energy market consulting associates

CitiPower 2026 - 2031 Regulatory Proposal

REVIEW OF ASPECTS OF PROPOSED EXPENDITURE ON REPEX, AUGEX 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 CitiPower 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 CitiPower. 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 CitiPower'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
ACS	Alternate Control Service
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plan
Augex	Augmentation expenditure
BK	Brunswick zone substation
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 CitiPower 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 CitiPower's revenue requirements for the next RCP.

Expenditure under assessment

Proposed repex

3. CitiPower has proposed $354.1 million for repex in the next RCP. This represents a 79% increase from the $197.5 million that CitiPower expects to incur in the current RCP.
4. We have been asked to review projects and programs with aggregate proposed capex of $198.1 million (or approximately 56%) of the proposed repex.

Proposed augex

5. CitiPower has proposed $215.0 million for augex over the next RCP. We have been asked to review projects and programs with aggregate proposed capex of $173 million and including an Electrification/CER project with proposed capex of $70 million. These projects comprise approximately 80% of CitiPower's proposed augex.

Proposed opex step change for vegetation management

6. CitiPower has proposed an opex step change for its vegetation management program of $33.6 million for the next RCP. CitiPower 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.
7. 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

8. In considering CitiPower'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.
9. We found that Victorian DNSPs' regulatory proposals, including CitiPower, 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.
10. In our review of the governance, management and forecasting methods that CitiPower applied in determining its forecast expenditure, we found examples of the following issues:

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

11. 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

12. The forecasts for CitiPower'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, CitiPower referred to a decay model as the basis of its forecast intervention volume. For crossarms, the volumes were based on projecting forward the current find rate of defects, and the bulk of the conductor forecast was based on a historical trend.

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

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

14. The increase in CitiPower's proposed repex program is driven by increases in replacement volumes and by increases in assumed unit rates. CitiPower 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 CitiPower 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.

15. In comparing costs with other DNSPs, we found examples where the cost was similar to costs of a DNSP including for the CBD region, however in other cases the costs were materially higher. CitiPower did not explain the basis of its costs, and we consider there are examples where the unit rates that CitiPower has assumed are not reflective of efficient costs.

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

16. CitiPower 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 CitiPower has applied to derive these values in some cases.

17. CitiPower'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 CitiPower has applied, for both its cost estimates and its benefit calculations. 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.

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

18. We found evidence that some of CitiPower'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

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

20. CitiPower 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.

21. 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.

22. In the case of the non-demand-driven projects, our concern is with the extent of potential variance in cost and benefit assumptions. CitiPower 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

23. 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 CitiPower 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-voltage, offsetting reactive responses to complaints, where the latter is less cost effective.

24. However, we have significant concerns with CitiPower's forecasting methodology that we consider has led to an overstatement of the expenditure that CitiPower 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 zero voltage complaints in FY24 to CitiPower's forecast of 48 voltage complaints in FY27, is also not credible from the information provided and affects the assumed quantum of augmentation required.

Assessment of proposed vegetation management opex step change

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

25. 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.

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

26. We then considered whether there had been a material increase to the expenditure requirements, including from an external source that requires an opex step change.

27. Based on our assessment of CPU's submission, the primary driver arises from new information provided through improvements to vegetation management (including 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.

28. We acknowledge the need for CPU to improve the level of compliance for its vegetation management activities. CitiPower has been progressively addressing a higher volume of vegetation spans with the aim of achieving a state of compliance (based on its LiDAR data) with the electric line clearance regulations by FY29, and which it has subsequently advanced the target year of compliance by one year to FY28.

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

29. We reviewed the assumptions proposed by CitiPower, and its modelling methods and found that:

- The ultimate size of the vegetation management program will likely be lower than CitiPower has assumed after taking into account additional factors
- CitiPower 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
- CitiPower has not correctly taken account of the BST forecasting method for opex in the calculation of the required step change, and
- Our benchmarking of CitiPower's historical costs indicates that it is higher than other NEM DNSPs; CitiPower 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

30. 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 CitiPower is currently incurring costs that are materially higher than other NEM DNSPs, including other Victorian DNSPs, for reasons that CitiPower is unable to explain.

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

32. Our analysis indicates that the need for additional opex is 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 further reduced the step change. However, changes were required to be applied to a number of factors, and which we consider less credible, to remove the need for an opex step change for CitiPower.

Implications for expenditure allowances

Our approach

33. 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 CitiPower's forecast and which we consider to be not justified or overstated.

34. 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.

35. To the extent we found evidence of systemic issues in its application of governance, management and forecasting issues, we have taken account of these in our review of the category level expenditure and as reflected in our proposed alternate forecast. We have not separately applied a further top-down adjustment.

36. We stress that our advice on an alternative forecast relates only to the projects and programs within the category of expenditure that we have been asked to review and does not necessarily have any implication for expenditure that was not within the scope of our review.

Alternative forecasts for reviewed projects

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

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

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

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

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

39. We consider that CitiPower is likely to require increased opex to achieve compliance in the next RCP. However, we consider that it has overstated its requirement and that a reasonable estimate for the additional opex that it would require would be of the order of $8.7 million.

1 INTRODUCTION

The AER has asked us to review and provide advice on aspects of CitiPower'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 CitiPower provided and on aspects of the NER relevant to assessment of expenditure allowances.

1.1 Purpose of this report

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

41. 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 CitiPower's revenue requirements for the next RCP.

1.2 Scope of requested work

42. 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)
- Opex
  - Vegetation management step change

43. We cover our assessment of other aspect of CitiPower'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

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

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

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

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

48. 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

49. 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

50. 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.

51. 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

52. 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

53. 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 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.

54. 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

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

56. We have sought to assess CitiPower's expenditure proposal based on CitiPower's analysis and CitiPower'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 CitiPower may subsequently provide additional information or a varied proposal, our assessment may differ from the findings presented in the current report.

57. We have been provided with a range of reports, internal documents, responses to information requests and modelling in support of what CitiPower 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 CitiPower'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

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

59. In each subsequent assessment section 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.

60. In each of these assessment sections we include:

- An overview of the proposed expenditure and a summary of CitiPower'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.

61. 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 - CitiPower historical performance.

62. We have taken as read the considerable volume of material and analysis that CitiPower 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

63. We have examined relevant documents that CitiPower 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.

64. 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.

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

66. 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

67. 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.

68. 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 CitiPower in its determination of its expenditure requirements for the next RCP. Specifically, whether the changes made by CitiPower 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

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

70. We then consider the materials provided by CitiPower 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.

71. We next consider whether CitiPower 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.

72. 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 CitiPower 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

73. Common to our review of Victorian DNSPs, CitiPower'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.

74. For the next RCP, Victorian DNSPs like other NSPs across the NEM are responding to macroeconomic changes including electrification and change in demand. 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 CitiPower's regulatory proposal.

75. 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.

76. 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

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

- Average reliability performance is generally improving, which suggests that CitiPower's asset management process has improved service levels
- According to the safety regulator ESV, despite relatively low numbers, the number of asset failure incidents are higher than the long-term average
- Despite increase in the rate of line clearance non-compliance over time, more recent performance has been improving
- Network utilisation is decreasing over time, and now aligns with the DNSP average, and
- Voltage compliance has been well within the functional compliance limit set under the EDCoP.[1]

2.2.3 General observations relating to expenditure performance

78. CitiPower'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 CitiPower's network:

- Capex delivery performance is subject to a range of factors, with actual capex on average tracking more closely to forecast capex recently,
- CitiPower expects the net capex to be lower than the capex allowance for the current RCP, and
- Over the last 5 years, actual opex is lower than forecast opex resulting in an underspend against the opex allowance.

2.3 Presentation of submission information

79. In this section we consider the degree to which CitiPower has adhered to the expenditure assessment guidelines.

[1] Victorian Electricity Distribution Code of Practice

2.3.1 AER guidance on expectations

80. 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.

81. In our 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 by:

- Identification and evidence of the network need
- Quantitative cost-benefit analysis (CBA), 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.

82. The AER's 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.'*[2]

83. When considered together, and also drawing from relevant parts of other AER guidelines,[3] 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

84. 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*
>
> – *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.'*[4]

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

3 Including the asset replacement guidelines

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

2.3.3 Summary of information provided for its expenditure forecast

85. 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	Selected 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

86. The information provided initially by CitiPower 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 CitiPower were not transparent. We made numerous requests for the models and supporting information that CitiPower 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.

87. 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.

88. Where CitiPower has proposed to change the expenditure included in the submission from its initial proposal, we have noted this in our assessment.

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

89. 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.

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

90. 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.'[5]

91. 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.

92. 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 CP ATT 6.02,'*[6] and which is discussed in our companion report to the AER.

93. 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.

94. Notwithstanding the strengthening of stakeholder engagement in its governance arrangements, we concluded that CitiPower'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

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

96. The respective CPU regulatory proposals state that:

'The development of our expenditure forecasts also occurred through multiple expenditure iterations that progressively refined our investment portfolio. This process continually challenged and limited expenditure to those investments that deliver clear value for our customers.'[7]

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

5 CitiPower response to IR006 Question 2

6 CitiPower response to IR006 Question 2

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

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: CitiPower – IR006 – general capex – 20250320 question 3

The portfolio review process has included three expenditure iterations

98. CitiPower describes three expenditure iterations:[8]

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

99. 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 CitiPower expenditure iterations ($m, 2026)

Category	Pre-draft proposal	Draft proposal	Regulatory proposal
Augmentation	286	299	208
Net connections	141	195	230
Replacement	351	299	336
ICT	114	147	128
Non-network assets (other)	91	91	110
Total	**982**	**1,031**	**1,013**

Source: CitiPower response to IR014 question 1

100. 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.

101. 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 total portfolio or category level (where it is more difficult to robustly understand the impacts of subsequent adjustments).'*[9]

8 CitiPower response to IR006 Question 3

9 CitiPower response to IR006 Question 3

102. 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).

103. 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*.'[10] 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).'*[11]

104. 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 $250 million of projects removed from its forecast is offset by project additions

105. In its regulatory proposal, CitiPower refers to $250 million of investments removed from the forecast expenditure.[12] We asked CitiPower to describe the nature of the investments removed from the forecast expenditure, and which we summarise the key drivers as:[13]

- refinements to project options
- Updated demand forecasts, including lower forecasts for both CER and electrification uptake
- Updated asset and cost data, and
- Reliance on uncertainty framework - projects that could be treated as contingent or managed through a pass-through application during the period (if required) were removed from the expenditure forecast.

106. CitiPower also provided a worksheet[14] that explained the basis of the claimed $250 million reduction and which comprised 30 individual projects with almost $200 million associated with augex and repex projects. However, CitiPower states that due to project additions, the reduction is not visible in the totals.

10 CitiPower response to IR014 Question 2

11 CitiPower response to IR014 Question 2 (and IR006)

12 CitiPower Regulatory Proposal 2026-31 - Part B - Explanatory Statement - Jan2025, page 9

13 CitiPower response to IR006 Question 3

14 CitiPower - IR014 - Q1 - iteration changes.xls

2.4.3 Activity forecasting methods

Repex activity forecasting

107. 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

108. Augex is typically forecast using bottom-up methods, as CitiPower has done, and responds to specific drivers which may vary from one regulatory period to another. Figure 2.1 summarises Victoria Power Network's (i.e. CitiPower and Powercor) expenditure forecasting approach for demand-driven and non-demand-driven works.

Figure 2.1: VPN's forecasting approach for augex

Augmentation Demand driven works to meet localised growth and demand at peak times, and non-demand driven works to maintain reliability, security and quality of supply	• Augmentation projects to resolve demand-driven constraints are identified by forecasting load growth and voltage levels and comparing these to available network capacity and voltage compliance obligations. Our augmentation forecast only includes capital works where the value of alleviating a constraint exceeds the cost • Non-demand driven works are forecast by considering the potential risk and consequence of adverse events, and to meet stipulated regulatory obligations where relevant

Source: EMCa extract from Table 1, CitiPower - Expenditure forecasting methodology - 2026-31 - June 2024

109. 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[15] described in its Network Planning Framework.. The documents and content are consistent with what we would expect to see.

110. CitiPower (with Powercor, United Energy and consultants) has recently developed a Customer Electrification Forecasting Methodology (and related documents) which it applied to derive forecast expenditure to respond to the expected impacts of customer-driven electrification. We consider the application of these methodologies in the relevant projects within our scope of review.

Opex step change forecasting

111. 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

112. 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*

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

otherwise be undertaken in the near future, such that investing now is a least or no-regrets action.'[16]

113. 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

114. Risk cost assessment and economic modelling are crucial for determining the optimal timing of electricity infrastructure investments. Cost-benefit analysis (CBA, also referred to as or 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.

115. 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.

116. In reviewing its economic modelling, we frequently encountered cases where CitiPower (and 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

117. 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.

118. We have not commented on demand forecasts. The AER has advised us that it will assess CitiPower'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. If not considered by CPU in its sensitivity analyses, we include consideration of a 'low demand case scenario', which is a demand forecast of 100% 50PoE[17] rather than the 70%:30% weighted 50PoE/10PoE forecast used by CitiPower for planning purposes.

119. 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.

120. 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.

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[16] CitIPower's response to IR006 Question 7

[17] Probability of exceedance, so 50PoE is shorthand for 50% probability of exceedance, for example

121. 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.

122. 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

123. 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]

124. 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 CPU's standard cost estimation methodologies that it uses for business-as-usual project delivery purposes.[19]

125. The methodology nominates that final project cost estimates for major projects are based on P50 estimates,[20] 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, or evidence of its inclusions in the projects and programs we reviewed.

We did not see sufficient evidence of estimation accuracy and review

126. 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 five projects totalling approximately $24 million.[21] We do not consider this sample representative of the capex program that allows any meaningful conclusions to be drawn.

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

18 CitiPower's response to IR006

19 CitiPower's response to IR014 Question 6

20 P50 represents the project cost to provide a 50% level of confidence in the outcome; there is a 50% likelihood that the final project cost will not exceed the P50 value

21 CitiPower - IR006 - Q9(b) - completed projects - public

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

128. 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.

129. 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.

130. 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.

131. CitiPower did not explain the basis of its costs. In comparing costs of CitiPower with other DNSPs, we found examples where the cost was similar to costs of a DNSP including for the CBD region, however in other cases the costs were materially higher.

2.4.6 Deliverability

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

132. CitiPower (and Powercor), unlike many other DNSPs, applies a predominately using an in-house delivery model, supplemented by external delivery partners where required. CitiPower considers 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.[22]

133. 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.

134. Our benchmarking indicates that CitiPower is amongst the highest cost DNSPs.

135. 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. CitiPower (and Powercor) should be able to demonstrate why its delivery arrangements reflect highest value to customers.

CitiPower has taken some steps to lessen the delivery challenge

136. 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 provider,
- Distribution line works - moderated forecasts for overhead conductor and network hardening (i.e. it did not propose all works that were identified as economic), and extended the compliance timeframe for its 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.

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22 CP RIN 27 - Governance, forecasting and deliverability overview

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

137. 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 27. 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.

138. 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
- Outlines strategies to address any gap including growing the internal or external workforce, and steps to achieve this.

139. CitiPower's response[23] 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, CitiPower draws from the ability of Powercor to increase its workforce size to complete the uplift in wood pole replacement and also the REFCL program.

140. Given the proposed increases that are proposed by CitiPower, 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.

141. 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 CitiPower 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

142. The Better Resets Handbook published by the AER nominates four expectations of a network business' capital expenditure proposal:[24]

- 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.

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

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23 CitiPower's response to IR014 Question 11

24 AER. Better Reset Handbook - December 2021.

Additional information was necessary to complete our review

144. 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.

145. 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

146. 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 determined. Particularly where economic assessment methods have not been applied, we expected to see, but 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

147. 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

148. Risk cost assessment and economic modelling are crucial for determining the optimal timing of electricity infrastructure investments. CBA serves as a foundational tool in this process, enabling stakeholders to evaluate the financial viability and timing of investments under uncertainty. We found the following issues:

- Assessment periods for costs and benefits were not the same in the CBA models and had led to an overstatement of the net economic benefit
- Unsupported input assumptions, including for the estimation of benefits, 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

149. CitiPower and Powercor has 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.

150. Across the capex and opex forecast that we reviewed, we found examples of inadequately supported 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 CitiPower’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.

151. 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 analyses. In our assessment of the proposed expenditure, we consider that the timing for some projects is deferred beyond the end of the next RCP.

152. Some input assumptions adopted by CitiPower have 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

153. 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 proposed by CitiPower are high. In comparing costs of CitiPower with other DNSPs, we found examples where the cost was similar to costs of a DNSP including for the CBD region, however in other cases the costs were materially higher. CitiPower and Powercor do not provide an explanation for the higher costs.

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

155. 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 increase resource capacity

156. 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.

157. Given the proposed increases that are proposed by CitiPower, 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 CitiPower has addressed the delivery risks in relation to the individual projects and programs as a part of our assessment of the associated expenditure.

158. 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 CitiPower has taken reasonable steps to develop the required delivery capacity to deliver its proposed works program.

2.5.2 Implications for the expenditure forecast

159. 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)

CitiPower 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 CitiPower's assessment of asset condition including increases to zone substation-based replacement activity.

The AER has asked us to assess a subset of CitiPower's proposed $354.1 million replacement capex for the next RCP, across most of its asset groups and which accounts for approximately 56% of the proposed repex.

Overall, we consider that the proposed repex of $198.1 million that we reviewed is not a reasonable forecast of its requirements and is 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 CitiPower has proposed.

3.1 Introduction

160. We reviewed the information provided by CitiPower 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 CitiPower has incurred and is expected to incur in the remainder of the current RCP.

161. To the extent that CitiPower 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 the information we have relied upon in our analysis in the sections that follow.

162. 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 CitiPower has proposed

3.2.1 Proposed repex

Summary of proposed repex

163. CitiPower has proposed $354.1 million for repex in the next RCP as shown in Table 3.1. This represents a 79% increase from the $197.5 million that CitiPower expects to incur in the current RCP.

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

Asset Group	Current RCP	2026-27	2027-28	2028-29	2029-30	2030-31	Total next RCP
Poles & staking	**26.8**	7.7	7.7	7.8	7.8	7.9	**38.8**
Pole top structures	**33.6**	8.9	7.8	8.1	7.2	7.7	**39.7**
Overhead conductor	**0.5**	0.2	0.2	0.2	0.2	0.2	**0.9**
Underground cable	**40.6**	14.7	14.6	14.3	13.6	12.6	**69.8**
Service line	**6.0**	0.6	0.6	0.6	0.6	0.6	**3.1**
Transformer	**11.7**	8.7	6.9	6.6	9.7	8.1	**40.0**
Switchgear	**50.4**	26.7	23.4	17.5	16.2	13.5	**97.3**
SCADA, network control & protection systems	**13.6**	9.0	14.5	7.7	5.9	3.4	**40.5**
Other	**14.3**	4.9	4.8	4.6	4.9	4.8	**24.0**
Total	**197.5**	**81.3**	**80.5**	**67.4**	**66.1**	**58.7**	**354.1**

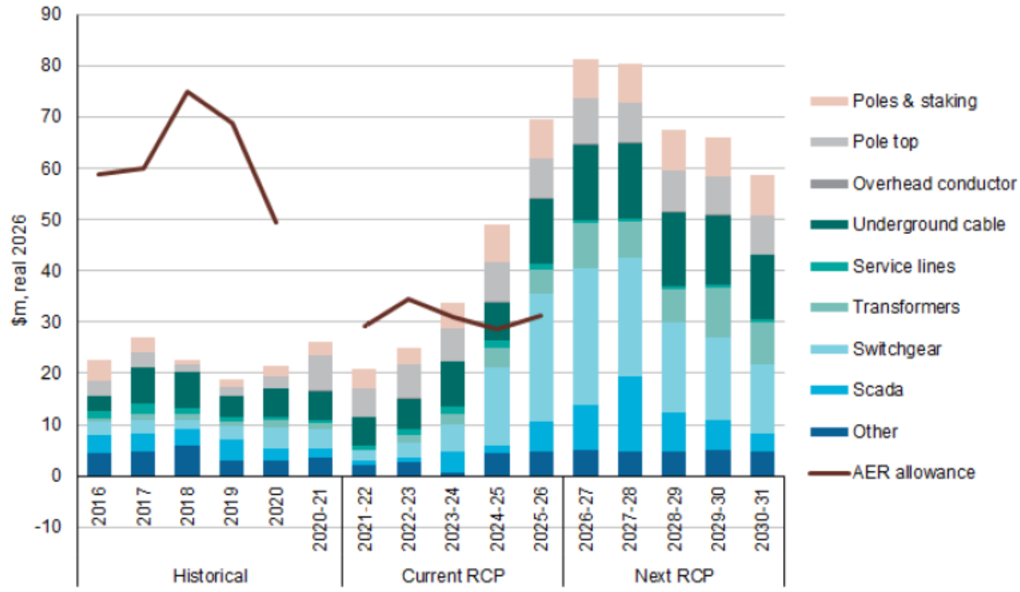
Source: EMCa table derived from CitiPower RIN Workbook 1 – Forecast template – Jan2025 and its annual RIN

164. CitiPower has proposed large increases to several asset groups namely underground cables and substation asset replacement.

Historical trend

165. 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: CitiPower proposed repex compared with current and historical - $m, real FY2026



Source: CitiPower RIN Workbook 1 – Forecast template – Jan2025 and its annual RIN

166. As shown in Figure 3.1, CitiPower expects to materially overspend its repex compared with the allowance in the current period. CitiPower explains the overspend as being the result of the following factors:

- rising input costs, and

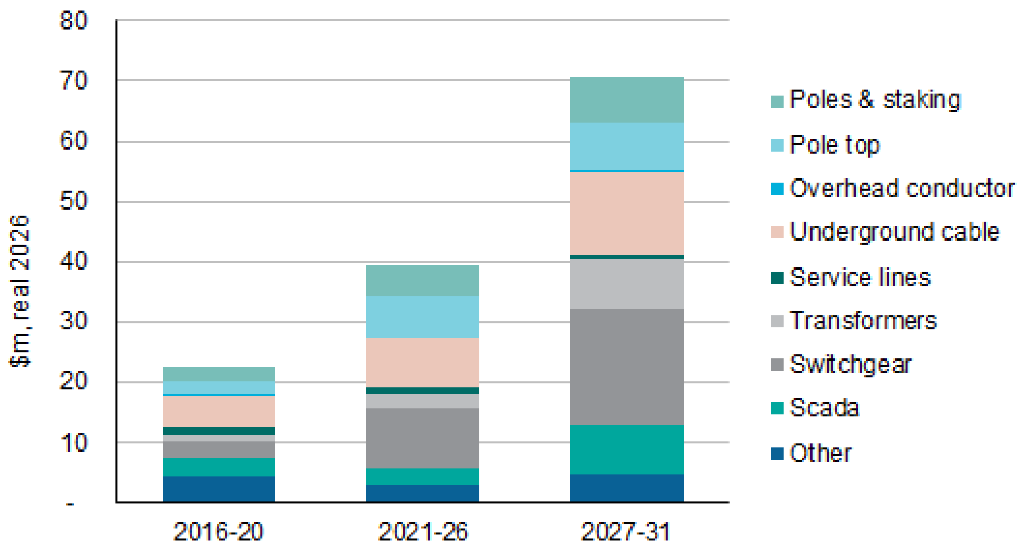
- increasing expenditure consistent with a longer-term trend of increasing asset replacements of high-volume distribution assets, which is reflective of the characteristics of the underlying asset populations.

167. We looked for evidence of the rising input costs, and the impact on CitiPower 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

168. 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 to $40 million per year in the current period then a further proposed increase to approximately $70 million per year. The largest increases relate to switchgear and cables.

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



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

169. 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 Summary observations

170. CitiPower 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.

171. CitiPower expects to incur a higher level of repex than was included in the AER's FD, driven by estimated step increases in the final years of the current period. CitiPower attributes the overspend to increases in cost of delivering its repex program – labour and materials. The forecast overspend remains subject to CitiPower's ability to deliver on its estimated expenditure, which represents a further step increase in the last two years of the current RCP above the latest year of actual costs. The largest increases are associated with the switchgear and underground cables asset groups.

3.2.3 EMCa's scope of repex review

172. Of the $354.1 million that CitiPower has proposed for repex in the next RCP, our scope relates to $198.1 million (or approximately 56%) as shown in Table 3.2.

Table 3.2: 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	7.7	7.7	7.8	7.8	7.9	**38.8**
Pole top	7.6	6.5	6.7	5.8	6.3	**32.9**
Transformers	7.3	4.7	4.0	8.7	6.2	**31.0**
Switchgear	22.4	23.4	16.7	11.1	5.5	**79.1**
SCADA, protection and control	4.0	6.6	0.7	0.7	0.7	**12.8**
Other	0.6	0.7	0.7	0.7	0.7	**3.5**
TOTAL	**49.7**	**49.6**	**36.6**	**34.9**	**27.2**	**198.1**

Source: EMCa table derived from CitiPower SCS capex model

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

3.3 Assessment

3.3.1 Poles

What CitiPower has proposed

174. The scope for our assessment for the Poles asset group is shown by asset category in Table 3.3. This is the total for the RIN asset group.

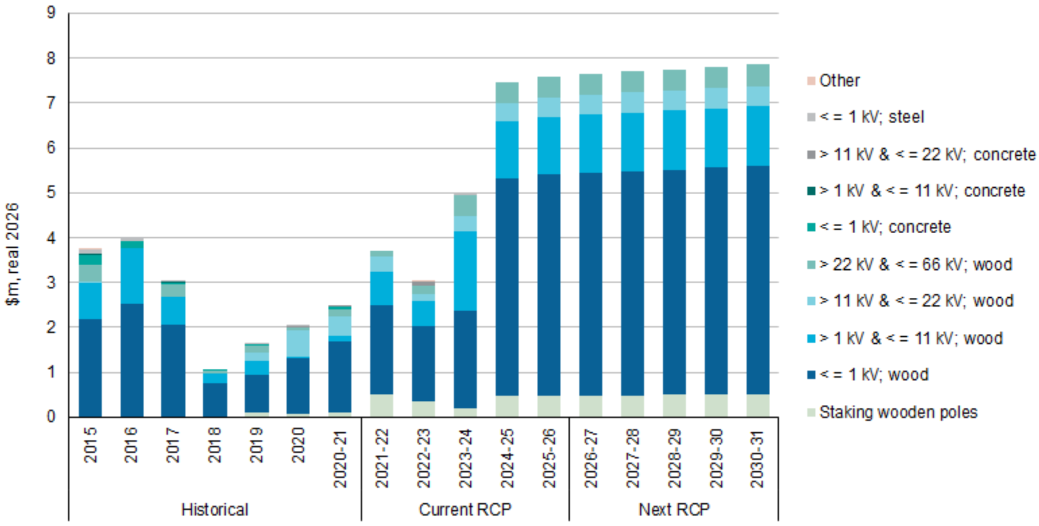
Table 3.3: EMCa scope of CitiPower's proposed pole repex - $m, real FY2026

Pole	2026-27	2027-28	2028-29	2029-30	2030-31	Total
HV pole replacement	2.2	2.2	2.2	2.3	2.3	**11.2**
LV pole replacement	5.0	5.0	5.0	5.1	5.1	**25.1**
Pole reinforcement	0.5	0.5	0.5	0.5	0.5	**2.5**
Total	**7.7**	**7.7**	**7.8**	**7.8**	**7.9**	**38.8**

Source: EMCa table derived from CitiPower SCS capex model

175. The total poles repex proposed by CitiPower is $38.8 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, real FY2026

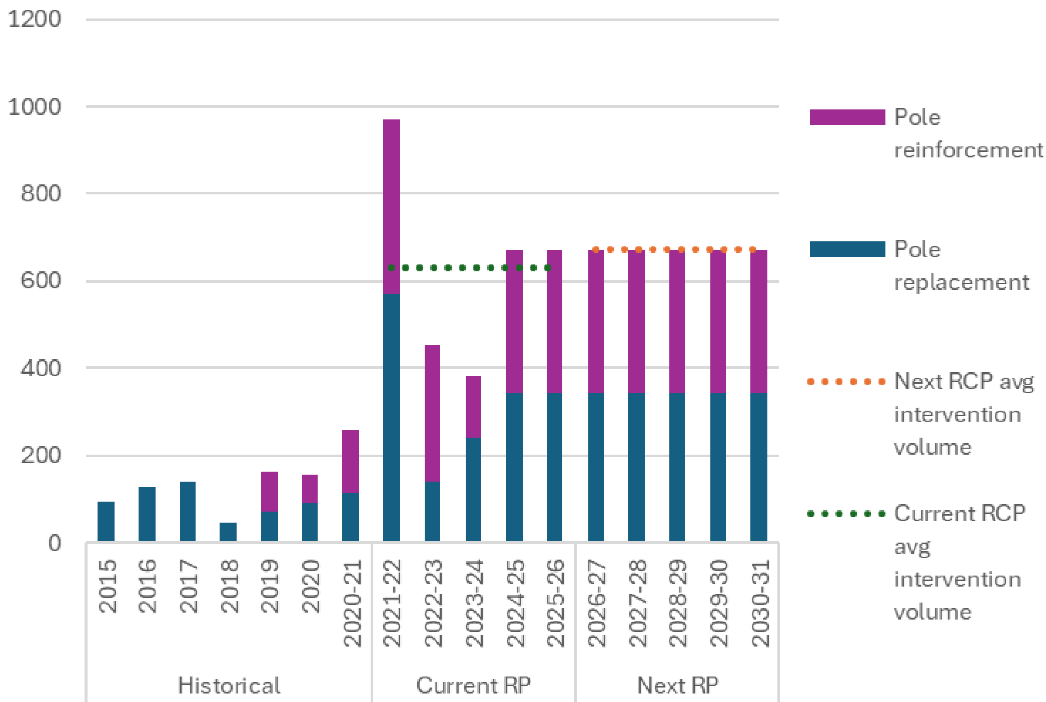


Source: Derived from RIN

176. CitiPower states that in the current RCP it is observing an increasing proportion of wood poles requiring intervention due to deterioration. On that basis, CitiPower proposes an increase in the next RCP of approximately $12 million from the current RCP estimate of $27 million.

177. The historical and forecast intervention volumes are shown in Figure 3.4. We observe a large spike in intervention volumes in 2021-22, which CitiPower has not explained but which appears to be driven by an increase to pole replacement volumes. However, this is not reflected in the expenditure trend in Figure 3.3.

Figure 3.4: Pole intervention volume



Source: Derived from RIN

Assessment

CitiPower states it has proposed a small uplift for the next RCP, which is only true based on its estimated replacement volumes

178. The increase referred to by CitiPower in the current RCP is only related to the 2024-25 and 2025-26 years of the current RCP, and which are both estimates. In the prior years, the number of interventions has been decreasing, and if the spike in 2021-22 (notably for LV poles) is included the average is around 600 poles p.a.

