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Regulatory Submission for period 2021/22 to 2025/26

CITIPOWER - REVIEW OF ASPECTS OF PROPOSED EXPENDITURE

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

August 2020

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be applied to the prescribed distribution services of CitiPower from 1st July 2021 to 30th June 2026. 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.

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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 EMCa prior to 31st July 2020 and any information provided after this time may not have been taken into account.

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ABBREVIATIONS

Term	Definition
ABS	Air-break switch
ACS	Asset Class Strategy
ACSC	Australian Cyber Security Centre
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Electricity Sector Cyber Security Framework
AFAP	As Far As Practicable
AHI	Asset Health Index
AMI	Advanced Metering Infrastructure
AMI NST	Advanced Metering Infrastructure Neutral Screen Testing
AMS	Asset Management Strategies
augex	Augmentation capital expenditure
B/C	Benefit/cost
BCA	Bushfire Construction Areas
BI/BW	Business Intelligence/business Warehousing
BMP	Bushfire Management Plan
BST	Base Step Trend
Capex	Capital expenditure
capex	Capital expenditure
CBA	Cost Benefit Analysis
CBD	Central Business District
CBRM	Condition Based Risk Management
CCC	Customer Consultative Committee
CIC	Capital Investment Committee
CIE	Centre of International Economics
CIGRE	Conseil International des Grands Réseaux Electriques; this translates as Council on Large Electric Systems
CNAIM	Common Network Asset Indices Methodology
CP	CitiPower
DAPR	Distribution Annual Planning Report
DBYD	Dial Before You Dig
DER	Distributed Energy Resources

DERMS	Distributed Energy Resource Management System
DGA	Dissolved Gas Analysis
DNSP	Distribution Network Service Provider
DVMS	Dynamic Voltage Management System
EBSS	Efficiency Benefit Sharing Scheme
EBSS	Efficiency Benefit Sharing Scheme
EFCAP	Energy Futures Customer Advisory Panel
ELCA	Electrical Line Construction Area
EMS	Enterprise Management Systems
EMT	Executive Management Team
ENA	Electricity Networks Association
ERP	Enterprise Resource Planning
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EV	Electric Vehicle
FY	Financial Year
GIS	Geospatial Information System
HBRA	Hazardous Bushfire Risk Areas
HI	Health Index
HV	High Voltage
IaaS	Infrastructure as a Service
ICT	Information and Communications Technology
IGF	Investment Governance Framework
IR	Information Request
IRR	Internal Rate of Return
ISO	International Organization for Standardization
IVR	Interactive Voice Response
kV	kilovolt
LBRA	Low Bushfire Risk Area
LDC	Load Duration Curves
LIDAR	Light Detection and Ranging
LQ	Little Queen substation
LSAA	Local Service Area Agents
LV	Low voltage
MGL	Multi-Greek Letter
MIL	Maturity Indicator Level

MVA	Mega Volt Amp
NEMMCO	National Energy Market Management Company
NER	National Electricity Rules
NNS	Non-network Solutions
NPV	Net Present Value
NST	Neutral Screen Testing
OLTC	On-load Tap Changer
opex	Operating expenditure
OT	Operational Technology
PAL	Powercor
PoE	Probability of Exceedance
PoF	Probability of Failure
PPCF	Portfolio and Project Controls Framework
PV	Photovoltaic generation (i.e. solar). (Depending on context, may refer to the Present Value of a cost or benefit stream)
PVC	Poly Vinyl Chloride
RAB	Regulatory Asset Base
RBAM	Risk Based Asset Management
RCM	Reliability Centred Maintenance
RCP	Regulatory Control Period
REFCL	Rapid Earth Fault Current Limiter
repex	Replacement (capital) expenditure
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
RMCC	Risk Management and Compliance Committee
RMU	Ring Main Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SAPN	South Australia Power Networks
SCADA	Supervisory Control and Data Acquisition
SE	Solar Enablement
SI	Serviceability Index
SME	Subject Matter Expert
SWER	Single Wire Earth Return
UCS	Unified Computing System

UE	United Energy
VCR	Value of Customer Reliability
VPN	Victoria Power Networks
WAN	Wide Area Network
ZSS	Zone Substation

1 INTRODUCTION

1.1 Scope

1. This report provides our assessment of certain aspects of CitiPower's proposed expenditure allowances, and the framework of governance, management and forecasting methods that the business has used to establish these proposed amounts. The report scope covers the following topics:

- Expenditure governance, management, and forecasting framework as applied by CitiPower;
- Repex;
- Non-DER augex;
- Solar Enablement expenditure (which comprises an augex component and a proposed opex step change);
- ICT expenditure (which includes capex and a proposed opex step change);
- Property-related capex; and
- Minor repairs opex.

2. The purpose of this report is to provide the AER with our assessment of the aspects of expenditure set out above, and the basis for our findings.

1.2 Structure of this report

3. The items within our scope are covered as follows:

- In section 2, we provide an overview of the expenditure that we have been asked to assess. This includes expenditure as proposed by CitiPower (and as represented in its RIN data), and also disaggregated data providing expenditure context for specific projects and expenditure categories that are referred to throughout the report.
- In section 3, we provide our assessment of CitiPower's investment governance and management frameworks and relevant aspects of its expenditure forecasting methodologies.
- In section 4, we provide our assessment of CitiPower's proposed repex.
- In section 5, we provide our assessment of CitiPower's proposed non-DER augex.
- In section 6, we provide our assessment of CitiPower's proposed Solar Enablement program, which includes its proposed Solar Enablement augex and proposed Solar Enablement operational expenditure as an opex step change.
- Section 7 provides our assessment of CitiPower's proposed ICT capex, and of its proposed ICT Cloud-related opex step change. This includes the ICT component of some related work under Solar Enablement (i.e., Digital Networks – see also section 6) and the ICT component of Facilities Security Upgrades, which are covered in section 8.
- In section 8, we provide our assessment of CitiPower's proposed property capex.
- In section 9, we provide our assessment of CitiPower's proposed addition of an allowance for minor repairs to CitiPower's base opex expenditure.

4. Two appendices follow the main sections of the report, as follows:

- In Appendix A, we provide contextual information related to consideration of an enhanced pole replacement program for CitiPower.

- In Appendix B, we provide an overview and assessment of the CBRM and risk monetisation model that CitiPower has used in seeking to justify its proposed expenditure for transformer and switchgear replacements.

1.3 Presentation of expenditure amounts

5. Expenditure is presented in this report in $2021 real terms, unless stated otherwise. In some cases, we have converted to this term from information provided by the business in other terms.[1]

6. CitiPower has proposed expenditure allowances which it has real-cost escalated in aggregate. However, project and program-level information presented by CitiPower (such as in the project models and business cases) has generally not had escalation applied. Accordingly, in this report, we have presented expenditure information in non-escalated terms to preserve comparability with the source data provided. We have footnoted any graphs and tables that comprise non-escalated expenditure.

7. 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 and minor differences due to rounding. Any such discrepancies do not affect our findings.

[1] Where we have needed to convert cost information provided by the business from expenditure denominated in terms other than $2021, we have done so using a common index series that CitiPower applied in its RIN. In some cases, we observe that CitiPower used different indices in the information that it provided to us, and this may result in small discrepancies. Any such discrepancies are not sufficient to have influenced our findings.

2 BACKGROUND INFORMATION

2.1 Introduction

8. This section is structured in accordance with our brief. We show, in turn, CitiPower's:

- Total net capex;
- Repex;
- Augex (including solar enablement capex);
- ICT capex;
- Property-related capex; and
- Opex (focused on the step changes and proposed reclassification that we have been asked to assess).

9. The graphs and tables that follow document the expenditures that we have been asked to assess. It includes RIN data provided by CitiPower and aggregated data from its project models. We have sought to aggregate project information in ways that match the structure by which we have assessed overall expenditures. For example, we have structured:

- Repex data by RIN group, with the exception that we have combined poles expenditure and pole staking expenditure;
- Augex data by 'function types' that CitiPower has defined;
- ICT expenditure by project and as categorised by CitiPower as Recurrent and Non-recurrent; and
- Property expenditure programs for facilities upgrades and a building compliance program.

10. We also show proposed expenditure for each of the focus projects that AER asked us to assess, in the context of Powercor's overall expenditure.

11. CitiPower modified some aspects of its proposed expenditure after submission to the AER by removing some proposed expenditure, and we have accordingly removed these amounts from the expenditure information that we have assessed.

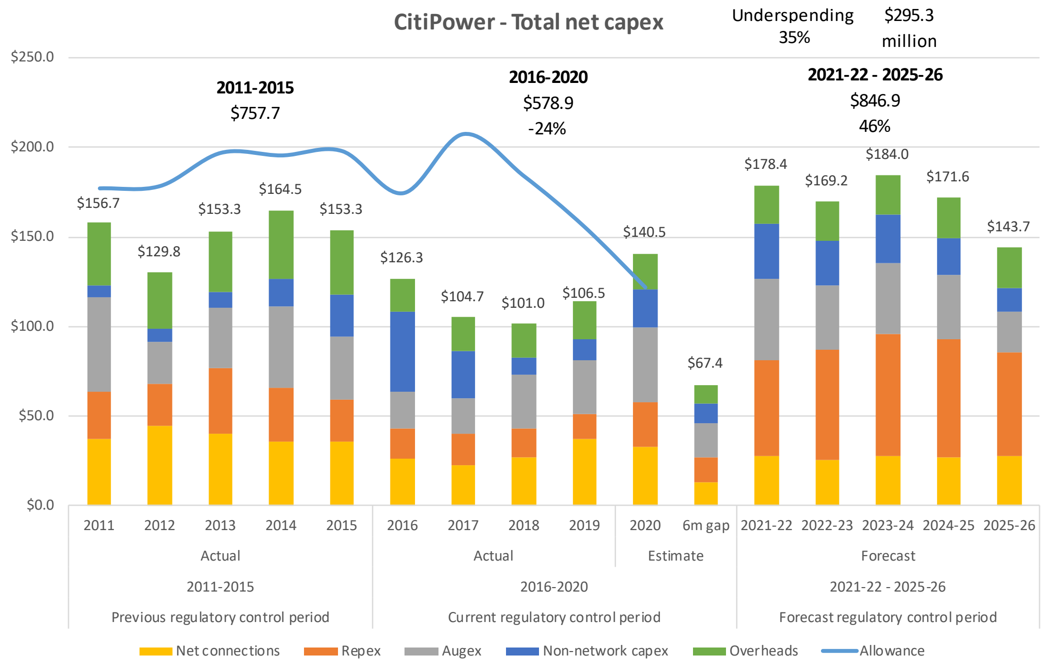
12. In this section, we also provide some high-level trend information for context. More focused expenditure and trend information, relevant to our assessments, is provided in the assessment section of this report.

13. Finally, in this section, we reproduce aspects of the NER which are relevant to our assessments.

2.2 Total Net Capex

14. Table 2.1 below shows actual and estimated CitiPower total net capex vs AER allowance for prior RCP's and forecast CitiPower total net capex for the next RCP.

Figure 2.1: CitiPower Total net Capex vs AER Allowance



Source: AER trend analysis 'Victoria Total Net Capex - 21 May 2020'

2.3 Category expenditure and trends

2.3.1 Repex

RIN data

15. Table 2.1 shows repex by RIN Group for the next RCP as reported in the RIN. CitiPower's total forecast repex for the next RCP is $308.0m, This mirrors how repex was presented in CitiPower's Regulatory Proposal in that it includes the RIN Group "Public Lighting", which should not have been included as SCS, as well as the Environmental Management program, under RIN Group "Other", which has since been withdrawn and substituted with a much smaller forecast.

16. Table 2.2 shows our assessment of the proposed Repex by RIN Group following these adjustments.

Table 2.1: CitiPower repex for the next RCP – As reported in CitiPower's RP - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	12.8	13.0	13.3	13.5	13.8	66.5
Pole Top Structures	3.2	3.3	3.3	3.4	3.4	16.7
Overhead Conductors	0.1	0.1	0.1	0.1	0.1	0.6
Underground Cables	0.6	0.7	0.7	0.7	0.7	3.4
Service Lines	3.2	3.3	3.4	3.5	3.6	17.1
Public Lighting	0.1	0.1	0.1	0.1	0.1	0.4
Transformers	3.2	6.4	6.1	4.1	2.2	21.9
Switchgear	7.0	10.6	12.1	12.6	17.5	59.7
SCADA, Network Control and Protection	5.2	5.2	5.4	5.6	5.7	27.0
Other	18.3	19.2	23.9	22.2	11.2	94.9
Total	**53.7**	**61.9**	**68.4**	**65.7**	**58.3**	**308.0**

Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Table 2.2: CitiPower repex for the next RCP – Following adjustments for Environmental Management and Public Lighting - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	12.8	13.0	13.3	13.5	13.8	66.5
Pole Top Structures	3.2	3.3	3.3	3.4	3.4	16.7
Overhead Conductors	0.1	0.1	0.1	0.1	0.1	0.6
Underground Cables	0.6	0.7	0.7	0.7	0.7	3.4
Service Lines	3.2	3.3	3.4	3.5	3.6	17.1
Transformers	3.2	6.4	6.1	4.1	2.2	21.9
Switchgear	7.0	10.6	12.1	12.6	17.5	59.7
SCADA, Network Control and Protection	5.2	5.2	5.4	5.6	5.7	27.0
Other	4.9	4.9	4.9	4.9	5.1	24.7
Total	**40.2**	**47.5**	**49.3**	**48.4**	**52.1**	**237.5**

Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020' Includes real cost

Repex from the project models as mapped to RIN Groups

17. The following table shows project-level repex as now proposed by CitiPower. Public Lighting and the originally proposed Environmental Management program have been removed and substituted. Real cost escalation has not been included in the project model analysis. Values have been inflated where necessary to be in the common basis of Real 2021 dollars.

Table 2.3: CitiPower Repex – As Amended by CP (After withdrawals) - $m, real 2021

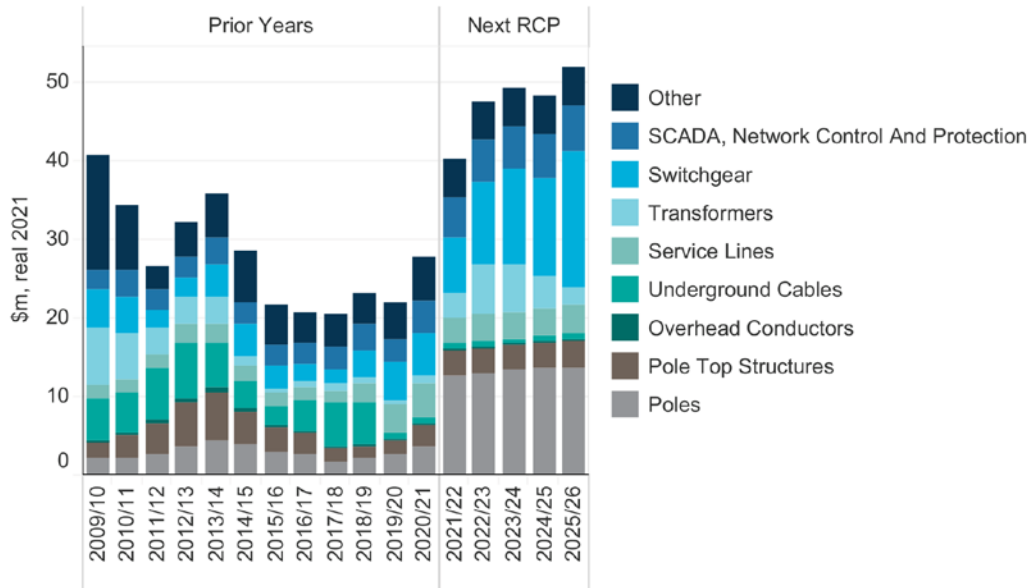
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	12.6	12.6	12.6	12.7	12.7	63.2
Pole Top Structures	3.2	3.2	3.2	3.2	3.2	15.8
Overhead Conductors	0.1	0.1	0.1	0.1	0.1	0.6
Underground Cables	0.6	0.6	0.6	0.6	0.6	3.2
Service Lines	3.2	3.2	3.2	3.3	3.3	16.2
Transformers	3.1	6.2	5.8	3.8	2.0	20.9
Switchgear	6.9	10.2	11.5	11.7	16.1	56.5
SCADA, Network Control and Protection	5.1	5.1	5.1	5.2	5.2	25.7
Other	4.8	4.8	4.7	4.7	4.8	23.7
Total	**39.5**	**46.0**	**46.9**	**45.3**	**48.1**	**225.8**

Source: EMCa analysis of CP MODs 4.06, 4.09, 4.10, 4.11. Excludes real cost escalation. Excludes Public Lighting & Environmental Management program.

Repex trend

18. Repex trends over time, by RIN Group, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. 2018/2019 FY has been populated using escalated project model data provided by the AER. Forecast values for the Public Lighting RIN Group and for the Environmental Management program have been removed. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.2: CitiPower repex – as amended by CP (After withdrawals) - $m, real 2021



Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020', 'CitiPower consolidated RIN - repex - 2018-19_sent to EMCa'. Financial Years. Includes real cost escalation. Excludes Public Lighting & forecast Environmental Management program.

Repex by program, showing AER focus projects

19. The following table shows the sum of the AER's designated repex focus projects and programs within each mapped RIN Group using data from the project models without real cost escalation.

Table 2.4: CitiPower repex (as amended by CP) showing AER Focus Projects and Programs - $m, real 2021

Group / AER Focus	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	12.6	12.6	12.6	12.7	12.7	63.2
AER Focus: Wood Poles	*11.8*	*11.8*	*11.8*	*11.8*	*11.8*	*58.9*
Other	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*4.3*
Pole Top Structures	3.2	3.2	3.2	3.2	3.2	15.8
Overhead Conductors	0.1	0.1	0.1	0.1	0.1	0.6
Underground Cables	0.6	0.6	0.6	0.6	0.6	3.2
Service Lines	3.2	3.2	3.2	3.3	3.3	16.2
Transformers	3.1	6.2	5.8	3.8	2.0	20.9
AER Focus: ZS Transformers	*2.8*	*5.8*	*5.4*	*3.5*	*1.6*	*19.1*
Other	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.8*
Switchgear	6.9	10.2	11.5	11.7	16.1	56.5
AER Focus: Little Queen Switchboard Replacement		*0.0*	*2.6*	*6.0*	*10.4*	*19.0*
Other	*6.9*	*10.2*	*8.9*	*5.7*	*5.8*	*37.4*
SCADA, Network Control and Protection	5.1	5.1	5.1	5.2	5.2	25.7
AER Focus: Protection and Replacement Program	*5.1*	*5.1*	*5.1*	*5.2*	*5.2*	*25.7*
Other	4.8	4.8	4.7	4.7	4.8	23.7
Total	**39.5**	**46.0**	**46.9**	**45.3**	**48.1**	**225.8**

Source: EMCa analysis of CitiPower MODs 4.06, 4.09, 4.10, 4.11. Excludes real cost escalation

2.3.2 Augex

RIN data

20. The table below shows CitiPower's augex for the next RCP as reported in the RIN and RP by RIN Category.

Table 2.5: CitiPower augex for the next RCP – as reported in CitiPower's RP - $m, real 2021

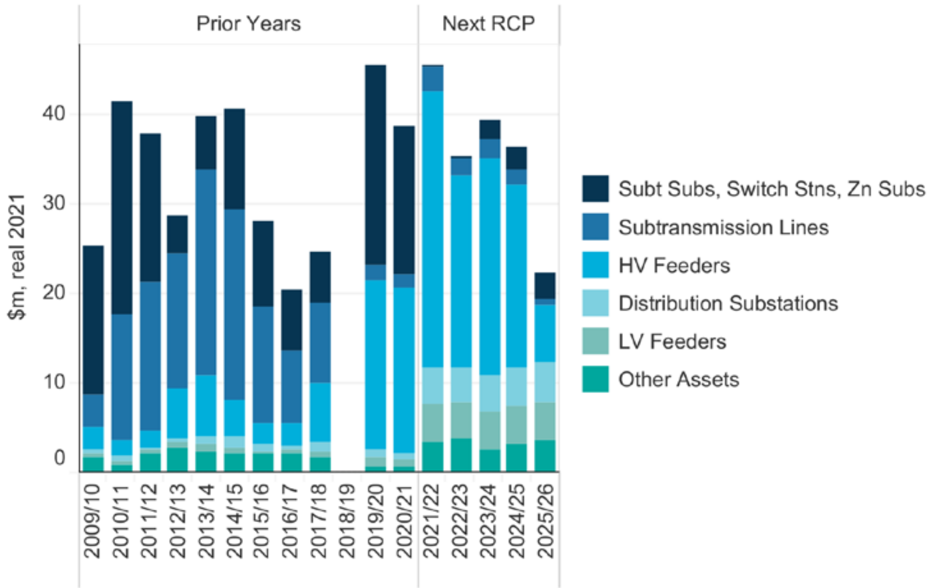
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	0.3	0.1	2.1	2.4	3.0	8.0
Subtransmission Lines	2.7	1.9	2.1	1.8	0.6	9.0
HV Feeders	30.9	21.5	24.2	20.5	6.4	103.5
Distribution Substations	4.1	3.9	4.2	4.2	4.4	20.8
LV Feeders	4.1	3.9	4.2	4.2	4.4	20.8
Other Assets	3.5	3.9	2.5	3.2	3.6	16.8
Total	**45.6**	**35.2**	**39.3**	**36.3**	**22.3**	**178.9**

Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Augex trend

21. Augex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.3: CitiPower augex trend - $m, real 2021



Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

Augex by function type, showing AER focus projects and additional business cases

22. Table 2.6 below shows CitiPower's augex project expenditure for the next RCP organised by the Function Types provided in CitiPower's Consolidated Capex Model (10.05).This table also shows augex for each of the AER focus projects that we assessed. 'Other' augex is included for reconciliation purposes. Real cost escalation has been excluded.

Table 2.6: CitiPower augex for the next RCP by Function Type & AER Focus Projects - $m, real 2021

Function Type / Focus	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Augmentation of Subtransmission	30.8	14.1	15.1	16.2	6.4	82.5
AER Focus projects						
Brunswick SA	*18.2*	*10.5*				*28.7*
Port Melbourne		*2.6*	*9.8*	*7.2*		*19.6*
Russell Place SA	*11.2*					*11.2*
Other	1.4	1.0	5.3	9.0	6.4	23.0
CBD Security	2.3	8.6	9.9	4.7		25.5
AER Focus projects						
CBD Supply	*2.3*	*8.6*	*9.9*	*4.7*		*25.5*
Augmentation of Zone Substations	0.3	0.1	2.0	2.2	2.8	7.5
LV Augmentation	8.1	7.6	8.0	7.9	8.1	39.7
AER Focus projects						
Solar Enablement	*6.6*	*6.0*	*6.3*	*6.2*	*6.3*	*31.5*
Other	1.5	1.6	1.7	1.7	1.8	8.2
Zone Substation Automation	3.5	3.8	2.4	3.0	3.3	16.0
Total	**44.9**	**34.1**	**37.4**	**34.0**	**20.7**	**171.1**

Source: EMCa analysis of CitiPower MOD 6.01, 6.04, 10.05. Excludes real cost escalation.

2.3.3 ICT

RIN data

23. Table 2.7 below shows ICT Capex by RIN Category for the next RCP, including real cost escalation.

Table 2.7: CitiPower ICT capex for the next RCP by RIN Category - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Corporate Services	3.3	2.7	2.3	3.9	1.6	13.9
Customer Engagement	1.7	0.8	1.9	0.8	0.3	5.4
Cyber Security	1.7	1.7	1.9	1.8	1.5	8.6
Field Work & Construction	1.4	3.9	6.3	5.4	0.5	17.5
Market Compliance	8.6	3.0	2.2	1.0	1.9	16.8
Network Assets and Network Operations	6.7	6.7	7.4	3.8	3.3	27.8
Service Management and Ops	1.2	1.2	1.2	1.2	1.2	6.1
Total	**24.6**	**19.9**	**23.2**	**18.0**	**10.4**	**96.1**

Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

ICT capex projects categorised as Recurrent/Non-recurrent

24. Table 2.8 below shows ICT capex, for both Recurrent and Non-recurrent expenditure, for the next RCP. AER Focus Projects have been highlighted. Real cost escalation has been excluded.

Table 2.8: CitiPower ICT capex for the next RCP by project - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Recurrent	**12.3**	**11.3**	**9.3**	**10.4**	**8.0**	**51.3**
AER Focus projects						
Infrastructure with Cloud migration	*2.8*	*2.3*	*1.9*	*2.5*	*1.4*	*10.8*
Network Management	*2.3*	*2.1*	*0.6*	*1.7*	*1.9*	*8.5*
Other						
BI/BW	*0.1*	*0.7*	*0.2*	*0.1*	*0.1*	*1.1*
Customer Enablement	*0.1*	*0.3*	*0.8*	*0.1*	*0.1*	*1.6*
Cyber security	*1.2*	*1.2*	*1.3*	*1.2*	*1.0*	*5.8*
Device replacement	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*	*5.8*
Enterprise Management Systems -Non-SAP	*1.4*	*0.9*	*0.6*	*1.4*	*0.1*	*4.4*
Facilities' security	*0.5*	*0.4*	*0.3*	*1.2*	*0.1*	*2.6*
General compliance	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*4.6*
Market Systems	*0.4*	*0.4*	*1.2*		*0.8*	*2.8*
SAP S/4HANA	*0.4*	*0.7*			*0.4*	*1.6*
Telephony	*1.0*	*0.3*	*0.3*		*0.1*	*1.7*
Non-recurrent	**12.0**	**8.0**	**12.9**	**6.6**	**1.6**	**41.2**
5 Minute Settlements	*7.2*	*1.6*	*0.0*	*0.0*	*0.1*	*8.9*
Customer Enablement	*0.5*	*0.1*	*0.7*	*0.6*		*1.9*
Cyber security	*0.5*	*0.5*	*0.5*	*0.5*	*0.4*	*2.5*
Digital network	*2.8*	*3.2*	*3.1*	*0.9*	*1.2*	*11.1*
Intelligent engineering		*0.9*	*3.1*	*0.5*		*4.4*
SAP S/4HANA		*1.8*	*5.4*	*4.1*		*11.3*
Solar enablement DVMS	*1.1*					*1.1*
Grand Total	**24.3**	**19.4**	**22.2**	**17.0**	**9.7**	**92.5**

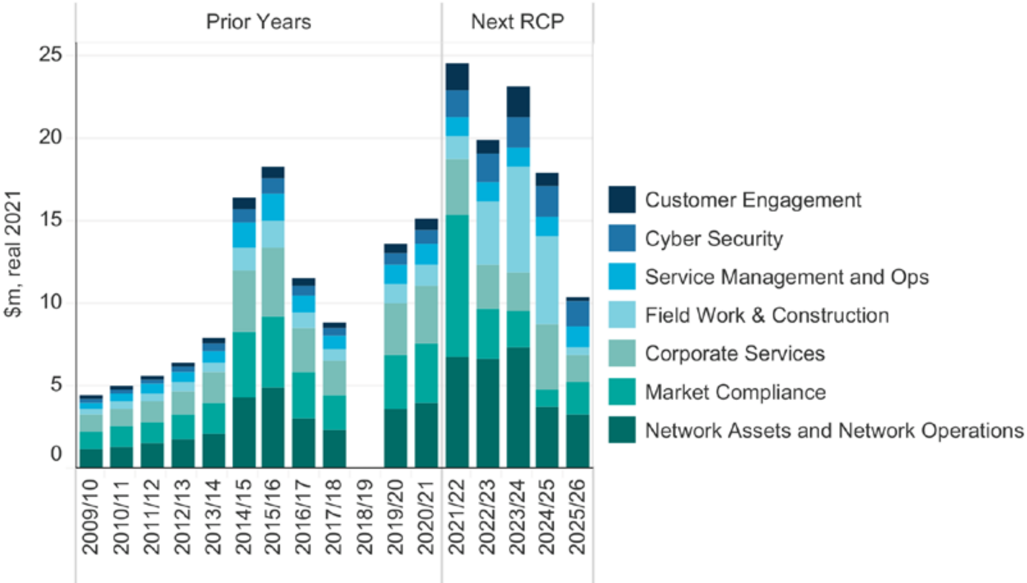
Source: EMCa analysis of CitiPower MOD 7.01. Excludes real cost escalation

ICT capex trend

25. Figure 2.4 shows CitiPower's ICT capex trends for prior RCP's and the next RCP, by RIN Category, that have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

26. We note that ICT capex is split between PAL and CP based on a fixed percentage (%) apportionment. As such, the trends for both companies follow the same shape albeit at different scales.

Figure 2.4: CitiPower ICT capex trend by RIN Category - $m, real 2021

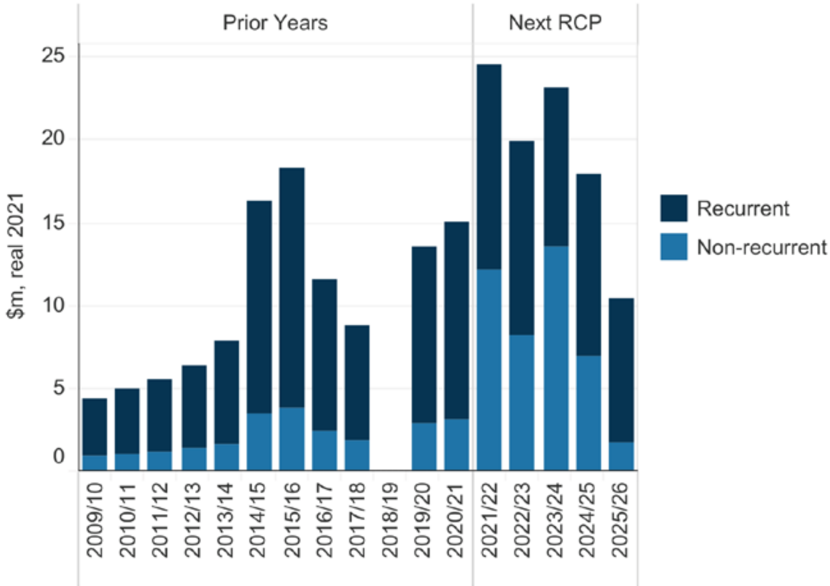


Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

ICT Capex trends by Recurrent/Non-Recurrent expenditure classification

27. Figure 2.5 shows the ICT capex trend, categorised by Recurrent and Non-recurrent capex, for prior years and the next RCP.

Figure 2.5: CitiPower ICT capex for the next RCP by Recurrent/Non-Recurrent - $m, real 2021



Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020' (CitiPower also provided historical data in Workbook 2. That data is in calendar years. While CitiPower claims that the Workbook 2 data reflects AER's new definitions, we observe that *the ratio of recurrent to non-recurrent expenditure in Workbook 2 is identical to that presented under the old definitions, per Workbook 8, and is also identical for each historical year)*

2.3.4 Property

RIN data

28. Property expenditure is not broken down in the RIN, existing only as a line item for "total buildings and property expenditure". Table 2.10 below shows total forecast property expenditure for the next RCP, including real cost escalation.

Table 2.9: CitiPower property capex for the next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total buildings and property expenditure	4.8	3.9	2.9	2.0	2.0	15.6
Total	**4.8**	**3.9**	**2.9**	**2.0**	**2.0**	**15.6**

Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

Project data

29. Table 2.11 below shows forecast Property expenditure from CitiPower's project models for the next RCP. Real cost escalation has been excluded.

Table 2.10: CitiPower Proposed Property Projects - $m, real 2021

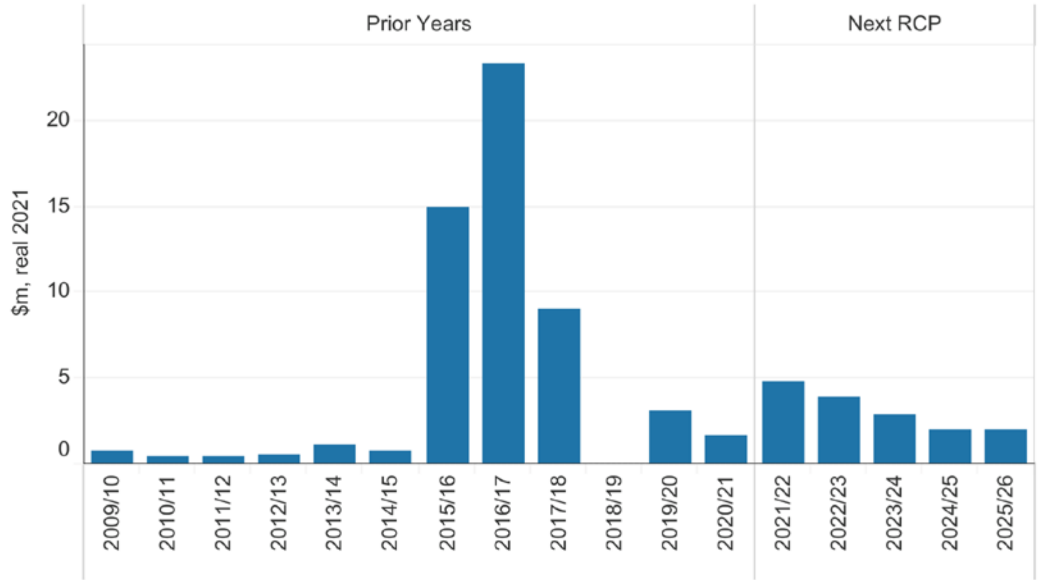
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Building compliance	1.8	1.8	1.2	0.6	0.6	6.0
Facilities	3.0	2.1	1.6	1.4	1.4	9.4
Total	**4.8**	**3.9**	**2.8**	**2.0**	**2.0**	**15.4**

Source: EMCa analysis of CitiPower MOD 8.01. Excludes real cost escalation

Property capex trend

30. In Figure 2.5 below, CitiPower's Property capex trend over time has been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years for prior RCP's and the next RCP. All expenditure has been inflated to Real 2021 dollars and includes real cost escalation.

Figure 2.6: CitiPower property capex trend - $m, real 2021



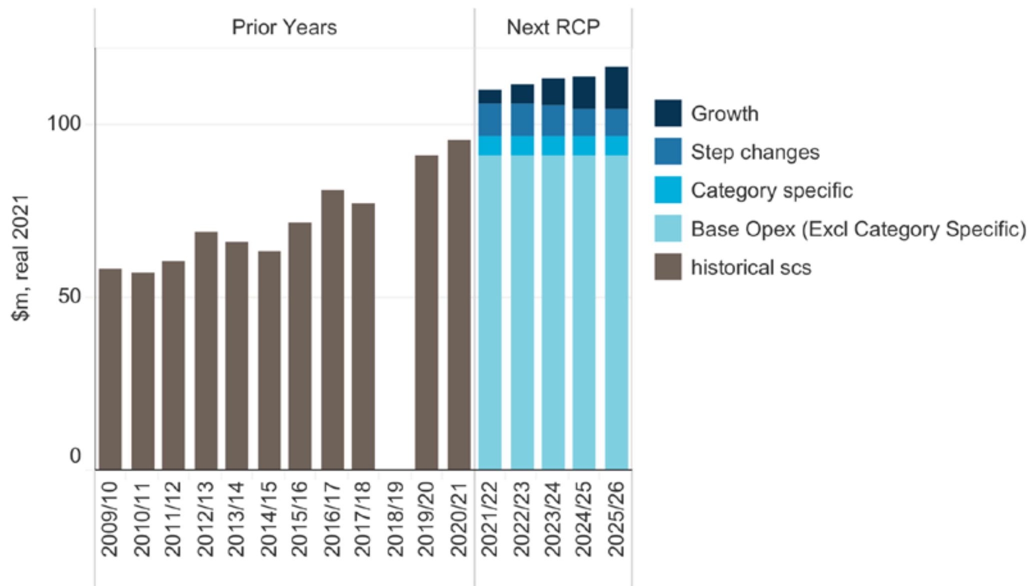
Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

2.3.5 Opex

Opex Trend and overview of next RCP

31. The opex trend over time has been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to Real 2021 dollars and Powercor's forecast includes its proposed real cost escalation.

Figure 2.7: CitiPower opex trend - $m, real 2021



Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

32. Proposed 'Step changes' and 'Category Specific' Opex for the next RCP are further categorised as follows. Includes real cost escalation.

Table 2.11: CitiPower's proposed 'Step Changes' and 'Category Specific' opex for the next RCP - $m, real 2021

Group & Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Step Changes	**9.8**	**9.4**	**8.8**	**7.7**	**8.0**	**43.6**
5-minute settlement	0.2	0.3	0.4	0.5	0.6	1.9
EPA regulations change	2.4	2.2	1.2	0.1	0.1	6.1
ESV levy	0.3	0.3	0.3	0.3	0.3	1.5
Financial year RIN	0.4	0.4	0.4	0.4	0.4	1.8
IT cloud solutions	0.3	0.3	0.5	0.6	0.6	2.3
Security of critical infrastructure	3.1	2.8	2.8	2.9	2.9	14.4
Solar enablement	0.4	0.3	0.3	0.2	0.1	1.3
Yarra trams pole relocation	2.8	2.8	2.9	2.9	3.0	14.4
Category Specific	**5.4**	**5.4**	**5.4**	**5.4**	**5.4**	**26.8**
Communications network	0.6	0.6	0.6	0.6	0.6	3.2
Emergency recoverable works	0.2	0.2	0.2	0.2	0.2	1.1
Replacement expenditure on faults and minor repairs	4.1	4.1	4.1	4.1	4.1	20.5
Wasted truck visits	0.4	0.4	0.4	0.4	0.4	2.1
Total	**15.2**	**14.8**	**14.2**	**13.1**	**13.3**	**70.5**

Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'.

Opex step changes & Category-specific opex in scope for EMCa's review

33. The AER has asked EMCa to provide advice on certain aspects of CitiPower's proposed opex – as shown in the table below, including real cost escalation.

Table 2.12: AER Focus sections of proposed opex - $m, real 2021

Group & Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Step Changes	**0.7**	**0.6**	**0.8**	**0.7**	**0.7**	**3.6**
IT cloud solutions	0.3	0.3	0.5	0.6	0.6	2.3
Solar enablement	0.4	0.3	0.3	0.2	0.1	1.3
Category Specific	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**20.5**
Replacement expenditure on faults and minor repairs	4.1	4.1	4.1	4.1	4.1	20.5
Total	**4.8**	**4.7**	**4.9**	**4.8**	**4.8**	**24.1**

Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

34. Our assessment of ICT cloud opex is in the ICT section (section 7), and our assessment of solar enablement opex is in the Solar Enablement section (section 6). Proposed expenditure for minor repairs is assessed in section 9.

2.4 NER Capex Objectives and Criteria

35. 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. 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 DNSP's capex proposal if it is satisfied that the capex proposal reasonably reflects the capital expenditure criteria and, in turn, appropriately references the capital expenditure objectives.

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

- Drawing on the wording of the first and second capex 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 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 capex 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 then 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 capex objective (emphasis added), encompassing the need for the DNSP to show that it has properly considered demand management and non-network options;
- We tend towards a strict interpretation of compliance (under the second capex objective), with the onus on the DNSP to evidence specific compliance requirements rather than to infer them; and
- We note the word 'maintain' in capex objectives 3 and 4 and, accordingly, we have sought evidence that the DNSP has demonstrated that it has properly assessed the proposed expenditure as being required to reasonably maintain, as opposed to enhance or diminish, the aspects referred to in those objectives.

37. The NER's capex criteria and capex objectives are reproduced below.

NER capital expenditure criteria

(c) 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 and cost inputs required to achieve the capital expenditure objectives.

