customer on average, and
- Option 3: accelerated SWER upgrades (to 3 phase) selected from the highest value sites (including non-economic sites) up to a cap of $110 million[103]
  - 1,160km of SWER upgraded adding 7.5MVA of capacity across 79 lines benefiting 2,117 customers at a cost of $52k per customer on average.

487. Powercor proposes Option 2 based on achieving a balance between cost and benefit and customer expectations.

Regional customers are supportive of investment of a minimum of $45 million in the next RCP

488. Powercor's customer feedback garnered from its engagement process over several years is described in detail in its business case. Powercor advises that:

> *'Acting on longer-term objectives to upgrade SWER was an important principle shared by our customers and stakeholders.'*[104]

489. Broad support for investing at least $45 million in the program was provided with some customers suggesting to treat Option 2 (at a cost of $65.4 million) as a test case and evaluating outcomes before committing to further investments and others suggesting that $45 million is insufficient.

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101 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 6

102 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, pages 20-24

103 Powercor's CBA model is based on selecting sites up to a cap of $103 million whereas the business case refers to a cap of $110 million [PAL MOD 3.30 - Regional and rural SWER upgrades - Apr2025 – Public]

104 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 24

Cost of SWER upgrades include a BCA factor

490. Powercor advises that it has used a 'BCA' Factor[105] in deriving costs to upgrade SWER ISO sites in high bushfire risk areas according to the formula in Figure 4.2:

Figure 4.2: SWER ISO cost of upgrade – BCA Factor

$$SWER\ ISO\ Upgrade\ Cost(\$) = BCA\ factor \times \sum(construction\ cost + transformer\ upgrade\ cost + pole\ replacement\ cost + HV\ switch\ cost)$$

Source: PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, page 68

491. No further explanation of the derivation of the factor is provided other than to note that the BCA Factor represents an additional cost applied to sites located in high bushfire risk areas, potentially increasing the project cost by up to 150%. Powercor provides unit costs for the SWER upgrade components which were derived from '*similar historical projects and by conducting high-level scope designs on several case studies involving the SWER to three-phase networks upgrades.'*[106] We assume that these unit costs do not include the BCA factor.

492. We do not consider that Powercor has provided sufficient information for us to find that the application of the BCA Factor is reasonable, including whether or not the AER has previously accepted its application.

In the absence of an alternative measure, Powercor has valued 'energy import risk' using VCR which we consider overstates the benefit and therefore the NPV of its solution[107]

493. Powercor quantifies the benefits from reducing base case risk via three components and valuation methods, aggregated at the SWER isolating transformer:[108]

- Energy at risk for importing customers experiencing voltages less than 216V, which is valued using VCR,
- Energy at risk for solar exports that are curtailed due to export-driven overvoltage, which is valued at CECV plus emissions valued in accordance with the AER's published CO_2 reduction value, and
- Bushfire risk, which is the annualised cost relating to the risk that network assets initiate a bushfire:
  - it is not clear to us how the bushfire risk was calculated because only hard-coded values were provided and there is no explanation in the business case, in the Customer electrification forecasting methodology document, or in the provided CBA model.

494. Powercor describes its methodology as determining an NPV from assigning a network solution to reduce the aggregate value of the 'energy at risk' at each SWER isolating transformer. Projects with optimal timing within the next RCP are prioritised according to the benefit to cost ratio (BCR, or 'risk to capex ratio', as Powercor refers to it in the model). This enables targeting sites with higher customer numbers.[109]

495. Powercor's model[110] includes a number of hard-coded numbers and other shortcuts, making it difficult to confirm that the cost-benefit analysis enunciated in the business case and its 'Customer electrification methodology' document have been applied appropriately. We asked for a more comprehensive model, and from Powercor's response[111] we are satisfied

105 Bushfire Category Area

106 PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, page 68

107 This issue is also common to Powercor's economic modelling for its proposed customer electrification program, which we describe in section 4.5 and also in Appendix A.

108 PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, section 17

109 PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, section 17.3

110 PAL MOD 3.30 - Regional and rural SWER upgrades - Jan2025 - Public

111 Powercor response to IR014, question 5, PAL MOD 3.30 - Regional and rural SWER upgrades - Apr2025 - Public

that the model works as described[112] with by far the largest benefit contribution being from Powercor's assessment of the cost of import curtailment due to undervoltage, with second-level contributions from the other two sources.

496. We therefore focused on Powercor's approach of valuing curtailment of 'undervoltage demand' which we have described 4.5.3. We conclude there that using VCR to represent the economic cost of undervoltage supply is a material overstatement of the likely value and therefore of the net economic benefit. It applies equally to this proposed program.

497. As a sensitivity analysis we tested for the impact of using a value of 1/10th of the latest VCR. If we do so, then only five projects (none of which apply the BCA Factor) included in Powercor's proposed SWER upgrade program would remain economically viable.

Modelling flaw

498. As we have found for a number of CBAs that Powercor has provided, it has calculated the NPV of the project using the annualised capex rather than the capex cost itself.[113] Because Powercor calculates annualised capex using an economic life that is much longer than its analysis period, this has the effect of understating the PV of the capex that it proposes and therefore overstates the NPV. This is therefore a further factor leading to overstatement of the claimed economic benefits, and therefore of the justification for the scale of the upgrade program that is economically beneficial.

Findings

499. We consider that the proposed regional and rural supply project is not sufficiently justified and results in an augex forecast that is significantly overstated.

500. The application of VCR to value 'curtailment of undervoltage demand' leads to a significant overestimate of the claimed economic value for this work. Since Powercor relies on this analysis as its justification, we therefore conclude that the level of work that Powercor proposes is similarly not justified. Furthermore, Powercor has applied a loading factor to the cost of replacing SWER isolating transformers in high bushfire risk areas of up to 150% without adequate justification.

501. We consider that there may be merit in a small program to address regional and rural supply issues, however this would involve only a small number of projects for which the economics are compelling, and with costs that do not include the 150% cost uplift factor.

4.3.3 Western growth corridor expansion

What Powercor has proposed

502. Table 4.5 shows the forecast augex for Powercor's preferred solution to forecast high demand growth in the Greater Western Melbourne corridor (comprising the Melton and Wyndham LGAs). The program comprises:

- Installation of a third transformer at Mount Cotteral zone substation (MTC) in FY27
- Rebuilding Bacchus Marsh zone substation (BMH) by FY28
- Building a new Rockbank East zone substation (RBE) by FY31, and
- Building a new Point Cook zone substation (PCK) by FY31 – but categorising it as a Contingent Project (and not included in the forecast augex shown in the table).

112 There is an issue with the derivation of the risk to capex ratio, but correction does not materially affect the results

113 We describe this further in Appendix B

Table 4.5: Powercor proposed Western growth corridor expansion program ($m, real FY2026)

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Western growth corridor expansion	32.4	15.5	8.8	20.3	15.9	**93.0**

Source: EMCa table derived from Powercor SCS capex model

Assessment

The identified need for augmentation of the Greater Western Melbourne network is compelling

503. Powercor has provided comprehensive information about the forecast peak demand versus N-1 and N capacity at each of the existing substations in the Greater Western Melbourne area. The location of each zone substation is shown in Figure 4.3 along with existing Terminal Stations and proposed new zone substations.[114]

Figure 4.3: Greater Western Melbourne network

Source: PAL BUS 3.07 – Greater western Melbourne supply area – Jan2025 – Public, Figure 1

504. Based on the information provided (including the demand forecasts) we observe that:

- The new MTC substation to be established by FY26 with two 25/33MVA 66/22kV transformers (to defer energy at risk from TNA, WBE, LV and MLN) will be overloaded almost immediately:
  - the 10PoE forecast is expected to exceed the N rating by FY28
  - Powercor identifies it as one of the greatest contributors to energy at risk in the Greater Western Melbourne network
  - it is prioritised for a 3rd transformer by FY28
- BMH comprises two 10/13.5MVA 66/22kV transformers, it is operating well above its N-1 capacity, and expansion requires a rebuild of the site to facilitate replacement of the existing transformers with new 25/33 MVA transformers, among other things

114 PAL BUS 3.07 – Greater western Me bourne supply area – Jan2025 – Public, Appendix A

- Forecast 50PoE demand on each of the following zone substations (each of which have 3 x 33MVA 66/22kV transformers) exceeds the N-1 capacity and forecast 10PoE demand will exceed the N capacity within the next RCP:
  - Truganina zone substation (TNA)
  - Laverton zone substation (LV)
  - Melton zone substation (MLN)
  - Laverton North substation (LVN)
  - Werribee zone substation (WBE)
- None of the five substations listed immediately above is suitable for capacity expansion for one or more reasons, including land constraints, and
- Powercor appears to have taken into account available distribution load transfer capacity (DTC) in representing the N-1 capacity in each case.

505. On this basis, there is a compelling case for Powercor to augment the capacity within the Western growth corridor within the next RCP.

Powercor considered five options and the choice between two options can be reserved until FY27 or FY28

506. As shown in Table 4.6, Powercor considered five options, selecting Option 3. Ultimately, Powercor recommends that the proposed new PCK project is categorised as a Contingent Project. This leads to exclusion of $32.9 million capex (of the total estimated cost of $57.5 million for the single transformer substation) from the capex model.

507. Powercor selects Option 3 on the basis that it offers the highest NPV and minimises the unserved energy in the supply area. However, Option 2 actually has the higher PV of benefits, and the NPV difference is insignificant.

Table 4.6: Powercor's summary of options analysis ($m, real 2026) – not including escalation

Option	Augmentations and sequencing	Project cost	Total Cost	Net benefit
1: Status quo	None		0.0	0.0
2. Southern capacity priority	MTC third transformer BMH rebuild (two transformers) New PCK (single transformer) New RBE (two transformers)	15.9 30.2 57.5 43.4	147.0	546.6
3. Northern capacity priority	MTC third transformer BMH rebuild (two transformers) New RBE (two transformers) New PCK (single transformer)	15.9 30.2 43.4 32.9	122.3 (incl PCK)	546.8
4. Lean investment: northern priority	MTC third transformer New RBE (two transformers) New PCK (single transformer)	15.9 43.4 57.5	116.8	528.2
5. Lean investment; southern priority	MTC third transformer BMH rebuild (two transformers) New PCK (two transformers)	15.9 30.2 69.1	115.2	495.8

Source: PAL BUS 3.07 – Greater western Melbourne supply area – Jan2025 – Public, Tables 7, 8, 12, 16, 20

508. Given the energy at risk at the substations in the supply area, Option 1 is not prudent.

509. Whilst Options 4 and 5 represent slightly lower capital costs than Option 3, the difference is relatively small (5%). We consider that with the forecast maximum demand the prudent choice is between Options 2 and 3. We have not been asked to assess the possibility of categorising PCK as a contingent project and, for the purposes of our assessment, we

assume that Option 3 cost does not include the cost attributed to the new PCK (single transformer).

510. Powercor offers three different patterns of expenditure for Option 3:

- Business case Table 1 (and the SCS capex model), which differ from Business Case Table 12, and
- The CBA model, which varies considerably from Tables 1 and 2 in the Business Case.

511. Similarly, the expenditure patterns and quantities vary between the two sources for Option 2. However, the misalignment between the two options in the CBA model are such that the NPV results are unlikely to be materially changed.

512. The choice between Option 2 and Option 3 can be made by Powercor in FY28, depending on updated load and energy forecasts. Table 4.7 shows the expenditure pattern from Table 1 in the business case for Option 3 (Northern capacity) which aligns with the capex model.

Table 4.7: Powercor's expenditure forecast for its preferred option 3 ($m, real 2026) – not including escalation

Project	FY27	FY28	FY29	FY30	FY31	Total[115]
MTC third transformer	15.9	-	-	-	-	**15.9**
BMH rebuild	15.1	15.1	-	-	-	**30.2**
New RBE zone substation	-	-	8.5	19.5	15.3	**43.4**
New PCK zone substation[116]	-	-	-	6.0	26.9	32.9
Total (all)	**31.0**	**15.1**	**8.5**	**25.6**	**42.2**	**122.3**
Total proposed[117]	**31.0**	**15.1**	**8.5**	**19.5**	**15.3**	**89.4**

Source: PAL BUS 3.07 – Greater western Melbourne supply area – Jan2025 – Public, Table 1

Powercor's sensitivity analyses confirm that Options 2 and 3 are the highest-ranked approaches but does not re-examine optimal timing

513. Powercor's sensitivity analysis in its provided model varies the capital cost and benefits by ±10% and provides a scenario with 10% higher capex and 10% lower benefits. Whilst Options 2 and 3 remain ahead of Options 4 and 5 on NPV, Powercor's model does not readily support consideration of the change to the optimal timing of the individual stages. Nor does it explicitly offer the ability to vary the demand forecast (for example, to 100% 50PoE rather than the weighted forecast).

514. We therefore asked Powercor to run its model with 100% 50PoE demand (as a 'low case'), which resulted in deferral of RBE substation by 12 months (i.e. from FY31 to FY32).[118]

515. This would have the effect of deferring the estimated $15.3 million from 2031 for the proposed new RBE substation into the following RCP.

Powercor's cost estimate is likely to represent a reasonable level at this stage of the project lifecycle

516. The project estimate is based on a combination of recent historical costs for similar work (scope and scale), with Powercor advising that cost estimates for high value zone substation work are reviewed in some detail.[119] We consider it reasonable to assume that Powercor will have good reference 'building block' costs for much of the prescribed work. We further see some evidence in the business case appendices of a reasonable understanding of the specific site challenges.

115 The total amount from the business case differs from the capex model without explanation.

116 Not included in Powercor's proposed amount

117 PCK is proposed as a contingent project and the estimated cost has not been included in Powercor's proposed augex

118 Powercor response to IR006, question 4(a)

119 Powercor response to IR004, question 11

Findings

517. We consider that the forecast expenditure for the Western growth corridor expansion project is reasonable.

518. The proposed programs under Options 2 and 3 are very similar from an economic and technical perspective. Of the options considered, one or the other of these is likely to represent the prudent approach to managing energy at risk in the Western growth corridor depending on where load growth actually is the strongest over time.

519. The first two stages of work (third transformer at MTC and rebuild BMH) are common to both options and it is reasonable to assume that they will be progressed according to the proposed timetable. The sequence of projects in the two options diverge from that point, however Powercor does not have to choose between the two until FY28.

520. As noted, the expenditure forecast does not include allowance for establishment of the new PCK zone substation because Powercor states that it intends to submit this as a contingent project.

4.4 Assessment of Non-demand augex

4.4.1 What Powercor has proposed

521. Table 4.8 shows the two programs within our scope for non-demand augex.

Table 4.8: EMCa's scope of Powercor proposed non-demand augex - $m, real FY2026

Non-demand	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Worst served customer program	0.9	6.0	6.0	2.2	0.0	**15.1**
Stand-alone power systems	0.0	0.8	0.9	0.9	1.4	**3.9**
Total	**0.9**	**6.8**	**6.9**	**3.1**	**1.4**	**19.0**

Source: EMCa table derived from Powercor SCS capex model

4.4.2 Worst-served customer program

What Powercor has proposed

522. Powercor proposes capex of $15.1 million across four HV tie-line projects, as summarised in Table 4.9. The four projects are designed to improve supply reliability in worst-served areas. The four projects were selected from a candidate list of 25 supply areas based on technical and economic feasibility.

Table 4.9: Summary of proposed worst-served customer reliability improvement projects ($m, real 2026) – not including escalation[120]

Project	Cost*	NPV	Benefit to cost ratio (PV)	Completion year proposed
BAN-WND tie line	3.5	17.7	10.3	FY28
BAN-BMH tie line	3.1	9.1	6.8	FY29
CLC-BAS tie line	5.4	2.6	1.9	FY30
TRG-WBL tie line	2.6	2.5	2.9	FY30

Source: PAL BUS 3.09 – Regional and rural equity – Jan25 – Public Tables 13-20

120 aggregate capital cost differs from the capex model

Assessment

The GSL is well below the worst-served feeder supply level threshold considered by PAL for the program

523. Victorian DNSPs are subject to the Electricity Distribution Code of Practice (EDCoP). Of relevance, there is a guaranteed service level (GSL) which can be approximately equated to nine unplanned sustained interruptions[121] per year or 18 hours of unplanned sustained interruptions per year.

524. On this basis, Powercor recognises that many worst-served customers are often not eligible to receive compensation (which ranges from $90 to $380 per qualifying event) through the GSL provisions.

The drivers for the program are electrification, government reviews and customer support

525. Powercor's proposed worst-served feeder program is predicated on three key drivers:

- The changing use of energy, with growing electrification, which it assumes will lead to higher impacts on the poorer service levels in its networks
- Recent Victorian government reviews following extreme storms in 2021 and 2024, with the latter concluding that '*distribution businesses should proactively address worst performing feeders to reduce the number and impact of outages',*[122] and
- Willingness to pay research by Powercor which established a strong preference from its customers for a $12 million or $20 million improvement program, with *'expressed concern about the inequity gap between the service levels of urban and regional and rural customers…and that without action the gap in service levels will continue to widen.'*[123]

526. On this basis, we consider it is appropriate for Powercor to consider the technical and economic merits of a worst-served customer improvement program.

Powercor's methodology is based on a cost-benefit analysis which includes a (new) worst-served customer value

527. Powercor has identified 28 areas in its network in which customers experienced 700 minutes (11.6 hours) or more off supply per year and eight or more outages per annum. It assessed solutions which would materially reduce unserved energy, based on economic viability. Powercor also considered sections of the SWER network that could be replaced with stand-alone power systems to improve reliability outcomes for select customers, which we discuss in section 4.4.3.

528. Powercor considered up to four options (diesel generator microgrid, diesel generator and BESS microgrid, HV tie line, and undergrounding) for each of the 28 sites, with the 'do nothing' case as the counterfactual. In each case Powercor selected the tie-line approach, which from the information provided, is clearly the cost-effective solution. From this analysis, Powercor identified the four projects listed in Table 4.9 that were economically viable.

529. Powercor further states that the cost of these projects relative to the customers impacted is not supported as economically viable under the STPIS.[124]

Typical causes of outages are weather, equipment failure and vegetation

530. The four feeders which Powercor selected are in each case described as being very long radial lines, often through areas of high vegetation (e.g. forested areas), being vulnerable to tree falls, bushfires, lightning strikes, and extreme weather events.

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121 Longer than three minutes

122 *PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 26 and DEECA, Electricity Distribution Network Source: Insert-source-details Resilience Review, Final recommendations report, p. 9*

123 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 27

124 Powercor's response to IR006, question 14(a)

531. To project the relevant impact of climate change over time, Powercor '*applied wind escalation to historical outages*',[125] noting that '*wind is notoriously hard to model…*'. It states that it included sensitivity analyses that '*account for no wind escalation' and additional wind escalation*.'[126] We can see no evidence of this sensitivity study in the spreadsheets provided, however there are results in each model derived from varying costs (±10%), benefits (±10%) and increased cost (+10%) *and* reduced benefit (-10%), each of which still lead to positive NPVs for the selected projects.

532. Importantly, without understanding how the wind-modelling was done and the contribution to the benefit, we are unable to discern whether a reduction in benefits of 10% accounts for no wind loading. Furthermore, given the uncertainty in the input assumptions, a sensitivity analysis of -20% benefit is likely to be a more reasonable test of the robustness of the NPV in each case.

Benefits attributed to tie lines are reasonable

533. Powercor attributes SAIDI and SAIFI reduction benefits to each tie line in its four CBA models, with the values shown in Table 4.10 for tie-line BAN-BMH by way of example.

Table 4.10: Powercor's benefit assumptions for the BAN-BMH tie line

Factor	BAN003		BMH003	
	SAIDI	SAIFI	SAIDI	SAIFI
Fault location: likelihood fault is in transfer zone	40%	40%	20%	20%
Transfer capacity: ability of healthy tie feeder to pick up transfer	10%	10%	90%	90%
Operational constraints: % time restriction is in place[127]	5%	25%	5%	25%
REFCL operation mode (fire vs non-fire season)[128]	40%	40%	40%	40%
Overall	**31%**	**24%**	**5%**	**4%**

Source: PAL MOD 3.24 - worst served customers BAN-BMH - Jan2025 - Public

534. The improvements are not the same for the two feeders in this case, however for the other three cases, the benefits are symmetrical across the two feeders. The process Powercor followed for deriving the factors appears to be reasonable, but only time will tell if the assumptions are borne out in practice.

Derivation of value of reliability in worst-served areas

535. Powercor's economic analysis includes three tiers of unserved energy valuation, shown in Table 4.11. The value of network resilience (VNR) is incremental to the VCR and was derived by Powercor from the AER's final decision on interim values.[129] The 2024 update to the VCR significantly reduced the residential VCR, and assuming that a significant proportion of the customers served by the SWER lines in question will be residential, the benefits could be reduced significantly.

536. The worst-served customer (WSC) value is also incremental to the VCR and was developed by Powercor with its customers. The VCR is based on 2023 values (in turn derived from escalation of 2019 values in the AER's report) as a weighted average according to the proportion of customer categories in the relevant supply areas.

125 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 36

126 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 36

127 Restriction on the ability to transfer customers - reclose suppression for tree clearing or live line work; ability to complete auto transfer between Zone Substations

128 Restricts duration of temporary transfers

129 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 31

Table 4.11: Inputs to Powercor's economic analysis of potential reduction in EUE from minutes off supply

Worst-served customer tiers (customer minutes off supply p.a.)	Valuation method	Value applied $/MWh (2023)
0-500 minutes	VCR	44,753
500-700 minutes	WSC (incremental)	22,300*
720+ minutes	VNR (incremental)	
domestic		19,880
commercial		52,200
industrial		74,790
agricultural		44,400
others		52,200

Source: EMCa derived from PAL BUS 3.09 page 30 and PAL MOD 3.24
** Powercor refer to $67,500 (VCR + WSC) but subsequently advised that the aggregate value is $151,433*

537. We asked for more information about the WSC derivation and were advised that:[130]

- It was developed initially in 2021 and updated in 2023 at the recommendation of the Customer Advisory Panel (CAP),
- The updated values were very similar to the initial values which are included in the feeder tie models;[131] however Powercor subsequently advised that there was an error in its derivation and the correct value is $151,433/MWh, and
- The target reliability improvement relates to reducing the number of customers who experience greater than 500 minutes off supply per annum from 22,572 to 15,000.

538. Powercor states that the introduction of WSC is a new approach to creating additional economic value for improving supply to select worst-served customers and responds to the encouragement to DNSPs such as Powercor from the Victorian government.

Correcting for a number of unsupported or overstated input assumptions results in negative economic benefit for two of the four projects

539. We used Powercor's provided CBA models for each of the four tie-line projects with the following modifications:

- Updating the VCR to the AER's 2024 values, noting that the CBA models provide the proportions for the area classifications (e.g. domestic is 32% of the customer base with Commercial and industrial at 63%), and
- Modifying the assumed benefits as follows:
  - removing the SAIFI benefit as the SAIFI improvement from the proposed solutions is not adequately justified
  - removing the benefits from the reduced impact of Major Event Days (MED) as these equate to a resilience benefit and resilience-driven projects are considered separately (by CPU and by the AER),
  - ensuring benefits commence after the project is commissioned.

540. With these changes, two of the four tie-line projects (CLC-BAS and TRG-WBL) are uneconomic.

Findings

541. We consider that the proposed scope of the worst-served customer program has not been sufficiently justified, and that the proposed augex is materially overstated.

542. Whilst the solutions provided are technically sound, there is not an obligation on Powercor to undertake the work, and so the economic analysis must be robust. The NPVs derived by

130 Powercor response to IR006, question 14(d)

131 PAL MOD 3.24, 3.35, 3.26, 3.27

Powercor for the four selected projects are positive but are sensitive to changes in input factors. We consider that there is significant uncertainty in the claimed net benefit given the reliance on assumptions about wind escalation (linked to climate change), the bespoke WSC, the inclusion of a resilience loading, and the materially high VCR value.

543. We are not convinced that all four projects are economically justified. Powercor has presented the program as a reliability improvement program however, it could also be interpreted as a climate resilience program.

4.4.3 Stand-alone power systems

What Powercor has proposed

544. Powercor proposes to install 17 stand-alone power systems (SAPS) on the SWER network at an upfront capital cost of $3.9 million over the next RCP. SAPS operating costs will persist for the assumed 25-year life of the facilities. The overhead lines currently supplying the 15 customers to be supplied by SAPS will be retired two years after the SAPS are commissioned and the avoided maintenance and replacement costs of these lines are the key sources of value. The sites/customers have been selected from Powercor's analysis which considers the benefits and costs of installing SAPS and retiring overhead lines for all customers downstream of a 'node' in the SWER network.