179. Without these increases, the average historical pole interventions would be materially lower, and the proposed increase materially higher.

180. Based on the historical expenditure, which does not include the spike in intervention volumes, we estimate that the average intervention volume over the current RCP to be:

- approximately 2,500 poles, or 500 poles p.a. including the estimates for the last two years, or
- approximately 400 poles p.a. based on the first three years only.

Model provided with submission is opaque and does not reconcile with its proposal

181. CitiPower states that it has established its forecast based on a combination of:[25]

- fault-based pole intervention forecast, using a simple average over the previous four-year period
- corrective forecasts comprising two separate sub-categories—observable visual defects, and measurable pole condition:
  - observable defects forecast based on an average over the previous four-year period
  - wood pole measurable condition-based intervention forecast based on its serviceability model, and
- risk based - CitiPower has not included a risk-based pole intervention forecast for the next RCP.

182. The model provided by CitiPower does not provide the build-up of the forecast as described above, instead it focusses solely on a decay-based model of the condition data, generating a forecast of 4,806 condition-based pole interventions.[26] We were not able to reconcile the forecast interventions in this model with CitiPower's proposed 3,359 pole interventions for the next RCP.

183. We did not find evidence of a direction from ESV or comments in its bushfire mitigation plan that specify a minimum number of pole interventions that apply to the current or next RCP, as we found for Powercor's network.

Forecasting method that CitiPower has applied is based primarily on condition-based interventions

184. From our discussions at the onsite meeting with CitiPower, we were made aware of other forecasting models that were applied, and which are based on a build-up of CitiPower's pole intervention requirements. In its response to our request,[27] CitiPower provided an updated model[28] indicating volume of 671 pa or 3,355 in total over the next RCP, as shown in Table 3.4. This total closely aligns with the proposed intervention volume of 3359.[29]

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[25] EMCa derived from CP BUS 4.01 – Poles – Jan2025 – Public

[26] CP MOD 4.12 – wood pole condition forecast – Jan 2025

[27] CitiPower response to IR015 Question 2

[28] CitiPower - IR015 - Q2 - poles forecast data

[29] Minor differences can be explained by the use of decimal places when determining totals for the RCP as a multiple of the annual volume.

Table 3.4: Build-up of pole intervention program

Intervention type	Poles pa	2026-31 poles	Source
Average annual wood pole measured condition and observable defect interventions	601	3,005	Combination of predicted unserviceable poles and AC serviceable P3 and criticality >=3 and poles determined using a decay-rate assumptions
Average observed defects	49	245	Historical 5-year average
Average annual fault interventions	21	105	Historical 5-year average
Total	**671**	**3,355**	
Wood pole reinforcements	331	1,655	
Pole replacements	340	1,700	
Total	**671**	**3,355**	

Source: Derived from IR015 Q2 pole forecast data

185. The condition-based components arise from its pole calculator data and decay modelling as shown in Table 3.5.

Table 3.5: Summary of CitiPower'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	4,567	100%	571	2,855
AC serviceable P3 and criticality ≥ 3	236	100%	30	150
Serviceable P4, HBRA, SWT <75 and age ≥ 50	3	0%	0	0
Total	**4,806**	**-**	**601**	**3,005**

Source: EMCa derived from pole counterfactual model

186. We understand that the decay modelling predicts the sound wood thickness of each pole based on the historical annual decay rate of sound wood thickness. This is used as a key input to the wood pole serviceability and therefore the forecast number of poles that require intervention.

187. Specifically, the intervention criteria listed in the table above is drawn from a hard-coded field in the pole calculator data referred to as 'over-riding classification.'

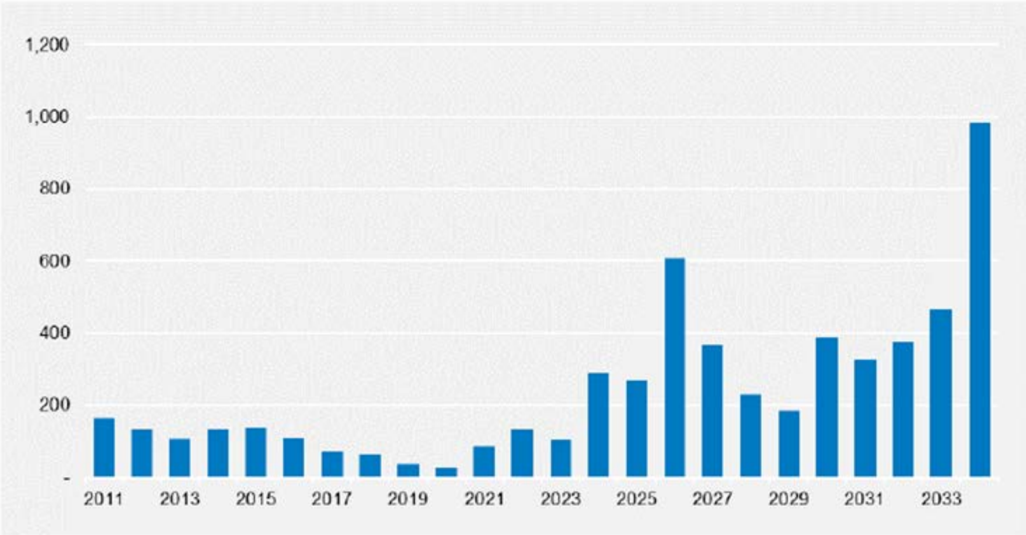
188. Whilst we have been provided with what we believe is CitiPower's serviceability assessment model, the data is an output of another model and does not allow our detailed review. We identified some asset data accuracy / completeness issues however we focussed on whether the outputs were reasonable. We did not find sufficient correlation between the outputs from its modelling and the observations of performance to increase our confidence in the forecast.

189. We have not looked in detail at the serviceability index mechanism and pole calculator on the basis that this has been subject to review by ESV. As a part of that review, ESV were critical that CPU had not sufficiently taken account of decay over time in developing a forecast of its pole intervention requirements.

Decay modelling has indicated a lower forecast intervention volume than CitiPower has proposed

190. In Figure 3.5 we have reproduced the forecast replacement volume of unserviceable and added-control serviceable poles for the next RCP that CitiPower describe as the output of its decay modelling. The predicted volume over the next RCP more closely aligns with an intervention volume of 400 pa rather than the 601 poles p.a. that CitiPower has proposed.[30]

Figure 3.5: Projected volume of unserviceable and added control serviceable poles based on sound wood thickness



Source: CP BUS 4.01 – Poles – Jan2025 – Public, Figure 5

Powercor uses the same forecasting method, however it adopts a lower forecast than CitiPower as indicated by its decay model

191. In Powercor's case, it has adopted volumes included in its bushfire mitigation plan and which are lower than predicted from its forecasted decay rate. In our view, this suggests that the model is likely to indicate a higher volume of replacements than are required. If this holds true for CitiPower also, then the forecast replacement volume for the next RCP should be reduced to a level at or below that indicated by its decay model.

192. We asked CitiPower to indicate how CPU has determined the prudent scope and timing of the proposed pole replacement volume for the next RCP, including by consideration of alternate replacement volumes. CitiPower stated that:

> *'...interventions driven by measured condition represent the majority of our forecast volumes. These volumes address the loss of pole strength due to wood rot, with sound wood thickness used to determine pole residual strength.*
>
> *We predict the poles sound wood thickness in 2031 using existing measurements of sound wood thickness and our historical annual decay rate of sound wood thickness. This is used to determine the serviceability of the pole in 2031.'*[31]

193. In terms of consideration of alternate replacement volumes:

> *'Lower intervention volumes for measured condition were not actively considered, as this would not be consistent with our existing asset management practices. Further, we are*

30 We have not reviewed the basis for the historical volume of pole replacements included in the forecasting model, however pole replacement volumes of 100 poles p.a. or less are broadly consistent with data in the RIN, with the exception of the unexplained spike in 2021-22

31 CitiPower response to IR015 Question 5

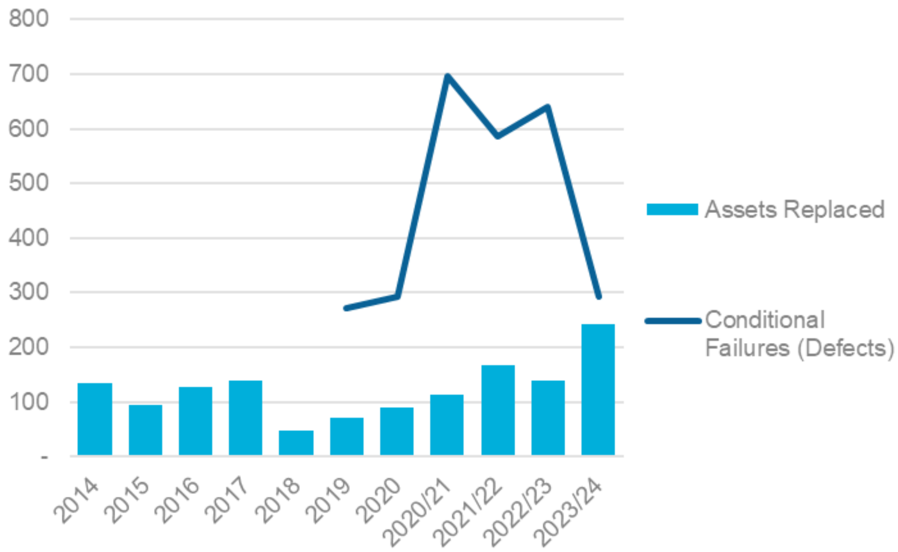
observing increasing high-priority defects and our unassisted wood pole failures are amongst the highest of the Victorian distributors. These are consistent with the characteristics of our existing wood pole population (e.g. material volumes of aged, lower durability poles, as well as high proportion of very-aged high durability class poles). Higher volumes were not considered to be warranted either, including in light of overall affordability considerations for customers.'[32]

194. CitiPower has not demonstrated that it has taken prudent steps to compare the results of its modelling to demonstrate that the proposed forecast is prudent.

Trend of pole-based defects and failures do not indicate a worsening trend as described by CitiPower

195. CitiPower claim that its pole failures are the highest or second highest in Victoria since 2019 and defects are increasing. We reviewed the data provided by CitiPower shown in Figure 3.6 which indicates a declining trend in defects with a similar downward trend in unassisted failures since 2021.

Figure 3.6: Trend of defects and failures for poles



Source: EMCa analysis of IR007 Q3 historical data

196. The asset class strategy provided by CitiPower indicates an increase in priority defects, however this was not the trend we observed in the data shown above. The trend of high priority defects provided by CitiPower indicate that defects more than doubled in 2021 (corresponding with 2020-21) and continued at high levels in the subsequent two years. As a result of this trend, we would expect to find an increase in intervention volumes in these years and did not. Instead, we observe an increase in interventions in 2021-22 only and then increasing again in 2023-24 and by which time the defects had decreased. This suggests to us, that the increase is responding to other factors and that CitiPower has already arrested the observed decline in performance.

197. The generally accepted industry benchmark for unassisted pole failure is approximately 1 in 10,000 poles. CitiPower's documents state that:

'Our unassisted wood pole failures have remained relatively stable since 2020, however, at around 0.55 failures per 10,000 poles, are the second highest amongst Victorian'[33]

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[32] CitiPower response to IR015 Question 5

[33] CP BUS 4.01 – Poles – Jan2025 – Public, page 7

198. Based on the combination of factors, we do not observe a compelling case for any increase in pole intervention volumes in the next RCP.

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

199. In its regulatory proposal, CitiPower states that:

> *'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]

200. We asked CitiPower 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 CitiPower 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 CitiPower to explain the basis of this decision, where an average unit rate is typically applied to avoid the potential distortions in any single year. CitiPower 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]

201. 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 do not benchmark well amongst peers

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

203. In Table 3.6, we show the range of wood pole unit rates, comprising the majority of the forecast expenditure for 2024, being the year used by CitiPower in its derivation of unit rates for the next RCP.

[34] CitiPower Regulatory Proposal 2026-31 - Part B - Explanatory Statement - Jan2025, page 47

[35] CitiPower response to IR006 Question 9 (c) – unit rates

[36] CitiPower response to IR014, Question 7

Table 3.6: 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**

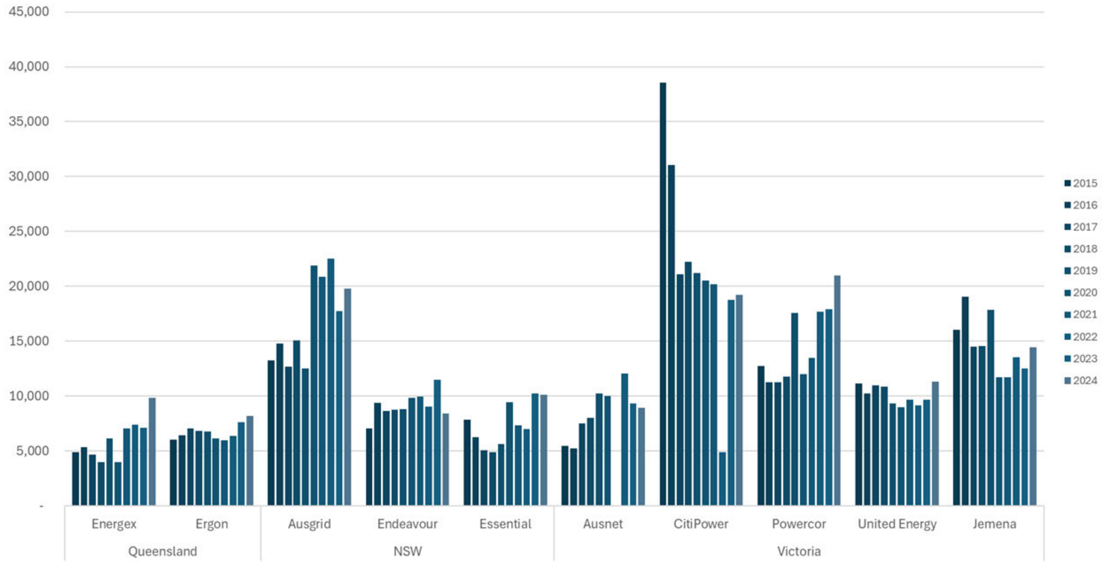
Source: EMCa derived from historical RIN

204. In Table 3.6, we have also produced the simple average of costs across the Victorian DNSPs. CitiPower's costs are high relative to other Victorian DNSPs, and similar to Powercor.

205. When we considered CitiPower's unit rates with DNSPs having CBD networks, such as Ausgrid, we found that CitiPower's unit costs were similar. Based on this comparison, we consider that the higher costs incurred by CitiPower are more likely due to the built-up nature of the electricity network including CBD areas.

206. In Figure 3.7 we show the historical trend of costs across all NEM DNSPs for LV wood pole replacement.

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



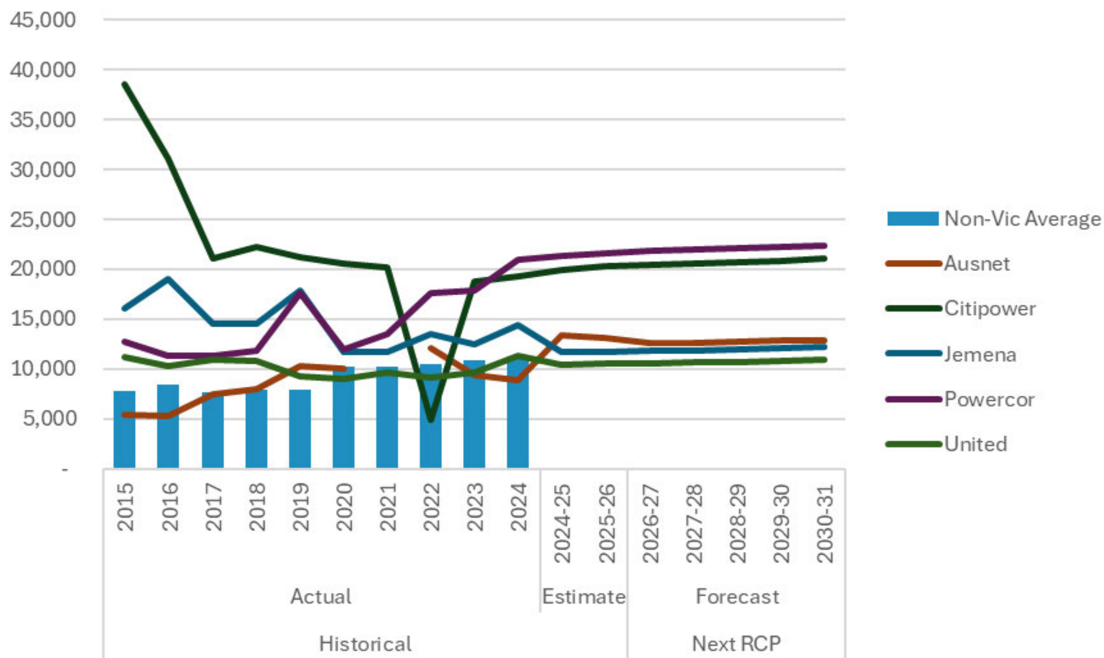
Source: Source: EMCa derived from RIN

207. As can be seen from this graph, CitiPower's costs have been trending down and this trend is also evident for other DNSPs. However, CitiPower is materially above the costs reported by other Victorian DNSPs and NEM DNSPs more generally.

Unit rates are similar for DNSPs with CBD networks

208. In Figure 3.8, 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 3.8: Historical LV pole replacement unit rate - $ FY2026



Source: EMCa derived from RIN

209. The unit rate for CitiPower is the second highest of the Victorian DNSPs, closely aligned with Powercor. The trend is similar across each of the categories of pole-related

expenditure. 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. However, CitiPower's costs are relatively consistent despite being higher than other DNSPs. As noted previously, the differential may in-part be attributed to the higher costs of managing a network in a CBD / inner-urban environment.

Forecast staking ratio is reasonable

210. CitiPower state that relative to the Powercor network, higher staking rates are generally possible in CitiPower for a number of reasons. The staking level is based on 5-year historical average (FY20 to FY24) of 59% and range from a minimum of 37% to a high of 71%. We consider that CitiPower's pole staking ratio is reasonable.

Findings

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

212. The proposed increase in pole intervention volumes is not sufficiently justified and is above that indicated by CitiPower's own modelling and performance of the pole asset class.

3.3.2 Pole top structures

What CitiPower has proposed

213. The scope for our assessment for the Pole top structures asset group is shown by asset category in Table 3.7, totalling $32.9m.

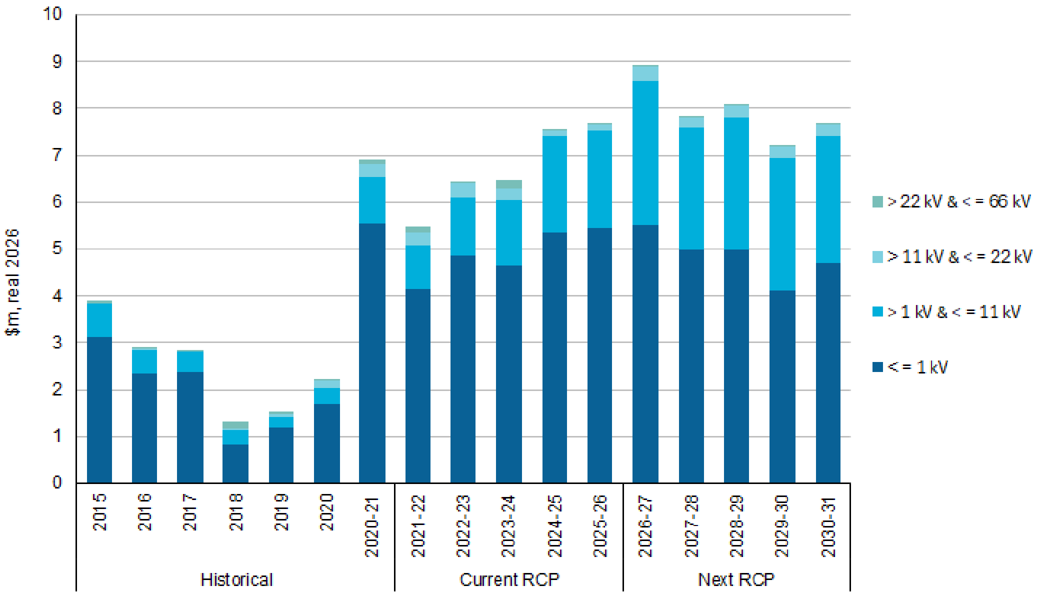
Table 3.7: EMCa scope of CitiPower's proposed pole top replacement - $m, real FY2026

Pole top	2026-27	2027-28	2028-29	2029-30	2030-31	Total
HV pole top replacement	2.1	1.5	1.8	1.7	1.6	**8.6**
LV pole top replacement	5.5	5.0	5.0	4.1	4.7	**24.3**
Total	**7.6**	**6.5**	**6.7**	**5.8**	**6.3**	**32.9**

Source: EMCa table derived from CitiPower SCS capex model

214. We note that there is an additional unplanned line maintenance project that explains the difference between Table 3.7 and the repex included for the pole top structure asset group of $39.7 million. The historical and forecast repex is shown in Figure 3.9.

Figure 3.9: Historical and forecast pole top structure repex - $m FY2026

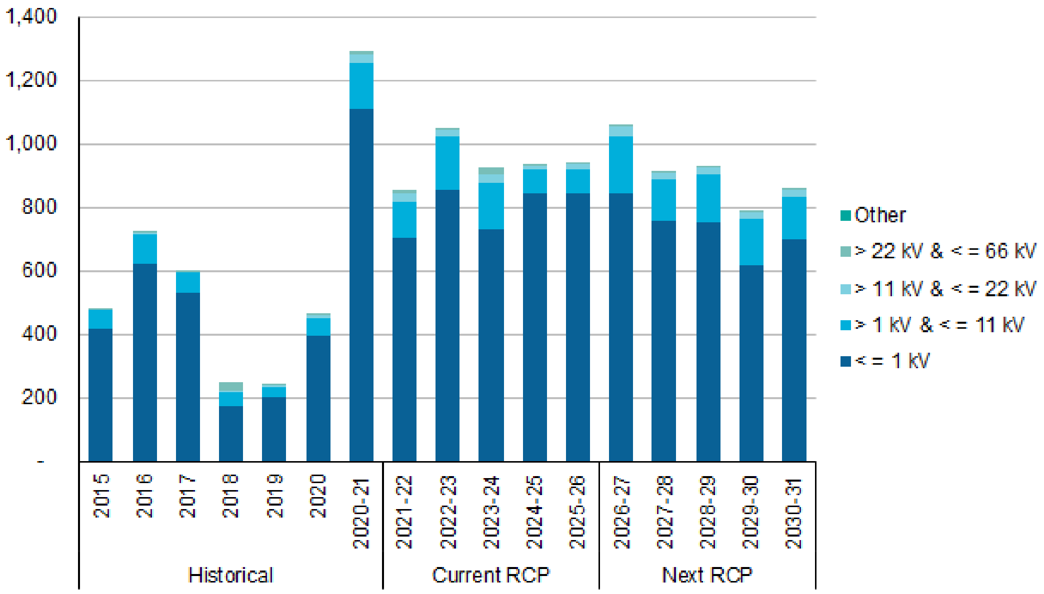


Source: EMCa graph derived from CitiPower RIN

215. CitiPower's proposed repex for the next RCP is slightly higher at approximately $40 million compared with $34 million in the current period. The increase is driven primarily through a different composition of replacements and changes to unit rates.

216. In Figure 3.10 we show the asset replacement volume for pole top structures from the RIN. CitiPower has proposed a slight decrease in replacement volumes in the next RCP, being 4,541 compared with the current period total of 4,696.

Figure 3.10: Historical and forecast pole top structure replacement volume



Source: EMCa derived from RIN

217. Similar to the trend we observed for pole interventions, there is an unexplained increase in volumes in 2020-21. We suspect this may have been associated with a change to the inspection practice for crossarms in 2020, where CitiPower introduced the use of a pole top camera at all inspections, and which led to an uplift in defects.

Assessment

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

218. CitiPower did not provide a model for its crossarm replacement program. We asked CitiPower to explain how it derived its forecast replacement volumes, which we understood were a combination of fault and corrective forecasts.

219. In response to our request for information,[37] CitiPower provided a distribution lines volume forecast model which detailed the calculations it had relied upon. The forecasting method and volumes are summarised in Table 3.8.

Table 3.8: Derivation of proposed crossarm replacement volumes

Program	Driver	Forecast method	Total for next RCP
HV pole top replacement	Corrective	Historical average	751
	Faults	Historical average	114
LV pole top replacement	Corrective	Historical average	3,085
	Faults	Historical average	584
Total			**4,533**

Source: Derived from CitiPower's response to IR015, distribution lines volume forecast model

220. The analysis undertaken by CitiPower 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 find rate is determined as the 3-year average defect find rate from the available data, being the period 2019/20 to 2021/22, and
- Fault-based replacement based on the average of five years historical data to 2023/24.

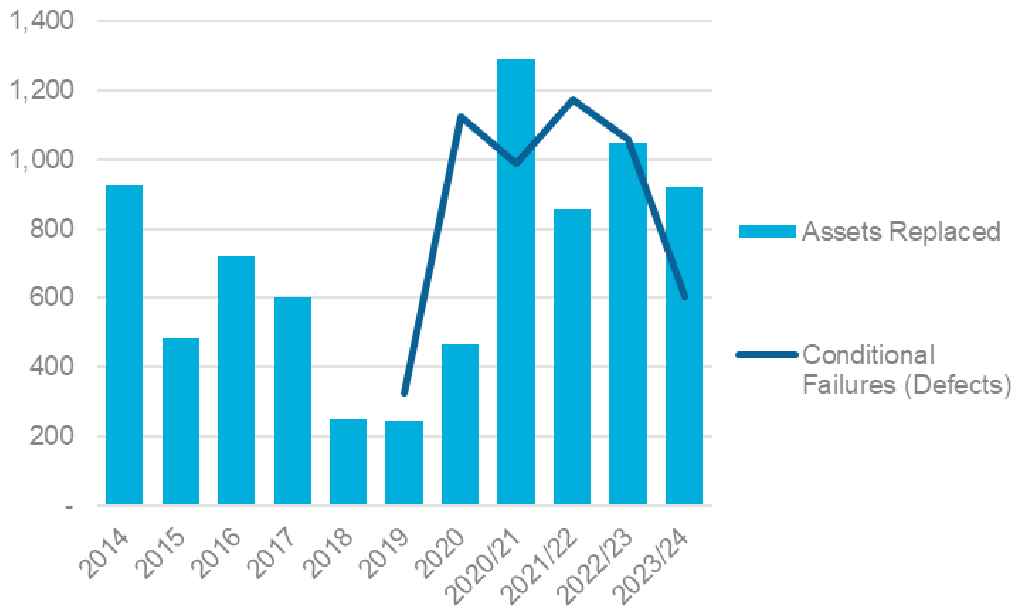
221. Unsurprisingly, the historical data leads to a similar forecast replacement volume to the volume that CitiPower has historically incurred, adjusted for inspection variability. We expected CitiPower to update its forecasting to include the latest completed year, being 2023/24 for its defect-based forecast, but it has not done so.

CitiPower has not adequately taken account of the impact of related replacement programs or the declining defect trend

222. The defects and failure information provided by CitiPower indicates a declining trend in defects since 2021/22, which coincides with the increased volume of crossarm replacements. We show the declining defects in Figure 3.11. The data for unassisted failures is limited to the last 5 years and shows a slightly increasing trend.

37 CitiPower response to IR015 Question 6

Figure 3.11: Trend of defects and failures for crossarms



Source: EMCa analysis of IR007 Q3 historical data

223. Absent another explanation, a declining number of defects would be expected to result in a reduction to the number of crossarms being replaced in its crossarm replacement program. Moreover, whilst the data in Figure 3.11 includes total crossarm replacements (including pole replacements) the forecasting method applied to the crossarm replacement program does not take account of the increases to the pole replacement forecast.

Unit rates do not benchmark well amongst peers

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

225. In Table 3.9 we show the range of crossarm unit rates incurred by DNSPs across the NEM in 2024, being the year used by CitiPower in its derivation of unit rates for the next RCP.

Table 3.9: Comparison of 2024 unit rates - $m FY2026

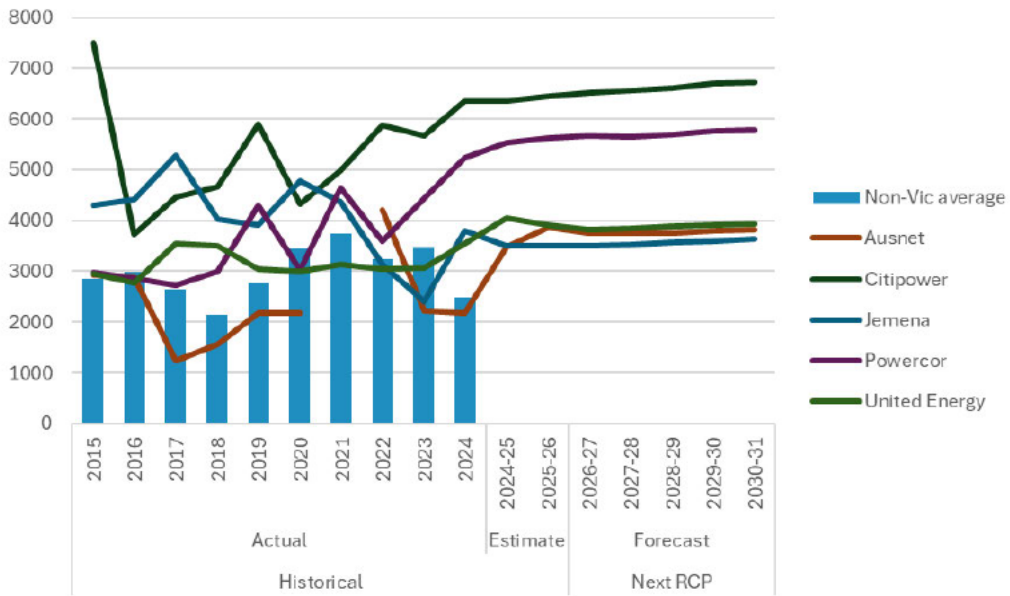
2024 unit rates	<=1kv	>11kv&<=22kv
Non-Victoria		
Ausgrid	3,941	3,941
Endeavour	2,312	3,854
Energex	4,489	2,519
Ergon	4,064	-
Essential	1,679	1,761
Average	**3,297**	**2,415**
Victoria		
AusNet	2,176	2,807
CitiPower	6,364	9,640
Jemena	3,798	5,094
Powercor	5,248	7,162
United Energy	3,550	3,776
Average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

Source: EMCa derived from historical RIN

226. The historical unit rates reported by CitiPower, like Powercor, are higher than we had expected for many distribution lines assets.