Source: NER 6.5.7(c) Forecast capital expenditure, v111

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 achieve 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; and

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

Source: NER 6.5.7(a) Forecast capital expenditure, v111

3 REVIEW OF INVESTMENT GOVERNANCE AND MANAGEMENT FRAMEWORK

In this section, we provide an overview of the expenditure governance and management framework applied by CitiPower. We subsequently assess the extent to which expenditure forecasts developed under this framework, and that are within our scope of review, are likely to be prudent and efficient.

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

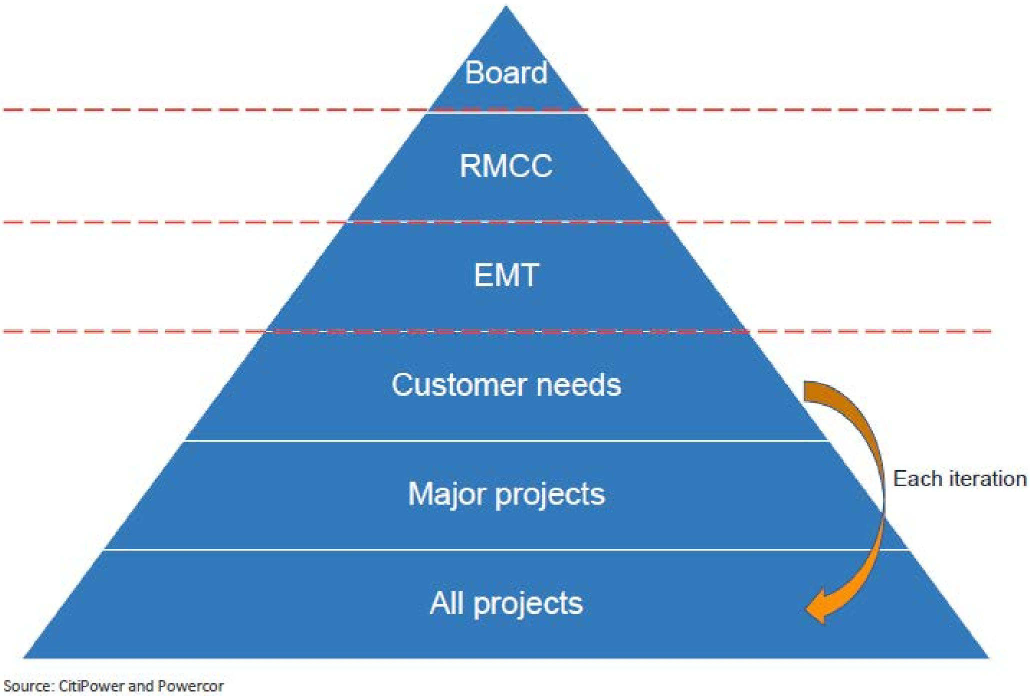
3.1 CitiPower's framework

3.1.1 Investment governance and management framework

Overview of the framework

38. The investment governance framework that is applied across the Victoria Power Networks (VPN) for capex is reproduced in the following figure.

Figure 3.1: Hierarchy of approach to overall investment decision



Source: Response to information request IR019a – EMCa questions – governance and repex

39. CitiPower explains each of the elements of the VPN framework as follows:[2]

- '***All projects***: *all investments that are likely to be made over the regulatory period were prepared as an initial iteration of expenditure. We removed all projects that were*

2 Response to information request IR019a

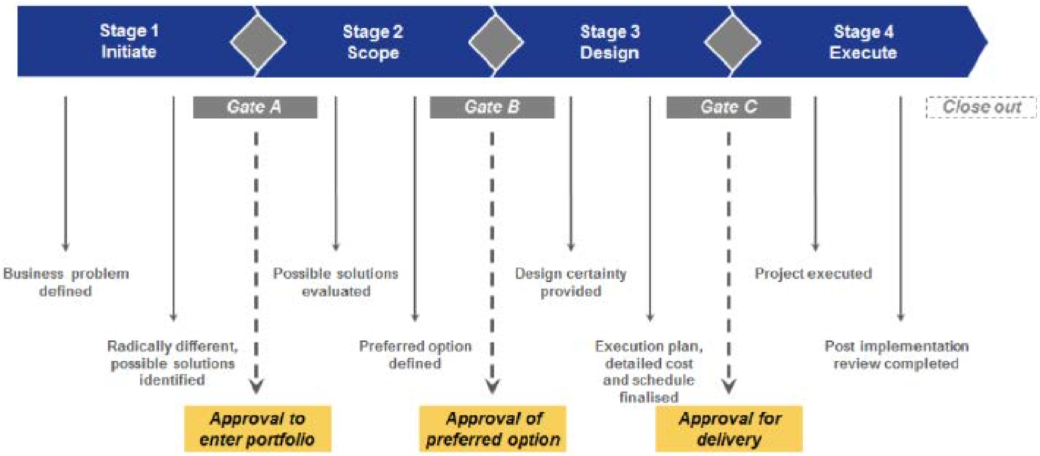
considered to be productivity enhancing, or where the driver was reliability improvements, as these projects will be self-funded by VPN during the period. Within each iteration, the list of all projects was revisited based on new or updated information.

- ***Major projects**: all major projects were assessed to understand their drivers and benefits to all customers. Those projects that had a compliance driver, or where the benefits of the project outweighed the cost to consumers, were prioritised in the iterations. Within each iteration, the major projects were revisited based on new or updated information that may have shifted the timing, or revised parameters.*
- ***Customer needs**: these were overlaid against the overall forecasts. Throughout the stakeholder engagement for the regulatory reset, affordability remained a primary concern for our customers. For other projects, our forecasts were refined based on stakeholder feedback or support for a particular investment. Within each iteration, the expenditure and projects were reviewed based on updated stakeholder feedback.*
- ***Executive Management Team (**EMT**)**: each iteration was submitted to the EMT for review. The EMT acts as a control of the regulatory risks associated with the regulatory reset for VPN, and considered the overall package of investment for the period to 2026. In particular, the EMT reviewed each expenditure iteration taking into account whether it would meet the capital expenditure objectives set out in clause 6.5.7 of the National Electricity Rules (NER), as well as the capital expenditure criteria and factors.*
- ***Risk Management and Compliance Committee (**RMCC**)**: is a Board Committee that oversees the risk profile of VPN and ensures that appropriate policies and procedures are adopted for the timely and accurate identification, reporting and management of significant risks to VPN. It also assists the Board to oversee compliance with obligations determined by statute, legislation, regulation, contract or agreement. The RMCC reviewed the controls in relation to risks arising from changes to the regulations, as well as the regulatory reset.*
- ***Board**: the* VPN *Board has ultimate responsibility for VPN's capital investment forecasts for the 2021-2026 regulatory period. The Board ensures that the forecasts find a balance between meeting VPN and shareholder's needs as well as those of our customers, while managing the various risks over the medium term. The draft and final regulatory proposal forecasts were reviewed by the Board, and they approved the material assumptions underpinning the forecasts.'*

Portfolio and project gating framework

40. VPN also has a Portfolio and Project Controls Framework (PPCF). The PPCF includes four stages and three approval gates as shown in the figure below.

Figure 3.2: Portfolio and Project Controls Framework (PPCF)



Source: Asset Management framework

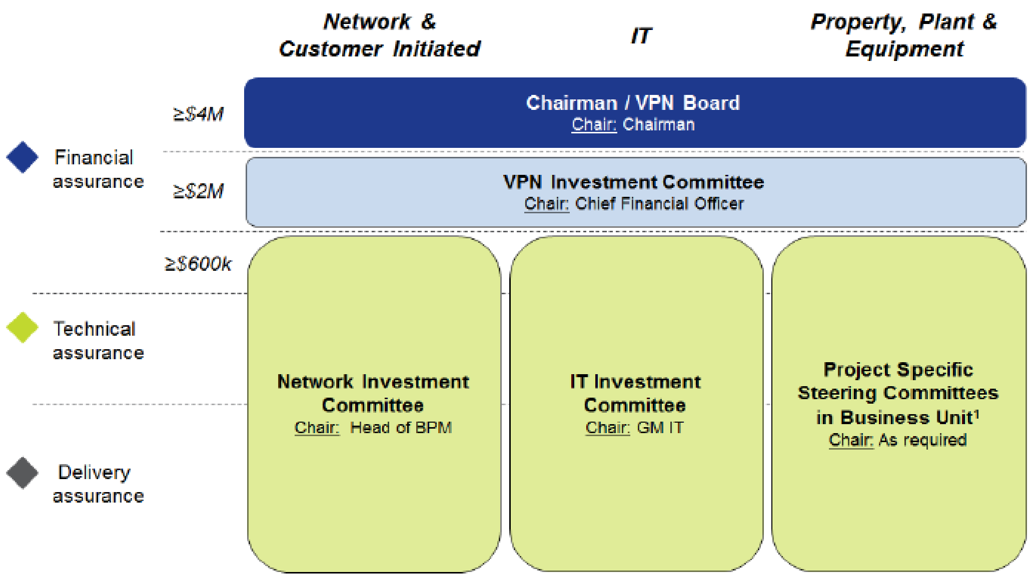
41. We understand from discussions with CitiPower that a large proportion of the projects and programs for the Regulatory Proposal forecasts are at the stage of Gate 1 only.

42. VPN describe its capital investment policy as requiring the following governance and controls for capital investment decisions:

- projects must comply with the VPN Portfolio and Projects controls framework;
- projects within the scope of the PPCF and at the request of management shall be subject to a financial peer review, and a technical review; and
- a post-implementation review must be performed within a reasonable time after the completion of the project.

43. The review and approval of expenditure proposals are based on the level of expenditure, project type and complexity. In the figure below, we show the committee structure that VPN has in place for providing financial, technical and delivery assurance for projects.

Figure 3.3: VPN committees for providing financial, technical and delivery assurance for projects



Source: PPCF
Note 1: These are ad hoc Project Committees that will have assigned chairs depending on project type and requirements.

Source: Response to information request IR019a EMCa question – governance and repex

3.1.2 Portfolio optimisation

Overview

44. In response to our request for details of the portfolio planning and management process undertaken to determine the programs/projects that comprise the whole-of-business expenditure portfolio, CitiPower stated that:[3]

- *'rigorous checks were made to the forecasts, including reviews by subject matter experts (SME), senior managers and the General Manager of the respective business unit, as well as other quality assurance steps to ensure that the amounts are free from error*
- *rigorous checks were made to the various models used in preparing the forecasts*
- *all major projects were assessed to understand their drivers and benefits to all customers. Risk-monetisation modelling was undertaken to ensure that:*
  - *we only invest when the cost of replacing existing infrastructure is lower than the total value of the underlying risks*
  - *capital works for augmentation were only forecast where the cost of mitigation a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand-side solution is feasible*
  - *the highest risk mitigation option was selected for information and communication technology (ICT) projects, where the ICT risks and business risks were assessed against the expected costs*
- *the forecasts are consistent with the requirements for prudency and efficiency of capital expenditure.'*

45. CitiPower described a number of oversight steering committees including the Capital Investment Committee (CIC) that review the capital expenditure is targeted to deliver optimum outcomes for shareholders, customers, the community and employees.

Top-down review methods

46. CitiPower stated that:[4]

> *'.. in the absence of asset management intervention, network risk levels are forecast to increase over the next regulatory period. These risks include demand related, asset performance and bushfire risks. The interventions outlined in our regulatory proposal are driven by our asset management programs (including regulatory obligations) and articulated in specific projects addressing these risks. We believe the governance over the preparation of the expenditure has provided a significant level of review.'*

Review of Regulatory proposal forecast

Development of the expenditure forecast

47. CitiPower stated[5] that its Regulatory Proposal is based on its 'Steady State' planning scenario,[6] and aligns with its current asset management and planning strategies, and its current risk management profile.

48. CitiPower has established a steering committee ("SteerCo") which consists of all Executive Management team members. The SteerCo is responsible for overseeing projects identified

3 Response to information request IR019a

4 Response to information request IR019a

5 Response to information request IR032

6 The premise of the Steady State scenario assumes that electricity is managed and supplied in much the same way as it is today. There is a strong driver to reduce costs whilst maintaining network performance and ensuring security of supply.

in the businesses' strategic program of works, as determined annually and includes the Regulatory Proposal.

49. CitiPower describes that the expenditure forecasts provided in its Regulatory Proposal have been subject to:

- internally conducted deep dives and peer review by SMEs by expenditure category including deep dives included SMEs, general managers, Energy Futures Customer Advisory Panel (EFCAP) and Customer Consultative Committee (CCC);
- public comment and review of its draft proposal;
- deep dives with external stakeholders including customer groups, the AER, the Victorian Government and local councils and community groups; and
- category level expenditure deep dives on expenditure iterations between the draft and final Regulatory Proposal.

50. For ICT, a different approach was used including subjecting the proposed program to external review and advice on how best to prepare and present the expenditure forecasts.

Review of iterations of expenditure

51. CitiPower advised that the development of the first expenditure iteration was prepared in June 2018, with a total of nine iterations of the capital program prior to submission of the regulatory proposal.[7] Over the iterations CitiPower describe that the gross capex varied from $1,263m to $995m.[8] All expenditure iterations were presented to the SteerCo.

52. CitiPower describe the role of the SteerCo as having:[9]

> *'provided 'top down' level guidance on expenditure at the category level. It also provided strategic direction on a number of 'marquee projects' such as solar enablement and proactive pole replacement.'*

3.1.3 Risk management framework

Overview

53. VPN has established an Enterprise Risk Management framework which sets out the governance framework for risk. The risk framework includes a 5x5 risk matrix and a risk appetite statement approved by the Board.

Risk monetisation method

54. CitiPower has developed risk monetisation models that seek to quantify the risk of an asset failure on the network. The risk models indicate earliest opportunity to invest in addressing the risk.

55. Having introduced models in 2018 and introduced revised versions in 2019, many of the models indicate that CitiPower has already found opportunities to defer investment and is operating at a point beyond the earliest time to invest.

56. For repex, CitiPower describes its approach as:[10]

> *'Specifically, our approach to monetising risk when assessing investment decisions is to determine the annual asset risk cost (as shown in figure 4.12). This approach is taken for all identified failure modes for an asset, and the sum of the annual asset risk cost for all failure modes is compared to the annualised cost of the preferred option to determine*

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7 Response to information request IR032

8 By comparison, the total capex included in the Regulatory Proposal is $852m. CitiPower, Regulatory Proposal page 10

9 Response to information request IR032

10 CitiPower Regulatory Proposal page 44

the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.'

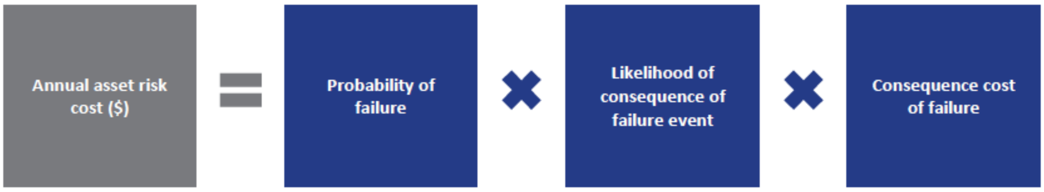
57. For repex, the risk monetisation models are currently applied only to zone substations and switchgear, primarily driven by the risk and cost of unserved energy.

58. The approach for repex seeks to establish:

- A probability of asset failure;
- Likelihood of the consequence occurring; and
- Cost consequence of a failure event.

59. This determination of asset-risk cost is captured in the figure below.

Figure 3.4: Calculation of annual asset-risk cost



Source: CitiPower Regulatory proposal Figure 4.12

60. CitiPower's risk/cost models sum the risk costs for network reliability, safety, financial and environmental risks.

61. Scenarios are based on central, lower, and upper sensitivity settings. RCM sensitivities are set for 5 scenarios at one of lower, central, or upper ranges. For PoF, capex and opex, VCR and environmental costs, the range is +/-10%. For demand the range is +/-5%.

62. The outputs are risk/cost vs annualised cost comparisons for each scenario. The optimal asset replacement investment timing is identified by comparing the annual monetised risk value of the existing asset and the annualised investment cost for each scenario.

63. In our assessment of proposed expenditure allowances, we tested the sensitivity of the models to a different sensitivity range to identify projects and repex that can be reasonably deferred.

3.1.4 Asset management framework

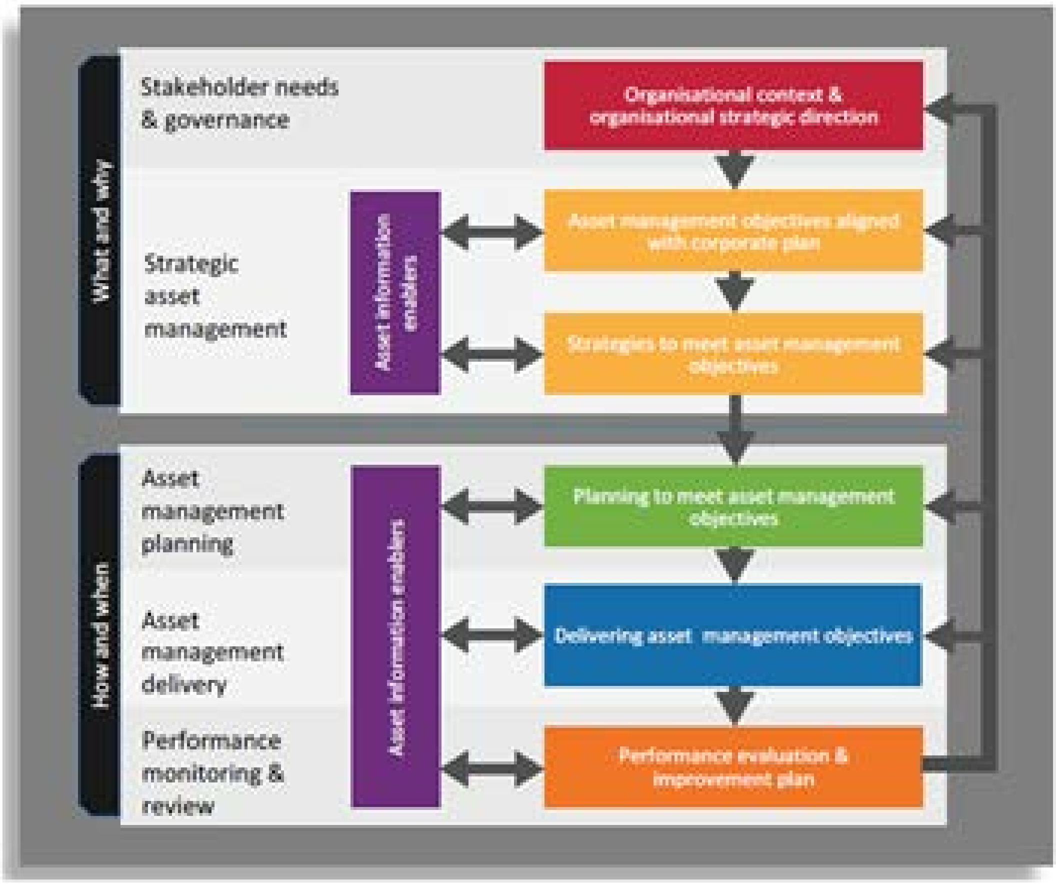
64. CitiPower describes the VPN asset management approach as being aligned with the principles of the International Organization for Standardization (ISO) 55000 for asset management standards. The asset management system includes:[11]

- *'an asset management policy which sets out VPN's asset management principles and is endorsed by senior management and approved by the* Chief Executive Officer*;*
- *a* Strategic Asset Management Plan *(*SAMP*) which sets high level asset management strategies and objectives which are demonstrably linked to overall organisational objectives;*
- *management strategies which are used to develop the system and improve underlying processes;*
- *implementation processes and activities which deliver the plans; and*
- *performance measurement and improvement.'*

65. The asset management system is structured according to the following diagram.

[11] Response to information request IR019a

Figure 3.5: Scope of VPN Asset Management System



Source: CP ATT021 Strategic asset management, Figure 22

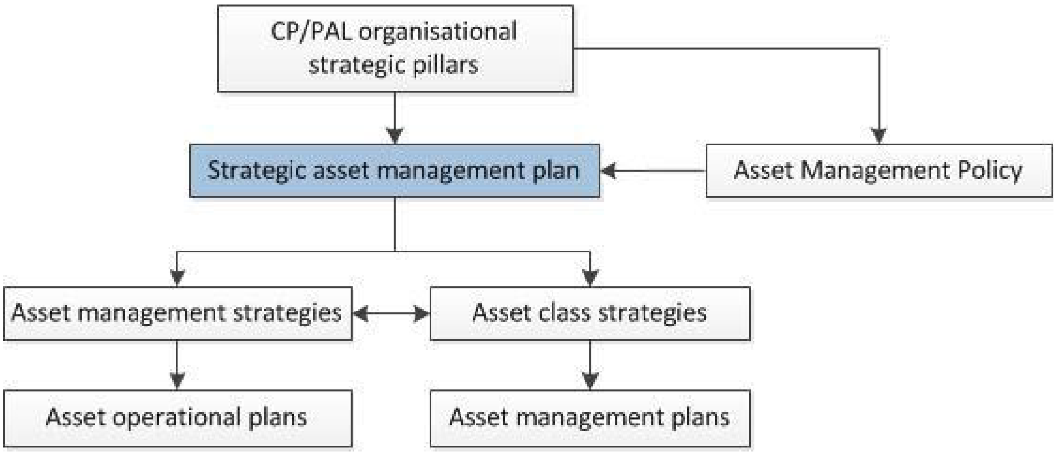
Asset management strategies and asset class strategies and plans

66. As detailed in its SAMP, VPN are developing a suite of Asset Management Strategies (AMS) and Asset Class Strategies (ACS). VPN describe these as:

- AMS address key AM activities that apply across all asset classes; and
- ACS focus on AM activities specific to the asset class.

67. The relationship between these elements is described in the figure below.

Figure 3.6: Strategy and planning hierarchy



Source: CP ATT021 Strategic asset management, Figure 23

68. The SAMP includes a description of the Asset Management Committee to provide governance and oversight of the asset management system, with a structure of the committee and sub-committees to align with the asset management strategy accountabilities.

Changes to asset management practice

69. Changes to the asset management practices that are likely to have an impact to the forecast are described in RIN016.

3.1.5 Expenditure forecasting methods and assumptions

Overview

70. CitiPower has described its modelling approach for capital expenditure as being the combination of its individual capital expenditure models as inputs to its consolidated capex model.

Expenditure justification

71. The regulatory proposal includes a number of business cases, expenditure models and other supporting information. The business cases, and in some cases risk models, account for the proportions of expenditure shown in the table below - as advised by each of the businesses we were asked to review.

Table 3.1: Proportion of expenditure included in business case documentation

Category	Powercor	CitiPower	United Energy
Repex	47%	68%	51%
Augex	74%	71%	55%
ICT	100%	100%	100%

Source: Onsite presentations to AER/EMCa by Powercor, CitiPower and United Energy

72. In addition, expenditure models provide a list of all line items that comprise the expenditure forecast for each expenditure category.

73. In response to our request for justification of expenditure that is not included in the business cases provided, we were directed to information provided with the regulatory proposal submission including the expenditure models.

Cost estimation

74. CitiPower describes the cost estimation approach for network capex as being largely based upon its revealed actual costs. In response to our request for a copy of its cost estimation methodology, or similar explanation of the cost estimation and cost forecasting systems, methods and procedures, benchmarks, project cost estimation performance and approach for determining unit rates applied to the forecast capex, CitiPower states that:[12]

> *'Robust cost estimates have been prepared for our regulatory proposal which, where applicable, have been sourced from:*
>
> – *average historical unit costs, which may have been derived from historical revenues and volumes;*
> – *market based outcomes from competitive tender processes;*
> – *estimated data obtained from contractors or vendors; and*

[12] Response to information request IR019a

– *actual historical costs for similar projects.*

For example, for replacement projects, the unit rates for high-volume works are based on average historical unit rates over the period 2014/15 to 2017/18. For larger works, project costs are based on the observed, actual costs of like-projects.'

Deliverability

75. In response to our request for an explanation of the delivery strategy and plan, including evidence of an assessment of the ability to deliver the proposed step increase in forecast expenditure, CitiPower states that:[13]

'Our labour force is structured to provide flexibility in managing labour resources. This allows us to deliver our total capital program, including the forecast increase in replacement investment. For example, our labour contracts include the following types:

- Internal labour—these are permanent employees who provide the base level of labour required to provide a base level of labour services. To operate sustainably over the long term, we must ensure we have secure access to a sufficient quantity of labour with the skills and knowledge required to deliver the minimum level of network and corporate services;
- Resource partners—these are third-party businesses, for example Lend Lease and Electrix, that provide additional labour services on an as needs basis. We utilise our resource partners to manage increased workloads that may arise for specific work programs. Resource partners are identified through a three yearly market testing process; and
- Contractors—we utilise contractors for skill-specific work including electrical work, fault response, metering works, civil works (i.e. digging works), traffic management, design work and vegetation management. We have different contractual arrangements with our contractors, ranging from longer term contracts with third party businesses to project-specific arrangements with individual registered electrical contractors.

The mix between internal and external labour resources will be determined by, amongst other things: workload volumes; timing and locations; skills and competencies requirements; resource availability; peak period workloads; and labour rates for internal versus external resources.

Resource partners and contractors provide a degree of flexibility in allocating resources to meet varying annual workload levels. These flexible arrangements enable Powercor [sic] to minimise the costs of engaging external resources to assist in delivering the services that customers require.

VPN has a strong history of successfully delivering major capital investment programs, including our Rapid Earth Fault Current Limiter (REFCL) program and the roll-out of smart meters.'

3.2 Assessment of CitiPower's framework

3.2.1 Risk management

Risk framework is generally consistent with industry practice

76. The risk framework at the enterprise level is consistent with industry practice, along with the establishment of risk appetite statements. However, we did see evidence that this was applied differently across VPN, specifically that the application for CitiPower differed from

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Powercor in relation to its poles repex program. We explore this further as a part of our assessment of the poles repex.

It is misleading to treat all AFAP projects as safety regulatory obligations, without sufficient review

77. CitiPower refers to its Electricity Safety Management Scheme (ESMS) as the means by which it demonstrates that risks arising from its electricity networks are minimised As Far As Practicable (AFAP). CitiPower also indicates that the application of disproportionality factors included in its risk monetisation models is consistent with its ESMS.

78. We understand from the onsite discussions that CitiPower hold workshops to identify projects to satisfy their AFAP obligations, and that these projects are subsequently discussed with ESV. CitiPower stated that once its proposed projects are included in the Bushfire Management Plan (BMP) that it submits to ESV, CitiPower considers that completion of the activity is a regulatory obligation.

79. To our knowledge, ESV does not undertake economic analysis to allow it to approve strategies developed by CitiPower as the basis of establishing new regulatory obligations. Whilst each DNSP is required to develop and submit a Bushfire Management Plan consistent with its regulatory obligations, to ensure that the risk is AFAP, our understanding is that the economic and risk decisions remain with the DNSP consistent with its commercial and wider regulatory obligations including to the NER.

80. From the information provided to us, we consider it is misleading to assert that all components of the plan are regulatory obligations once included in the BMP and must continue without review. We saw evidence that 'safety/compliance' related projects have been included in CitiPower's forecast; however, we were not provided with sufficient justification to determine the basis of their inclusion, including how CitiPower determines that the projects are required to consider its AFAP obligations.

Application of risk assessments to asset replacement decisions is not clearly evident

81. With the exception of those relatively confined categories where risk monetisation models are applied and were provided to us for review, the application of risk management to the balance of CitiPower's forecast expenditure is not clearly evident. Instead, we consider that CitiPower appears to have based its forecast on continuing existing asset management practices.

3.2.2 Risk monetisation

Reasonableness of applied method for repex

82. We consider that the approach adopted by CitiPower is generally consistent with the AER practice guide.

Reasonableness of applied assumptions

83. A key driver of risk cost as applied by CitiPower is the calculation of unserved energy. We observe that other risk costs, including for safety risk, are much lower.

84. We note that CitiPower uses a reasonable value for the value of a statistical life and a disproportionality factor of three (3) which we consider is reasonable for the analysis.

85. The reliability of the CBRM output depends on:

- accuracy of asset information (age/condition/history); and
- the selection of the constants used in determining the PoF curves.

86. The accuracy of risk/cost model output depends on:

- quality of input data; and
- integrity of the models – RCM model is new (2019) and relatively complex.

87. We discuss each of the input assumptions relied upon in the risk model in the sub-sections that follow.

88. We have not reviewed the demand forecast applied to the CitiPower system demand or the process of calibrating demand forecast for each zone substation. We would expect the demand at the zone substation level to take account of local demand growth including spot loads in the zone substation load area.

Calculation of the probability of failure appears reasonable

89. The CBRM methodology implemented in 2008 provides the probability of failure, and the likelihood and consequence cost of failure. These are inputs to the Risk Cost model.

90. Asset Health Index (AHI) is determined by applying asset condition modifiers to an initial AHI based on engineering knowledge of the asset (mainly age); the modifiers take into account such data as oil tests, OLTC age and condition. A reliability modifier is used if an asset type has a known alternative PoF.

91. The modified (current) AHI is s projected to derive future health indices which, through the application of a formula, produces the PoF projection used in the RCM.

92. The PoF is determined in the CBRM model by applying the AHI to a formula derived PoF curve (provided by EA Technology and tested against Powercor/CitiPower experience). Constants are applied to calibrate the curve.

Value of VCR is weighted to outage duration

93. The value that CitiPower has used for VCR is based on the AEMO 2014 report, escalated to current terms. This value is then weighted (adjusted) for outage duration for each customer class to derive a composite value of VCR that is used in the calculation of the cost of unserved energy. This has the effect of significantly reducing the value of VCR and unserved energy cost component.

94. We understand that CitiPower intends to update the use of its value of VCR to the values recently published by the AER. Whilst this would reflect more recent studies, the impact to the risk cost modelling is likely to be low given the weighting approach applied by CitiPower.

Use of a probability weighted demand using a 70:30 ratio has not been sufficiently justified

95. The risk cost model uses a probability weighted blend of the 10% Probability of Exceedance (PoE) demand forecast and the 50% PoE demand forecast. The weighting is 30% of the 10% PoE demand forecast to 70% of the 50% PoE demand forecast.

96. We asked for an explanation of the approach during the onsite discussions with CitiPower. In summary, CitiPower advised that the approach was:

- consistent with the approach taken by AEMO in calculating unserved energy;
- consistent with CitiPower's current practice; and
- consistent with current Victorian industry practice.

97. We consider the key issue here is the application of a planning methodology to estimate the forecast expected value of unserved energy. Whilst we did not receive a written response on this topic, we understand that CitiPower considers that using the 50% PoE does not represent a realistic expectation of demand.

98. We consider that the expected value of unserved energy is not a function of the peak demand alone. It should take account of the Load Duration Curve, since the amount of energy unserved (if any) as a result of an equipment outage depends on the load during the time of the outage, and this also is influenced by any mitigation measures. We have observed different methods for taking account of these factors in DNSPs and TNSPs.

99. CitiPower has asserted that the 70:30 method is the method used by all Victorian DNSPs. We are not able to verify this, however we have not encountered a 70:30 weighting being applied in planning methods in other DNSPs across the NEM or in Western Australia.

CitiPower has not demonstrated that its 70:30 assumption is valid for DNSP planning purposes, nor how it is derived.

100. We consider that resolving an appropriate and suitably common methodology for planning in distribution networks across Australia is of considerable importance. This goes beyond our brief of assessing the proposed expenditure using the information provided by the three Victorian DNSPs that we have been asked to assess. However, where we have found this aspect of each business' forecasting methodology to be relevant in our assessments of proposed repex and augex, we sought information from the business on any sensitivity analysis undertaken. Where provided, we have reported on this in our assessment.

Limited verification of modelling outcomes (including sensitivity analysis)

101. The Risk/Cost model is a new and complex excel model and CP/PAL confirmed that it has not been audited. However, we note that CitiPower has engaged the assistance of experts in the development of its CBRM method and risk/cost model.[14]

102. Since we do not have visibility to CitiPower's overall prioritisation of projects, we cannot identify projects that were rejected by CitiPower as a means to validate projects that were included in the forecast. Absent this information, there is potential for the Risk/Cost model to have only been applied to those projects already selected for replacement in the forecast period.

103. Based on our review of CitiPower's risk modelling, a number of interventions were identified to be completed in prior years but which have not been undertaken. For instance, we asked CitiPower to explain its rationale for not commencing the replacement of transformer assets in the current RCP based on its assessment that the optimal time to replace was prior to the commencement of the next RCP. In seeking to account for the fact that the investment has not been undertaken so far, CitiPower states that:[15]

> *'In the current regulatory period, we have been transitioning to more sophisticated risk quantification and monetisation to manage any impacts associated with declining condition of major network assets. This commenced with the introduction of load indices in our investment decisions for major zone substation plant (rather than just health indices), and has evolved to the development and application of the risk monetisation model used in our regulatory proposal (which has also been applied to identify the efficient timing for in-flight projects).*
>
> *The application of our risk monetisation modelling has identified that some interventions are already efficient. We have regard to this in the development of a balanced works program, and actively manage risk in the intervening period (e.g. through amended works practices) until works can be designed, scheduled and completed (including completion of RIT-Ds where relevant).'*

104. We consider how effectively CitiPower has been managing the risk presented by its zone substation assets in our assessment of expenditure, including review of other indicators of asset condition.

3.2.3 Asset Management

Asset planning and investment prioritisation not provided

105. In its Asset Management System framework document, VPN describes that it has:[16]

> *'implemented a new value framework comprising a set of measures that will form the basis for quantitatively prioritising investments. The value framework is being used to*

[14] Response to information request IR032/IR035, Q19

[15] Response to information request IR019a

[16] Response to information request IR019a EMCa questions – governance and repex, Asset Management System Framework

configure the Copperleaf C55 asset planning and investment tool to facilitate the quantitative prioritisation of investments going forward. The value framework will be used for the first time informing our 2020 budget and 5 year financial plan.'

106. During our onsite review meetings with CitiPower, we understood that the implementation of a prioritisation framework was ongoing and not relied upon for development of the forecast expenditure. We were not provided with details of the framework or how it had been applied to the capex portfolio by VPN. Based on the description provided by VPN, the framework and tool is likely to provide a useful means to undertake scenarios at the portfolio level, and undertake sensitivity analysis to assist justify investments based on benefit to customers or VPN.

Ensuring the robustness of the provided models was a focus of our assessment

107. VPN has advised that its capital expenditure forecasts were planned and prepared using asset management and planning strategies, and:[17]

'In particular, for each relevant asset category, the planning and incurring of capital expenditure in accordance with the replacement asset management strategies and network capacity planning strategies.'

108. In response to our request to provide details of the portfolio planning and management process across the portfolio, VPN stated:

'In preparing the capital expenditure forecasts, we note that:

- *rigorous checks were made to the forecasts, including reviews by subject matter experts (SME), senior managers and the General Manager of the respective business unit, as well as other quality assurance steps to ensure that the amounts are free from error;*
- *rigorous checks were made to the various models used in preparing the forecasts;*
- *all major projects were assessed to understand their drivers and benefits to all customers. Risk-monetisation modelling was undertaken to ensure that:*
  - *we only invest when the cost of replacing existing infrastructure is lower than the total value of the underlying risks;*
  - *capital works for augmentation were only forecast where the cost of mitigation a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand-side solution is feasible;*
  - *the highest risk mitigation option was selected for information and communication technology (ICT) projects, where the ICT risks and business risks were assessed against the expected costs; and*
- *the forecasts are consistent with the requirements for prudency and efficiency of capital expenditure.'*

109. We have reviewed each of the models and other supporting information provided to justify the forecast capex and present our assessment in the subsequent sections of this report. We looked for alignment between the portfolio and provided strategy documents, and the robustness of the modelling and risk assessment relied upon in preparing the capex forecast.

Asset class strategies are too high level to assist with expenditure justification

110. The asset strategy documents provided are high-level, and whilst an important artefact to demonstrate the alignment of the strategies and objectives for each asset class to the SAMP, they fall short of detailing the strategies, plans (including changes to) at an asset class level.

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17 Response to information request IR019a EMCa questions – governance and repex

111. The plans do not include discussion of the responses to the challenges and objectives in terms of intervention options considered, risk assessment and application of models for technical and economic analysis. Where this information is provided, separate tot eh asset class strategies, we have taken this into account in our assessment.

Asset management strategies have not been considered in our review

112. On advice from VPN, asset management and operational plans are still being developed. Examples were not provided and therefore have not been considered in our review.

3.2.4 Top-down assessment and portfolio prioritisation

Measures of network performance are improving

113. During the onsite discussion, CitiPower stated that the frequency of extreme weather events was increasing, the associated level of network risk was also increasing, and that both of these are indicators of an increasing level of repex requirement.

114. At a global level, this trend is not evident in the information provided by CitiPower, namely:

- We observe an improving trend of key service performance measures including SAIDI, SAIFI and public safety events. Similarly, the number of fire start events is also decreasing;
- Based on declarations by CitiPower in RIN016, with the exception of the proposed changes to pole management, there are no material changes proposed to its asset management approach; and
- CitiPower's expenditure associated with network faults has remained relatively stable irrespective of total replacement investment.[18]

115. We do not consider these observations to be consistent with CitiPower's claims that the level of network risk is increasing, or that repex requirements are increasing. We have reviewed these claims for increases to individual asset groups in our expenditure assessment.

Bottom-up methodologies appear to be based primarily on a reactive management approach

116. We have observed that the increases to the forecast expenditure are associated with new projects added to the current level of 'base' repex, which appears to be based on projecting forward the historical level of defects.

117. For example:

- The environmental management program was added to the forecast to retrospectively apply noise abatement and bunding solutions to existing substation sites. CitiPower described the driver of this work as responding to new legislation and associated obligations that were to be introduced by the EPA. Our understanding of the legislation is that the obligations on CitiPower are consistent with those that currently exist and that are reflected in current design and maintenance practices;
- Programs are introduced in response to AFAP obligations that appear separate to - and are potentially duplications of - programs developed as part of managing the specific asset class, such as conductor replacement and pole top structure replacement; and
- There are increases to expenditure, particularly repex, in the last two years of the current RCP that are associated with the introduction of new projects and programs. With the exception of the changes to CitiPower's pole management practices, the introduction of these programs is not sufficiently explained.

118. We did not see evidence of prioritisation of the portfolio to address the highest areas of risk, or optimisation of the proposed projects and programs. The examples indicate to us that

18 Response to information request IR032 and IR035

there is further opportunity to prioritise existing projects and programs to target the highest areas of risk.

Projects are at an early stage of development

119. We understand that the projects and programs proposed in the forecast are at Gate A of the investment framework. Projects and programs typically pass Gate B about a year before commencement.

120. Therefore, the portfolio that is actually delivered is likely to be different to the portfolio that is presented in the proposal. Whilst this is the nature of the forecast, we sought to understand the changes made through the process of approval, the sensitivity analysis undertaken to investment decisions and consideration of option value in the risk analysis undertaken by CitiPower in our assessment of expenditure.

Full impact of cost efficiencies not evident in forecast

121. CitiPower advised of efficiencies to its capex program delivered in the current RCP of $274m through its World Class program.[19] There were similar opex efficiencies claimed.

122. We requested details of the breakdown of the efficiencies delivered by this program to understand the level of deferred work from sustained efficiency savings, and to ascertain whether such efficiencies are reflected in the forecast expenditure.