Assessment

Powercor considered four options, three of which Powercor consider not credible

545. The identified need is to prevent further deterioration in supply for end-of-SWER line customers. To respond to this need, Powercor presents four options in its business case and selects Option 2:

- Option 1: Base case – no additional investment; Powercor does not consider this to be a credible path because it does not meet the identified need
- Option 2: Install SAPS for customers at the end of SWER lines - this option is to retire overhead SWER assets and install SAPS for selected customers; the customers will typically be located in very remote areas at the end of long lines or those who experience a large amount of outage minutes every year
- Option 3: install diesel generator microgrids in selected SWER areas - Powercor does not consider this to be a credible solution because the cost is prohibitive for the handful of customers at the end of SWER lines, and
- Option 4: Undergrounding SWER lines – Powercor considers that at $3 million to $10 million per customer this is not a credible solution.

546. Therefore, Powercor has proposed only one credible option. As discussed below, Powercor actually proposes a subset of the option in the form of a pilot study.

SAPS modelling methodology makes many assumptions that need to be tested in practice before the costs and benefits can be confirmed

547. Powercor advises that it undertook a 'nodal analysis', involving a cost-benefit analysis of 29,502 nodes in its network. The methodology is set out in a provided report.[132]

548. Figure 4.4 shows both the sources of cost and benefit associated with the SAPS evaluation methodology. The value streams are reasonable and logically present avoided repex (viz. annualised cost of replacing network assets at end-of-life) from removing SWER assets as the largest benefit. The SAPS opex is associated with the PV of the system and fixed ancillary costs.[133] We have not seen evidence of the net benefits accounted for in the RP, however they are relatively small.

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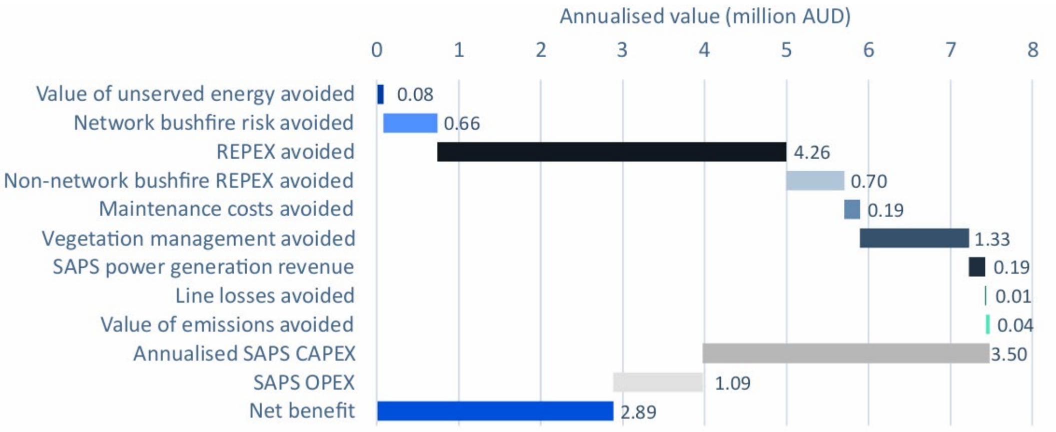
[132] PAL ATT 3.07 - Blunomy - SAPS methodology - Apr2024 – Public

[133] PAL ATT 3.07 - Blunomy - SAPS methodology - Apr2024 – Public, Table 3

Figure 4.4: SAPS value streams



Source: PAL ATT 3.07 - Blunomy - SAPS methodology - Apr2024 – Public, Figure 3

549. The methodology report includes many assumptions and qualifications but does draw on experiences of other DNSPs (notably Essential Energy). It provides a reasonable and transparent approach with Blunomy/Powercor showing all the sources of information. Whilst overall the methodology appears sound, we have some concerns which affect the NPV and therefore the selection of sites:

- Recurrent SAPS opex and IT opex and SAPS benefits accrue over 25 years but non-recurrent capex (SAPS replacement), and ICT capex replacement is not accounted for,
- The operating cost of the diesel generators is not apparent, and
- The $30,000 transition payment[134] to the 15 customers does not appear to be accounted for in the Blunomy report.

550. We asked Powercor for further information about the CBA and selection process and were provided with a supplementary spreadsheet[135] that, together with the spreadsheet[136] provided with its initial proposal satisfied us that (i) the diesel generation cost has been accounted for, and (ii) the transition payment is included, but not in the derivation of the NPV for 'selection' purposes, which is reasonable.

551. Although reasonable in their own right, collectively, the estimations, averaging, and qualifications of inputs to the derivation of cost and benefits above point to the need for confirming parameters across a number of sites before progressing with a roll-out based on economic/nodal analysis.

Powercor proposes a $5.9 million totex pilot study

552. Powercor has proposed a pilot program, selecting 17 SAPS sites from the 71 SAPS (at 44 nodes) identified from its nodal analysis as being economically viable:

> *'… since SAPS are a relatively new in Victoria, we are only proposing to install 17 SAPS in the next regulatory period. We expect to expand the SAPS portfolio in the following regulatory period once we have a demonstrated track record of integrating these into our systems to provide customers greater confidence on service level outcomes associated with this approach.'*[137]

134 The off-grid support payment is referred to in the Blunomy report once; a referenced document is AEMO's SAPS settlement price document, but a link between the two and the basis for the quantum of the payment is not transparent; The transition payment is referred to only once in Powercor's business case, and the derivation of it is not clear. It is included in Powercor's CBA model, but as a hard-coded number

135 Powercor - IR006 - Q14 - SAPS nodal analysis

136 PAL MOD 3.28 - SAPS roll-out - Jan2025 - Public

137 PAL BUS 3.09 – Regional and rural equity – Jan2025 – Public, page 56

553. The totex for the proposed 17 SAPS serving 15 customers is $5.9 million totex ($5.1 million NPV, $0.4 million per customer). The capital cost of the 17 SAPS alone is estimated at $2.0 million, with $1.2 million capex for asset retirement costs, $0.3 million capex for transition payments, $0.5m million capex for IT, and $1.9 million opex over the 20-year study period.

Benefits include the WSC and VNR loadings on top of a high assumed VCR

554. For reasons we espouse in our assessment of the Worst-served customer program, we consider that the proposed SAPS program is, at least in part, a resilience-driven program with uncertain realisable benefits. Further the benefits are materially overstated from use of the outdated VCR in Powercor's CBA model.

555. In our view, unless Powercor can demonstrate the technical benefit of deployment of all 17 SAPS, the pilot should be able to produce the necessary confirmation of parameters through a subset of the proposed program. For example, if the top five sites with six SAPS were established as soon as practicable, the results of 2-3 years of operation could be consolidated for evaluation towards the end of the next RCP for consideration of more extensive deployment in the following RCP.

Findings

556. We consider that the scope of the proposed SAPS project is not sufficiently justified and the justified level of augex materially overstated when considered against the NER criteria, even considering that Powercor has proposed the project as a pilot study. The project selected on economic grounds relies on benefits derived from improved resilience, which is being considered separately by the AER.

557. SAPS have been deployed by a number of utilities across Australia and the technical merit of them has been tested. However, it is important and appropriate for Powercor to confirm costs and benefits through a pilot study before contemplating more extensive deployment. Powercor has selected eight sites (17 SAPS) for its pilot study in the next RCP, however based on the information provided, we are not convinced of the merit of:

- the full complement of 17 SAPS, and
- extending deployment across the full 5 years of the study period as proposed.

558. Instead, we consider that a much smaller number of sites (each with the highest economic value) could be considered for the next RCP to provide more certainty about key parameters (costs and benefits, customer acceptance, etc) prior to possible inclusion in the proposal for the 2032-36 RCP for a wider deployment.

4.5 Assessment of CER Customer-driven electrification program augex

4.5.1 Introduction

559. Powercor proposes an augex customer driven electrification program as part of its Electrification and CER strategy. This strategy is common across the three CPU entities, and we describe it in our associated report.[138]

560. In aggregate, Powercor proposes $156.7 million (totex) for CER and Electrification. We assess its proposed ICT capex of $27.4m and ICT opex of $28.7m in our associated report. In the current report, we therefore review its proposed customer-driven electrification augex program.

[138] EMCa review of CitiPower, Powercor and United Energy (CPU) proposed ICT, CER and Electrification expenditure for 2026-31 regulatory period

4.5.2 What Powercor has proposed

561. As shown in Table 4.12, Powercor proposes a $100.6 million program to improve its steady-state voltage compliance over the duration of the next RCP by investing in:[139]

- Proactive LV augmentation
- HV augmentation, and
- Reactive augmentation.

562. It also recognises a small capex reduction of $1.4 million from avoided augmentation from non-network solutions, which it has accounted for in its proposed capex.

Table 4.12: Powercor proposed customer-driven electrification program ($m, real FY2026)

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer-driven electrification	9.5	21.4	15.5	25.2	29.0	**100.6**

Source: EMCa table derived from Powercor SCS capex model

4.5.3 Assessment

Victorian DNSPs have voltage compliance obligations under the Australian Standards and Electricity Distribution Code of Practice (EDCoP)

563. The EDCoP obligates Victorian DNSPs to maintain voltage levels between 216 and 253 volts at least 99 per cent of the time.[140] Functional compliance is met if these limits are maintained for at least 95 per cent of the DNSP's customers. Powercor advises that:

> *'Voltage breaches are considered a tier one EDCoP breach, which carry civil penalties of up to $11,855,400 for periods in which we are non-compliant.'*[141]

Powercor's focus is on undervoltage compliance

564. Powercor reports that it has largely remediated over-voltage non-compliance by 2022 by implementing a dynamic voltage management system (DVMS), adjusting distribution substation (DSS) tap settings, phase balancing, and by shifting voltage settings across its network.

565. Powercor also reports that it receives customer complaints that must be addressed if they are receiving non-compliant power quality (or service level) and expects these to increase in volume (and cost) as more customers 'electrify' their homes.[142]

566. Powercor's voltage performance is shown in Figure 4.5. Its current undervoltage performance is 97%. However, with the extent of electrification forecast over the next RCP, Powercor's new time-series modelling capability[143] indicates that undervoltage issues will increasingly arise. Powercor claims that this will lead to malfunctioning appliances, EVs not charging, flickering lights, curtailed PV export, increased energy costs, and reductions in the lifespans of electrical equipment.

139 CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 1

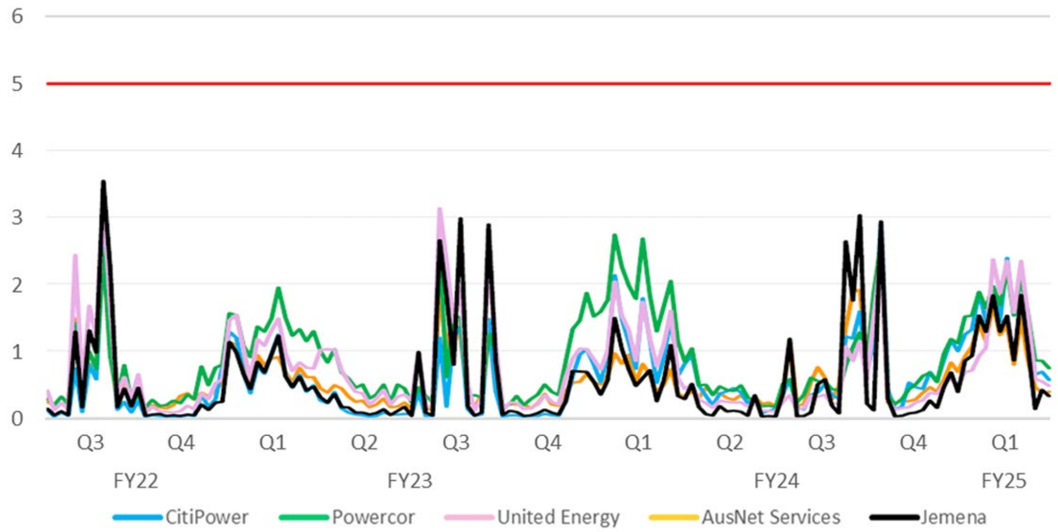
140 ESC, Electricity Distribution Code of Practice (V2), 2023, clause 20.4.1 and note to Table 2, page 82

141 PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public– Public, page 7

142 PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, page 7

143 PAL ATT 2.04 – Zepben – Detailed customer electrification forecasting methodology – Jan2025 – Public; developed using AMI data to simulate power flows at each customer connection every 30 minutes over 10 years

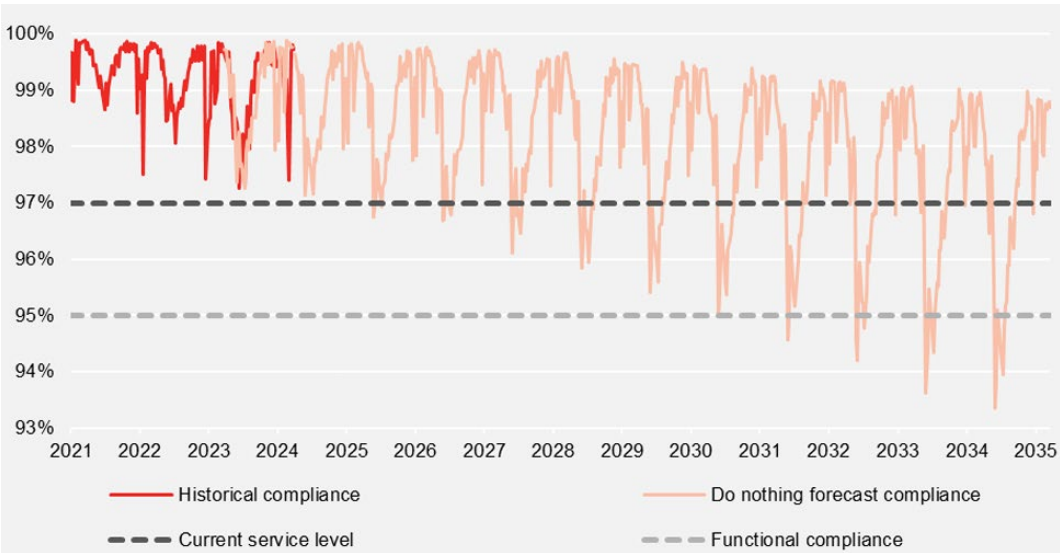
Figure 4.5: Undervoltage non-compliance of Victorian DNSPs (%)



Source: PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Figure 5. The orange line drawn at 5% represents the functional compliance threshold

567. Powercor claims that the result of a modelled 'do nothing' scenario is non-compliance by FY31. That is, it considers that it would breach the 95% Functional Compliance Limit in that year, as shown in Figure 4.6. Powercor claims that this approach will inevitably and progressively lead to more customer complaints related to undervoltage during the next regulatory period, despite technically not breaching the functional limit within this period (at least according to the modelling).

Figure 4.6: Powercor projection of voltage compliance under the 'do nothing' scenario (%)



Source: PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Figure 8

568. The combination of the description of its methodology and the methodology report itself are sufficient to satisfy us that the methodology is a reasonable basis from which to forecast future LV voltage performance. However, as with all modelling, a crucial aspect is the quality of the inputs and other parameter assumptions. These are challenging, given that there is little historical information available so far, given that the electrification journey is only beginning. However, with this caveat over the outcome of applying the methodology, we consider that there is a prima facie case for Powercor to consider options to remain compliant with its power quality obligations through the next RCP, with the focus on undervoltage management.

569. Powercor estimates that there will be 1,373 customer voltage complaints over the next RCP under the base case, each of which will need to be rectified.[144]

Powercor's proposed expenditure is significantly higher than in the current period

570. In response to an information request, Powercor advised that its total expenditure on addressing voltage non-compliance in the current RCP is estimated to be $11.9 million on its reactive responses and $11.0 million on its proactive solar enablement program.[145] Powercor noted that:

- The historical expenditure was directed primarily to addressing over-voltage non-compliance, with over-voltage managed through relatively low-cost solutions (tap changes, phase balancing) and its DVMS, and
- The outlook is for increasing under-voltage challenges which are relatively more expensive to address and that its forecast electrification expenditure is based entirely on maintaining undervoltage service levels.

Proactive versus reactive upgrades

571. Powercor is required to rectify all power-quality related complaints (provided the issue is from the supply side) and therefore the less complaints it receives, the lower its 'reactive' voltage management cost over time. In turn, this means that forecasting the number of non-compliant sites and the undervoltage complaints from them is a key aspect of Powercor's modelling for voltage management costs.

572. Proactive investments to address undervoltage include DSS offloads and reconductoring LV feeder sections. Powercor's analysis leads it to conclude that:

- Proactive upgrades are more efficient over the long-term because Powercor can optimise investment location and timing and deliver higher long-term service levels for a given cost, reducing the number of complaints over the duration of the next RCP compared to a purely reactive approach, but that
- Proactive investments are more expensive in the short term because some sites would be upgraded in advance of customers complaining (despite these customers receiving poor and/or non-compliant service levels).

573. This is the premise of its proposed 'proactive-first' investment in two of the three options it presents in its business case, as discussed below.

There is a disconnect between Powercor's historical number of power quality complaints and its forecast under-voltage complaints

574. Powercor states in its business case that it received 167 complaints in FY24.[146] It does not specifically state that these are voltage-related complaints (or even PQ complaints), but this is inferred.

575. We requested further information from CPU, with the response stating that:[147]

> *'The Customer complaints figures…are a projection of the expected undervoltage complaints received per year under the base case…Consistent with historical trends, a proportion of these complaints will be driven by network issues, which would require expenditure to resolve the undervoltage issue under jurisdictional compliance obligations. We have applied a Reactive Conversion Factor to the complaints forecast, based on historical rates, which gives us the forecast of complaints that are related to network-caused undervoltage issues and will require network expenditure.*

[144] PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 5

[145] Powercor response to IR014, question 1

[146] PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 2

[147] PAL response to IR006, question 3(a)

576. We have summarised the numerical aspects of the response in Table 4.13, which shows that the complaints projected in the business case are assumed to be voltage-driven complaints but that only a proportion of them result in network projects (i.e. to rectify the issue).

Table 4.13: Powercor – Forecast voltage complaints and conversion to reactive network rectification projects

	FY27	FY28	FY29	FY30	FY31	Total
Forecast # complaints in Table 5 of business case	220	240	273	303	337	**1,373**
Conversion factor derived by CPU	*0.35*	*0.37*	*0.38*	*0.39*	*0.40*	
# complaints forecast to require network projects	78	88	103	118	135	**522**

Source: PAL response to IR006, question 3(a)

577. The starting point for Powercor's forecast of voltage-driven complaints is similar to the total number of complaints reported in its 2024 RIN at 170 for the year. However, Powercor identifies only ***two*** of these 170 complaints as being related to technical quality of supply. The equivalent number in the 2023 RIN is also two technical complaints, with 16 in the 2022 RIN.

578. The gap between the RIN and the inputs to Powercor's model is not credible. It would appear that either Powercor's RIN data is incorrect or the forecast number of 'technical quality of supply complaints' forecast from 2027 onwards is massively overstated.

579. This is of fundamental importance because Powercor forecasts a substantial increase in the number of non-compliant sites and voltage complaints over the next RCP, both of which informs its proposed augmentation program:

- Non-compliant sites are targeted through the proactive augmentation program, and
- The forecast number of complaints requiring network projects drive the reactive program.

580. If the starting number is wrong, then Powercor's projections and forecast expenditure to maintain or improve voltage compliance performance will also be wrong. This undermines confidence in Powercor's options analysis and the proposed expenditure, which we consider below.

Powercor considered three options and proposes to 'maintain' service levels

581. Powercor presents the three options identified in Table 4.14. Option 2 is recommended.

Table 4.14: Summary of Powercor's comparative options analysis - $m, real 2026[148]

Option	FY31 voltage compliance	Total # forecast customer complaints	Cost ($m)
1. Base Case – do not breach functional limit	95.0%	1,373	$50.9[149]
2. Maintain service levels (recommended)	97.0%	938	$97.1
3. Improve service levels	97.2%	717	$209.2[150]

Source: PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Tables 5-11

582. The Base Case is premised on responding to complaints reactively, and only utilising proactive investments to achieve functional compliance, investing as late as possible. The

148 Powercor escalates the proposed cost (shown in its business case as $97.1m) to $100.1m in its regulatory submission

149 This total cost is derived from line items in Table 6 and differs from the total cost presented in the table of $49.5m

150 In Table 11 (from which this figure was sourced) there is some inconsistent data which we have ignored

result of this approach is that only $100k is proposed to be spent on a single proactive upgrade in FY31.[151, 152]

583. Whilst Option 3, as modelled, is expected to result in 221 less voltage complaints over the duration of the next RCP, it comes at a high incremental cost compared to Option 2. In our view (and Powercor's) it is not representative of a good cost-benefit trade-off.

584. For Option 2, Powercor's modelling is designed to proactively target sites based on the highest number of customers that would become compliant and only to the level required to maintain the service level at 97% across the next RCP. According to Powercor's business case, it proposes the following Option 2 capex included in Table 4.15.

Table 4.15: Nature and net cost of proposed electrification works - $m, real 2026 (unescalated)

	Cost ($m)
Proactive LV augmentation	63.0
Reactive LV augmentation (to respond to a forecast 938 complaints)	26.6
High voltage cluster augmentation[153]	8.9
Less Avoided augmentation from non-network solutions	-1.4
Total	**97.1**

Source: PAL Att 2.01

585. The HV augmentation involves upgrading selected HV feeders to address downstream LV circuits. Powercor has identified seven HV projects, covering 3,497 customers at $4.0 million less than the equivalent LV augmentation cost. As a solution, we consider this to be a reasonable approach, and our primary concern is the extent to which Powercor has justified the need for the scale of the overall program that it has proposed.

Powercor's proposed proactive program represents a very high cost per complaint addressed

586. As shown in Table 4.14 and Table 4.15, the cost of Powercor's proposed proactive option (option 2, at $97.1m) is $46.2m more than its 'base case' reactive option (at $50.9m). We consider it more reasonable to assess Powercor's program from the viewpoint of addressing underlying voltage degradation than solely as a means of reducing complaints. Nevertheless, an observation from Table 4.14 is that the cost to proactively reduce Powercor's forecast number of complaints from 1,373 over the five-year period, to 938 – a difference of 435 complaints (or 87 per year) – is around $106,000 per complaint. Intuitively, it seems unlikely that a customer would 'value' their complaint at this level.

Powercor's proactive investment methodology is highly sensitive to the assumed target service level

587. Powercor has relied on a simulation model to forecast the extent to which it expects undervoltage to occur. We provide an overview of this modelling in Appendix A. In brief, this model relies on voltage profile simulations for each feeder for each 30-minute interval, for the next 10 years. From this, it derives a set of 'economic' interventions to maintain an assumed target service level over the period and derives the cost of this program and an estimate of its economic value.

588. As we show in Appendix A, the model is highly sensitivity to the target service level, which is a model input assumption. Powercor has set this at 97% over the period to 'maintain' its current service level; however, we find that if it was to set a target of 96%, which is still

151 PAL BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table6, page 27

152 The Base case gives very similar results to the 'do nothing' case descr bed above, however 'doing nothing' is a misnomer, as Powercor still needs to respond to non-compliances. We therefore expect the cost of the 'do nothing proactive' case to be close to that indicated for the Base Case.

153 An HV cluster is a group of distribution substations located in close proximity and connected to a common HV feeder or a spur of the feeder (PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, page 59)

above its Functional Compliance obligations of 95%, the model defines an augmentation program requirement that is only around 20% of the cost that Powercor has proposed.

589. Noting that Powercor's simulations indicate that (under a 'do-nothing' scenario) it would risk breaching its compliance obligations only by around the beginning of the subsequent RCP, we consider that there are approaches that are considerably less costly than investment in long-lived augmentations in the next RCP. As with all Victorian DNSPs, Powercor will have the benefit of comprehensive AMI data to deploy a mix of focused HV, LV, proactive and reactive interventions where and when required. We consider that these needs will reveal themselves with better precision close to the time when they are required, as feeder-level variations in electrification uptake and accompanying customer behaviours become evident.

590. Powercor will also be able to gauge the extent to which it can rescue voltage decline through non-network approaches, including the Flexible Services that it will be rolling out during this period. Powercor may find, for example, that it can allow voltage service levels to decline slightly in the short term, with confidence that it can arrest and potentially reverse this decline through (preferably) non-network solutions, but with augex solutions as a backstop option.

Voltage service level decline due to electrification may be less than forecast

591. While the simulation modelling of voltage levels that has been undertaken for Powercor is relatively sophisticated and of considerable value in helping to assess its future needs, as with all forecasting models it is dependent on a range of assumptions.