227. In Figure 3.12, we show the historical unit rate for a LV crossarm replacement for Victorian DNSPs compared with the average cross non-Victorian DNSPs using information from the RIN to understand whether there were any common factors contributing to the cost.

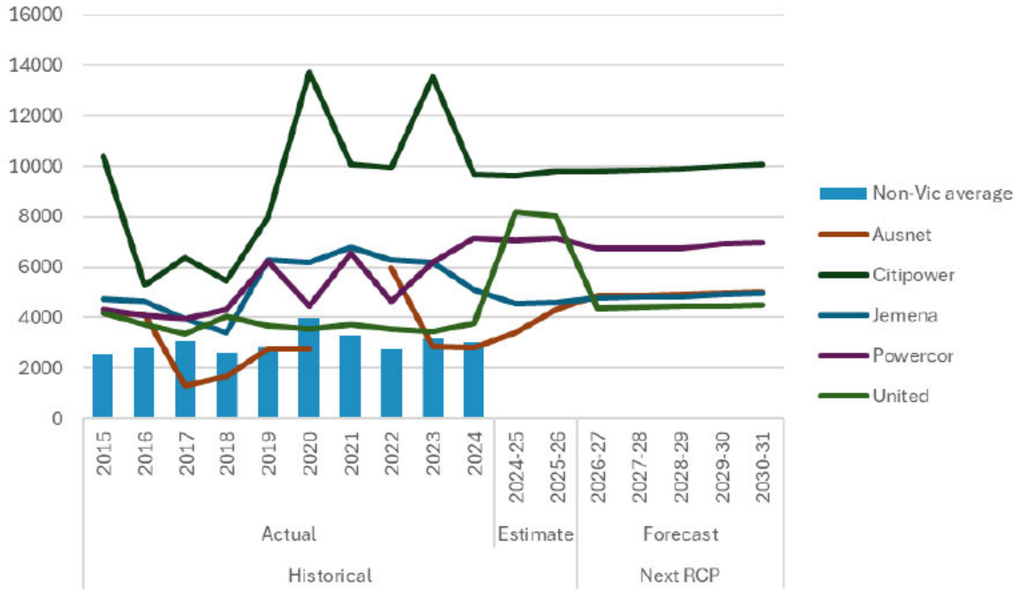
Figure 3.12: Historical LV crossarm replacement unit rate - $ FY2026



Source: EMCa derived from RIN

228. We repeated the analysis for the 22kV crossarm replacement as shown in Figure 3.13, with similar results.

Figure 3.13: Historical 22kV crossarm replacement unit rate - $ FY2026



Source: EMCa derived from RIN

229. This trend presents CitiPower as a clear outlier for unit costs when compared to Victorian DNSPs. Powercor (and CitiPower) are also an outlier across the NEM.

230. Whilst there may be some differences in CitiPower given it is an urban/CBD network that may result in higher unit costs than other DNSPs, our analysis indicates that the unit rates are materially higher than other DNSPs including those with CBD networks.

Findings

231. We consider that the proposed pole top structure repex for crossarm replacement is overstated. CitiPower has not adequately taken account of the impact of related replacement programs or declining defect trends and which we lead it to a higher replacement volume than is prudent. Also, the unit rates applied by CitiPower for its crossarm replacement are materially higher than other comparable DNSPs and contribute to a higher than efficient level of expenditure.

3.3.3 Transformers

What CitiPower has proposed

232. The scope for our assessment for the Transformers asset group is shown by asset category in Table 3.10.

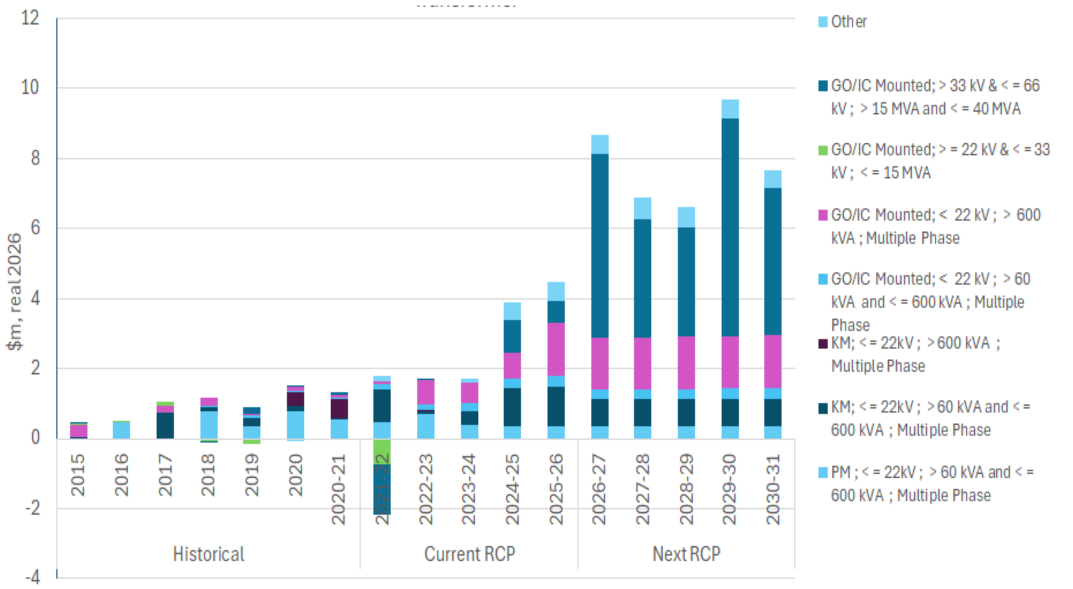
Table 3.10: EMCa scope of CitiPower's proposed transformer replacement - $m, real FY2026

Transformer	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Minor station works	0.2	0.5	0.2	0.2	1.8	**3.0**
Transformer refurbishment	1.2	1.2	1.2	1.3	0.0	**5.0**
ZSS transformer replacement	5.9	2.9	2.5	7.3	4.4	**23.0**
Total	**7.3**	**4.7**	**4.0**	**8.7**	**6.2**	**31.0**

Source: EMCa table derived from CitiPower SCS capex model

233. In Figure 3.14 we present the historical and forecast expenditure for the transformer 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 3.14: Historical and forecast transformer repex $m FY2026



Source: EMCa derived from RIN

234. We observe increases to its kiosk mounted <=600kVA and ground mounted > 600kVA transformers estimated in 2024-25, and which continue at these higher levels into the next RCP. In addition, CitiPower is proposing a material increase to its 66kV transformer replacements in the next RCP, to which our review relates, compared with the historical trend.

Assessment of transformer replacement program

Three transformer replacements are proposed for the next RCP

235. CitiPower has included transformer replacements at Armadale, Northcote and Victoria Market substations as described in its Asset class strategy document (BUS 4.08).

236. A summary of the three transformer sites is included in Table 3.11.

Table 3.11: Summary of proposed transformer replacement projects ($m FY2026)

Substation	Summary of need	Preferred option	Forecast expenditure	NPV	Completion year
Armadale (AR)	Transformers are 61 years old and are at the end of life, with key components past their design life and showing signs of deterioration.	Replace T2	7.2	7.9	FY30
Northcote (NC)	Transformers are nearly 60 years old and carry significant load at risk due to limited HV transfer capability. As the neighbouring HV supply areas are mainly 6.6kV, NC has limited HV parallel and transfers to other zone substations in the area	Replace T1	8.5	10.8	FY28
Victoria Market (VM)	Transformers, installed in 1966, are therefore 58 years old. CitiPower claim a higher aging rate due to higher ambient operating temperatures due to indoor design.	Replace T1	6.2	7.9	FY31

Source: EMCa analysis

237. CitiPower proposes replacing T1 at VM in the current period, however the AER determined that it had not sufficiently demonstrated that the project was prudent, citing amongst other things, the transformer condition information.

238. For the next RCP, CitiPower states that it has identified five transformers for replacement. However, following review of the capex portfolio, identified overlap with its proposed augex projects at Collingwood (B) and Collingwood (CW), subsequently removing these projects from the repex forecast. Its economic assessment determined that augmentation options were the most prudent and economic solution at these sites.

239. CitiPower (and Powercor) state that a proportion of supply risk for its substation transformers is managed through the augmentation program, as a function of the high growth that the network experiences.

CitiPower has relied solely on its economic analysis for transformer replacement

240. We asked CitiPower for any major changes to the management of its substation transformer assets over the last 10 years (if any). CitiPower 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 '*[38]

241. We also requested copies of condition reports. CitiPower 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*

38 CitiPower's response to IR007

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.'[39]

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

Risk methodology applied for its replacement projects appears reasonable

243. Given the proposed increase in substation transformer repex, we asked CitiPower 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 CitiPower 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.'[40]

244. We consider that the evolution of the risk methodology outlined by CitiPower is reasonable.

245. CitiPower has developed a Parallel risk model[41] using this methodology which it uses determine the risks for each asset at each substation, which are then input into each of the economic models for each site.

246. 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).'[42]

247. 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 followed by failure of the transformer, then environmental risk.

Options analysis does not consider transformer life extension

248. In its asset class strategy, CitiPower define the refurbishment of a transformer as:

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39 CitiPower's response to IR007 question 2

40 CitiPower's response to IR007 question 2

41 CP MOD 4.10 - Parallel risk model - Jan2025 - Public

42 CP ATT 4.01 - Asset risk quantification guide - Jan2025 - Public

'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.'[43]

249. However, CitiPower's options analysis does not consider its refurbishment option as providing life extension, as we would expect. Our understanding was confirmed in the onsite discussion, that consideration of alternates to replacement was limited in scope. A life extension option, if proven to be feasible for the transformer fleet, may provide CitiPower with ability to manage increasing transformer risk and stage transformer replacements in future years.

250. 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). CitiPower states that the option is technically possible, however refurbishment is most effective on mid-life where equipment is showing signs of deterioration. Based on its assessment of the current age profile, CitiPower concluded that many of the oldest assets would not benefit from refurbishment works, so the residual risk for these transformers would still be high.

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

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

252. 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 3.12, and consideration of the geography of the areas, suggests a higher weightage to business customers. In the latest AER VCR study published in 2024, the values were materially changed including a reduction to the business 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 some of the nominated substation sites will be deferred relative to what CitiPower has proposed.

Table 3.12: Summary of VCR assumed for CitiPower's proposed transformer replacement projects

Substation		Location	VCR ($2023)
AR	Armadale	Urban	52.31
NC	Northcote	Urban	35.89
VM	Victoria market	CBD	35.60

Source: EMCa analysis of transformer models

253. In addition, CitiPower has applied a multiple of VCR in its assessment of the unserved energy for VM as a CBD substation. We reviewed the Asset risk quantification guide included with the submission which states:

'For zone substations within the CBD (BQ, LQ, FR, WA, WP, JA, VM and MP), a VCR multiplier of 2.7 times the VCR value to reflect the increased GRP per MWh that applies to the Central Business District (CBD) of Melbourne. This modifier is required to reflect the increased risk in the area and ensure the risk valuation is reflective of the increased redundancy requirements in the CBD in Victoria.'[44]

254. During our onsite meeting, CitiPower referred to similar practice for the Sydney CBD:

[43] CP BUS 4.08 - Zone substation transformer - Jan2025 - Public

[44] CP ATT 4.01 - Asset risk quantification guide - Jan2025 - Public, page 16

'For CBD sites, we include an additional GRP modifier applied to the VCR based (noting that our figure of (sic) conservative, as the applicable data includes inner-suburbs as well as the CBD) to align with the approach used for Sydney's CBD'[45]

255. We reviewed the 2024 published VCR report and did not find any mention of VCR for the Melbourne (or Sydney) CBD. We checked the application guidelines for RIT-D and found that whilst RIT-D proponents were provided with an ability to vary the VCR applied for projects:

'RIT–D proponents should use VCR calculations based on an accepted estimate, such as those produced by AEMO, or by us from 31 December 2019'[46]

256. Also, that any variation should be based on a transparent methodology and suitably justified:

'Therefore any deviation from or adjustment of our published VCR values (for example, to reflect a specific mix of customers or HILP event that is already captured in our VCR estimates) must be clearly justified, setting out why it would not be appropriate to apply, or why it would be appropriate to make adjustments to, our published values. In coming to a decision to apply separate VCRs, RIT–D proponents should consult directly with both us and the customers to whom the VCR applies.' [47]

257. In terms of the application of an alternate estimate of VCR for the Sydney CBD by Ausgrid, we refer to the AER determination of the Sydney CBD RIT-D project where the AER determined that:

'…after taking into account the additional information provided by Ausgrid and additional analysis undertaken by our consultant, it is clear that the selection of the preferred option and the optimal timing of the project is insensitive to a reasonable alternative VCR estimate. Our determination that Ausgrid's decision was in accordance of the RIT-D requirements does not depend on the reasonableness of the specific VCR it applied. Given this, we do not consider this decision to be a precedent as it is based on historical approaches to determining VCR estimates.'[48]

258. We have not been provided with sufficient justification for the use of a 2.7 multiplier, including through the use of scenarios in the economic assessment of the VM substation project. On that basis, we do not consider that CitiPower has met the burden of proof outlined by the AER and consider the published values of VCR should apply to this project.

259. The aggregate environmental risk is a hard-coded value which we understand is similar to the values developed as a part of its environmental management program, which we consider is not a reasonable estimate of the environmental risk, as discussed in a subsequent section of our assessment.

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

260. The calculation of costs and benefits are not reviewed on the same basis. Specifically, we find that 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.[49] Adjustments to align the assessment periods results in reductions to the NPV, that are already small in value, to the point that the nominated sites are not economic to proceed in the next RCP.

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45 CPU onsite presentation – repex, March 2025, slide 43

46 AER, Application guidelines |Regulatory investment test for distribution, page 27

47 AER, Application guidelines |Regulatory investment test for distribution, page 28

48 AER, Decision Reliability Requirements in Sydney CBD Determination on dispute - application of the regulatory investment test for distribution, page 7

49 Refer to Appendix B

Cost estimates for substation projects appear high

261. CitiPower 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.

262. 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.

263. 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 3.13: 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

264. In its draft decision for the current period, the AER did not accept the initially proposed unit rates for its transformer replacement projects as they were materially higher than other distributors. In its final decision, the AER accepted the unit rates based on additional information provided by CitiPower. [50]

265. We do not have access to the information relied on by AER in making this determination. Based on the AER decision, and using a simple average, CitiPower had proposed to undertake five projects in the current RCP at a total cost of $17 million ($2021) or approximately $20.5 million ($2026), resulting in an average cost of around $4 million. The costs included for the next RCP by CitiPower are materially higher, and which CitiPower has not adequately explained.

266. We also 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 CitiPower (and Powercor).

Assessment of transformer environmental management program

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

267. In addition to its proposed transformer replacements, CitiPower has included a program to address identified oil leaks at its zone substation sites. CitiPower 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.*'[51]

268. CitiPower has submitted a model[52] that identifies 11 transformers where it considers that the cost to address the risk is lower than its assessment of the risk-cost, identified as a benefit to cost ratio >1. The program spans the current and next RCP, with 8 transformers proposed in the next RCP.

50 AER Attachment 5: Capital expenditure | Final decision – CitiPower 2021–26, page 5-17

51 CP BUS 4.08 - Zone substation transformer - Jan2025 - Public

52 CP MOD 4.04 - Transformer refurbishment - Jan2025 – Public

Quantification of base risk cost is not correct

269. CitiPower 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 CitiPower's risk assessment quantification guide.[53]

270. 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

271. 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.
- Distance modifier is also not intuitively correct, as the risk increases with distance from water source – it should be the other way around.
- Bunding modifier largely set to 1, therefore not used, and
- PCB modifier is set to 1 or 5 - 5 when PCBs are present and which would have higher environmental cost and so is directionally consistent but does not apply to the selected transformers for the next RCP.

272. 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

273. 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).'*[54]

274. CitiPower 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 (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

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

[53] CP ATT 4.01 - Asset risk quantification guide - Jan2025 - Public

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

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

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

277. We understand that CitiPower 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

278. 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.

279. 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.'*[55]

280. We requested CitiPower to provide a justification statement identifying the need, scope, and timing and to provide the supporting economic analysis for the minor station works repex, and miscellaneous plant and stations repex. These projects totalled $3.0 million.

281. In its response, CitiPower 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.'*[56]

282. We acknowledge the need for unplanned reactive works in zone substations, including on the assets included in CitiPower's response. We have not been provided with the historical data relied upon to calculate the historical average based on its stated forecasting approach. We observe a step increase in the final year that is materially above other years in the forecast. Subject to review of the balance of the substation related repex forecast that may assist explain this trend, the minor station works program should closely align with a historical trend.

Findings

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

284. For the proposed transformer replacements, we were not provided with additional supporting information that demonstrated that the transformers were at end-of-life as CitiPower has claimed. Our assessment has therefore focussed on the economic analysis

55 CP BUS 4.08 - Zone substation transformer - Jan2025 - Public

56 CitiPower response to IR015 Question 15

which CitiPower has used to support the proposed program. We found that cost estimates were high, and specific adjustment for more reasonable input assumptions is likely to lead to deferral of the proposed VM transformer replacement beyond the next RCP.

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

286. Inclusion of a reactive program for substation assets is reasonable. However, absent a better explanation, the forecast expenditure should more closely follow a historical average.

3.3.4 Switchgear

What CitiPower has proposed

287. The scope for our assessment for the Switchgear asset group is shown by asset category in Table 3.14.

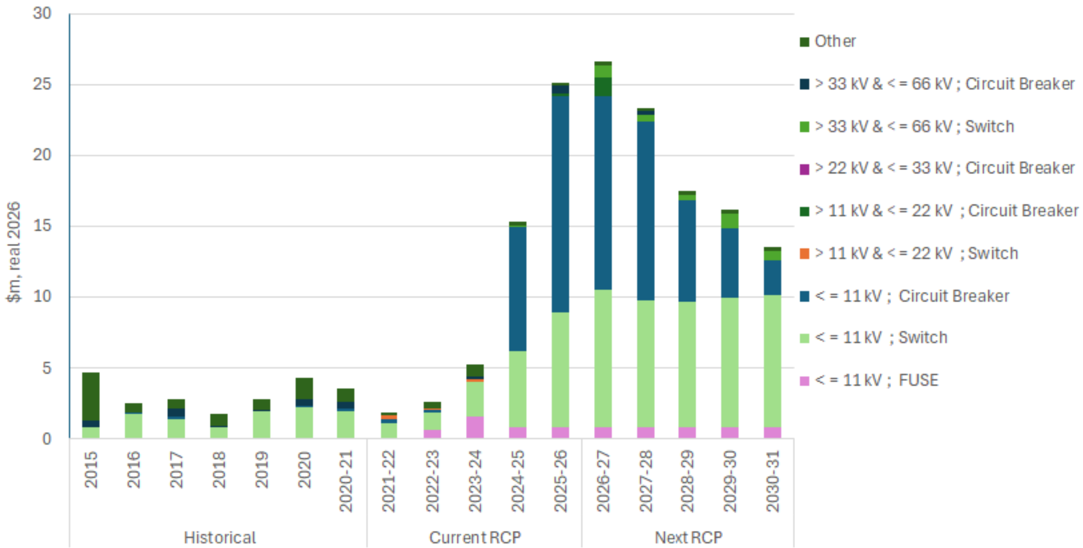
Table 3.14: EMCa scope of CitiPower's proposed Switchgear replacement - $m, real FY2026

Switchgear	2026-27	2027-28	2028-29	2029-30	2030-31	Total
ZSS switchboard replacement	22.4	23.4	16.7	11.1	5.5	**79.1**

Source: EMCa table derived from CitiPower SCS capex model

288. In Figure 3.15 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 3.15: Historical and forecast switchgear repex $m FY2026



Source: EMCa derived from RIN

289. We observe increases to the replacement of 11kV 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 11kV CBs, which are typically associated with switchboard replacement projects, we see a large increase compared with the historical trend.

Assessment of switchboard replacement program

Eight switchboard replacements are proposed for completion in the next RCP

290. CitiPower has included switchboard replacements at five substations (AR, RD, NC and VM), switchboard retirement at R and completion of three in-flight switchboard replacements (CW, LQ and B) that were commenced in the current RCP as described in its Asset class overview document.[57]

291. We summarise each of the switchboard projects, drawing from output of the modelling, in Table 3.15.

Table 3.15: Summary of proposed switchgear replacement projects ($m, real FY2026)

Substation	Summary of need	Preferred option	NPV	Completion year
In-flight replacement projects				
CW	Network voltage conversion	Replace the switchboard and relays	-	2026-27
LQ	Compound-filled, non-arc fault contained design (J-type oil filled CBs) at end of life	Replace the switchboard and relays	-	2027-28
B	Compound-filled, non-arc fault contained design (J-type oil filled CBs) at end of life with prior damage	Replace the switchboard and relays	-	2028-29
Forecast retirement project				
R	22kV switchboard is of the non-arc fault contained bulk oil design and is metal clad with cast iron body and compound insulation, all of which are known issues across the industry with programs to progressively replace this equipment.	Retire switchboard and replace with three RMUs	0.7	2026-27
Forecast replacement projects				
AR	Bulk oil non-arc fault contained design (J-type oil filled CBs) with presence of partial discharge	Replace the switchboard and relays	2.3	2027-28
RD	Bulk oil non-arc fault contained design (J-type oil filled CBs) with presence of partial discharge	Replace the switchboard and relays	1.0	2028-29
NC	Bulk oil non-arc fault contained design (J-type oil filled CBs) with presence of partial discharge	Replace the switchboard and relays	3.1	2029-30
VM	Critical site, existing deterioration, age risk and no available spare parts	Replace the switchboard and relays	12.7	2030-31

Source: EMCa analysis of CitiPower BUS 4.09 and individual switchboard replacement models

292. The NPV results included in the above table are based on the switchboard models provided. We have indicated the completion year as being the timing of the proposed capex. We

57 CP BUS 4.09 – Zone substation switchgear – Jan2025 – Public

found that the NPV results included in the asset class strategy document did not align with the model, and also that the models were based on all projects commencing in 2026-27.

In-flight projects were largely included in the determination for the current period

293. CitiPower state that the inflight projects were largely included in the AER's determination for the current period as being prudent. We summarise the status of the projects in Table 3.16.

Table 3.16: Status of in-flight switchboard replacement projects

Substation	RIT-D status	2021-26 Determination	Timing considerations	Completion year
Collingwood (CW)	Planned 2025	Not included, newly identified project	Planned to commence in the current RCP Driven by network conversion needs, however it allows for more efficient replacement of B	2026-27
Little Queen (LQ)	Complete	Partly included, to span multiple periods	Commenced Delayed due to dependant projects	2027-28
Collingwood (B)	Planned 2025	Included	Planned to commence in the current RCP Delayed due to cost increase, change of option	2028-29

Source: Asset class overview, BUS 4.09

294. CitiPower provided the RIT-D assessment for LQ which supports completion of the proposed project, however, did not provide detailed project descriptions or models that support the proposed expenditure, options analysis or timing for CW and B.

295. According to CitiPower's 2024 DAPR, the timing of the CW and B switchboard replacement projects is to align with the establishment of new capacity being extra feeders required for the zone substation F offload at CW (in connection with the conversion project), and the third transformer in B in 2029. Specifically, the CW project is driven by network conversion needs, and for that reason would normally be considered as an augex project.

296. Based on our reading of the asset class strategy, we consider that plans to reduce the population of non-arc fault contained switchboards with oil filled old circuit breakers of the type targeted by CitiPower is consistent with industry practice. Also, based on CitiPower's representation of the rationale for progressing CW prior to B, is that it provides a more efficient option to addressing the risks in the load area serviced by B and CW substations, as the replacement of B had previously been identified as prudent.

297. In our assessment of the transformer repex, we noted that CitiPower had identified overlaps with its proposed augex projects at Collingwood (B) and Collingwood (CW), subsequently removing these projects from the transformer repex forecast. However, the switchboard projects have been retained as repex. We are not aware of the reasons for this decision. We review the related augex in section 4 of this report.

298. We note that both the CW and B projects will be subject to RIT-D assessments.

CitiPower has relied solely on its economic analysis for its proposed switchboard replacement program

299. We asked CitiPower for any major changes to the management of its substation switchgear assets over the last 10 years (if any). CitiPower 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)'[58]

300. We also requested copies of condition reports. CitiPower stated that for zone substation assets, whilst its program considers condition, it is not driven by condition, as was the case for substation transformers.[59]

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

Asset risk methodology applied for its replacement projects appears reasonable

302. Given the proposed increase in substation switchboard repex, we asked Powercor and CitiPower 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 a response provided by Powercor, reference was made to CitiPower substations as:

'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.'[60]

303. We consider that the evolution of the asset risk methodology outlined in the collective responses by Powercor and CitiPower is reasonable.

CitiPower has considered a range of options focussed on addressing the identified substation level risk

304. CitiPower states that it considers the failure of circuit breakers and the impact on the broader network at a substation level, taking account of the following factors in its risk evaluation method:[61]

- The probability of circuit breaker failure (based on historical asset failure data to determine the probability of failure)
- Joint and conditional probability based on similarity of circuit breaker at the zone substation
- Available redundancy and load transfer capability at the zone substation
- Zone substation load forecast, including the energy facilitated by the network
- The number of transformers off-line in the event of a circuit breaker failure
- The length of the outage caused by the circuit breaker failure, and
- Increased station risk until the circuit breaker is replaced or repaired.

305. In Figure 3.16, we show the credible options that CitiPower has considered for its switchboard intervention.

58 CitiPower response to IR007 question 2

59 CitiPower response to IR007 question 2

60 CitiPower response to IR005 question 2

61 CitiPower Asset class overview – zone substation switchgear, page 9

Figure 3.16: Credible zone substation switchboard intervention options identified by CitiPower

OPTION	DESCRIPTION
Do-nothing different	No change to existing practices and no planned replacement
Online monitoring	Install online monitoring on the circuit breaker or switchboard
Revised maintenance program	This option updates our maintenance practice and timing on each circuit breaker or switchboard bus
Simultaneous replacement of circuit breakers or switchboard and relays	Replace the circuit breakers or entire switchboard and relays simultaneously
Separate replacement of circuit breakers or switchboard and relays	Replace the relays first (because new circuit breakers can only interface with modern digital relays), followed by the replacement of the circuit breakers or switchboard (noting this will entail some re-work on the relays)

Source: CitiPower Asset class overview – zone substation switchgear, Table 4

306. CitiPower's asset management plan refers to a plan to replace oil-filled 11kV circuit breakers with vacuum type or suitably insulated breakers in line with current industry practice,[62] which we have understood has been replaced by the decision to identify and mitigate risks at a substation level. We typically see evaluation of targeted replacement of circuit breakers alongside staged and full substation rebuild options in the economic analysis. These options were not included in its economic analysis. Consideration of other technically feasible options, such as targeted replacement of circuit breakers, would have provided greater confidence in CitiPower's preferred option.

307. On this basis, we therefore considered CitiPower's preferred option for addressing the identified risks at a substation level:

> *'Our risk evaluation method assesses risk at the zone substation level instead of the individual circuit breaker. Assessing risks at zone substation level recognises the unique characteristic of circuit breakers and their impact on the network and customers.'*[63]

308. Many of the switchboards targeted for replacement include J18 and J22 oil-filled circuit breakers and are within a bulk oil non-arc fault contained switchboard design. It is common that these designs form part of a replacement program. In addition, CitiPower states that these sites are experiencing accelerated deterioration with presence of partial discharge indicating breakdown of the insulation. We acknowledge that the source of failure and therefore risk extends beyond the individual circuit breaker assets to the insulation of the switchboard, connections and secondary equipment – most of which are not addressed through the replacement of individual circuit breakers. However, as stated above, this is typically a consideration of the options analysis to determine the most effective solution based on the condition of the switchboard, from both technical (inclusive of safety and reliability) and economic (inclusive of cost and timing) risk dimensions.

309. CitiPower also considered and rejected, as non-credible, options for the replacement of one bus of the switchboard and refurbishment options. Based on the arguments presented by CitiPower, this decision is formed on a reasonable basis.

62 CitiPower – IR007 – Q2(a) – AMP – zone substation circuit breakers

63 CitiPower Asset class overview – zone substation switchgear, page 9

CitiPower considers a range of sources of risk

310. Switchboard replacements are modelled as a collective arrangement of multiple busses and are modelled using an approach[64] applicable to systems with designed redundancy.

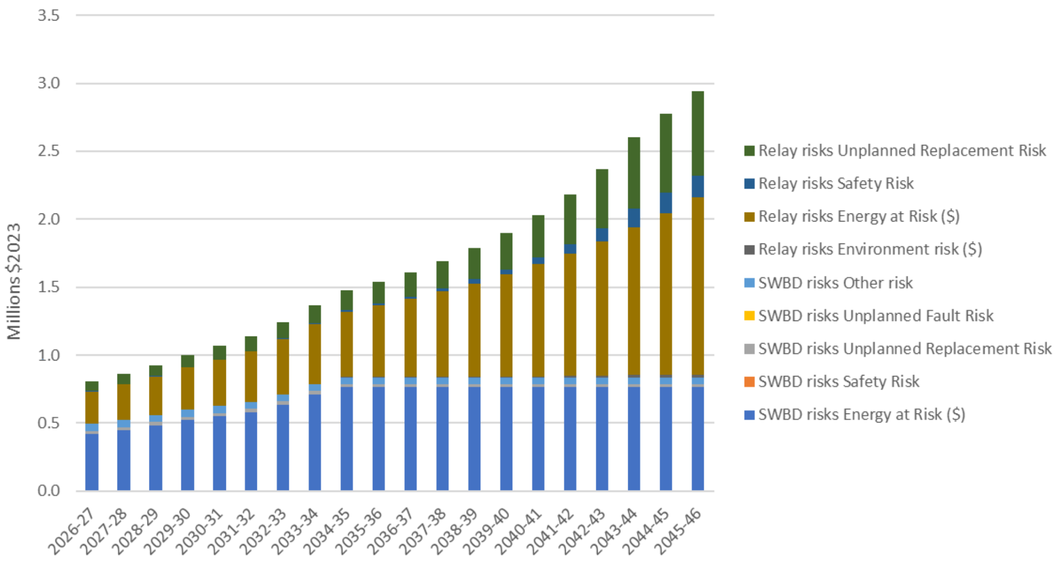
311. CitiPower has identified risks from the following sources in its models:

- Switchboard risks – a combination of energy at risk, safety risk, unplanned replacement risk, unplanned fault risk and other risks; the associated risk costs are developed from its parallel risk model, and
- Relay risks – a combination of energy at risk, environmental risk, safety risk and unplanned risks; the risks are stated as being derived from its relay risk model, however the model provided to us is limited to the proposed projects and does not include the risks associated with the switchboard projects.