123. In its response, CitiPower stated that:[20]

> *'It is not possible to provide the detailed breakdown of these efficiencies by expenditure class.'*

124. It did however clarify the nature of the efficiencies gained:[21]

> *'As described in CP APP02 and PAL APP02 - What we have delivered, most of the World Class initiatives had an impact on network capital expenditure.*
>
> *In terms of technology innovations automation of field works, design and connections all enhanced network expenditure efficiency. Further network expenditure savings were realised through revised contracting arrangements for material procurement, traffic management and metering and servicing. Lean and efficient service delivery model enabled consolidation of key functions across the businesses into single points of responsibility e.g. procurement. Changes to our service delivery model also allowed removal of layers of management and synergies/downsizing to be achieved through joint provision of corporate services. Lastly efficient investment decisions relied on exploitation of advanced metering infrastructure technology and the introduction of risk monetisation and calibration of our condition based risk modelling.*
>
> *These savings are now embedded in our businesses, whether it be historical unit rates, historical material costs, reduced employee numbers or our current asset management practices.'*

125. In our assessment, we sought evidence that these efficiency savings had been reflected in the unit costs that were applied in the development of CitiPower's forecast expenditure.

126. CitiPower states[22] that its forecast of high-volume, low-cost asset interventions is largely consistent with its historical investment based on an average of observed historical replacement volumes. We requested that CitiPower confirm how it determined the sample

[19] CitiPower - Appendix 02 - What we have delivered - 31 January 2020

[20] CitiPower's response to information request IR032 and IR035

[21] CitiPower's response to information request IR032 and IR035

[22] CitiPower Regulatory Proposal page 46

period (e.g., number of years) to include in the forecast method when considering linear trend or average methods. CitiPower stated that:[23]

> *'Our high-volume, low-cost asset interventions are typically forecast based on a four-year average of historical volumes and unit rates. A four-year averaging period provides a reasonable balance between using the most current data available and the risk that a shorter period (i.e. a single year) may over or under-state future volumes. A four-year averaging period is also consistent with the approach used by the AER in its repex model.'*

127. We note that the above information does not apply to the derivation of the pole intervention forecasts. For all volume-based replacement programs, including poles, CitiPower states that the unit rates:[24]

> *'…are based on average historical unit rates over the period 2014/15 to 2017/18.'*

128. We observe that this period aligns with the period that CitiPower undertook its World Class program. Using this period, without adjustment, is not likely to take account of the full benefits arising from the World Class program and is likely to overstate the unit rates for each of the programs.

129. Based on the information provided by CitiPower, we are not convinced that the full capital efficiencies that it is currently achieving from its World Class program are reflected in the costs relied upon for developing its forecast expenditure.

3.2.5 Justification of expenditure

Justification documentation that was provided is not robust

130. The originally provided justification documentation did not constitute an adequate level of supporting evidence to justify the proposed expenditure. We therefore requested additional information from CitiPower to justify the proposed expenditure (i.e., business cases or similar) for the total forecast expenditure in each asset group including details of the scope, key drivers, the asset condition and risk information relied upon in developing the forecast, the options considered and the financial analysis undertaken together with any relevant models. We also asked for a copy of any modelling outputs that had been used in determining the proposed expenditure.

131. In its response, CitiPower directed us to the existing business case documents and models, the expenditure models, relevant asset class strategies, RIN016 and responses to previous information requests.

132. We also discussed our requests during our onsite meeting with CitiPower where CitiPower directed us to the same information. We asked further questions of CitiPower and where new information was provided, we have reviewed to this in our assessment.

133. In some cases, we were able to determine the volume of replacements and associated forecast expenditure for the next RCP by applying the derived unit rates. However, in other cases, we were unable to ascertain the rationale for inclusion of the program in the forecast, or the basis for the replacement volumes, from the documentation that CitiPower supplied.

Project and program justification documentation is weak

134. The information provided in the business case documents was specific to a number of projects and programs. Similarly, the responses to information requests drew on specific models and explanations, which left areas of the proposed forecast expenditure largely unexplained. We used the information provided to derive historical replacement volumes and trends and sought to ascertain the basis for inclusion of programs into the forecast from other information provided such as asset strategy documents.

23 Response to information request IR032 and IR035

24 Response to information request IR019a

135. We observed a reliance on the expenditure models which included lists of projects and programs. We consider this information to reflect an assumption that the underlying level of replacement volumes will continue and be projected forward using an averaging approach.

136. We did not see consideration of improving service outcomes to ascertain whether the existing program reflected a prudent level of expenditure, or that the proposed introduction of additional proactive programs would not displace the underlying level of replacement. In most cases, we observed this was a flat profile, indicating a constant replacement rate.

Forecast replacement volumes are not supported by evidence of observed performance

137. CitiPower's forecast replacement volumes are based on its revealed historical replacement volumes. Based on the reactive 'find and fix' replacement approach, we consider that reliance on historical trends is not sufficient justification for the forecast – this approach may tend to overstate the required level of expenditure by effectively assuming the same level of work will be repeated.

138. This indicates that the work is a function of factors other than the observed performance of the assets.

Absence of evidentiary support

139. There is an absence of evidence to justify the volume and cost assumptions that CitiPower has included in its proposed forecast, and to explain how use of these assumptions will produce an optimised risk outcome.

3.3 Summary of findings

The regulatory proposal governance processes of the business do not always align with their stated investment governance frameworks

140. CitiPower has described the Investment Governance Framework (IGF), including the risk assessment and management review and approval process, that was applied to the development of its expenditure forecast. However, we consider that CitiPower has deviated from this governance process in preparing its regulatory proposal.

141. We sought to understand the magnitude and impact of these deviations and their adherence (or otherwise) to the requirements of the NER and expenditure assessment guidelines, consistent with our scope of work.

We have focused our review on the application of CitiPower's governance and management framework in our assessment of expenditure

142. The elements of the governance and management framework described to us by CitiPower are generally consistent with industry practice. We have been largely guided by discussions with CitiPower and the description provided of its review and engagement processes, conducted as part of the development of its Regulatory Proposal and expenditure forecast. We have focused our assessment on CitiPower's application of each of the elements of this framework in developing and reviewing its expenditure forecast for the next RCP.

143. As discussed in sections 4 to 8 for capex, and section 9 for opex, we have concerns with the practical application of CitiPower's governance and management elements and its forecasting processes to actual projects and programs, based on the evidence provided from our assessment of the aspects of capex and opex that are within our scope.

Forecast is likely to be overstated due to the limited application of portfolio-level assessment and optimisation

144. We observe that the approach taken to the development and review of the portfolio varies across the different expenditure categories. We have not been provided with compelling evidence to confirm that CitiPower has effectively established a link between its proposed

program and intended benefit to consumers including as measured by network performance outcomes and network risk.

145. At a portfolio level, we observe that CitiPower intends to deliver a significant underspend of the AER's capex allowance for the current RCP, due to a combination of initiatives including changes to management of risk, its forecasting practices and efficiency improvement programs. We sought evidence of how these changes have been applied in the development of its forecast expenditure for the next RCP.

CitiPower's application of risk and supplied risk-cost models are very sensitive to its consequence assumptions

146. In our assessment of the proposed expenditure, we sought evidence of the justification of the proposed expenditure including how the Risk Framework and risk cost models to its capex forecast had been applied. We also looked for evidence of how CitiPower's forecasting methodologies have applied reasonable assumptions, that those assumptions were supported with evidence, and that CitiPower had accounted for option value and alternative solutions.

147. We have outlined the specific aspects of CitiPower's expenditure forecasting methodologies for each of the expenditure categories we have reviewed,[25] along with our assessment of these methodologies as a part of our assessment of each expenditure category.

CitiPower has declared significant efficiencies in the current period, but does not appear to have accounted for these in their forecasts

148. We have not seen evidence that the significant cost efficiencies declared by CitiPower in the current period have been incorporated into their forecast expenditure. This is consistent with the observation that CitiPower has considerably underspent their capex allowances in the current period. Accordingly, we consider that there is potential for further cost efficiency to be accounted for in their proposed capex allowances.

Our assessment of governance and management relates to the aspects of CitiPower's forecast included in our scope of review

149. Our assessment of CitiPower's expenditure relates only to certain aspects of CitiPower's expenditure. In sections 4 to 9 below, we consider CitiPower's application of its expenditure forecasting methodologies to the relevant capex and opex categories.

25 repex, augmentation (non-DER and DER driven), ICT, and property

4 ASSESSMENT OF PROPOSED REPEX

In this section, we present our assessment of forecast repex that CitiPower has proposed for each RIN group in the next RCP. Our review is focused on the major drivers of expenditure.

We consider that CitiPower's proposed repex is not a reasonable forecast of its requirements. We consider that CitiPower's proposed repex for wood pole replacements is considerably overstated and that elements of its proposed repex for service lines, pole top structures, transformers, switchgear, SCADA and 'other' repex groups are also overstated (though to a lesser degree).

We consider that CitiPower's proposed repex for overhead conductor and underground cable replacements is reasonable.

We consider that CitiPower's forecast is also upwardly biased through not having properly taken account of unit cost efficiencies that it has demonstrably realised in the current RCP.

4.1 Introduction

150. We reviewed the information provided by CitiPower to support its proposed repex forecast, including a sample of projects and programs. Our focus was to ascertain the extent to which the issues identified in the preceding sections are evident at the activity level, and to validate that the forecast expenditure reflects the NER criteria.

151. We sought to establish the strategic basis for, and the reasonableness of, CitiPower's proposed repex for each of the identified categories of expenditure. 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.

152. CitiPower has provided its bottom-up forecast and described how this forecast has been apportioned to each of the RIN groups. We have referred to this in our assessment.

153. The AER has identified a number of 'Focus' projects to us. Accordingly, we have included these in our assessment of CitiPower's proposed repex forecast as shown in Table 4.2.

154. We first summarise and compare CitiPower's proposed expenditure for the next RCP with its historical actual and estimated expenditure in the prior and current RCP. We subsequently provide our review of CitiPower's forecast for each repex RIN group. The summary information provided below largely replicates information provided in Section 2.3, but is included again in this section for easy reference and to provide context to the observations that we make relevant to our assessment.

4.2 Summary of CitiPower's proposed repex

4.2.1 Overview

155. CitiPower's repex forecast originally proposed in its regulatory submission is $308.0m for the next RCP. As described in Section 2, CitiPower subsequently withdrew Environmental Management and substituted with a much lower amount and it had included Public Lighting, which we have removed.

156. Table 4.1 shows our assessment of the proposed Repex by RIN Group following these adjustments.

Table 4.1: CitiPower repex for the next RCP – Following adjustments for Environmental Management and Public Lighting - $m, real 2021

Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	12.8	13.0	13.3	13.5	13.8	66.5
Pole Top Structures	3.2	3.3	3.3	3.4	3.4	16.7
Overhead Conductors	0.1	0.1	0.1	0.1	0.1	0.6
Underground Cables	0.6	0.7	0.7	0.7	0.7	3.4
Service Lines	3.2	3.3	3.4	3.5	3.6	17.1
Transformers	3.2	6.4	6.1	4.1	2.2	21.9
Switchgear	7.0	10.6	12.1	12.6	17.5	59.7
SCADA, Network Control and Protection	5.2	5.2	5.4	5.6	5.7	27.0
Other	4.9	4.9	4.9	4.9	5.1	24.7
Total	**40.2**	**47.5**	**49.3**	**48.4**	**52.1**	**237.5**

Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020' Includes real cost escalation

4.2.2 Repex from the project models as mapped to RIN Groups

157. The following table shows project-level repex of $225.8m for the next RCP. We also show the AER focus projects and relevant amounts. Public Lighting has been removed and the Environmental Management program has been adjusted, consistent with the table above. The table also shows the AER focus projects and relevant amounts.

158. Real cost escalation is not included in CitiPower's project model analysis. Values have been inflated where necessary to be in the common basis of Real 2021 dollars. While noting that real cost escalation would need to be reapplied (to the extent that it is considered valid), the costs in the following table reflect the amounts that we have assessed.

Table 4.2: CitiPower repex – Following adjustments for Environmental Management and Public Lighting showing AER Focus Projects and Programs - $m, real 2021

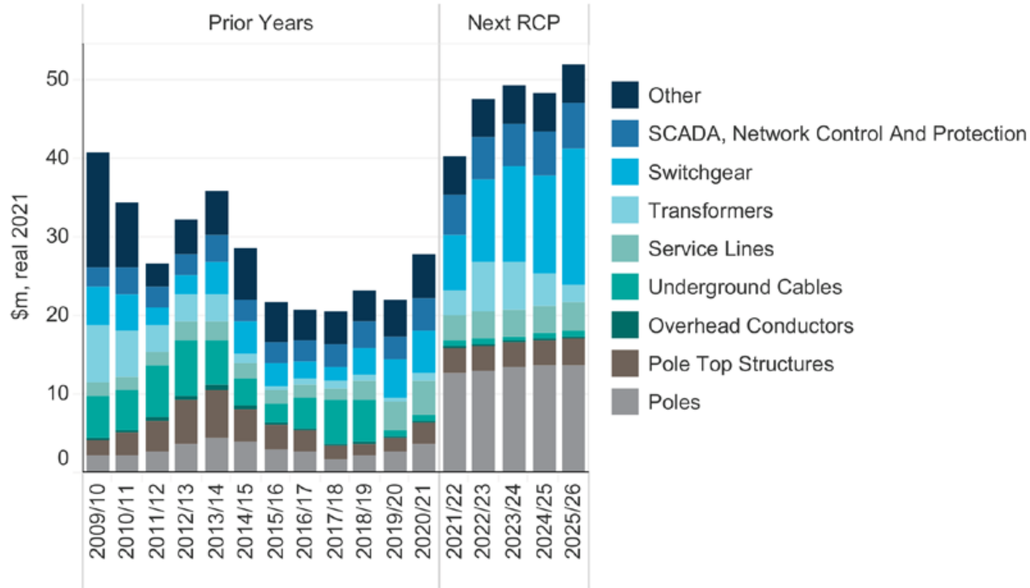
Group / AER Focus	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Poles	12.6	12.6	12.6	12.7	12.7	63.2
AER Focus: Wood Pole Management	*11.8*	*11.8*	*11.8*	*11.8*	*11.8*	*58.9*
Other	*0.8*	*0.8*	*0.9*	*0.9*	*0.9*	*4.3*
Pole Top Structures	3.2	3.2	3.2	3.2	3.2	15.8
Overhead Conductors	0.1	0.1	0.1	0.1	0.1	0.6
Underground Cables	0.6	0.6	0.6	0.6	0.6	3.2
Service Lines	3.2	3.2	3.2	3.3	3.3	16.2
Transformers	3.1	6.2	5.8	3.8	2.0	20.9
AER Focus: ZS Transformer Replacement	*2.8*	*5.8*	*5.4*	*3.5*	*1.6*	*19.1*
Other	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*1.8*
Switchgear	6.9	10.2	11.5	11.7	16.1	56.5
AER Focus: Little Queen Switchboard Replacement		*0.0*	*2.6*	*6.0*	*10.4*	*19.0*
Other	*6.9*	*10.2*	*8.9*	*5.7*	*5.8*	*37.4*
SCADA, Network Control and Protection	5.1	5.1	5.1	5.2	5.2	25.7
AER Focus: Protection and Replacement Program	*5.1*	*5.1*	*5.1*	*5.2*	*5.2*	*25.7*
Other	4.8	4.8	4.7	4.7	4.8	23.7
Total	**39.5**	**46.0**	**46.9**	**45.3**	**48.1**	**225.8**

Source: EMCa analysis of CitiPower MODs 4.06, 4.09, 4.10, 4.11. Excludes real cost escalation

4.2.3 Repex trend

159. Repex trends over time, by RIN Group, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. 2018/2019 FY has been filled in using escalated project model data provided by the AER. The Public Lighting RIN Group has been removed as well as the forecast values for the Environmental Management program from the 'Other' repex group. All expenditure has been inflated to real 2021 dollars and includes real cost escalation.

Figure 4.1: CitiPower repex – – Following adjustments for Environmental Management and Public Lighting - $m, real 2021[26]



Source: EMCa analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020', 'PAL consolidated RIN - repex - 2018-19_sent to EMCa'.

4.2.4 Observations from Repex trend

160. The figure above shows that CitiPower's actual replacement expenditure in the current RCP has been relatively flat. However, the forecast for the next RCP shows a significant step up and then a steady year-over-year proposed increase across most expenditure categories, driven primarily by higher expenditure in the 'poles', 'pole-top structures', 'transformers', and 'switchgear' groups. This has led us to consider in particular the groups with significant expenditure discontinuities at the next RCP and the claimed drivers for these changes.

4.3 Assessment of CitiPower's repex activity forecasting methods

4.3.1 Overview

161. CitiPower has applied a combination of forecasting methods to develop its bottom-up repex forecast, which are discussed below and comprise:

- Defect-driven programs - focused on high-volume, low-cost asset interventions including pole-top structures and conductors;
- Other project and program-based expenditure - including wood poles, where CBRM techniques have been applied (such as for substation-based assets), and other project specific expenditure; and
- Network faults.

4.3.2 Defect driven programs

162. As discussed in section 3, the high-volume, low-cost asset interventions (excluding wood poles) are forecast based on a four-year average of historical volumes and unit rates. CitiPower stated that:[27]

26 Includes real cost escalation and excludes Public Lighting & Environmental Management program

27 CitiPower's response to information request IR032

'as the majority of our forecasts are based on historical volumes and/or historical unit rates, it is not expected that service outcomes driven by these forecasts will fundamentally change (i.e. they will be maintained).'

163. Given that a large part of the forecast repex is based on this method, we asked what sensitivity analysis CitiPower has undertaken to determine the level of confidence in the forecast - given the significant expenditure increases proposed. CitiPower stated that:[28]

'…with the exception of our pole replacement forecasts (which are justified separately, and have been the subject of a rigorous review by ESV), our replacement expenditure forecast is consistent with the AER's repex model outcomes. Similarly, our unmodelled expenditure component aligns with that forecast using the AER's previous methodology, noting that as previously communicated, we have withdrawn the forecast step up in our environmental compliance investment.'

164. In our assessment of the forecast expenditure, we reviewed the proposed defect-driven programs and projects in combination. We also reviewed whether CitiPower has sufficiently justified the proposed expenditure, including any changes from the level of expenditure that it has been incurring to deliver the current service outcomes against the requirements of the NER.

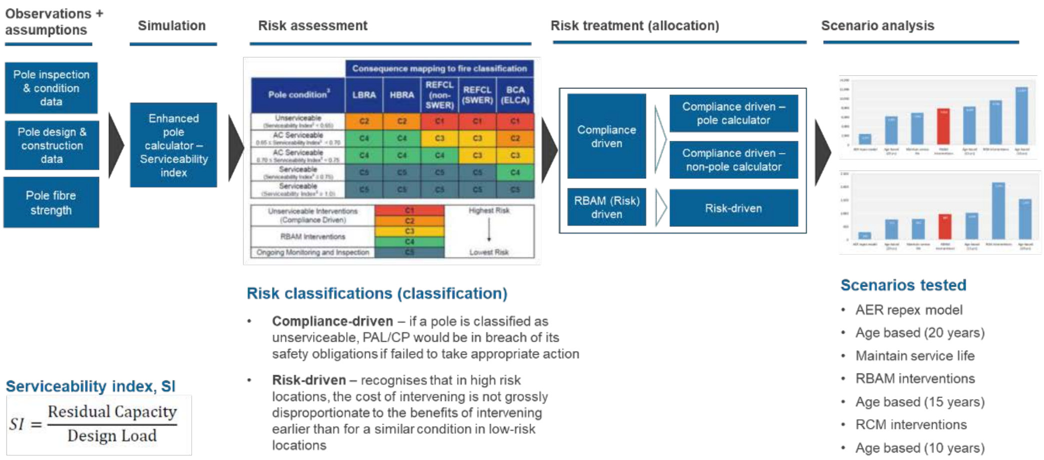
165. For some asset groups, including for service lines, CitiPower provided more granular defect and replacement data to support inclusion of its proposed service line replacement programs. We comment on these in our assessment of the associated expenditure.

4.3.3 Other projects and programs

Wood pole replacement program

166. We summarise the forecasting method applied for the development of the wood poles forecast expenditure (excluding network faults) for CitiPower in the figure below.

Figure 4.2: Overview of forecasting method for wood pole expenditure – Powercor and CitiPower



Source: EMCa from information and explanations provided in CitiPower documents

167. We include discussion of each of the elements of this forecasting method in our assessment of the proposed expenditure in the subsequent sections.

Substation transformer and switchgear replacement

168. VPN applies the CBRM methodology to certain plant-based asset classes (namely transformers and circuit breakers), as well as protection and control equipment. In addition,

28 CitiPower's response to information request IR032

risk monetisation methodologies are applied for selected transformer and switchgear replacements.

169. We have reviewed the process through which CitiPower developed its repex forecasts including the application of its CBRM and risk monetisation models and the business cases it supplied. We provide a review of the CBRM method and risk monetisation models proposed by CitiPower in Appendix B.

170. In our assessment of the proposed expenditure, we have applied tests to the various models and challenged output forecasts.

171. Whilst CitiPower includes data for all transformers, circuit breakers and switchgear in its CBRM model, it does not subject all its substation assets to risk monetisation assessment.

Protection replacement projects

172. CitiPower has applied the CBRM methodology to protection relays in a similar way as it has for substation transformer and switchgear to identify candidate projects for replacement.

Other targeted project and program expenditure

173. A number of additional projects and programs are included in CitiPower's repex forecast that have been forecast using other methods. The level of detail provided in support of these projects is limited to a single line description in the provided expenditure models, with the associated year on year costs hard-coded into these models.

174. We looked for evidence of the justification for the proposed expenditure from the information provided. We expected the level of justification to be consistent with the normal requirements of a business case-like document, to support the development of a prudent, efficient, and reasonable program of forecast expenditure.

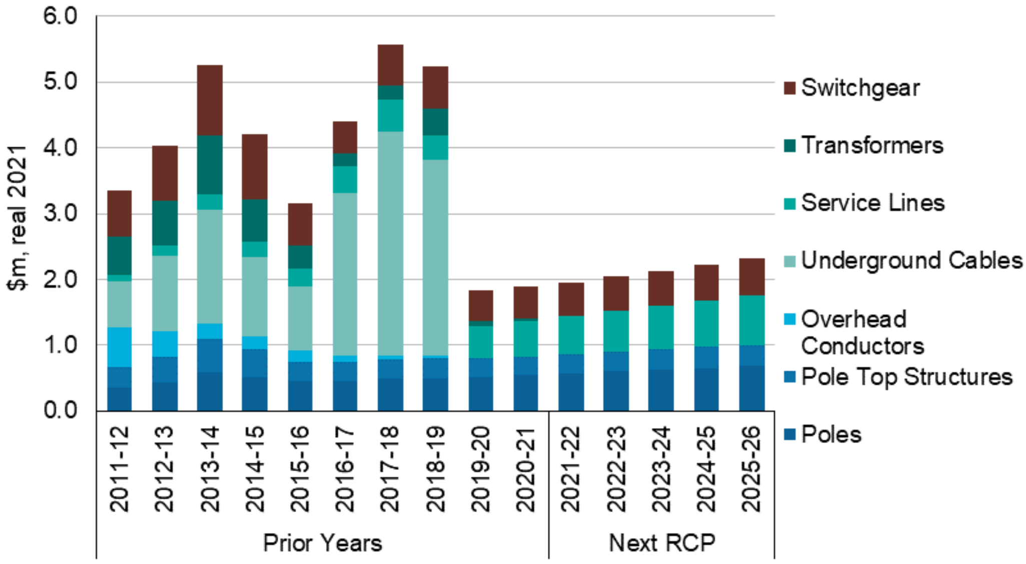
175. However, in the majority of cases, business cases were not provided for these projects. The supporting detail provided in other documentation was, in general, not sufficient to justify the proposed volume and cost assumptions that CitiPower has included in its repex forecast.

4.3.4 Network faults

176. CitiPower included an allocation of $10.7m for network faults in its forecast repex, across multiple RIN groups.[29] The composition by RIN group is shown in the figure below.

[29] Excludes Public Lighting

Figure 4.3: CitiPower's forecast network fault related repex by group - $m, real 2021



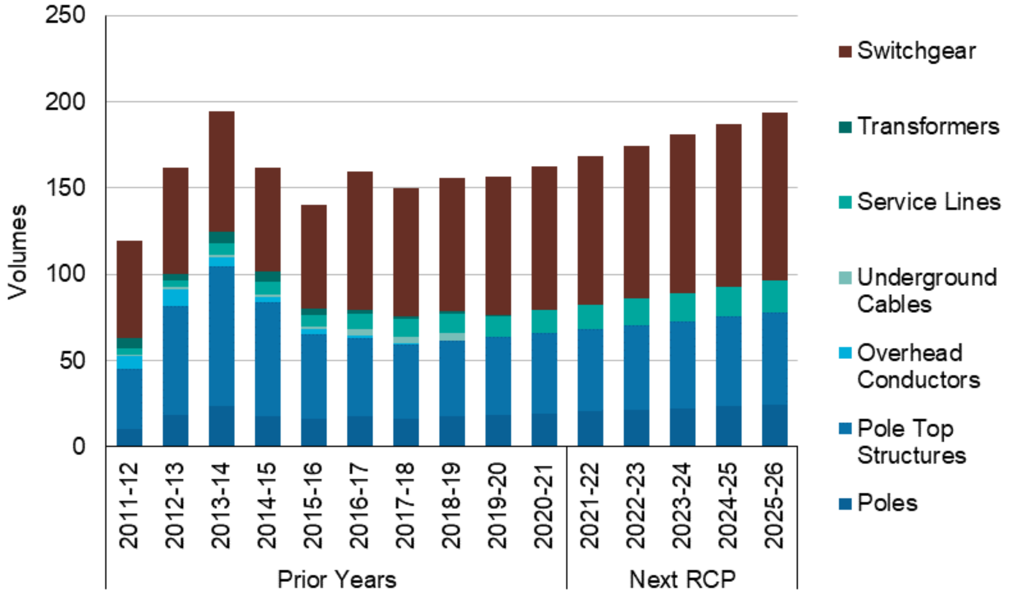
Source: EMCa analysis of CitiPower MOD4.11

177. The expenditure for the period up to and including 2018/19 is based on actual historical expenditure. The forecast network fault expenditure for the remainder of the current RCP and the next RCP is much lower, primarily due to the removal of underground cable and overhead conductor expenditure as seen from 2019-20. We consider this as part of our assessment of minor repairs in section 9, and which includes the expenditure relating to network faults for underground cables and overhead conductors.

178. For the remainder of the current RCP, from 2019/20, CitiPower has estimated expenditure based on a forecast replacement rate and unit cost. The forecast replacement level for each RIN asset group is developed by taking the average increase/decrease over the period 2011/12 to 2017/18 in units and adding this in each year commencing 2018/19 on a linear trend. That is, for 2019/20, the replacement volume is the sum of the replacement volume in 2017/18 plus twice the average increase/decrease.

179. We show the changes in replacement volume that correspond to the forecast expenditure in the figure below.

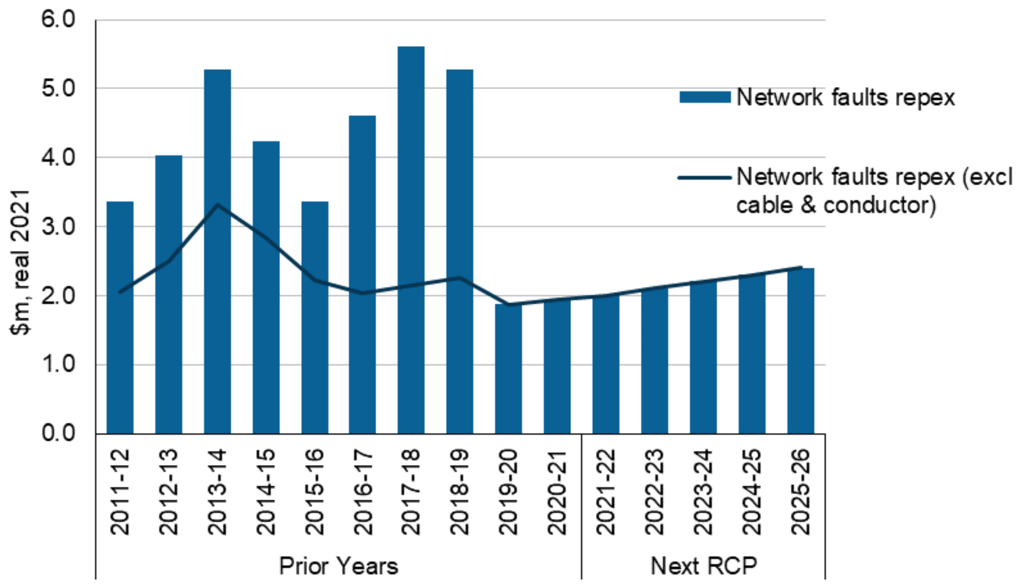
Figure 4.4: Replacement volume trend for network faults repex by RIN group



Source: EMCa analysis of CitiPower MOD 4.11. Groups with zero replacement volumes have been removed. Note that units of volume differ between asset groups and are as designated in the RIN. They are therefore not strictly additive but are presented here to show trends.

180. We note that CitiPower has excluded underground cable and overhead conductor volumes from its forecast of network fault repex in the next RCP.[30]

Figure 4.5: Comparison of CitiPower's forecast network fault related repex with and without cable and conductor repex - $m, real 2021



Source: EMCa analysis of CitiPower MOD 4.11

181. The unit rate for network faults repex is derived in the same way as for other volumetric repex, being the average over the historical period 2014/15 to 2017/18.

182. In response to our request to explain the basis for its network fault expenditure, CitiPower stated that:[31]

30 The long-term historical average has been $3.3m per year transformer repex in network faults

31 CitiPower's response to information request IR032

'For network faults, a longer-term trend was used. A longer period was considered reasonable given the persistence of the trend and our confidence in the robustness of the underlying data.'

183. We agree that network faults can be random and are typically driven by weather events; this also means that the composition of assets that are likely to require fault-driven replacement may change from year to year.

184. We requested that CitiPower confirm if any adjustments had been made to the network faults forecast in light of the proposed increase in planned replacement programs and improving network reliability. In response, CitiPower stated that:

'Our network faults forecast has not been adjusted to account for our planned replacement program. This is because network faults can be random, and are primarily driven by severe weather events. The severity of these events limit the correlation to asset condition, which is a key driver of much of our planned replacement programs.'

185. CitiPower has not explained the rationale for an increasing fault driven expenditure, given the relatively flat historical trend. In the absence of better information, the level of expenditure associated with network faults is more likely to remain similar to historical levels, rather than an increasing trend as proposed.

186. In our assessment of expenditure by RIN group, we have noted where CitiPower has included a forecast for network faults based on the forecasting method described earlier. Accordingly, we have not included any further assessment of the network faults expenditure.

4.4 Assessment of CitiPower's proposed repex by RIN group

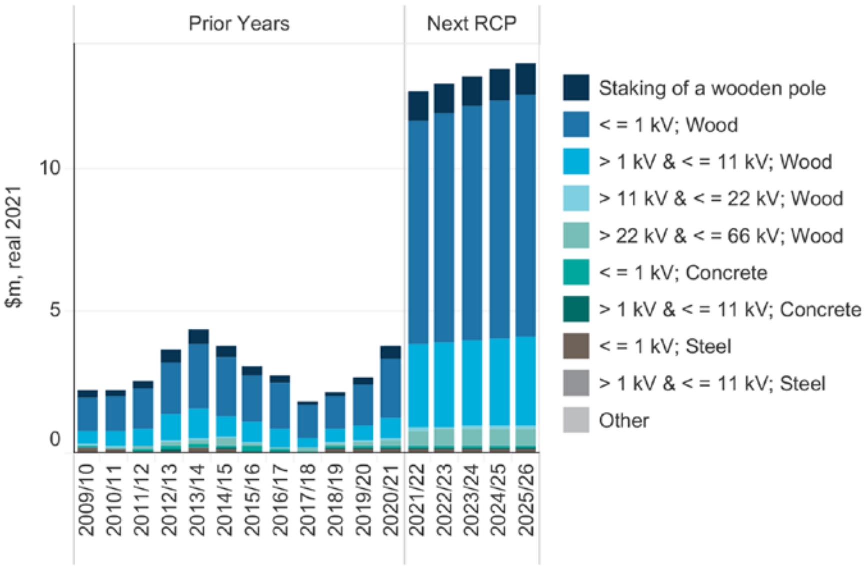
4.4.1 Poles

CitiPower's forecast

187. CitiPower has proposed $66.5m[32] for the Poles asset group (including pole staking) in its repex forecast for the next RCP. The expenditure profile for the Poles asset group comparing the next RCP with previous years is shown in the figure below.

32 CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.6: Poles repex by asset category - $m, real 2021



Source: CitiPower Reset RIN

188. The figure above shows the largest increase associated with LV pole replacement. The major components of expenditure and program by construction type are shown in the tables below (and which reconcile to CitiPower's program when real cost escalation is excluded).

Table 4.3: Components of CitiPower's proposed pole repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total RCP
Pole Replacement	11.0	11.0	11.0	11.0	11.0	55.0
Pole Life Extension	1.0	1.0	1.0	1.0	1.0	5.1
Network Faults	0.6	0.6	0.6	0.7	0.7	3.1
Total	**12.6**	**12.6**	**12.6**	**12.7**	**12.7**	**63.2**

Source: CP MOD 4.06 and MOD 4.11. Excludes real cost escalation

Table 4.4: CitiPower's proposed pole repex by construction type - $m, real 2021

Construction	2021/22	2022/23	2023/24	2024/25	2025/26	Total RCP
Wood poles	12.4	12.4	12.4	12.4	12.5	62.0
Concrete poles	0.1	0.1	0.1	0.1	0.1	0.4
Other	0.2	0.2	0.2	0.2	0.2	0.8
Total	**12.6**	**12.6**	**12.6**	**12.7**	**12.7**	**63.2**

Source: CP MOD 4.06 and MOD 4.11. Excludes real cost escalation

189. CitiPower has provided the following documentation with its submission to support its expenditure:

- a business case for its wood pole replacement program[33] totalling $58.9m ($2019); and
- models comprising its lines replacement expenditure (MOD4.06) and network faults related expenditure (MOD 4.11) which include poles repex.

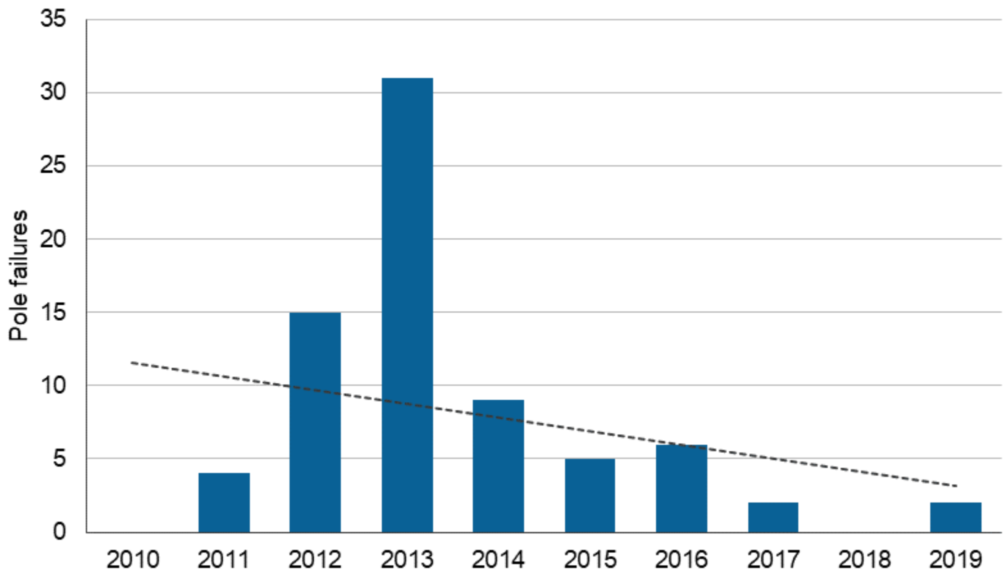
33 PAL BUS 4.0 2 and CP BUS 4.02 Wood Pole replacement program

Our assessment

CitiPower's network is not exhibiting the same level of risk as Powercor

190. The failure rates and trends evident in the Powercor network, are not evident in the CitiPower network. We have re-produced the failure rates for CitiPower in the chart below.

Figure 4.7: Historical wood pole failures



Source: EMCa analysis of CitiPower's response to information request IR032 and IR035 EMCa questions following onsite meetings

191. The above chart shows a declining trend for wood pole failures, with the corresponding failure rate per 10,000 poles for 2019 of 0.5.

192. CitiPower has not demonstrated that the same systemic issues present in the Powercor network are also present in the CitiPower network to support its proposed increase in poles repex. CitiPower advised that the proposed program is supported by business case justification that has regard to multiple options that provide a level of sensitivity analysis and which are consistent with the outcomes of the AER repex model.

193. As stated earlier in our report, we have not been asked to review the application of AER's repex model by CitiPower or the outcomes of the repex model.

194. We understand that CitiPower's wood pole management practices are the same as those applied for Powercor. Therefore, many of the conclusions reached by ESV in its review of Powercor's asset management practice are likely to be directly applicable to CitiPower's wood pole population, including taking into account fibre degradation in wood poles and alignment with contemporary Australian Standards for overhead line design.

195. To our knowledge, ESV has not issued a corrective order, or instruction to CitiPower (or to Powercor) to make changes to its asset management practice or to nominate a program of wood pole management that would constitute a new compliance obligation.

CitiPower has proposed a step increase in pole treatment volume that is primarily driven by the introduction of its 'enhanced pole calculator'

196. CitiPower has developed its enhanced pole calculator in response to concerns raised by ESV as noted above. The enhanced pole calculator is intended to be used as a basis for predicting wood pole condition and deriving forecast replacement and reinforcement volumes.

197. The resulting profile of the forecast replacement and reinforcement volumes over time and the corresponding rate of reinforcement is shown in the figure below.

Whilst application of the same forecasting approach as Powercor for treatment volumes is reasonable, some parameters are likely to differ from Powercor's

198. As stated above, the inclusion of factors such as fibre degradation and assessment of pole loading using limit state methods consistent with AS7000 should, once it is validated, result in a reliable basis for forecasting CitiPower's wood pole program.

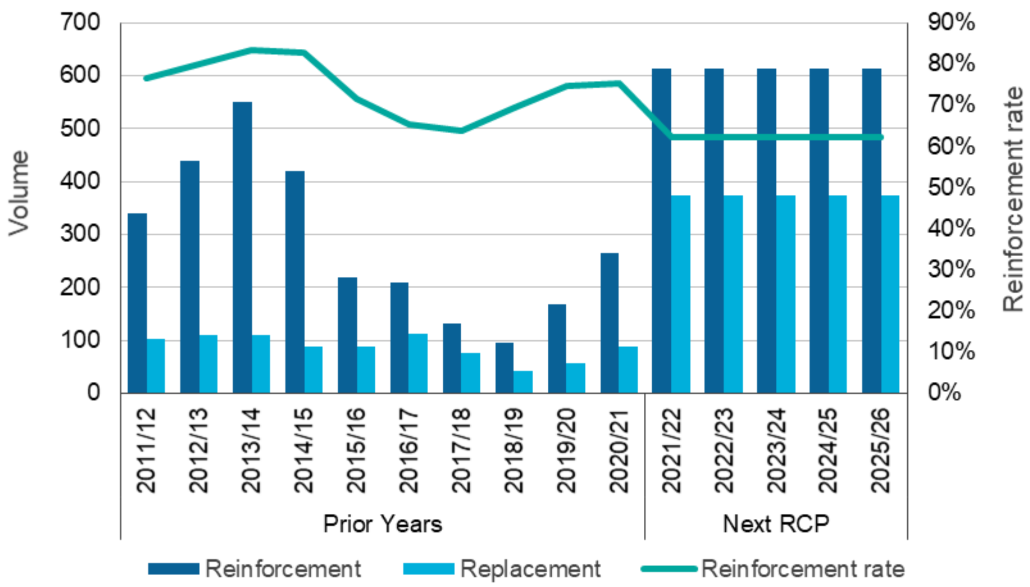
199. The proposed pole interventions have been based on the outcome of the enhanced pole calculator (i.e., used as a forecasting tool) which predicts a serviceability index for each pole based on a range of input assumptions and wood pole measurements.