592. An aspect that we do not observe in the modelling is to explore geographical variation in the uptake of electrification. For example, we consider it a reasonable hypothesis that EV uptake and at-home EV charging and charging behaviours may well vary at the 'postcode' level and for many feeders may have only a slow impact.

593. It is also a reasonable hypothesis that home electrification rates will vary considerably across the service area. New suburbs in Victoria will be fully electrified, in which case we assume that Powercor will design its networks accordingly from the outset and will not require a subsequent 'electrification augex' program for them. By contrast, it is in existing suburbs that Powercor will need to address decline in compliance due to electrification, but electrification in these suburbs may occur far more gradually than average across the service area, as appliances are replaced. Even if Powercor's overall assumptions regarding EV and electrification demands are reasonable at the aggregate level, this variation could significantly affect the scale of work needed.

594. We have not seen evidence that such factors have been considered and, if they have not, then both could lead to lower levels of undervoltage than Powercor has relied on as the basis for its proposed augex program.

Powercor assesses the customer benefit of its program by assuming undervoltage supply is curtailed and valuing this at VCR

595. In its modelling, the customer benefit from addressing undervoltage supply is derived from the assumed alleviation of energy supplied to customers below 216V by network augmentation. Powercor values energy supplied to customers at non-compliant voltages using the VCR. It linearly weights application of the VCR between 0% of the VCR at 216V (the 'soft' compliance limit) rising to 100% of the VCR at 207V (or lower).

596. EV charging interruption is the main example given for valuing curtailment at VCR. Other impacts from undervoltage that Powercor assumes will intensify over the next RCP to the extent that voltage service levels decline are heating, cooling, cooking malfunction, and appliance lifespan degradation.

597. Powercor models the impact of augmentation options in reducing the amount of energy supplied at non-compliant voltages. It assesses the customer benefit from an upgrade as the difference between the pre- and post-augmentation undervoltage supply, valued at VCR.

It is an overestimate to assert that supply will be curtailed at the levels that Powercor assumes, and to value undervoltage supply at VCR

598. Whilst Powercor (with CitiPower and United Energy) has put considerable effort into developing the models underpinning their analyses, using the VCR to assign value to energy supplied with non-compliant voltages is not consistent with the AER's intended application of it, even for curtailment of EV charging. The impact of not being able to charge an EV for some time is not the same as the impact of being entirely without supply within the household. We expect that the VCR is much higher than the economic cost of an undervoltage excursion and much higher than what people would be prepared to pay, given what we assume to be modest impacts. For example:

- There may be an inconvenience factor in an EV charger tripping off, which may be for minutes or for a few hours. In most circumstances, and assuming that the charger resets when voltage is restored, we consider that the pause in charging will have minimal consumer impact and may not even be noticed; we consider that assigning a VCR value of the order to $43/kWh to this inconvenience grossly overstates the likely economic value
- Tripping of air-conditioning due to under/overvoltage protection settings again may cause temporary inconvenience, though this depends for how long it trips, and
- The impact on other appliances is, in our view, unlikely to lead to major inconvenience or widespread damage individually or collectively and for the most part would not be noticed.

599. We asked Powercor to explain its rationale for the choice of VCR and in summary, its response was (i) that it is the closest measure currently available, and (ii) customer feedback is that they do not distinguish between reliability and power quality.[154] We consider that its customer feedback is likely explainable largely because those customers that have been supplied at times under voltage, may well be unaware of it, providing more indication of the minor impact that for the most part this has had. For example, we have already referred above to the very small number of voltage complaints that Powercor receives.

600. In summary, we consider that from a technical perspective undervoltage below 207V for the most part does not lead to a supply outage and that valuing such supply at VCR is a significant overstatement of the economic cost.

Powercor's reactive investment methodology

601. In addition to proactive investments, Powercor is required to respond to customer power quality complaints and remediate the issue as soon as practicable. Despite the proactive investment under its preferred option, it forecasts receiving 938 complaints which will require remediation work. Powercor advises that it remediates at the lowest cost rather than highest possible value.

602. Applying the conversion factors and average costs for minor and major rectification projects supplied by CPU to the proposed number of reactive projects under the Base Case and the Maintain option gives the results shown in Table 4.16. We sought to verify these costs using the costs per major and per minor project given in the business case, however the values that we derive from Powercor's stated assumptions differ from those that Powercor has proposed.

603. As shown in the table, we find that the $50.9m cost of the Base Case is materially overstated, and the business case proposed cost of $26.6m for the reactive project cost component of Option 2 is also overstated.

[154] Powercor response to IR014, question 3(b)

Table 4.16: Options cost analysis – reactive projects, $m 2026

Option	Number of complaints from Business Case	Business case + PAL ATT2.01[155]			Reactive projects cost	
		# network projects	# major projects	# minor projects	Business case ($m)	EMCa analysis ($m)[156]
Option 1: Base Case	1,373	522	177	345	$50.9	$32.4
Option 2: Maintain	938	357	121	236	$26.6	$22.2

Source: EMCa analysis of information in UE BUS 3.01 and PAL ATT 2.01 Table 22

604. Overall, the average cost per reactive project is $97.5k for the Base case and $74.5k for the Maintain option (using the business case data). This material difference is not explained. However, the more significant issue, as explained earlier, is that both cost forecasts are based on Powercor's forecast of the number of voltage complaints, but which appears to be significantly overstated relative to other data that it provided.

Powercor has managed potential for duplication amongst its programs appropriately

605. We asked Powercor to provide further detail to that in the business case about the steps it has taken to avoid duplication between its various programs. We are satisfied with the response.[157]

Sensitivity analysis is not sufficient

606. Powercor included only one form of sensitivity analysis in its business case (and none in its provided model): modelling the non-compliance forecast for the Base Case using the 10PoE demand forecast. This shows that the proposed level of 'maintain' investment would only hold compliance above the functional limit until 2029, rather than a date much further into the future with the base demand assumption (which is not apparent, but which we assume is 50PoE).

607. This analysis is not an adequate substitute for a thorough sensitivity analysis to test the robustness of the proposed expenditure, particularly given the issues that we have described with the methodology for deriving economic proactive augmentation projects. We consider that there is considerably more productive scope for sensitivity analysis around the impacts of electrification itself, than only varying the underlying demand forecast.

4.5.4 Findings

608. Powercor has not sufficiently justified the proposed customer electrification program and the proposed augex is materially overstated.

~~609.~~ We are satisfied that forecast demand and an expected trend to electrification will, other things being equal, tend to result in a decrease in voltage service levels over the regulatory period and that some 'PQ' expenditure will be required to manage this. Powercor's modelling indicates that it is likely to maintain compliance until around the end of the next regulatory period and we consider it more likely that the impact will be less than Powercor has forecast.

610. However, we have four significant concerns with Powercor's forecasting methodology that we consider has led to a significant overstatement of the expenditure that Powercor will require in the next RCP. We consider that:

- Powercor has overstated the need and justification to maintain voltage service at current levels throughout the period. From a risk perspective, a slight decline would have

155 Ratio is 34% major projects and 66% minor projects

156 Major project cost is $113k and Minor project cost is $36k as per PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, Table 22

157 Powercor response to IR014, question 3(d)

considerably less impact on customers than Powercor is assuming, may be arrested by non-network solutions such as Powercor intends to deploy in any case, and would void the need for the proposed very substantial network augex investment

- Powercor can remain within its Functional Compliance obligations with a considerably lower level of proactive intervention and, through utilisation of its extensive AMI data, can monitor PQ at the LV level, utilising its DVM system and taking account of the impact of Flexible Services, and target any augmentation-based interventions as may be required, when required
- Powercor's use of VCR to value energy served to customers at less than 216 volts is not a valid application of the VCR. It leads to a significant overstatement of the economic cost of undervoltage supply and therefore to a significant overstatement of the economic benefits of Powercor's proposed proactive program, and
- Powercor's information on voltage complaints is highly inconsistent and cannot be relied on as a factor in considering the scale of reactive work required under any of the options that Powercor has considered.

611. On this basis, we consider that Powercor has not justified the considerable increase in augex that it has proposed to enable a proactive electrification program.

4.6 Assessment of Bushfire mitigation augex

4.6.1 What Powercor has proposed

612. Powercor has proposed $143.1 million for its bushfire mitigation augex as shown in Table 4.17, comprising three programs.[158]

Table 4.17: EMCa's scope of Powercor proposed bushfire mitigation augex - $m, real 2026

Augex by Driver	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Minimising bushfire risk	6.7	10.9	4.3	4.3	-	**26.2**
Maintain REFCL reliability through the deployment of fault indicators on the SWER network	-	4.3	4.3	4.3	-	**12.9**
Minimising bushfire risks from SWER lines through upgrade of bare overhead conductor to covered conductor and EFDs	6.7	6.7	-	-	-	**13.4**
Non-mandated REFCL	-	-	-	9.5	9.6	**19.1**
REFCL compliance	19.4	37.0	10.1	16.3	15.0	**97.8**
Total	**32.8**	**58.9**	**18.7**	**34.4**	**24.6**	**169.4**

Source: EMCa table derived from Powercor SCS capex model

613. This forms a part of the bushfire mitigation program proposed by Powercor as detailed in Table 3.2 included in section 3.

614. The bushfire mitigation program includes projects based on outcomes of Powercor's 'As Far As Practicable' (AFAP) assessment for the next RCP, comprising:

- minimising bushfire risks from SWER lines, and
- minimising bushfire risks in the Horsham supply area (non-mandated REFCL).

615. The program also includes projects focussed on maintaining REFCL compliance and maintaining service levels given the adverse effect that REFCL settings have had on customer supply reliability:

158 Minimising bushfire risk has two projects, maintain REFCL reliability and minimise bushfire risk from SWER.

- maintaining REFCL compliance, and
- maintaining REFCL reliability.

616. We consider the projects proposed by Powercor, noting that in its capex model, Powercor has combined minimising bushfire risks from SWER lines and maintaining reliability into a single project titled minimising bushfire risk.

4.6.2 Maintain REFCL reliability

What Powercor has proposed

617. In Appendix B of its supporting information,[159] Powercor describes the need to restore reliability for customers following the reduced automation capability of its Fault Detection Isolation and Restoration (FDIR) schemes on REFCL protected networks, particularly associated with earth fault detection capability at its existing remote-controlled switch and sectionaliser sites. The FDIR schemes do not function as intended on REFCL-protected networks due to the near instantaneous operation of the REFCL at the zone substation.

618. We understand that the project targets augmentation at 149 feeders. We asked Powercor to elaborate on the selection process for 149 feeders, specifically the rationale for selecting each of the 149 existing remote-controlled switch and sectionaliser sites across all REFCL protected networks, including any reliability analysis.

619. In its response,[160] Powercor stated that the 149 sites represent the entire fleet of remote-control gas switches and sectionalisers on REFCL networks.

Assessment

Powercor has demonstrated the impact of REFCLs on reliability

620. Powercor states that the reliability of REFCL protected feeders has been negatively impacted, resulting in a significantly larger number of customers being taken off supply due to operation of the REFCL than necessary.

621. We asked Powercor to provide the performance of the feeders protected by REFCLs relative to other feeders in the network and were provided the chart in Figure 4.7. In support of the chart, Powercor states:

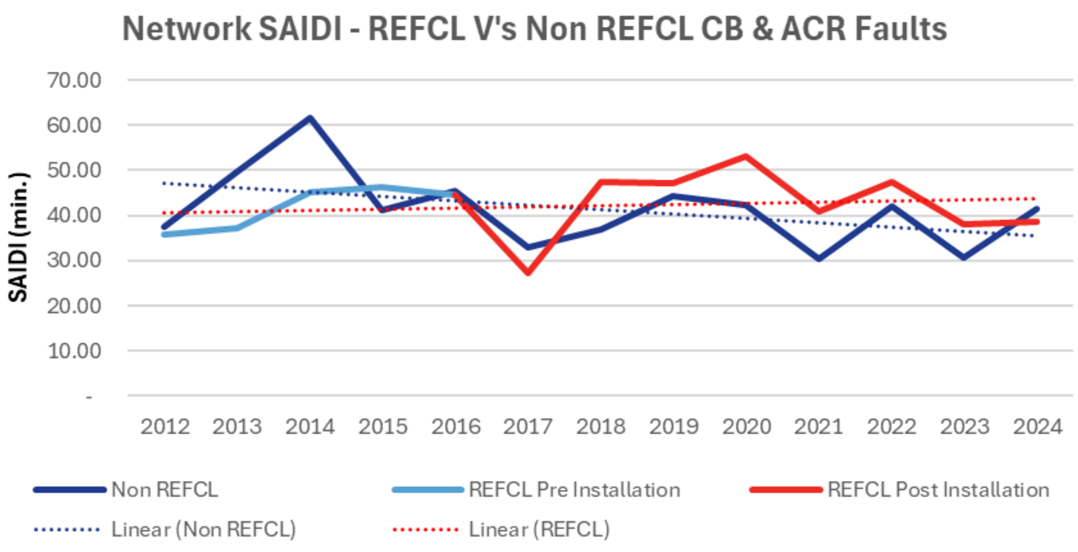
> *'REFCLs were first introduced in Powercor in 2016. Since 2016, REFCL SAIDI has increased by 5% on average, whereas non-REFCL SAIDI has reduced by 18% on average. Similarly, SAIFI on REFCL protected networks has increased by 48% on average, whereas SAIFI on non-REFCL networks has reduced by 17% on average.'*[161]

[159] PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public

[160] Powercor response to IR006 Question 9

[161] Powercor response to IR006 Question 9

Figure 4.7: Comparison of network SAIDI for REFCL and non-REFCL networks



Source: IR006 question 9

622. However, we observe that over a period of 10 years, the REFCL network SAIDI is flat. It is only the introduction of results in the earlier years that shift the apparent long-term trend, and which was prior to the introduction of REFCLs. It is therefore unclear to what if any extent the introduction of REFCLs had on these earlier events.

623. Considering the results post 2016, when REFCLs were first introduced, the two networks show a similar level of year-on-year improvement in reliability from 2015, albeit the average SAIDI for the REFCL networks is approximately 10% higher.

624. Accepting the premise that the introduction of REFCLs lessens the ability for the network devices to detect earth faults, and that earth faults are the dominant fault on these networks, then a decline in reliability is likely.

However, Powercor is currently implementing a project to improve reliability of REFCL networks

625. In response to our information requests, Powercor stated that it is in the process of reinstating earth fault discrimination on all ACRs on its REFCL networks by replacing all ACRs with REFCL compatible devices.

626. We reviewed the plans proposed for the current period and found evidence of a project in the current period titled Mitigating REFCL reliability impacts ($13.0 million capex $2021) 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. The AER included this in its determination for the current RCP.[162]

627. In the supporting business case,[163] Powercor describes its modelling methodology which includes estimating the additional customer minutes off supply from the incompatibility of REFCLs with traditional devices and converting this to an estimate of unserved energy which it values at VCR.

628. Powercor does not appear to account for the benefits arising from its current project.

162 AER, Attachment 5: Capital expenditure | Draft decision – Powercor 2021–26, page 5-45

163 Powercor - Business Case 4.05 - Mitigating REFCL reliability impacts - 31 January 2020

The benefits assumed by Powercor for the proposed program are overstated

629. In its model,[164] Powercor has assumed reliability benefits of 5% SAIDI benefit and 2.5% SAIFI for feeders. We asked Powercor how the benefits were derived and also how the improvements targeted by other programs have been considered in this program.

630. Powercor stated that:

> *'Remote controlled switches and sectionalisers provide fault indication and remote switching capability that is utilised to identify fault locations and restore healthy sections of the network through our Distribution Management System.*
>
> *This program will restore the fault indication capability to pre-REFCL levels as far as technologically feasible. In relation to the worst served feeder tie projects, the re-instatement of fault indication capability further enhances the value proposition of our proposed projects, enabling more effective fault indication and automation of the ties themselves.'*[165]

631. Table 4.18 shows the methodology used to calculate the benefits of this program, with key inputs as shown.

Table 4.18: Powercor's derivation of reliability benefits from its FIDAR scheme

	Benefit of remote control switch / sectionalisers on rural long feeders	Proportion of earth faults	REFCL earth fault detection sensitivity success	Capability restoration improvement
SAIDI	14%	70%	50%	14% x 70% x 50% = 5%
SAIFI	7%	70%	50%	7% x 70% x 50% = 2.5%

Source: IR006 question 10

632. We understand this to mean that the project proposes the installation of fault indication capability to existing switches. However, the benefits appear to have been derived from the installation of the remote control switches / sectionalisers themselves and not the incremental benefit of the earth fault indication.

633. We asked Powercor to provide the derivation of the SAIDI and SAIFI benefit of Remote Control Switch / sectionalisers on rural long feeders. In response[166] we were provided the data shown in Table 4.19.

164 PAL MOD 3.29 REFCL reliability

165 Powercor response to IR006 Question 10

166 Powercor response to IR013 Question 20

Table 4.19: Improvements from Remote Control Gas Switches (RCGS) program

Theoretical improvements	RCGS mid-feeder, no tie	RCGS mid-feeder, operates as auto sectionaliser in conjunction with upstream protection	RCGS mid-feeder with remote feeder tie; manual restoration of health feeder sections (approx. 15 min)	RCGS mid-feeder with FDIR automation enabled; remote restoration of health feeder sections (<3 min)
SAIDI imp	21%	25%	41%	50%
SAIFI imp	0%	25%	0%	50%
RGCS scheme distribution for Rural long	40%	40%	15%	5%

Source: EMCa table derived from Powercor response to IR013 Question 20

634. The automation success rate for Rural Long is assumed to be 50% on the basis that Rural Long feeders have low fault currents and therefore some fault types are not easily detected. Protection sensitivity on RCGS and ACR is poorer than feeder CBs. Rural long feeders also supply remote areas with limited or no transfer capability. Powercor calculate the weighted improvement as being 14% for SAIDI and 7% for SAIFI.

635. We consider that the reliability benefits claimed by Powercor are overstated, and make the following observations:

- The calculation appears to overstate the likely incremental benefits from introduction of fault indicators only. Whilst they may be an integral part of a FDIR scheme, the analysis does not appear to take adequate account of the existing functionality
- The decline in reliability observed cannot be directly attributed to the lack of fault indication only, and is more likely attributed to the decline in device coordination to which the current period project is targeted
- The current operation of REFCLs, and therefore decline of reliability attributed to REFCLs, is limited to the fire season when they are in operation, and
- We are not convinced that fault indication capability improves SAIFI, as it is an indication a fault has travelled passed the location of the fault indicator and which allows for FDIR schemes to operate and/or improved fault location for patrols etc. This has an impact on reducing the duration of the outage, and not the frequency of the outage. Our observation appears to be supported by the wording in the table above that refers to restoration. However, if the fault indication capability is used to assist isolate faulted sections, thereby reducing the frequency of outages to some customers, then there may be some benefit to SAIFI.

636. We also requested that Powercor provides a description of the values of network SAIDI and network SAIFI included in MOD 3.29, including by providing the source of these values and how they reflect variability in reliability performance for each of these networks. From Powercor's response[167] we understand that the feeder level performance is based on a 5-year average ending in FY23. Based on this response, it does not appear to take account of the reliability benefits of the current reliability improvement project that is not due to be completed until 2027.

The REFCL operation reflected in an updated ESV policy is likely to have a negative impact on reliability, and is not yet included

637. During our onsite discussion with Powercor, we were made aware of a change in policy published by ESV relating to the operation of REFCLs, specifically bypass mode, effective from 6 December 2024. In response to our request, Powercor provided us with a copy of the updated ESV policy which states:

[167] Powercor response to IR013 Question 19

'Bypass mode should not be used by distribution businesses to address adverse supply reliability impacts due to REFCLs. We expect distribution businesses to commit and take steps, as soon as practicable, to deploy REFCL-compatible Automatic Circuit Reclosers and fault-finding devices and undertake network upgrades to address supply reliability issues directly.'[168]

638. Our understanding is that Powercor currently deploys bypass mode during the non-fire season, and if this is not adopted it will adversely impact network reliability.

639. In its response, Powercor stated that:

'After the release of this policy, Powercor sought clarification from ESV in regard to the cessation of by-pass mode. ESV clarified that they recognise that there is a need for a 'transition period' and that distribution businesses reflect transition plans in their BMP for ESV assessment.

As presented in our bushfire program, Powercor is part way through a program to replace legacy ACRs on REFCL protected networks with REFCL compatible ACRs. This program is planned for completion by the end of 2027 and will restore approximately 50 per cent of the deteriorated reliability performance.'[169]

640. We understand that the Powercor program is directionally consistent with the ESV policy, however we are not convinced by the magnitude of the benefits claimed by Powercor, and after moderation the models do not support a positive net economic benefit arising from this project.

641. Powercor also states that:

'ESV expect distribution businesses to update their BMPs to reflect compliance with this policy inclusive of a transition plan to address reliability issues. Powercor will submit an updated BMP for ESV assessment in August of this year.

Our BMP is likely to indicate that we will cease using by-pass mode from 2032.'[170]

642. The current BMP does not refer to this program.

Findings

643. We consider that the Maintain REFCL reliability project has not been sufficiently justified.

644. The REFCL reliability project was not in fact targeted at bushfire risk reduction, but reliability improvement. For this project, we accept that customers on REFCL connected networks have experienced a decline in reliability. However, Powercor has not sufficiently taken account of the benefits arising from a similar project underway in the current RCP to improve reliability of REFCL networks.

645. Notwithstanding the above, and which may significantly reduce the benefits of a further program, we consider the benefits attributed to fault indication capability are materially overstated, and after moderation do not support positive net economic benefits arising from this project.

168 Powercor - IR013 - Q23 - ESV - REFCL operating policy

169 Powercor response to IR013 Question 23

170 Powercor response to IR013 Question 23

4.6.3 Minimising bushfire risks from SWER lines through upgrade of bare overhead conductor to covered conductor

What Powercor has proposed

646. In Appendix E of its supporting information,[171] Powercor describes the need to minimise as far as practicable the fire risk of its SWER network in its highest bushfire risk areas.

647. Powercor considers options to replace overhead bare conductor with covered conductor and early fault detection (EFD) technology, either targeting highest risk areas of the network or full rollout of EFD on SWER.

648. Powercor describes that the method for identifying SWER lines targeted for either covered conductor or EFD was based on the following approach to reduce the ignition risk posed by SWER conductors:

- primary mitigation strategy—covered conductor was identified as the most effective option for risk reduction. It was prioritised based on modelling individual sections of SWER bare conductors, which highlighted those at high risk due to factors such as age, condition, and associated fire risks. The selection of specific lines was based on their demonstrated risk profiles, ensuring that the installation targets those segments that pose the greatest risk, and
- complementing risk management approach—EFD was considered as the next viable option for the remaining high-risk exposed sections of SWER conductors that would not be addressed by the installation of covered conductor.

649. Powercor's preferred option was the targeted installation of covered conductor and EFD on SWER lines in electric line clearance areas (ELCA), REFCL areas and HBRA (option 5) as providing the highest net benefit of the options considered. The scope included EFD technology installed on 2,107km of highest risk SWER lines in ELCA, REFCL and HBRA (total of 602 devices) and install covered conductor on 76km of SWER lines that do not have EFD monitoring.

Assessment

Powercor's economic analysis is based on erroneous assumptions and once corrected, the net benefits are negative

650. Powercor states that the result of its sensitivity analysis was that the preferred option remains economic under most sensitivities. However, the NPV of the preferred option is $1.7 million, and which we consider is based on erroneous assumptions, namely:[172]

- The capex is understated. We note that the cost estimate was based on bare SWER replacements and adapted by addition of covered conductor components to the expected cost and EFD costs informed by vendors and trial experience. However, the calculation of the NPV is based on the annualised capex, rather than the incurred capex. As the assessment period and asset life assumptions are not aligned, this means that the capex used in the calculation of the NPV is lower than will be required to deliver the claimed benefits[173], and
- The opex is also understated. The model includes an assumption around the ongoing licencing and inspection costs for the EFD devices, however these costs are not included. Only the annual alert validation opex cost is included. We assume that the opex costs associated with EFD 7.5 yearly site visit for battery change and inspection opex cost ($0.6 million $2023) and annual SaaS licencing opex cost after the first 5 years ($0.5 million $2023) have not been included as they are incurred outside of the next RCP timing, or that the costs are already included in the opex base year. However,

171 PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public

172 MOD 3.23 - Minimise bushfire risk from SWER - Jan2025 – Public

173 Refer to Appendix B

not including these costs in the economic analysis understates the costs that are likely to be incurred.