312. As an indoor switchboard, risks associated with control cables and insulators present for Powercor substation sites are not similarly present for CitiPower.

313. The largest source of risk is associated with the estimated energy at risk. A sample of CitiPower's risk cost stack for the VM switchboard project is provided in Figure 3.17. The estimated unserved energy risk contributed by relays at this site exceeds the unserved energy risk of the switchboard after 15 years.

Figure 3.17: Example of the risk cost stack for VM switchboard



Source: EMCa analysis of model for MOD 4.05 VM switchboard and relay

314. For VM substation, we could not identify the source of the 'other risk' included at $50k pa. We were also surprised that given the stated operating limitations of the site and partial discharge, that the assessed safety risks were low. We concluded that the key risks that CitiPower has assessed as driving the timing are in fact related to unserved energy and therefore considered how this had been developed more closely.

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

315. We have reviewed the calculation of the energy at risk included in CitiPower's Parallel risk model and consider this is a reasonable estimate. We cannot undertake a similar exercise for the values assumed for the relay risk, however the process should be similar. To calculate the unserved energy, CitiPower multiplies the energy at risk by VCR, which is determined for each site.

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

316. We have not been provided with the customer weightings for calculation of the VCR applied in its unserved energy calculation. The values applied to these projects are shown in Table 3.17.

Table 3.17: Summary of VCR assumed for the proposed switchboard replacement projects

Substation	Location	VCR (2023)
R	URBAN	50.11
AR	URBAN	35.60
RD	URBAN	34.34
NC	URBAN	35.89
VM	CBD	52.31

Source: EMCa derived from switchboard models

317. As indicated in our assessment of the proposed transformer projects, when 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 will be deferred. The multiple of VCR is also applied for the VM switchboard project as it has been for the transformer replacement project.

318. Furthermore, we note that for AR, NC and VM substations CitiPower is proposing transformer and switchboard replacements in the next RCP, and for which a change in assumptions is likely to impact the prudent timing of both projects.

319. For the R switchboard decommissioning project, a further risk is added to the analysis as 'other.' However, CitiPower does not explain the source of this risk, nor has it provided additional supporting information to assist with understanding the condition and/or safety risk at the site. We found similar wording in the 2024 DAPR in support of this project, however this project was not included in the 2023 DAPR.

320. If this risk value was removed, and a change to the VCR applied, the project timing is likely to be deferred beyond the end of the next RCP.

321. We note that CitiPower has also proposed a contingent project for the rebuild of R Zone Substation if the demand exceeds CitiPower's forecast. We have not reviewed this contingent project.

322. However, based on the qualitative descriptions of the switchboard condition and associated risks (viz. non-arc fault contained bulk oil design and metal clad with cast iron body and compound insulation) and also the changes to the safety risk profile of the site, the retirement of the 22kV switchboard in the next RCP is prudent. CitiPower has identified a reasonable low-cost solution.

We have identified several modelling errors

323. We identified some issues with the calculations relied upon by CitiPower in its modelling:

- The calculation of net benefits is based on the 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, which differs from the benefits over 20 years; this will understate the capex, and
- 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 assumes the inputs are in $2026.

324. Assuming that the lower cost estimates provided by CitiPower are accurate, this should lead to an increase in the net benefits, all else being equal.

325. In addition to the modelling errors we describe above, we did not see evidence supporting CitiPower's nominated optimal timing of these replacements. As noted above, the optimal timing is later than proposed due to application of more reasonable inputs. In addition, we observe that the timing of the VM project appears contingent on completion of the project at LQ which has already been delayed. LQ is currently planned for completion in FY28 and given its location, may be subject to further delay.

Cost estimates for substation replacement projects appear high

326. As discussed in our assessment of the cost estimates for the proposed transformer replacement, the cost estimates for the switchboard replacements appear similarly high, for the same reasons.

Findings

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

328. Three of the eight proposed replacement projects are inflight projects, and which were largely included in the AER's determination for the current period as being prudent. These projects remain at varying stages of approval and delivery in the current RCP, with some roll-over of expenditure into the next RCP. The projects align with the timing of projects included in its DAPR, and therefore we have relied on the representations made by CitiPower that these will be materially commenced in the current RCP. To the extent that the information differs from that provided by CitiPower, the finding may change.

329. Due to the high safety risk identified at R substation, we consider that, based on the information provided by CitiPower, it is prudent to include the retirement of the R substation switchboard in the next RCP despite the modelling concerns that we have identified.

330. Our assessment for the remaining four projects to be commenced in the next RCP has focussed on the economic analysis that has been provided, accepting that CitiPower has adopted an asset management approach to identify and mitigate risks at a substation level. We found several modelling issues, which were likely to overstate the benefits of the proposed projects. We found that adjustment for more reasonable input assumptions is likely to lead to deferral of some of the proposed replacement expenditure beyond the next RCP.

331. The switchboard replacement program includes a material increase in expenditure compared with the historical average and relies on large expenditure currently estimated to be incurred in the final two years of the current RCP. The deferral of the identified in-flight switchboard replacement projects in the current RCP raises concerns that ongoing delays may impact the timing of the individual projects and deliverability of the proposed program, or that CitiPower may identify additional methods to defer the identified work. We have not taken this into account at the individual project level. However, this may impact the overall deliverability of the capex program, when considered against all other projects and programs that CitiPower has proposed.

3.3.5 SCADA, protection and control

What CitiPower has proposed

332. The scope for our assessment for the SCADA, protection and control asset group is shown in Table 3.18, which excludes some related repex.

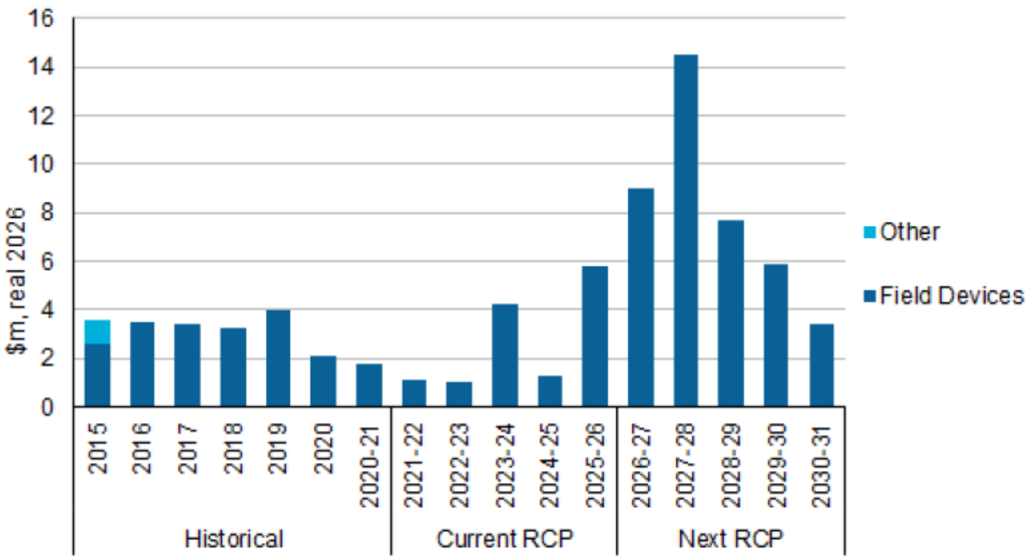
Table 3.18: EMCa scope of CitiPower's proposed SCADA, protection and control replacement - $m, real FY2026

SCADA, protection & control	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Relay replacements	3.3	5.9	0.0	0.0	0.0	**9.2**
Secondary defects, batteries and chargers	0.7	0.7	0.7	0.7	0.7	**3.6**
Total	**4.0**	**6.6**	**0.7**	**0.7**	**0.7**	**12.8**

Source: EMCa table derived from CitiPower SCS capex model

333. In Figure 3.18 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 3.18: Historical and forecast SCADA, network control and protection repex, $m FY2026



Source: EMCa derived from RIN

Assessment

CitiPower has forecast an increase in defect and failure of its protection fleet

334. CitiPower states that based on its assessment of condition of its asset population, it expects the defects and failures being experienced to increase over time.

335. The challenges listed by CitiPower include the age profile of the protection fleet:

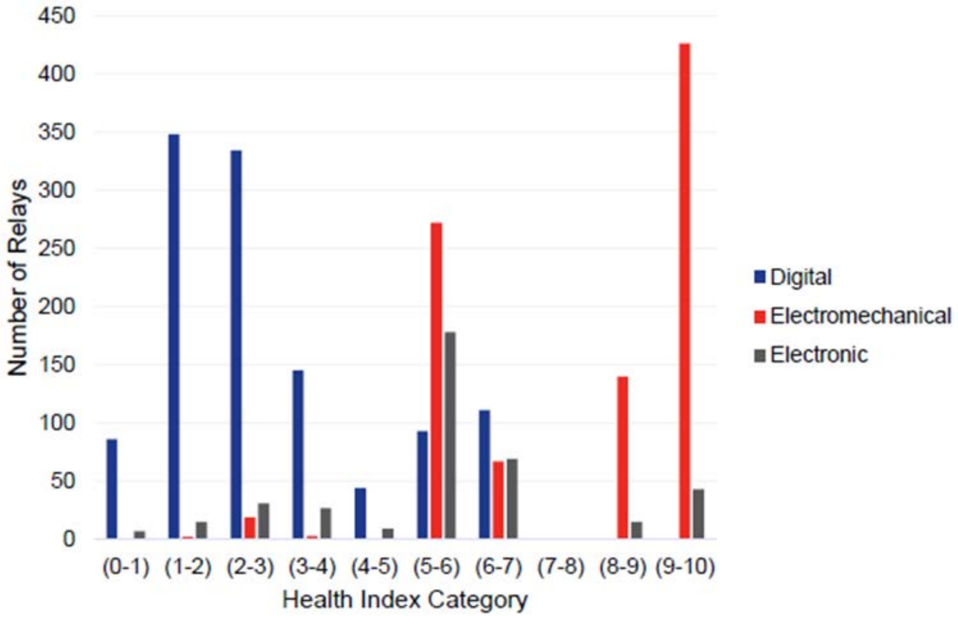
> *'The age profile of CitiPower and Powercor's protection devices indicates that there is a large volume of relays, especially electromechanical and electronic relays, that will likely require replacement over the next ten years. This will require additional specialist resources for protection design, replacement and for testing and commissioning.'*[65]

336. CitiPower has determined that 33% of relays will be in a critical condition in 2026, increasing to 51% by 2031. CitiPower takes account of the underlying condition of its fleet of relays using CBRM, which we consider as part of its proposed planned replacement program.

337. The results of its CBRM are shown in Figure 3.19.

65 CP BUS 4.10 - Protection and control - Jan2025 - Public

Figure 3.19: Current HI for relay population



Source: AMP – protection and control, Figure 7 provided with IR007

338. The HI results indicate a large population of relays, predominantly electromechanical type, already identified at the top end of the CBRM range.

Unplanned replacement program is reasonable

339. Described in the asset class strategy as Unplanned interventions, and listed in the capex model as Secondary defects, batteries and chargers, CitiPower 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.'*[66]

340. 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 failures are increasing over the last five years

Planned relay replacements is limited to two projects

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

342. CitiPower'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 6 per cent of the relay population in the next regulatory period, the risk by 2031 is reduced by approximately 25 per cent (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.'*[67]

66 CP BUS 4.10 - Protection and control - Jan2025 - Public, page 9

67 CP BUS 4.10 - Protection and control - Jan2025 - Public, page 2

343. In the asset class strategy, CitiPower has included relay replacement at two substations, being Balaclava (BC) for completion inf FY27 and Fishermans Bend (FB) for completion in FY28.

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

Risk-based assessment derived from CBRM

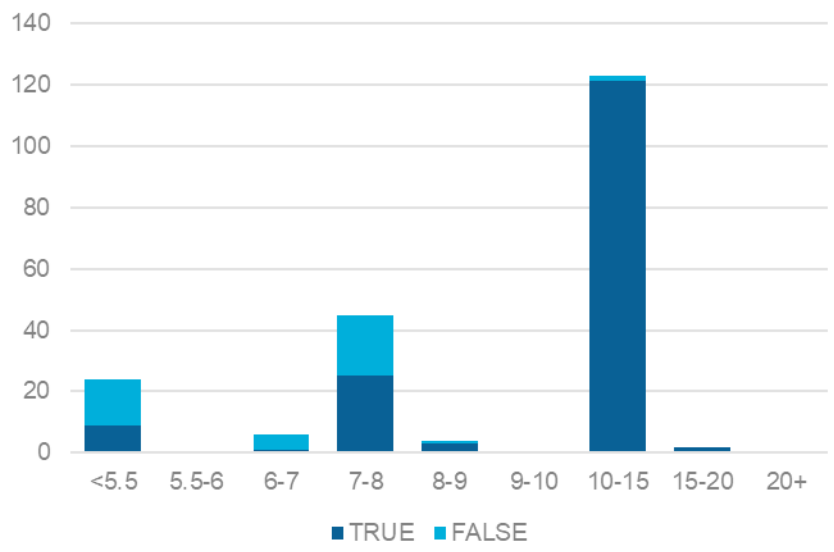
345. Assessment of the proposed relay replacements is derived using CBRM from 2021. As a result, most of the current period projects incorporated the Health Index (HI) component. Moving to CBRM has integrated monetised risk assessments.

346. On review of the included model, the high-priority relays identified for replacement using CBRM are indicated by a manual flag. 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.

347. We observe a reasonable level of correlation between HI and relays selected by replacement. 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 3.20, with the largest population of relays in the HI range of 10-15, and a proportion of these not targeted for replacement. Similarly, there is a proportion of relays identified with a low (healthy) HI that is targeted for replacement.

348. There may be valid reasons for these decisions, however CitiPower does not explain the relationship between HI values and replacement decisions in the proposed projects. In the main, relays with a high HI are targeted.

Figure 3.20: Comparison of current and future protection relay HI values



Source: EMCa analysis of CP MOD 4.11 - relay replacement - Jan2025 - Public

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

349. The derivation of risk costs is hard-coded and therefore is not able to be reviewed by us. We observe that the largest risk cost was associated with network performance and 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 suspect that this program will be similarly impacted.

350. The assessment period for the capex and benefits is not aligned in the NPV analysis, leading to the capex being understated. Once corrected, the NPV is reduced. However, for

the projects proposed by CitiPower, the benefits are sufficiently positive that changes to the input assumptions are unlikely to change the results.

Findings

351. We consider that the proposed SCADA, network control and protection repex is reasonable.

352. We have some concerns relating to the justification for the risk costs that CitiPower has assumed in its analysis, however on balance, we consider that the targeted nature of the planned program to two substation sites is reasonable.

3.3.6 Other repex

What CitiPower has proposed

353. The scope for our assessment for the other repex asset group in Table 3.19.

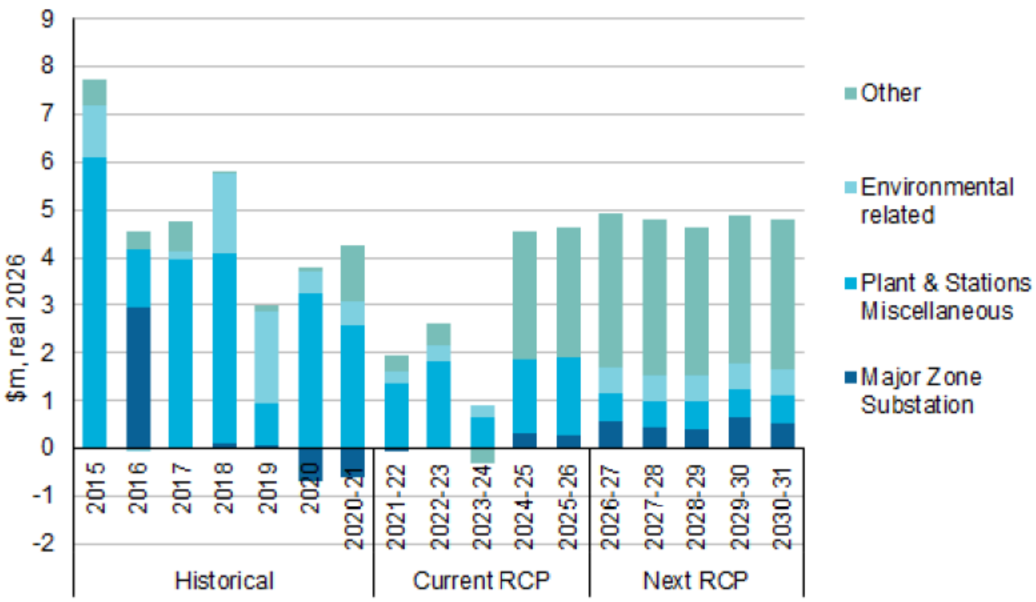
Table 3.19: EMCa scope of CitiPower's proposed other replacement - $m, real FY2026

Other	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Miscellaneous plant and station	0.6	0.7	0.7	0.7	0.7	3.5

Source: EMCa table derived from CitiPower SCS capex model

354. In Figure 3.21 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 3.21: CitiPower's proposed other repex - $m FY2026



Source: EMCA derived from RIN

355. 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

356. As outlined in its response to our questions relating to its proposed substation transformer repex, CitiPower 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'[68]

357. Whilst we acknowledge the need for unplanned and reactive works in zone substations, including on the assets included in CitiPower's response, we consider that this response is unsatisfactory. As stated in section 2, we consider that CitiPower 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 the forecast. However, we were not provided such evidence from CitiPower.

Findings

358. 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 CitiPower 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

359. CitiPower has proposed a repex forecast that is 129% above the repex included in the capex allowance for the current RCP and 79% above the repex that it expects to incur in the current RCP. CitiPower refers to increasing defects and unit costs as the key drivers for this proposed increase.

360. We have been asked by the AER to consider approximately 56% of the proposed repex by CitiPower 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 CitiPower's capex model for our review. Our findings relate to the projects and programs included in our review.

361. The information provided initially by CitiPower 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 CitiPower 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.

[68] CitiPower response to IR015 Question 15

Distribution lines-related programs

362. The models for its distribution lines related expenditure were largely based on the historical trends in defects, and not economic analysis as required under the AER guidance. For poles, CitiPower referred to a decay model as the basis of its forecast intervention volume. For crossarms, the volumes were based on projecting forward the current find rate of defects.

363. We did not find evidence of compelling analysis of alternate replacement volumes or options that demonstrated that CitiPower's forecast is prudent and efficient. We consider that evidence of robust analysis of this nature is critical considering the uplift in expenditure that CitiPower has proposed. Instead, we found a lack of, or deficiencies in, that analysis that CitiPower had relied on, and which leads to our finding that CitiPower's proposed repex for its distribution lines-related program is overstated.

Unit rates

364. The increase in CitiPower's repex program is driven by increases in replacement volumes and unit rates. CitiPower 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 CitiPower 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.

365. In comparing costs with other DNSPs, we found examples where the cost was similar to costs of a DNSP including for the CBD region, however in other cases the costs were materially higher. CitiPower did not explain the basis of its costs, and we consider there are examples where the unit rates that CitiPower has assumed are not reflective of efficient costs.

Substation-related expenditure

366. CitiPower 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 be based on hard-coded values which limited our ability to understand the methods that CitiPower had applied to derive this value in some cases.

367. CitiPower's recent development of its risk quantification framework meant that it has placed greater emphasis on its economic models, and we reviewed these in some detail. We found issues with the modelling methods and input assumptions that CitiPower 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.

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

369. We found evidence that some of CitiPower'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.

3.4.2 Implications for proposed capex allowance

370. We have been asked to review projects with aggregate proposed capex of $198 million. These projects comprise part of CitiPower's aggregate proposed repex of $354 million. In summary we find that:

- For the two projects that we were asked to review under the category of SCADA, protection and control, we consider CitiPower's proposed capex is reasonable.
- For each of the other five categories of expenditure that we were asked to review, we consider that CitiPower's proposed capex is not a reasonable forecast of its prudent and efficient expenditure requirements for the next RCP.

Alternative forecast methodology

371. Our proposed alternative forecast for these categories involves one or more of the following adjustments, to the extent that it formed the basis of CitiPower'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

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

373. 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)

CitiPower has proposed a material uplift in augex activity relative to the augex that it expects to incur in the current regulatory period and which is well under the regulatory allowance for this period. The uplift includes the introduction of programs in response to CitiPower's assessment of electrification/CER-related drivers.

The AER has asked us to assess a subset of CitiPower's proposed $215 million augmentation capex for the next RCP - specifically three demand-driven projects and two non-demand driven projects, which together account for approximately 80% of CitiPower's proposed augex.

We consider that CitiPower's proposed augex of $173 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 lead to an overstatement of the economic benefits.

We consider that a reasonable alternative forecast for the projects within the demand and non-demand augex categories that we reviewed, would be between 40% and 50% less than CitiPower has proposed.

4.1 Introduction

374. We have been asked by the AER to assess five of the twelve augmentation projects/programs that CitiPower submitted in its Proposal for the next RCP.

375. We reviewed the information provided by CitiPower to support each of the five projects and programs and as necessary asked clarifying questions, both in writing and at a face-to-face meeting with CitiPower representatives. We sought to confirm the need, quantum, and optimal timing of each project that we were asked to review.

376. In the sections that follow, we identify the projects we have been asked to review from CitiPower's full list, and then we present our assessment of the individual projects.

4.2 What CitiPower has proposed

4.2.1 Proposed augex

377. CitiPower has proposed $215.0 million capital expenditure in the next RCP, as listed in Table 4.1.

Table 4.1: CitiPower's proposed augex by driver - $m, real FY2026

Augex by driver	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Demand						
Brunswick modernisation program	27.6	20.0	0.0	6.3	6.3	**60.3**
Customer-driven electrification	3.7	4.9	9.5	10.7	12.1	**40.9**
Fisherman's Bend modernisation	0.0	2.6	2.6	0.0	0.0	**5.1**
HV feeder program	2.7	3.4	1.3	1.7	0.1	**9.2**
ZSS capacity upgrades	14.5	14.6	0.0	0.0	0.0	**29.1**
subtotal	**48.5**	**45.5**	**13.4**	**18.7**	**18.6**	**144.6**
Non-demand						
Asset relocations	4.7	4.7	4.7	4.7	4.7	**23.5**
CBD security of supply	9.0	10.6	0.0	0.0	0.0	**19.7**
Operational technology	1.1	1.1	1.1	1.1	1.1	**5.5**
System security	4.4	1.7	2.9	2.9	2.3	**14.2**
Communications	0.7	1.1	1.4	0.7	0.3	**4.1**
Metering	0.2	0.2	0.2	0.2	0.2	**0.9**
Network innovation	0.6	0.6	0.4	0.4	0.4	**2.4**
subtotal	**20.7**	**20.0**	**10.6**	**10.0**	**9.0**	**70.4**
Total	**69.3**	**65.5**	**24.0**	**28.6**	**27.6**	**215.0**

Source: EMCa table derived from CitiPower SCS capex model

378. We show a comparison between CitiPower's proposed augex in the next RCP compared with current and historical augex in Figure 4.1. CitiPower expects to underspend its regulatory allowance of $166 million by $58 million (-35%).[69] CitiPower attributes the underspend to:[70]

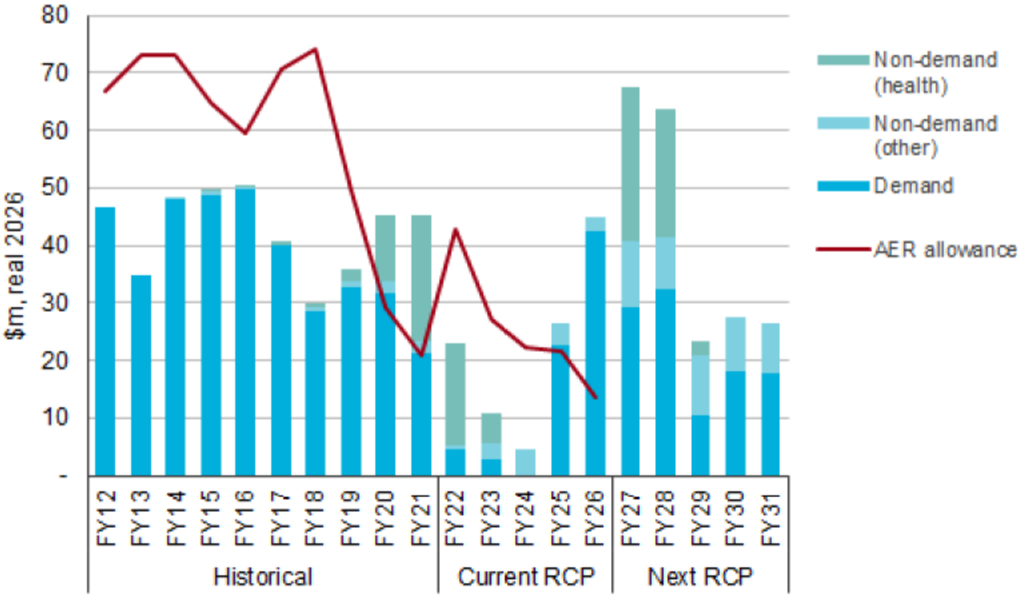
- The impact of COVID-19, delaying CitiPower's Brunswick supply area modernisation program, and its Tavistock Place supply upgrade
- More efficient management of customer energy resources driven by the stronger than expected performance of its DVMS and other low-cost interventions, and
- Lower than expected costs for the Russell Place supply offload due to the limited extent of required structural works.

379. The forecast expenditure shows a sharp rebound from the relatively low spend in the current RCP with the combined impact of significant uplifts in non-demand and demand-driven projects (including the revised Brunswick modernisation project and customer-driven electrification program).

69 CP RIN 11 - Expenditure transparency - Jan2025 – Public, Table1

70 CP RIN 11 - Expenditure transparency - Jan2025 – Public, page 2

Figure 4.1: CitiPower proposed compared with current and historical augex - $m, real 2026



Source: EMCa derived from CitiPower response to IR#008

4.2.2 EMCa's Scope of Augex Review

380. The AER has asked us to assess the projects listed in Table 4.2, which at $173.4 million in total represents 81% of the proposed total augex for the next RCP. We provide our assessment of each project in the subsequent sections.

Table 4.2: CitiPower proposed augex within EMCa's scope - $m, real FY2026

Augex within EMCa scope	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Demand						
Brunswick modernisation program	27.6	20.0	0.0	6.3	6.3	**60.3**
Customer-driven electrification[71]	3.7	4.9	9.5	10.7	12.1	**40.9**
ZSS capacity upgrades	14.5	14.6	0.0	0.0	0.0	**29.1**
subtotal	**45.8**	**39.5**	**9.5**	**17.0**	**18.4**	**130.3**
Non-demand						
Asset relocations	4.7	4.7	4.7	4.7	4.7	**23.5**
CBD security of supply	9.0	10.6	0.0	0.0	0.0	**19.7**
subtotal	**13.7**	**15.3**	**4.7**	**4.7**	**4.7**	**43.2**
Total	**59.5**	**54.8**	**14.2**	**21.7**	**23.2**	**173.4**

Source: EMCa table derived from CitiPower SCS capex model

4.3 Assessment of demand driven augex

4.3.1 What CitiPower has proposed

381. Table 4.3 shows two of the programs within our scope for demand-driven augex. (We review CitiPower's proposed customer-driven electrification program in section 4.5.)

71 Customer driven electrification is reviewed as an augex CER project, in section 4.6

Table 4.3: EMCa's scope of CitiPower proposed demand augex - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Brunswick modernisation program	27.6	20.0	0.0	6.3	6.3	**60.3**
ZSS capacity upgrades	14.5	14.6	0.0	0.0	0.0	**29.1**
Total	**42.1**	**34.6**	**0.0**	**6.3**	**6.3**	**89.4**

Source: EMCa table derived from CitiPower SCS capex model

Expressions of demand forecast

382. 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 CitiPower's blend of 70% 50PoE and 30% 10PoE used in its CBA models, also referred to as NPV models.

4.3.2 Brunswick modernisation program

What CitiPower has proposed

383. The Brunswick modernisation program comprises three related projects, the first two of which commence in the current RCP, with expenditure continuing into the next RCP:
- Offload load from Fitzroy zone substation (F) to Collingwood zone substation (CW)
- Offload load from Brunswick zone substation (BK) to West Brunswick zone substation (WB), and
- Install a third transformer and associated equipment at CW - in the next RCP

Table 4.4: EMCa scope of CitiPower proposed Brunswick modernisation program - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Brunswick modernisation program	27.6	20.0	0.0	6.3	6.3	**60.3**

Source: EMCa table derived from CitiPower SCS capex model

Assessment

Offloading F and BK to CW and BK is subject to a RIT-D (underway) and was accepted by the AER in its regulatory determination for the current RCP

384. The identified need for modernising the Brunswick supply area is:
- End-of-life assets at BK and F
- Modernising legacy 6.6kV distribution assets at BK and F, and
- Facilitating demand growth in the area.

385. The AER was satisfied in its determination for the current RCP that CitiPower's proposal to decommission F and BK after conversion from 6.6kV to 11kV was the efficient approach to managing end of life assets and network supply constraints (given forecast demand growth).[72] CitiPower subsequently deferred the planned work due to the impacts of the COVID pandemic. Its re-evaluation of the demand forecast, cost estimate, and technical options was included in a RIT-D, published in January 2025. It proposed the same solutions with the timing of the two offload projects to commence in FY25 and conclude in FY27 (offload F to CW) and in FY28 (offload BK to WB).