200. Whilst the design and construction of the network is likely to have followed a similar approach to Powercor, the design strength and loading of poles in the CitiPower network is likely to be different. For example, the shorter bay lengths that are likely to be present in CitiPower's network will contribute to lower loading levels (in general) than for Powercor.

201. This will be resolved over time as the pole calculator is progressively updated with data from assessment of individual poles rather than from application of assumptions to the pole population.

202. The profile of replacements and reinforcement volumes over time and the corresponding rate of reinforcement is shown in the chart below.

Figure 4.8: Pole intervention volumes over previous, current and next RCP (excluding network faults)



Source: EMCa analysis of CitiPower MOD 4.06

203. Applying the same assumptions for CitiPower as Powercor has done for its pole population, is likely to have resulted in higher forecast of poles at risk of failure, thus overstating CitiPower's assessment of its repex requirements.

Expenditure forecast is based on a bottom-up development of the program

204. Similar to Powercor, the expenditure forecast is based on a bottom-up forecast of the required pole treatment volumes and unit costs by pole category. This is shown in the table below.

Table 4.5: Proposed pole intervention volume in next RCP

Forecasting component	Replacement	Reinforcement	Total
Compliance driven interventions: pole calculator	1,252	301	1,553
Compliance driven interventions: non-pole calculator	610	153	763
Risk-driven interventions	-	2,617	2,617
Total	**1,862**	**3,071**	**4,933**

Source: CitiPower BUS 4.02 Table 8

205. In the information provided by CitiPower in its response to an information request,[34] we observed a variation against the volumes allocated between replacement and reinforcement with the information provided in the regulatory proposal. We asked CitiPower to clarify the impact to its expenditure forecast of the alternative replacement and reinforcement volumes.

206. In its response to our information request,[35] CitiPower has confirmed a forecasting error that results in a reduction of $1m p.a. to its expenditure forecast for poles.

Risk-based asset management approach does not include an economic test

207. CitiPower has developed a risk framework to map the pole condition for each wood pole (identified using its SI as determined from its enhanced pole calculator) against the bushfire classification of the pole location in increasing order of consequence as shown in the figure below.

Figure 4.9: Overview of risk based classifications for poles

Increasing consequence of failure

Increasing probability of failure

Pole condition	LBRA	HBRA	REFCL (non-SWER)	REFCL (SWER)	BCA (ELCA)
Unserviceable: Serviceability index < 0.65	C2	C2	C1	C1	C1
Added-control serviceable: 0.65 ≤ serviceability index <0.70	C4	C4	C3	C3	C2
Added-control serviceable: 0.70 ≤ serviceability index < 0.75	C4	C4	C4	C3	C3
Serviceable: 0.75 ≤ serviceability index < 1.0	C5	C5	C5	C5	C4
Serviceable: Serviceability index ≥ 1.0	C5	C5	C5	C5	C5

Source: CitiPower BUS 4.02 Figure 8

208. The consequence mapping reflects the following bushfire fire classifications:

- Bushfire Construction Areas (BCA)—CitiPower's highest bushfire consequence regions, and is used by CitiPower in place of Electrical Line Construction Area (ELCA);
- areas protected by a Rapid Earth Fault Current Limiter (REFCL) with Single Wire Earth Return (SWER) lines;
- areas protected by a REFCL with non-SWER lines;
- Hazardous Bushfire Risk Areas (HBRA); and
- Low Bushfire Risk Areas (LBRA).

34 Response to information request IR012

35 Response to information request IR032

209. CitiPower further assigns each pole into one of five risk categories, denoted by the terms C1 to C5[36] and which overlay the above framework. The risk categories are further grouped into:

- Compliance-driven interventions (comprising the interventions that are denoted by the risk categories of C1 and C2); and
- Risk-driven interventions (comprising the interventions that are denoted by the risk categories of C3 and C4).

210. CitiPower claims that its risk-based asset management approach is consistent with the AER's risk monetisation framework[37] as it has adopted serviceability criteria as a proxy for probability of failure and consequence mapping based on bushfire risk areas. Whilst CitiPower has sought to describe a relationship between serviceability index (as a proxy for the probability of failure) and consequence (using bushfire consequence area), the framework in its current form does not provide a basis for economic analysis to determine an efficient level of expenditure on a risk monetisation basis.

A lower risk threshold appears to have been applied to CitiPower when compared with Powercor

211. The same approach to mapping the serviceability index to bushfire consequence is applied to CitiPower's network. All poles assessed under the enhanced pole calculator in CitiPower's network fall into the low bushfire risk area consequence as shown in the table below.

Table 4.6: CitiPower Network - Mapping of pole condition to consequence areas

Pole condition classification	LBRA	HBRA	REFCL (non-SWER)	REFCL (SWER)	BCA (ELCA)
Unserviceable: Serviceability index < 0.65	1,553	-	-	-	-
Added control – serviceable: 0.65 ≤ serviceability index < 0.70	990	-	-	-	-
Added control – serviceable: 0.70 ≤ serviceability index < 0.75	3,037	-	-	-	-
Serviceable: 0.75 ≤ serviceability index < 1.0	20,007	-	-	-	-
Serviceable: Serviceability index ≥ 1.0	16,726	-	-	-	-

Source: CitiPower BUS 4.02 Wood pole replacement Figure Table 5

212. We have mapped CitiPower's proposed treatment volumes to the risk classifications in the table below.

36 C5 representing ongoing monitoring and inspection

37 CP BUS 4.02 page 3

Table 4.7: Proposed pole intervention volume in next RCP

Pole condition classification	C1	C2	C3	C4	Total
Unserviceable poles	-	1,553	-	-	1,553
Added control serviceable 0.65 <= SI <0.70	-	-	-	990	990
Added control serviceable 0.70 <= SI <0.75				2,390	2,390
Total	**-**	**1,553**	**-**	**3,380**	**4,933**

Source: EMCa analysis of CitiPower BUS 4.02 and MOD 4.06

213. As shown in the table above, CitiPower has included treatment of 3,380 poles in risk classification C4, which includes poles with a serviceability index greater or equal to 0.7 and less than 3.75 in the LBRA consequence area.

214. In contrast, there are no poles included in Powercor's forecast for the risk classification of C4 and only a proportion of poles at the lower risk classification of C3. CitiPower has not explained why it has proposed including poles into its forecast that are associated with a lower risk classification, and therefore adopting a lower risk threshold.

215. Based upon application of the same risk management framework as Powercor, we would expect to see a similar risk threshold applied to both businesses. In the absence of better information, it appears that CitiPower has relied on an upper limit of expenditure as provided by its review of the AER's repex model rather than application of a risk threshold.

Many of the assumptions relied upon in the enhanced pole calculator have not been validated

216. The enhanced pole calculator relies on a number of input assumptions which have not been verified:

- For the fibre strength, we understand that CitiPower has applied the results of ENA research. We have not been provided with evidence to understand how CitiPower has, or plans to, assure itself that these assumptions are reasonable;
- For the tip load calculation, we understand that CitiPower has not yet established tools to determine the load present at different parts of the network, which is subject to many variables including pole design, conductor and pole-top hardware. In place of appropriate tools, CitiPower has made an assumption of the tip load relative to the wood pole design rating. We understand that CitiPower has assigned a percentage of design ratings by consequence area, namely: 100% tip load to BCA consequence areas; 90% to REFCL consequence areas; and 80% for the remaining areas. We further understand that this is, in part, due to the design assumptions that CitiPower believes were applied at the time of construction; and
- Pole condition is being assessed under the current pole inspection method, including the assessment of diameter loss.

217. Whilst we have not been provided a copy of the enhanced pole calculator, based on our experience, the calculation of pole condition is likely to be very sensitive to these inputs. We asked CitiPower to describe how it had validated these parameters against observed performance or experience given the enhanced pole calculator has not yet been put into practice. CitiPower advised that it plans to undertake a testing program commencing in August 2020 to validate and calibrate these parameters, and which is expected to be completed by January 2021.[38] We requested details of the test method it intends to apply. This information was not available at the time of writing this report. We understand that CitiPower did not have any plans for destructive testing of poles.

218. Based on our experience, wood pole lines were originally designed with safety factors to ensure that the pole design is in excess of the load acting on the pole. To assume that the

[38] Response to information request IR010

tip load acting on the pole is equal to the design rating of the pole without adequate verification is likely to overstate the risk of pole failure. If this were the case, we would expect to see evidence provided by CitiPower to support this assertion (such as an increasing number of 'assisted' pole failures associated with poles that have failed due to forces above their design rating such as extreme weather events).

219. CitiPower does not describe how it has arrived at these parameters, particularly as they tend to reflect maximum values of a range, when compared with the selection of alternative parameters and that are likely to result in in a range of possible intervention volumes that are lower CitiPower's forecast.

Fault expenditure is similarly not recognised in an overall pole management strategy

220. CitiPower also includes expenditure for network faults associated with its pole assets. Unlike Powercor, all network fault expenditure for CitiPower is directed to wood poles. There is no fault expenditure allocated to concrete poles. Fault expenditure is not included in the business case. CitiPower has relied upon its models to justify its forecast for network faults:[39]

> *'…our forecast for network faults reflects persistent long term trends and our confidence in the robustness of the underlying data. Our forecast for the 2021–2026 regulatory period is consistent with the observed/estimated fault expenditure for the 2016–2020 regulatory period.*
>
> *Our network faults forecast has not been adjusted to account for our planned replacement program. This is because network faults can be random, and are primarily driven by severe weather events. The severity of these events limit the correlation to asset condition, which is a key driver of much of our planned replacement programs. The lack of correlation is observed in figure 5 and figure 6, which show that network faults have remained relatively stable irrespective of total replacement investment.'*

221. We discuss the network faults forecast in other parts of our assessment. We provide the component of network faults relating to poles in the table below.

Table 4.8: Forecast network fault expenditure (excluding real cost escalation) - $m, real 2021

Network faults	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Wood poles	0.6	0.6	0.6	0.7	0.7	3.1
Concrete poles	-	-	-	-	-	-
Total	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**3.1**

Source: EMCa analysis of CitiPower MOD 4.11

222. However, like Powercor, CitiPower is silent on the relationship between its proposed pole expenditure and expenditure that is included separately for network faults. We would expect that the pole management strategy or asset class strategy would consider the inter-relationship and make any adjustments required to reflect a higher level of planned works. We have not seen evidence of this consideration or any associated adjustment to forecast pole expenditure by CitiPower.

Options analysis is limited

223. CitiPower presents three options in its business case, namely:

- maintain the status quo (with a safety factor of 1.4);
- safety factor of 1.4 and maintain average age; and

39 Response to information request IR032 and IR035 – EMCa questions following onsite meetings

- implement proposed enhancements to the pole calculator and serviceability index calculation.

224. What we didn't see is an analysis of the intervention volumes in terms of failure rates and risk outcomes, including by varying the proposed treatment volumes or input assumptions.

225. We had understood from discussions with CitiPower that there was a focus on Class three strength poles. The Business case states that 59% of Class three poles currently exceed the average life expectancy of 50 years. Further, CitiPower provided a relationship between failed Class three poles with age, which shows an exponentially increasing trend.

226. However, the business case does not describe how CitiPower has addressed what appears to be an increasing failure rate and corresponding risk of lower durability poles (i.e., Class three strength poles) in its proposed intervention volumes.

227. We expected to see analysis of a range of intervention volumes and associated expenditure compared with the benefits of reducing levels of risk, including by considering durability class and consequence areas.

CitiPower's top-down review of its forecast is limited

228. The wood pole management business case[40] includes comparison of forecasts based on:

- AER repex model;
- Maintain service life approach;
- Condition-based approach; and
- Age based approach.

229. CitiPower states that:[41]

> *'Given the limitations of each of these measures, any comparisons should be used with caution. Notwithstanding this, our forecast intervention volumes based on proposed enhancements to our pole calculator and serviceability index are reasonably consistent with the maintain service life and age-based replacement estimates, and are lower than the alternative forecast using our 2019 RCM study.'*

230. We agree with CitiPower that direct comparison with these scenarios should be undertaken with caution. We did not see sufficient information that seeks to moderate the expenditure including with the top-down review methods described. We expected to see additional review methods including an estimate of the outcomes from the forecast expenditure in terms of network risk and/or an explanation of the relationship with what appears to be improving network performance measures.

231. For example, and as noted in an earlier section, CitiPower's reliability performance is good and improving and fire start events are declining. Without explanation, the proposed step increase in forecast expenditure does not align with the stated performance trend. We consider this would have been reviewed had a robust top-down review been undertaken.

As observed for Powercor, unit costs are generally lower when the period of averaging is brought forward

232. Unit rates are as shown in the table below. As we would expect to see, unit rates for CitiPower are slightly higher (based on revealed costs) due to the higher density of development associated with CitiPower's network than for Powercor, and for additional costs associated with traffic management, access and use of a higher number of complex poles.

40 PAL BUS 4.02 section 5.2

41 PAL BUS 4.02 page 25

Table 4.9: Impact of changing averaging period for unit costs (excluding real cost escalation) - $, real 2021

Category	5 years 13/14-17/18	4 years 14/15-17/18	3 years 15/16-17/18	1 year 17/18
Staking of a wooden pole	1,392	1,658	1,890	2,790
< = 1 kV; Wood	28,724	29,232	26,515	34,682
> 1 kV & < = 11 kV; Wood	25,559	26,909	24,792	45,372
> 11 kV & < = 22 kV; Wood	15,955	31,910	63,820	-
> 22 kV & < = 66 kV; Wood	34,983	35,695	36,417	27,543

Source: EMCa analysis of CitiPower MOD 4.06

233. In its response to our information request Powercor/CitiPower stated that:[42]

> *'Robust cost estimates have been prepared for our regulatory proposal which, where applicable, have been sourced from:*
>
> *• average historical unit costs, which may have been derived from historical revenues and volumes*
>
> *• market based outcomes from competitive tender processes*
>
> *• estimated data obtained from contractors or vendors*
>
> *• actual historical costs for similar projects*
>
> *For example, for replacement projects the unit rates for high-volume works are based on average historical unit rates over the period 2014/15 to 2017/18. For larger works, project costs are based on the observed, actual costs of like-projects.'*

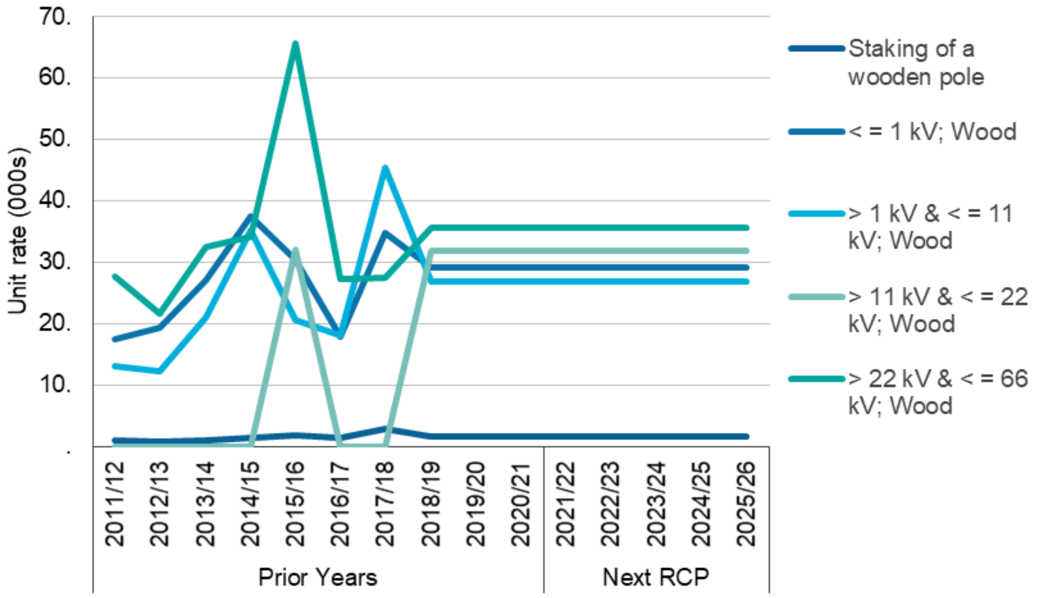
234. We observe, similar to Powercor, that the historical unit costs derived from historical expenditure and volume are sensitive to the averaging period used.

235. For pole replacement, our analysis indicates that the derived unit rates generally decrease as the averaging period is reduced. However, we also observe that the most recent actual costs are amongst the highest incurred. The reason for this increase was not provided by CitiPower. The results of our analysis are shown in the table below.

236. As discussed earlier in this report, the 'World Class program' undertaken by Powercor and CitiPower resulted in cost efficiencies that were likely to have taken a few years to flow through into each program of work. We plotted the derived unit rates in a similar way per year and included this in the chart below.

[42] Response to information request CP IR019a EMCa questions – governance and repex

Figure 4.10: Derived unit rates over time ($000s, real $2021 excluding real cost escalation)



Source: EMCa analysis of CitiPower MOD 4.06

237. The recasting of data between calendar year and financial year may have contributed to some volatility year on year, however we did not see this present in data for Powercor. The volatility is not explained, and links to similar volatility in the delivered volume of work for CitiPower.

238. Similar to Powercor, we observe what appear to be reductions to the unit rates at a similar time to when we understand the World Class program was undertaken, before the unit rates increase again in 2017/18. An averaging period that excludes 2017/18 would result in a reduction to the unit rates for the high-volume activities.[43]

Summary of our assessment

239. Based on the information available to us at the time of preparing this report, we consider that CitiPower has not sufficiently demonstrated that its proposed expenditure forecast for poles is prudent and efficient.

240. We have identified a number of issues associated with the assumptions applied by CitiPower in preparing its expenditure forecast for wood poles, and poles more generally. These issues, both individually and collectively, cast a level of doubt on whether CitiPower will require the repex that it proposes for its poles asset group to meet the requirements of the NER.

241. Based on the information provided by CitiPower, we do not consider that the forecast expenditure is representative of a prudent and efficient level for the following reasons:

- The information provided suggests that CitiPower's network does not exhibit the same level of risk as Powercor's network due to:
  - much lower and declining pole failure rates, which in part is the result of generally shorter spans (and associated lower pole loading) and larger diameter poles; and
  - higher historical levels of reinforcing.
- CitiPower has adopted the same forecasting approach as Powercor, and is subject to the same potential overstatement of input assumptions.
- The risk appetite for pole failure appears to have been adopted at a lower level than for Powercor, as indicated by the inclusion of poles with a lower risk classification of C4 into the forecast.

43 Related to wood pole reinforcement, LV wood pole replacement and 11kV wood pole replacement

- CitiPower's unit costs are higher than for Powercor and do not appear to reflect the full benefit of recent actual cost reductions.
- In response to our information request, CitiPower has confirmed a forecasting error that results in a reduction of $1m pa to their poles forecast.

242. We found evidence of the issues identified in section 4.3 and in section 3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

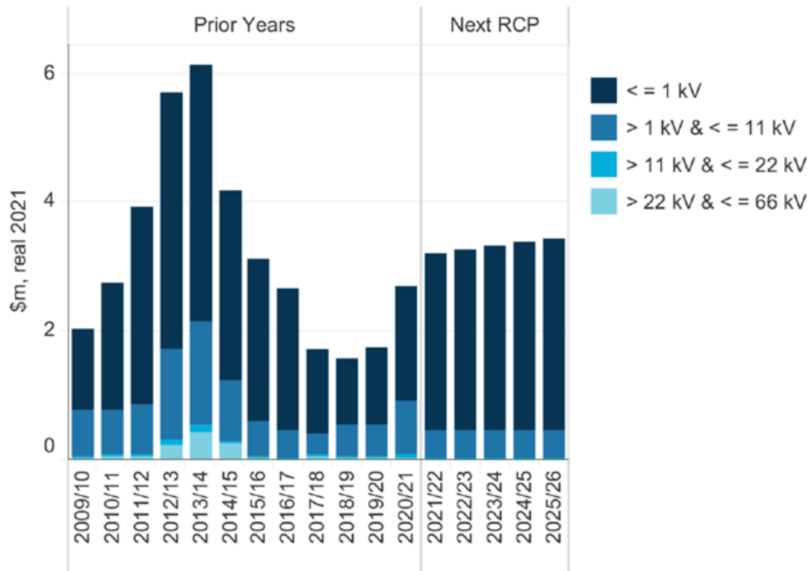
243. Accordingly, we consider that CitiPower has not justified the extent of the proposed increase to its forecast expenditure for the Poles group.

4.4.2 Pole top structures

CitiPower's forecast

244. CitiPower has proposed $16.7m[44] for the Pole top structure group in its repex forecast for the next RCP. The expenditure profile for the Pole-top structure group comparing the next RCP with previous years is shown in the figure below.

Figure 4.11: Pole top structure repex by asset category -$, real 2021



Source: CitiPower Reset RIN

245. The figure above shows a small increase from historical trend. The major components of expenditure are shown in the table below (and which reconcile to CitiPower's program when real cost escalation is excluded).

44 CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Table 4.10: Components of CitiPower's proposed pole-top structure repex for next RCP - $m, real 2021

Pole top structures	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Crossarm Replacement	2.9	2.9	2.9	2.9	2.9	14.3
Defect driven	*3.3*	*3.3*	*3.3*	*3.3*	*3.3*	*16.6*
Adjustment for pole volumes	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-2.3*
Network Faults	0.3	0.3	0.3	0.3	0.3	1.5
Total	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**15.8**

Source: EMCa analysis of CitiPower MOD 4.06 and MOD 4.11. Excludes real cost escalation

246. CitiPower has provided models comprising is lines replacement expenditure (MOD4.06) and network faults related expenditure (MOD 4.11) which include pole top structure repex. CitiPower has not provided a business case or other justification document for its proposed replacement volumes or expenditure. We therefore sought to understand the rationale for the forecast from other supporting information.[45]

Our assessment

Increased expenditure from current RCP not explained

247. According to CitiPower,[46] the expenditure associated with pole-top structure is increasing from $11.7m in the current RCP to $15.8m in the next RCP. CitiPower describe[47] the main drivers of replacement as being the asset condition based on inspection regime and/or asset failure. CitiPower has not explained the basis of its proposed increase.

Forecasting approach overstates the replacement volumes based on a historical 'find and fix' reactive management approach

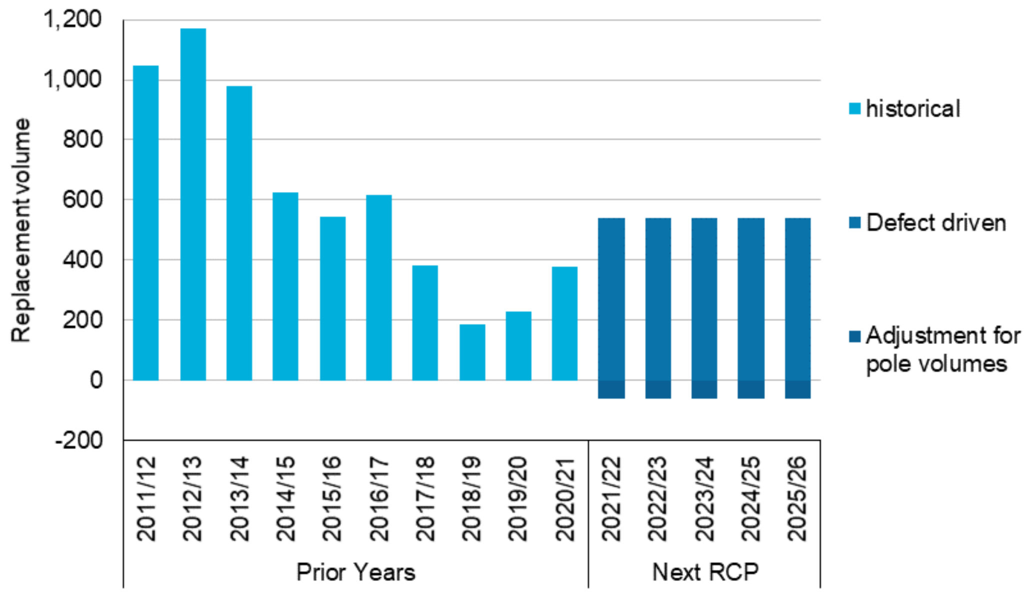
248. CitiPower describes its forecast for pole top structures as continuing its current find and fix approach. However, adoption of the averaging of historical defects over the period 2014/15 to 17/18 effectively "locks in" the elevated replacement volumes that are evidenced in the first in prior years and continue through to 2016/17. A replacement volume that more likely reflects the current practice would be based on data from a more recent period as shown in the figure below.

45 Including the Regulatory proposal, RIN016 and asset strategy documents

46 CitiPower Regulatory Proposal Table 4.4

47 CitiPower RIN response RIN016

Figure 4.12: Forecast pole-top replacement volumes (base replacement program)



Source: EMCa analysis of CitiPower MOD 4.06

249. We understand that the elevated replacement volume evidence in the period 2011/12 to 2014/15 was in response to elevated asset failures, and the program has since been completed. CitiPower has not explained the rationale for the lower replacement volumes, or why it considers that this replacement level is no longer reflective of a prudent level.

250. Making adjustments to move the averaging period to reflect more recent data results in a reduction to the defect driven replacement volumes. For example, assuming that the level of replacement approximated the 2017/18 levels would reduce the forecast defect driven replacement volume from 541 to 382,[48] a difference of 159 units per annum (with the largest variance arising from the replacement of LV cross-arms). We estimate that the cost of the additional LV cross-arm replacement is approximately $0.5m per annum.[49] If an averaging period is used, ignoring 2016/17, cost would be reduced further.

Proposed reduction included to account for increase in proposed pole replacement program is likely to be insufficient

251. CitiPower states that the [50]

> *'…pole-top structures and service line forecasts have been reduced to account for the expected overlap due to our increased pole replacement volumes'*

252. Based on our review of the provided models, the adjustment is included as a negative replacement volume of 63 units pa as shown in the figure above. This results in a corresponding reduction to the base replacement forecast for this group. The derivation of the 63 units is not provided.

253. We estimate that the proposed adjustment amount accounts for approximately 20% of replaced poles included in the incremental pole replacement included for the next RCP.[51] Due to the proposed pole replacement program there is likely to be a reduction in the number of LV cross-arm replacements required, as crossarms are typically replaced only when a pole is replaced.

48 Without considering the adjustment for the proposed increase in pole intervention volumes

49 Based on the proposed unit cost and which may differ if a different averaging period is applied.

50 CitiPower Regulatory Proposal, footnote to Table 4.4

51 Based on the most recent estimated pole replacement volume. Using the historical average wood pole replacement volume from 2014/15 to 2017/18 results in reducing this percentage by a few percent

254. From our analysis, the proposed pole replacement program will replace, on average, an additional 282 poles per annum (including crossarms) compared to the period 2014/15 to 2017/18. This will likely result in a larger reduction to the planned crossarm replacement program than CitiPower has proposed.

Summary of our assessment

255. A replacement volume that more closely reflects the current asset management practice, should be based on recent data. CitiPower submits that it has done this, however the inclusion of early years in the averaging means that this is not the basis of their forecast replacement volumes.

256. We found evidence of the issues identified in section 4.3 and in section 3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

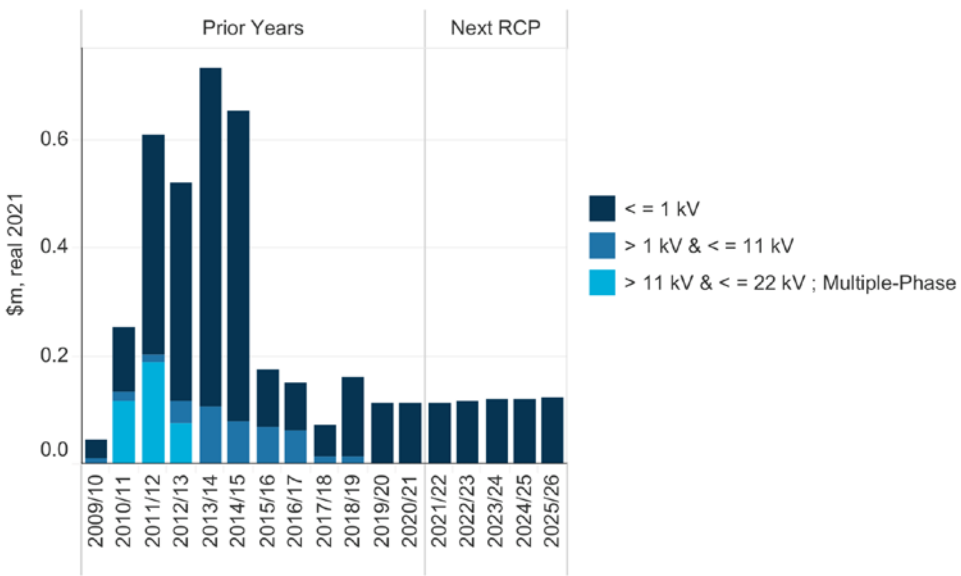
257. Accordingly, we consider that CitiPower has not justified the extent of the proposed increase to its forecast expenditure for Pole top structures.

4.4.3 Overhead conductors

CitiPower's forecast

258. CitiPower has proposed $0.6m[52] for the Overhead conductor group in its repex forecast for the next RCP. The expenditure profile for the Overhead conductor group comparing the next RCP with previous years is shown in the figure below.

Figure 4.13: Overhead conductor repex by asset category - $m, real 2021



Source: CitiPower Reset RIN

259. The figure above shows a similar level of forecast expenditure when compared with recent history, and that is lower than the historical average. On review of the composition of the forecast, CitiPower has included a single program based on its historical defects as shown in the table below (and which reconcile to CitiPower's program when real cost escalation is excluded). As noted earlier, the network fault repex for conductors has been removed for the next RCP, and similarly removed from the Reset RIN and therefore is not present in the above figure.

52 CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Table 4.11: Components of CitiPower's proposed Overhead conductor repex for next RCP - $m, 2021

Overhead conductor	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Defect driven	0.1	0.1	0.1	0.1	0.1	0.6
Network Faults	-	-	-	-	-	-
Total	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.6**

Source: EMCa analysis of CitiPower MOD 4.06 and MOD 4.11. Excludes real cost escalation

260. CitiPower has provided a line replacement model (MOD4.06), of which overhead conductor replacement is a component, to support its proposed expenditure.

Our assessment

261. CitiPower has forecast a small increase in replacement volumes of its overhead conductor assets, when compared with recent history, to 0.6km per annum bringing the total cost to $0.6m for the next RCP as shown in the table above.

262. The main driver of replacement is described as the asset condition based on inspection regime and/or asset failure. The increase is associated with the introduction of annual LIDAR for conductor clearances to be developed and applied.

Summary of our assessment

263. On the basis that CitiPower has determined that this volume is necessary to meet its safety obligations, we consider that the forecast replacement volumes for the Overhead conductor group is reasonable.

264. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

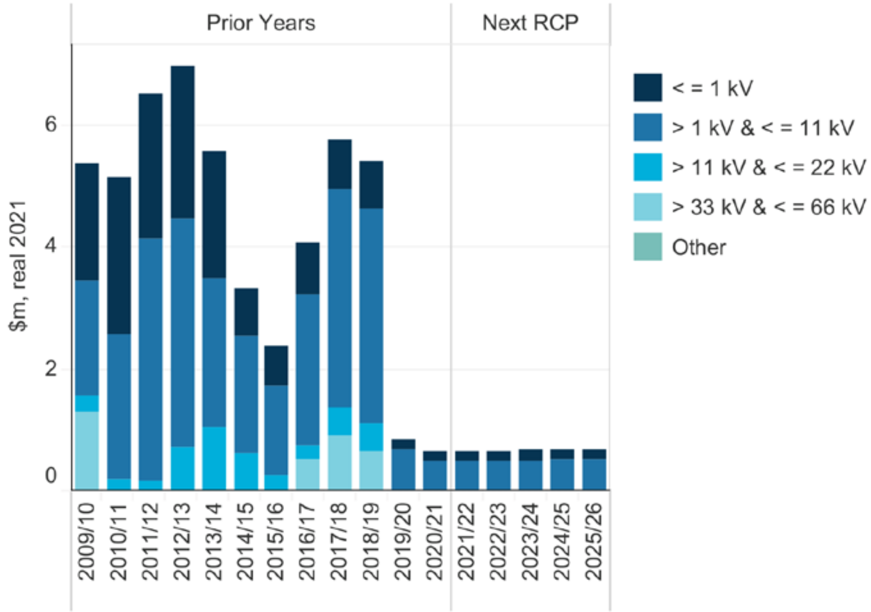
4.4.4 Underground cable

CitiPower's forecast

265. CitiPower has proposed $3.4m[53] for the Underground cable group in its repex forecast for the next RCP. The expenditure profile for the Underground cable group comparing the next RCP with previous years is shown in the figure below.

[53] CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.14: Underground cable repex by asset category - $m, real 2021



Source: CitiPower Reset RIN

266. The figure above shows a large decrease in forecast expenditure when compared with historical levels. The major components of expenditure by program are shown in the table below (and which reconcile to CitiPower's program when real cost escalation is excluded.) As noted earlier, the network fault repex for underground cables has been removed for the next RCP, and similarly removed from the Reset RIN and therefore is not present in the above figure.

Table 4.12: Components of CitiPower's proposed underground cable repex for next RCP - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Volumetric programs						
Network Faults	-	-	-	-	-	-
Projects						
HV UG Cable Replacement	0.5	0.5	0.5	0.5	0.5	2.4
LV UG Cables Planned Replacement	0.2	0.2	0.2	0.2	0.2	0.8
Total	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**3.2**

Source: EMCa analysis of CitiPower MOD 4.06 and MOD 4.11. Excludes real cost escalation

267. CitiPower has provided a line replacement model (MOD4.06), of which underground cable is a component, to support its proposed expenditure.

Our assessment

268. CitiPower has not provided an explanation for why it has reduced its underground cable expenditure below a level indicated by its historical trend.

269. In its documentation, CitiPower state that:[54]

> *'We have a very small targeted replacement program for underground cables. Underground cables are managed through defects and fix on failure approach. Additionally, we replace damaged sections in piecemeal fashion. Regular scheduled*

[54] CitiPower RIN016

tests for oil filled and XLPE cables include insulation and sheath resistance tests and oil DGA tests. Engineering assessment is applied to prioritise cable defects.'

270. The forecast expenditure for its two components of LV cable replacement and HV cable replacement are proposed to be held at 2020/21 levels, which is a small increase for HV underground cable replacement from 2019/20. We have not been provided with any prior expenditure at these component levels and are therefore reliant on review of trend analysis from the RIN.

271. We note that the forecast underground cable expenditure excludes the network faults related expenditure as discussed in section 4.3.4.

Summary of our assessment

272. On the basis that CitiPower has determined that this volume is necessary to meet its safety obligations, we consider that the forecast replacement volumes for the Underground cable group is reasonable.

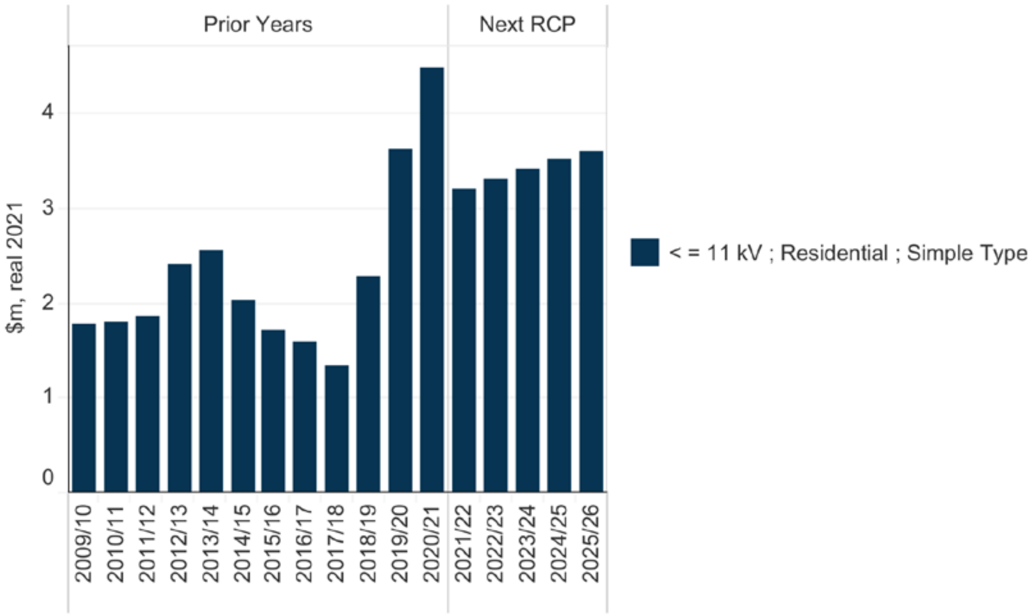
273. We found evidence of the issues identified in section 4.3 and in section 3 that indicate an over-forecasting bias and of cost estimate that may be higher than would be reflective of an efficient level. However, on balance, due to the low level of expenditure, the forecast is likely to be reasonable.

4.4.5 Service lines

CitiPower's forecast

274. CitiPower has proposed $17.1m[55] for Service lines in its repex forecast for the next RCP. The expenditure profile for Service lines comparing the next RCP with previous years is shown in the figure below.

Figure 4.15: Service lines repex by asset category - $m, real 2021



Source: CitiPower Reset RIN

275. The figure above shows an increase associated with residentials service line replacement, at a level similar to that estimated to be incurred in 2019-20. The major components of

55 CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

expenditure and program by construction type are shown in the tables below (and which reconcile to CitiPower's program when real cost escalation is excluded.)

Table 4.13: Components of CitiPower's proposed Service lines repex for next RCP - $m, real 2021

Service lines	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Obsolete & Defective Overhead Services	2.6	2.6	2.6	2.6	2.6	12.9
Defect driven	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*4.3*
PVC Grey Program	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*2.3*
AMI NST	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*
Veranda Access	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*5.7*
Adjustment for pole volumes	*-0.1*	*-0.1*	*-0.1*	*-0.1*	*-0.1*	*-0.4*
Network Faults	0.6	0.6	0.7	0.7	0.8	3.4
Total	**3.2**	**3.2**	**3.2**	**3.3**	**3.3**	**16.2**

Source: EMCa analysis of CitiPower MOD 4.06 and MOD 4.11. Excludes real cost escalation

276. CitiPower has provided a line replacement model (MOD4.06), of which service line replacement is a component, to support its proposed expenditure.

Our assessment

Increases to proposed planned expenditure

277. The main driver of replacement is the asset condition based on inspection regime and/or asset failure. CitiPower's forecast for service lines is composed of a number of components as shown in the table above.