651. The evidence provided by Powercor for the costs of the EFD technology was based on the unit cost for supply, support and licencing for 150 units only. We consider that, once corrected to more reasonably take account of the costs that Powercor will incur, the program has a negative NPV for this project.

652. We also checked option 2, which includes covered conductor only. We understand that Powercor has ranked each of the conductor sections from highest to lowest present value, from which it has selected the program comprising 76km. However, when we review the NPV from option 2, based on the rationale above, the NPV is negative.

We do not find the AFAP assessment compelling

653. Powercor presents this project as arising from its AFAP assessment. Powercor directed us to the AFAP Validation Assessment conducted by GHD. On review of this supporting document, we find that it was focussed on the reasonableness of the procedure and whether that procedure was followed by Powercor rather than a review of individual projects.

654. In Appendix C, GHD refers to two critical discrepancies or gaps in relation to the scope of this project, with recommendations to provide data to validate the recommendation to include this project. GHD notes that updated information had been reviewed, and the recommendation validated.

655. We asked for the material that was referred to in the review by GHD, and that GHD had relied upon in its assessment. We were provided a range of documents including the AFAP risk mitigation investment assessment procedure, network safety risk AFAP options analysis, and bushfire risk AFAP options analysis.[174]

656. We found reference in the materials provided by Powercor to having considered deployment of covered conductor and EFD, however based on our reading, Powercor does not deem these investments as passing its disproportionality test as shown in Table 4.20.

Table 4.20: AFAP options analysis for covered conductor

		Disproportionality Test "(≥ 1 = Pass; < = Fail)"		
Ref	Control option	ELCAs	REFCL areas	HBRAs
1	Augment all bare HV conductors with covered conductor (22kV focused)	0.14	0.11	0.15
5	Deploy pre-fault detection on HV	0.50	0.39	0.52
104	Deploy Early Fault Detection (delta of AMI analytics & HV crossarm replacements)	0.60	0.46	0.62

Source: Powercor - IR004 - Q4(a) - bushfire risk AFAP options analysis - public

657. In the bushfire risk AFAP options analysis, reference is made to ideas[175] titled 'Targeted SWER EFD', and 'Replace 22kV & 12.7kV bare OH with covered conductor in highest risk exposed areas' being assessed separately. However, we were not provided with these assessments. The only model we were provided was the economic analysis, and which we consider below.

658. The GHD review looked at the procedure that Powercor had followed and not the risk or economic assessment of individual projects.

174 Powercor response to IR004 Q4(a)

175 This worksheet lists all the ideas which have been identified collectively by the business for managing 'Catastrophic Bushfire Risk'

659. We did not find evidence of a compliance obligation to proceed with this project, or that the economic analysis indicated that it was prudent to proceed with the proposed project on the basis that it was economic for the next RCP. It is reasonable to consider a program to target the highest risk areas of the SWER, however Powercor has not adequately demonstrated that the program as proposed is prudent or efficient.

The assessment of benefits is low

660. The benefits of this program arise from reductions to bushfire risk and energy at risk. The assumptions are summarised in Table 4.21.

Table 4.21: Risk assumptions for Option 5, expressed in $2023

Risk component	Value
Bushfire risk	
Annual bushfire risk reduction from EFD after installation	$906,637
Annual bushfire risk reduction after installation of 76km of covered conductor	$338,855
Total annual bushfire risk reduction	**$1,245,492**[176]
Residual annual bushfire risk after program completion	$13,543,676
Energy at risk	
Energy at risk reduction by EFD	33%
Annual energy at risk per km of SWER line (per km)	$40
Annual energy at risk reduction per km of SWER from EFD	$13.26
Length of SWER protected by EFD (km)	2,107
Total annual energy at risk reduction from EFD	**$27,932**
Length of SWER protected by covered conductor (km)	76
Total annual energy at risk reduction from covered conductor	$3,053
Residual annual energy at risk after program completion	$817,722
Program duration (years)	2
Annual bushfire risk reduction for each of the program year	**$622,746**
Annual energy at risk reduction for each program year	**$15,492**

Source: PAL MOD 3.23 Minimise bushfire risk from SWER

661. The benefits arise from the bushfire risk modelling. Powercor explains the process that has been applied to generate the stated benefits, and which appears to be reasonable. In aggregate, the benefits are low.

The EFD program is an extension of the concept project in the current RCP, but requires further development of the technology

662. The EFD devices detect partial discharges that occur from early signs of a fault (for example deteriorating insulator material, conductor degradation). Data regarding the early signs of fault are communicated to Powercor via the device's inbuilt cellular communications module. As such, the technology helps detect and pinpoint defects (with an accuracy of ±10 metres) in electrical infrastructure before they develop into electrical faults that cause equipment damage, permanent outages, and public safety threats such as fallen wires and bushfires.

176 The annual bushfire risk reduction is maintained for the 15-year lifespan of the EFD devices (and added back after this time).

663. EFD devices have not been installed previously in Australian distribution networks. AusNet, Powercor/CitiPower, Victorian state government and IND.T[177] have undertaken various trials of EFD devices in Victorian networks.

664. Powercor states that the learnings from the trial included that:

> *'our inspection validation activities showed that the EFDs installed on the Powercor network have the capability to identify defects that if left untreated may eventuate to a failure and result in a fire start'* [178]

665. Powercor states that field validation of EFD alerts is essential prior to rolling out fault trucks and that there are many alerts where defects could not be validated. Based on our own reading, we consider that the number of alerts currently being generated by these devices are very high and which requires an intelligent approach, perhaps with the support of AI to isolate potential defects prior to selecting sites for field validation. To our knowledge this element of the proposed program has not yet been sufficiently developed.

Benefits of the EFD devices remain uncertain, and require ongoing development of the technology

666. We understand that to overcome the uncertainty associated with the alerts generated from this technology, Powercor had applied a scale factor to account for its effectiveness in locating defects. We asked Powercor to confirm the effectiveness of EFD devices, and how this effectiveness has been included in the modelling of bushfire benefits in the business case / economic model.

667. In its response,[179] Powercor provided a table identifying the SWER bushfire risk causes, probability of occurring and effectiveness of the EFD technology in mitigating the various causes of fire starts, as the basis of its effectiveness value of 33%. Powercor has applied this to the benefits in the NPV model. The largest contributors are insulator (leakage) and vegetation related causes.

668. Whilst this overall figure aligns with discussion we have had with Powercor and AusNet Services, we consider the effectiveness assigned to individual bushfire risk causes may be higher than the observed experience. For example, Powercor assigns an 80% effectiveness of EFDs in mitigating a fire starts caused by conductor failure. Based on information provided from the trial, and which was also shared with Powercor, we conclude that the devices generate a large number of spurious readings which if not adequately filtered lead to unnecessary and inefficient truck rolls.

669. We requested a copy of the latest report from the trial project. The trial report was prepared by the vendor IND.T, as a deliverable of the trial. Interestingly, the report stated that the only EFD systems on SWER were installed over 5 years ago and have since been retired.

670. More recent results support that this technology has the potential to identify defects, however the experience to date is that issues confirmed by inspection did not require urgent attention, and there was no evidence to suggest that the defect would not be raised using traditional techniques.

671. Based on our reading of supporting materials, we determined that there was a high level of spurious alerts generated from these systems which are not able to be actioned. Analysis of alerts is a manual time-consuming process. If all were acted upon, this would result in significant resources to investigate, and worse if expanded to additional devices on the network.

Findings

672. We consider that the Minimising bushfire risk from SWER project has not been sufficiently justified.

177 IND.T Intelligent Network Diagnostic Technology with offices in Richmond Victoria, https://ind-technology.com/

178 IR013 – repex – 20250430 – public, question 30

179 Powercor - IR013 - repex- 20250430 – public, question 31

673. We consider that a program to target the highest risk areas of the SWER is reasonable, however Powercor has not adequately demonstrated that the program as proposed is prudent or efficient. Specifically, we have concerns that the benefits of the EFD devices remain highly uncertain and require ongoing development of the technology.

4.6.4 Non-mandated REFCL

What Powercor has proposed

674. In Appendix C of its supporting information,[180] Powercor describes the need to assess potential bushfire risk mitigation measures to reduce the fire risk associated with Horsham bare 22kV overhead lines, as far as practicable. ESV stated in its January 2024 consultation paper of REFCL operations that it is possible that additional deployment of REFCL technology, or extending the coverage of existing REFCLs, may be a practicable means by which relevant hazards and risks are mitigated, and therefore should be done to meet general duties obligations.

Assessment

Powercor claims to address the highest bushfire risk location

675. Powercor states that it had considered the top five highest risk non-REFCL protected substations and concluded that Horsham (HSM) substation represents the highest risk - $2 million pa (22kV feeders present risk with disproportionality factors (DFs) applied, $2022).

676. We accept the analysis as presented and note that this is an assessment of non-REFCL protected substations only.

677. In response, Powercor considered a range of options to address the bushfire risk at HSM only. The recommended option is to install a single REFCL at Horsham zone substation by the end of the next RCP, commencing in FY29.

678. As Horsham is not specified in Schedule 1 of the Electricity Safety (Bushfire Mitigation) Regulations 2023, Powercor is not required to achieve the same capacity requirements and has assumed a 50 per cent fire risk reduction at this location (compared with 54% at the required capacity).

Economic analysis is not compelling

679. The benefits of the proposed project are a combination of bushfire risk from its bushfire risk model, and safety risk. Reductions to bushfire risk of 50% are claimed from the installation of a single REFCL, which are based on the CSIRO study and used for the mandated REFCLs.

680. Safety risk is based on a fatal incident arising from contact with the HV network every year, valued at VSL. Powercor then consider the safety risk reduction being 98% during times the REFCL is in operation. We consider that this method overstates the underlying risk as it assumes as a counterfactual a death every year across the network, and the risk reduction arising from REFCLs which are applied only to parts of the network.

681. Powercor calculates the NPV for this project as $3.4 million, however the assessment considers the costs and benefits over differing timeframes, namely 30 years life for the costs (using annualised costs) and benefits over the assessment period of 20 years. This results in understating the costs to achieve the stated benefits.[181] After considering the costs as proposed within the assessment period, we consider the NPV is marginal. Moderating the benefits further decreases the NPV.

682. The bushfire risk remains flat throughout the assessment period. We accept this may be a simplification to the analysis; however we expect that the bushfire risk may be positively

180 PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public

181 Refer to Appendix B

impacted by the scope of the safety and replacement programs, and potentially negatively impacted by deterioration of the assets.

Cost appears high compared with other REFCL projects

683. Powercor states that the cost of this option was based on similar completed projects as part of the original VBRC REFCL tranche 3 program. We compared the cost of this project to the cost estimates of the REFCL compliance program, which included new REFCLs. We found that the Horsham cost estimate was marginally higher than that included in the REFCL compliance project, and much higher for the included distribution works.

Powercor does not present optimal timing

684. Powercor does not undertake analysis of the optimal timing for this project, that maximises the NPV. The project is currently planned for the end of the next RCP and may be a candidate to consider for deferral given the scope of the bushfire risk program. Powercor did not test the sensitivity of its analysis to alternate timing of this project to address the bushfire risk.

Findings

685. We consider that the non-mandated REFCL project in Horsham has not been sufficiently justified.

686. We consider that a program to target the highest risk areas of the SWER is reasonable, including the use of non-mandated REFCL where they can be demonstrated as economic options. Powercor has not adequately demonstrated that the project as proposed is prudent or efficient to undertake in the next RCP.

687. We have concerns with the proposed cost of the project and are of the view that there is potential for this project to be deferred outside of the next RCP given the scope of the bushfire risk program.

4.6.5 REFCL compliance

What Powercor has proposed

688. In Appendix A of its supporting information[182], Powercor describes its assessment of the least cost technically acceptable REFCL projects. We present these in Table 4.22.

[182] PAL BUS 3.11 – Bushfire mitigation forecast overview – Jan2025 – Public

Table 4.22: REFCL compliance – preferred option and cost $m FY2026

Location	Preferred option	Cost	Completion year
Ararat	Isolating substations	0.3	2026/27
Ballarat East stage 2	New transformer, additional REFCL and iso subs	14.6	2028/29
Bendigo Terminal Station	Feeder reconfiguration	3.3	2027/28
Bendigo	New transformer, additional REFCL and transfers	13.4	2030/31
Colac	REFCL mini grids	7.8	2027/28
Eaglehawk	New transformer, additional REFCL and transfers	12.8	2027/28
Gheringhap[183]	Feeder reconfiguration	3.7	2030/31
Gisborne	New REFCL and feeder arrangement (in-flight project)	9.3	2026/27
Koroit	Isolating substations	0.6	2026/27
Terang	New REFCL and feeder transfers	5.6	2028/29
Torquay[184]	Feeder reconfiguration	3.1	2029/30
Tranche one remediation	Phase balancing capacitors / swapping	2.3	n/a
Winchelsea	Isolation substations	5.3	2027/28
Woodend	New transformer, additional REFCL and transfers	12.6	2029/30
Total	**Preferred options**	**94.6**	
Total (incl escalation)	**Preferred options**	**97.8**	

Source: Table 3, PAL BUS 3.11 Bushfire mitigation overview

Assessment

Powercor has an obligation to maintain REFCL compliance

689. As stated by the AER in its final decision for the current period:

> *'Following the 2009 Victorian Bushfires Royal Commission, legislative amendments were introduced to reduce the likelihood of bushfire starts from electrical equipment faults. These amendments place regulatory obligations to achieve certain protection performance requirements (referred to as 'required capacity') at 22 of Powercor's zone substations. A REFCL is a protection device typically installed at a zone substation used to achieve the required capacity to reduce the risk of faulted power lines starting bushfires.'*[185]

690. In our view, the Amended Bushfire Mitigation Regulations oblige Powercor to ensure that each polyphase electric line originating from the selected Tranche 1 and Tranche 2 zone substations have the 'required capacity' to ensure proper functioning of the REFCLs on an ongoing basis.

183 The Gheringhap (GHP) zone substation and its two REFCLs were established in 2023 as part of the tranche three REFCL installation program. GHP substation doesn't have any points assigned to it as the substation was part of an exemption. The area was supplied by Geelong substation, which is a 4 point station, therefore 4 points are assumed.

184 The Torquay (TQY) substation as established in 2023 as part of the tranche three REFCL installation program. TQY doesn't have any points assigned to it as the substation was part of an exemption. The area was supplied by Waurn Ponds substation, which is a 4 point station, therefore 4 points are assumed.

185 AER - Final decision - Powercor distribution determination 2021–26 - Attachment 5 - Capital expenditure, page 5-30

Forecast capacitance levels

691. Increasing capacitive current is driving the need to invest in further mitigation efforts to ensure Powercor can maintain compliance with the Regulations. In the current RCP Powercor used forecast network capacitive charging current as the metric to assess REFCL performance.

692. For the next RCP, Powercor has used the forecast damping current against the damping current threshold limit, which can vary by asset based on the sensitivity of the REFCL protection settings to capacitance. Where this threshold limit is exceeded at a REFCL site, it indicates a probable non-compliance issue.

693. Powercor describe damping current as:

> *'Damping current is the combination of network capacitance and network damping ratio, which is directly related to the system's ability to limit fault currents to safe levels. Based on our further extensive experience in implementing and maintaining REFCL systems in our network, to enable the use of a consistent threshold limit across all REFCL sites, we have now adopted damping current as the REFCL performance assessment metric. We conduct annual testing of each REFCL system to confirm the damping current performance.'*[186]

694. One-off programs of work, such as the undergrounding of overhead networks as part of the VBRC Powerline Replacement Program, are removed from the growth rate calculations. Any forecast works for these one-off programs are factored into the network capacitance forecasts to reflect the forecast year of completion.

695. The network damping ratio is based on the annual measured value on a total fire ban day. The forecast network capacitive current is then multiplied by the network damping ratio to obtain the damping current forecast.

696. We asked Powercor to explain the basis for the change in forecasting method from capacitance current to damping current, and whether this changed the list of projects significantly when compared with the original method. In its response, Powercor stated that:

> *'Historically, we have used the network capacitive charging current multiplied by the damping ratio to assess REFCL projects. The capacitive charging current is a constant and the damping ratio changes throughout the day and over time as it depends on environmental conditions and network topology characteristics. This led to time-varying assessments of REFCL performance.*
>
> *Compliance with REFCL performance thresholds is required at all times, however, our performance varied through the day and over time. We therefore adopted a fixed damping ratio set at levels seen during total fire ban days, which leads to a single REFCL performance threshold through time to simplify the assessment, which we refer to as damping current.*
>
> *The damping current is still the network capacitive charging current multiplied by the damping ratio, which is the same methodology we have previously used and it produces the same results. The benefit is that it is simpler and does not vary over time. Because we are still using the same assessment metrics and methodology, any approval from ESV or the Victorian REFCL Technical Working Group was not considered relevant or necessary.*
>
> *The damping current methodology has been applied by our network since 2022. It was also the basis of our published RIT-D for Ballarat East in November 2023.*
>
> *There are no changes to the forecast list of projects or timings when using the capacitive charging current method because it uses the same assessment metrics.'*[187]

[186] PAL BUS 3.11 Bushfire mitigation forecast overview, page 17

[187] Powercor response to IR006 Question 6

697. We are satisfied that the method applied by Powercor is reasonable.

Powercor has selected options in each case from a suitable set of options to maintain compliance

698. Depending on the characteristics of the supply system and the substation at which the potential non-compliance is forecast, Powercor considers the option from one or more of the following options:

- Feeder reconfiguration
- Isolating transformers
- REFCL minigrid (isolating transformer and REFCL)
- New REFCL
- Mini zone substation with power transformer, and
- New zone substation.

699. Powercor has considered the least cost option that is required for each location. Neither an NPV nor other detailed financial analyses have been performed for this business case due to the compliance nature of this project.

700. On the basis of the descriptions of the options and option selection steps, we consider Powercor's forecasting process to be reasonable.

Option for Bendigo substation requires further analysis given uncertainty of forecast

701. Powercor has proposed REFCL works at Bendigo substation (BGO) due to the REFCL damping current limits forecast to be exceeded on the BGO bus 2 by 2032. Powercor has determined that the preferred option is to install a third 66/22kV transformer and associated switchgear and secondary systems, the installation of a third REFCL and transfer of feeders to the new transformer and associated REFCL.

702. The limit on Bus 2 is forecast to be exceeded in 2032 as shown in Table 4.23. This is based on forecast growth rates applied from 2023, given the last actual data was available in 2022.

Table 4.23: Forecast charging current (with 2022 compliance testing results) versus limits

Forecast year	Charging current BUS 1	Limit BUS 1	Charging current BUS 2	Limit BUS 2
2027	100.2	117.2	95.3	106.3
2028	102.3	117.2	97.7	106.3
2029	104.4	117.2	100.0	106.3
2030	106.5	117.2	102.4	106.3
2031	108.6	117.2	104.7	106.3
2032	110.7	117.2	**107.1**	**106.3**

Source: EMCa derived from BGO REFCL Forecast

703. In absence of an area plan to understand how this network is forecast to develop, and more recent confirmation of the growth rates, we consider that there is a reasonable level of uncertainty surrounding the need for a high-cost solution. Given the timing of the potential exceedance, we would have expected a lower cost solution to have been selected. In its consideration of the feeder configuration option, Powercor concludes that there are no viable options available to transfer network due to a lack of REFCL transfer capacity in the neighbouring Eagle Hawk and Bendigo Terminal zone substation networks.

704. However, there are REFCL works proposed at both of these sites with a third transformer and a REFCL is proposed for 2027 at Eagle Hawk. In addition, feeder configuration works are proposed at Bendigo Terminal station, presumably to transfer network to Eagle Hawk. It

remains unclear to us why a similar option is not available to manage the forecast exceedance at Bendigo, if only to preserve option value for consideration of the prudent augmentation option at a later time, and which is more likely beyond the next RCP.

Tranche one remediation works included

705. Powercor has proposed to review all networks associated with tranche one zone substations as part of the remediation works to ensure they meet the same standard of performance as more recent installations, particularly in relation to low voltage balancing capacitors and phase-swapping.

706. This work arises from the lessons learnt following works at the Gisborne and Woodend zone substations, being the first of the tranche one substations.

707. We consider that the remediation works, and cost estimate are reasonable given the uncertainty of the required works.

Cost estimation

708. We asked for evidence of the cost estimates for the projects included in this program. In response Powercor provided a breakdown of labour, materials and contract costs. Cost estimates provided[188] compare reasonably with its historical project costs, at the total level, which Powercor states has been the source of the cost estimates.

709. We note that the AER in its final determination for Powercor raised concerns in relation to the costs for REFCLs when compared with Jemena and AusNet, and considered that benchmarking distributors' REFCL costs continues to be appropriate. However, we do not have access to detailed historical costs, or detailed actual costs for completed REFCL projects across Victorian DNSPs to undertake benchmarking.

Findings

710. We consider that the REFCL compliance project is overstated.

711. Powercor has undertaken a reasonable forecasting method for the majority of its proposed capex. However, for the Bendigo substation, Powercor has also proposed works at adjacent substations which may provide staging options and preserve option value for consideration of the prudent augmentation option at a later time, and which is more likely to occur beyond the next RCP.

4.6.6 Summary of assessment of bushfire mitigation augex

712. We considered four programs proposed by Powercor to manage bushfire risk:

- Maintain REFCL reliability through the deployment of fault indicators on the SWER network
- Minimising bushfire risks from SWER lines through upgrade of bare overhead conductor to covered conductor and EFDs
- Non-mandated REFCL, and
- REFCL compliance.

713. Powercor's own documentation identified the RECL compliance and REFCL reliability projects as relating to its compliance obligations, and the balance in response to its AFAP assessment. In our review, this was a more accurate representation of the projects.

714. The REFCL reliability project was not in fact targeted at bushfire risk reduction, but reliability improvement. This was also evident in Powercor's documentation. For this project, we accept that customers on REFCL connected networks have experienced a decline in reliability. However, we consider that Powercor has not adequately demonstrated that this project is justified. We reach this conclusion due to our assessment that the benefits

188 Powercor response to IR013 Q17 REFCL cost estimates

claimed by Powercor are overstated, and that Powercor has not sufficiently taken account of its project approved for the current RCP targeting the same reliability impact of REFCLs.

715. For the REFCL compliance project, Powercor has undertaken a reasonable forecasting method for the majority of its proposed capex. However, for the Bendigo substation, Powercor has also proposed works at adjacent substations which may provide staging options and preserve option value for consideration of the prudent augmentation option at a later time, and which is more likely to occur beyond the next RCP.

716. For the projects proposed in response to its AFAP assessment, we do not consider the projects are sufficiently justified. Whilst Powercor is seeking to address the identified bushfire risk, the outcomes of its modelling are not sufficiently positive to be compelling to proceed in the next RCP.

4.7 Findings and implications for proposed augex

4.7.1 Summary of findings

717. We consider that collectively and individually the projects and programs that we have reviewed overstate the required augex for the next RCP.

Context

718. We have assessed eight individual augmentation projects/programs submitted with Powercor's proposal, representing 75% of the total augex proposed for the next RCP. Our findings may not necessarily be applicable to the balance of the program.

719. We have not commented on demand forecasts. The AER has advised us that it will assess Powercor's demand forecast separately and will consider our findings accordingly. However, we have, for demand-driven projects, commented on the sensitivity of the proposed project optimal timing to negative variance in the demand forecast. Our 'low demand case scenario' is a demand forecast of 100% 50PoE rather than the 70%:30% weighted 50PoE/10PoE forecast used by Powercor for planning purposes.

General

720. Powercor has presented business cases and supporting cost-benefit analysis (CBA) models that provide foundational material to support our assessment. However, we needed to ask a number of clarifying questions, primarily because the CBA models provided were not fully transparent to us, containing hard-coded data, for example.

721. Powercor responded to our clarifying questions, and this enhanced our understanding of each project and program.

722. The business cases provided to support the projects/programs (together with the CBA models) present a reasonable range of options to respond to generally well-articulated needs.

Demand-and non-demand driven projects/programs

723. In each of the projects/programs we were satisfied that there was a compelling need for Powercor to consider means of mitigating risk and or improving service levels.

724. Powercor presented a range of options and in each case selected the option with the highest NPV. We consider that in each case the selected strategy was appropriate in responding to the identified need. However, with the demand-driven projects, we have issues with the economic analyses, leading us to conclude that the proposed capex is overstated. Reasons vary between projects, but include:

- Input assumptions that are overstated (e.g. in the case of 2023 VCRs), not credible, or unsupported based on the information provided, and
- Estimated cost is unreasonably high.