72 Australian Energy Regulator, CitiPower Distribution determination 2021 to 2026 – Draft decision – Attachment 5 Capital expenditure, 2021, pages 56-57

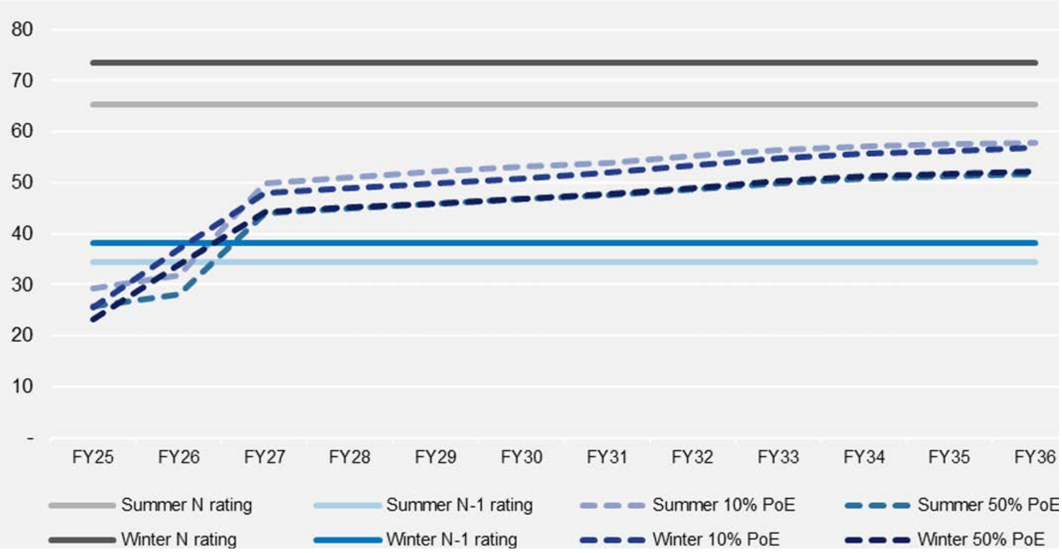
386. Based on the information in the RIT-D, we consider that the two off-load projects remain as the most economic approach to address the three identified drivers. Given that the costs have been subject to a recent update, we are also satisfied that the cost estimates are reasonably based.

Following the load transfers, CW and WB are forecast to be overloaded in the next RCP

387. CitiPower proposes further augmentation to address the cumulative effects of forecast continued demand growth on CW and WB over the course of the next RCP. For example, Figure 4.2 shows that CW is expected to be operating above its N-1 capacity from the summer of FY27 with the sharp increase in demand following load transfer from F.

388. This and a similar issue at WB support the need for CitiPower to consider options to address the increasing energy at risk.

Figure 4.2: CitiPower – demand forecast versus capacity at CW (11kV, MVA)



Source: CP BUS 3.03 – Brunswick modernisation – Jan2025 – Public, Figure 2

CitiPower has selected the prudent option to address overloading of WB and CW post decommissioning of F and BK

389. In addition to 'doing nothing more' over the next RCP to address the forecast overload of WB and CW, CitiPower considered two network and one non-network options:[73]

- 1. Install a third transformer and associated equipment at CW
- 2. Rebuild Brunswick (C) substation with transfers to it from WB and CW, noting that C was decommissioned in 2022, and
- 3. Non-network solution (BESS, SAPS, or demand management).

390. CitiPower determined that the net benefit for Option 3 was materially higher than for Option 2, and the capital cost would be lower. It also formed the view, which we consider to be reasonable, that it is unlikely that a NNS will be economic, given the consistent overload of the N-1 capacity that is forecast from early in the next RCP. We are satisfied that CitiPower has selected the appropriate solution from those considered and aside from the possibility of a demand management solution arising from the market in response to the DAPR or from CitiPower's Demand Side Engagement Strategy,[74] it is likely to be the economic approach.

[73] CP ATT 3.06 – Brunswick modernisation RIT-D draft report – Jan2025 – Public, Table 24

[74] CP ATT 3.05 – Distribution Annual Planning Report – Jan2025 – Public, pages 10-11

The cost estimate for establishing the third CW transformer is not reasonable

391. We consider that the cost of the third CW transformer project is overstated for the following reasons:

- The cost seems very high for installing a third 66/11kV transformer at $12.65 million – no evidence is provided to support the cost estimate in any of the referenced documents
  - there is no cost breakdown in the business case nor explanation of the basis for the derived cost
  - the cost in the CBA model is hard coded with no explanatory notes
  - the cost in the CBA capex models is split equally between FY30 and FY31, which is indicative of a high-level estimate
- The January 2025 RIT-D includes $7.0 million for the third transformer and a combined $57.5 million for the two offload projects in $2024; the latter is costed at $64.0 million ($2026) in the business case, which should mean the third transformer project cost is $7.9 million ($2026) using the same conversion factor, and
- CitiPower's Collingwood third 66/22kV transformer project nominates $8.0 million ($2026).

392. Whilst it is possible that there is supporting work to enable the transformer installation, this was not apparent from the scope presented.

Optimal timing with base case demand assumptions is FY32 but we have issues with the EUE derivation and there is considerable demand uncertainty

393. As shown in Figure 4.3, 2032 is the economic timing for the third transformer (i.e. by the summer of FY32). For planning purposes, it is reasonable to schedule the work to be completed by the end of FY31 to allow for some schedule slippage.

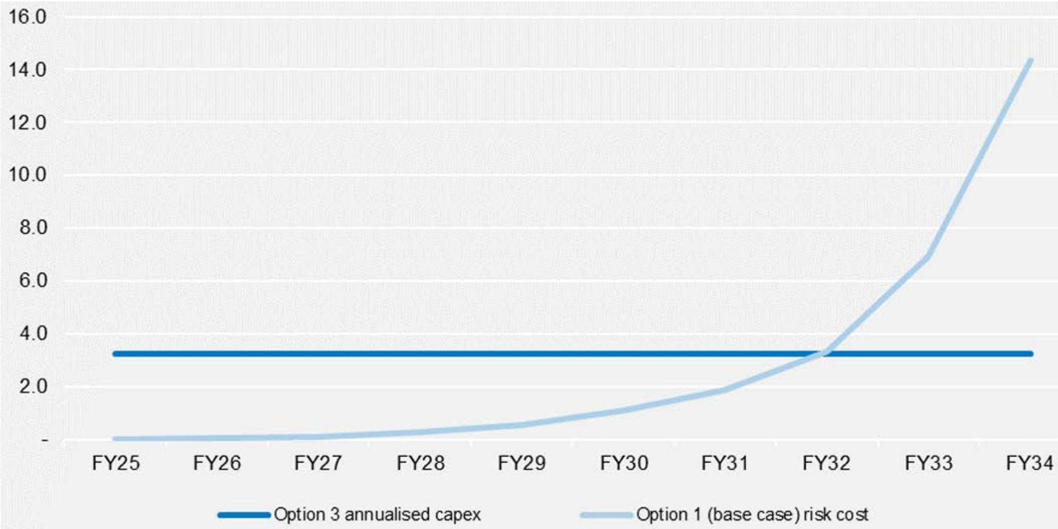
394. The expected unserved energy (EUE) in the CBA model provided was hard-coded, so we asked CitiPower to provide the spreadsheet with the EUE derivation. We have the following concerns with the derivation of the EUE:[75]

- It appears to derive the 10PoE forecast from a 2019 ratio of the 10PoE to the 50PoE, which is not an approach we have seen before and regardless should have been updated
- Zero transfer from CW to contiguous substations is assumed in the base case – which we consider to be an overly conservative assumption
- We were unable to reconcile the hard coded (weighted) energy at risk in the CBA model with the energy at risk derived in the supplementary models – to this end, there appears to be some intermediary step between the two spreadsheets which is not apparent to us, and
- It was not clear what weighting of 50PoE and 10PoE was applied, however we assume from other CitiPower projects that it is 70% 50PoE and 30% 10PoE.

395. Given the significant uncertainty with demand forecasts (particularly for projects where the economic timing is 6-7 years in the future), and in this case, the lack of clarity regarding the EUE calculations, we scrutinised the sensitivity of results to variances in key variables.

75 BrunsMod_Opt2_CW_EaR.xlsx and related spreadsheets

Figure 4.3: CitiPower's derived optimal timing for the 3rd CW transformer



Source: CP BUS 3.03 – Brunswick modernisation – Jan2025 – Public, Figure 5

396. The sensitivity analysis shows that the third transformer at CW remains as the preferred approach based on NPV, however CitiPower's analysis did not vary demand nor was the optimal timing for each sensitivity scenario presented.

397. An informative demand scenario is 100% 50PoE as, by definition, this is the median value each year. Whilst we were not readily able to derive the optimal timing using the 50PoE forecast from the spreadsheet provided, we consider that it is reasonable to assume that the optimal timing would be delayed by one-to two years. When combined with the likelihood of some DTC being available in response to N-1 events, we consider the project could be delayed by at least one year.

Findings

398. We consider that the augex for the proposed Brunswick modernisation project in the next RCP is not adequately justified.

399. The projects scheduled to commence in the current RCP to transfer load from F to CW and BK to BW are the prudent approaches to managing the three identified drivers. The estimated capital cost of $4 million (in the next RCP) to complete the transfers is reasonable.

400. The proposed addition of a third transformer at CW (and subsequent transfers from BW to CW) to manage forecast overloads at CW and BW following the transfers from F and BK is the prudent solution.

401. However, we consider that:

- The estimated cost of $12.7 million capex to install the third transformer at CW is inadequately justified, and
- The apparent absence of accounting for DTC from CW to BW if required for an N-1 event at CW means that the 2032 economic derived by CitiPower may be too early.

402. We also note that if the demand increases more closely aligned to the 50PoE forecast than the weighted demand forecast applied by CitiPower, then this would likely defer the optimal timing.

4.3.3 Zone Substation (ZSS) capacity upgrades

What CitiPower has proposed

403. Two projects are in scope, both of which respond to thermal constraints in the respective supply areas:

- Collingwood zone substation (B) supply area - the proposed solution is to add a third transformer at B by the summer of FY28,[76] and
- Bouverie Queensbury zone substation (BQ) supply area – the proposed solution is to add a third transformer at BQ by the summer of FY28.[77]

404. Table 4.5 shows the proposed annual expenditure over the next RCP.

Table 4.5: EMCa scope of CitiPower proposed ZSS capacity upgrades - $m, real FY2026

Augex within EMCa scope	2026-27	2027-28	2028-29	2029-30	2030-31	Total
ZSS capacity upgrades	14.5	14.6	-	-	-	**29.1**

Source: EMCa table derived from CitiPower SCS capex model

Assessment of the proposed third transformer at Collingwood (B)

The firm capacity at B does not account for distribution load transfer capacity

405. B includes two 20/27MVA 66/11kV transformers supplying mainly residential customers, with the summer firm capacity (N-1) nominated as 29MVA.[78] This appears low, noting that the firm capacity of the nearby two-transformer Collingwood substation (CW) is nominated as 34.4MVA,[79] which is commensurate with the typical cyclic rating of 20/27MVA transformers. It may be the case that the load factor on B is relatively high. We also note that 20/27 MVA transformers may be able to be uprated to a continuous 33MVA rating with the addition of oil pumps, which if technically feasible, provides a relatively inexpensive means of increasing firm capacity.

406. We also note that 6.5 MVA of distribution load transfer capacity (DTC) is available from B (in 2024),[80] but which could reasonably be expected to deteriorate somewhat over time.

407. We would therefore expect the firm capacity of B to be between 35.5MVA and 40.9MVA (or the demand forecast should be adjusted by -6.5MVA) to properly account for DTC and cyclic rating.

408. However, the DAPR states that '*CitiPower has estimated the magnitude and impact of loss of load by considering the energy at risk and the annual hours at risk. These estimates, exclude any planned augmentation or operational response such as load transfers to mitigate the impact of an outage.*'[81]

409. We consider that this results in a conservative estimate of the optimal timing for the proposed augmentation, particularly given there is significant DTC.

410. We do note that contiguous substations to B are also forecast to be loaded beyond their firm capacity in the future:

- The 50PoE maximum demand on Collingwood (CW) is forecast to be operating above its firm capacity from FY26 until a proposed third transformer is installed in FY30[82] (refer to the Brunswick modernisation program in section 4.3.1), and
- The 10PoE maximum demand on North Richmond (NR) is forecast to exceed its firm capacity in FY31.[83]

411. Figure 4.4 from CitiPower's business case shows the maximum demand exceeding the summer and winter N-1 capacity since 2024. If the firm capacity was modelled at 40.9MVA,

[76] CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, Table 1

[77] CP BUS 3.02 – Bouverie Queensberry supply area – Jan2025 – Public, Table 1

[78] CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, page 3

[79] CW has 2 x 20/27MVA transformers per CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, page 4

[80] CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, page 6

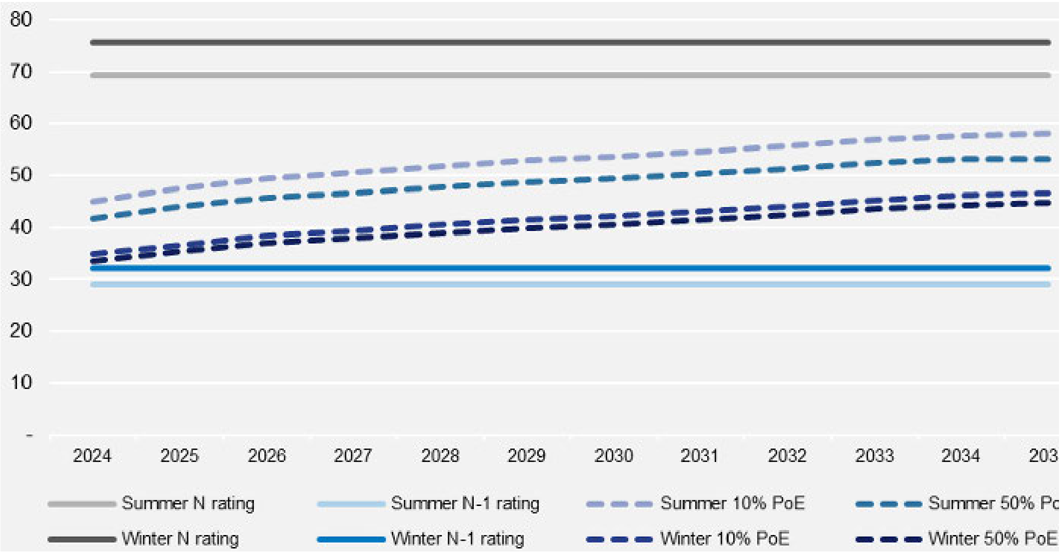
[81] CP ATT 3.05 – Distribution Annual Planning Report – Jan2025 – Public, page 40

[82] CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, Figure 3

[83] CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, Figure 3

this would reduce the energy at risk materially, noting that it takes time to undertake the switching necessary to enact distribution transfer post an N-1 event, so the energy at risk derivation would need to take this into account.

Figure 4.4: CitiPower's maximum demand forecast vs capacity for B



Source: CP BUS 3.05 – Collingwood supply area – Jan2025 – Public, Figure 2

The optimal timing for the preferred solution may be later than FY28

412. CitiPower considered five options:

1. Maintain the status quo.
2. Add a third transformer and associated equipment at B (preferred option)
3. Offload feeders at B to CW
4. Offload feeders at B to NR,[84] and
5. Unspecified non-network solution.

413. Option 1 is discounted by CitiPower as a credible solution because it does not address the energy at risk long term. We consider this to be a reasonable position. Based on the information in the business case regarding Options 3-5, Options 3 and 4 are unlikely to be superior to Option 2, which has the lowest capital cost and highest NPV. Option 5 is unlikely to be economic as a standalone solution, however, a NNS may be able to be used as a deferment strategy for the third transformer at B.

414. CitiPower's derived optimal timing is FY28 (i.e. install the third transformer for the summer of FY28) and it plans the expenditure to be incurred over FY27 and FY28.

415. The provided CBA model did not allow us to understand the derivation of the energy at risk and EUE. In response to our request, CitiPower provided a supplementary energy at risk spreadsheet, but this again included hard-coded numbers with reference to yet other spreadsheets which we did not receive.[85] We are therefore not able to readily quantify the impact of including DTC and a higher cyclic rating (and/or transformer uprating, if it is technically possible) on the optimal timing of the third B transformer.

Sensitivity analysis does not include re-evaluation of the optimal timing

416. CitiPower's CBA model includes five scenarios in which input parameters are varied: capex (±10%), total benefits (±10%), and capex 10% higher and Benefits 10% lower. In our view, the benefit reduction scenario is a reasonable proxy for using 100% 50PoE to test the NPV.

[84] North Richmond ZSS

[85] CitiPower's response to IR014 question 12, which refers to B3rd_Opt2_B_EaR.xlsx; Do Nothing.xlsx

417. The proposed Option 2 remains materially NPV positive even under the fifth, most onerous scenario considered. However, CitiPower does not include revaluation of the optimal timing under the sensitivity scenarios.

418. We note further that if the peak demand tracks more closely to the 50PoE forecast than the weighted demand forecast used in the CBA model, then the energy at risk would be further reduced and deferral to the next RCP becomes a stronger possibility.

Findings

419. The proposed expenditure at Collingwood (B) substation is not adequately justified and we consequently consider it is significantly overstated (as presented).

420. Whilst installation of a third transformer at B is the prudent option to manage forecast overload of B, CitiPower does not appear to account for DTC in its CBA model. If this is the case, accounting for DTC would have the effect of reducing the EUE, reducing the quantified benefit, reducing the NPV and deferring the optimal timing. Furthermore, the cyclic rating used to determine the N-1 capacity of B looks comparatively low.

421. Whilst we were not able to accurately quantify the impacts of these factors on the project optimal timing, we consider that it is more likely than not, that the third transformer could be prudently delayed to the following RCP.

422. We also note that the RIT-D assessment process may identify a NNS that CitiPower can economically apply to defer the requirement for the third transformer to the following RCP.

Assessment of the proposed third transformer at BQ

The key augmentation driver is overload of VM

423. Victoria Market zone substation (VM) comprises three 20/27MVA 66/11kV transformers. In the DAPR, it is stated that the VM switchboard is at the end of its technical life and is due to be retired in 2028. By this time, CitiPower advises that the entire zone substation load of 66.5 MVA will be at risk for 100% of the year.[86] There is no mention of the switchboard in the business case.[87] We have based our assessment primarily on information in the business case.

424. As shown in Figure 4.5, the N-1 capacity of 57.9MVA (summer) for VM is forecast to be exceeded in the summer of FY26 or FY27. The 57.9MVA rating is 3.9MVA above the combined nameplate rating of two of the three transformers, which indicates a relatively modest cyclic rating has been applied. This may be due to a relatively high loading factor for the substation but it is not adequately explained. Based on the cyclic rating of 34.4MVA for the B transformers discussed above, we would expect the firm capacity to be 68.8MVA plus an allowance for DTC.

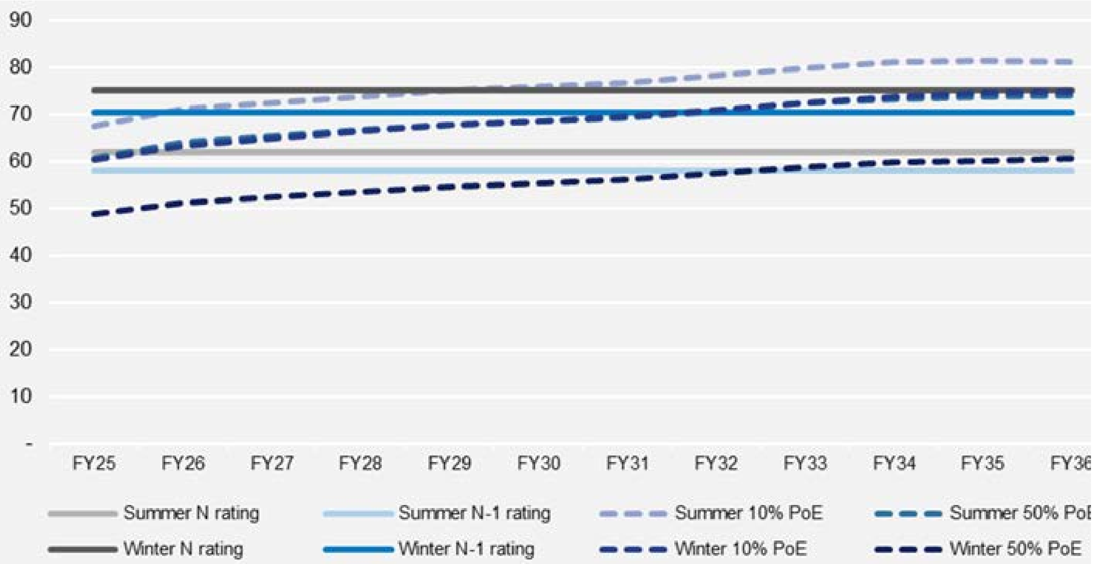
425. As discussed above, CitiPower does not include DTC in its derivation of the magnitude and impact of loss of load. We consider that this results in a conservative estimate of the optimal timing for replacement, particularly when there is significant DTC.

426. BQ is contiguous to VM and comprises two 55MVA 66/11 transformers with an N-1 capacity of 64.9MVA (summer) which is expected to be exceeded from FY25 onwards. By contrast with VM, the firm capacity for BQ does appear to be based on the cyclic rating.

[86] CP ATT 3.05 – Distribution Annual Planning Report – Jan2025 – Public, pages 76-77

[87] CP BUS 3.02 – Bouverie Queensberry supply area – Jan2025 – Public

Figure 4.5: CitiPower's maximum demand forecast vs capacity for VM



Source: CP BUS 3.02 – Bouverie Queensberry – Jan2025 – Public, Figure 3

The optimal timing for the preferred solution may be prudently deferred

427. To manage the risk of unserved energy due to the overloading of VM and BQ, CitiPower considered five options:

1. Maintain the status quo
2. Install a third transformer at BQ and offload VM to BQ
3. Rebuild Lauren Street zone substation (LS) to supply the Arden precinct
4. Rebuild LS and offload BQ and VM to LS, and
5. Non-network solution.

428. It selected Option 2 because it has the lowest cost and highest NPV of the options considered. We consider that based on the information provided in the business case Option 2 is the prudent option and we turned our attention to the optimal timing of the work.

429. CitiPower's derived optimal timing is FY28 and plans the expenditure of $20.2 million to be incurred equally over FY27 and FY28.

430. The two factors discussed above lead us to conclude that the BQ third transformer mat be able to be deferred, even to the following RCP:

- From the DAPR, there appears to be considerable DTC available to respond to N-1 events, and
- Approximately 10 MVA appears to be unaccounted for in the firm capacity from transformer cyclic rating.

431. However, we were not able to use CitiPower's provided CBA model[88] to derive an alternative optimal timing because of the hard-coded energy at risk values in the spreadsheet.

Sensitivity analysis does not include re-evaluation of the optimal timing

432. CitiPower's CBA model includes five scenarios in which input parameters are varied: capex (±10%), total benefits (±10%), and capex 10% higher with benefits 10% lower. In our view, the benefit reduction scenario is a reasonable proxy for using 100% 50PoE to test the NPV.

88 CP MOD 3.04 - Bouverie Queensberry supply area - Jan2025 - Public

433. The proposed Option 2 remains NPV positive even under the fifth, most onerous scenario considered. However, CitiPower does not include revaluation of the optimal timing under the sensitivity scenarios.

434. We note further that if the peak demand tracks more closely to the 50PoE demand forecast than the weighted demand forecast used in the CBA model, then the energy at risk would be further reduced and deferral to the next RCP becomes a stronger possibility.

Findings

435. The proposed expenditure at Bouverie Queensberry (BQ) substation is not adequately justified and we consequently consider it is significantly overstated (as presented).

436. Whilst installation of a third transformer at BQ is the prudent option to manage forecast overload of VM and BQ, CitiPower does not appear to account for DTC in its CBA model. If this is the case, including it would have the effect of reducing the EUE, reducing the quantified benefit, reducing the NPV and pushing out the optimal timing. Furthermore, the cyclic rating used to determine the N-1 capacity of VM looks comparatively low.

437. Whilst we were not able to accurately quantify the impacts of these factors on the project optimal timing, we consider that it is more likely than not, that the third transformer could be prudently delayed to the following RCP.

438. We also note that the RIT-D assessment process may identify a NNS that CitiPower can economically apply to defer the requirement for the third transformer to the following RCP.

4.4 Our assessment of Non-Demand augex

4.4.1 What CitiPower has proposed

439. Table 4.6 shows the two programs within our scope for non-demand augex.

Table 4.6: EMCa's scope of CitiPower proposed non-demand augex - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Asset relocations	4.7	4.7	4.7	4.7	4.7	23.5
CBD security of supply	9.0	10.6	0.0	0.0	0.0	19.7
Total	**13.7**	**15.3**	**4.7**	**4.7**	**4.7**	**43.2**

Source: EMCa table derived from CitiPower SCS capex model

4.4.2 Asset relocations

What CitiPower has proposed

440. CitiPower proposes $23.5 million to relocate its assets installed on Yarra Trams poles in response to an estimated 130 pole relocations p.a. initiated by Yarra Trams as shown in Table 4.6.

Assessment

CitiPower submitted an opex step change for pole relocations in the current RCP in its 2021-206 Regulatory Proposal

441. In its Proposal for the current RCP, CitiPower included an adjusted $12.7 million ($2020-21) opex step change to account for its expected volume of relocation of its assets mounted on to-be-relocated Yarra Trams poles. The AER did not include the proposed opex step change in its Draft Decision. In its Revised Proposal, CitiPower submitted $4.9 million opex ($2020-21):

'CitiPower's revised proposal is $9.6 million ($2020–21) lower than its original proposal, following updates to the number of forecast poles that Yarra Trams plan to relocate over the 2021–26 regulatory control period, as well as the blended cost estimated for the relocation of each pole-top asset.'[89]

442. The AER subsequently approved non-recurrent opex of $4.3 million ($2020-21) in its Final Decision after making an adjustment to the assumed blended cost, having been satisfied that CitiPower is required to cover the costs to remove and relocate any assets on the poles that Yarra Trams relocates/replaces.

For the next RCP, CitiPower provided three options in its business case

443. CitiPower's three options were to (1) not relocate the assets, (2) maintain the existing approach, and (3) install new poles or move assets underground. We are satisfied that Option 2 is the prudent choice and that, as with the current RCP, there is no recourse for CitiPower to recover its costs from Yarra Trams.

CitiPower's proposed expenditure for the next RCP is based on historical volumes and costs

444. In its CBA model,[90] CitiPower provided the 2021 – 2023 actual number of poles that were relocated by Yarra Trams and for which it needed to take corrective action, and a forecast for 2024. It averaged the number of poles to arrive at a forecast of 130 poles p.a. for the five years of the next RCP, noting that its 2024 estimate was 166 poles.

445. Similarly, CitiPower used an average of the actual and forecast expenditure to arrive at an average unit cost of $30,553 ($2024), leading to an annual average expenditure of $4.0 million ($2024).

446. The business case includes the actual 2024 volume (160), a different number of poles (113) for 2023 than included in its model, and a revised annual average expenditure for the next RCP of $3.9 million ($2026).[91]

447. CitiPower explains that the cost varies substantially at the individual pole relocation level because of differences in the solutions required. It states that '*[w]e typically scope, design and plan groups of co-located works to ensure that the most efficient solution is chosen for each set of relocations.'* This is a reasonable approach.

448. Whilst in isolation CitiPower's described forecasting methodology is reasonable, CitiPower provides no explanation of:

- Its forecast for the next RCP being for capex rather than non-recurrent opex, with:
  - no apparent adjustment to its recurrent opex to offset the proposed 're-categorisation' as capex, and
  - without justification for the change in categorisation; nor
- Why it has not relied upon, or at least taken into account, Yarra Trams' forecast pole relocation volumes and locations.[92]

449. These matters should be fully explained by CitiPower.

Findings

450. We consider that the proposed augex for asset relocations is not adequately justified and is materially overstated.

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89 AER - Final decision - CitiPower distribution determination 2021–26 - Attachment 6 - Operating expenditure, pages 6-36 to 6-37

90 CP MOD 3.10 - Yarra Trams pole relocation - Jan2025 - Public

91 We note that the 2023 actual volume in the business case is 113 poles but in the CBA model it is given as 154 poles. The anomaly is not explained but has only a small impact on the forecast average annual expenditure.

92 As part of its Revised 2021-26 Proposal, CitiPower submitted a letter from Yarra Trams that, among other things, provided project volumes and locations of its expected pole relocations from FY21 to FY27, CitiPower Revised Regulatory Proposal – 2021-26 – ATT53 – Yarra Trams CitiPower letter 20 December 2020

451. Whilst CitiPower has selected the prudent option, that is to continue its current approach to managing its assets on relocated Yarra Trams poles, it has not provided sufficient information to support its forecast expenditure nor its categorisation as capex instead of opex. If it is to be classified as opex, an adjustment to its base year opex would be required.

4.4.3 CBD security of supply

What CitiPower has proposed

452. CitiPower propose constructing three new 'jumbo' feeders from Montague zone substation (MG) to Little Bourke Street zone substation (JA) at a cost of $19.7 million, as shown in Table 4.6. Rebuilding the decommissioned Spencer Street zone substation (J) is submitted as a Contingent Project, at an estimated capital cost of $70.9 million,[93] which is not included in its proposed augex.

453. The driver of the project is a forecast breach of the 'N-1 Secure' planning criterion.

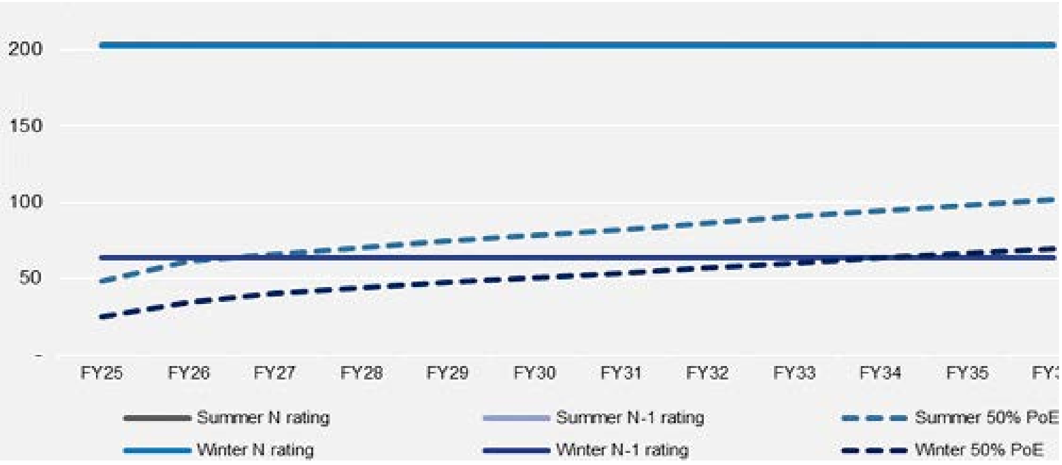
Assessment

The N-1 Secure planning criterion is forecast to be breached in FY27 triggering the need to act

454. Under the EDCoP, CitiPower is required to ensure the Melbourne CBD operates within the 'N-1 Secure' planning criterion, which requires it to maintain supply after the loss of two 66kV cable elements with an allowance of 30 minutes for switching after loss of the first element.[94] Therefore, CitiPower is subject to a deterministic planning criterion (i.e. probabilistic planning criteria do not apply in this case).