278. The components of the services replacement program include three proactive replacement programs:[56]

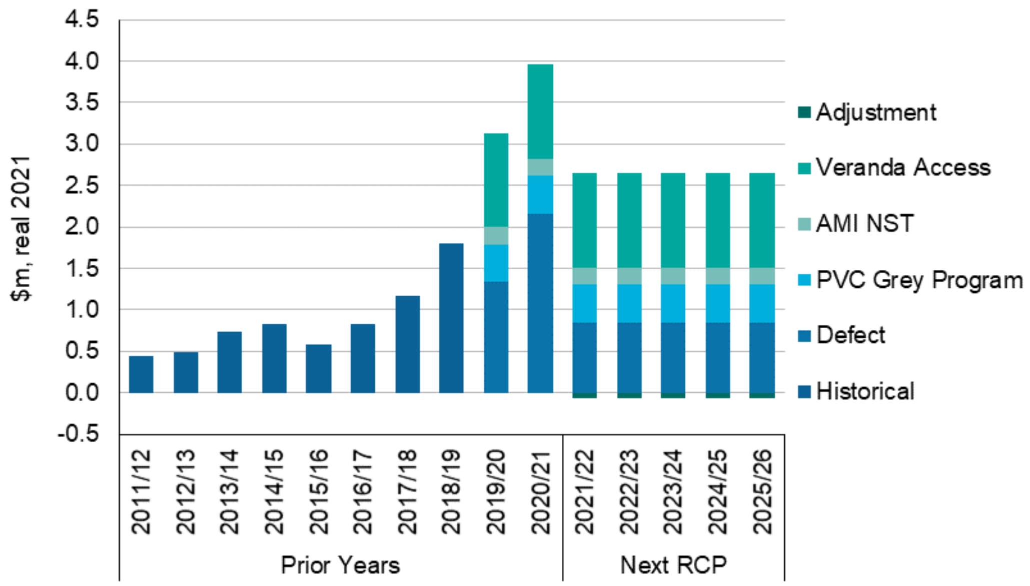
- PVC grey[57] refers to the twisted Polyvinyl Chloride (PVC) grey service cable replacement program, which addresses a failure mode whereby the insulation at the connection point can be pierced, and cause any attached metalwork on the premise to become energised;
- AMI NST – Advanced Metering Infrastructure Neutral Screen Testing program that '*proactively detects hazardous neutral services by applying an algorithm to smart meter data that identifies particular voltage and current signatures (that are consistent with potentially faulty service connections)*'; and
- Veranda access – this program is not described in CitiPower's Regulatory proposal. We infer from the expenditure model provided that this program relates to replacement of services where access using standard work procedures is not possible, and a non-standard replacement task is required (such as for difficult access).

279. We show the breakdown of the service line repex by program in the figure below. The estimated and forecast defect driven expenditure is of a similar level to that which CitiPower has been incurring. We also show the adjustment to the replacement volumes as a result of the proposed increased pole replacement, included as a negative volume by CitiPower. This is a small percentage of the forecast replacement volumes.

56 CitiPower Regulatory Proposal, page 34-35

57 The metal hook connection used on a twisted PVC grey service cable is commonly referred to as a 'dog-bone'. The term 'dog bone' is interchangeable with 'PVC grey service cable replacement'

Figure 4.16: Historical and proposed planned replacement expenditure by services program (excl network faults) - $m, real 2021



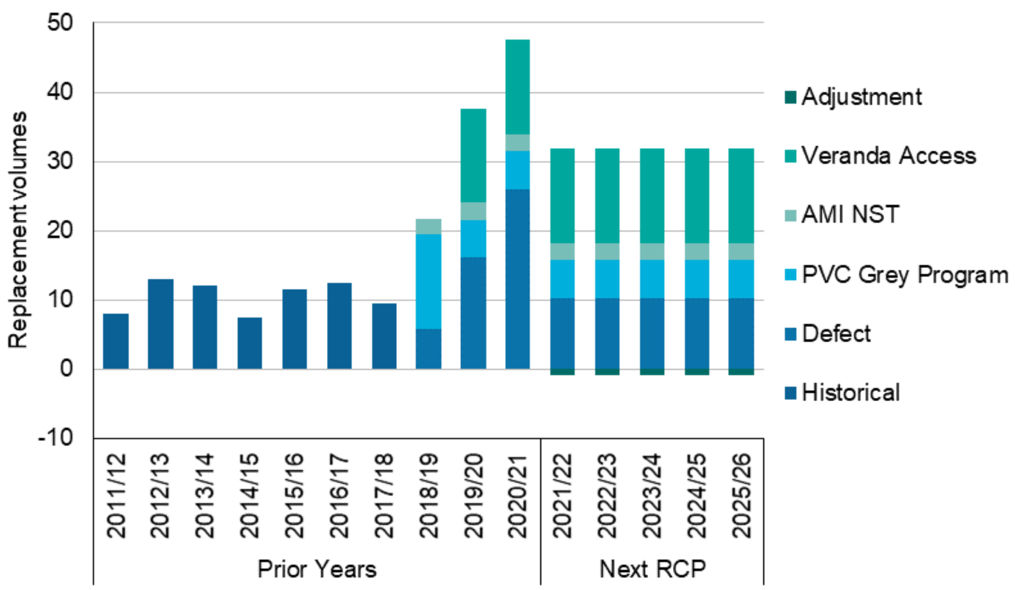
Source: EMCa analysis of CitiPower MOD4.06

Introduction of programs does not appear to be supported by performance

280. CitiPower has included three programs for service line replacement in addition to its base level of replacement (excluding network faults). We looked for evidence to support the introduction of this program in the current period, and for it to continue into the next RCP.

281. As shown in the figure below, the introduction of the proposed programs represents a step increase in replacement when compared with historical replacement volumes. This is shown in the figure below.

Figure 4.17: Historical and forecast service lines replacement volumes



Source: EMCa analysis of CitiPower MOD4.06

282. We looked for evidence to support the introduction of new programs in response to a decline in asset condition, or some observable decline in performance indicators. Based on our review of the historical public safety incidents and fire start performance provided by

CitiPower[58], we observed a declining trend in safety impact fire starts and asset failures, and a level trend of reportable incidents involving the public (including asset failures).

283. The introduction of these programs appears to be primarily driven by CitiPower's consumer engagement:[59]

> *'The options presented for these [replacement of twisted PVC and NST] programs included a status-quo option (i.e., consistent with our existing asset management approach), and incremental replacements to proactively reduce safety risk. Customers were provided with indicative bill impacts associated with each option, as well as the cumulative impact of selecting multiple safety programs throughout the entire forum.*
>
> *Our customers were overwhelmingly supportive of using smart meters to detect faults for repair. Further, our customers wanted us to initiate these programs immediately, rather than wait until the 2021–2026 regulatory period.*
>
> *Based on our customer feedback, we have brought forward the timing of these projects into the current regulatory period.'*

284. We did not see reference to the veranda access program in the consumer engagement, and which constitutes over 40% of the proposed expenditure.

Assumptions are based on limited data

285. CitiPower has included some more recent defect and replacement data for each of the asset populations, and has used this data as the basis of forecasting additional replacement volumes as follows:

- For the 'PVC grey' replacement program,[60] the replacement volume is simply the implied failure rated by CitiPower of 1.23%[61] being the 'P28 fault notifications found as result of testing' multiplied by the population of PVC grey services (being 20,163).[62] On further review of the model, the replacement volumes are extrapolated from elevated levels of replacement that occurred in 2018, which were in the order of four to five times the replacement levels that occurred prior to and following this period. In the absence of better information, we don't consider that a single data point is sufficient evidence to justify replacement at these higher levels;
- For the 'AMI NST' replacement program, the replacement rates are based on a 12-month period of replacement that commenced in 2018 and was completed in 2019. As above, absent other information, this single period does not provide sufficient evidence to indicate an underlying issue. We understand that smart meters are used to identify faults by applying an algorithm to smart meter data. This would suggest that a population of service lines would be identified, and a program developed to address them, rather than the observed level of faults in each month of a 12-month sample period being repeated in each year of the nine years of data provided; and
- For the 'veranda access' replacement program, CitiPower has identified 13.7 service replacement kms per annum (which is equivalent to 623 service lines per annum) of the total population of 112,660 services. This is calculated by an estimated percentage of the population of services that '*cannot be accessed via SWP'*[63] that require replacement, and replacement assumptions per year. CitiPower has not justified its

58 Response to information request IR032 – EMCa questions following onsite meetings

59 CitiPower Regulatory Proposal, page 33

60 Also referred to as the 'Dogbone' program by CitiPower

61 The same failure rate is assumed across Powercor and CitiPower's network

62 A further step converts the number of replacements to km pa by dividing by the average service length of 22m, for presentation in the RIN

63 The term SWP was not defined by CitiPower in its expenditure model. We assume that SWP refers to Safe Work Practices

estimate of services that require replacement, and which are significantly higher than provided for Powercor's network.

286. Use of more recent replacement data is positive, however remains insufficient without other corroborating evidence that the incurred replacement levels are directed at addressing an elevated level of safety risk, systemic issues or defect. It is also unclear why this replacement volume should be undertaken in addition to the underlying level of defect driven replacements that are forecast based on other methods.

287. The veranda access program is not included in the descriptions provided of the included services programs in the Regulatory Proposal, and did not feature in CitiPower's description of its consumer engagement.

No assessment of risk or cost benefit from CitiPower's analysis

288. Absent a clear performance driver, there may be a reason to introduce these programs where the net economic benefits of doing so are positive. Accordingly, we looked for evidence of a risk assessment and accompanying cost benefit analysis.

289. Whilst CitiPower recognises the need for a cost benefit analysis where it may be prudent to further reduce safety risks, it has not provided this as part of its justification. In its response to an information request, CitiPower state that:[64]

> *'We have not undertaken cost-benefit analysis for this expenditure given the forecast methods outlined above, [based on observed experience] the underlying asset populations, and the current and ongoing nature of the replacement works [which commenced in 2018/19].'*

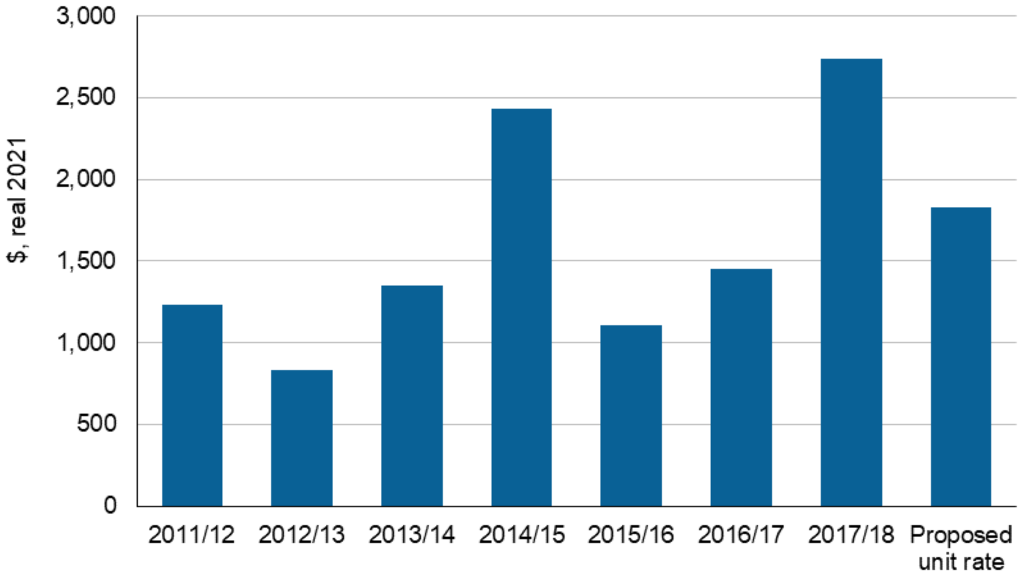
290. We did not find a risk assessment to support the introduction of the proposed new proactive replacement programs.

High unit rates are reflected in the forecast expenditure

291. Consistent with CitiPower's forecasting method, the unit rates reflect the average over the period 2014/15 to 2017/18. As discussed in section 3, when we review the unit rates achieved by CitiPower for its service line replacement, we see evidence that it has achieved lower rates than it has proposed. CitiPower has not explained the increase in unit rates observed for 2017-18.

64 Response to information request IR016

Figure 4.18: Derived historical unit rate for residential simple type service line replacements - $, real 2021



Source: EMCa analysis of CitiPower MOD4.06

Summary of our assessment

292. Whilst programs of the type proposed by CitiPower are common across the industry, and likely to require focus within CitiPower's network, CitiPower has not adequately demonstrated that the defect driven program, if prioritised based on highest risk service lines, will not be sufficient to meet its safety obligations.

293. We found evidence of the issues identified in section 4.3 and in section 3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

294. We have been provided additional information in IR049 relating to the rationale for the service lines repex, however this information does not materially alter our findings. Accordingly, we consider that CitiPower has not justified the extent of the proposed increase to its forecast expenditure for the Service lines repex group.

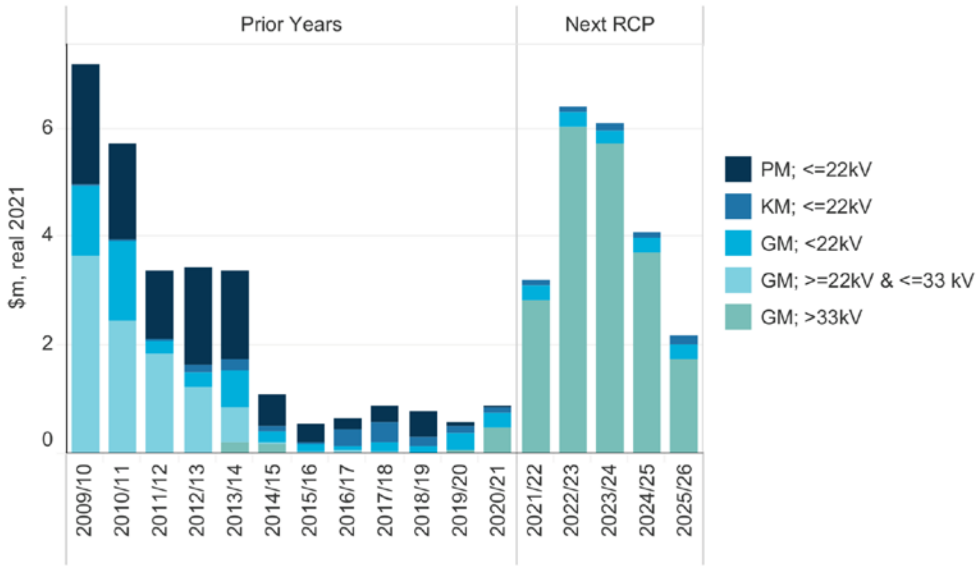
4.4.6 Transformers

CitiPower's forecast

295. CitiPower has proposed $21.9m[65] for the Transformer group in its repex forecast for the next RCP. The expenditure profile for the Transformer group comparing the next RCP with previous years is shown in the figure below.

[65] CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.19: Transformer repex by asset category - $m, real 2021



Source: CitiPower Reset RIN. PM = Pole Mounted, KM = Kiosk Mounted and GM = Ground mounted

296. The figure above shows that the largest increases and the largest component of forecast transformer expenditure in the next RCP are associated with the replacement of substation related transformers. The major components (projects and programs) of forecast expenditure are shown in the table below (and which reconcile to CitiPower's program when real cost escalation is excluded.)

Table 4.14: Components of CitiPower's proposed Transformer repex for next RCP - $m, real 2021

Transformers	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Network Faults	-	-	-	-	-	-
Projects						
Transformer Replacement	2.8	5.8	5.4	3.5	1.6	19.1
AR T1	*-*	*-*	*-*	*-*	*0.0*	*0.0*
CW T1	*-*	*-*	*-*	*-*	*0.0*	*0.0*
NR T1	*0.0*	*0.4*	*1.9*	*1.5*	*-*	*3.9*
NR T2	*-*	*0.0*	*0.4*	*1.9*	*1.5*	*3.9*
VM T1	*0.4*	*1.9*	*1.5*	*-*	*-*	*3.9*
WA T1	*1.9*	*1.5*	*-*	*-*	*-*	*3.5*
WA T2	*0.4*	*1.9*	*1.5*	*-*	*-*	*3.9*
Indoor Substation Transformer Replacement	0.2	0.2	0.2	0.2	0.2	0.9
Kiosk Substation Replacement (Condition)	0.1	0.1	0.1	0.1	0.2	0.6
High Rise Indoor Oil Transformer replacement	0.1	0.1	0.1	0.1	0.1	0.3
Total	**3.1**	**6.2**	**5.8**	**3.8**	**2.0**	**20.9**

Source: EMCa analysis of CitiPower MOD 4.06 and MOD 4.11. Excludes real cost escalation

297. As shown in the table above, and noted in our assessment of network faults, CitiPower has removed the transformer repex from its forecast of network faults.

298. CitiPower has provided the following documentation with its submission to support its expenditure:

- expenditure model comprising its transformer replacement expenditure (MOD4.09);
- a business case for its transformer risk and investment evaluation, [66] provided in support of the planned transformer replacement program totalling $19.1m; and
- risk monetisation models for five transformer replacements.[67]

Our assessment

Increased expenditure driven by inclusion of zone substation transformer replacement

299. CitiPower proposes replacing five zone substation transformers during the next RCP at a total cost of $19.1m.[68] CitiPower informed us that it has decommissioned 17 transformers[69] in the current period which, as a consequence, removes the need for end of life replacement.

300. CitiPower currently has 102 substation transformers with an average age of 46.7 years, with three transformer assets currently older than their estimated service life.[70] The five zone substation transformers that CitiPower proposes to replace are:

- Celestial Avenue (WA) transformer no 1 and 2 at a total cost of $7.4m;
- Victoria Market (VM) transformer no 1 at a cost of $3.9m; and
- North Richmond (NR) transformer no 1 and 2 at a total cost of $7.8m.

301. For all the above projects CitiPower has provided details within the supplied business case document, the CBRM outputs and a risk monetisation models that it has relied upon.

302. In addition, we note that CitiPower has proposed four transformer replacements as part of its augex forecast, where the primary driver is asset condition related risk of failure. These projects are:

- Brunswick area strategy;
- Port Melbourne Area strategy; and
- Russell Place Supply Area - Russell Place zone substation replacement.

303. We consider these separately in our assessment of augex.

The process used to select projects for application of CitiPower's risk monetisation method appears reasonable

304. In 2018, at the commencement of its process for establishing a risk prioritised replacement expenditure forecast, CitiPower calibrated its CBRM model to identify an initial list of 37 transformers as potential replacement candidates. These transformers were selected on the basis of having an Asset Health Index (HI) greater than 5.5. We consider that this was a reasonable starting point particularly because, in its CBRM model, CitiPower considers aspects such as test results, location and duty when establishing its HI for transformers.

305. From its initial list, CitiPower removed transformers to be decommissioned and those planned to have repair/refurbishment work. It also removed transformers for further analysis on the basis that they have experienced low loading or are identified as posing low consequence resulting from failure. In its response to our questions, CitiPower described

66 CP BUS 4.03 Transformer evaluation methodology

67 NR transformer no. 1 (MOD4.12), NR transformer no. 2 (MOD4.13), VM transformer no. 1 (MOD4.14), WA transformer no. 1 (MOD4.15), and WA transformer no. 2 (MOD4.16)

68 There is a further two transformer replacements for AR T1 and CW T1 with a sum of $26k each, and which we infer is for preparatory work for future transformer replacement projects

69 CitiPower Regulatory Proposal, Figure 4.6

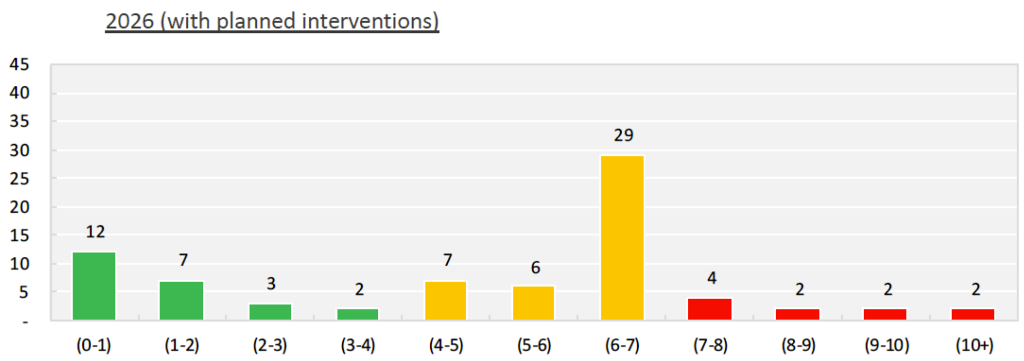
70 CitiPower Asset Class Strategy – zone substation transformers, August 2019

how it made decisions regarding the replacement or refurbishment of major substation plant on a case-by-case basis.

306. By taking into account transformer history, availability of spares and hidden failure modes, CitiPower reduced its list of candidates further. It applied its risk monetisation analysis to the final five transformers included in its forecast.

307. The profile of HI for transformers, before and after the proposed replacement expenditure, provides further support to the claim that CitiPower is applying appropriate engineering judgement rather than replacing transformers that reach a specific age and/or condition. We show the final HI values as at 2026 in the chart below which indicates that after the planned replacement, CitiPower expect to have 10 transformers with a HI value at 7 or above, which indicates that the transformer is in a deteriorating condition.

Figure 4.20: Profile of predicted HI for transformers as at 2026 with planned replacements for CitiPower

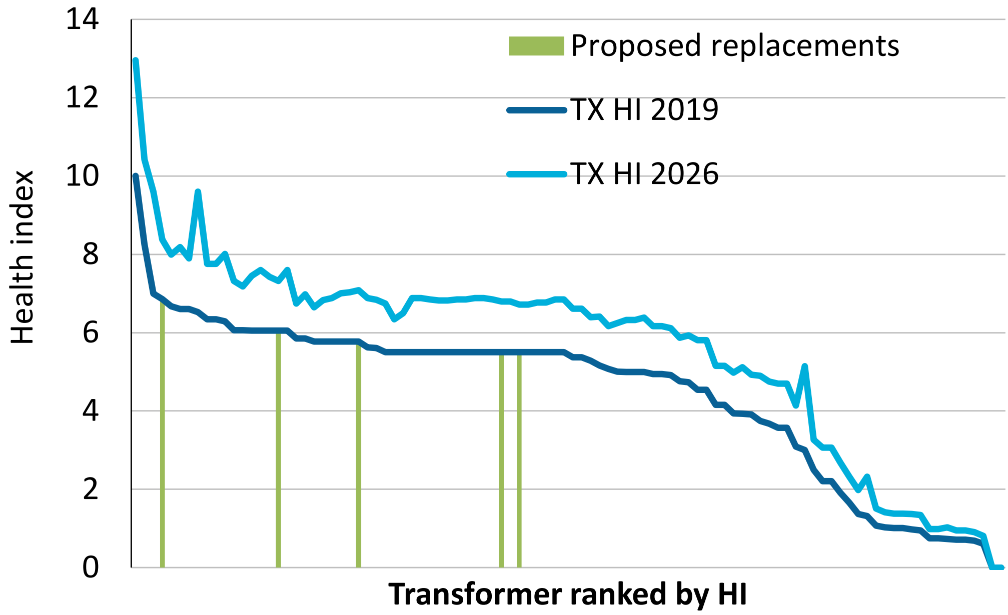


Source: CitiPower and Powercor - IR032 and IR035 - EMCa questions following onsite meetings – Public, page 13

308. Whilst CitiPower has provided us with the volume of HI for each transformer, we have no visibility of the interventions planned for each transformer or how the options have been assessed to determine that the proposed program reflects a prudent level of expenditure.

309. We did gain a perspective of the effect of the selection by sorting the transformer population by HI. The results are shown below.

Figure 4.21: Comparison of HI at 2019 and 2026 by transformer for CitiPower



Source: EMCa's analysis of data sourced from CitiPower032 and PAL035 - Q15 - CBRM HI and POF summary (corrected) - received 15 June 2020

310. In the above figure, we compare the 2019 HI for each substation transformer in CitiPower's network, against the projected value for 2026 HI for each transformer if no replacements are made. The vertical columns indicate CitiPower's proposed transformer replacements. This supports the conclusion that CitiPower is targeting, but not replacing all of transformers with the highest HI.

CitiPower does not appear to sufficiently consider options in its analysis

311. The transformers to which CitiPower's risk monetisation modelling applies is limited to the five transformers proposed for replacement in the next RCP. At this point, CitiPower had already determined that the candidate transformers required replacement. We have not been provided with details of candidate projects where a lower cost refurbishment and/or condition monitoring option was selected as evidence of how it had considered other treatment options across its fleet of transformers, or details specific to the four transformers for which it proposes a replacement decision. Based on the information provided, our understanding is that the risk monetisation process is used only to determine the optimum timing of the of the selected option.

312. CitiPower does also refer to the introduction of a bushing replacement program:[71]

> *'A bushing replacement program is underway for ZSS power transformers—due to some past failures, we have already replaced our highest risk oil filled bushings from our network during the 2016–2020 period and are continuing to do targeted replacement of our oil filled bushing population with Resin impregnated paper bushings. Historical Category Analysis RIN submissions contain the number of bushings replaced per year, included in the Table 2.2 Repex 'Other' category'.*

313. We do not see evidence of expenditure allocated to these lower cost interventions for its transformer asset fleet within this category of expenditure. As discussed in our assessment of its 'other' repex group, we did see evidence of transformer refurbishment included there. However, it is unclear to us how the options for refurbishment are undertaken and how they relate to the outputs of the CBRM models used for management of the transformer fleet.

314. The absence of clear consideration of options for the proposed projects casts a level of doubt on the decision process used for selecting transformers for replacement as it has

[71] CitiPower Repex RIN response RIN016

proposed. We also do not have visibility of the treatment options for which CitiPower predicts will be at a higher value of HI by the end of the next RCP, which indicates a condition that is further deteriorated than those proposed for replacement.

CitiPower has assumed a low major failure mode rate for its substation transformers

315. We observed that CitiPower had assumed a low failure rate for its substation transformers. We asked CitiPower to provide the historical failure mode data for its substation transformers that was considered when establishing its CBRM inputs to the risk monetisation process.

316. CitiPower confirmed that it had not experienced any major transformer failures during this five-year period:

> *'We have not experienced a major failure in the last five years. However, it was not considered appropriate to use a failure rate of zero for major failures, as many failure modes for transformers, including core, winding and bushing failures, have the potential to result in internal arcing and explosion or fire.*
>
> *Rather, our experience suggests that a failure rate of 0.1 (or one asset in 10 years) would be a reasonable approximation for our total power transformer population. This equates to a failure rate of 0.0004 per transformer.'*

317. CitiPower advises that its assumed failure rate is significantly lower than other industry values, particularly given its aged asset population.[72] For example, the Transformer Reliability Survey, CIGRE Working Group A2.37, December 2015 (TB64) gives failure rate values of 0.004 to 0.012 for major failures.

318. Projecting a zero major failure rate for transformers with the age profile and condition assessments of CitiPower's transformer fleet would not be appropriate. Assumptions on probability of failure are important inputs to the risk monetisation model and for major and catastrophic failure modes with high associated risk costs, relatively small movements can be material to the result.

319. The PoF values in the transformer risk monetisation models[73] supplied by CitiPower are consistent with the CBRM models provided in response to our questions. We have applied additional sensitivity testing to the probability of failure values relied upon in the risk monetisation models. We found that whilst the models are sensitive to this value, and that it had to be reduced by an unreasonable amount to move the replacement dates beyond the next RCP.

320. Key parameters relied on in its risk-cost analysis are not justified. In the annualised risk cost analysis provided by CitiPower, the central (base case) scenario for each of the five transformers indicates that the optimal timing for the transformer replacement has already passed as the total risk cost exceeds the annualised cost of intervention in 2019.

321. We observe that the critical driver of the optimum date for replacement in the models is risk cost to account for an event where one asset failure coincides with another major or significant failure, a planned outage, or maintenance of assets at that substation.[74] Coincident events lead to additional unserved energy related risk costs.

322. The risk cost is very sensitive to the assumed likelihood of consequences of an N-2 contingent outage for a significant failure event; which CitiPower set at 4% for all scenarios. It has not justified the selection of this value. CitiPower supplied the following explanation of its approach to contingent outage consequence:[75]

72 Response to information request IR035 - EMCa questions following onsite meetings – Public, response to question 18

73 For example, CitiPower MOD 4.15 - WA transformer no.1 - Jan2020 - Public

74 CitiPower BUS 4.03 Transformer evaluation methodology, page 9

75 CitiPower BUS 4.03 Transformer evaluation methodology, page 9

'Network performance consequences may include the costs of unserved energy associated with coincident outages (e.g. where a failure coincides with another major or significant failure, a planned outage, or maintenance of assets at that substation).'

323. We would expect that the likelihood of a coincident outage occurring in the event of a failure of the transformer, which in turn results in a widespread outage, as proposed by CitiPower is very small. This is often referred to in terms of low probability, high consequence events and is rarely observed.

324. It is inherently challenging to 'accurately' determine some of the parameters proposed by CitiPower in its risk monetisation model. Whilst CitiPower applied scenarios for combinations of adjusted input assumptions, we consider that CitiPower should have undertaken comprehensive sensitivity analyses to demonstrate that its analysis is robust and the proposed expenditure forecast is reasonable.

Other assumptions included in its risk models contribute to an overstatement of risk cost

325. In the absence of evidence to support the assumptions that CitiPower has applied in its risk monetisation model, we consider that the model is likely to be overstating the risk. Examples of assumptions that are potentially overstated, and that are in addition to comments on the likelihood of consequence for coincident outages, are provided below:

- **Likelihood of consequence of failure**: For transformers, CitiPower sets the likelihood of unserved energy consequences at 96% for significant events and 76% for major failure modes. In our view CitiPower should have tested the sensitivity of its proposed capex to these assumptions;
- **Probability weighted demand forecast**: The network performance cost is calculated based on the time taken to install generators to restore supply and applying a weighted average of the 50th and 10th percentile expected unserved energy estimates. As discussed in section 3, CitiPower applies weightings of 70% and 30% (respectively) to the demand forecast and which we consider is likely to result in an over-estimate of the unserved energy;
- **Progressive restoration of supply**: CitiPower identifies the unserved energy as that which is initially resulting from load that cannot be transferred to alternate supplies following a significant or major failure. The model reduces the unserved energy once the generators begin to be used to restore supply. It is also possible that supplies may be progressively restored from alternative supply points, thereby reducing generation operating costs. We question whether the input assumptions have adequately taken into account the probable extent of the opportunities available to progressively restore supplies. We agree that generation cost is likely to be required for an outage, however not necessarily for the entire repair time;
- **Cost of generation**: We consider that the estimated costs of generation may be higher than would be incurred during an actual event. In the absence of firm evidence that the costs are reasonable, we consider that a lower cost should be used; and
- **Use of gross rather than net risk costs**: The risk cost monetisation assessment applied by CitiPower compares the total risk cost prior to the replacement occurring with the annualised cost of replacement. This incorrectly assumes that no risk costs will be present when the replacement has been made. We consider that the model should first calculate the true benefit, being the difference between the pre-investment and post-investment risk cost, and then compare this value with the annualised costs. Whilst the post-investment costs might be relatively low, the current model may be overstating the risk cost outcomes.

326. The application of over-stated assumptions is likely to result in an over-statement of risk-cost and result in earlier timing for replacement than would otherwise be the case. When we make adjustments to reflect more reasonable assumptions, we find that the 'optimal' replacement timing is deferred for a number of projects from that proposed by CitiPower.

327. We remain concerned that the models as presented by CitiPower do not appear to adequately assist with CitiPower's investment decision making, or assist with identifying an

optimal date for replacement due primarily to the overstated risk assumptions. Rather, the model appears to be used as a means to further support the investment decision to replace the nominated transformer assets, which have been selected using other methods.

Aggregate impact of risk cost analysis is not visible

328. In considering the impact of a potential bias to over-stating the risk cost observed in the proposed expenditure, we sought to understand the aggregate level of risk that is likely to exist across CitiPower's fleet of transformers.

329. For all five replacement projects, the transformer is operating beyond its expected life of 60 years. At this age, the risk of failure increases as reflected in the CBRM model output. The transformers have a HI at the higher end of the range of HIs for CitiPower's transformer fleet and it is reasonable to consider them for evaluation of replacement / refurbishment options.

330. The basis of the selection process to establish the prioritisation of projects subjected to risk monetisation has not been satisfactorily explained and supported by analysis and other evidence. Because of this, we are unable to confirm that the specific projects have a higher priority for replacement than others, or that the composition of the proposed program will actually be delivered.

The cost estimates are based on early stage unit costs

331. CitiPower has included the same unit cost of $3.8m for its proposed transformer replacement projects, and which also align with Powercor's unit cost for transformer replacement.

332. In response to a request for a build-up of the unit cost, CitiPower advised that the cost was based on replacement works at Warrnambool (WBL) and Terang (TRG) zone substations as described below:[76]

- *'the relatively simple scope of our WBL and TRG zone substations means they are likely to represent a 'generic' transformer replacement (or at least, they are unlikely to represent overly complex or expensive projects, noting that increased after-hours works scheduling, traffic management costs, and/or space/access constraints evident at many CitiPower sites are not reflected);*
- *the same design and procurement processes are applied across our CitiPower and Powercor networks; and*
- *the same internal workgroup will undertake the delivery of these projects.'*

333. Only two projects are referred to by CitiPower, as CitiPower had not recently undertaken major substation transformer replacements prior to these projects. Actual costs are only available for WBL.[77]

334. Applying historical costs of similar projects is reasonable at the first approval gate as the accuracy of the cost estimates are likely to be improved as the project is developed, risks are quantified, and scoping assumptions are refined. We consider that, as the project progresses, the cost estimates are likely to be refined and efficiencies will be realised. Particularly, as CitiPower has included two transformer replacements at each of two sites, we would expect to see some efficiencies in design and construction costs, which constitute a large proportion of the cost build-up.[78]

Remaining transformer replacement appears reasonable

335. Based on our review of the composition of the forecast, the distribution transformer replacement volume and expenditure appear to be consistent with the historical trend. We were not provided with a copy of the asset class strategy or operational plans that include

[76] Response to information request IR054

[77] This project incurred a cost over-run due to unexpected cavity works undertaken at this site, following the discovery of underground caves that were not identified in the geotechnical survey.

[78] Labour accounts for around 50% of the build-up cost estimate from TRG and WBL

distribution transformers to confirm any specific strategies being targeted by CitiPower in the next RCP.

336. In the absence of better information, CitiPower appear to be basing its justification on historical trend analysis, and by reference to the AER's repex model at the category level. Based on our review of the historical trend, and the level of proposed expenditure, the approach is likely to result in a reasonable estimate of requirements.

Summary of our assessment

337. The proposed increase in expenditure is driven by inclusion of zone substation transformer replacement. This accounts for 91% of the forecast expenditure for the next RCP.

338. CitiPower predicts that the number of zone substation transformers at or beyond a HI value of 7 will increase from 3 in 2019, to 21 in 2026. Whilst this is not by itself sufficient grounds to support an increased level of replacement, not acting on this information would be concerning as the level of deterioration of this asset class increases.

339. We consider that CitiPower should have undertaken, and presented in its RP, an economic analysis on a larger proportion of its transformer fleet to determine a prudent level of replacement. Whilst we can only assess the prudency of the proposed forecast expenditure on the basis of the information provided, we are unable to ascertain the relationship between a prudent level of expenditure and maintaining the level of network risk presented by this asset class.

340. We therefore focused our assessment on the information and models presented by CitiPower to support the proposed expenditure. We tested the robustness of CitiPower's risk monetisation models provided in support of its substation transformer expenditure. We found that the assumptions and parameters applied in its models lead to an overstatement of risk, and when corrected for reasonable assumptions, support deferral of a proportion of the proposed projects.

341. Due to the early stage and high-level nature of the cost estimates relied upon in development of the forecast, we consider that the estimated costs are higher than will likely be incurred by CitiPower once the projects are completed and efficiencies are realised.

342. We remain concerned that the information provided by CitiPower does not facilitate a complete understanding of how it manages the transformer asset class, including provision for condition monitoring and asset life extension strategies, which it states that it currently undertakes. We make further comment on this in our review of the 'Other' repex group.

343. For the remaining transformer categories we find that, based on our review of the historical trend and the level of proposed expenditure, the approach is likely to result in a reasonable estimate of requirements.

344. On balance, we consider that CitiPower will incur a lower level of expenditure for Transformer replacement than it has proposed.

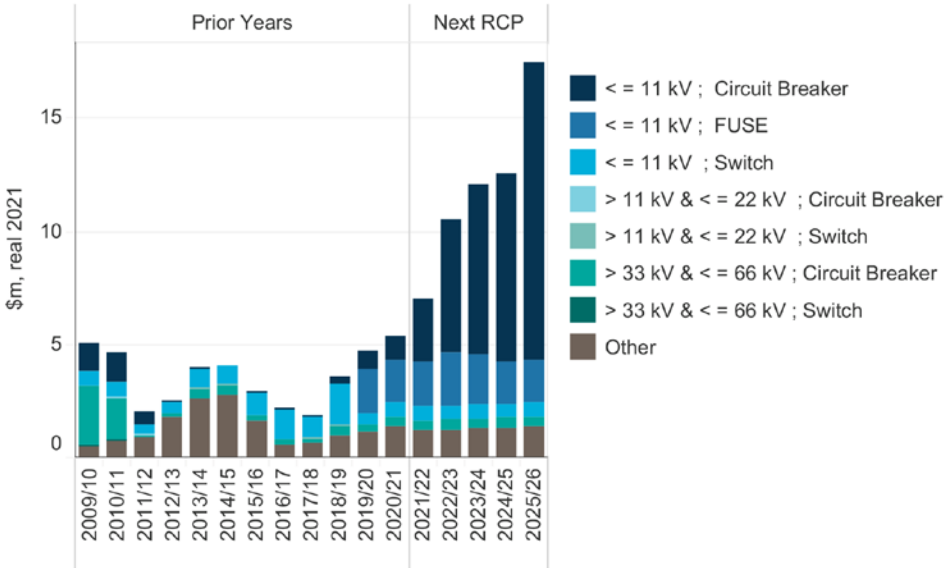
4.4.7 Switchgear

CitiPower's forecast

345. CitiPower has proposed $59.7m[79] for the Switchgear group in its repex forecast for the next RCP. The expenditure profile for the Switchgear group comparing the next RCP with previous years is shown in the figure below.

79 CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.22: Switchgear repex by asset category - $m real 2021



Source: CitiPower Reset RIN

346. The figure above shows the largest increase associated with the 11kV circuit breaker asset category. The major components of expenditure and program by construction type are shown in the tables below (and which reconcile to CitiPower's program when real cost escalation is excluded.)