725. In the case of the non-demand-driven projects, our concern is with the extent of potential variance in cost and benefit assumptions. Powercor has recognised this issue and has, appropriately, recommended limited scope/pilot projects to enable testing of assumptions. We support this but consider in both cases that smaller pilot programs are warranted with sufficient time given in the next RCP to test results before contemplating broader investments.

CER – Customer-driven electrification

726. We consider that the proposed expenditure is significantly overstated because of the following issues:

- Powercor has overstated the need and justification to maintain voltage service at current levels throughout the period – a slight decline would void the need for the majority of the proposed proactive augmentation
- Powercor has not fully explored the impact of alternatives to augmentation, such as flexible services, over time
- The use of VCR to value energy served to customers at less than 216 volts is not a valid application of the VCR and significantly overstates the economic value of proactive interventions
- The apparent sudden increase in assumed undervoltage complaints is not credible from the information provided, and
- All other things being equal, the cost for Powercor's preferred Option 2 (Maintain) reactive project component appears to be overstated.

Bushfire Mitigation projects/programs

727. Powercor's own documentation reasonably identifies the REFCL compliance and REFCL reliability projects as responding to its compliance obligations, with the balance responding to its AFAP assessment.

728. In our view Powercor has failed to adequately justify the level of expenditure for the REFCL reliability project and for the AFAP-driven projects, primarily because we consider the benefits claimed by Powercor to be overstated.

729. For the REFCL compliance project, Powercor has undertaken a reasonable forecasting method for the majority of its proposed capex. However, for the Bendigo substation, we consider there are approaches that can reasonably defer augmentation to beyond the next RCP.

4.7.2 Implications for proposed capex allowance

730. We have been asked to review projects with aggregate proposed capex of $421 million and which include an Electrification/CER project with proposed augex of $101 million. [189] These projects comprise part of Powercor's aggregate proposed augex of $565 million.

Alternative forecast methodology

731. For the projects within our scope in the bushfire mitigation augex category, our proposed alternative forecast involves one or more of the following adjustments, to the extent that it formed the basis of Powercor's forecast and which we consider to be not justified or to be overstated:

- Adjustment to the volume of work
- Adjustment to the timing of the proposed expenditure, resulting in deferment beyond the end of the next RCP, and/or

[189] Customer driven electrification

- Adjustments to correct modelling issues and/or unsupported or incorrect model input assumptions

732. For projects within our scope in the demand augex category, we consider that the proposed capex for one of the three projects (Western growth corridor expansion) is reasonable. Our proposed alternative forecast for the other two projects involves one or more of the following adjustments, to the extent that it formed the basis of Powercor's forecast and which we consider to be not justified or to be overstated:

- Adjustments to correct modelling issues and/or unsupported or incorrect model input assumptions, and/or
- Adjustment to align the forecast with historical spend, where an ongoing level of expenditure represents a reasonable default assumption and where the proposed increase was not otherwise justified.

733. For the projects within the non-demand augex category, we consider that the proposed capex is not reasonable. Our proposed alternative forecast involves one or more of the following adjustments, to the extent that it formed the basis of Powercor's forecast and which we consider to be not justified or to be overstated.

- Adjustment to the volume of work, and
- Adjustments to correct modelling issues and/or unsupported or incorrect model input assumptions

Alternative forecast of expenditure

734. We consider that a reasonable alternative forecast for the projects within the augex categories that we reviewed, would be between 40% and 50% less than Powercor has proposed.

735. We stress that our advice on an alternative forecast relates only to the projects within the augex category of expenditure within the scope of our review and does not necessarily have any implication for augex that was not within the scope of our review.

5 REVIEW OF PROPOSED OPEX STEP CHANGE - VEGETATION MANAGEMENT

Powercor has proposed an opex step change of $232.9 million in its initial submission for vegetation management, reflecting the additional expenditure that it proposes as being required for a pathway to compliance with its electric line clearance obligations that commence in the current period. Powercor subsequently updated its submission, but which only had a minor impact to its proposed overall opex step change, reducing it to $230 million, but increasing the number of spans to be cut from 77,000 to 92,000.

We have identified a number of issues with Powercor's modelling of the proposed vegetation management opex relating to the proposed volume of spans to be treated and costs to treat the identified spans and which result in an opex forecast that is materially overstated.

We consider that Powercor's proposed opex step change for vegetation management is not a reasonable forecast of its expenditure requirements for the next RCP. We are satisfied that additional improvement to vegetation management activities is required for Powercor to achieve compliance in the next RCP, however we consider that a number of factors in Powercor's forecast are not reasonable assumptions. Adjustment of Powercor's assumptions, which we applied in various combinations, leads us to conclude that Powercor does not require an opex step change.

5.1 Introduction

736. In this section, we present our assessment of the forecast opex step change that Powercor has proposed in the next RCP. We reviewed the information provided by Powercor to support its proposed opex step change for vegetation management, and its responses to our information requests on the topic.

5.2 What Powercor has proposed

5.2.1 Proposed vegetation management step change

737. Powercor has proposed an opex step change for its vegetation management program of $232.9 million for the next RCP as shown in Table 5.1.

Table 5.1: Powercor proposed vegetation management step change - $m, real FY2026

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation	12.4	26.9	55.7	57.4	58.7	**211.1**
Hazard trees	4.3	4.3	4.4	4.4	4.5	**21.8**
Total vegetation management step change	**16.7**	**31.2**	**60.1**	**61.8**	**63.1**	**232.9**

Source: EMCa table derived from PAL MOD 9.02 Vegetation management

738. Powercor claims that a change in the 'standard of compliance'[190] is required by the safety regulator, as a result of its enhanced approach to vegetation management (including adoption of LiDAR) and evidenced by an increased level of enforcement of the requirements of the governing regulations and electric line clearance management plan. Powercor claims that these requirements in turn require additional expenditure for vegetation management activities.

5.2.2 Understanding the build-up of the forecast

739. Powercor calculates its step change by first calculating a bottom-up build of its vegetation management opex requirements and reducing that by the opex included in its base year to determine the proposed step change. It does this by projecting forward its existing program and applying an uplift to the expenditure associated with its base program. We show the total opex in Table 5.2

Table 5.2: Powercor's bottom-up build of its vegetation management opex - $m, real FY2026

Total	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation cutting program	96.6	111.1	139.9	141.5	142.8	**631.8**
Hazard tree program	4.9	4.9	5.0	5.0	5.1	**24.9**
Total	**101.4**	**116.0**	**144.9**	**146.5**	**147.9**	**656.7**

Source: EMCa table derived from PAL MOD 9.02 Vegetation management

740. Next, Powercor subtracted the vegetation management opex that it expects to incur in its proposed base year opex as shown in Table 5.3.

Table 5.3: Powercor proposed total vegetation management opex - $m, real FY2026

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation						
Forecast	**96.6**	**111.1**	**139.9**	**141.5**	**142.8**	**631.8**
minus Base	84.1	84.1	84.1	84.1	84.1	**420.7**
step change	12.4	26.9	55.7	57.4	58.7	**211.1**
Hazard trees						
Forecast	**4.9**	**4.9**	**5.0**	**5.0**	**5.1**	**24.9**
minus Base	0.6	0.6	0.6	0.6	0.6	**3.1**
step change	4.3	4.3	4.4	4.4	4.5	**21.8**
Total step change	**16.7**	**31.2**	**60.1**	**61.8**	**63.1**	**232.9**

Source: EMCa table derived from PAL MOD 9.02 Vegetation management

5.2.3 Update to forecast opex step change

741. Subsequent to our discussions with Powercor at our onsite meeting, we asked Powercor to update the opex step change based on more recent actuals incurred in the program. The opex step change did not materially change in aggregate, though Powercor's timing of expenditure changed, as shown in Table 5.4

190 PAL ATT 9.02 – Vegetation management step change – Jan2025 – Public

Table 5.4: Powercor changes to vegetation management opex step change - $m, real FY2026

Step changes	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Initial submission	16.7	31.2	60.1	61.8	63.1	**232.9**
Updated in response to IR016	**30.2**	**49.3**	**49.8**	**50.2**	**50.5**	**230.0**

Source: EMCa table derived from PAL MOD 9.02 and IR016

742. We have relied on the more recent data provided in response to IR016 as the basis for our assessment.

5.2.4 Comparison of CPU businesses

743. The proposed opex step change has been based on the same methodology applied to each of the CitiPower, Powercor and United Energy networks. We show the proposed opex step change for each business in Table 5.5.

Table 5.5: Comparison of vegetation management opex across CPU businesses - $m, real FY2026

Step changes	CitiPower	Powercor	United Energy
Base program	20.3	432.4	138.8
Base uplift program	27.4	197.3	66.9
Total vegetation management opex	47.7	629.7	205.8
Proposed vegetation management opex step change	**32.1**	**230.0**	**76.8**

Source: EMCa table derived from updated vegetation management step change models provided with PARL IR016, CP IR017 and UE IR014

744. In Table 5.6 we show the unit rates assumed in FY25 for each of the summary categories.

[redacted]

745. We have examined each step change on its own merit and whether the proposal meets the requirements of a step change as set out in the Expenditure Forecast Assessment Guideline.

5.3 Assessment of the proposed step change

5.3.1 Methodology

AER guidance materials outline how opex step changes are assessed

746. As outlined in the AER's Better Resets Handbook, the AER assesses the efficiency of a business's proposed opex forecast at a total level, using the top-down 'base-step-trend' approach described in the AER's Expenditure assessment guideline.

747. In the Better Resets Handbook, the forecasting of the step change component of the base-step-trend approach is described as follows:

> *'Forecasting step changes in costs that are not compensated by base operating expenditure and trend, and are required to ensure the operating expenditure forecast meets the criteria in the Rules. Examples include cost increases associated with new regulatory obligations and trade-offs between capital expenditure and operating expenditure.'*[191]

748. The AER has set out its expectations for forecasting step changes, in that they are limited to a few in number, or none at all. Our understanding is that step changes should present material additional efficient costs to the business that are not provided for in the base or trend component of the opex forecast:

> *'New regulatory obligation step change*
>
> - *It is clearly linked to the new regulatory obligation and represents a major upward step to comply with it.*
> - *It will have an impact on the costs of providing prescribed network services and it can be demonstrated that it is not capable of being managed otherwise under forecast opex through in-built provisions under output, price and productivity growth.*
> - *No double counting of costs.*
>
> *Capex/opex substitution step change*
>
> - *It is supported by thorough cost-benefit analysis.*
> - *The avoided capex is estimated accurately and it more than offsets the increase in opex in net present value terms (that is, efficient substitution).*
> - *No double counting of costs.*
>
> *Step change driven by major external factor(s) outside the control of a business*
>
> - *It will have an impact on the costs of providing prescribed network services and it can be demonstrated that it is not capable of being managed otherwise under forecast opex, including through inbuilt provisions under output, price and productivity growth.*
> - *Where it involves incurring costs in complex areas or markets, it is accompanied by an expert report (including analysis of options, market outlook and opinion on the reasonableness of the proposed step change).*
> - *No double counting of costs.'*[192]

Step change derived from the requirements minus the expenditure incurred in its base year

749. CPU describes the forecasting method as a bottom-up build of requirements, based on its historical activities to inform its base level volume of work, which we refer to as its base program. CPU has added an uplift for each of the businesses, with the objective of moving to compliance by FY29.

750. In its updated submission, CPU estimates compliance is achieved one year earlier in FY28.

751. Powercor has proposed the base year as the penultimate year of the current regulatory period (i.e. FY25). The rationale is based on FY25 being the most recent year where audited actual data will be available at the time of the AER's final decision. However, audited actual data is not available at the time of this assessment and the use of FY25 remains an estimate of the volume and expenditure that Powercor expects to incur.

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191 AER Better Resets Handbook July 2024, page 23

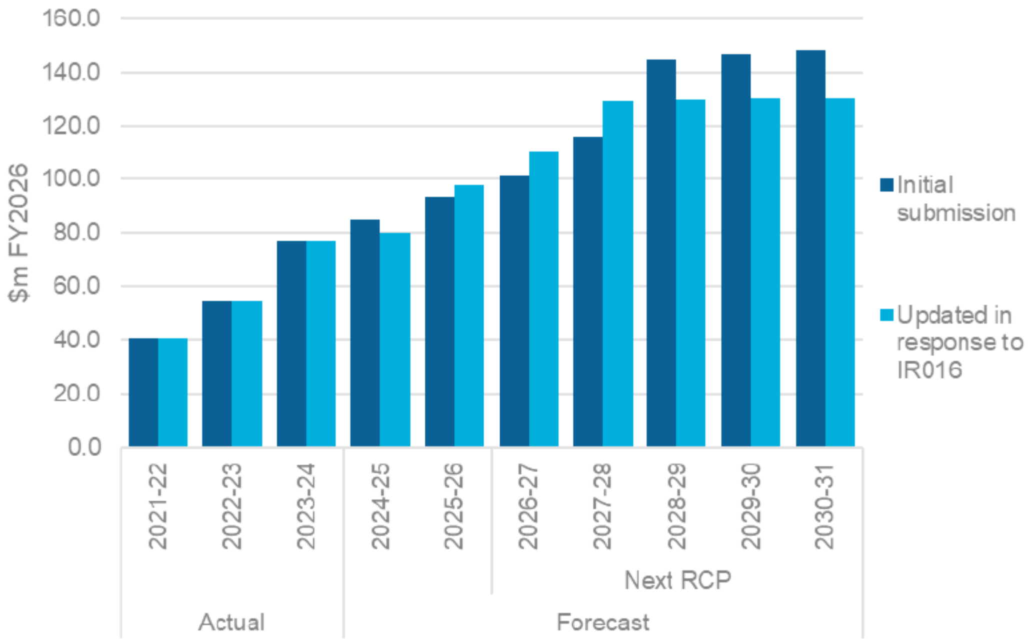
192 AER Better Resets Handbook, July 2024, page 26

Historical expenditure and volumes show an increasing vegetation program

752. The historical expenditure shows a rapid increase from FY22 based on the RIN as shown in Figure 5.1. This increase is forecast to continue into the next RCP, before leveling out in FY29 when Powercor considers that it will have achieved its electric line clearance obligations, and thereafter will move into maintaining compliance.

753. As a part of its response to IR016, Powercor states that it can achieve compliance 1-year earlier in FY28.

Figure 5.1: Historical and forecast expenditure - $m FY2026



Source: EMCa analysis of MOD 9.02, and IR016

754. The profile to achieve compliance is as Powercor has described, with the total expenditure having reduced at the time of compliance in its response to IR016, levelling at approximately $130 million pa.

CPU has made a number of modelling errors in its presentation of its base program

755. In Table 5.7 we show how Powercor has presented the calculation of its required step change. The calculation of the step change includes growth in the base program.

Table 5.7: Build-up of Powercor vegetation management program, $m FY2026

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	RCP Total
Base program	40.4	55.0	76.9	79.9	86.9	86.5	86.2	86.4	86.6	86.6	432.4
Uplift program	-	-	-	-	10.7	23.6	43.0	43.3	43.6	43.8	197.3
Total	40.4	55.0	76.9	79.9	97.6	110.1	129.2	129.7	130.2	130.4	629.7
Step change						**30.2**	**49.3**	**49.8**	**50.2**	**50.5**	**230.0**

Source: EMCa analysis of MOD 9.02, and IR016

756. We also show Powercor's base program in Figure 5.2.

[redacted]

757. The base program expenditure does not reflect how the overall opex allowance is calculated using the BST methodology, and which includes vegetation management opex in its application of the base year, which already includes output and trend factors that are applied over the next RCP as part of the opex roll-forward.

758. We consider that the opex required for its base program is effectively contained within its base year opex to which it has nominated the year FY25 and is an input to the BST methodology. As discussed previously, under the BST methodology the opex is rolled forward to account for output, price and productivity factors. This includes provision for real price escalation.

759. We have not seen sufficient justification of the need for any base year adjustments to the base year to account for increases that would not be expected to be captured under this methodology.

5.3.2 Assessment of volume of vegetation management spans that require cutting

The updated estimate reflects an increase to the estimated cut volume

760. Based on information provided in response to IR007, we observe an increase in cut volumes for CY2024, and which suggest that a higher cut volume may be achieved (in part due to higher resources) than is indicated in the FY25 estimate in Powercor's initial submission (based on historical average). We asked each of the CPU business to provide an updated estimated base program cut volume for FY25, using the span category descriptions included in its model and to identify the data relied upon to update the estimate.

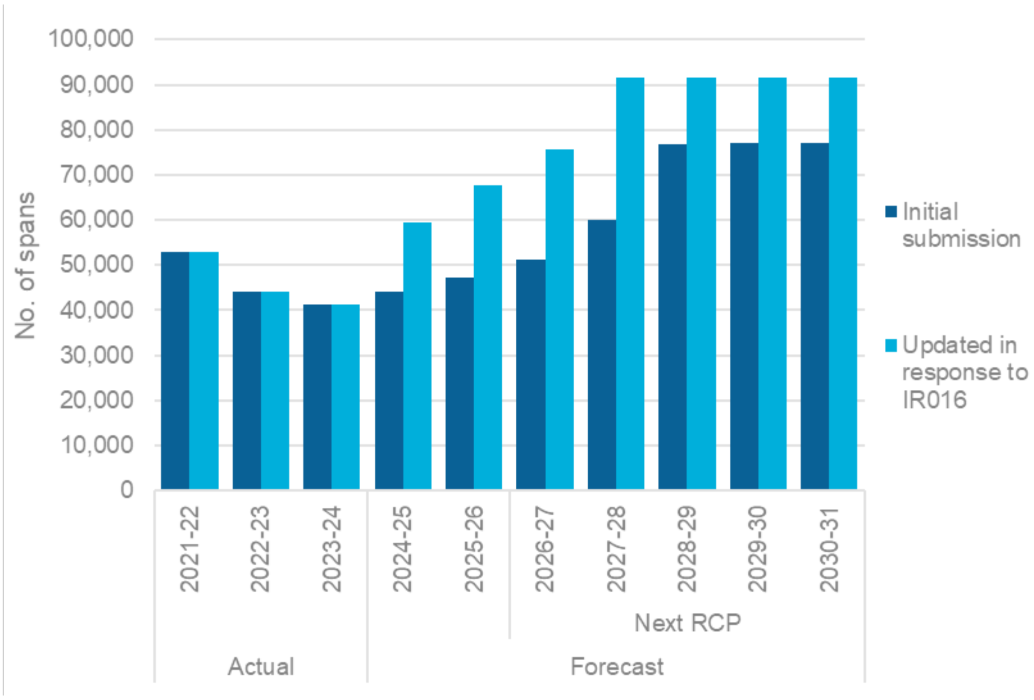
761. Powercor stated that:

> *'CY24 and CY25 March YTD cut volumes and FY25 unit rates were not available for the submission of the regulatory proposal. They are now available and MOD 9.02 has been updated to include FY25 estimated cut volumes (and FY25 unit rates).*
>
> *The estimated total base cut volume for FY25 comprises July 2024 to March 2025 actuals plus an estimate for April 2025 to June 2025 based on April 2024 to June 2024*

actuals. See table below of estimated FY25 base cut volume by span category which have been sourced from the April 2025 weekly status report.'[193]

762. In Figure 5.3 we show a comparison of the span volumes included in its initial submission and updated response. We had expected to see a similar profile on the basis that the cutting volumes are a large driver of the costs. However, we observe a much higher increase in volumes included in its IR016 response to 92,000 spans per year than had been included in the initial submission, which totalled 77,000 spans per year once compliance is achieved.

Figure 5.3: Historical and forecast vegetation management spans that are required to be cut



Source: EMCa analysis of MOD 9.02, and IR016

763. In the information provided in IR016, this revised total of approximately 92,000 spans has not been explained.

764. As the response updated the FY25 estimated volumes and therefor the base program volumes for future years, Powercor may have mistakenly not updated the required uplift volumes on the basis that the total volume of vegetation management spans to be treated should have been the same. This seems to align with our view of the model where the uplift volumes at the time of compliance are materially the same in its IR016 response as shown in Table 5.8.

193 Powercor response to IR016 Question 5

Table 5.8: Comparison of base program and uplift cutting volumes

	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Initial submission:							
Base program (Actual/estimate)	44,005	42,069	42,612	42,896	42,526	42,678	42,700
Uplift program (Forecast)	0	5,159	8,598	17,028	34,393	34,393	34,393
Total	**44,005**	**47,228**	**51,211**	**59,923**	**76,918**	**77,070**	**77,092**
IR016 updated submission:							
Base program (Actual/estimate)	59,517	59,597	59,522	59,545	59,555	59,541	59,547
Uplift program (Forecast)	0	8,011	16,023	32,045	32,045	32,045	32,045
Total	**59,517**	**67,608**	**75,544**	**91,590**	**91,600**	**91,586**	**91,592**

Source: EMCa analysis of MOD 9.02, and IR016

Proposed program is not aligned with Powercor's ELCMP

765. The ELCMP includes the annual inspection and forecast cutting plan in Figure 9. For Powercor this indicates an annual cutting program of 87,400 spans, inclusive of HBRA and LBRA. This figure is not aligned to either the historical cutting program nor the forecast cutting program in either the current or forecast RCP.

Figure 5.4: Annual inspection and cutting plan – LBRA and HBRA

LBRA	Total number of spans to be inspected (estimated) (100%)	Forecast number of spans with vegetation to be cut (annual)
CP	~61,000	16,000
PAL	~220,000	40,700
UE	~171,000	39,400

HBRA	Total number of spans to be inspected (estimated) (100%)	Forecast number of spans with vegetation to be cut (annual)
CP	-	-
PAL	~288,000	46,700
UE	~19,000	8,850

Source: CPU ELCMP Figure 9

766. Powercor states that the annual works program is developed each year and outlines the target inspection and cutting timeframes for each campaign region and remains subject to variations from year to year. However, the differences between each of the sources of information are material.

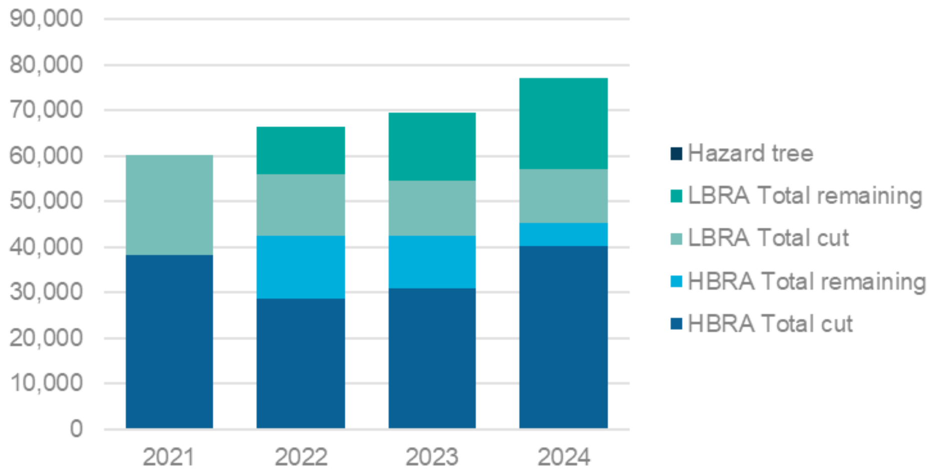
767. We have not placed any weight on the volumes included in the ELCMP as we understand that these are indicative, and do not reflect the output of the vegetation management system (VMS) or CPU's assessment of compliance.

The introduction of LiDAR has identified additional clearance issues, and which we consider provides a reasonable basis for an estimate of compliance

768. In response to our request for information, CPU provided data of its vegetation program for each of the businesses. In Figure 5.5 we have separated the data into Powercor's

completed cutting (HBRA and LBRA), hazard trees. and remaining. In this way we can see the total volume of work identified for Powercor's network.

Figure 5.5: Powercor - historical completion volumes



Source: EMCa analysis of Powercor data provided in response to IR007 question 4g

769. Based on information provided in response to IR007, the total cutting program is estimated as 77,140 spans, with 52,073 cut and 25,067 remaining. We consider that a volume of approximately 77,000 spans, based on data in in response to our questions from its LIDAR survey,[194] provides the basis of a more reasonable estimate.

The total cutting volume in the updated response overstates the requirements as it does not reflect the FY25 estimate

770. The increase in cutting volumes of HBRA plus LBRA from 2022 to 2024 is presumably as a result of the introduction of additional resource capacity. Notwithstanding there may be a timing difference, we would expect to see and did not see a similarly increasing trend in the initial submission.