455. JA substation is expected to be overloaded under the N-1 Secure Criterion if peak demand increases according to the summer 50PoE forecast, as shown in Figure 4.6. JA comprises of 3 x 66/11kV 55MVA transformers.

Figure 4.6: Maximum demand forecast at JA under the N-1 Secure scenario



Source: CP BUS 3.04 – CBD security of supply – Jan2025 – Public, Figure 2

456. The N-1 Secure 'breach' scenario is an outage of a 66kV cable at the West Melbourne Terminal Station (WMTS) which supplies JA, followed by a fault on one of the other sub-transmission cables supplying JA. In this case JA would only have one 55MVA transformer supplying into the Docklands precinct and the southwest portion of the CBD.

457. CitiPower advises that the cyclic rating of the JA 55MVA transformer is 63.9MVA (summer) and the operational transfer capacity of the network is 60.1MVA, meaning that the N-1

93 CP MOD 3.01 - CBD security of supply - Jan2025 – Public, $62.0 m ($2023) escalated

94 CP BUS 3.04 - CBD security of supply - Jan2025 – Public, page 4

Secure criterion is breached if summer demand exceeds the combined 124.0MVA capacity (or 123.8MVA in winter).

458. CitiPower provided a single line diagram in its business case to illustrate the scenario. However, it was incomplete and did not allow full confirmation of the outage scenario and our interrogation of the basis for the preferred option. At our meeting with CitiPower engineers at an onsite meeting in March 2026 we were consequently able to discuss the contingency scenarios and understood the basis for the options considered (and discussed below).

CitiPower considered three network options that would satisfy the N-1 Secure Criterion

459. In addition to Option 1 (maintain the status quo), which would not satisfy the N-1 Secure criterion with the forecast demand growth and therefore is not a credible approach, CitiPower identified three network and one non-network options:

- Option 2: construct new feeders from MG to JA
- Option 3: construct new feeders from MG to JA then rebuild J by the end of the next RCP
- Option 4: rebuild J substation as soon as practicable, and
- Option 5: non-network solution.

460. Option 2 is CitiPower's preference. The Option 2 scope is to construct three 12MVA 11kV feeders from MG to JA, with Option 4 proposed as a contingent project. The three feeders would provide meet CitiPower's supply obligation through to the end 2030 using to the current demand forecast. They are designated for completion in FY28, with the bulk of the expenditure in FY28.[95] In other words, Option 2 will, if the demand builds in accordance with the 50PoE forecast, result in approximately 12 months of non-compliance before the project is completed.

461. We note that the timing for completing the project may slip given the planning, approvals process, design and construction, and outage management complexities involved in implementing projects in the CBD.

462. An advantage of Option 2 is that it 'buys option value', providing for the potential deferral of the relatively expensive rebuild of J beyond 2030.

463. There was insufficient information in the business case to justify the need for three 12MVA feeders. However, based on our discussion at the onsite meeting we are satisfied that the configuration and rating of 36MVA is based on deferring the rebuild of J substation to at least 2030.

464. CitiPower identifies the NPV of Option 2 as $6.1 million, the highest of the three augmentation options considered. However, if the contingent project is required by the end of the next RCP (from CitiPower's analysis), the NPV reduces to -$23.5 million, which is the more meaningful comparative basis in our view.[96]

465. Option 3 is a combination of Options 2 and 4 but without the designation of Option 4 as a contingent project. The NPV of Option 3 is -$23.5 million.

466. The cost of Option 4 is approximately $70 million[97] because it '*includes a new building capable of supporting three 55MVA transformers, 66kV gas insulated switchgear, two 55MVA transformers [initially], new subtransmission lines and other associated equipment…'.*[98] The NPV of Option 4 is -$13.6 million.[99]

95 CP MOD 3.01 - CBD security of supply - Jan2025 - Public

96 CP BUS 3.04 - CBD security of supply - Jan2025 – Public, Table 2

97 CP MOD 3.01 - CBD security of supply - Jan2025 – Public, escalated from $2023

98 CP BUS 3.04 - CBD security of supply - Jan2025 – Public, page 7

99 CP BUS 3.04 - CBD security of supply - Jan2025 – Public, Table 2

467. In its CBA model, the rebuilt J is scheduled for completion in FY30, but our understanding is that this is on the basis of Option 2 proceeding and with Option 4/J re-build as a contingent project.

468. CitiPower considers that given the magnitude of the capacity shortfall, Option 5, a NNS, is unlikely to present a viable alternative. CitiPower will invite market responses to solve the constraint, as is required via the RIT-D for the augmentation project. Whilst we also consider that an NNS is unlikely to provide a long-term solution, it may be a viable staging strategy to maintain N-1 Secure compliance whilst rebuilding J as soon as practicable to give a cheaper solution.

469. In our view, CitiPower should proactively approach the market for a demand management service for an interim solution. There may for example be a considerable amount in aggregate of back-up generators in the relevant part of the CBD that could be contracted to operate in the unlikely event that there is a double sub-transmission line outage.

An alternative of addressing the configuration of JA is not feasible based on advice from CitiPower

470. We sought to understand why the limitations at JA that make the supply susceptible to losing two transformers under the designated contingency scenarios could not be addressed at JA. This would include for example adding line circuit breakers on the WMTS-JA3 and WP-JA 66kV line circuits at JA.

471. We were advised that due to space limitations this would be prohibitively expensive and/or not physically achievable.

Rebuilding J asap instead of adding the three feeders would save $17 million less the cost of contingency measures if such contingency measures can be identified

472. In the business case CitiPower states that Option 4 was discounted as a standalone solution because '…*we would remain non-compliant at the beginning of the regulatory period. Therefore, this option is not credible because we would not meet our compliance obligations.*[100]

473. We further examined CitiPower's rationale for not selecting Option 4 given that:

- The load forecast indicates it will be required by 2030 even with the 36MVA contribution from the three proposed new feeders
- If some means of bridging the non-compliance gap can be established, building J as early as practicable 'saves' the $17 million cost of the three feeders
- If J can be rebuilt by the summer of 2029, it represents only one extra year of non-compliance, and
- Option 4 presents the lowest NPV and would meet the forecast demand in the area for the foreseeable whilst maintaining N-1 Secure criterion for the foreseeable future.

474. We consider that it is possible that the rebuilt J could be commissioned just prior to the summer of FY29 (i.e. a second year of non-compliance) but given the risk of deferral due to the complexities noted for the feeder option, a contingency plan would need to be invoked. We consider that a two-pronged approach could be deployed by CitiPower in parallel with the RIT-T process:

- Formally seek relief for the compliance obligation by submitting the plan to the ESC, and
- Proactively seeking a demand management solution from the market to at least reduce the unserved energy in the worst case between the summer of FY27 and when the rebuilt J is commissioned.

[100] CP BUS 3.04 - CBD security of supply - Jan2025 – Public, page 7

Cost forecast is reasonable

475. We discussed the bases for the cost estimates with CitiPower, and we are satisfied that the costs for the various options are reasonable based on the stages of the project lifecycle that the various scope components are at and the scope and complexities of the projects.

Findings

476. We consider that the proposed augex for the construction of the three MGA-JA feeders is justified. It provides option value, possibly enabling significant deferral of the need to re-build J substation.

477. The proposed scope of work to build three feeders from MG to JA is the solution which minimises the time that CitiPower is non-compliant with the N-1 Secure Criterion. It also provides option value by supporting the *possible* deferment of the proposed J rebuild (if load growth is slower than forecast).

478. However, in parallel with the RIT-D assessment process, we suggest that CitiPower takes all reasonable steps to determine whether there is a viable means of deploying a NNS to bridge or at least mitigate the compliance gap the augex solutions. Depending on the outcome, it may be prudent to bring forward the J rebuild and not proceed with the three new feeders.

4.5 Assessment of CER Customer-driven electrification program augex

4.5.1 Introduction

479. CitiPower 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.[101]

480. In aggregate, CitiPower proposes $64.9 million (totex) for CER and Electrification. We assess its proposed ICT capex of $11.8 million, and ICT opex of $12.3 million in our associated report. In the current report, we therefore review its proposed customer-driven electrification augex program.

4.5.2 What CitiPower has proposed

481. As shown in Table 4.7, CitiPower proposes a $40.9 million capex program to improve its steady-state voltage compliance over the duration of the next RCP by investing in:[102]

- Proactive LV augmentation, and
- Reactive augmentation.

482. CitiPower also recognises a small capex reduction of $0.5 million from avoided augmentation non-network solutions, which it has accounted for in its total proposed capex.

Table 4.7: EMCa scope of CitiPower proposed Customer-driven electrification program - $m, real FY2026

Demand augex	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer-driven electrification	3.7	4.9	9.5	10.7	12.1	**40.9**

Source: EMCa table derived from CitiPower SCS capex model

101 EMCa report to AER on CPU ICT, CER and Electrification expenditure for 2026-31 regulatory period

102 CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 1

4.5.3 Assessment

Victorian DNSPs have voltage compliance obligations under the Australian Standards and Electricity Distribution Code of Practice (EDCoP)

483. The EDCoP obligates Victorian DNSPs to maintain voltage levels between 216 and 253 volts at least 99 per cent of the time.[103] Functional compliance is met if these limits are maintained for at least 95 per cent of the DNSP's customers. CitiPower 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.'* [104]

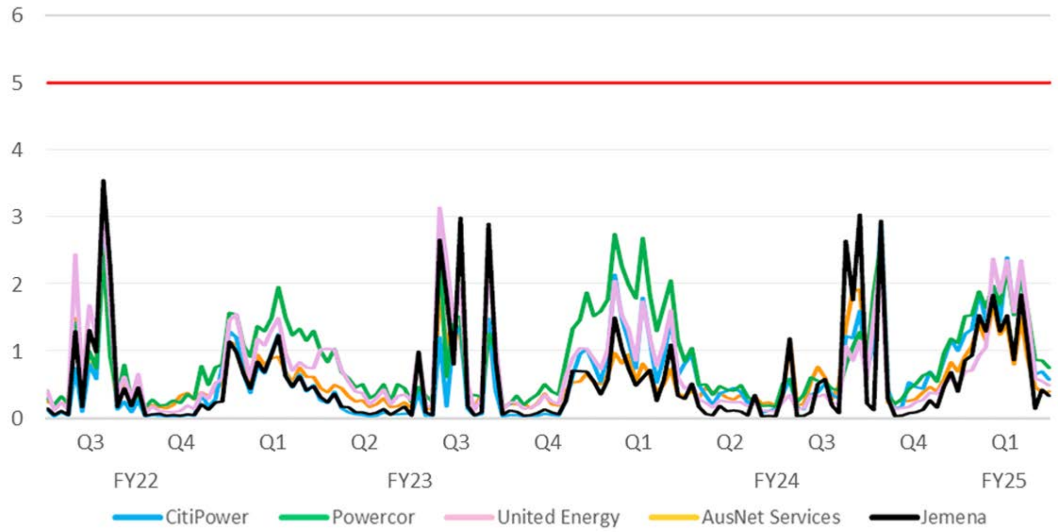
CitiPower's focus is on undervoltage compliance

484. CitiPower reports that it largely remediated overvoltage 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.

485. CitiPower 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.[105]

486. CitiPower's voltage performance is shown in Figure 4.7. CitiPower's current undervoltage performance is 97%. However, with the extent of electrification forecast over the next RCP, CPU's new time-series modelling capability[106] indicates that undervoltage issues will increasingly arise. CitiPower 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.

Figure 4.7: Undervoltage non-compliance of Victorian DNSPs (%)



Source: CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Figure 5

487. CitiPower 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 4.8. CitiPower claims that this approach will inevitably and

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[103] ESC, Electricity Distribution Code of Practice (V2), 2023, clause 20.4.1 and note to Table 2, page 82

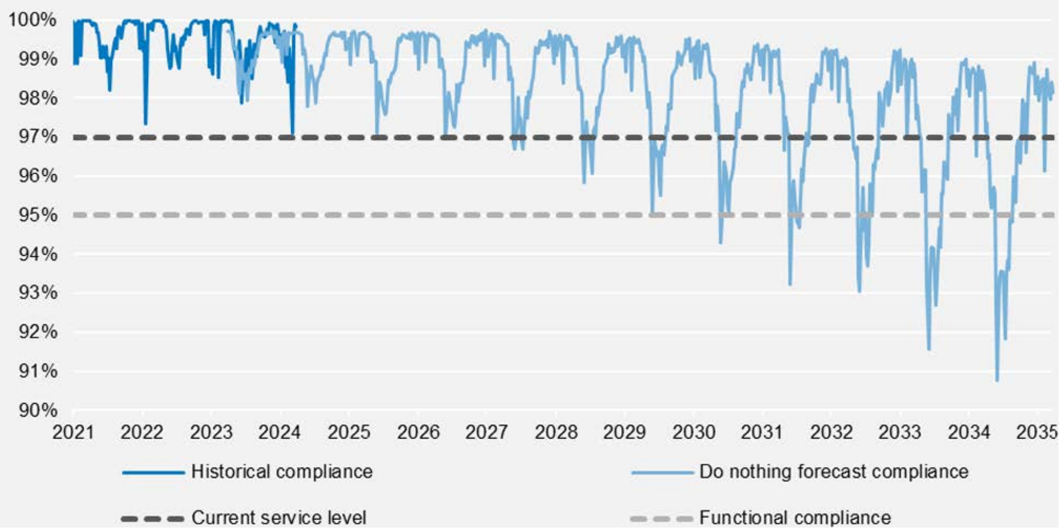
[104] CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, page 7

[105] CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, page 7

[106] 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

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 4.8: CitiPower projection of voltage compliance under the 'do nothing' scenario (%)



Source: CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Figure 8

488. 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. Such assumptions are challenging because 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 CitiPower to consider options to remain compliant with its power quality obligations through the next RCP, with the focus on undervoltage management.

489. CitiPower estimates that there will be 352 voltage complaints over the next RCP under the base case, each of which will need to be rectified.[107]

Proactive versus reactive upgrades

490. CitiPower 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 CitiPower's modelling for voltage management costs.

491. Proactive investments to address undervoltage include DSS offloads and reconductoring LV feeder sections. CitiPower's analysis leads it to conclude that:

- Proactive upgrades are more efficient over the long-term because CitiPower 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).

492. 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.

107 CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 5

There is a disconnect between CitiPower's historical power quality complaints and its forecast under-voltage complaints that require 'projects'

493. CitiPower states in its business case that it received 26 complaints in FY24.[108] It does not specifically state that these are voltage-related complaints (or even PQ complaints), but this is clearly inferred.

494. We requested further information from CPU, with the response advising that:[109]

> *'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.'*

495. We have summarised the numerical aspects of the response in Table 4.8, 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 4.8: CitiPower - complaints conversion to network rectification projects

	FY27	FY28	FY29	FY30	FY31	Total
# complaints in Table 5 of business case	48	57	71	86	90	**352**
Conversion factor derived by CPU	*0.56*	*0.56*	*0.56*	*0.56*	*0.56*	
# complaints forecast to require network projects	27	32	40	48	135	**197**

Source: CP per PAL response to IR006, question 3(a)

496. However, in the CitiPower's 2024 annual RIN,[110] there are ***zero*** complaints related *to technical quality of supply*. There are also zero technical quality of supply complaints in the 2023 annual RIN.

497. The gap between the RIN and the inputs to CitiPower's model is not credible. It would appear that either CitiPower's RIN data is incorrect or the forecast number of 'technical quality of supply complaints' forecast from 2027 onwards is massively overstated.

498. This is of fundamental importance because CitiPower forecast 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.

499. If the starting number is wrong, then CitiPower's projections and forecast expenditure to maintain or improve voltage compliance performance will also be wrong. This undermines confidence in CitiPower's options analysis and the proposed expenditure, which we consider below.

CitiPower considered three options and proposes to 'improve' service levels

500. CitiPower presents the three options identified in Table 4.9. Option 3 is recommended.

108 CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 2

109 CPU per PAL response to IR006, question 3(a)

110 CitiPower 2023-24 - Annual - RIN Response - Consolidated - 31 October 2024 - PUBLIC(17470103.1)

Table 4.9: Summary of CitiPower's comparative options analysis

Option	FY31 voltage compliance	Total # forecast customer complaints	Cost ($m 2026)
1. Base Case – do not breach Functional limit	95.6%	352	$30.1
2. Maintain service levels	97.0%	237	$39.4
3. Improve service levels (recommended)	97.1%	176	$39.5*

Source: CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Tables 5-10
*** this does not match the capex model amount of $40.9m because of labour escalation*

501. The intuitively implausible cost equality between Options 2 and 3 is achieved by CitiPower investing more in proactive LV augmentation than reactive augmentation in Option 3. Proactive augmentation is prioritised to reduce the number of complaints and therefore the reactive expenditure. Specifically, CitiPower proposes '*pursuing all proactive investments where the customer benefit from an upgrade exceeds the augmentation cost. The preferred investment year is chosen based on when the annualised benefits exceed the annualised cost.*' [111] According to CitiPower's business case, it proposes the following Option 3 capex included in Table 4.10.

Table 4.10: Nature and net cost of proposed electrification works -$m, real 2026 (unescalated)

	Cost ($m)
Proactive augmentation	26.6
Reactive augmentation (to respond to a forecast 176 complaints)	13.4
Less Avoided augmentation from non-network solutions	-0.5
Total	**39.5**

Source: CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, Table 10

CitiPower's proactive investment methodology is highly sensitive to the assumed target service level

502. CitiPower has relied on a simulation model to forecast the extent to which it expects undervoltage to occur. We provide an overview of this model 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.

503. The model is highly sensitivity to the target service level, which is a model input assumption. CitiPower's target service level setting is 97% over the period. In Powercor's equivalent model, the setting is 97%. From Powercor's model we find that if it was to set a target of 96%, which is still above its Functional Compliance obligation of 95%, the model defines an augmentation program requirement that is only around 20% of the cost that Powercor has proposed. We do not have an equivalent CitiPower model,[112] however as the methodologies are identically applied, we consider it reasonable to assume that the outcome would be similar for CitiPower's augmentation program.

504. Noting that CitiPower'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, CitiPower 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

111 CP BUS 3.01 – Customer-driven electrification – Jan2025 – Public, page 33

112 Powercor provided a more detailed version of its model PAL MOD 3.31 which allowed the service level target to be varied

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.

505. CitiPower 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. CitiPower 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

506. While the simulation modelling of voltage levels that has been undertaken for CitiPower 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.

507. 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.

508. It is also a reasonable hypothesis that home electrification rates will vary considerably across the service area. New developments within the inner-city suburbs and the CBD are likely to be fully electrified, in which case we assume that CitiPower will design its networks accordingly and will not require a subsequent 'electrification augex' program for them. By contrast, existing premises and businesses could reasonably expect to transition away from gas far more gradually than average, as appliances are replaced, mitigating the impact on voltage levels. Even if CitiPower's overall assumptions regarding EV and electrification demands are reasonable at the aggregate level, this variation could significantly affect the scale of work needed.

509. 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 CitiPower has relied on as the basis for its proposed augex program.

CitiPower assesses the customer benefit of its program by assuming undervoltage supply is curtailed and valuing this at VCR

510. 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. CitiPower 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).

511. EV charging interruption is the main example given for valuing curtailment at VCR. Other impacts from undervoltage that CitiPower assumes will intensify over the next RCP to the extent that voltage service levels decline are heating, cooling, cooking malfunction, and appliance lifespan degradation.

512. CitiPower 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 CitiPower assumes, and to value undervoltage supply at VCR

513. Whilst CitiPower (with Powercor 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.

514. We asked for an explanation of the rationale for the choice of VCR and in summary, the 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.[113] 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 CitiPower receives.

515. 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.

CitiPower's reactive investment methodology

516. In addition to proactive investments, CitiPower 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 99 complaints which will require remediation work.[114] CitiPower advises that it remediates at the lowest cost rather than highest possible value.

517. CitiPower provided the conversion factors and average costs for minor and major rectification projects. Applying them to the proposed number of reactive projects under the Base Case and the Improve option gives the results shown in Table 4.11. This indicates that the cost of the Base Case is somewhat overstated, and the reactive project cost component of Option 3 is also overstated.

Table 4.11: Options cost analysis – reactive projects

Option	Number of complaints from Business Case	Business case + CP ATT2.01[115]			Reactive projects cost	
		# network projects	# major projects	# minor projects	Business case ($m)	EMCa analysis ($m)[116]
Option 1: Base Case	352	197	150	47	$28.0	$24.4
Option 3: Improve	176	99	75	24	$13.4	$12.2

Source: EMCa analysis of information in CP BUS 3.01 and CP ATT 2.01 Table 22 (which applies to CPU)

113 Powercor response to IR014, question 3(b) which is applicable to CitiPower and United Energy

114 Based on the 56% conversion factor applied to the 176 forecast complaints over the next RCP

115 Ratio is 76% major projects and 24% minor projects

116 Major project cost is $150k and Minor project cost is $41k as per PAL ATT 2.01 – Customer electrification forecasting methodology – Jan2025, Table 22

518. From the business case data, the average cost per reactive project is $142k for the Base case and $135k for the Maintain option. This difference, although relatively small, is not explained.

CitiPower has managed potential for duplication amongst its programs appropriately

519. We asked CitiPower 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.[117]

Sensitivity analysis is not sufficient

520. CitiPower included only one form of sensitivity analysis in its business case (and none in its provided model)[118] being modelling the forecast non-compliance for the Base Case using the 10PoE demand forecast. This shows that the proposed level of 'improve' investment would only hold compliance above the functional limit until 2035, rather than a date much further into the future with the base demand assumption (which is not apparent, but which we assume is 50PoE).

521. 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

522. CitiPower has not sufficiently justified the proposed customer electrification program and the proposed augex is materially overstated.

523. 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. CPU's modelling indicates that it is likely to comply until around the end of the next regulatory period and we consider it more likely that the impact will be less than CitiPower has forecast.

524. However, we have four significant concerns with CPU's forecasting methodology that we consider has led to a significant overstatement of the expenditure that CitiPower will require in the next RCP. We consider that:

- CitiPower 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 considerably less impact on customers than CitiPower assumes, may be arrested by non-network solutions such as CitiPower intends to deploy in any case, and would void the need for the proposed very substantial proactive network augex investment
- CitiPower 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
- CitiPower'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 CitiPower's proposed proactive program, and
- CitiPower'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 CitiPower has considered.

117 Powercor response to IR014, question 3(d)

118 CP MOD 3.09 - Customer-driven electrification - Jan2025 – Public

525. On this basis, we consider that CitiPower has not justified the considerable increase in augex that it has proposed to enable a proactive electrification program

4.6 Our findings and implications for proposed augex

4.6.1 Summary of our findings

526. We consider that collectively and individually the projects and programs that we have reviewed overstate the required capex for the next RCP.

Context

527. We have assessed five individual augmentation projects/programs submitted with CitiPower's Proposal, representing 80% of the proposed total augex for the next RCP. Our findings may not necessarily be applicable to the balance of the program.

528. We have not commented on demand forecasts. The AER has advised us that it will assess CitiPower'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 CitiPower for planning purposes.

General

529. CitiPower has presented business cases and supporting cost-benefit analysis (CBA) models that provide foundational material to support 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.

530. CitiPower responded to our clarifying questions, and this enhanced our understanding of each project and program.

531. 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.

532. CitiPower has selected the highest NPV option in each case (except for the CBD security of supply project as this based on a deterministic requirement) and the business case present both the optimal timing and sensitivity analyses focussed on the NPV.

533. In each case, the economic viability and/or availability of non-network solutions was discounted in favour of network solutions, with CitiPower deferring in each case to the RIT-D process to bring forth market-led NNSs.

534. One significant issue from the business cases and the CBA models is the limited information on the cost estimation for projects. We consider that the cost estimates in several projects are overstated.

535. Sensitivity analyses are presented in each case with the emphasis on demonstrating the robustness of the NPV of the selected option against negative variances (i.e. NPV remains positive) and superiority to the other options. This is good practice, however the sensitivity analyses did not encompass changes to the optimal timing. We have sought to do so, either by asking CitiPower to undertake studies or by doing them ourselves if CitiPower's models readily support the analysis.

Demand-driven projects and programs

536. In each of the projects/programs we were satisfied that there was a compelling need for CitiPower to consider means of mitigating risk of unserved energy with increasing demand.

537. CitiPower presented a good range of options but did not countenance a NNS as a sub-option to a network solution to economically defer network expansion. We consider that

CitiPower should consider all possible means of deferring investment in 50 plus year assets given there is considerable uncertainty about future demand. We therefore looked closely at how option value could be preserved.

538. We identified several modelling issues that lead to an overstatement of the NPV, including:

- The lack of recognition of temporary DTC to help reduce the EUE from N-1 contingencies
- What appear to be understated capacity ratings, and
- Inappropriate use of VCR.

539. These factors, individually and collectively lead to a lower monetised value of 'avoided' EUE and therefore are likely to lead to deferral of the economic timing of work.

Non-demand driven projects and programs

540. For the Asset relocation project, CitiPower's presented inconsistent information in its model and in its business case, however the material issue was the absence of evidence from Yarra Trams itself about its forecast pole relocations. Not only would this provide confirmation of volume but would also assist CitiPower in estimating the cost more accurately, taking into account relative complexity. Such a forecast was available to CitiPower for its revised proposal following the AER's draft decision for the current RCP. Due to these issues, we consider that as presented the estimate for the program is significantly overstated.

541. For the CBD Security of Supply project, CitiPower has selected the pragmatic solution to address the near-term compliance issue as quickly as possible, and which buys 'option value' to help manage the uncertainty of the optimal timing of the much more expensive Spencer Street zone substation (J) rebuild. We consider that there may be cost-effective NNS in that area of the CBD to potentially 'bridge the compliance gap' until the timing of the need for J is clearer. We further consider that CitiPower should proactively explore NNS options (i.e. in advance of or in parallel with the RIT-D process), again not as a standalone solution but a means of deferral of capex.

CER – Customer-driven electrification

542. We consider that the proposed expenditure is significantly overstated because of the following issues:

- CitiPower 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
- CitiPower 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 in our opinion 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 CitiPower's preferred Option 3 (Improve) reactive project component appears to be overstated.

Summary of project findings

543. We consider the capex to be reasonable for one of the five CitiPower projects that we reviewed (CBD Security of Supply).

544. For each of the other projects that we were asked to review, we consider that CitiPower's proposed capex is not a reasonable forecast of its expenditure requirements for the next RCP.

4.6.2 Implications for proposed capex allowance

545. We were asked to review five projects in the demand and non-demand augex categories which have aggregate proposed capex of $173 million, and which includes Electrification/CER projects with aggregate proposed augex of $40 million.[119] These projects comprise part of CitiPower's aggregate proposed augex of $215 million.

Alternative forecast methodology

546. Our proposed alternative forecast for these categories involves one or more of the following adjustments, to the extent that it formed the basis of CitiPower's forecast and which we consider to be not justified or overstated:

- Adjustment to the timing of the proposed expenditure, resulting in deferment beyond the end of the next RCP
- 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.

Alternative forecast of expenditure

547. We consider that a reasonable alternative forecast for CitiPower for the augex projects within the demand and non-demand capex categories that we reviewed, would be between 40% and 50% less than CitiPower has proposed.

548. We stress that our advice on an alternative forecast relates only to the projects within the scope of our review and does not necessarily have any implication for augex that is not within the scope of our review.

119 Customer driven electrification and ZSS capacity upgrades

5 REVIEW OF PROPOSED OPEX - VEGETATION MANAGEMENT

CitiPower has proposed an opex step change of $33.6 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. CitiPower subsequently updated its submission, but this only had a minor impact to its proposed overall opex step change, reducing it to $32.1 million and marginally increased the number of spans to be cut.

We have identified a number of issues with CitiPower'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 CitiPower'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 CitiPower to achieve compliance in the next RCP, however we consider that a number of factors in CitiPower's forecast are not reasonable assumptions. Adjustment of CitiPower's assumptions, which we applied in various combinations, leads us to conclude that CitiPower requires an opex step change that is materially lower than it has proposed.

We consider that an opex step change of $8.7 million developed based on a more reasonable interpretation of CitiPower's data provides an efficient opex step change.

5.1 Introduction

549. In this section, we present our assessment of the forecast opex step change that CitiPower has proposed in the next RCP. We reviewed the information provided by CitiPower to support its proposed opex step change for vegetation management, and its responses to our information requests on the topic.

5.2 What CitiPower has proposed

5.2.1 Vegetation management opex step change

550. CitiPower has proposed an opex step change for its vegetation management program of $33.6 million for the next RCP as shown in Table 5.1.

Table 5.1: CitiPower total proposed vegetation management step change - $m, real FY2026

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation	5.7	6.5	7.0	7.1	7.2	**33.6**
Hazard trees	0.0	0.0	0.0	0.0	0.0	**0.0**
Total vegetation management step change	**5.7**	**6.5**	**7.0**	**7.1**	**7.2**	**33.6**

Source: EMCa table derived from CP MOD 8.02 – Vegetation Management

551. CitiPower claims that a change in the 'standard of compliance'[120] 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. CitiPower claims that these requirements in turn require additional expenditure for vegetation management activities.

5.2.2 Understanding the build-up of the forecast

552. CitiPower 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: CitiPower'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	7.7	8.5	9.0	9.1	9.2	**43.6**
Hazard tree program	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	**7.8**	**8.5**	**9.1**	**9.2**	**9.2**	**43.7**

Source: EMCa table derived from CP MOD 8.02 Vegetation management

553. Next, CitiPower subtracted the vegetation management opex that it expected to incur in its proposed base year opex as shown in Table 5.3.

Table 5.3: CitiPower's proposed total vegetation management opex - $m, real FY2026

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation						
Forecast	7.8	8.5	9.1	9.2	9.2	**43.7**
minus Base	*-2.0*	*-2.0*	*-2.0*	*-2.0*	*-2.0*	***-10.1***
Total step change	**5.7**	**6.5**	**7.0**	**7.1**	**7.2**	**33.6**

Source: EMCa table derived from CP MOD 8.02 Vegetation management

5.2.3 Update to forecast opex step change

554. Subsequent to our discussions with CitiPower at our onsite meeting, we asked CitiPower to update the opex step change based on more recent actuals incurred in the program. The opex step change did not materially change, as shown in Table 5.4.

120 CP ATT 8.02 – Vegetation management step change – Jan2025 – Public

Table 5.4: CitiPower 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	5.7	6.5	7.0	7.1	7.2	**33.6**
Updated in response to IR017	5.2	6.6	6.7	6.8	6.9	**32.1**

Source: EMCa table derived from CP MOD 8.02 and CitiPower's response to IR017

555. We have relied on the more recent data provided in response to IR017 as the basis for our assessment.

5.2.4 Comparison of CPU businesses

556. The proposed opex step change is 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

557. In Table 5.6 we show the unit rates assumed in FY25 for each of the summary categories.

[redacted]

558. 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

559. 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.