Table 4.15: Components of CitiPower's proposed Switchgear repex for next RCP - $m, real 2021

Switchgear	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Programs						
Network Faults	0.5	0.5	0.5	0.5	0.6	2.6
Projects						
HV Switchboard Replacement	1.2	4.2	5.7	6.0	10.5	27.6
LQ 11kV Email HQ (Compound)	*0.0*	*0.0*	*2.6*	*6.0*	*10.4*	*19.0*
B 11kV Email J18	*1.2*	*4.2*	*3.1*	*0.0*	*0.0*	*8.5*
Multiple Switchboard Project 2	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*0.2*
6.6 & 11kV Circuit Breaker Replacement (full bus)	1.5	1.4	1.5	1.8	1.6	7.9
HV Fuses and Surge Diverters	0.7	0.7	0.7	0.7	0.7	3.6
HV Combo Switch (indoor) Replacement	0.5	0.5	0.5	0.5	0.5	2.6
RMU Oil Switch Replacement	0.4	0.4	0.4	0.4	0.4	2.1
66kV Circuit Breaker Replacement	0.4	0.4	0.4	0.4	0.4	2.0
Indoor HV ABS Replacement	0.4	0.4	0.4	0.4	0.4	1.8
LV OCB Replacement	0.2	0.2	0.2	0.2	0.1	1.1
Low Gas RMU Replacement	0.2	0.2	0.2	0.2	0.2	1.0
Outdoor HV ABS Replacement (Non-Geveas)	0.2	0.5	0.3	0.0	0.0	1.0
LV ACB replacement	0.2	0.2	0.2	0.2	0.3	0.9
Andelect SDAF 14 RMU Replacement	0.2	0.2	0.2	0.2	0.2	0.8
Defective LV CB Replacement	0.2	0.2	0.2	0.2	0.2	0.8
Defective RMU Oil Switch Replacement	0.1	0.1	0.1	0.1	0.1	0.5
Defective LV ACB & MCCB replacement - Merlin Gerin Kiosks	0.1	0.1	0.0	0.0	0.0	0.2
Total	**6.9**	**10.2**	**11.5**	**11.7**	**16.1**	**56.5**

Source: EMCa analysis of CitiPower MOD 4.06 and MOD 4.11. Excludes real cost escalation

347. CitiPower has provided the following documentation with its submission to support its expenditure:

- models comprising its Plant and stations replacement expenditure (MOD4.09), volumetric program (MOD4.06) and network faults related expenditure (MOD 4.11) which includes switchgear related repex; and
- a business case for replacement of the switchboards at Little Queen[80] and Collingwood[81] substations totalling $27.5m and its J18 circuit breaker replacement program[82] and associated expenditure models.[83]

80 CitiPower BUS 4.04 LQ supply area

81 CitiPower BUS 4.05 B supply area

82 CitiPower BUS 4.07 J18 circuit breakers

83 LQ supply area (MOD4.03), B supply area (MOD4.02), and J18 circuit breaker replacement (MOD 4.04, 4.17, 4.18, 4.19 and 4.20)

Our assessment

Overview of stated drivers

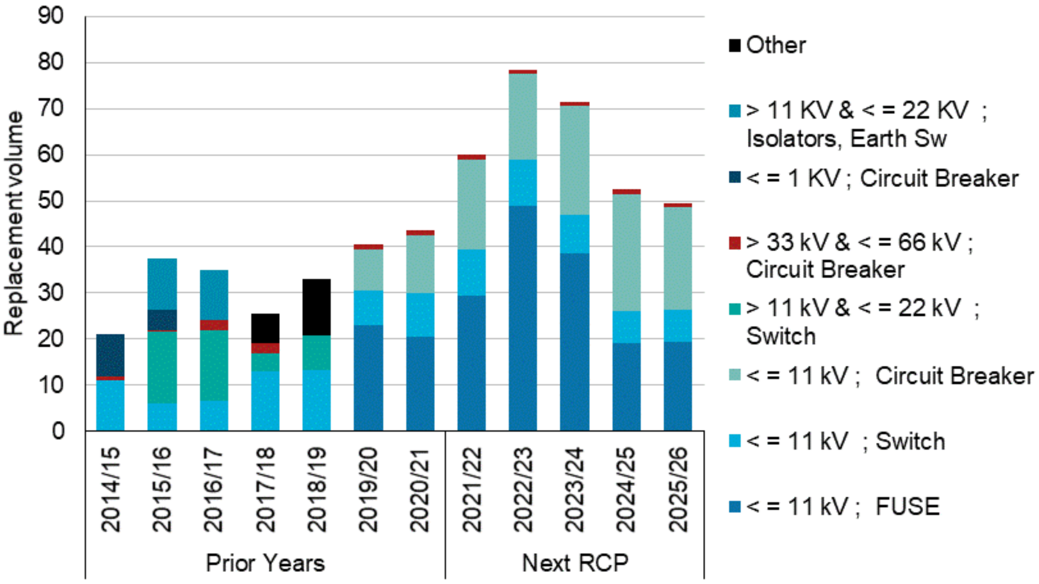
348. CitiPower describe the drivers of its switchgear group as:[84]

> *'Asset condition based on inspection regime, operational experience and/or asset failure for distribution or overhead line switchgear. It is noted that some portion within such asset categories are proactively replaced due to safety concerns. Asset condition and risk profile based on inspection and testing regime, operational experience such as fault history, health indices, value of lost load, emergency cost, etc. and/or asset failure for zone substation switchgear.'*

349. CitiPower measures and maintains health indices for this particular asset group, especially for higher voltage equipment, from which it forms a risk profile and compares it with the cost of replacement to justify investment.

350. We show the replacement volumes proposed as a part of the switchgear group forecast in the figure below by asset category. We have excluded the replacement volumes for HV fuses and surge diverters due to the much higher numbers which would impact the presentation of data in the figure.

Figure 4.23: Historical and forecast replacement volumes of switchgear by asset category (excluding HV fuses and surge diverters)



Source: EMCa analysis of CitiPower MOD4.09

351. The largest increases, by volume, are associated with the 11kV fuse category - which we understand is associated with the HV Fuses and Surge diverter replacement and 11kV circuit breaker replacement. 11kV circuit breaker replacement is split into major programs including:

- Switchboard replacement;
- Circuit breaker replacement; and
- HV switch replacement, including ABS.

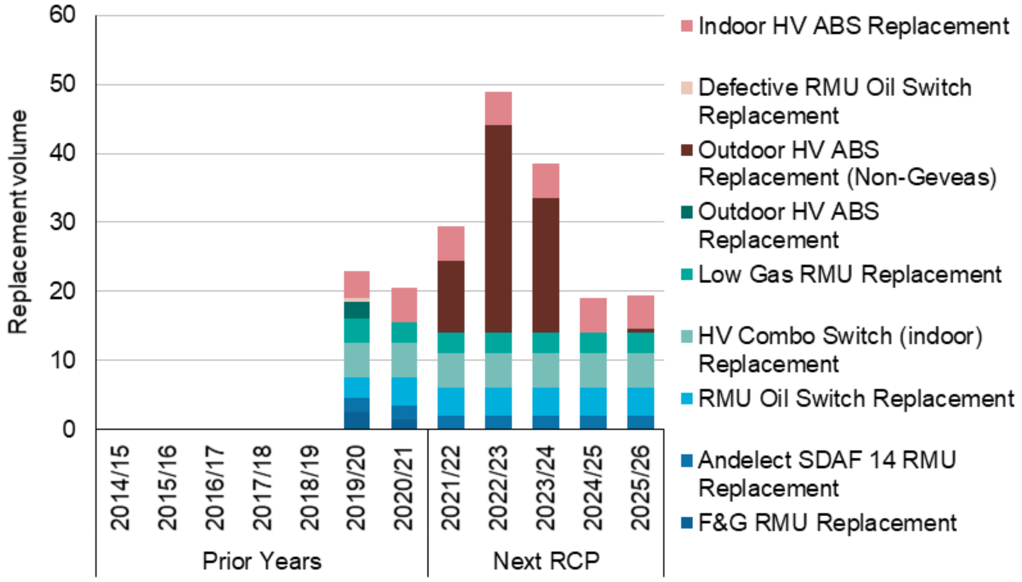
352. We review each of these categories and major programs below.

[84] CitiPower RIN response RIN016

HV switch replacement

353. CitiPower has proposed $9.8m for HV switch replacement for defective ABS's and RMU's. The proposed replacement volumes for HV switch replacements is shown in the figure below. However, we observe that the expenditure and volumes do not correlate well, as there are items with expenditure that do not have corresponding replacement volumes.

Figure 4.24: Historical and forecast HV switch replacement volumes



Source: EMCa analysis of CitiPower MOD4.09

354. CitiPower has not provided any detail on the composition of this forecast, other than its expenditure model (CP MOD 4.09) which merely presents the proposed expenditure and separately indicates the proposed replacement volume. We have found instances where there wasn't a strong correlation between the replacement volume and the proposed expenditure, which in part may be explained by multi-year replacement projects.

355. Beyond extrapolating the historical average, and which is not provided prior to 2019/20, it appears to us that these programs have only recently commenced. CitiPower propose to increase these replacement volumes in the next RCP.

356. We observe the introduction of a replacement program for the non-Gevea branded ABS switches, which are also installed in Powercor's network. Like Powercor, we did not see justification for this program or other programs included in the forecast. It is therefore not clear to us how CitiPower determined that this was the optimum expenditure for the next RCP (e.g., by considering condition and risk). We therefore reviewed trends at a category level.

Review of the process used to select switchboard replacement projects for inclusion into the forecast

357. CitiPower has 141 switchboards installed at zone substations. Most operate as part of the 11 kV network. CitiPower has identified that 55% of its switchboards are beyond the estimated service life of 51 years for these assets, with 20% being more than 60 years old. Based on age, 94 zone substation switchboards will be at or beyond the estimated service life in the next 10 years.

358. The PoF of switchboards is developed through a CBRM model which CitiPower first applied in 2018 when developing its switchboard management strategy. The HI and resulting PoF

is currently driven by identification of defects and failures for switchboard components and other condition measures (e.g., oil testing) for circuit breakers.[85]

359. We did not identify any issues with the CBRM inputs and outputs relied upon by CitiPower.

360. CitiPower plans to progressively remove the highest-risk switchboards from service and has targeted five separate zone substation and applied a risk-monetisation approach to determine the efficient intervention timing.

361. In response to our questions CitiPower explained how it had selected switchboards for risk monetisation assessment:

> *'For our switchboard replacements, the drivers for selection were based on age, obsolescence (i.e., no spares availability), previous catastrophic failures, safety issues, and observed partial discharge activity on the respective switchboards.'* [86]

362. The proposed repex also includes two projects for which it has provided business cases and risk monetisation models. These projects are:

- Little Queen supply area - switchboard replacement at a cost of $19.1m; and
- Collingwood supply area - switchboard replacement at a cost of $8.5m.

363. In addition, CitiPower has included a cost of $0.2m in the final year of the next RCP titled Multiple Switchboard Project 2, for which it has not provided any further details.

CitiPower has considered reasonable options for replacement of Little Queen and Collingwood

364. The information supplied by CitiPower in its business case supported the consideration of the switchboard for replacements, especially given the important loads that are supplied.

- The Little Queen (LQ) zone substation was constructed in the 1970s to supply Melbourne's CBD. The compound-insulated switchboard is 47 years old and is planned for replacement by the end of 2025; and
- Collingwood (B) zone substation was constructed in the 1960s. The compound-insulated switchboard scheduled for replacement is of a similar age and is planned for replacement by the end of 2024.

365. Prior to applying its risk monetisation assessment method CitiPower undertook options analysis to determine the most appropriate action to take to the address the risk posed by its aging switchboards. This approach is discussed in the business case, unlike its zone substation transformer replacement assessment, which did not include the options assessment in its business case documents or in the risk monetisation model.

366. Two options were costed for each of the projects as shown in the table below.

Table 4.16: Options considered where costings were undertaken

	Little Queen (LQ) substation	Collingwood (B) substation
Option 2	Replace existing switchboard in the same building ($19m)	Offload the substation to North Richmond ($14.6m)
Option 3	Establish new switchboard at an alternate site ($27.2m)	Replace existing switchboard in the same building ($8.5m)

Source: CitiPower BUS 4.04 - LQ supply area - Jan2020 – Public and CP BUS 4.05 - B supply area - Jan2020 - Public

367. On the basis of these cost estimates, option 2 was identified as the preferred option for LQ and option 3 for B substation. Both of the preferred options were subjected to risk monetisation assessment to determine the optimum replacement time.

[85] PAL IR017 and CitiPower IR019 - ACS - zone substation switchgear, page 12

[86] CitiPower response to information request IR032 - EMCa questions following onsite meetings – Public, page 20

368. Included in the options for the two switchboard projects are ‘non-network solution’ and maintain status quo options. CitiPower first identified the load available to transfer and then considered non-network solutions for the balance.

- For LQ, establishing the load transfer option was considered by CitiPower and results in 45MVA of transfers. However, implementing the load transfer restricts the switching and contingency transfer capacity in the CBD, and exacerbates constraints at adjacent sites. The excessive establishment costs and annual operating costs of a non-network solutions at this site, due primarily to the residual demand of 55MVA, were considered to be prohibitively expensive.[87]
- For B, similar to LQ, the residual demand remains high at 30MVA after available load transfers. CitiPower concluded that meeting this load through non-network solutions would be excessive for the same reasons as the LQ switchboard, and not considered viable. We consider that CitiPower’s conclusions not to proceed with non-network solutions for these projects are reasonable given the location of the substations and loading levels, which limit the available options and add significant cost.

369. To assess the maintain status quo option, CitiPower says that it has compared the risk cost for the increasing risk of catastrophic failure results in interruptions to customer supply for extended periods of time, with the results for its preferred option in its risk monetisation model. CitiPower considers that this approach:

> *‘…provides a conservative assessment of the potential risk-cost of maintaining the status-quo, as the costs of responding to a catastrophic failure are greater than those for a planned intervention.’*[88]

370. Our understanding of CitiPower’s explanation is that the risk cost monetisation model essentially represents the status quo option in its risk cost curve. As there is no annualised cost of replacement cost for status quo, this option will be the preferred option until the preferred option’s annualised cost is below the risk cost curve. However, we consider that this is not what the risk monetisation actually does.

The application of health indices for switchboards may be overstating the level of deterioration

371. For LQ, the current HI values for the switchboard sections[89] range from 3.57 to 5.50 indicating the onset of detectable deterioration and do not suggest that the switchboard is currently at a heightened risk, but that deterioration will become more significant by the end of the next RCP. However, the HI alone does not indicate that immediate action is justified.

372. From the HI’s, a PoF function is determined and used as an input to the risk monetisation model. To determine the HI for the whole switchboard, CitiPower says that it establishes an initial HI for each bus section by using knowledge and experience of the asset’s performance and expected lifetime. The initial HI values are then modified for known condition factors. We observed this process in the CBRM model for switchboards. However, CitiPower does not explain how it converted the individual bus section HI into the composite PoF used in the risk monetisation model.

373. We also observed that the composite PoF values applied in the model were slightly higher than those contained in the CBRM model.[90]

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87 Based on the expected service life of existing generator, photo-voltaic cell and battery storage solutions an overall period of 20-years is expected before replacement will be necessary

88 CitiPower MOD 4.02 - B supply area - Jan2020 – Public, page 10

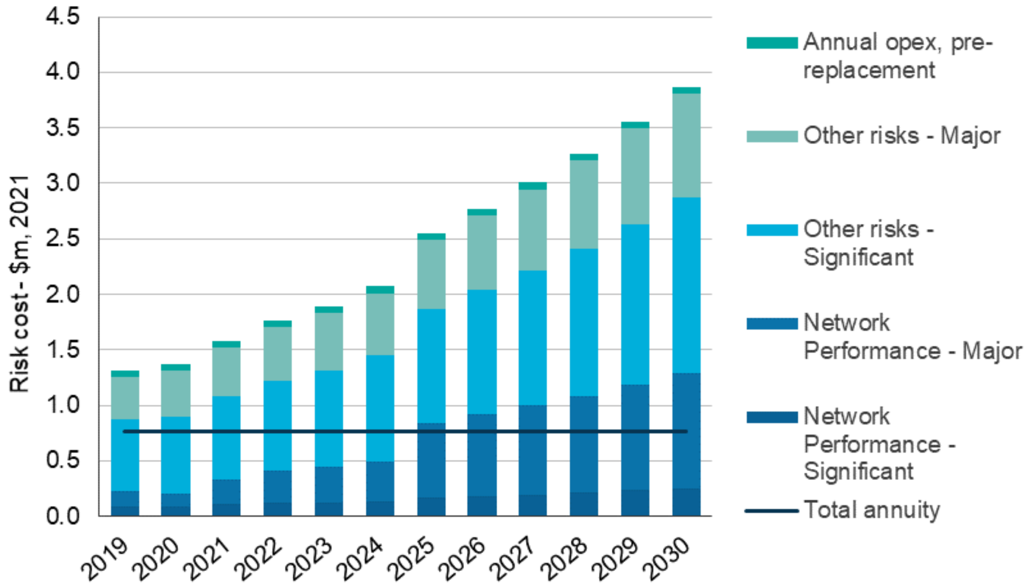
89 CitiPower response to information request IR019 - CBRM HI and POF summary - switchboards

90 We also noted an alignment issue between the CBRM and Risk monetisation models. The CBRM used minor, significant and major failure modes and the Risk monetisation model uses significant and major. The minor CBRM value appears to be used as the significant in the risk monetisation model. Also, Significant in the CBRM appears to be used as major in the risk monetisation model

The risk monetisation model results in replacement of new assets

374. The annualised risk cost outcomes for CitiPower's central (base case) scenario are shown in the chart below.[91] This indicates that the optimal timing for the switchboard replacement has already passed as the total risk cost exceeds the annualised cost of intervention below in 2019. However, CitiPower advised that it is currently monitoring these risks and is planning to commence the replacement works in 2022/23 with completion expected in 2025/26.

Figure 4.25: Risk monetisation model outputs for the LQ substation switchboard replacement project (Base Case) - $m, real 2021



Source: EMCa analysis of CitiPower MOD 4.03 - LQ supply area

375. The above chart clearly indicates that the key components driving the need for replacement are network performance and other risks associated with the replacement cost in the event of a failure. The model assumes that for a major failure mode the switchboard will require a full replacement at a cost of $19.0m, and the likelihood of the consequence cost being realised is 100%. We consider that these and other assumptions are likely resulting in an overstated risk cost.

376. We tested the model for younger assets, to understand the results should a new switchboard be installed at LQ, and to identify any input assumptions that may be leading to an over-estimate of risk.

377. By applying a lower PoF for the significant and major risks, commensurate with an asset at HI value of 5, the model determined that the optimum replacement time was still within the next RCP. This suggests to us that the model is tending towards earlier replacement of assets that have remaining health.

Other assumptions included in its risk models contribute to an overstatement of risk cost

378. In the absence of evidence to support the assumptions that CitiPower has applied in its risk monetisation model we consider that the model is likely to be overstating the risk. We found examples of the same issues identified for the transformer projects as discussed in section 4.4.6.

379. Specifically, for switchboards, CitiPower set the likelihood of consequence to 100% because it has determined that significant and major failure modes could not occur without causing loss of the asset and some consequences must occur if there is a significant asset failure. We question whether such an event will necessarily result in a 100% likelihood of the total

91 CitiPower MOD 4.03 - LQ supply area - Jan2020 – Public, Base Case tab

consequence occurring. For example, some load may be supplied for an alternative source, which would reduce the duration of any interruption experienced.

380. As for transformers, we remain concerned that the risk-monetisation model as presented by CitiPower to support its switchboard replacements does not appear to assist with its investment decision making or assist with identifying an optimal date for replacement due primarily to overstated risk assumptions.

CitiPower has not adequately justified the timing for its switchboard replacements

381. When we substitute more reasonable values for a number of the assumptions used in the model, the optimal replacement time is changed.

- For LQ switchboard, the optimal replacement time shifts towards the end of the next RCP. A delay of a single year, results in deferring $10.4m (54% of the total project cost) beyond the next RCP. We consider that, on balance, having considered the asset condition and criticality of this site as presented by CitiPower, it is likely that CitiPower will defer completion of this replacement by at least one year into the 2026/31 RCP; and
- For Collingwood switchboard, whilst we consider that the HI values are not signalling an immediate need for replacement, the description of the condition of the assets indicates that replacement is required. The previous failure damage and repairs suggests that the HI may not be capturing the full implications of the temporary repair work undertaken following the earlier fault damage. On this basis we consider that the Collingwood switchboard is likely to be completed in the next RCP.

382. We note that the demand forecast increases throughout the period. It is not within our scope to review the demand forecasting methodology in detail, nor to propose alternative forecasts at the zone substation and feeder levels (which are the focus of our assessment) for growth-driven capex and opex. Instead, we have applied sensitivity analyses to the demand forecast assumed by CitiPower to test the robustness of the selected option and the timing of the proposed work.

383. When adjustments are made to the 50PoE demand forecast, that has the result of reducing the N-2 demand at risk, or if CitiPower undertakes other initiatives to reduce the N-2 load at risk, the projects may reasonably be deferred beyond the next RCP.

CitiPower has not adequately justified the forecast costs for its switchboard replacements

384. The intervention cost assumptions which underpin the repex forecast for the projects are based on CitiPower's historical costs for similar projects. Whilst CitiPower states that it has applied top down challenges to test its forecast, we have seen no evidence that this has affected forecast project costs. For example, CitiPower has not demonstrated that the efficiency gains claimed from its World Class Program[92] were included as an adjustment to its historical unit costs applied to the project capex and opex forecasts. Based on the information provided, CitiPower has not demonstrated that the proposed project costs are reasonable and prudent. We have been provided additional information in IR049 relating to the project costs that does not alter our findings.

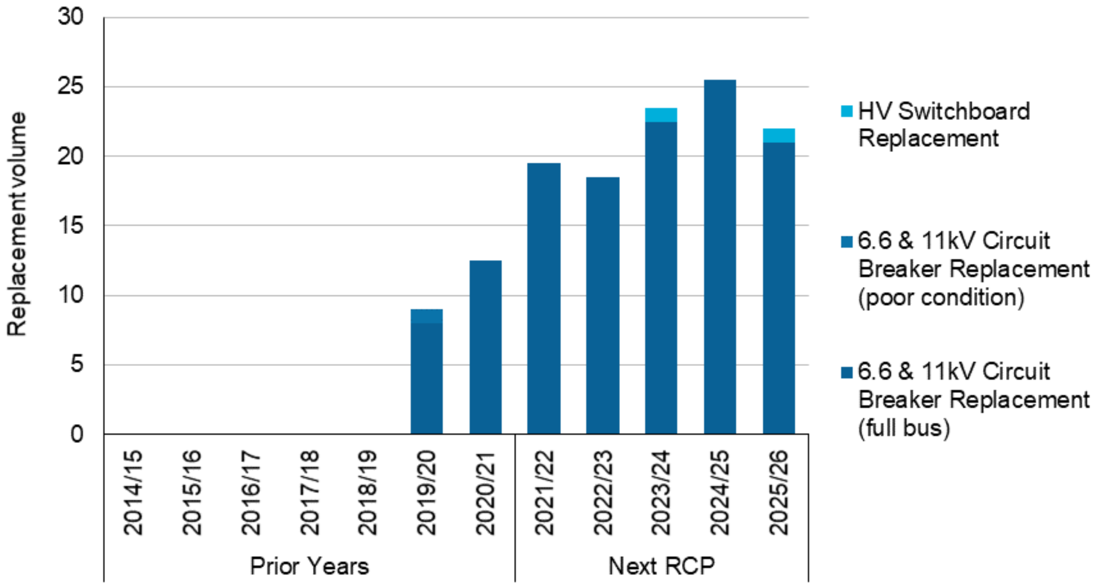
CitiPower has proposed additional 6.6 & 11kV Circuit Breaker replacement projects

385. CitiPower has proposed $7.9m for replacement of 6.6 and 11kV circuit breakers. This is comprised of $7.1m to replace its J18/J22 circuit breaker population consistent with the provided business case, and a further $0.8m for replacements at MP substation of LMT-type circuit breakers which are not described by CitiPower. We sought evidence of the basis for inclusion of the LMT-type circuit breaker replacement in CitiPower's Asset Class Strategy (ACS) for zone substation switchgear. Whilst this document summarises the asset fleet, its age, condition and a strategy to address emerging issues, it does not provide a direct link to the replacement forecast.

[92] CitiPower response to information request IR032 - EMCa questions following onsite meetings – Public, page 7

386. The proposed volume of replacement is shown in the figure below. We have found instances where there wasn't a strong correlation between the replacement volume and the proposed expenditure, which in part may be explained by multi-year replacement projects.

Figure 4.26: Historical and forecast replacement volumes for circuit breaker replacement



Source: EMCa analysis of CitiPower MOD4.09

Application of the risk cost analysis for CB replacement is not compelling

387. CitiPower has over 1,110 zone substation circuit breakers. These primarily operate at 11kV within indoor switchboards, with the majority being oil type circuit breakers. The most common circuit breakers are J18 models, with J22 models also representing a material percentage of the population. The combination of J18 and J22 type circuit breakers represent approximately 40% of all circuit breakers installed.

388. CitiPower has identified that ongoing asset ageing and degradation will lead to an increasing risk of catastrophic failure, resulting in possible explosion and fire. This is further complicated by equipment obsolescence which means it is not possible to replace defective components.

389. CitiPower has identified the need for a proactive replacement program, targeting the highest risk locations. The safety risks of this switchgear are recognised across the industry, and there are similar replacement programs in place in other DNSPs, as explained by CitiPower.

390. In its business case, CitiPower has assessed five options, with its preferred option (Option four) to replace existing oil-filled J18/J22 circuit breakers with modern vacuum circuit breakers at selected, high consequence zone substations. The program commenced in 2020. The substations proposed to be completed in the next RCP are:

- Albert Park zone substation;
- Armadale zone substation;
- Fisherman's Bend zone substation;
- Flinders/Ramsden zone substation; and
- Toorak zone substation.

391. The preferred option was selected from what appears to be a qualitative assessment only. CitiPower describes the selection of these sites as being the highest risk. We have not been provided with the decision framework, or information on the population of this CB type with associated consequence ratings for each site to confirm this assessment.

392. CitiPower's preferred option is the only option to be subjected to the risk monetisation model, which is undertaken for each substation site. CitiPower describes the use of its risk monetisation model to:

> *'…inform the timing of our J18 and J22 circuit breaker replacement program (consistent with our preferred option—option four).'*[93]

393. The optimal timing for all sites is determined when the annual risk cost exceeds the annualised replacement costs. For all sites reviewed, the models indicate that the optimal replacement time is in the past. This suggests to us, as we found for the switchboard replacements, that CitiPower is not using the model to assist with its investment decision making or in determination of an optimal replacement time.

394. The model applied by CitiPower is the same model applied for switchboard replacements. The model is sensitive to changes to the input assumptions. When we substitute more reasonable values for a number of the assumptions used in the model, the optimal replacement time is deferred from that proposed by CitiPower.

395. These changes cast a level of doubt over the use of the model to justify the proposed expenditure forecast. For the replacement of the J18/J22 circuit breakers, there is established industry practice and justification for a replacement program to be undertaken for this asset type. CitiPower should draw from the experience of others to strengthen its justification for the proposed program.

396. CitiPower states that it has used historical costs escalated to 2019 dollars to provide unit cost inputs for the replacement program. As for other replacement projects we consider that the information provided is insufficient to demonstrate that the forecast costs are efficient and prudent.

397. Based on the information provided, the extent of the increase associated with the proposed expenditure is not justified.

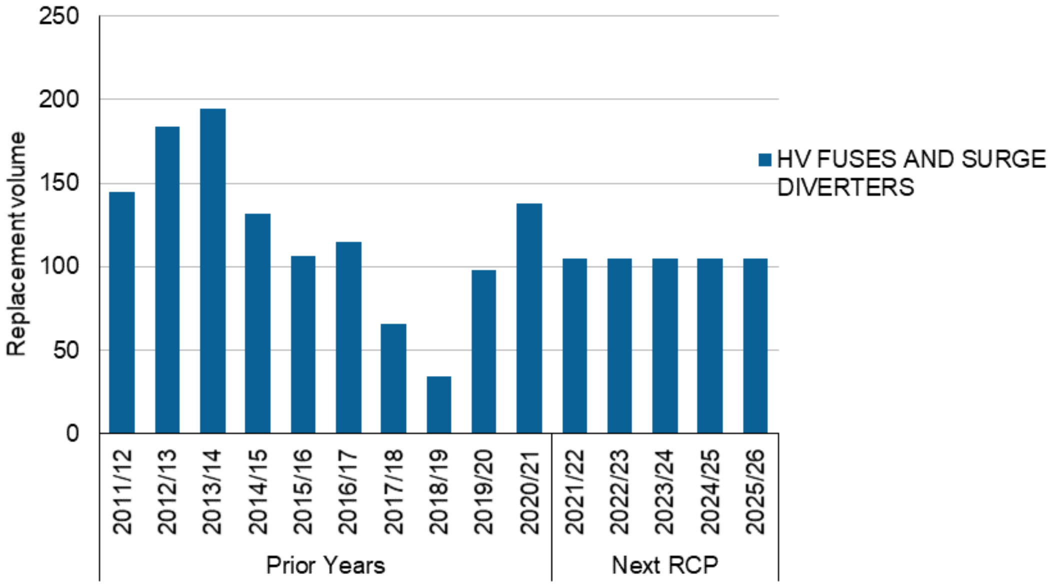
HV Fuse and Surge diverter replacements likely to be reasonable

398. CitiPower has proposed $3.6m for the replacement of HV fuses and surge diverters. The development of the forecast follows the method described in section 4.3 for high volume, low cost asset interventions.

399. As shown in the figure below, the replacement volume is similar to the long-term average, however slightly higher than the recent historical replacement level (noting that 2020/21 is a forecast).

93 CitiPower BUS J18 circuit breakers

Figure 4.27: Comparison of historical and forecast HV fuse and surge diverter volumes



Source: EMCa analysis of CitiPower MOD4.09

400. CitiPower has not provided any detail on the composition of this forecast, other than its expenditure model (CP MOD 4.06), which merely presents the proposed volume and expenditure (based on its historical unit rate). Beyond extrapolating the historical average, it is therefore not clear to us how CitiPower determined that this was the optimum expenditure for the next RCP (e.g., by considering condition and risk).

401. Based on observed performance, we consider that it is appropriate to maintain similar levels of replacement to those CitiPower has historically undertaken. However, as discussed in our review of CitiPower forecasting methods in section 3 and in section 4.3, we remain concerned that the methods applied by CitiPower in developing its forecast may not reflect a prudent and efficient forecast.

Inclusion of other circuit breaker replacement projects are not adequately supported

402. CitiPower has proposed

- $3.0m for LV circuit breaker replacement, at an average of 8.5 replacement projects per year; and
- $2.0m for 66kV CB replacement, at an average of 1 replacement project per year.

403. CitiPower has not provided sufficient detail on the composition of this forecast or how it has determined the proposed expenditure, other than as a line item in its expenditure model (CP MOD 4.09), and separately indicate the proposed replacement volume. We have found instances where there wasn't a strong correlation between the replacement volume and the proposed expenditure, which in part may be explained by multi-year replacement projects.

404. Beyond extrapolating the historical average, where that information was provided, it is not clear to us how CitiPower determined that this was the optimum expenditure for the next RCP (e.g., by considering condition and risk). We therefore reviewed trends at a category level.

405. For these items, there is limited historical information to draw upon. Where it is provided, the classification of the expenditure appears to differ from what is proposed for the next RCP. In its current form, we do not consider that this information can be relied upon. We would expect to see, similar to HV CB and switchboards, CitiPower include these assets in its CBRM model and apply a decision framework to identify and/or target replacement of the highest risk assets or sites.

Summary of our assessment

406. The extent of the proposed increase in capex over the next RCP is not adequately supported as being a prudent and efficient forecast of expenditure. The risk monetisation models in their current form, and the application of input assumptions as proposed by CitiPower, result in outcomes that are not credible.

407. CitiPower has identified projects that appear to be reasonable candidates for consideration for replacement. However, the information provided does not adequately support the proposed timing and expenditure.

408. We would expect that the risk cost models would be reviewed, and sensitivity analysis applied, to key parameters to support the proposed investment. We also consider that the analysis should be broadened, to justify selection of the proposed level of replacement and the nominated sites from the population of assets. Absent this analysis, the outcome of the risk cost analysis for these projects remains unsupported, particularly where:

- CitiPower has selected the preferred option prior to the risk cost analysis;
- only projects included in the proposed expenditure are included in the risk costs analysis, to our knowledge; and
- the optimal replacement date precedes the study period.

409. We found evidence of the issues identified in section 4.3 and in section 3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

410. As for other asset groups, we did not find sufficient evidence of a rigorous top down review of the proposed program costs or that efficiency and other gains had been adequately applied to unit cost inputs.

411. Accordingly, we consider that CitiPower has not justified the extent of the proposed increase to its forecast expenditure for the Switchgear group.

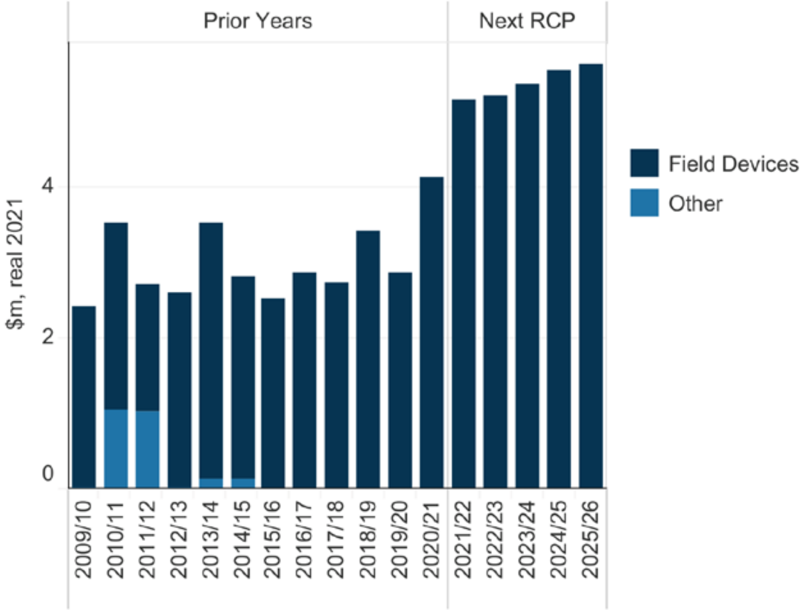
4.4.8 SCADA, network control and protection

CitiPower's forecast

412. CitiPower has proposed $27.0m[94] for the SCADA, network control and protection group in its repex forecast for the next RCP. The expenditure profile for SCADA, network control and protection comparing the next RCP with previous years is shown in the figure below.

[94] CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows

Figure 4.28: SCADA, network control & protection systems repex by asset category - $m, real 2021



Source: CitiPower Reset RIN

413. The figure above shows a step increase in expenditure at the commencement of the next RCP, when compared with the historical average. The major components of expenditure and program by construction type are shown in the tables below (and which reconcile to CitiPower's program when real cost escalation is excluded).

Table 4.17: Components of CitiPower's proposed SCADA, network control & protection systems repex for next RCP - $m, real 2021

SCADA, network control & protection systems	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Project groupings						
Protection relay & RTU replacement	5.0	4.9	5.0	5.1	5.1	25.1
Battery & charger requirements	0.1	0.1	0.1	0.1	0.1	0.5
Total	**5.1**	**5.0**	**5.1**	**5.2**	**5.2**	**25.6**

Source: EMCa assignment to project groupings based on project titles included in CitiPower MOD 4.06. Excludes real cost escalation

414. CitiPower has provided a protection replacement expenditure model (MOD4.10) to support its proposed expenditure.

Our assessment

CitiPower has relied on its CBRM model outputs for the proposed expenditure

415. We requested summary justification documents (i.e., business cases or similar) for the total forecast expenditure in this group including details of the scope, key drivers, the asset condition and risk information relied upon in developing the forecast, the options considered and the financial analysis undertaken and any relevant models. We also asked CitiPower to provide a copy of any modelling that was used in determining the proposed expenditure.

416. CitiPower referred to its expenditure model (MOD 4.10) which contains a list of projects and expenditure by year and its Reset RIN response (RIN016) both of which were provided

within its regulatory proposal. We were also provided with a copy of the protection and control asset class strategy.[95]

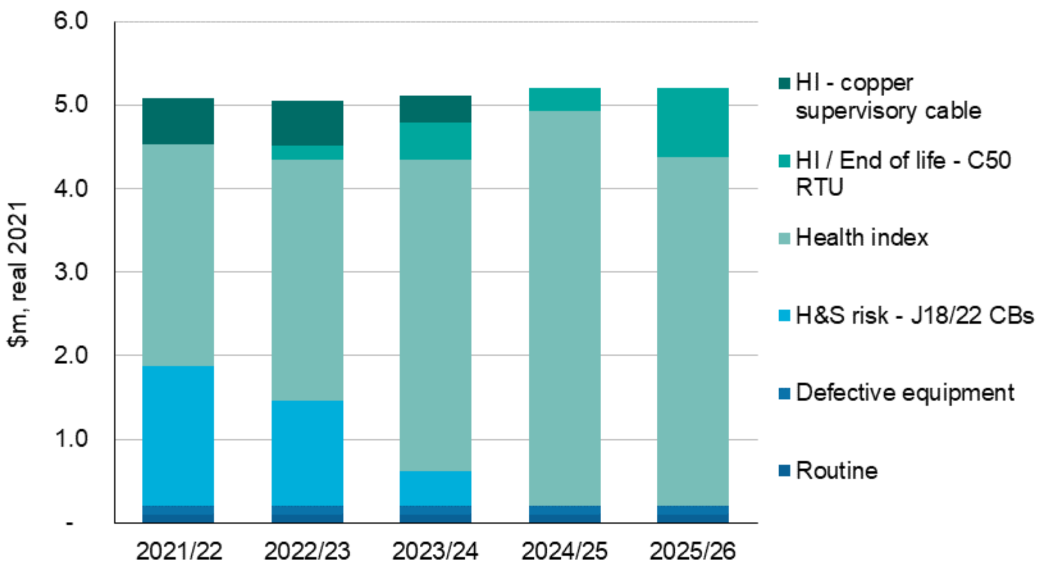
417. Collectively these documents do not provide justification for the proposed forecast expenditure, including how the replacement projects were selected or how the level of expenditure is reflective of a prudent and efficient level.

418. In response to further questions to clarify its forecasting method, CitiPower provided a copy of its CBRM model on which it relied to develop the forecast expenditure. In the model, CitiPower nominated an expenditure driver for each project.[96]

419. CitiPower has applied a CBRM methodology to drive a large proportion of its planned replacement expenditure requirements. Approximately 80% of the expenditure forecast is driven by end of life or condition-based replacement, or a combination of the two drivers.

420. The expenditure profile for this group of repex is shown in the chart below by the expenditure driver nominated by CitiPower.

Figure 4.29: Protection and control related repex by driver - $m, real 2021



Source: EMCa review of CitiPower's response to IR032 Q14 CP MOD4.10 – drivers. Excludes real cost escalation

An increase to the level of condition-based replacement appears reasonable

421. As CitiPower has identified asset condition as the dominant driver, we reviewed the CBRM model relied upon to generate the forecast replacement expenditure. The model has been developed by EA Technology and includes a methodology similar to that applied for its major substation plant.