771. In the updated model provided in response to IR016, Powercor included an increase to the cutting volume from 44,000 to approximately 60,000 spans in 2024-25. We therefore expected to see a reduction in the incremental cutting volumes to achieve compliance. However, this does not appear to have been the case as the total volume increased from 77,000 to 92,000 spans. We suspect that Powercor has made an error, which leads to an overstatement of the required cutting volumes – and which should be the difference between the estimate of 77,000 spans p.a. and the FY25 estimate of 60,000 spans.

The basis for the classification applied to the estimated uplift cutting volume has not been adequately demonstrated

772. CPU has assigned a classification of the cutting volume to its priority clearance codes, being 'VP1' (highest priority), 'VP2' (medium priority) and VP3 (lowest priority). CPU has also assigned categories of rectification and remaining cuts, which when considered together make up the vegetation management program. We were not provided with the rationale for the classifications and categorisations.

773. Whilst the unit rates assigned for the LBRA-rural[195] and HBRA zones were the same, and LBRA-urban were lower, independent of the priority clearance codes, we were not clear how the volumes assigned to rectification versus remaining were determined. The assumption

194 Powercor response to IR007

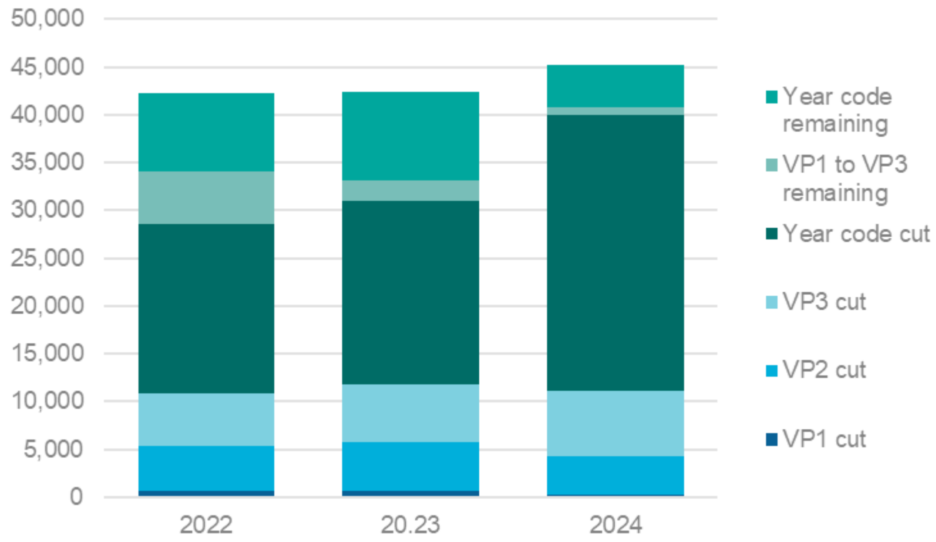
195 LBRA Rural is viewed as the same risk profile level as HBRA Rural and requires the same level of experience, labour and machinery to complete

applied by CPU is that the volume of rectification spans, attracting a higher unit rate due to the tight rectification timeframes involved,[196] will continue to increase over time.

774. As discussed previously, we would expect VP rectification cuts to decrease over time once compliance has been achieved.

775. In Figure 5.6 we illustrate the impact of Powercor's priority focus on vegetation management in the HBRA region, which shows that whilst the maintenance cutting (year code cutting) has increased over this time, the number of spans requiring VP rectification cutting has not.

Figure 5.6: Volume of HBRA spans over the period 2022 to 2024



Source: EMCa derived from PAL IR007 Question 4g

776. Secondly, on the basis that CPU has prioritised HBRA first, then LBRA rural and finally LBRA urban, we would expect that remaining cutting volumes in HBRA would be low and may have been addressed in the current year.

777. Lastly, there is also an increasing trend of cuts attributed to the 'liveline' category which are some of the most expensive, and which is not explained. The classification and categorisation adopted by Powercor has not been adequately explained.

The ultimate size of the vegetation management program will be the result of additional factors, that Powercor does not appear to have taken into account

778. Whilst the 77,000 spans p.a. arising from its latest LiDAR survey provide a reasonable basis for a starting estimate, Powercor has not yet achieved compliance. This means that there is a proportion of spans identified for cutting that are not completed in any year. Whilst these may be determined as being a lower priority, they remain a compliance obligation and indicate that the program is unlikely to be optimised for resource, time or location. This means that the program effectiveness is not likely to optimal, and contractors may not be used efficiently, which impacts the costs incurred and the frequency to which a contractor may return to a span to undertake maintenance versus priority cuts.

779. For example, whilst the growth patterns of vegetation are subject to a range of factors, in principle preventative maintenance cuts should avoid the need for a proportion of priority cuts, thereby reducing the overall program size and cost.

196 Contractors typically work in a different manner when cutting to rectification timeframes. This type of cutting is usually less efficient than planned cutting, including because contractors cannot travel down a line on the network, cutting spans sequentially to deliver economies of scale. Instead, they must program cutting to cut to the timeframes set out in the ELCMP, which does not allow for the same economies of scale.

780. Whilst Powercor appears to recognise the potential for changes to its program as a result of increasing capability, no adjustment was made to the program:

> *'We note that our forecast of incremental span volumes, and accordingly, our step change amount, does not include an allowance for any change in span volumes that may occur as a result of us continuing to increase our vegetation management capabilities to reflect changes in technology or our use of AI, such that we identify more or less spans that require cutting for compliance with the Code.'*[197]

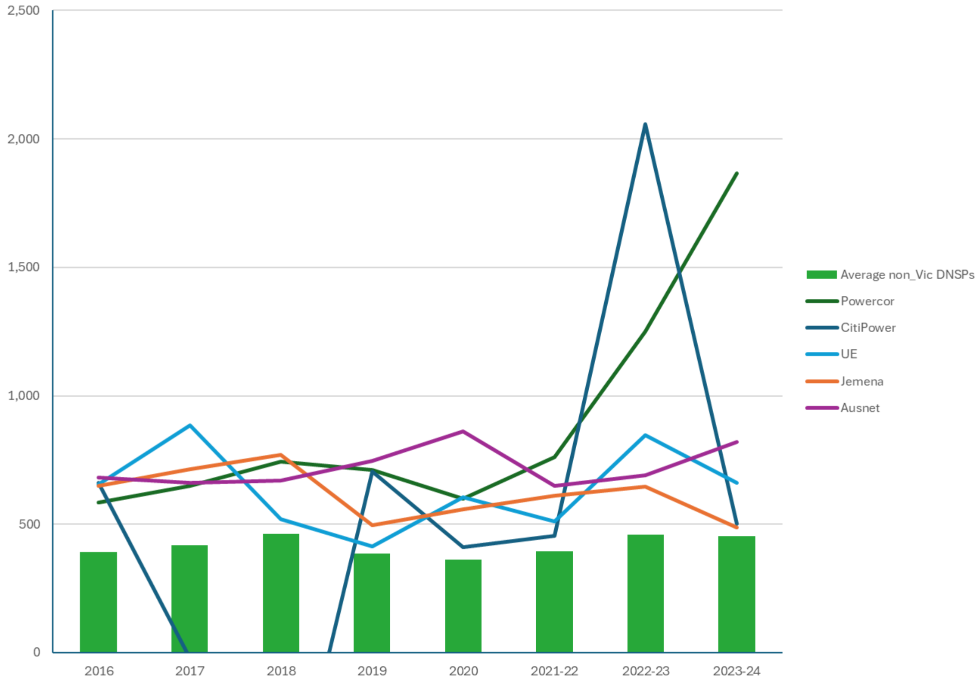
781. Given the current period of transition to compliance, it is not possible to estimate with a high degree of accuracy the likely reduction to the size of the vegetation management program, nor is this reduction likely to follow a linear trend. However, we expect that a reduction to the volume of spans estimated is likely once compliance has been achieved.

5.3.3 Assessment of unit rates

Historical unit rates have been increasing

782. We considered unit rates over time, as shown in Figure 5.7, and observe that the Victorian DNSP unit rates are largely flat in real terms, with the exception of Powercor and CitiPower, which both increased from 2021-22 with CitiPower subsequently reducing to previous levels in 2023-24. The negative amounts are not explained by CitiPower.

Figure 5.7: Trend of average vegetation management unit rates - $, FY2026



Source: EMCa analysis of RIN data

783. Using historical data, the measures we have reviewed indicate that Powercor and CitiPower are amongst the highest cost businesses for vegetation management, and not – using these measures – undertaking the work at an efficient cost. If the cost increases that Powercor proposes were to be included in this analysis, the differences to other NEM businesses would be greater still.

784. The historical unit rates are also indicative of a program that is progressing towards compliance and is not likely to have been optimised by resource, time or location, as not all

197 PAL ATT 9.02 – Vegetation management step change – Jan2025 – Public, page 14

spans that Powercor has identified as requiring cutting have been cut due to resourcing and time constraints.

CPU has included further increases to its unit rates for the next RCP, above historical levels and Powercor has the highest of the CPU businesses

785. During our onsite discussions we were told that vegetation contractors had exited the market following the covid-period, and also that some costs incurred by vegetation management contractors had increased e.g. training and traffic management. We would have expected that these additional costs would similarly impact all DNSPs but this does not appear to be the case.

786. We expect that some of the increases evident in the historical unit rates may be indicative of growing the market capacity, and that attracting contractors into the market is likely to have resulted in Powercor incurring higher rates, or a premium to market rates. Resourcing issues appear to be recognised in the business case provided by Powercor, and these issues are contributing to a higher than efficient level of cost for compliance. We expect that, assuming this is the case, then these rates should reduce with time as sufficient competition for resources is established.

787. We observed that CPU has included an increase to its unit rates commencing in the first year of the next RCP. We also observed that the unit rates applied for Powercor were higher than equivalent rates applied in CitiPower and United Energy. Powercor has not explained these differences or justified the proposed increase from the commencement of the next RCP.

CPU has included real price escalation to its base program and uplift program

788. The build-up of CPU's modelling shows a small increase in unit rates applied to the base program expenditure. In the calculation of the expenditure required for vegetation management, we consider that as the base year expenditure is rolled-forward, the trend component of the opex BST methodology includes real price escalation. Therefore, including real cost escalation results in double counting of this cost.

789. The same real price escalation is also applied to the unit rates included in Powercor's uplift program, but as this is not included in the base year expenditure or the roll-forward, addition of real cost escalation is reasonable for this component.

790. The real price escalation applied by CPU is shown in Table 5.9.

Table 5.9: Real price escalation (percentage)

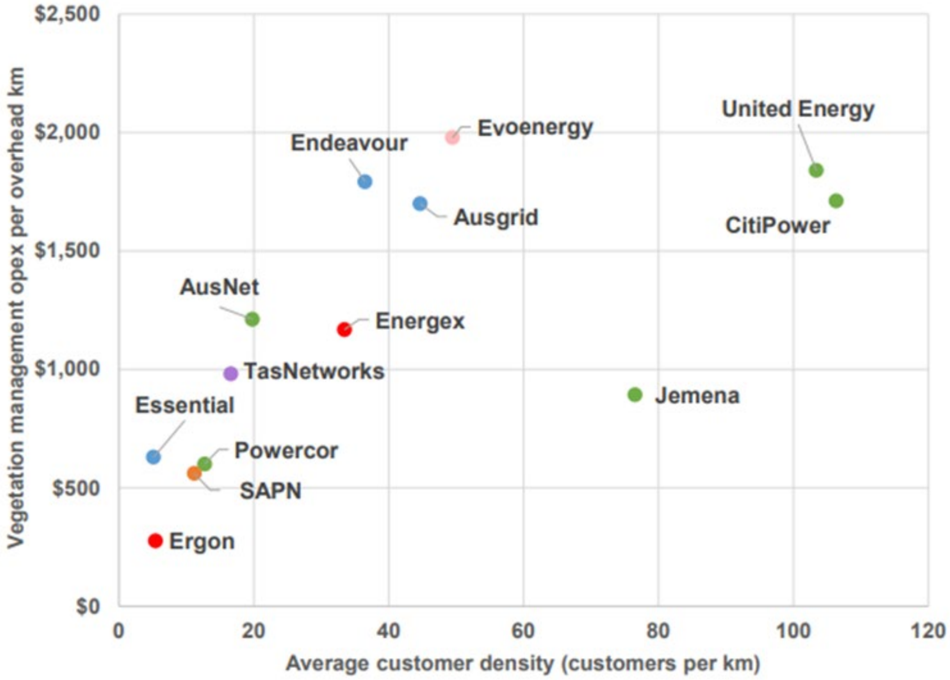
Real price escalation p.a. (average)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Powercor	0.49	1.93	2.23	1.21	0.69	0.85	0.98	0.92
CitiPower	0.46	1.79	2.07	1.13	0.64	0.79	0.91	0.85
United Energy	0.41	1.61	1.87	1.01	0.58	0.71	0.82	0.77

Source: EMCa table derived from updated vegetation management step change models provided with PARL IR016, CP IR017 and UE IR014

Updated industry benchmarking places Powercor and CitiPower amongst the highest cost businesses in the NEM for vegetation management

791. In the AER's 2024 annual benchmarking report, Powercor is identified as having one of the lowest vegetation management expenditures per kilometre of overhead circuit line length in the NEM, whilst CitiPower and United Energy are amongst the highest. We reproduce the analysis relied upon by the AER in Figure 5.8.

Figure 5.8: 2024 - vegetation management opex per km of overhead length ($2023) - average 2019-23



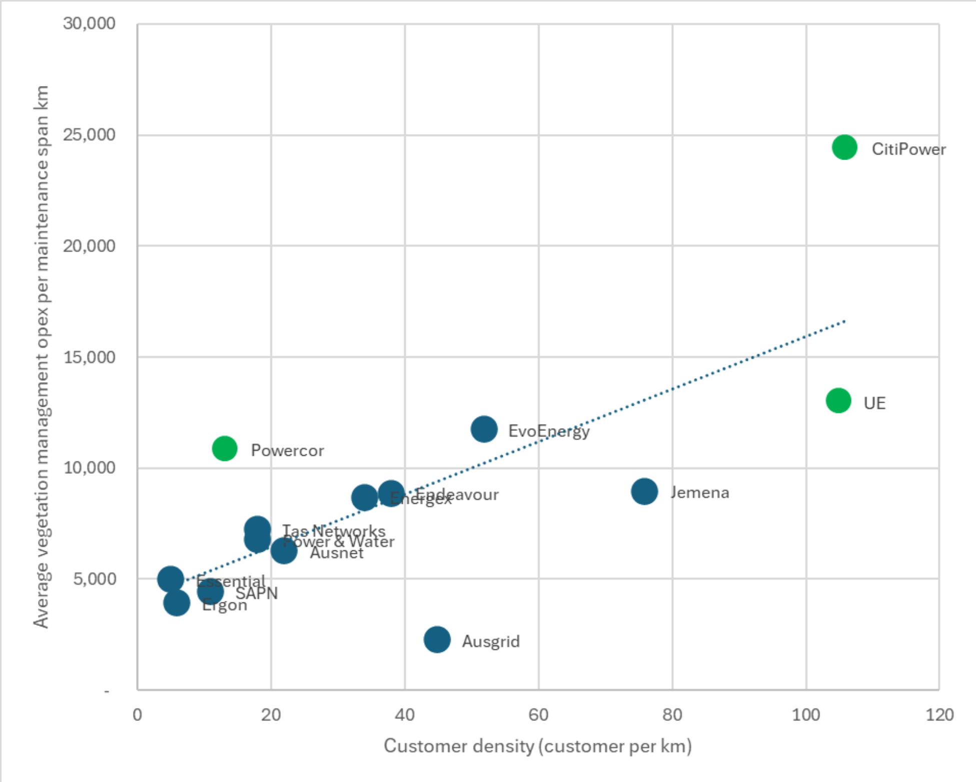
Source: AER analysis; Economic Benchmarking RINs.

Source: AER, 2024 Annual Benchmarking Report – Distribution network service providers, Figure 19

792. The Annual benchmarking report noted difficulties in analysis into the quantity and quality of data related to vegetation management due to concerns regarding the comparability and consistency of some of the data. The report also refers to intensified vegetation management arising from bushfire risk related regulatory obligations being a contributing factor to higher costs for Victorian DNSPs.

793. We undertook our analysis of the RIN data to understand the relationship between the three-year average vegetation management opex per maintenance span km. The results are shown in Figure 5.9. Whilst the results are similar for many of the DNSPs, the results for CPU businesses indicate a higher opex per maintenance span than was identified in the AER benchmarking for overhead line length. We consider that this is due to a lower number of spans identified as requiring vegetation maintenance, for the CPU businesses.

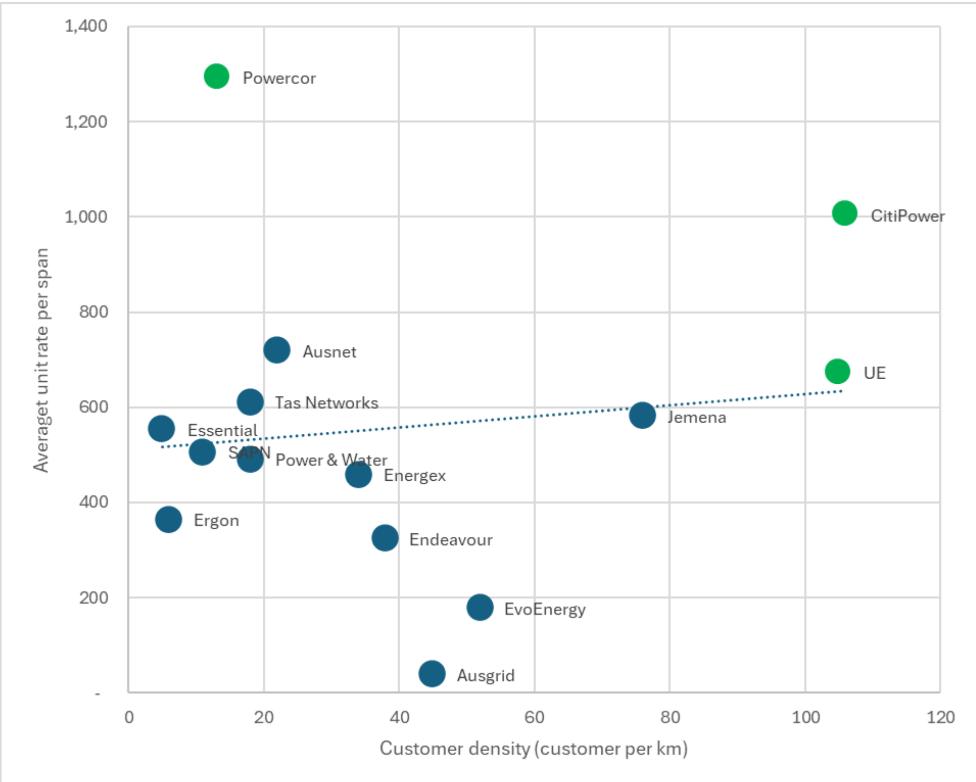
Figure 5.9: Average vegetation management opex per maintenance span km versus customer density



Source: EMCa analysis of RIN data

794. We also considered the average unit rates over the same period as shown in Figure 5.10.

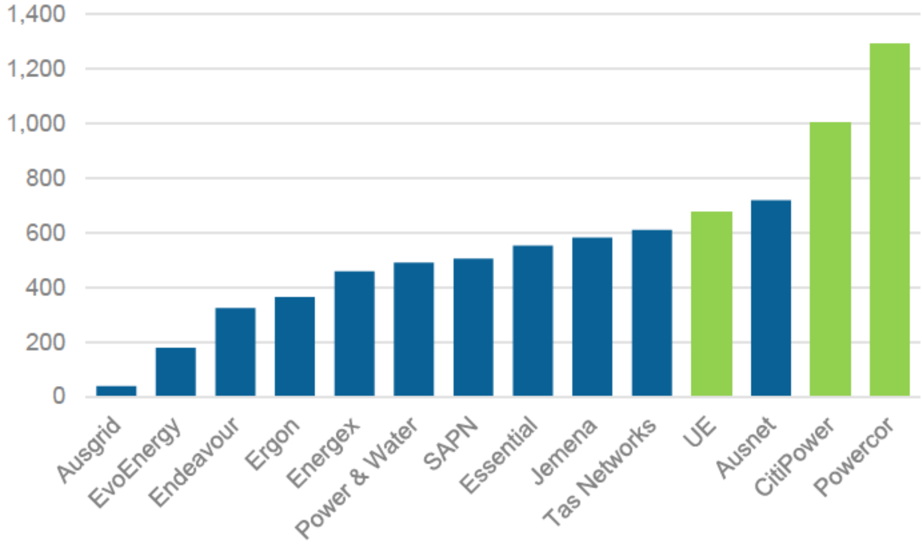
Figure 5.10: Average vegetation management unit rate per span versus customer density



Source: EMCa analysis of RIN data

795. Using the same three-year averages, we see in Figure 5.11 that Powercor and CitiPower have the highest historical unit rates.

Figure 5.11: Comparison of 3-year vegetation management unit rates (FY22-FY24) - $, FY2026



Source: EMCa analysis of RIN data

796. Based on the benchmarking results, the costs for Powercor's vegetation management program are significantly higher when compared to other DNSPs. Powercor has not demonstrated why these costs are reasonable or reflective of an efficient cost.

5.3.4 Assessment of additional matters

Powercor has included an increase to its hazard tree program

797. Powercor states that it has included additional expenditure of $22 million to increase the hazard tree inspection cycle from every five years to every three years. Powercor states that it is currently non-compliant with its ELCMP regarding hazard tree inspection cycles, which require a three-year cycle.

798. Within its model, Powercor calculates the uplift in its hazard tree program (in addition to its base program) as being the difference between a hard-coded value of $6 million and the BAU hazard tree program in 2022-23, then increased for real price escalation since that time to 2026-27, then increased for the remainder of the next RCP by real price escalation. A comment in the model refers to the $3 million value as being an '*uplift by 2.3 times the 2022/23 actual Hazard tree cutting cost of $2.6m (CAT RIN 2.7.2)*' without further explanation.

799. The basis for this calculation method is not provided, and we consider this is insufficient justification for the proposed step increase.

Powercor has included an increase in its LiDAR and contractor liaison costs

800. Powercor states that it has included an increase of $2 million in its forecast contractor liaison cost to reflect the additional staff it will require to manage its contractors as it ramps up its cutting activities to achieve Code compliance. A similar cost is also proposed for CitiPower.

801. The contractor liaison costs are based on 2023-24 costs and include an uplift of $480,000 p.a. from 2025-26 and are increased annually using price escalation.

802. The costs for LiDAR and contractor liaison are already included in the base year expenditure. The increase in volumes appears to being met with the same contractors,

albeit with an increase in the number of crews, and we have not seen adequate justification for the proposed increase. The LiDAR costs are hard-coded, proposed to commence in FY25 based on the assumptions as shown in Table 5.10, and are increased annually using price escalation.

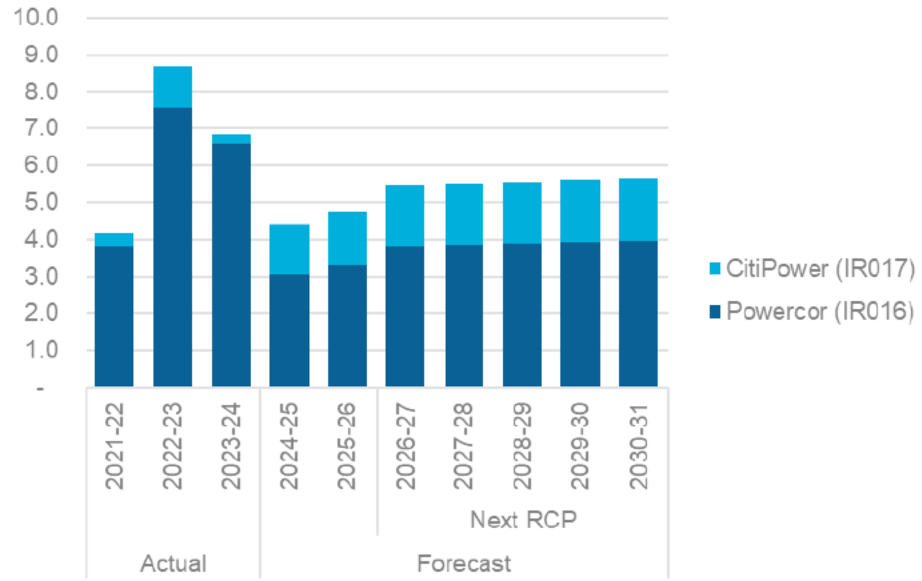
Table 5.10: Powercor LiDAR cost assumptions

Cost item	Cost ($m Dec23)	Cost assumptions
LiDAR capture	2.85	Costs include pilot wages, helicopter maintenance, helicopter fuel, rental of hanger
LiDAR data classification	0.40	Costs include LiDAR lab, consultancy
Total	**3.25**	

Source: PAL MOD 9.02

803. We were made aware that CPU had changed the allocation of its shared LiDAR costs between CitiPower and Powercor, such that Powercor has been allocated a lower percentage of the shared LiDAR costs. In Figure 5.12 we show the LiDAR costs over time for CitiPower and Powercor, and can see that the allocation has changed, and that the change was made in 2024-25 which Powercor is claiming as its base year. We also note that Powercor has reduced its LiDAR costs relative to its historical costs.