560. 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.'*[121]

561. 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.'*[122]

Step change derived from the requirements minus the expenditure incurred in its base year

562. 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

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[121] AER Better Resets Handbook July 2024, page 23

[122] AER Better Resets Handbook, July 2024, page 26

program. CPU has added an uplift for each of the businesses, with the objective of moving to compliance by FY29.

563. In its updated submission, CPU estimates compliance is achieved one year earlier in FY28. CitiPower 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.

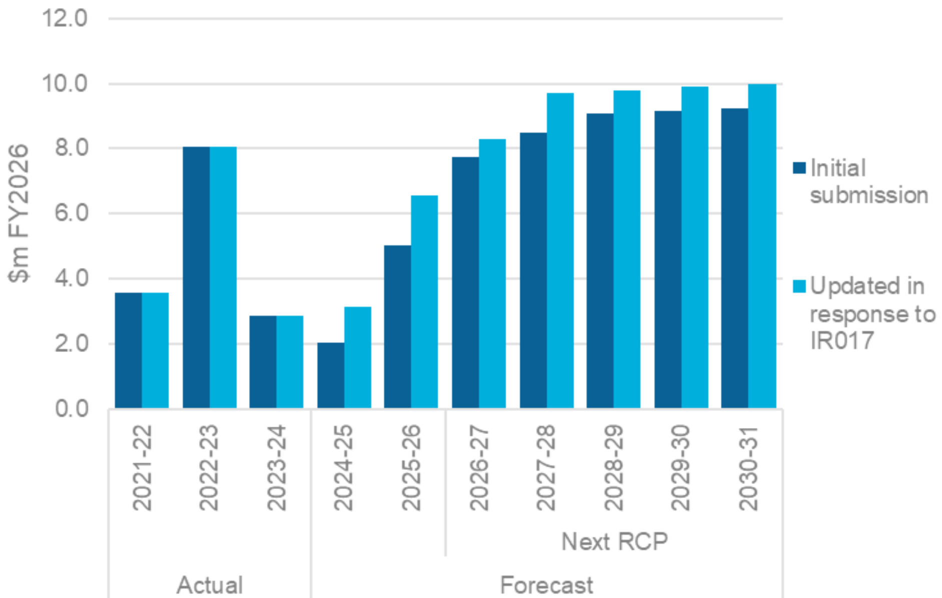
564. However, audited actual data is not available at the time of this assessment and the use of FY25 remains an estimate of the volume and expenditure that CitiPower expects to incur.

Historical expenditure and volumes show an increasing vegetation program

565. 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 CitiPower considers that it will achieve compliance and move into maintaining compliance with its electric line clearance obligations.

566. As a part of its response to IR017, we observe that (similar to the plan for Powercor) CitiPower seeks to achieve compliance one year earlier, in FY28.

Figure 5.1: Historical and forecast expenditure - $m FY2026



Source: EMCa analysis of MOD 9.02, and CitiPower's response to IR017

567. The profile to achieve compliance is as CitiPower has described, with the total expenditure having reduced at the time of compliance in its response to IR017, levelling at approximately $10 million pa. The high-level of expenditure in 2022-23 has not been explained, nor the corresponding higher level of cutting that would have been achieved in that year.

568. The revised response indicates a higher opex requirement than CitiPower included in its initial submission. This is due to a higher estimate of cut volumes and unit rates.

CPU has made a number of modelling errors in its presentation of its base program

569. In Table 5.7 we show how CitiPower 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 CitiPower vegetation management program, $m FY2026

	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	RCP Total
Base program	3.6	8.1	2.9	3.1	3.7	4.0	4.0	4.1	4.1	4.1	20.3
Uplift program	0.0	0.0	0.0	0.0	2.8	4.3	5.7	5.8	5.8	5.9	27.4
Total	**3.6**	**8.1**	**2.9**	**3.1**	**6.6**	**8.3**	**9.7**	**9.8**	**9.9**	**10.0**	**47.7**
Step change						**5.2**	**6.6**	**6.7**	**6.8**	**6.9**	**32.1**

Source: EMCa analysis of MOD 8.02, and IR017

570. We show CitiPower's base program in Figure 5.1. CitiPower did not explain why expenditure in FY23 was much higher than the surrounding years, and which does not align with the profile of vegetation cuts.

[redacted]

[redacted]

571. 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.

572. 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.

573. 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

574. 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

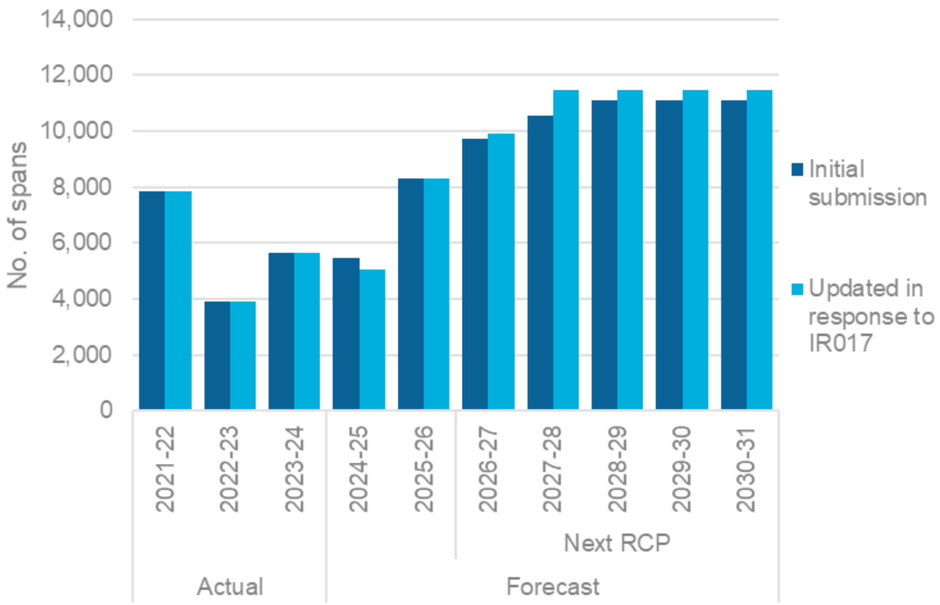
due to higher resources) than is indicated in the FY25 estimate in CitiPower's initial submission (based on historical average). We asked each of the CPU business to provide an updated estimated base program cut volume for FY25, using the span category descriptions included in its model and to indicate the data relied upon to update the estimate.

575. CitiPower 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.'*[123]

576. In Figure 5.3 we show the trend in volumes. 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 higher increase in volumes in IR017 than has been included in the initial submission, and a slightly lower starting volume in FY25.

Figure 5.3: Historical and forecast vegetation management spans that are required to be cut



Source: EMCa analysis of MOD 8.02, and CitiPower's response to IR017

577. Based on the initial submission we observe the total volumes converge around 11,000 spans pa once compliance is achieved. In the information provided in IR017, this number has increased to over 11,400 without explanation.

Proposed program is not aligned with CitiPower's ELCMP

578. The ELCMP includes the annual inspection and forecast cutting plan in Figure 9. For CitiPower this indicates an annual cutting program of 16,000 spans. This figure is not aligned to either the historical cutting program or the forecasting cutting program in either the current or forecast RCP.

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[123] CitiPower response to IR017 Question 5

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

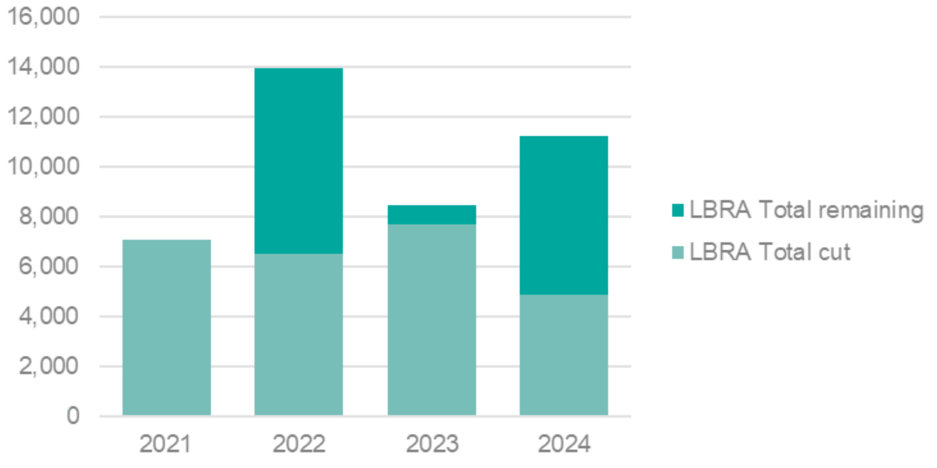
579. CitiPower states that the annual works program is developed each year and outlines the target inspection and cutting timeframes for each campaign region and remains subject to variations from year to year. However, the differences between each of the sources of information are material.

580. 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 the spans to be cut

581. 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 CitiPower's completed cutting (HBRA and LBRA), hazard trees and remaining. In this way we can see the total volume of work identified for CitiPower's network.

Figure 5.5: CitiPower historical completion volumes



Source: EMCa analysis of CitiPower data provided in Powercor's response to IR007 question 4g

582. Based on information provided in response to IR007, the total cutting program is estimated in 2024 as 11,245 spans, with 4,873 cut and 6,372 remaining. However, there is a high level of variability over the preceding years, such that CY2024 may not be a reasonable indicator of the level of spans required to be cut to achieve compliance.

583. Whilst there may be a relationship between the introduction of LiDAR and an increase in the number of vegetation management spans identified, the relationship is not obvious from this data as the total volume changes in each year. At a total level, we would have expected that the total volume of spans to be cut to be similar in each year.

584. We consider that a volume of approximately 9,850 spans, based on an average of the last two years data in in response to our questions from its LIDAR survey,[124] is a more reasonable estimate.

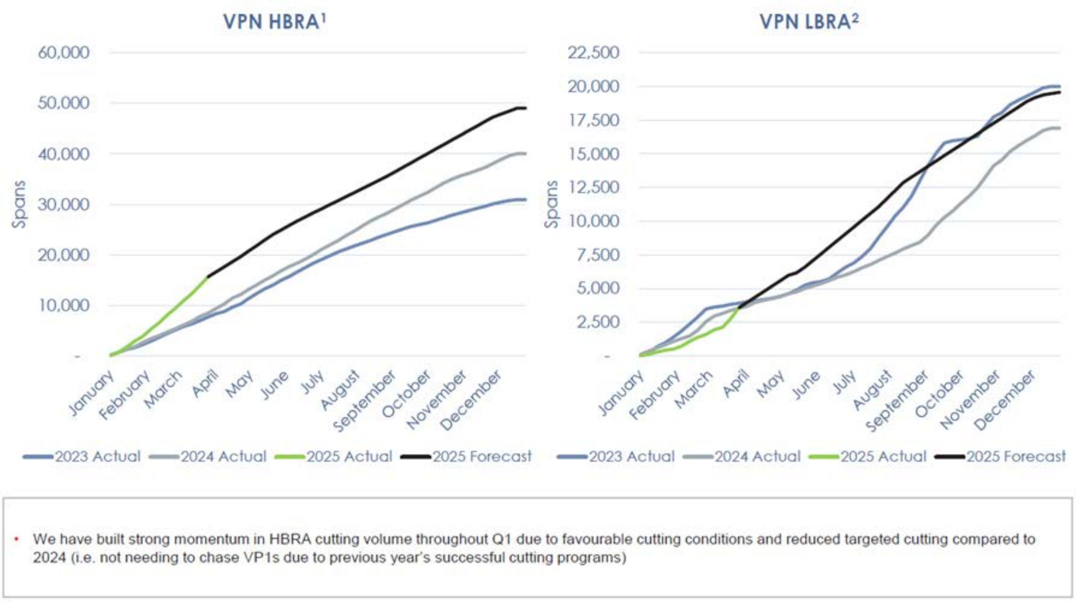
Base program should reflect a current estimate of current cutting volumes

585. In the updated model provided in response to IR017 CitiPower included a decrease to the cutting volume from 5,453 to 5,070 in 2024-25. CitiPower has not explained this reduction, given we were expecting to see higher volumes as CPU seeks to achieve compliance, and increases in cutting resources.

586. We consider that CitiPower’s estimated cutting volume should be based on its latest forecast completion rates in 2024-25. From information provided by CPU, we consider that the forecast completion rates in 2024-25 are likely higher than has been estimated by CitiPower. In Figure 5.6 we show the forecast completion for LBRA, which is approximately 19,000 spans for 2025. If we approximate the completion rates across the 2024-25 year and remove approximately 12,000 spans for the 2024-25 year as reported by Powercor, a balance of 5,500 spans would result.

587. We therefore consider a more reasonable estimate for CitiPower in FY25 is around 5,500 spans, which aligns with the initial submission and a year-on-year increasing trend in vegetation cutting for CitiPower.

Figure 5.6: VPN cutting status as at March 2025



Source: CitiPower - IR017 - Q2 - weekly status report - 1 April 2025 - public

588. A more reasonable estimate is a program adjusted to reflect a base program of approximately 5,500 spans then increasing to achieve 9,850 spans p.a.

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124 CitiPower data provided in Powercor’s response to IR007 question 4g

The basis for the classification applied to the estimated uplift cutting volume has not been adequately demonstrated

589. 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). For CitiPower, the uplift spans were allocated to remaining cuts and liveline.

590. We observe 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 CitiPower has 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

591. Whilst the 10,000 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 are a proportion of spans identified for cutting that are not completed in any year, and whilst 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 undertaking maintenance versus priority cuts. 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.

592. Whilst Powercor appear 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.'*[125]

593. 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.

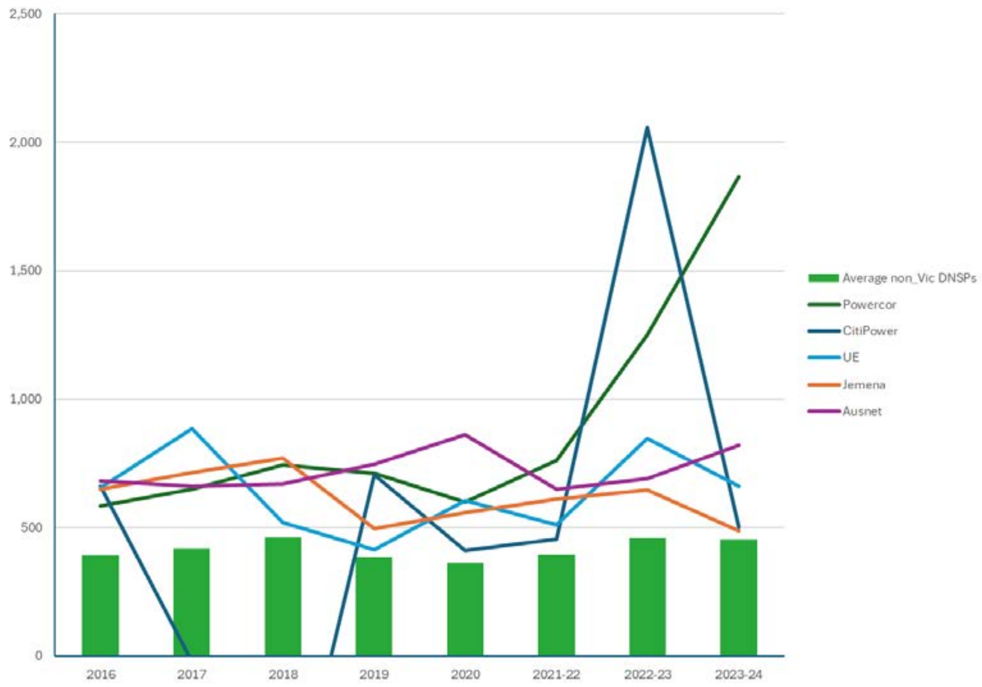
5.3.3 Assessment of unit rates

Historical unit rates have been increasing

594. We considered unit rates over time as shown in Figure 5.7 and observe that the Victorian DNSP unit rates were 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.

[125] PAL ATT 9.02 – Vegetation management step change – Jan2025 – Public, page 14

Figure 5.7: Trend of average vegetation management unit rates - $, FY2026



Source: EMCa analysis of RIN data

595. 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 – indicative of an efficient cost. If the cost increases that CitiPower proposes were to be included in this analysis, the differences to other NEM businesses would be greater still.

596. 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 spans that CitiPower 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

597. 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.

598. 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 CitiPower incurring higher rates, or a premium to market rates. Resourcing issues appear to be recognised in the business case provided by CitiPower, and that 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.

599. 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 CitiPower were lower than the equivalent rates applied in Powercor and United Energy.

CPU has applied real price escalation to its base program and uplift program

600. 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.

601. The same real price escalation is also applied to the unit rates included in CitiPower'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.

602. The real price escalation applied by CPU is shown in Table 5.8 below.

Table 5.8: Real price escalation (percentage)

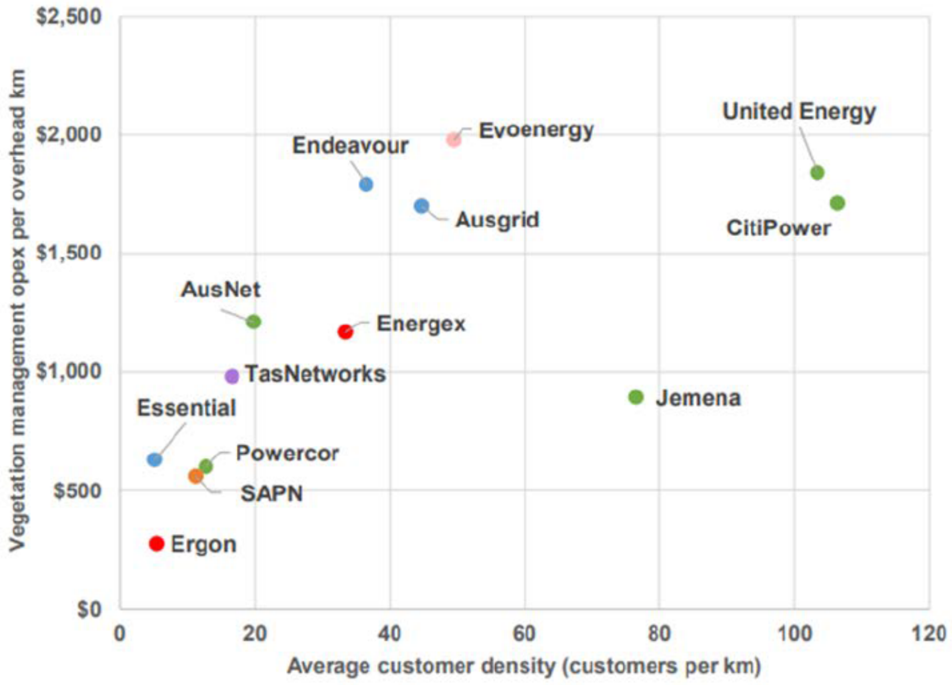
Real price escalation p.a (average)	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Powercor	0.49	1.93	2.23	1.21	0.69	0.85	0.98	0.92
CitiPower	0.46	1.79	2.07	1.13	0.64	0.79	0.91	0.85
United Energy	0.41	1.61	1.87	1.01	0.58	0.71	0.82	0.77

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

603. In the AER's 2024 annual benchmarking report, CitiPower and United Energy are identified as having amongst the highest vegetation management expenditure per kilometre of overhead circuit line length in the NEM, whilst Powercor is identified as having one of the lowest. We reproduce the analysis relied upon by the AER in Figure 5.8.

Figure 5.8: Vegetation management opex per km of overhead length ($2023) - average 2019-23



Source: AER analysis; Economic Benchmarking RINs.

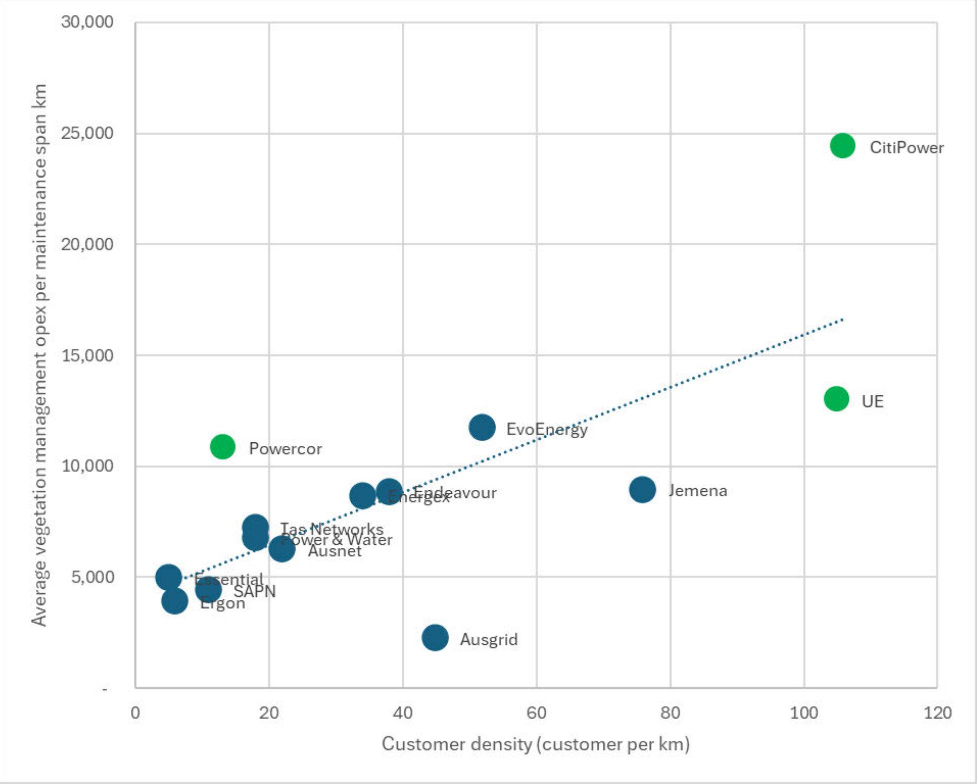
Source: AER, 2024 Annual Benchmarking Report – Distribution network service providers, Figure 19

604. 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.

605. 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 DNSPs, the results for CPU businesses indicate a higher opex per maintenance span than as indicated 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.

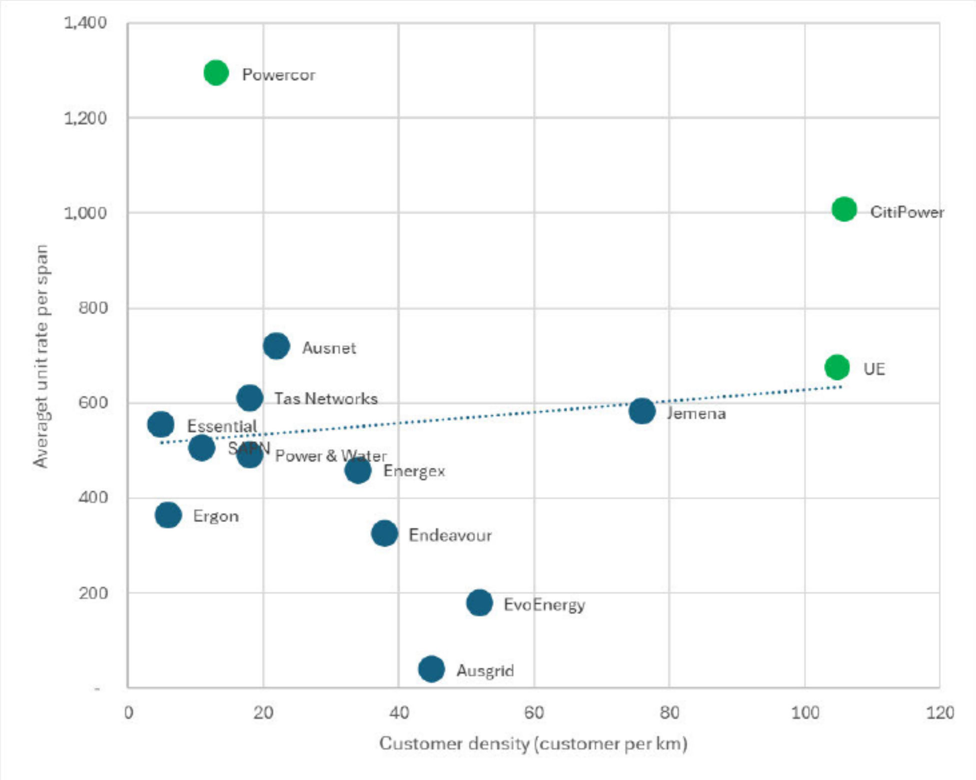
Figure 5.9: Average vegetation management opex per maintenance span km versus customer density



Source: EMCa analysis of RIN data

606. We also considered the average unit rates over the same period as shown in Figure 5.10.

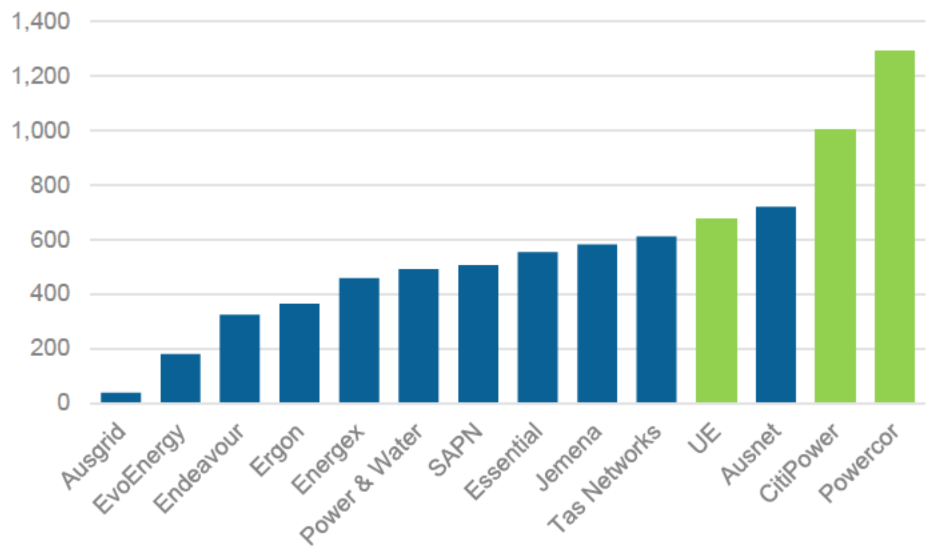
Figure 5.10: Average vegetation management unit rate per span versus customer density



Source: EMCa analysis of RIN data

607. Using another representation, 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

608. Based on the benchmarking results, the costs for CitiPower's vegetation management program are significantly higher when compared to other DNSPs. CitiPower has not demonstrated why these costs are reasonable or reflective of an efficient cost.

5.3.4 Assessment of additional matters

CitiPower has included an increase in its LiDAR and contractor liaison costs

609. CitiPower states that it has included an increase in its forecast contractor liaison costs to reflect the additional staff it will require to manage its contractors as it ramps up its cutting activities in order to achieve Code compliance of $2 million. A similar cost is also proposed for Powercor.

610. The LiDAR costs are hard-coded, proposed to commence in FY25 based on the assumptions shown in Table 5.9, and are increased annually using price escalation.

Table 5.9: CitiPower LiDAR cost assumptions

Cost item	Cost ($m Dec23)	Cost assumptions
LiDAR capture	1.25	Costs include pilot wages, helicopter maintenance, helicopter fuel, rental of hanger
LiDAR data classification	0.17	Costs include LiDAR lab, consultancy
Total	**1.42**	

Source: CP MOD 8.02

611. The contractor liaison costs are based on 2023-24 costs and include an uplift in liaison costs of $480,000 p.a from 2025-26[126] and are increased annually using price escalation.

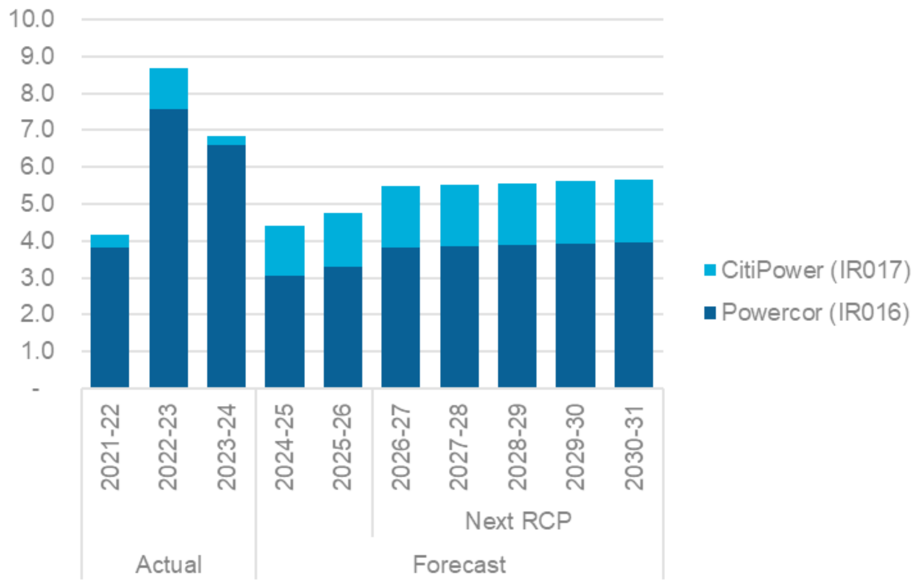
612. The costs for LiDAR and contractor liaison are already included in the base year expenditure. The increase in volumes appears to being met with the same contractors, albeit an increase in the number of crews, and we have not seen adequate justification for the proposed increase.

613. CitiPower refers to an increase in the LiDAR inspection costs of $7 million, based on an updated approach to allocating its shared LiDAR costs between CitiPower and Powercor, such that CitiPower has been allocated a higher percentage of its shared LiDAR costs.

614. 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 CitiPower is claiming as its base year, and therefore is not a reason for an increase in the forecast.

[126] The model includes a comment that the incremental costs are $200k pa, however $480k has been applied

Figure 5.12: Proportion of LiDAR costs – Powercor and CitiPower, $m FY2026



Source: EMCa analysis of PAL MOD9.02 and CP MOD 8.02

615. 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

616. 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.

617. 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 CPU 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 CitiPower has not made provision for in its opex step change forecast.