422. CitiPower has not provided a description of the provided CBRM model. We have ascertained the key features of this model (from our own enquiry) as:

- it assigns a health index to each relay based on its age;
- it modifies the HI based on its 'generic reliability rating' which is a value of 1 to 4, with 1 being the poorest reliability. A value is assigned to each relay in another dataset input by CitiPower. The calculation of this rating has not been provided;
- this results in an adjusted HI, with a corresponding assessment of years to reach end of life; and

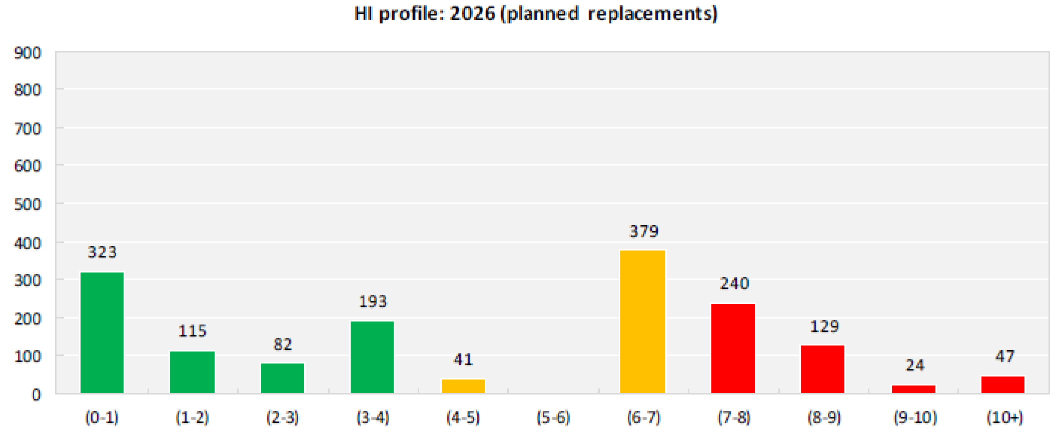
95 CitiPower's response to information request IR019

96 CitiPower's response to information request IR032 Q14

- a forecast HI is developed based on application of aging reduction factors to an asset degradation curve.

423. CitiPower's profile of HI values for its fleet of protection relays as at the year 2026, with the planned replacement projects included.

Figure 4.30: Summary of HI for protection assets as at year 2026



Source: Response to information request IR032 – CBRM HI and POF summary

424. CitiPower did describe the components of its program in its response to our request.[97] This information aligned with the identified drivers of expenditure in Figure 4.29. This includes consideration of: (i) asset condition and risk; (ii) asset obsolescence; (iii) system security compliance; and (iv) penetration of embedded generation. CitiPower has used the CBRM model to inform the development of the proposed program, in particular: [98]

> *'…assets with a health index greater than 6.0 were assessed, with any subsequent replacement decisions having regard to the consequences of failure associated with these assets.'*

425. We have not been provided with an explanation of the model, or how the outputs of the model have been used to determine the projects that it has included in the forecast expenditure for the next RCP. Our enquiry into the model was also not able to identify this relationship.

426. We note that the model produces a probability of failure and what appears to be an assessment of network performance consequence from failure of the protection assets. It is not evident from the model, or from the information provided, how CitiPower has used this information, if at all, in producing its expenditure forecast.

427. The produced HI results suggest that there is a growing population of relays that require replacement. However, upon review of the asset class strategy, there is no evidence of an increased level of replacement compared with historical practice.

428. We accept that, notwithstanding that CitiPower has not explained the relationship between its CBRM and its proposed expenditure, CitiPower has established the need for an increase of its SCADA, network control and protection replacement program. However, the extent of the proposed increase and the timing of replacement projects has not been demonstrated with the information provided.

Summary of our assessment

429. CitiPower has not demonstrated the relationship between its CBRM tool and its forecast expenditure, to determine how it has arrived at a prudent level of replacement for this group.

97 CitiPower Response to information request IR032 Q14 supplementary response

98 CitiPower Response to information request IR032 Q14 supplementary response

Further, we were not able to find a basis to support the inclusion of some projects into the forecast.

430. We found evidence of the issues identified in section 4.3 and in section 3 that indicate an over-forecasting bias and of cost estimate that may be higher than would be reflective of an efficient level.

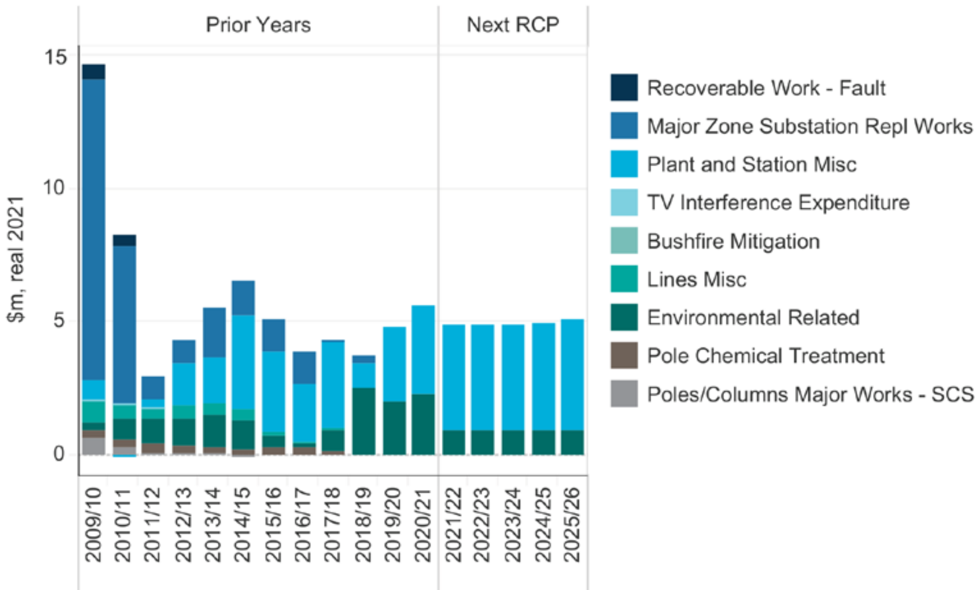
431. We consider that CitiPower has not justified the extent of the proposed increase to its forecast expenditure for SCADA, network control and protection repex.

4.4.9 Other repex

CitiPower's forecast

432. CitiPower has proposed $24.7m[99] for the Other repex group in its repex forecast for the next RCP. The expenditure profile for the Other repex group comparing the next RCP with previous years is shown in the figure below.

Figure 4.31: Other repex by asset category - $m, real 2021



Source: CitiPower Reset RIN

433. The figure above shows the proposed expenditure is similar to the historical trend. The major components of expenditure and program by construction type are shown in the tables below (and which reconcile to CitiPower's program when real cost escalation is excluded).

99 CitiPower Reset RIN. This figure includes real cost escalation, which is not included in the project-based table information which follows, and includes the adjusted environmental management program.

Table 4.18: Components of CitiPower's proposed Other repex for next RCP - $m, real 2021

Other repex	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Projects						
CBD Roadway Pit Refurbishments from inspection	2.8	2.8	2.8	2.8	2.8	14.1
Unplanned Plant Replacement	0.4	0.4	0.4	0.4	0.4	2.1
Transformer Refurbishment	0.2	0.2	0.2	0.2	0.2	1.2
66kV Transformer Bushing Replacement	0.2	0.2	0.2	0.2	0.3	1.1
66kV Wall/Floor/Roof/Bushings	0.2	0.2	0.1	0.0	0.0	0.4
LV Underground Pillar/Pit Replacement	0.0	0.0	0.0	0.0	0.0	0.2
Environmental Management program	0.9	0.9	0.9	0.9	0.9	4.6
Total	**4.8**	**4.8**	**4.7**	**4.7**	**4.7**	**23.7**

Source: CP MOD 4.06 and MOD 4.11. Excludes real cost escalation

434. CitiPower has provided the following documentation with its submission to support its expenditure:

- a business case for its CBD pit refurbishment program[100] totalling $14.1m and supporting model (MOD4.05); and
- models comprising plant and stations expenditure (MOD4.09) of which some projects are allocated to the 'other' repex group.

Our assessment

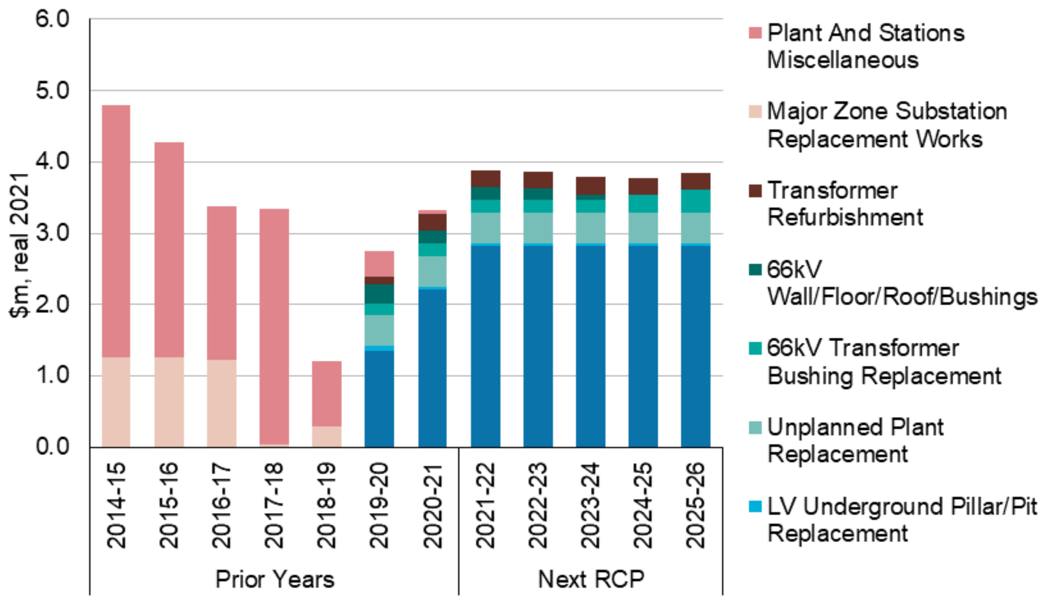
Proposed expenditure is dominated by a single project

435. We show the historical and forecast expenditure for the 'Other' repex group, which is dominated by the introduction of the CBD Roadway Pit refurbishment program as shown in the figure below as provided in CitiPower's expenditure model. The breakdown of the historical expenditure was not provided, although we understand a component of expenditure incurred in 2017 and 2018 was also attributed to reactive pit repair.[101]

100 CitiPower BUS4.06 CBD cable pits

101 CitiPower BUS4.06 CBD cable pits, page 9

Figure 4.32: Historical and forecast 'other' repex group by project - $m, real 2021



Source: EMCa analysis of MOD 4.09. Excludes real cost escalation

Adoption of a CBD pit refurbishment program is sound

436. CitiPower proposes to prioritise the remediation of 45 of its highest risk pits at a cost of $14.1m over the next RCP. CitiPower owns and manages approximately 1,129 cable pits in the Melbourne CBD. The cable pits form part of the pit and conduit system, which has been progressively installed since the 1930s.

437. CitiPower states that the asset management approach to managing pit defects changed in 2018 in response to concerns that the reactive approach was:[102]

> *'.. creating an unacceptable safety risk to employees, the public and our assets after a number of pits were found to be compromised during augmentation works and customer projects'*

438. Following a change in its approach, CitiPower states that:[103]

> *'Since 2018, our inspections of cable pits have found that 20% of our sites require remedial repair or replacement works due to corrosion. The remediation work typically includes the urgent installation of temporary supports to maintain the integrity of the pit roof until the repair of replacement works can be undertaken'*

439. CitiPower estimates that around 5% of roadway pits are in a hazardous condition, at end of life, and are expected to fail within the next 10 years.

Modelling does not support the program as proposed by CitiPower

440. CitiPower has provided a risk cost model to support the proposed expenditure. The risk model is largely driven by the determination of catastrophic safety risk costs. Catastrophic safety risks are associated with loss of life.

441. On inspection of the probability of failure values used by CitiPower, we observe that the values are an order of magnitude higher for catastrophic risk (at around 10%) than for other risk categories (at around 1%). This is incongruent with the provided business case, which states:[104]

102 CitiPower BUS 4.06 CBD cable pit refurbishments, p5

103 CitiPower BUS 4.06 CBD cable pit refurbishments, p8

104 CitiPower BUS 4.06 CBD cable pit refurbishments, p11

'It is expected that the potential for failure due to a pedestrian is significantly lower than for dynamic loading due to a vehicle. Specifically, it has been assumed that the failure rate for a hazardous cable pit due to pedestrian loading is 10% of that for a vehicle loading. Applying this failure rate to the whole population (as pedestrians could walk on both those in the footpath and those in the roadway) yields a probability of failure of 0.96%.'

442. The catastrophic risk would typically be assigned with a consequence of higher magnitude such as loss of life, and more likely involving a pedestrian. A pit collapse from dynamic loading is more likely to involve a vehicle and, with the associated protections available in a vehicle, the event is less likely to result in a fatality. This appears to be supported by CitiPower's business case which states:[105]

'… a 9.15% probability that a single roadside pit will fail due to dynamic loading from traffic.'

443. CitiPower has included a likelihood of consequence of 20% that a catastrophic failure of a pit will result in a loss of life. We consider that this is likely to overstate the risk of loss of life, as represented by the catastrophic failure, particularly when moderated for the time a person may be present at the time of the catastrophic failure and incur fatal injuries. We also suspect that the probability of failure values included for catastrophic failure and significant failure are reversed. Based on our review of the models, and the way CitiPower has categorised risks, we would expect that the risk of catastrophic failure would be lower than for a significant risk.

444. When making adjustments for the above in the risk monetisation models provided, the risk cost does not exceed the annualised program cost in the study period. Absent better information, we consider that a program of a similar size to continuing a reactive management approach of $2.9m,[106] is likely to be more representative of an efficient level of expenditure.

Balance of works is likely to be reasonable

445. We were not provided with any supporting documentation for the balance of projects, after removal of the CBD pit refurbishment related repex, to provide the rationale for these projects.

446. In the absence of better information, CitiPower appear to be basing its justification on the remaining parts of the transformer replacement program on historical trend and by reference to its total unmodelled expenditure.

447. The forecast averages $1.0m per annum, with the major components for activities that we would normally associate with life extension activities for transformers, and which should be considered alongside an assessment of transformer related expenditure.

Summary of our assessment

448. The extent of proposed increase is not adequately supported as being a prudent and efficient forecast of expenditure. We consider that the risk monetisation models in their current form and application of input assumptions as proposed by CitiPower to support the proposed CBD Pit Refurbishment program result in outcomes that are not credible.

449. We consider that the input assumptions should be reviewed and the economic analysis should be broadened to justify inclusion of the CBD Pit Refurbishment program. Absent this analysis, the outcome of the risk cost analysis, when adjusting for more reasonable assumptions, results in a lower level of expenditure for this program.

105 CitiPower BUS 4.06 CBD cable pit refurbishments, p11

106 Based on CitiPower's estimate of expenditure for the next RCP from expenditure incurrent in 2017 and 2018 as described in CitiPower BUS4.06 CBD cable pits, page 9

450. Notwithstanding that the expenditure proposed for the 'Other' repex group is comparable with the historical trend, CitiPower has not justified the components of its forecast expenditure.

4.5 Findings and implications for CitiPower's repex forecast

4.5.1 Summary of findings

The originally provided justification documentation did not constitute an adequate level of supporting evidence to justify the proposed expenditure

451. In our assessment of the proposed expenditure, we sought to understand the basis for inclusion of the project and programs into the forecast and rationale for the proposed replacement volumes. We therefore looked for evidence of justification of the proposed expenditure, consistent with the normal requirements of a business case-like document, from the information we were provided to the development of a prudent, efficient and reasonable program of forecast expenditure.

452. Based on our experience, we consider that a typical DNSP should have this information readily available to support its claims. This is consistent with our experience of having undertaken numerous expenditure reviews for the AER, supported by the AER's capital expenditure assessment guideline and was reflected in our information requests to each business.

453. In many cases there is an absence of evidence to justify the volume and cost assumptions that each business has included in its proposed forecast.

Some proposed projects and programs may duplicate work already in 'base' repex, and do not appear to have been considered within the prioritisation and optimisation processes of the governance and management framework

454. CitiPower has described application of an iterative top-down challenge process to their capex forecasts (as described in section 3). We understand that projects were excluded from the proposal as a part of the Executive review process. However, we also see evidence that projects and programs are included into the forecast without evidence of prioritisation or optimisation of the portfolio given the existence of similar programs of an ongoing nature, referred to as the 'base' level of repex.

455. Specifically, we are concerned that the application of an optimisation (or prioritisation) process was limited, to the point that it was unlikely to meaningfully consider the extent of projects that may be reasonably deferred in the proposed forecast.

456. We observed evidence of a bias in the forecast to include additional projects to the forecast capex, above what is considered a 'base' level of capex, and which appeared to be fall within a reasonable level as determined by the AER's repex model as determined by CitiPower.

Forecast likely overstated due to lack of portfolio-level assessment of link between proposed program and intended network performance outcomes, including risk mitigation

457. In the absence of reasonable top-down checks, including with reference to improving network performance indicators, we consider that the forecast is likely to overstate the level of expenditure required. We did not see a systematic application of risk, economic analysis of assessment at the portfolio level for determining an efficient level of expenditure for the associated improvement in risk.

Full impact of delivered cost efficiencies not evident in the forecast expenditure

458. In terms of cost efficiency, we are not convinced that the cost efficiencies identified by CitiPower, and which have been realised during the current RCP, are adequately reflected in the unit costs relied upon by CitiPower in preparing its forecast expenditure. We found evidence of the issues identified in section 3 and in section 4.3 that indicate an over-forecasting bias and of cost estimates that may be higher than would be reflective of an efficient level.

4.5.2 Implications to forecast expenditure

459. Based on the information available to us at the time of preparing this report, we consider that CitiPower has not sufficiently demonstrated that its proposed repex forecast is prudent and efficient. We provide a summary of our assessment by RIN group below.

460. On the basis that CitiPower has determined that the proposed replacement volume for its **Overhead Conductor** and **Underground Cable** groups is necessary to meet its safety obligations, we consider that the forecast replacement volumes are reasonable. Whilst the issues we have identified in section 3 are likely to be evident for this expenditure, we consider that, on balance, the forecast capex is also likely to be reasonable.

461. For many of the remaining groups, we consider that CitiPower has not established a reasonable basis for the extent of the proposed increases in expenditure. We found:

- **Poles**: we do not consider that CitiPower has established a reasonable basis for increasing the volume of wood pole treatments to the extent proposed. Accordingly, the forecast expenditure is not representative of a prudent and efficient level.
- **Pole top structures**: a replacement volume that more likely reflects the current asset management practice, as CitiPower submits is the basis of their forecast replacement volumes, should be based on more recent data.
- **Transformers**: we tested the robustness of CitiPower's risk monetisation models provided in support of its substation transformer expenditure. We found that the assumptions and parameters applied in its models lead to an overstatement of risk, and when corrected for reasonable assumptions, support deferral of a proportion of projects. We consider that CitiPower will incur a level of expenditure on Transformer replacement at a level lower than it has proposed.
- **Switchgear**: CitiPower has identified projects that appear to be reasonable candidates for consideration for replacement. However, the information provided does not adequately support the proposed timing and expenditure. We consider that the risk monetisation models in their current form, and application of input assumptions as proposed by CitiPower, result in outcomes that are not credible.
- **Service lines**: CitiPower has not adequately demonstrated that the defect driven program, if prioritised based on highest risk service lines, will be insufficient to meet its safety obligations absent additional expenditure.
- **SCADA, network control and protection**: CitiPower has not demonstrated the relationship between its CBRM tool and its forecast expenditure. Whilst we saw evidence to support an increase on historical volumes, we did not see how it has arrived at a prudent level of replacement. Further, we were not able to find a basis to support the inclusion of some projects into the forecast.
- **Other** repex: the proposed increase is not adequately supported as being a prudent and efficient forecast of expenditure. We consider that the risk monetisation models in their current form, and application of input assumptions as proposed by CitiPower to support the proposed CBD Pit Refurbishment program, result in outcomes that are not credible.

5 REVIEW OF PROPOSED NON-DER AUGEX

In this section, we present our assessment of CitiPower's forecast augex expenditure for the next RCP, except for solar enablement expenditure.

We used sensitivity analysis to examine the robustness of the proposed options and the timing of activity to variances in the demand forecast. The results suggest that CitiPower's proposed non-DER augex is likely to be over-estimated based on our use of sensitivity analyses to examine the robustness of the proposed options and timing of activity to variances in the demand forecast.

For the Focus Projects designated by the AER, our analysis suggests that the Brunswick supply area, Russell Place supply area and CBD supply area business cases are likely to satisfy the capex criteria. In our view, the proposed capex for the Port Melbourne supply area may not satisfy the capex criteria.

CitiPower has provided business cases for approximately 70% of the proposed capex and most are supported by cost-benefit models. This has proved useful in examining the justification for project expenditure. However, CitiPower has presented little supporting information to justify the quantum of the remaining expenditure, relying it seems, on its planning process and cost estimation methodology as evidence of prudent and efficient capex forecasts. We consider that this is not sufficient evidence.

5.1 Introduction

462. We reviewed the information provided by CitiPower to support its proposed augex (non-solar enablement) forecast, including the business cases and relevant supporting information. Our focus is to assess the extent to which the forecast expenditure is likely to meet the NER criteria.

463. The AER has identified four 'Focus' projects which we have included explicitly in our assessment of the proposed augex forecast, within the relevant category of expenditure, as denoted below:

- Brunswick supply area;
- Port Melbourne supply area;
- Russell Place supply area; and
- CBD supply area.

464. CitiPower's solar enablement project is also an augex project and a focus project (as designated by the AER for our review) and we refer to it for completeness in our overview of augex expenditure in the next section. However, our assessment of this project is presented in section 6.

5.2 Summary of CitiPower's proposed augex

5.2.1 Overview

465. CitiPower has proposed $178.9m for total augex for the next RCP, at an average annual expenditure of $35.8m. In the table below we show augex by RIN Category, including real cost escalation.

Table 5.1: CitiPower's proposed total augex for the next RCP - $m, real 2021

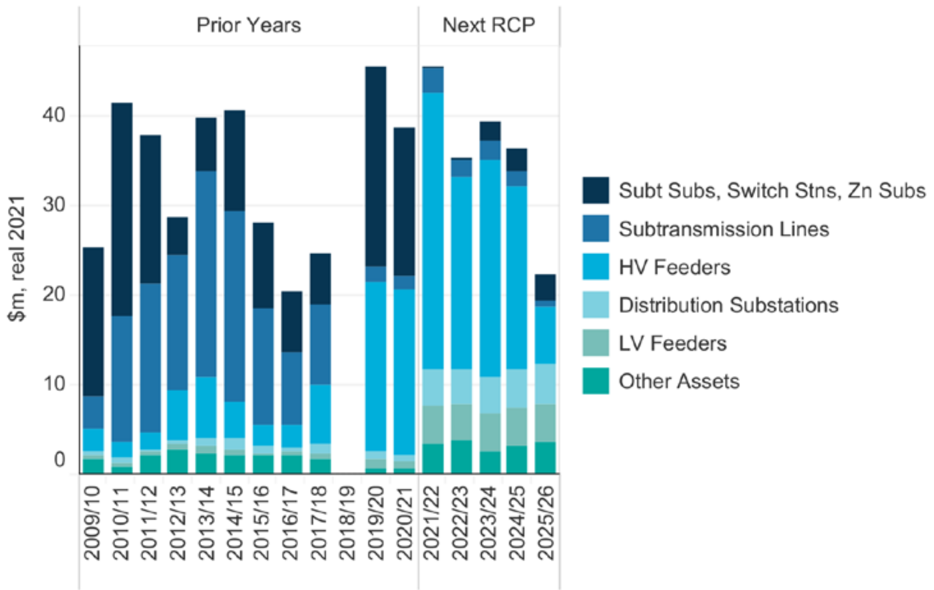
Group	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Subtransmission Substations, Switching Stations, Zone Substations	0.3	0.1	2.1	2.4	3.0	8.0
Subtransmission Lines	2.7	1.9	2.1	1.8	0.6	9.0
HV Feeders	30.9	21.5	24.2	20.5	6.4	103.5
Distribution Substations	4.1	3.9	4.2	4.2	4.4	20.8
LV Feeders	4.1	3.9	4.2	4.2	4.4	20.8
Other Assets	3.5	3.9	2.5	3.2	3.6	16.8
Total	**45.6**	**35.2**	**39.3**	**36.3**	**22.3**	**178.9**

Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

5.2.2 Augex trend

466. Augex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. All expenditure has been inflated to real 2021 dollars and forecast expenditure includes CitiPower's proposed real cost escalation.

Figure 5.1: CitiPower's augex expenditure by asset category -$m, real 2021



Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

5.2.3 Observations from the augex trend

467. The augex forecast by CitiPower for the next RCP continues the relatively high level of 2019/20-2020/21 expenditure into the first year of the next RCP, with the uplift driven by HV feeders and the solar enablement program (which extends across every year of the next RCP). The uplift in HV feeders is offset to some extent by a reduction across every year of the next RCP in LV feeder work and subtransmission substation activity.

5.2.4 Augex categorised by function

468. The table below groups projects by function type and illustrates the AER focus projects referred to above, and the additional business cases that we reviewed. Our assessment is structured according to these function types.

Table 5.2: CitiPower augex for the next RCP by Function Type and showing AER Focus projects and additional business cases reviewed - $m, real 2021[107]

Function Type / Focus & BC	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Augmentation of Subtransmission	30.8	14.1	15.1	16.2	6.4	82.5
AER Focus projects						
Brunswick SA	*18.2*	*10.5*				*28.7*
Port Melbourne		*2.6*	*9.8*	*7.2*		*19.6*
Russell Place SA	*11.2*					*11.2*
Other	1.4	1.0	5.3	9.0	6.4	23.0
CBD Security	2.3	8.6	9.9	4.7		25.5
AER Focus projects						
CBD Supply	*2.3*	*8.6*	*9.9*	*4.7*		*25.5*
Augmentation of Zone Substations	0.3	0.1	2.0	2.2	2.8	7.5
LV Augmentation	8.1	7.6	8.0	7.9	8.1	39.7
AER Focus projects						
Solar Enablement	*6.6*	*6.0*	*6.3*	*6.2*	*6.3*	*31.5*
Other	1.5	1.6	1.7	1.7	1.8	8.2
Zone Substation Automation	3.5	3.8	2.4	3.0	3.3	16.0
Additional Business Cases						
3G	*1.9*	*1.9*				*3.8*
5 Minute Settlement	*0.1*	*0.3*	*0.2*	*0.2*	*0.3*	*1.1*
Digital Network	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*5.5*
Other	0.4	0.5	1.1	1.7	2.0	5.6
Total	**44.9**	**34.1**	**37.4**	**34.0**	**20.7**	**171.1**

Source: EMCa analysis of CP MOD 6.01, 6.04, 6.09.

5.3 CitiPower's augex forecasting methods

469. CitiPower's augex investment includes both demand-driven and non-demand driven projects.

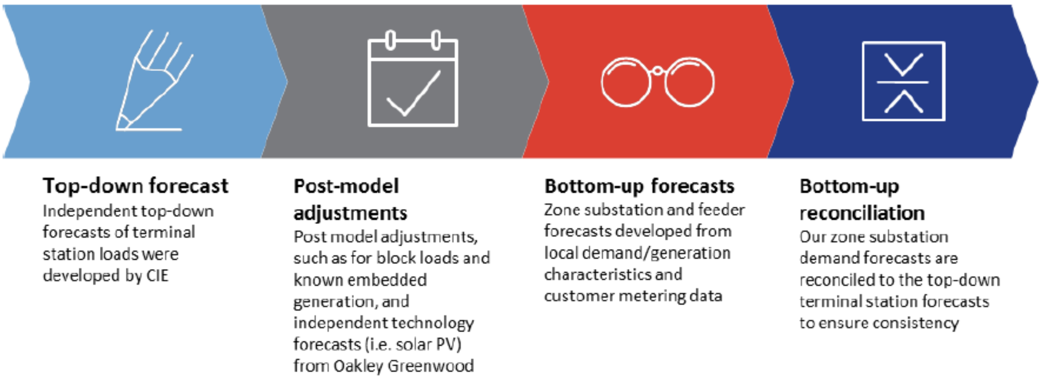
Demand-driven augmentation

470. Based on forecast demand, CitiPower determines where the capacity of its network is expected to be exceeded and identifies the appropriate intervention. Typical interventions include reconfiguring the network, addition of infrastructure and implementing non-network solutions.

471. The figure below summarises CitiPower's demand forecasting approach.

[107] Solar Enablement is reviewed in section 6

Figure 5.2: CitiPower's demand forecasting approach



Source: CitiPower Regulatory Proposal, page 75

472. CitiPower applies a probabilistic approach to planning demand-driven investment decisions in which it estimates the probability of an outage occurring within the peak period and determines the energy at risk of not being supplied. The energy at risk of not being supplied is monetised by assigning the Value of Customer Reliability (VCR) determined by AEMO.

473. CitiPower states that '[o]*ur augmentation forecast only includes capital works where the cost of mitigating a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand side solution is not feasible.'*[108]

Non-demand driven augmentation

474. CitiPower has forecast expenditure to address non-demand driven issues on the network. These include responding to compliance obligations (such as the installation and operation of REFCL infrastructure) and to address the impact of future fault currents, voltage levels and voltage quality. [109]

Non-network solutions

475. CitiPower considers non-network solutions to avoid or defer the need to invest in network augmentation when it is efficient. It seeks non-network solutions through its DAPR, public forums, RIT-D process for major augmentation works and through its demand side engagement register. [110]

Cost forecasts[111]

476. CitiPower states that it forecast costs for capex projects '*… based on recent historical costs for efficiently delivered projects of similar scope, size and geographic locations'* and '*rates from service providers that are derived from periodic tendering where available and appropriate. This includes our materials cost forecasts, which are procured through stringent contracting.'*

477. CitiPower adjusts costs for forecast growth in real input prices over time, such as labour, materials, and contracted services.

5.3.2 Assessment of CitiPower's augex forecasting methods

CitiPower's top-down/bottom-up demand forecast reconciliation approach is consistent with industry practice

478. At a high level, CitiPower's demand forecasting methodology, shown in Figure 5.2, is consistent with industry practice in that it includes a reconciliation between its top-down

108 CitiPower, Regulator Proposal, p76

109 CitiPower, Regulatory Proposal, p75

110 CitiPower, Regulatory Proposal, p77

111 CitiPower, Regulatory Proposal, p77

forecast at the terminal station level that is prepared by the Centre of International Economics (CIE) and CitiPower's own bottom-up forecasts at a zone substation level. Victoria holds an advantage over other states in having data from the smart meter population, which provides data to help substantiate its bottom-up forecasts.

479. CitiPower has advised that it used the most recent available full year of data to prepare its forecast, which is from the 2017/18 year. This data is now two years old. CitiPower has stated that it will update its forecast with more recent data for its revised regulatory proposal, but for now, we acknowledge that the demand forecasts are based on this information.

480. As with all forecasts, the key aspects are the underlying assumptions and the factors that are taken into account (or not) to manage prospective changes in consumer behaviour, including potential changes to price signals (such as via changes to tariffs and tariff structure), government policy (such as the Victorian government's Solar Homes program), and technology innovation and adoption. We note, for example, that the top-down forecast includes input assumptions regarding solar PV penetration.

481. It is not within our scope to review the demand forecasting methodology in detail, nor to propose alternative forecasts at the zone substation and feeder levels (which are the focus of our assessment) for growth-driven capex and opex. Instead, we have applied sensitivity analyses to test the robustness of the selected option and the timing of the proposed work, as we discuss below.

Energy at risk is hard-coded into the model

482. CitiPower has calculated the energy at risk outside of the probabilistic planning model that was provided with CitiPower's regulatory proposal. We reviewed CitiPower's supporting documentation to understand the calculation method. The energy at risk is estimated by *'scaling a normalised annual load duration curve to the forecast load in MVA and determining the difference (being energy at risk) between the N-1 rating and the forecast load.'*[112]

483. CitiPower takes the average of the Load Duration Curves (LDC) of the last five years for the substation in question and has presented examples. We consider CitiPower's approach to be reasonable.

The value of expected unserved energy is hard-coded into the model, but can be varied by weighting of the forecast peak demand PoE

484. Our understanding is that CitiPower's expected unserved energy is based on unplanned transformer outages. The assumed probability of a transformer outage in a year is the number of transformers multiplied by the probability of failure (PoF) of 1% per annum per transformer, multiplied by 2.6 months mean outage time and divided by 12 months.[113] The PoF rate and restoration times are similar to those used in the industry except where mobile transformers or substations are available (which CitiPower does not have).

485. CitiPower further explains that *'[t]he unserved energy is initially that which cannot be transferred to alternate supplies following the significant or major failure. This reduces once the generators start to come on line taking account of the number of generators which may be brought on line each day until sufficient generation support has been installed to meet the demand unserved following the initial incident.'*[114] This applies when peak demand is less than the substation's N-1 firm capacity, above which load transfer is not taken into account in calculating the unserved energy. We consider that this approach is reasonable.

486. CitiPower's probabilistic planning model uses a probability weighted blend of the 10% PoE peak demand forecast and the 50% PoE[115] peak demand forecast. This is used to vary the expected value of unserved energy by scaling the expected unserved energy at 10% PoE

[112] CitiPower ATT001- Augex Planning Policy and Guidelines, page 26, which is a joint CitiPower/Powercor document

[113] CitiPower, ATT001- Augex Planning Policy and Guidelines, page 26, which is a joint CitiPower/Powercor document

[114] CitiPower, CP BUS 4.03 – Transformer evaluation methodology, page 8

[115] 50th percentile demand forecast or 50 per cent probability of exceedance (PoE) is the "most-likely" level of demand. Actual demand in any given year has a 50 per cent probability of being higher than the 50th percentile demand forecast

and at 50% PoE. CitiPower's weighting is 30% of the 10% PoE peak demand forecast to 70% of the 50% PoE peak demand forecast. Our assessment of this approach is discussed in section 3.

487. Rather than debate the origins and merits or otherwise of this fundamental planning input, our sensitivity analyses have included testing the robustness of the proposed option and the timing of the option (i.e., within the next RCP or not) to negative variances in the demand forecast.

Value of VCR is weighted to outage duration

488. The value that CitiPower has used for value of customer reliability (VCR) is based on the AEMO 2014 report, escalated to current terms. This value is then weighted (adjusted) for each customer class to derive a composite value of VCR that is used in the calculation of the cost of unserved energy. This is a reasonable approach.

489. We understand that CitiPower intends to update the use of its value of VCR to the values recently published by the AER. Whilst this would reflect more recent studies, the impact to the risk cost modelling is likely to be low given the weighting approach applied by CitiPower.

CitiPower's probabilistic planning models limit sensitivity analyses

490. CitiPower has provided the AER with probabilistic planning models in support of the majority of its proposed augex. The models include some facility for sensitivity analyses – for example, it is easy to change the weighting of the PoE between the 50% PoE and the 10% PoE, the discount rate, the demand management cost per MW, and the VCR.

491. However, the model includes a disconnect between the assumed timing of network capex for the various solutions and the energy at risk. This is because the timing and quantum of the expected unserved energy (in MWh) is hard coded into the energy at risk calculation.

492. We have focused on the sensitivity of the planned work to negative variances of key inputs to CitiPower's probabilistic planning to take into account demand and energy forecasting uncertainty because:

- Negative variances may defer expenditure, whereas positive variances are likely to bring capex forward and still within the next RCP;
- There are known technologies (such as battery storage) and other potential changes (such as tariff restructuring) that may significantly impact augex project timings by reducing peak demands and associated energy at risk at the feeder and substation level. However, the impact of these changes is uncertain over the next 5-6 years; and
- It allows us to consider the likely 'option value' or, in other words, the value of deferring large capital investment decisions in network assets for as long as practicable to help enhance the prospects that the assets will be sufficiently utilised in the future.

CitiPower's cost forecasting methodology has possible shortcomings

493. CitiPower's approach of using a combination of relevant historical costs and/or updates from suppliers or vendors when competitive prices are not available is a reasonable approach to unit cost forecasting. However, there are two possible exceptions, both concerning historical costs:

- where CitiPower's cost estimate is based on its historical internal costs without reference to industry benchmarks, it is possible that CitiPower's costs are not reflective of efficient levels; and
- where CitiPower's unit cost estimate is averaged over several years of historical costs, the average may not accurately reflect current practices and/or market conditions.

494. In our project-level assessments, we identify any concerns with this aspect of CitiPower's expenditure forecasts.

5.4 Augmentation of Subtransmission

5.4.1 Introduction

495. In this section, we assess three of the four AER focus projects: Brunswick supply area ($28.7m); Port Melbourne supply area ($19.6m); and Russell Place supply area ($11.2m).

496. The remainder of CitiPower's subtransmission augex is comprised of 12 projects, which in aggregate have forecast expenditure of $23.0m in the next RCP.

5.4.2 Brunswick area strategy

497. Three projects are designated for completion in the next RCP as part of the Brunswick area strategy as denoted below:[116]

- Offload Brunswick (BK) substation to West Brunswick (WB) zone substation ($12.0m);
- Offload Fitzroy (F) substation to Collingwood (CW) zone substation ($12.6m); and
- Brunswick supply area upgrade per RIT-D ($4.2m).

498. The total expenditure of these three projects in the next RCP is $28.7m.

499. The Brunswick area upgrade project is subject to the RIT-D process and involves offloading the 22kV/6.6kV Brunswick substation referred to as C. The project commenced in 2019/20 and is expected to be completed in 2021/22 with forecast expenditure of $4.2m. We have not evaluated the prudency of this previously committed expenditure, as CitiPower provided no information in support of the forecast expenditure.

Overview

500. The Brunswick area of CitiPower's network is supplied by Brunswick Terminal Substation (BTS) and West Melbourne Terminal Substation (WMTS). Five zone substations are supplied by BTS and WMTS which, in turn, supply the Brunswick area.

501. The condition of assets at BK and F, which are both 22/6.6kV substations, triggered an options evaluation for the entire Brunswick area.

Our assessment

The project augmentation expenditure could be classified as replacement expenditure

502. CitiPower identifies the overarching need as being to efficiently meet forecast consumer demand for electrical power throughout the Brunswick area. CitiPower found that the BK and F substations are ageing assets that are subject to deteriorating health and that present an increasing risk to the operation of the network, as well as the safety of workers and the community.

503. CitiPower has provided an overarching criterion for categorising its network repex projects and programs:

> *'Replacement expenditure is about maintaining the performance of the distribution network, not improving it. Where replacement expenditure has incrementally increased to deliver a safety benefit, that has been identified in the regulatory proposal and is accompanied (where not mandated by compliance) by a cost benefit analysis.'*[117]

504. The reason the project is classified as augex, rather than repex, appears to be because CitiPower is taking the opportunity to upgrade the outdated 6.6kV distribution voltage to 11kV; this will create additional capacity for longer-term future load growth.

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116 CitiPower Attachment 092 – GHD- Augex Brunswick, page 4

117 CitiPower's response to IR032

505. At both substations, peak demand is well below the N-1 rating. Therefore, there is little risk to supply interruption for a single transformer outage over the next 5-10 years. Catastrophic failure of a transformer or a switchboard (e.g., fire) may lead to total loss of supply.

506. We consider that the project expenditure could be treated as repex rather than augex. This distinction does not change our assessment.

Poor asset condition at substation BK and F indicates intervention is likely to be required within the next five-ten years[118]

507. We have considered CitiPower's approach to assessing asset condition in our assessment of CitiPower's repex forecast. Refer to section 4. We consider CitiPower's input approach to be reasonable for determining whether the preferred option is required in the next RCP or later, with the application of sensitivity analyses to test the robustness of the results.

508. The CBRM analysis has determined that all three transformers at BK substation will have a health index (HI) of 8 by 2021 and will deteriorate further over the course of the next RCP. The risk monetisation model provided by CitiPower for the project indicates that when assessed over twenty years, the BK substation no 1 transformer would reach HI 12.

509. Similarly, the HV substation switchgear at BK substation is forecast to have an HI pf 6.3 by 2021 and is also forecast to deteriorate further over the next RCP. The BK substation switchboard is now 55 years old and tests since 2017 have revealed low insulation resistance. The deteriorating insulation resistance indicates that, without intervention, the switchboard will continue to deteriorate until an arc-fault occurs. The general site infrastructure at BK substation is also showing increasing equipment defect rates.