Figure 5.12: Proportion of LiDAR costs – Powercor and CitiPower, $m FY2026



Source: EMCa analysis of PAL MOD9.02 and CP MOD 8.02

804. We consider that the annual increases using price escalation are already included in the trend growth factors of the opex BST methodology, when applied to the base year expenditure, and do not need to be applied separately.

We consider that additional efficiencies are likely to come from new delivery capability, systems and processes

805. With the increased data available from LiDAR, we expect CPU to leverage greater efficiency in delivery of its vegetation management program. During our onsite discussions, we heard of examples where CPU was seeking to mitigate the highest risk areas first, as it increased capability to meet a higher volume of vegetation spans requiring treatment that it had

previously undertaken. This will lead to a level of inefficiency as the work schedule may not be optimised.

806. As the program stabilises, and the delivery capability increases, there is greater potential to increase the efficiency of work scheduling. As cutting volumes are increased, there may be spans identified that require less frequent cutting than Powercor has assumed. The introduction of Artificial Intelligence (AI) may also result in reductions to the cutting volume. Whilst these factors are not certain, it is more likely than not that efficiencies in program delivery will be made over the duration of the program, and which Powercor has not made provision for in its opex step change forecast.

807. It is generally recognised that the introduction of LiDAR and advanced analytics increases compliance and reduces opex related to vegetation management.[198] Powercor states that it has already delivered benefits from LiDAR and which we would expect to continue to be realised in the next RCP including:

> *'The introduction of LiDAR, and our advancements in its application, have significantly improved our vegetation management practices and processes over the course of the 2021–26 regulatory period. These improvements have greatly enhanced our ability to identify existing non-compliances with the Code clearance requirements or non-compliances that are expected to arise prior to the next inspection and cutting cycle (necessitating cutting in order to maintain compliance at all times), and our ability to do so in a timely manner.'*[199]

808. Sources state that '*Optimising these works programs by leveraging emerging technologies and advanced analytics can save utilities 10 – 15 per cent of their annual vegetation management spend.*'[200] We estimate that the efficiencies that CPU can achieve are likely to be of a similar order, and may be reflected across multiple regulatory periods recognising the current focus on compliance.

5.4 Findings and implications of the proposed opex step change

5.4.1 Summary of findings

Assessment against step change criteria

There has been no change to regulation obligations

809. We firstly considered whether the proposed step change met the requirement of the opex step change criteria. Based on CPU's submission, there has been no change to its regulatory obligations. The electric line clearance requirements have not changed since the commencement of the current RCP, and CPU has not advised of any change to its electric line clearance obligations that are likely to positively or negatively impact the expenditure requirements in the next RCP.

An increase in enforcement does not constitute a change to obligations

810. CPU argues there has been a change in the 'standard of compliance' of the current electric line clearance requirements, as evidenced by the increase in enforcement by Energy Safe

198 ENA 2020, Data opportunities for smarter networks accessed at https://www.energynetworks.com.au/resources/reports/data-opportunities-for-smarter-networks/

199 PAL ATT 9.02 – Vegetation management step change – Jan2025 – Public, page 2

200 Based on an article from ESRI accessed at https://esriaustralia.com.au/blog/how-landscape-vegetation-management-changing

Victoria. Given there has been no change to the obligations, we do not consider that changes to enforcement practices meet the opex step change criteria.

Assessment of the need for a material increase in expenditure

LiDAR data used as part of improvements to vegetation management has identified a volume of spans to be treated that exceeds the current program to meet its compliance obligations

811. The primary driver of Powercor's proposed increase arises from new information provided through the application of LiDAR technology that has identified vegetation encroaching the minimum clearance space for a large number of spans, and which exceeds the number of spans requiring cutting previously identified under its visual inspection method. Powercor has been progressively addressing a higher volume of vegetation spans with the view of achieving a state of compliance (based on its LiDAR data) with the electric line clearance regulations by FY29. Powercor has subsequently advanced the target year of compliance by one year to FY28.

Powercor has already achieved a material increase to its cutting volumes in FY25

812. In responding to our request to update its estimate for the program to be completed in FY25, Powercor stated that the completed vegetation management spans had increased from around 44,000 to 60,000, representing over 40% increase from the prior year of 41,000 spans.

The ultimate size of the vegetation management program will be the result of additional factors, that Powercor does not appear to have taken into account

813. Whilst the 77,000 spans p.a. arising from its latest LiDAR survey provide a reasonable basis for a starting estimate, Powercor states that it has not yet achieved compliance. Therefore, the program effectiveness is not likely to optimal, and contractors may not be used efficiently, which impacts the costs incurred and the frequency to which a contractor may return to a span to undertaking maintenance versus priority cuts.

814. Given the current period of transition to compliance, it is not possible to estimate with a high degree of accuracy the likely reduction to the size of the vegetation management program, nor is this likely to be a linear trend. However, we expect that a reduction to the volume of spans estimated is likely once compliance is achieved.

Powercor has not correctly taken account of the BST forecasting method for opex

815. We consider that a bottom-up build of its requirements is an appropriate forecasting method to understand the vegetation management expenditure, however Powercor's application of the forecasting method does not adequately consider the BST method for forecasting overall opex when considering whether a step change is required or the extent of such a step change. This includes taking account of existing provisions for output, price and productivity factors applied to the base year opex.

Basis of forecast step change is likely to overstate the required expenditure

816. Powercor has not demonstrated that the proposed forecast of its expenditure requirements is efficient as the proposed volume and unit costs are overstated. We base this on:

- indications from data provided by CPU that the LiDAR program has identified a vegetation management program that is smaller than CPU has proposed to achieve compliance,
- the estimated cutting for 2024-25 is higher than the estimate relied upon by Powercor to establish the requirements for each of the businesses, and when combined with a smaller total volume to achieve compliance results in a reduced total expenditure,
- inadequate justification for proposed uplifts in contractor liaison and hazard trees,

- unit rates are amongst the highest in Victoria, and higher than the revealed costs, without sufficient justification,
- relatively new application of LiDAR technology and spatial analytics, which amongst other things will require several years to be refined including updating of the VMS to establish a stable vegetation management program, and
- once stabilised the program can be expected to enable efficiencies to be realised and which are not currently included in the forecast of its opex requirements, and which we consider can be material.

817. As a consequence of the issues we have identified, we consider that the opex that Powercor consider that it will require is materially overstated.

Benchmarking of Powercor's historical costs indicate that it is higher than other NEM DNSPs

818. In our review of vegetation management costs at a total level, as a proportion of total opex and average unit costs, the historical costs for Powercor and CitiPower indicate that it is amongst the highest in the NEM.

819. Using these measures, accounting for potential differences between Victorian and non-Victorian businesses, the costs are higher than an efficient level. If the proposed increases are included in this analysis, as are being proposed by the CPU businesses, the differences to other NEM businesses will widen further.

820. CPU has not provided a rationale for why it is incurring costs that are materially higher, why these higher rates are reflective of an efficient level or what measures are in place, or being put into place, to reduce the costs to an efficient level.

Adjustment for a range of uncertainty and efficiency factors is likely to reduce the need for an opex step change

821. We consider that whilst CPU businesses are building capacity and capability to meet their compliance requirements, the opportunities for competitive forces to apply downward pressure on prices from the market are lessened. However, over time, we consider there should be opportunities for pricing to moderate, and then to improve. This is also supported by our own benchmarking analysis which indicates that Powercor is incurring costs that are materially higher than other NEM DNSPs, including other Victorian DNSPs.

822. We further consider that the program, once stabilised, offers Powercor an ability to reduce not only the costs but potentially the volume of spans to be treated through greater targeting of maintenance cutting practices.

Application of sensitivity analysis reduces the need for additional opex to zero

823. After moderation for the modelling issues that we found, and which reduce the required opex significantly, we also subjected the program to changes to the volume, unit rates and efficiency factors. The goal was to understand whether, given the uncertainty of these factors and materiality of the issues we found (such as identified in the benchmarking) would remove the need for additional opex.

824. We found that the need for additional opex was very sensitive to relatively small changes in these factors, meaning that relatively small reductions to volume or costs (towards the benchmark cost) or increases in efficiency removed the need for a step change. The analysis indicated to us that Powercor had a reasonable allowance for vegetation management opex included in the application of the FY25 base year to the BST methodology, taking account of trend factors.

5.4.2 Implications for proposed opex step change allowance

825. We consider that Powercor's proposed opex step change for vegetation management is not a reasonable forecast of its expenditure requirements for the next RCP.

826. We are satisfied that additional improvement to vegetation management activities is required for Powercor to achieve compliance in the next RCP, however we consider that a number of factors in Powercor's forecast are not reasonable assumptions.

827. We made adjustments to Powercor's forecasting methodology, to the extent that it formed the basis of Powercor's forecast and which we consider to be not justified or overstated including:

- Adjustments to correct modelling of the base year opex
- Adjustment to the forecast volume of tree cutting and hazard tree programs that has been proposed, including to remove those elements that have not been sufficiently justified
- Adjustment to the unit cost basis for the proposed forecast
- Adjustment to align the forecast with the estimated 2024-25 volumes as included in information provided by Powercor
- Adjustment to account for a productivity and efficiency benefit each year following from the application of LiDAR and delivery efficiencies to be realised from the year in which compliance I s achieved

828. Adjustment of these assumptions, which we applied in various combinations, leads us to conclude that Powercor does not require an opex step change.

APPENDIX A – CITIPOWER, POWERCOR AND UNITED ENERGY'S ECONOMIC MODELLING OF PROPOSED ELECTRIFICATION PROGRAM[201]

A.1 Introduction

829. CitiPower, Powercor and United Energy have each provided a model that they have used to (a) define a program of work to address the forecast voltage impact of electrification and (b) to support their claims that this program is economic.[202] These models are common in approach. For illustrative purposes, we refer here to the Powercor model, noting that our findings apply to all three.

830. Powercor provided an initial model along with its regulatory submission, in January 2025. While this model purports to be based on identifying a program of economic interventions, it does not provide an overall economic assessment, for example, in the form of an NPV for the proposed program. Further, the model is largely comprised of sheets of hard coded data, one of which is over 80,000 rows, but which provide little insight as to how the model identifies such economic interventions or their net economic benefits.

831. We asked for a version of the model that includes formula that would then allow us to trace the modelling relationships and Powercor provided such a model in April 2025. Our observations here apply to the later version of the model.

A.2 Summary of electrification model objectives and approach

A.2.1 Model descriptive information

832. Powercor provided a document that describes its *Customer Electrification Forecasting Methodology* (PAL Att 2.01) and we rely largely on this document for our understanding of its approach and its associated customer-driven electrification model.

833. Powercor also provided a document with its regulatory submission with a file name '*Detailed customer electrification forecasting methodology.*'[203] However the cover title of this document is '*Hosting Capacity Study – Network wide HV & LV Scenario based Hosting Capacity Analysis*.' We find that this document essentially describes the process by which technical hosting capacity and voltage have been simulated and forecast for ten years at a feeder level. This model provides outputs which include the forecast amount of energy supplied at over- and under-voltage levels and which it values at CECV (for over-voltage) and VCR (for under-voltage)[204]

834. Our summary description of the electrification model is based on our review of Powercor's methodology report (Att 3.01) and from examining the model itself. We focus our description

201 Aspects of the methodologies that we refer to in this appendix, in particular regarding valuation of the costs of undervoltage supply, are also relevant to Powercor's modelling of the benefits of its proposed regional and rural supply which we describe in section 4.3.2

202 PAL MOD 3.31

203 PAL attachment 2.04

204 As above, page 10: Definition of '*load_exceeding_normal_een_vcr*'

on the elements that appear to drive the output that Powercor has relied on, and our summary description is also therefore not a complete description of the model.

A.2.2 Our summary understanding of the model

835. The model seeks to establish a program of LV augmentation works, that meets a target level of service. For this purpose, the model establishes and undertakes calculations for three options: to improve, maintain, or reduce service levels.

836. In the model, an HV clustering intervention is assumed as a given, and the cost and avoided LV augmentation from this are hard coded. Assumed benefits of avoided LV augmentation from non-network solutions (which we assume to be primarily flexible imports) and from DSS overlap are similarly hard coded.

837. The model then undertakes a feeder-level assessment to calculate the most economic proactive LV augmentations in each year, to maintain the target level of service, choosing from the options of DSS offload or reconductoring.

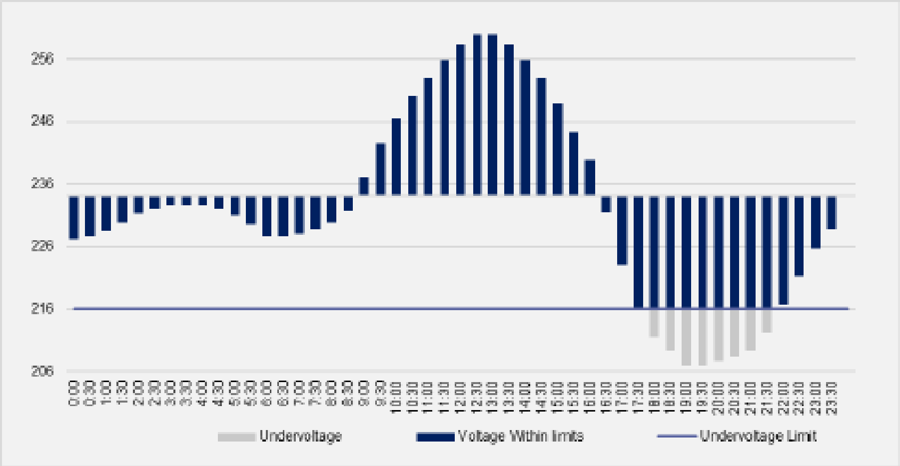
838. The model calculates an economic value for the alleviated supply resulting from the ‘chosen’ interventions, as the product of the modelled supply that is brought back within the compliant voltage levels and the VCR.

A.2.3 Powercor’s modelling of the economic value of undervoltage supply

839. Powercor provides the diagrams shown in figure A.1 to illustrate how its half-hourly simulation of voltage is transformed to an assessment of ‘energy at risk’.

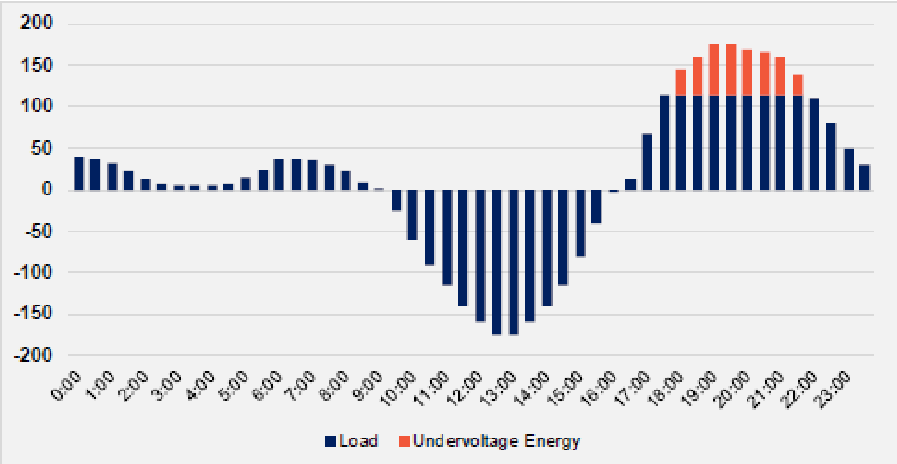
Figure A.1: Powercor example of voltage simulation and assumed 'energy at risk'

FIGURE 18 EXAMPLE VOLTAGE FLOW (V)



To calculate energy at risk, results are produced in kWh of load, shown in Figure 20

FIGURE 19 EXAMPLE UNDERVOLTAGE ENERGY AT RISK (KWH)



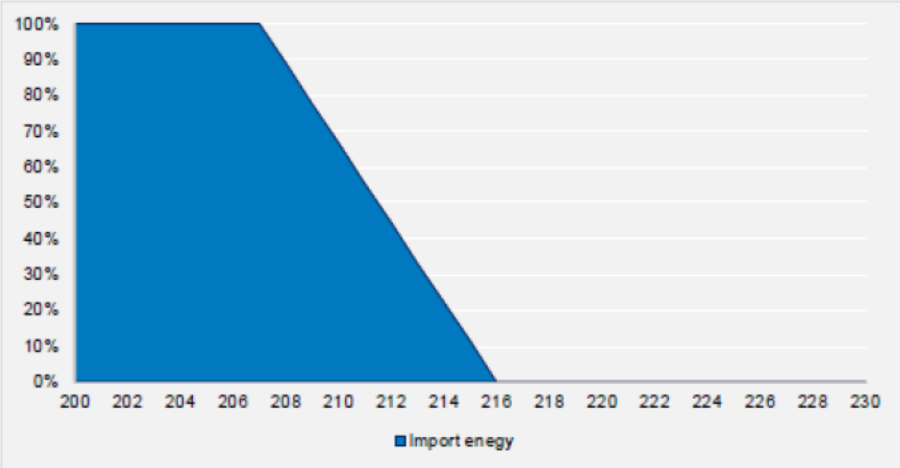
Source: PAL Att 2.01, figures 18 and 19

840. In Powercor's modelling, the value of the energy at risk is scaled linearly from 216V to 207V, below which it is assumed to be entirely curtailed, with this curtailment valued at VCR.

Figure A.2: Scaling of assumed energy lost to undervoltage

FIGURE 20 SCALING OF ENERGY LOST TO UNDERVOLTAGE (V)

This scaling is applied to the load_undervoltage_normal_kwh as described in section 5.1



Energy at risk is then multiplied by the Value of Customer Reliability (VCR) to provide a total dollar cost, at Equation 1.

Source: Pal Att 2.01, figure 20

841. Powercor's model simulates these forecast outcomes at the interval-level for each feeder, for 10 years

A.3 Sensitivity analysis

842. After investigating model logic, to the extent that it is present in the model provided, we undertook sensitivity analysis on two assumptions that we observed to be key drivers of model output.

843. The main driver in the model is, as expected, the target (voltage) service level. We tested for sensitivity to this input and, as we show in Table A.1, we find that for Powercor if this parameter is changed to target a 96% rather than the current 97%, then the required proactive program size would reduce from $72.7m to $15.4m. With this change, almost all of the required expenditure would be in the final two years of the next regulatory period.

844. As we describe in section 4.5, Powercor has not justified the use of VCR to value the cost to consumers of supply at a voltage below the lower voltage limit. We consider that this significantly overstates this cost, and therefore significantly overstates the benefits of alleviating such supply. While we are not aware of any well-founded estimate for such a value, we tested the sensitivity of the model by applying a scaling factor of 0.1 to this value. As shown in Table A.1, this marginally increases the model's estimate of the required LV augmentation cost but reduces the NPV result to less than one-tenth of its previous value.

Table A.1: Sensitivity analysis from Powercor economic modelling of proposed customer-driven electrification program. Capex and NPV ($m real 2026)

	FY27	FY28	FY29	FY30	FY31	TOTAL	*NPV*
Powercor analysis	5.5	18.4	7.9	20.0	20.9	**72.7**	*1,196.4*
EMCa sensitivity analysis 1: Reduce compliance from 97% to 96%	-0.3	-0.3	1.1	6.3	8.6	**15.4**	*524.2*
EMCa sensitivity analysis 2: As for (1) plus VCR scaling factor of 0.1	-0.3	-0.3	1.2	6.8	10.0	**17.4**	*48.4*

Source: EMCa sensitivity analysis, from PAL MOD 3.31

845. As a further observation, the model as provided by Powercor calculates approximately twice the amount of benefit occurring in the four years modelled after the end of the next period, compared with the benefits modelled within the next period.

A.4 Our conclusion on Powercor's electrification program economic model

846. Our investigation of the model shows its extreme sensitivity to the following assumptions:

- The 'required' size of the program is highly sensitive to the target level of compliance. While Powercor has defined its preferred option as maintaining the current level of compliance, we find that a small relaxation of this assumption (while still within its Functional Compliance obligations) would reduce the scale of the program that the model suggests, to one-fifth of the amount that Powercor proposes, and
- The economics of the program are highly sensitive to the assumed per-kWh benefit to customers of alleviating undervoltage supply, for which Powercor uses VCR.

847. Finally, we note that the economic model is based on input from the feeder-level voltage simulation technical modelling that has been conducted for Powercor. As we note in section 4.5, the methodology described for this appears reasonable, however it too is based on significant assumptions regarding electrification uptake and future customer usage behavioural patterns in an evolving sector that presents a challenge to any such forecasting to 2031.

APPENDIX B – ECONOMIC ASSESSMENT METHODOLOGY ISSUES

B.1 Introduction

848. For projects that CitiPower, Powercor and United Energy have sought to justify on economic grounds, they provided supporting economic models. In a number of instances we find one or other of the following issues, which appear to be systemic.

B.2 Economic assessment utilising annuitised capex as a proxy for capex

849. Whereas a standard Discounted Cashflow (DCF) analysis assesses the NPV of a project over a given analysis period, taking account of the forecast capex, opex and benefits in that period, we find that the CPU businesses have commonly applied an approach in which the capex is first annuitised, and then the NPV for the project is assessed taking account of this annuitised value as a proxy for capex, rather than the capex itself.

850. Where the life of the relevant asset is the same as the analysis period, it can be shown that this alternative method yields the same result. However, in instances where the asset life is longer than the analysis period, this alternative method overstates the economic benefit and this is typically the case in models provided by the CPU businesses.

851. We illustrate this in table B.1 with an example in which the assumed life of the proposed asset is 50 years. With the assumptions we have applied, the project would have a negative NPV (minus $3.68m). However, under the 'annuitised cost' method that has been commonly used in CPU economic models, the project presents as having a positive NPV (in this example, $6.17m).

Table B.1: Illustrative example of overstatement bias for NPV calculated with annuitised capex

Parameters	Value	*Unit*
Capex	25	*$m*
Asset life	50	*years*
Assumed benefit	1.5	*$m/year*
Analysis period	20	*years*
Discount rate	3.50%	*%*

Summary results	PV capex	Annuitised capex	PV annuitised capex	PV Benefits	NPV
Discounted cashflow method	-$25.00	N/A	N/A	$21.32	**-$3.68**
Annuitised capex method	N/A	-$1.07	-$15.15	$21.32	**$6.17**

Source: EMCa

852. We find that CPU's common application of this method for calculating the NPV of the projects that it proposes, results in a systemic overstatement of their net economic benefit.

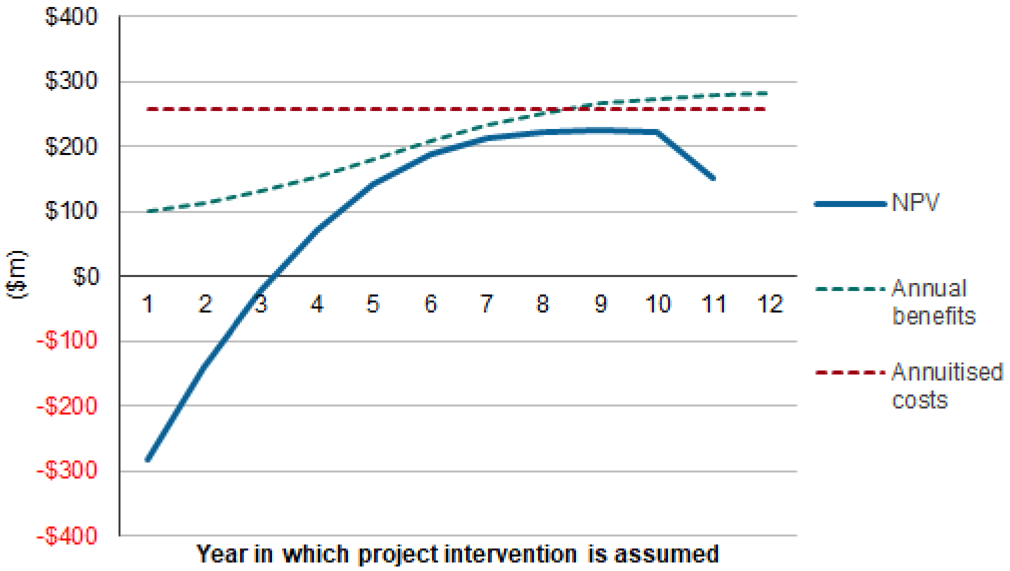
B.3 Economic timing

853. It is frequently the case in economic assessments in support of electricity infrastructure investments, that there is an escalating counterfactual economic cost (including an escalating risk-cost), and which the proposed investment is intended to address. This increasing cost for the counterfactual therefore defines the benefit that can be achieved by the proposed solution.