618. It is generally recognised that the introduction of LiDAR and advanced analytics increases compliance and reduces opex related to vegetation management.[127] CitiPower 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*

[127] ENA 2020, Data opportunities for smarter networks accessed at https://www.energynetworks.com.au/resources/reports/data-opportunities-for-smarter-networks/

(necessitating cutting in order to maintain compliance at all times), and our ability to do so in a timely manner.'[128]

619. 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.*'[129] We estimate that the efficiencies that CPU 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

620. 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

621. CPU argues that there has been a change in 'accepted practice' of the current electric line clearance requirements, as evidenced by the increase in enforcement by Energy Safe 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

622. The primary driver of CitiPower'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. CitiPower has been progressively addressing a higher volume of vegetation spans with the aim of achieving a state of compliance (based on its LiDAR data) with the electric line clearance regulations by FY29. CitiPower has subsequently advanced the target year of compliance by one-year to FY28.

We estimate that CitiPower has maintained the size of its program in FY25

623. In responding to our request to update its estimate for the program to be completed in FY25, CitiPower reduced the size of its program. However, based on other information provided by CitiPower, we consider that it has at least maintained its cutting volumes. Comparisons

128 CP ATT 8.02 – Vegetation management step change – Jan2025 – Public, page 2

129 Based on an article from ESRI accessed at https://esriaustralia.com.au/blog/how-landscape-vegetation-management-changing

from prior years are not reliable as the volumes and expenditure are volatile, however on average CitiPower has maintained similar volumes.

The ultimate size of the vegetation management program will be the result of additional factors, that CitiPower does not appear to have taken into account

624. Whilst the 9,850 spans p.a. arising from its latest LiDAR survey provide a reasonable basis for a starting estimate, CitiPower 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.

625. 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.

CitiPower has not correctly taken account of the BST forecasting method for opex

626. We consider that a bottom-up build of its requirements is an appropriate forecasting method to understand the vegetation management expenditure, however CitiPower'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.

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

627. CitiPower 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,
- our alternate estimated cutting for 2024-25 maintains the size of the current program, 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,
- 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.

628. As a consequence of the issues we have identified, we consider that the opex that CitiPower consider that it will require is materially overstated.

Benchmarking of CitiPower's historical costs indicate that it is higher than other NEM DNSPs

629. 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.

630. 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.

631. 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

632. 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 CitiPower is incurring costs that are materially higher than other NEM DNSPs, including other Victorian DNSPs.

633. We further consider that the program, once stabilised, offers CitiPower 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 a level lower than CitiPower has proposed

634. 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.

635. We found that the need for additional opex was 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 further reduced the step change. However, changes were required to be applied to a number of factors, and which we consider less credible, to remove the need for an opex step change for CitiPower.

5.4.2 Implications for proposed opex step change allowance

636. We consider that CitiPower's proposed opex step change for vegetation management is not a reasonable forecast of its expenditure requirements for the next RCP.

637. We are satisfied that additional improvement to vegetation management activities is required for CitiPower to achieve compliance in the next RCP, however we consider that a number of factors in CitiPower's forecast are not reasonable assumptions.

638. We made adjustments to CitiPower's forecasting methodology, to the extent that it formed the basis of CitiPower'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 CitiPower
- 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 is achieved

639. Adjustment of these assumptions, which we applied in various combinations, leads us to conclude that CitiPower requires a materially lower opex step change than it has proposed.

We consider that an opex step change of $8.7 million developed based on a more reasonable interpretation of CitiPower's data provides an efficient opex step change.

APPENDIX A – CITIPOWER, POWERCOR AND UNITED ENERGY'S ECONOMIC MODELLING OF PROPOSED ELECTRIFICATION PROGRAM

A.1 Introduction

640. 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.[130] These models are common in approach. For illustrative purposes, we refer here to the Powercor model, noting that our findings apply to all three.

641. 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.

642. 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

643. 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.

644. Powercor also provided a document with its regulatory submission with a file name '*Detailed customer electrification forecasting methodology.*'[131] 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)[132]

645. 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 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

130 PAL MOD 3.31

131 PAL attachment 2.04

132 As above, page 10: Definition of '*load_exceeding_normal_een_vcr*'

646. 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.

647. 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.

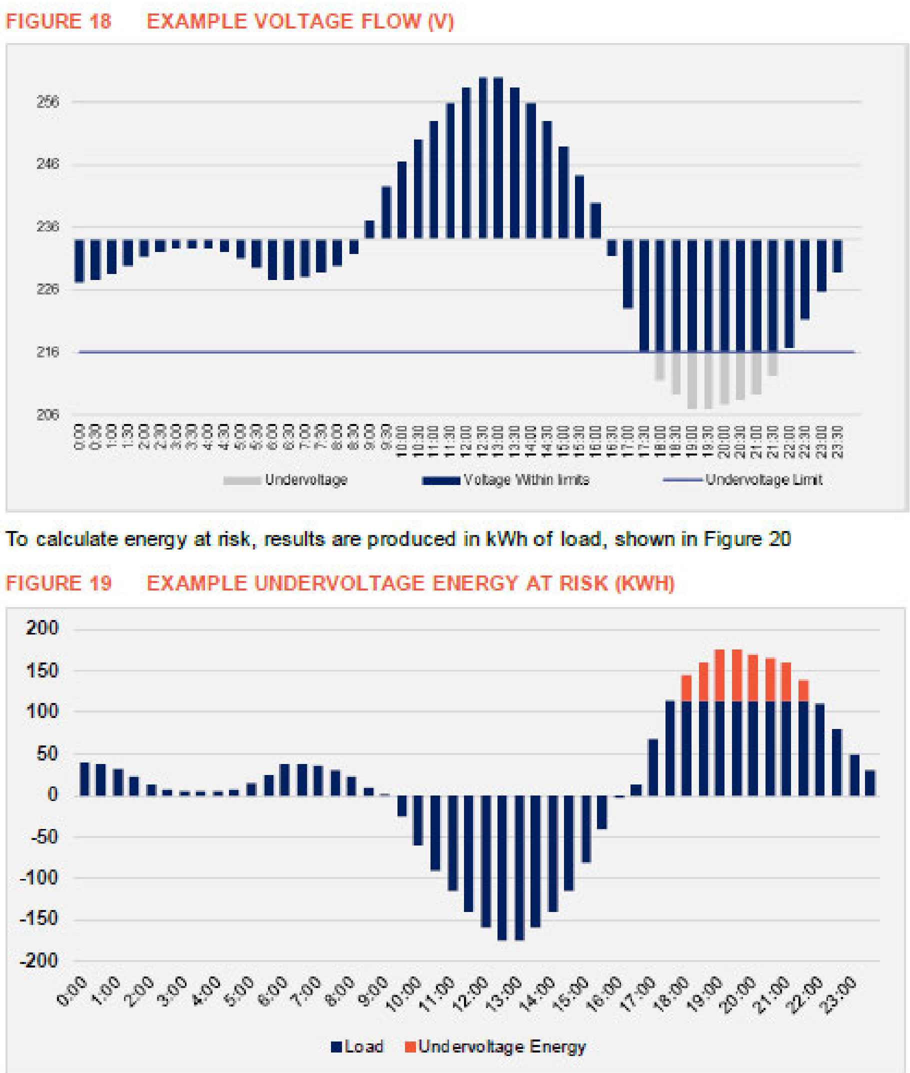
648. The model then undertakes a feeder-level assessment to calculate the most economic proactive LV augmentations in each year, to maintain the target level of service, choosing from the options of DSS offload or reconductoring.

649. 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

650. 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’



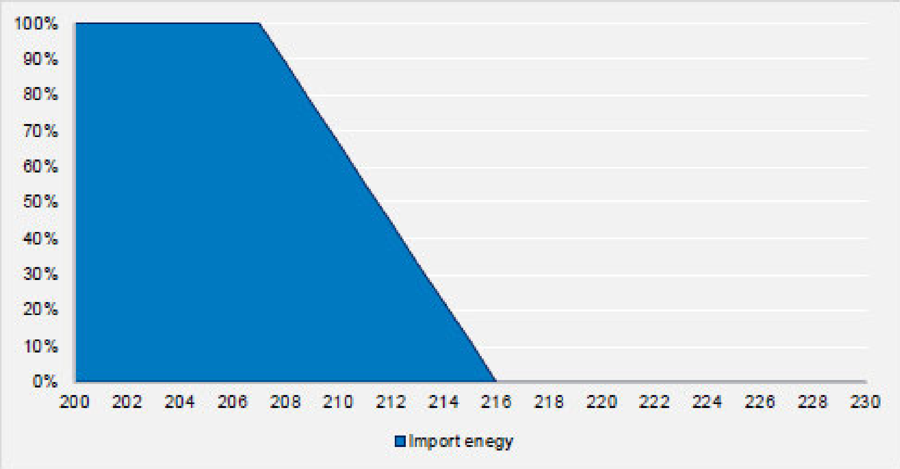
Source: PAL Att 2.01, figures 18 and 19

651. 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

652. Powercor's model simulates these forecast outcomes at the interval-level for each feeder, for 10 years

A.3 Sensitivity analysis

653. 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.

654. 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.

655. As we describe in section 4.5, CitiPower 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

656. 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

657. 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.

658. 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

659. 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 utilisation annuitised capex as a proxy for capex

660. 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.

661. 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.

662. In table B.1 we illustrate this result 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

663. 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.

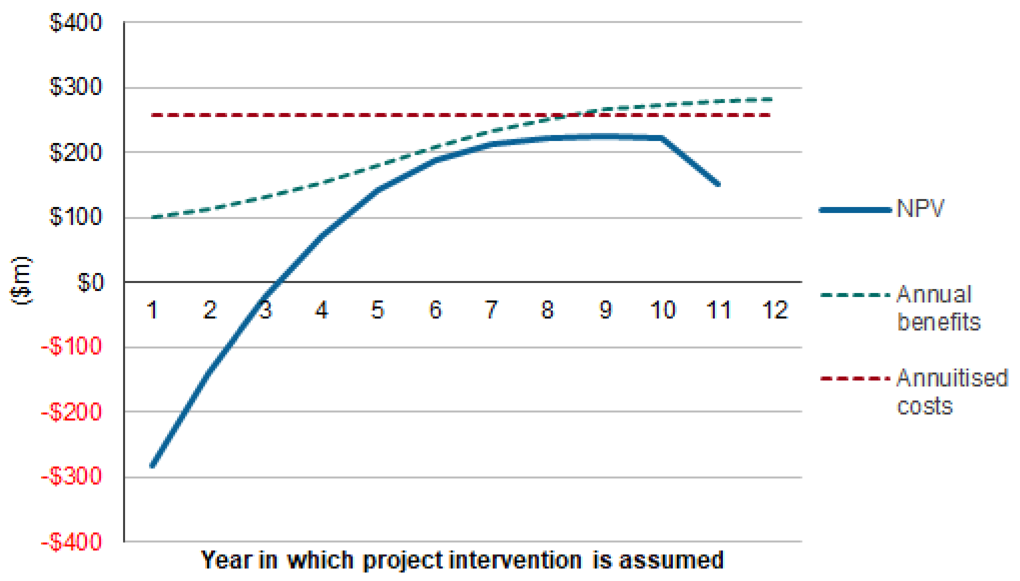
B.3 Economic timing

664. 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.

665. The question of identifying the optimum economic timing for the solution was addressed by AER in an industry practice application note.[133] In short, under microeconomic theory, it can be shown the optimum timing occurs when the annual benefits exceed the annuitised cost.

666. 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[134]



Source: EMCa (illustrative example only)

667. 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

[133] AER, Industry practice application note; Asset replacement planning, January 2019. See Figure 1 (page 37)

[134] 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.

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***.

- 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.

668. 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.

669. We consider this especially problematic where economic modelling of hundreds or thousands of potential interventions are 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

670. 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 CitiPower's network:

- Average reliability performance is generally improving, which suggest that CitiPower's asset management process has improved service levels
- According to the safety regulator ESV, despite relatively low numbers, the number of asset failure incidents are higher than the long-term average
- Despite increase in the rate of line clearance non-compliance over time, more recent performance has been improving, and
- Network utilisation is decreasing over time, and now aligns with the DNSP average

671. 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 CitiPower's network:

- Capex delivery performance is subject to a range of factors, with actual capex on average tracking more closely to forecast capex recently
- CitiPower expects the net capex to be lower than the capex allowance for the current RCP, and
- Over the last 5 years, actual opex is lower than forecast opex resulting in an underspend against the opex allowance.

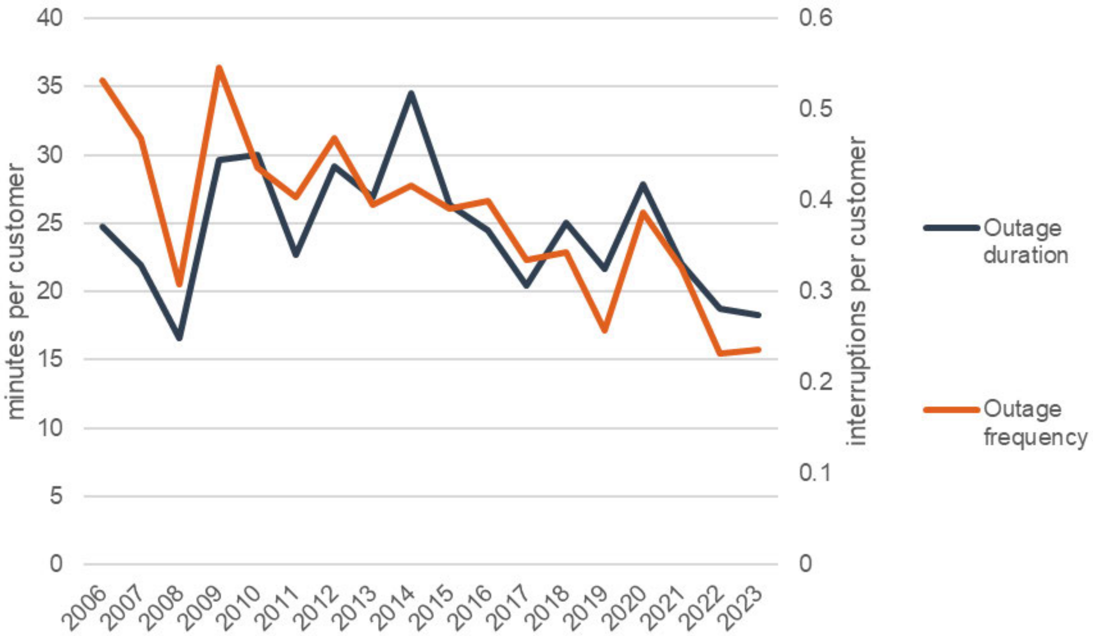
C.2 Current period service performance

Average reliability performance is generally improving, which suggest that CitiPower's asset management process has improved service levels

672. In its 2024 network performance report,[135] the AER stated that, on average, reliability had been improving for customers. Figure C.1 shows average outage duration and outage frequency data for CitiPower based on the AER network performance report data. This indicates a reducing trend of outage duration and outage frequency.

135 AER, 2024 Electricity and gas network performance report

Figure C.1: Comparison of CitiPower historical outage duration and outage frequency



Source: AER Network performance report

673. Outage frequency is 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. In general, this would suggest that CitiPower's asset management processes have been effective at improving service levels. We make further observations as it relates to the scope of our assessment of the expenditure as relevant.

According to the safety regulator ESV, despite relatively low numbers, the number of asset failure incidents are higher than the long-term average

674. ESV publish the number of serious electrical incidents reported to Energy Safe by CitiPower 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.

675. According to ESV, the most common incidents on the CitiPower network in 2022–23 were

> *'vehicle contact, dug-up cables, connection faults and other contact events. One of these items is within the control of CitiPower (connection faults) and the other three are largely outside its control.'*[136]

676. For asset failures, ESV state:

> *'The numbers of asset failure incidents were higher in 2022–23 than the long-term average in five categories and lower in three categories. Contact incidents were higher in two categories, lower in three categories and stable (within five per cent) in one category.'*[137]

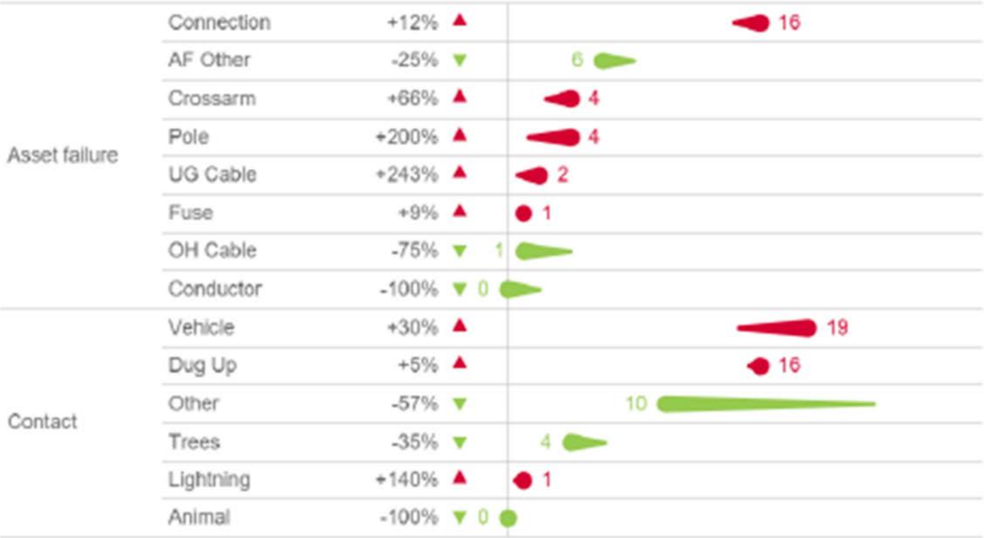
677. The asset failure numbers for CitiPower are relatively low, however were higher for its connection, pole and crossarm assets as shown in Figure C.2. ESV state that is commencing a review of the conductor and connection management practices of all distribution networks in 2023–24.

678. Connection failures was the sole source of fire incidents as shown in Figure C.3.

[136] ESV, 2023 Safety Performance report on Victorian Electricity Networks

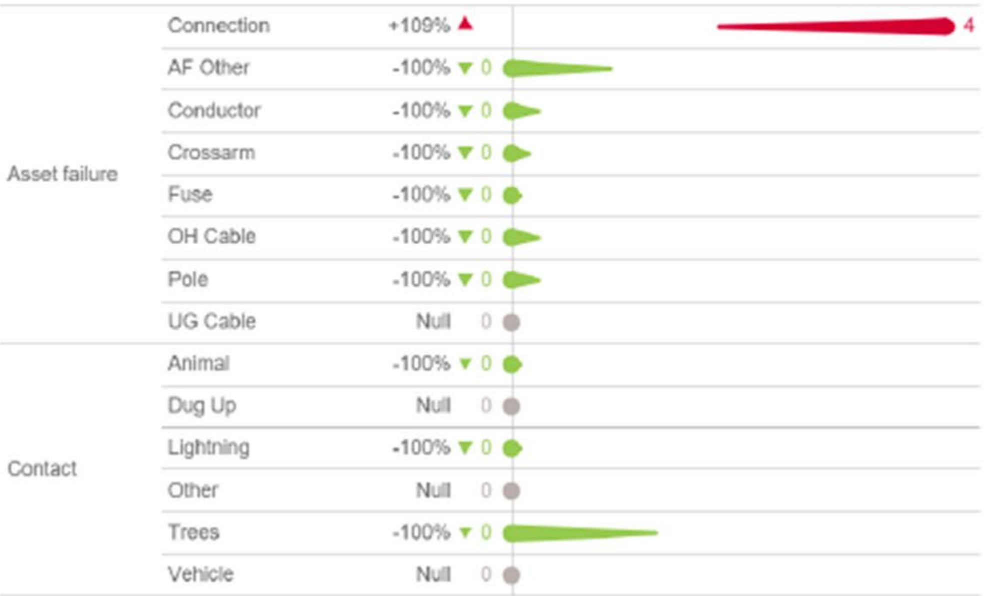
[137] Ibid

Figure C.2: Incidents on the CitiPower network



Source: ESV report, Figure 32

Figure C.3: Incidents on the CitiPower network resulting in ground fires

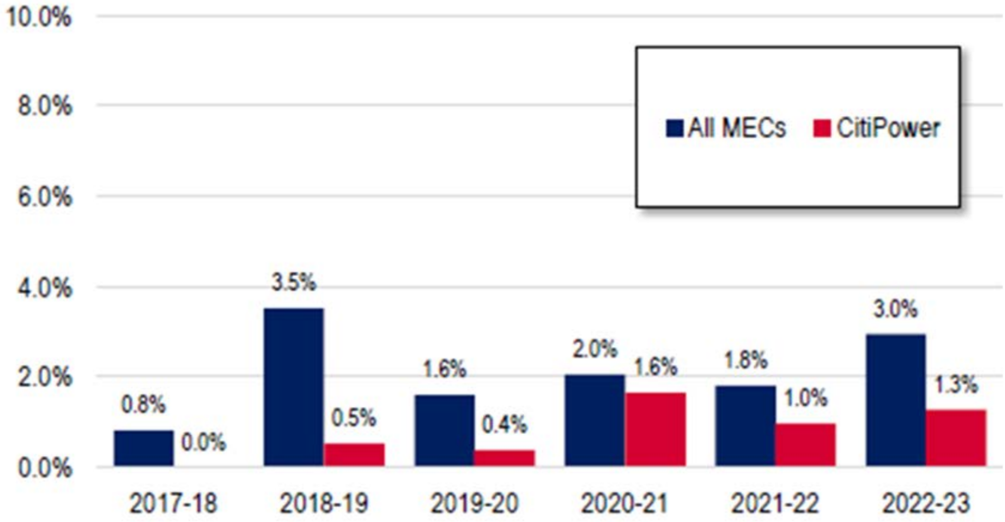


Source: ESV report, Figure 33

Despite an increase in the rate of line clearance non-compliance over time, more recent performance has been improving

679. 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.

Figure C.4: Rate of CitiPower major non-compliances (HBRA and LBRA)



Source: ESV report, Figure 31

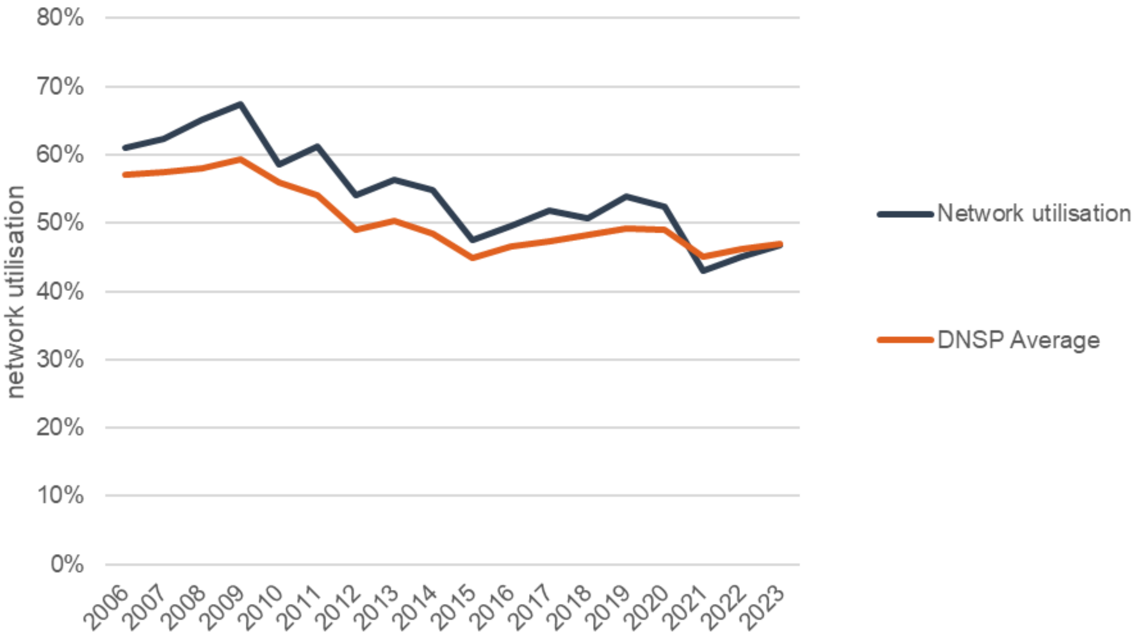
680. Despite the gradual increase in the rate of major non-compliances, and need for further improvement, ESV considered that the more recent trend is improving.

Network utilisation is decreasing over time, and now aligns with the DNSP average

681. Network utilisation is an indicator of the capacity of the electricity network, and whilst it does not account for localised constraints or complexities associated with the two-way flow of energy, it is a coarse measure of the ability for networks to make greater use of the network assets.

682. Figure C.5 shows that CitiPower's network utilisation is decreasing over time, in line with the DNSP average.

Figure C.5: Comparison of CitiPower historical network utilisation versus DNSP average



Source: AER Network performance report

C.3 Current period expenditure performance

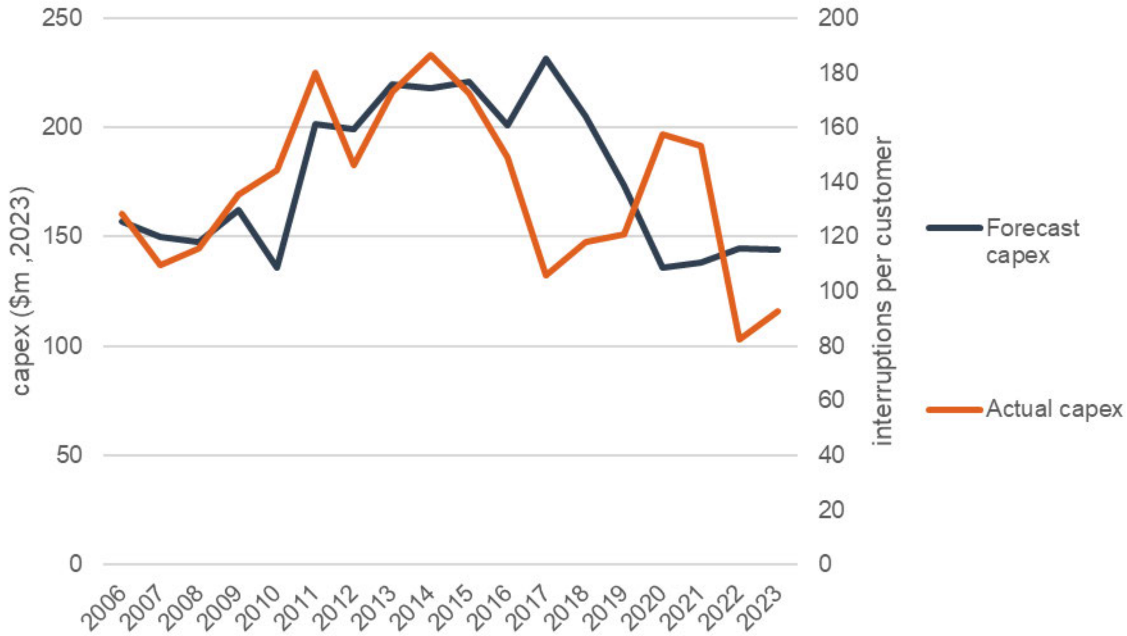
Capex delivery performance is subject to a range of factors, with actual capex on average tracking more closely to forecast capex recently

683. In its 2024 network performance report,[138] 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.*[139]

684. Figure C.6 shows the forecast vs actual capex for CitiPower 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.

Figure C.6: Comparison of CitiPower historical actual with forecast capex



Source: AER Network performance report

CitiPower expects the net capex to be lower than the capex allowance for the current RCP

685. Overall, CitiPower state that it expects the net capital expenditure to be lower than the AER's capex allowance in the current period (but will exceed this allowance after one-off asset disposals are excluded).

686. CitiPower is expecting to materially underspend the component of the allowance allocated to augex and to 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

[138] AER, 2024 Electricity and gas network performance report

[139] AER, 2024 Electricity and gas network performance report, page 29

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.

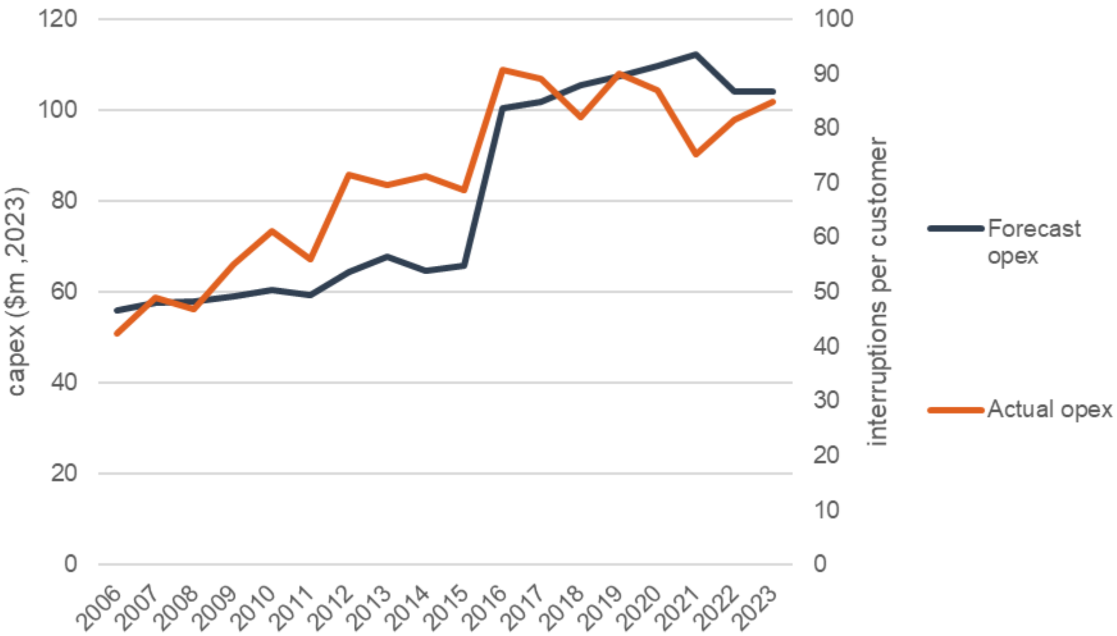
Over the last 5 years, actual opex is lower than forecast opex resulting in an underspend against the opex allowance

687. In its 2024 network performance report,[140] 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.'* [141]

688. Figure C.7 shows a comparison of historical actual with forecast opex for CitiPower. Whilst we have not been asked to consider overall opex, we observe that there has been a recent underspend of opex by CitiPower consistent with the observations by the AER across NSPs.

Figure C.7: Comparison of CitiPower historical actual and forecast opex



Source: AER Network performance report

140 AER, 2024 Electricity and gas network performance report

141 AER, 2024 Electricity and gas network performance report, page 29