854. The question of identifying the optimum economic timing for the solution was addressed by AER in an industry practice application note.[205] In short, under microeconomic theory, it can be shown the optimum timing occurs when the annual benefits exceed the annuitised cost.

855. The illustration in figure B.1 shows a project for which benefits (green) increase over time. The annuitised cost of the project is shown in red. The blue NPV line shows the NPV for this project as a function of when the project is assumed to be undertaken – that is, it reflects a series of timing options for the project, if undertaken in any year up to the eleventh year.

Figure B.1: Illustration that defines the optimum timing for an investment[206]



Source: EMCa (illustrative example only)

856. As can be seen from the graph:

- If undertaken prior to year 3, the project would have a negative NPV.
- If the project was undertaken in any year from year 3 to year 7, the annual benefits are less than the annuitised cost and it would therefore not be economic to undertake the project.
  - This is the case despite the project having a positive NPV if undertaken after year 3. This result occurs because the net benefits beyond year 7 in this example more than offset the net costs before that (in the NPV calculation). But it remains the case that the project is not economic if undertaken in the period up to year 7 because the benefits do not exceed the cost ***in that period***.

205 AER, Industry practice application note; Asset replacement planning, January 2019. See Figure 1 (page 37)

206 Analysis in this worked example is based on an asset that is assumed to last, and therefore provide benefits for, 20 years from the date that it is commissioned. Benefits therefore continue beyond year 12 but are shown only to that year in order to focus on the timing decision.

- From around year 8, the example shows that the annual benefits exceed the annuitised cost, demonstrating that the project is then justified. The graph shows that this timing also provides the highest NPV of the timing options considered.
- If the project was deferred beyond year 8, the NPV declines, because the net benefit of undertaking the project (as evidenced by the green benefits line exceeding the red annuitised cost line) is lost.

857. We provide this refresher on economic timing as we observed in the course of our assessments numerous instances in which a positive NPV was presented as evidence that a proposed project was justified within the next regulatory period, without having tested optimum timing in accordance with the AER practice note.

858. We consider this especially problematic where economic modelling of hundreds or thousands of potential interventions is simulated to determine a scope of work by applying a logic goal that progressively tests each potential intervention year-by-year for a positive NPV. If the modelled goal is set only to identify when each potential intervention would first have a positive NPV, and then to include each such intervention in the proposed work program, then the modelling will almost certainly be biased towards including such interventions prematurely and therefore over-estimating the extent to which such interventions are economically justified within the period.

APPENDIX C - REVIEW OF HISTORICAL PERFORMANCE

C.1 Summary

859. We observe that the network performance has generally been improving, along with asset performance despite the impact of several major weather events across Victoria. For Powercor's network:

- Average reliability performance is generally improving, which suggest that Powercor's asset management process has maintained service levels
- According to the safety regulator ESV, the number of all asset failure incidents and contact incidents are lower than the long-term average
- Rate of line clearance non-compliance has recently improved, however the regulator is concerned by a worsening long-term trend
- Network utilisation has been flat over the last 10 years, and remains higher than the DNSP average

860. We observe that the actual expenditure has historically tracked lower than the forecast expenditure. Issues such as increasing labour and material costs, and deferral of works that occurred during the current RCP also have implications for the forecast in the next RCP, and we consider the implications in the projects and programs that we have reviewed. For Powercor's network:

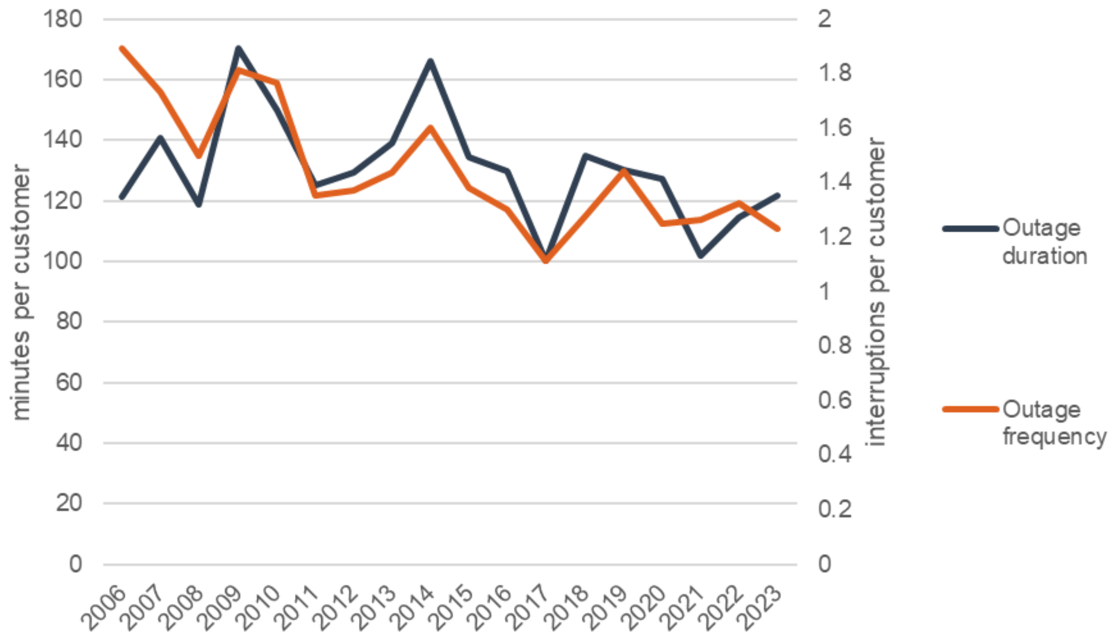
- Capex delivery performance is subject to a range of factors, with actual capex tracking more closely to forecast capex recently
- Powercor expects the net capex to exceed the capex allowance for the current RCP
- Over the last 5 years, actual opex is slightly higher than the forecast opex resulting in an overspend against the opex allowance

C.2 Current period service performance

Average reliability performance is generally improving, which suggest that Powercor's asset management process has maintained service levels

861. The AER noted that, on average, reliability had been improving for customers. Figure C.1 shows average outage duration and outage frequency data for Powercor based on the AER network performance report data. This indicates a flattening of outage duration and outage frequency.

Figure C.1: Comparison of Powercor historical outage duration and outage frequency



Source: AER Network performance report

862. Outage frequency may be considered an indicator of the effectiveness of asset management, to the degree that the trend is linked to preventable events and not actions of extreme weather or third parties. We make further observations as it relates to the scope of our assessment of the expenditure as relevant.

According to the safety regulator ESV, the number of all asset failure incidents and contact incidents are lower than the long-term average

863. ESV publish the number of serious electrical incidents reported to Energy Safe by Powercor during the 2022–23 period, in its 2023 safety performance report on Victorian Electricity networks. The 2024 report was not available at the time of our review.

864. According to ESV, the most common incidents on the Powercor network in 2022–23 were:

> *'HV fuse failures, tree contact, animal contact and connection failures. The numbers of all asset failure incidents were lower in 2022–23 than the long-term average, except for fuse failures which were 16 per cent above the average.'* [207]

865. The asset failure incidents are decreasing for most asset types with material reductions in distribution line and connection assets as shown in Figure C.2. ESV state that is commencing a review of the conductor and connection management practices of all distribution networks in 2023–24.

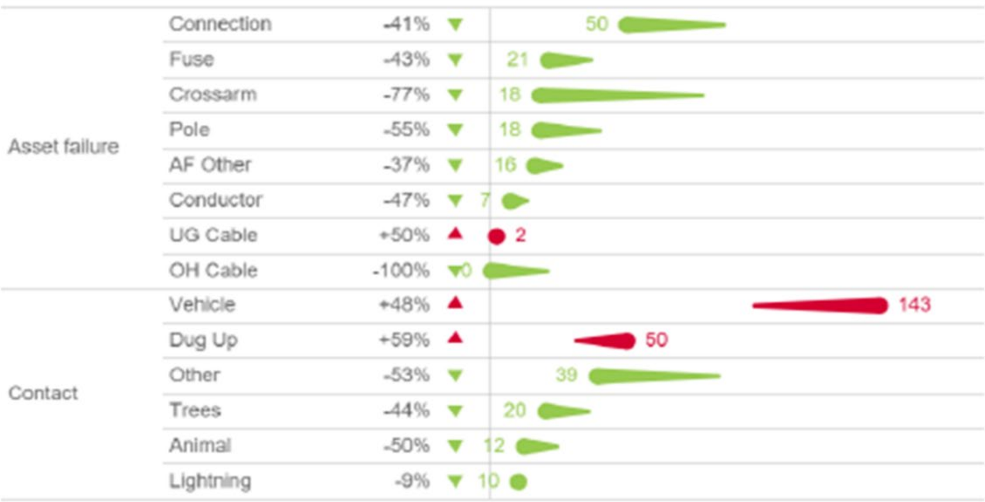
866. The number of fires were lower than the long-term average. The most common causes of fire incidents as shown in Figure C.3 were:

> *'Connection faults, vehicle impacts, other contact events and tree contacts were the most common causes of network-related fires. One of these (connection faults) is within full control of Powercor to manage, one is partially in its control (tree contacts) and two are largely outside its control (vehicle impacts and other contact events).'* [208]

[207] ESV, 2023 Safety Performance report on Victorian Electricity Networks

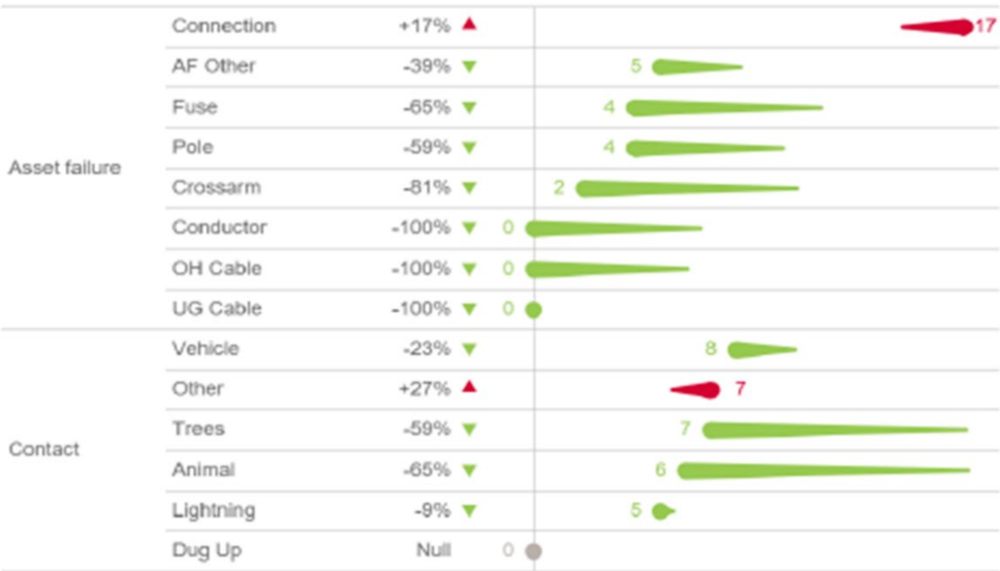
[208] Ibid

Figure C.2: Incidents on the Powercor network



Source: ESV report, Figure 40

Figure C.3: Incidents on the Powercor network resulting in ground fires

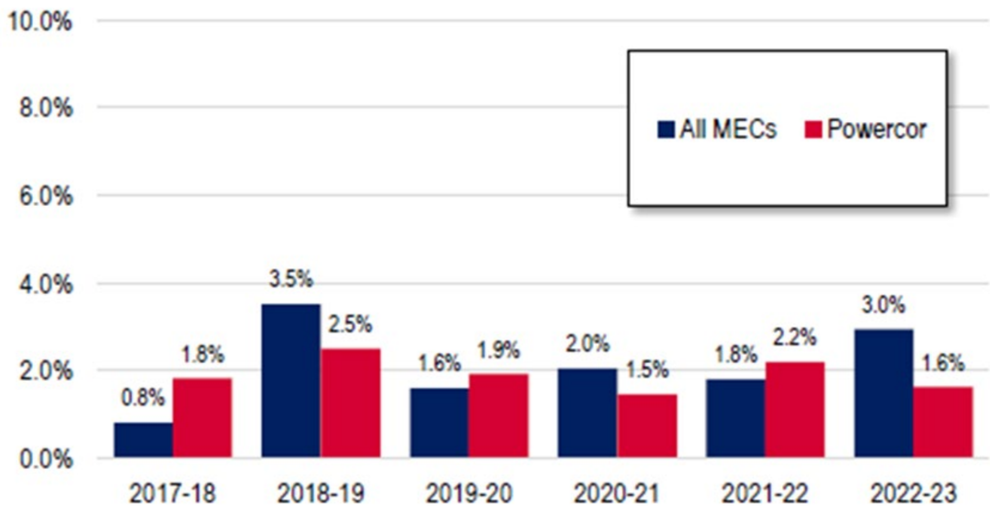


Source: ESV report, Figure 41

Rate of line clearance non-compliance has recently improved, however the regulator is concerned by a worsening long-term trend

867. ESV also undertake inspections of the network to determine any spans that may not be compliant with the electricity line clearance regulations. The trend in major non-compliances is shown in Figure C.4. A major non-compliance is regarded as a high-risk situation where vegetation is touching, is growing through, or could soon touch, uninsulated conductors. This has resulted in greater use of ESV's enforcement option to issue infringement notices and fines.

Figure C.4: Rate of Powercor major non-compliances (HBRA and LBRA)



Source: ESV report, Figure 39

868. We observe a decrease in the most recent rate of major non-compliances in Powercor's, and a reduction when compared with the total across Victorian DNSPs. However ESV state that it is concerned that:

> *'The rate of non-compliant vegetation in HBRA on the Powercor network has been elevated and generally increasing over the last four years. Energy Safe is concerned that non-compliance rates could return to the historic high of 2017-18 if this trend is not arrested now. The rate of non-compliant vegetation in LBRA has remained stable since 2019–20.'*[209]

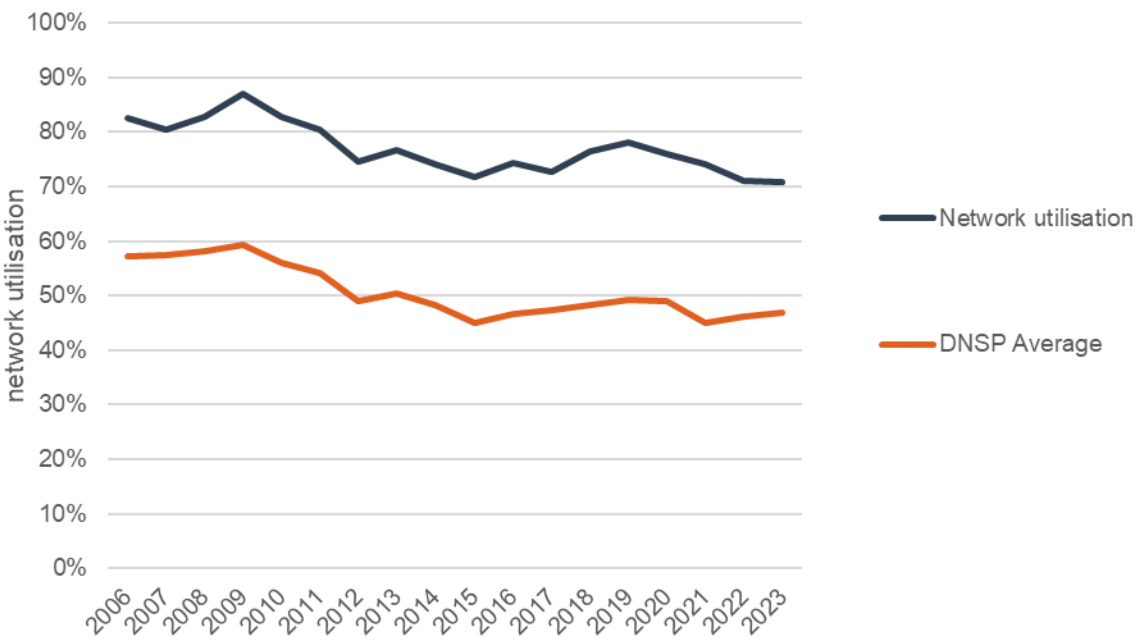
Network utilisation has been flat over the last 10 years, and remains higher than the DNSP average

869. Network utilisation is an indicator of the capacity of the electricity network, and whilst does not account for localised constraints or complexities associated with the two-way flow of energy, is a coarse measure of the ability for networks to make greater use of the network assets.

870. Figure C.5 shows that Powercor's network utilisation is relatively flat over time, and continues to have a network utilisation above the DNSP average.

[209] Ibid

Figure C.5: Comparison of Powercor historical network utilisation versus DNSP average



Source: AER Network performance report

C.3 Current period expenditure performance

Capex delivery performance is subject to a range of factors, with actual capex tracking more closely to forecast capex recently

871. In its 2024 network performance report,[210] the AER considered the aggregate over/under-spend and the timing of capex across the regulatory period. Whilst the over/under spend in any one year may not be instructive, the AER concluded from its analysis that

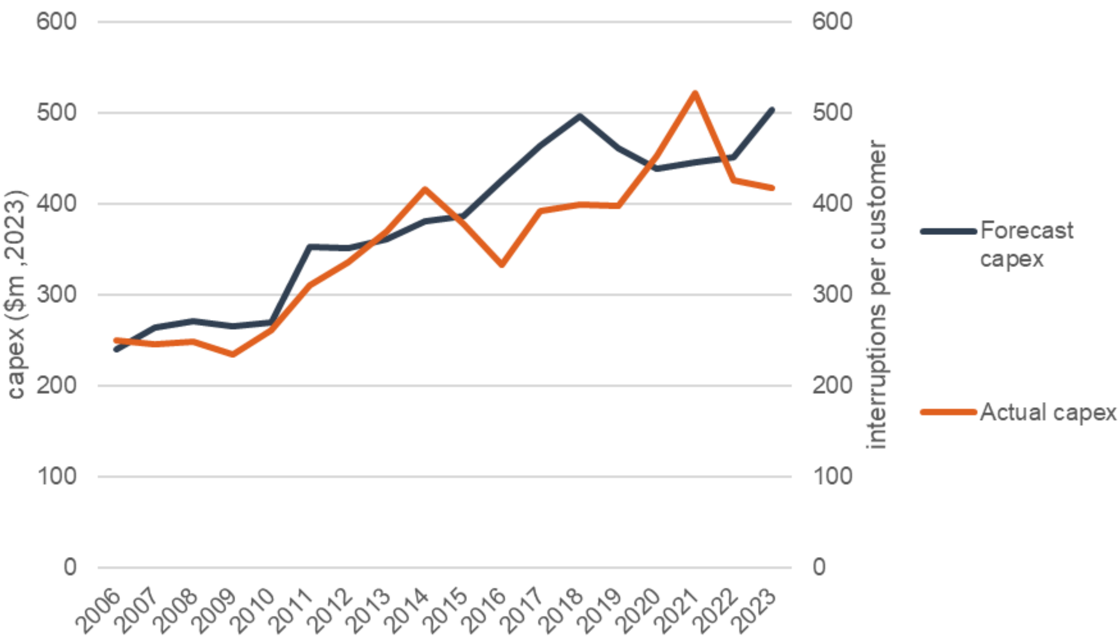
> *'Our first report looked at the timing of capex and concluded that NSPs tend to:*
> *• underspend by a greater extent early in regulatory periods*
> *• spend closer to, or above capex forecasts later in regulatory periods*
> *In our analysis we noted that there are different factors that can determine patterns of capex, and that one of the issues may be that capex incentives, financial or otherwise, vary through the course of the regulatory period.'*[211]

872. Figure C.6 shows the forecast vs actual capex for Powercor based on the AER network performance report data. Closer analysis is required of the drivers of the capex delivery performance in any regulatory period and year to year. We make further observations as it relates to the scope of our assessment of the expenditure as relevant.

210 AER, 2024 Electricity and gas network performance report

211 AER, 2024 Electricity and gas network performance report, page 29

Figure C.6: Comparison of Powercor historical actual with forecast capex



Source: AER Network performance report

Powercor expects the net capex to exceed the capex allowance for the current RCP

873. Overall, Powercor state that it expects the net capital expenditure to exceed the AER's allowance (and will further exceed this allowance after one-off asset disposals are excluded).

874. Powercor is expecting to underspend the component of the allowance allocated to augex and materially exceed the component of the allowance allocated to repex. For augex, factors such as lower peak demand and consumption, deferred projects and lower expected costs have contributed to the underspend. For repex, the expenditure reflects rising input costs, noting the impacts of the pandemic and ongoing global supply chain pressures have limited the ability for contract management to mitigate these uplifts.

Over the last 5 years, actual opex is slightly higher than the forecast opex resulting in an overspend against the opex allowance

875. In its 2024 network performance report,[212] the AER also considered totex and opex each year and across the regulatory periods:

> *'There has been a cumulative underspend by NSPs of their opex allowance for 6 consecutive regulatory years, with both DNSPs and TNSPs underspending their allowance. Opex efficiency by NSPs will contribute to outperformance against their allowed returns, though it will benefit consumers through lower opex expenditure forecasts in future regulatory determinations. This is a key feature of our incentive based regulatory framework and enhances the propensity for continual improvement by NSPs in delivering better outcomes for consumers.'*[213]

876. Figure C.7 shows a comparison of historical actual with forecast opex for Powercor. Whilst we have not been asked to consider overall opex, we observe that there has been a recent underspend of opex by Powercor consistent with the observations by the AER across NSPs.

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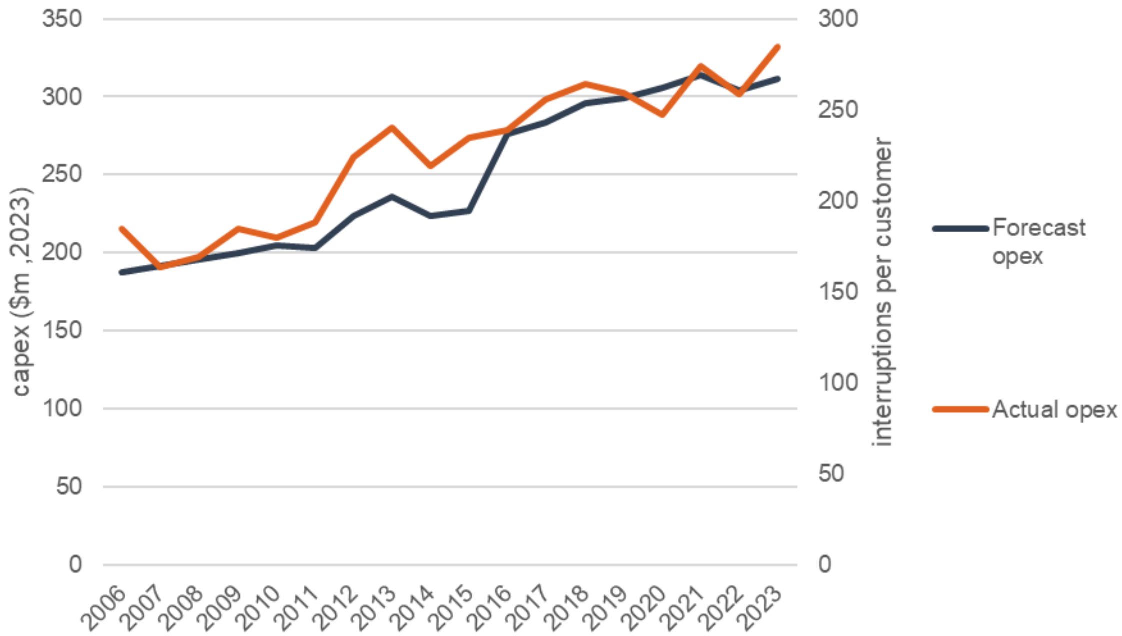
212 AER, 2024 Electricity and gas network performance report

213 AER, 2024 Electricity and gas network performance report, page 29

Figure C.7: Comparison of Powercor historical actual and forecast opex



Source: AER Network performance report