510. CitiPower presents similar information for F substation.

511. Based on this information, we are satisfied there is a case for intervention at BK and at F substations within the next five-ten years to avoid supply loss, and environmental and safety risks.

512. One of the reasons supporting selection of CitiPower's preferred option is that it aligns with its strategy of progressively retiring its 6.6kV assets, which is consistent with industry trends. CitiPower states that:[119, 120]

> *'The 6.6 kV assets are comprised of outdated technologies and installation practices that are more prone to failure than modern equivalent assets e.g. paper insulated cables and directly buried underground. The increased risk of failure is compounded by the 6.6kV networks being "islanded" from the adjacent 11kV network. The islanding means that customers on the 6.6kV network cannot be supplied by adjacent 11kV feeders during outage events.'*

513. Furthermore, 6.6kV has limited capacity to supply the high-density loads and high peak demands typically found in CBDs. CitiPower states that the: "*Brunswick and Port Melbourne areas are the last remaining localities continuing to operate using the 6.6 kV distribution voltage.*"

514. In our view, the strategy of progressively retiring 6.6kV distribution assets as they reach end-of-life, as proposed by CitiPower, is consistent with industry trends throughout Australia.

The range of options considered by CitiPower is adequate and the selected option is likely to be the prudent choice

515. As shown in the table below, CitiPower considered eight options, including Non-network Solutions (NNS). Due to receiving no responses to its request from the market for an NNS,

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118 CitiPower Attachment 092, pages 11-12

119 CitiPower Attachment 092, pages 13

120 We refer to CitiPower only in reference to the rest of our assessment whereas CitiPower commissioned GHD to undertake planning studies for it as reported in CitiPower Attachment 092 – GHG – Augex Brunswick

CitiPower concluded that NNS options are not feasible for this project and focused instead on network solutions. We consider this to be a reasonable approach.

516. The table below summarises the results of CitiPower's options analysis. It shows that Options 5c and 5d have the lowest capital cost and Option 5d has the lowest annualised cost. These options also provide the opportunity to redevelop or sell the BK and F substation sites.

Table 5.3: Summary of the results of CitiPower's option analysis - $m, real 2018[121]

Options		Capex	Annualised Cost	Rank
Option 1:	Continued maintenance and monitoring	0	13.8	7
Option 2:	Non-network solutions	53	13.7	6
Option 3:	Life extension of existing assets	n/a	n/a	n/a
Option 4:	Replacement of existing assets (in-situ)	68	3.2	5
Option 5a:	Redevelop C substation and offload F substation and BK substation to C substation at 22/6.6 kV	37	2.1	4
Option 5b:	Redevelop C substation and offload F substation and BK substation to C substation at 66/11 kV	30	1.7	2
Option 5c:	Offload F substation to CW substation and BK substation to WB substation at 66/6.6 kV	26	1.8	3
Option 5d:	Offload F substation to CW substation and BK substation to WB substation at 66/11 kV	26	1.6	1

Source: CitiPower Attachment 092, Table 11, page 34. Expenditure terms are not denominated in this table but are assumed to be $2018, based on the date of the report

The optimal timing for completion of the project is likely to be within the next RCP

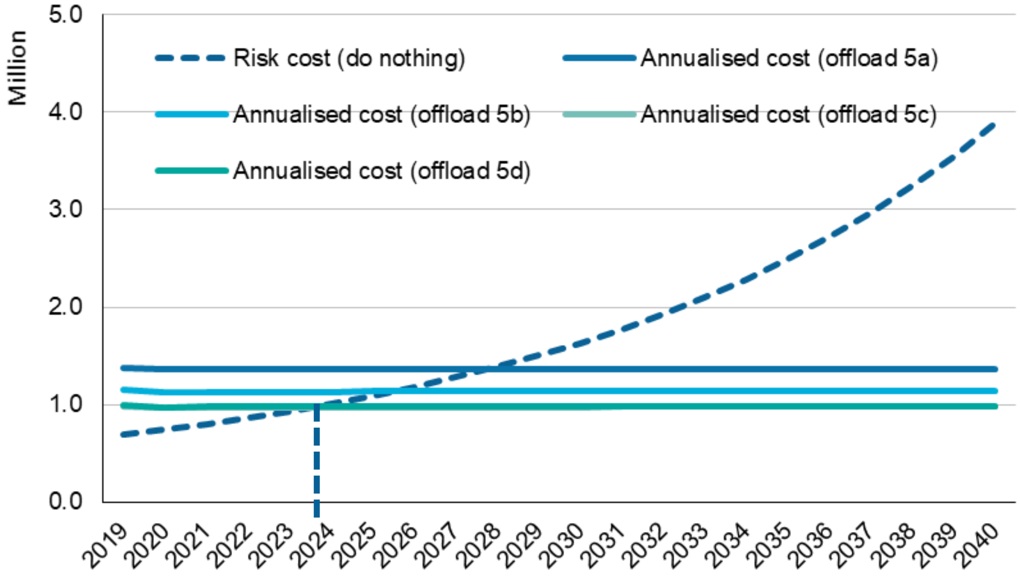
517. We have reviewed the failure modes applied in the model, the consequence areas, and the annual asset failure and consequence probabilities in section 4. We consider the input assumptions are reasonable to determine whether the preferred option is required in the next RCP or later.

518. CitiPower applied a VCR of $37,743/MWh which is hard-coded into its model without reference to its derivation. This value indicates an approximately 50:50 weighting of commercial and residential customers, which is likely to be reasonable for the Brunswick supply area.

519. The figure below shows the result of CitiPower's probabilistic risk-cost analysis, comparing the annualised cost of Options 5a-5d with the annualised risk cost. The efficient timing is the point at which the annualised risk cost exceeds the annualised cost of the solution. This occurs for the preferred Option 5d (which has the lowest annualised cost) in 2024.

121 Option 3 was not considered to be credible given the condition of the assets at F and BK substations.

Figure 5.3: Brunswick supply area - annualised cost vs annualised risk for Options 5a – 5d ($2018)



Source: CitiPower, CP MOD 6.05

520. CitiPower undertook a sensitivity analysis to test the robustness of options to variations of the key assumptions. CitiPower produced results for 16 scenarios in addition to the base scenario by varying Direct costs only, Risk costs only, and Direct and risk costs with combinations of ±10% and ±20% variances.[122]

521. CitiPower concludes that the optimal project timing for all of the scenarios is 2023 and has scheduled the two projects to be completed by 2022/23 and commencing in the current RCP. The figure above seems to indicate that it would be prudent to commission the work prior to the summer of 2023/24, but CitiPower may have other reasons for commissioning it in 2022/23.

522. According to CitiPower's sensitivity analysis, the only scenario for which the optimal timing for completion of the project may extend beyond the next RCP is when risk costs are 20% lower than its central estimate and costs are 20% higher. While this is a plausible scenario, we consider it remains prudent to undertake the work in the next RCP given that:

- 16 of the 17 scenarios considered lead to an economically optimum timing within the next RCP (or in the current RCP); and
- the condition of Tx 1 at BK substation and the F substation switchboard in particular is already poor/at end-of-life and represent safety hazards that should be addressed within the span of the next RCP.

The cost estimate is likely to be reasonable

523. The scope of work incorporates:[123]

- *decommissioning BK and F zone substations and augmenting WB and CW zone substations sites to accommodate modern equivalent assets to supply BK and F zone substation loads respectively*;
- *Extending the 11 kV distribution network from WB and CW zone substations to connect to existing feeders supplying BK and F zone substation loads; and*
- *Installing new distribution transformers at 11 kV downstream of WB and CW zone substations.*

122 CitiPower- Attachment 092 – GHD – Augex Brunswick, page 37 and CP MOD 6.05

123 CitiPower Attachment 092, page 32

524. CitiPower has provided a breakdown of the unit costs and volumes for each component of the work required to deliver Option 5d. We note that work has commenced to offload BK and F substations in the current RCP. As the project is scheduled to commence in 2020/21, we assume that, according to its capital expenditure governance process, CitiPower would by now have refined the project cost as part of its approval process. We also note that CitiPower has recent experience in substation-related work and therefore should have reasonable building-block information for this project.

525. We therefore consider that the cost estimate is likely to be reasonable.

Summary of our assessment

526. We consider that the range of options studied by CitiPower is reasonable. Our analysis suggests that Option 5d is likely to represent the prudent approach, as proposed by CitiPower because it: (i) addresses the reliability, safety and environmental risks at Fitzroy and Brunswick substations; and (ii) addresses the operational inflexibility and other matters associated with the 6.6kV HV network.

527. Based on the sensitivity analyses, it reasonable to conclude that the optimal timing is likely to be within the next RCP.

5.4.3 Port Melbourne supply area

Overview of project

528. The Port Melbourne supply area is located to the west of the Melbourne CBD. This area is supplied by the Fisherman's Bend Terminal Station (FBTS) and six zone substations.

529. Fisherman's Bend (E) zone substation supplies a small and reducing load of approximately 4MVA. It is located adjacent to WG substation and can '*easily be electrically connected allowing WG zone substation to take up E zone substation's load.*[124] The condition of assets at PM and E substations, which are both 66/6.6kV substations, triggered an options evaluation for the entire Brunswick area.

530. Two projects are designated for completion in the next RCP as part of the Port Melbourne area strategy:

- Offload E substation to Westgate substation ($2.4m); and
- Offload PM substation to WG substation ($17.2m).

531. The total expenditure of these two projects in the next RCP is $19.6m.

Our assessment

The project augmentation expenditure could be classified as replacement expenditure

532. For the same reasons we describe in section 5.4.2, we consider that the expenditure for this project could be treated as repex rather than augex. This distinction does not change our assessment.

533. At both substations, peak demand is less than the N-1 rating and the load at E substation is 4MVA and is forecast to decrease. Therefore, there is little risk to supply interruption for a single transformer outage. Catastrophic failure of a transformer or a switchboard (e.g., fire) could lead to total loss of supply.

The asset condition at substation PM substation indicates intervention is likely to be required within the next ten years

534. We have considered CitiPower's approach to assessing asset condition in our assessment of CitiPower's repex forecast. Refer to section 4. We consider that CitiPower's approach is reasonable.

124 CitiPower Attachment 093 – GHD – Augex Port Melbourne, page 8

535. CitiPower's model rates the HIs of the three PM substation transformers as being in fair condition (5.2-5.5).[125] The transformers are respectively 55, 57 and 58 years old,[126] and relatively rapid deterioration with age is expected over the next ten years. This will increase the risk of failure. No HI information is provided for E substation; however, the transformers are 54 and 58 years old, respectively. The PM substation switchboards are 56 years old and do not meet modern design standards and are not arc fault contained or vented, which presents a safety risk. The E substation switchboard is 53 years old and is assessed by CitiPower to be approaching end-of-life, although no HI data is presented.

536. Based on this information, we are satisfied that there is a case for intervention at PM and at E substations within the next ten years.

The strategy of progressively retiring 6.6kV assets is consistent with industry trends

537. One of the reasons supporting selection of CitiPower's preferred option is that it aligns with its strategy of progressively retiring its 6.6kV assets. For the same reasons described in our assessment of CitiPower's proposed Brunswick supply area projects (section 5.4.2), we consider that CitiPower's strategy of progressively retiring 6.6kV distribution assets as they reach end-of-life is consistent with industry trends throughout Australia.

The range of options considered by CitiPower is adequate and the selected option is likely to be the prudent choice

538. As described in the table below, CitiPower[127] considered seven options including an NNS. Because it received no responses to its request from the market for NNSs, CitiPower concluded that NNS options are not feasible for this project and focused instead on network solutions. We consider this to be a reasonable conclusion.

539. The table below summarises the results of CitiPower's options analysis. It shows that Options 5c and 5d have the lowest capital cost and Option 5d has the lowest annualised cost. These options also provide the opportunity to redevelop or sell the PM and E substation sites.

Table 5.4: Summary of the results of CitiPower's option analysis – $m, real 2018

Options		Capex	Annualised Cost	Rank
Option 1:	Continued maintenance and monitoring	0	7.5	5
Option 2:	Non-network solutions	39	10.0	6
Option 3:	Life extension of existing assets	n/a	n/a	n/a
Option 4:	Replacement of existing assets (in-situ)	31	1.4	3
Option 5a:	Offload PM and E substations to WG substation at 11 kV	17	1.0	1
Option 5b:	Offload E substation to WG substation at 11 kV and PM substation to FB substation at 6.6 kV	34	1.7	4
Option 5c:	Offload E substation to WG substation at 11 kV and PM substation to FB substation at 11 kV	26	1.3	2

Source: CitiPower Attachment 092, Table 11, p34[128]

125 CitiPower CP MOD 6.05

126 CitiPower Attachment 093 – GHD – Augex Port Melbourne, page 11

127 We refer to CitiPower only in reference to the rest of our assessment whereas CitiPower commissioned GHD to undertake planning studies for it as reported in CitiPower Attachment 093 – GHG – Augex Port Melbourne

128 Option 3 was not considered by CitiPower to be credible given the condition of the assets at PM and E substations

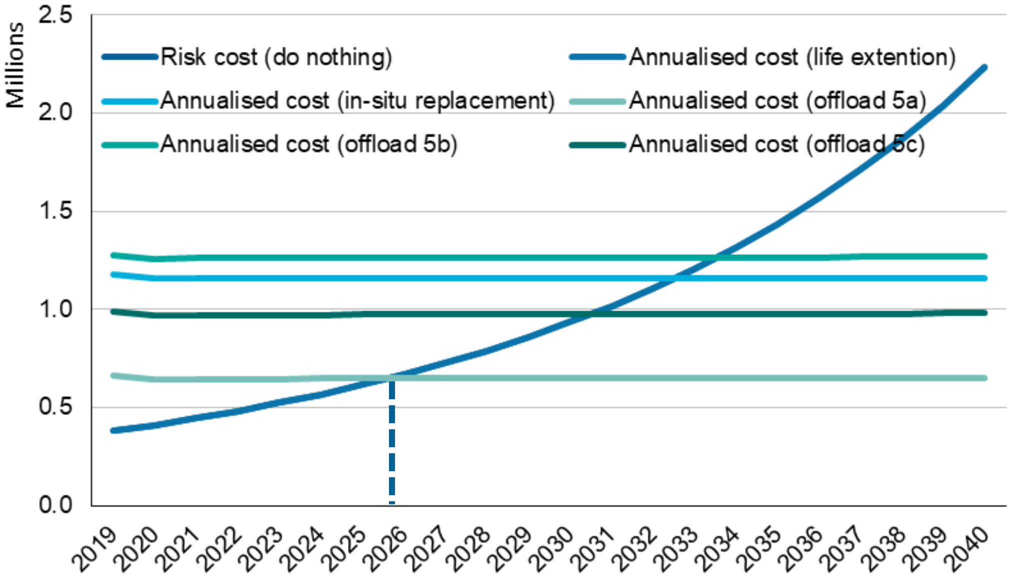
The optimal timing for completion of the project may be able to be prudently deferred

540. We have reviewed the failure modes applied in the model, the consequence areas, and the annual asset failure and consequence probabilities in section 4. We consider the input approach is reasonable to determine whether the preferred option is required in the next RCP or later, with the application of sensitivity analyses to test the robustness of the results.

541. CitiPower applied a VCR of $37,743/MWh which is hard-coded into its model without reference to its derivation. This value indicates an approximately 50:50 weighting of commercial and residential customers, which is likely to be reasonable for the Port Melbourne supply area.

542. The figure below shows the result of CitiPower's probabilistic risk-cost analysis comparing the annualised cost of solutions 5a-5c with the annualised risk cost. This shows that the risk cost exceeds the Option 5a annualised cost in 2026.

Figure 5.4: Port Melbourne supply area - annualised cost vs annualised risk for Options 5a – 5c ($2018)



Source: CP MOD 6.05

543. CitiPower undertook a sensitivity analysis to test the robustness of options with variations to key assumptions. CitiPower produced results for 16 scenarios in addition to the base scenario by varying Direct costs only, Risk costs only, and Direct + and risk costs with combinations of ±10% and ±20% variances.[129]

544. CitiPower concludes that the optimal project timing for all of the scenarios is 2024, which is the average of all scenarios. It has scheduled the two projects to be completed by 2024/25.

545. According to CitiPower's sensitivity analysis, the only scenario for which the optimal timing for completion of the project is likely to extend beyond the next RCP is when risk costs are lower than its base estimate by 10% and costs are higher by 10%.

546. We understand from CitiPower's response to a request for further information, that there is 1.7MVA of transfer capacity from PM substation to E substation that was not included in the modelling of the risk cost.[130] The transfer capacity is will reduce the energy at risk and, all things being equal, will defer the modelled economic timing of the preferred option.

547. We also note that:

- the condition of the two in-service transformers is fair;

[129] CitiPower Attachment 093 – GHD – Augex Port Melbourne, page 34

[130] CitiPower response to IR054, question 1

- the consequence of a single transformer failure is relatively low and will most likely not lead to loss of supply; and
- the probability of a catastrophic outage is extremely low (at about 0.2%).[131]

548. Whilst we are mindful of the safety risks inherent in E substation and PM substation, operational measures may continue to be deployed to limit safety risk.

549. Collectively, this analysis suggests that completion of the project to offload E substation to WG substation and offload PM substation to FB substation may be able to be prudently deferred beyond the next RCP.

The cost estimate is likely to be reasonable

550. The scope of work incorporates:[132]

- *'Decommissioning assets at PM and E;*
- *Building a new switch-room at WG to house new assets;*[133] *and*
- *Extending the 66 kV overhead lines from [WG] to cut in to the supply of [PM], and upgrading and extending the 11 kV distribution network from [WG] to connect to existing feeders supplying [PM] loads.'*

551. CitiPower has provided a breakdown of the unit costs and volumes for each component of the work required to deliver Option 5a.

552. The volumes of work and the cost components appear to be consistent with the scope of work. However, for a project of this magnitude and complexity, we would have expected CitiPower to provide separate and preferably independent advice regarding the efficiency of the cost. We do recognise, however, that CitiPower has recent experience in designing, costing, and delivering substation-related work, and it should therefore have reasonable building-block information for this project. On this basis, we consider that it is likely that the cost estimate is set at a reasonable level.

Summary of our assessment

553. We consider that the range of options studied by CitiPower is reasonable. We further consider that Option 5a as selected by CitiPower is the prudent approach as we expect it will: (i) address the reliability, safety, and environmental risks at Fitzroy and Brunswick substations; and (ii) address the operational inflexibility and other matters associated with the 6.6kV HV network.

554. Our analysis suggests that it may be prudent to defer completion of the project beyond the next RCP.

5.4.4 Russell Place supply area

Overview of project

555. Russell Place (RP) zone substation comprises 3 x 22/6.6kV 10MVA transformers supplied by underground 22kV cables from Richmond Terminal Station (RTS). Transformer No 3 is out-of-service. RP substation is in the Melbourne CBD in a building basement in Russell Place and supplies an approximate two block area of the CBD.

556. CitiPower proposes to decommission RP substation and convert the 66kV network to 11kV, and to establish additional HV feeder links to transfer RP load to Waratah Place (WP) zone substation. The forecast cost of this project in the next RCP is $11.2m. The project is scheduled to commence in the current RCP.

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131 CitiPower Attachment 093 – GHD – Augex Port Melbourne, page 17, noting that this is expected to increase year on year with the assumed deterioration of the assets

132 CitiPower Attachment 093, page 24

133 CitiPower advise that the existing ZS WG switch-room has no space to extend and accommodate additional assets

557. The primary project driver is the risks to supply reliability and to safety posed by the deterioration of the building in which RP substation is located and by the condition of the electrical assets. Peak demand exceeded the RP substation N-1 capacity in 2017.

Our assessment

The asset condition at RP substation indicates intervention is probably required within the next five to seven years

558. We have considered CitiPower's approach to assessing asset condition in our assessment of CitiPower's repex forecast. Refer to section 4. We consider CitiPower's approach to be reasonable.

559. The CBRM analysis has determined that the two in-service transformers will have an HI of 6.9 and 6.8 in 2020 increasing to 8.2 and 8.1 in 2027. These results indicate an end-of-life state within the next 5-7 years and options to mitigate the risk of failure require evaluation. The transformers were manufactured in 1951 (i.e., they are almost 70 years old). Spare parts are not available for the tap changers and a failure of the tap changer would potentially result in a long outage while replacement parts are fabricated.

560. The substation inner support walls of the building in which RP substation is located have been inspected and show signs of corrosion and water ingress.

561. The RP substation switchgear was manufactured in 1961 and has a HI of 7.0, rising to 8.0 in 2024. This indicates an end-of-life state and options to mitigate the risk of failure require evaluation.

The strategy of progressively retiring 6.6kV assets is consistent with industry trends

562. One of the reasons supporting selection of CitiPower's preferred option is that it aligns with its strategy of progressively retiring its 6.6kV assets. For the same reasons described in our assessment of CitiPower's proposed Brunswick supply area projects (section 5.4.2), we consider that CitiPower's strategy of progressively retiring 6.6kV distribution assets as they reach end-of-life is consistent with industry trends throughout Australia.

The range of options considered by CitiPower is adequate and the selected option is likely to be the prudent choice

563. As described in the table below, CitiPower considered four network options.[134] It did not consider NNSs:

> *Due to its location within the Melbourne CBD and the nature of the customers that zone substation RP supplies, CitiPower has determined that there are no credible non-network options that could address the energy at risk to defer or replace the proposed works. This determination is made under clause 5.17.4(c) and (d) of the NER.*[135]

564. The table below summarises the options identified and costed by CitiPower. We consider the range of options considered represents a reasonable range for analysis. Option 2, CitiPower's preferred option, has the lowest capital cost.

[134] Supplying RP load at 11 kV from two other nearby substations, MP and FR – however neither substations has the capacity to meet the load supplied from RP (CitiPower Attachment 125 – RIT-D Russell Place zone substation, page 14)

[135] CitiPower Attachment 125 – RIT-D Russell Place zone substation, page 14

Table 5.5: Summary of CitiPower's options - $m, real 2018[136]

Option		Capex Cost	Ranking
Option 0:	Business as usual – ongoing maintenance, building remediation, incidental replacements	1.0	4
Option 1:	Convert RP substation to 11 kV and continue to provide 6.6kV distribution	15.4	2
Option 2:	Retire RP substation and offload to WP substation, remove all equipment	12.6	1
Option 3:	Like-for-like replacement of RP substation and 22kV cables	19.5	3

Source: CitiPower Attachment 125 – RIT-D Russell Place zone substation

565. CitiPower also undertook an analysis that indicates the net present cost of Option 0 ($49.0m), Option 1 (15.0m) and Option 3 ($18.8m) are all higher than Option 2 ($11.8m).[137]

566. Option 2 aligns with CitiPower's strategy to retire the 22kV sub transmission network and upgrade the associated 6.6kV distribution network to the current operational standard of 11kV.

567. Option 2 resolves the condition and capacity-driven supply risks at RP substation at the lowest cost. Whilst we consider that it is usually good practice to retain substation sites, in this case it is not practicable. We consider retirement of the existing RP substation as the prudent approach, offloading it to WP.

The optimal timing for completion of the project is likely to be in the current RCP

568. CitiPower has not provided its modelling for the Russell Place project. It has, however, provided the RIT-D for the project which presents the results of its studies. Based on the explanation in the RIT-D document, we are satisfied that the same approach has been applied to this analysis as has been applied to the Brunswick, Port Melbourne, and CBD supply area analyses. On this basis, we consider that the results are likely to be a reasonable basis for determining whether the preferred option is required in the next RCP or later, with the application of sensitivity analyses to test the robustness of the results.

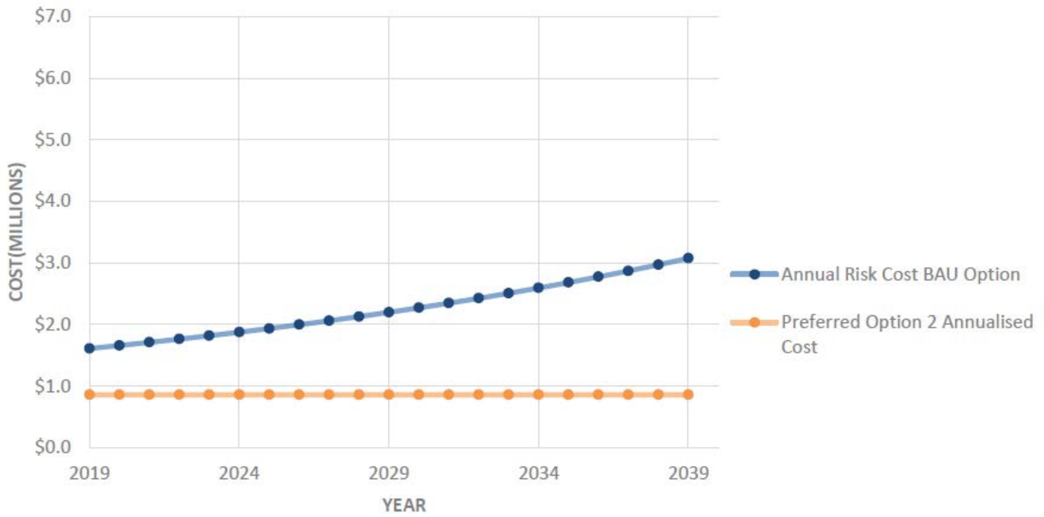
569. The figure below shows the result of CitiPower's probabilistic risk-cost analysis, comparing the annualised cost of Option 2 with the annualised risk cost with its 'central' scenario.[138] This shows that the risk cost exceeds the Option 2 annualised cost prior to the current RCP.

[136] The cost is a total project cost not the cost forecast for the next RCP

[137] CitiPower Attachment 125 – RIT-D Russell Place zone substation, Table 5.5

[138] The central scenario *'adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome*.' CitiPower Attachment 125 – RIT-D Russell Place zone substation, page 18

Figure 5.5: Russell Place supply area - annualised cost vs annualised risk for Option 2 (central scenario)



Source: CitiPower, Attachment 125 – RIT-D Russell Place zone substation, Fig 5.2, p25

570. CitiPower also developed four other scenarios:

- A: a combination of variables that assess a high-risk cost and high failure probability;
- B: a combination of variables that assess a low risk cost and low failure probability;
- C: risk costs and failure probability are central with a lower bound discount rate; and
- D: risk costs and failure probability are central with an upper bound discount rate.

571. This is a reasonable approach to a sensitivity analysis. The results show that the rankings indicated in the table above remain the same in each scenario. In all scenarios the risk cost already exceeds the annualised option 2 cost. On this basis, we consider that Option 2 should be completed as soon as practicable.

The estimated cost is likely to be reasonable

572. The scope of work incorporates:[139]

- *'decommission RP and remove all equipment;*
- *install four dedicated 11kV feeders from WP zone substation and upgrade 6.6kV distribution substations and switchgear to 11kV;*
- *decommission the 22kV transmission feeders; and*
- *building remediation works necessary for a decommissioned site.'*

573. CitiPower has not provided a breakdown of the unit costs and volumes for each component of the work required to deliver Option 2. However:

- CitiPower has recent experience in substation-related design, costing, and delivery, and it should therefore have reasonable building-block information for this project; and
- As the project is scheduled to commence in 2020/21, we assume that, according to its capital expenditure governance process, CitiPower will have refined the project cost estimate as part of its approval process.

574. We therefore consider that the estimate is likely to be reasonable.

Summary of our assessment

575. We consider that CitiPower has studied a reasonable range of options. We further consider that Option 2 is the prudent selection as we expect it will: (i) address the reliability of supply,

139 CitiPower Attachment 125 - RIT-D Russell Place supply area, page 13

safety, and environmental risks at Russell Place substation; and (ii) address the operational inflexibility and other matters associated with the 6.6kV HV networks.

576. Our assessment suggests that the optimal timing is for the project to be completed in the current RCP. However, as this appears to be unachievable, it should be completed as soon as practicable. CitiPower plans to complete the project in 2021/22.

577. We consider that the cost estimate to complete the project in 2021/22 of $11.2m is likely to be reasonable.

5.5 CBD security

578. There is a single project in this functional expenditure classification – CBD supply area – which we assess in the following section.

5.5.1 CBD supply area

Overview of project

579. Over the past 10 years, the southwest of Melbourne's CBD has been experiencing significant growth, placing increasing demands on the CBD electrical infrastructure.[140]

580. The southwest of the CBD is served by Tavistock Place (TP), Little Queen (LQ) and Little Bourke (JA) zone substations. TP supplies electricity at 6.6kV, noting that CitiPower's current standard is 11kV. TP substation is thereby islanded from surrounding 66/11kV substations.

581. The proposed project has the following primary components:

- Reconstructing the TP substation;
- Upgrading contiguous distribution sections from 6.6kV to 11kV; and
- Constructing new 11kV feeders from LQ and JA substations to TP substation.

582. This is referred to by CitiPower as Option 1. The estimated cost is $25.4m and the work is scheduled to be completed in 2024/25.

Our assessment

The projected loading on TP substation is likely to breach security thresholds within the next 5-7 years

583. CitiPower advises that under the Code it is required to:[141]

> *(a) carry out the capital and other works specified in the CBD security of supply upgrade plan in accordance with that plan; and*
>
> *(b) ensure that the Melbourne CBD distribution system meets the security of supply objectives specified in the CBD security of supply upgrade plan on and from the dates specified in the CBD security of supply upgrade plan.*

584. The relevant 66kV system configuration is shown in the figure below. According to CitiPower's load forecast, at 50% PoE, by 2026, 14MVA at JA substation and 24MVA at LQ substation is at risk, meaning the N-1 Secure standard will not be achieved. CitiPower further advises that the JA-LQ subtransmission line provides supply from JA substation to LQ substation, but LQ substation cannot supply JA substation because there is no 66kV bus

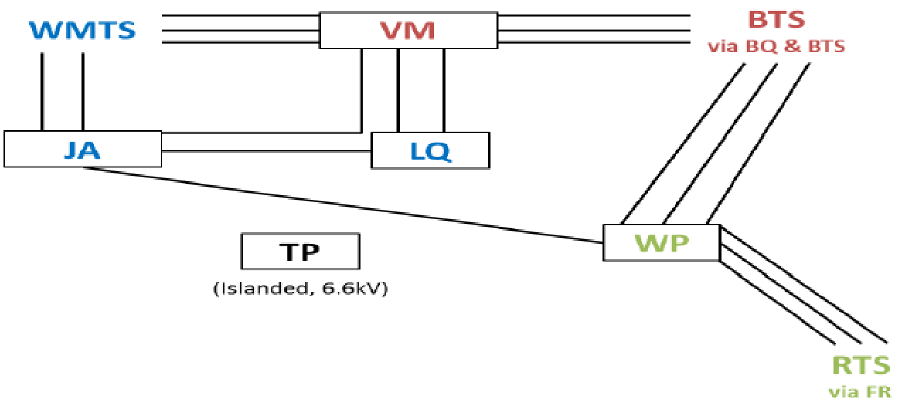
140 CitiPower, CP BUS 6.01, page 6

141 CP ATT102: Essential Services Commission (Victoria), Electricity Distribution Code, Clause 3.1A

at LQ substation.[142, 143] Consequently, the energy and hours at risk for JA substation are relatively small (80MWh, 17 hrs in 2026) but at JQ substation the energy at risk is forecast to be 1,264MWh for 235 hrs.

585. Given CitiPower's security obligations and the importance of CBD supply continuity, there is still a strong case for action within the next 5-7 years (i.e., even allowing for negative variances in peak demand growth projections from CitiPower's forecast).

Figure 5.6: 66kV system configuration – southwest Melbourne CBD



Source: CitiPower CP BUS 6.01, Figure 2, page11

The strategy of progressively retiring 6.6kV assets is consistent with industry trends

586. One of the reasons supporting selection of CitiPower's preferred option is that it aligns with its strategy of progressively retiring its 6.6kV assets. For the same reasons described in our assessment of CitiPower's proposed Brunswick supply area projects (section 5.4.2), we consider that CitiPower's strategy of progressively retiring 6.6kV distribution assets as they reach end-of-life is consistent with industry practice throughout Australia.

The range of options considered by CitiPower is adequate and the selected option is likely to be the prudent choice

587. As described in the table below, CitiPower considered four network options.[144] It did not consider NNS:

> *Demand management would not be able to meet the identified need of providing N-1 Secure standard within the CBD. If demand management is required, it indicates N-1 conditions cannot be met.*[145]

588. The table below summarises the options identified and costed by CitiPower. The range of options represent a reasonable range for analysis. Option 2, CitiPower's preferred option, has the lowest capital cost.

589. Option 0 was used as the counterfactual when determining the incremental benefits for options 1-3. However, due to the nature of the proposed options and the extent of energy-at-risk, the risk-cost analysis does not provide significant discrimination between the three network options.

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142 *The zone substations that this enhanced security project affects include BQ, FR, JA, LQ, MP, VM and WA. For an N-1 event, the network must be reconfigured within 30 minutes to securely withstand a second subtransmission line or cable contingency event* (PAL Attachment 001 – Augex planning policy, page16)

143 All sub-transmission supplies to LQ are directly connected to LQ transformers and it is not possible to supply a whole JA station load via LQ transformers by reverse power flow

144 Supplying RP substation load at 11 kV from two other nearby substations, MP and FR – however neither substations has the capacity to meet the load supplied from RP substation (CitiPower Attachment 125 – RIT-D Russell Place zone substation, page 14)

145 CitiPower BUS 6.01, page 21

Table 5.6: Summary of CitiPower's options analysis - $m, real 2019

Option		Capex Cost	NPV Incremental Benefits
Option 0:	Do nothing	0.0	n/a
Option 1:	Redevelop TP and construct new 11kV feeders from LQ and JA to TP	24.4	1,072
Option 2:	Augment Southbank (SB) substation and construct new 11kV feeders from LQ and JA to SB	29.4	1,013
Option 3:	Redevelop Victoria Market substation (VM) and construct new 11kV feeders from LQ and JA to VM.	27.4	1,072
Option 4	Demand management	n/a	n/a

Source: CP MOD 6.06[146]

590. Option 3 would meet the requirement to deliver the N-1 Secure standard for the CBD. However, there is insufficient supply from surrounding feeders/zone substations to supply VM substation customers during the re-building works, so it is not a credible solution.

591. Option 2 meets the requirement to deliver the N-1 Secure standard for the CBD. However, it is estimated to cost an estimated $5.0m (20%) more than Option 1, and to require feeder cables across Yarra River from Southbank to the CBD area. This would provide significant construction risk.

592. Option 1 meets the requirement to maintain the N-1 Secure standard for the CBD at the lowest comparative cost, and it '*will meet expected load requirements until 2035 initially, when an option to develop a third transformer will be available meaning there will be no unserved energy until 2040 with full development (30 connection points). We consider it to be the prudent selection.'*[147]

593. We agree that Option 1 is the prudent option of those considered and aside from considering the economically optimum timing, as discussed below, we have not identified an alternative, credible approach.

The optimal timing for completion of the project is within the next RCP

594. We have reviewed the probabilistic planning methodology in section 5.3.2 and consider that, when combined with adequate sensitivity analysis, it is a reasonable approach to comparative analysis and for determining the economically optimal timing of the selected project.

595. The figure below shows the output from CitiPower's model for its preferred option with:

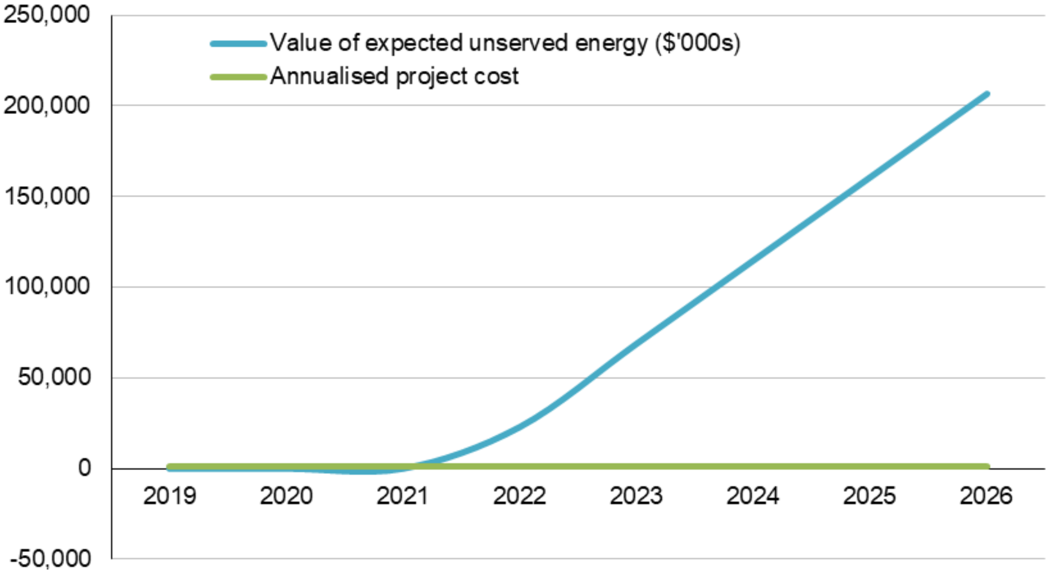
- VCR of $47,533, which results from a 94% weighting to the commercial segment VCR of $45,531; we consider the VCR to be reasonable; and
- Weighting of the peak demand forecast in the ratio of 70% of the 50%PoE and 30% of the 10%PoE – varying this ratio to 100% of the 50%PoE has the effect of reducing the peak demand forecast and therefore the energy at risk, however it does not defer the economic timing of the project beyond the next RCP.

596. On this basis we consider that the optimal timing for the preferred option is likely to be early in the next RCP.

146 Economic analysis of Option 4 was not provided by CitiPower

147 CitiPower BUS 6.01, p19

Figure 5.7: CBD security – energy at risk vs annualised project cost for Option 1 - $,000



Source: CitiPower, CP MOD 6.06

The cost estimate is likely to be reasonable

597. The scope of work incorporates:[148]

- *'Distribution works*
  - *8 new 6.5*MVA *feeders from TP18*
  - *2 new 11*kV *switch boards at TP*
  - *2 new 42/55MVA transformers at TP*
  - *66kV GIS;*
- *Sub-transmission cable works*
  - *2 new FBTS-TP 66kV supply (4,300m)*
  - *TP cut in JA-WP cable (500m).'*

598. CitiPower has only provided a high-level breakdown of the cost estimate for Option 2. For a project of this magnitude and complexity we would have expected CitiPower to provide separate and preferably independent advice regarding the efficiency of the cost. Nonetheless, we note that CitiPower has recent experience in substation design, costing, and delivery and it should therefore have reasonable building-block information relevant to this project. On this basis, we consider that the cost estimate is likely to be reasonable.

Summary of our assessment

599. We consider that the range of options studied by CitiPower is reasonable. We further consider that Option 1 is the prudent selection as we expect it will: (i) address the security of supply obligation; and (ii) address the operational inflexibility and other matters associated with the 6.6kV HV networks.

600. Our assessment suggests that the optimal timing is for the project to be completed in the current RCP. We note that CitiPower plans to complete the project in 2024/25.

601. We consider that the cost estimate of $25.4m capex is also likely to be reasonable.

[148] CitiPower BUS 6.01, p19

5.6 Augmentation of zone substations

5.6.1 Overview

602. CitiPower has proposed $7.5m capex in the next RCP associated with augmentation of zone substations. This category includes five projects:

- BQ 3rd 55MVA transformer ($4.0m);
- LS site evaluation and land purchase ($1.9m);
- NR 11kV switchboard ($1.1m);
- WMTS 22kV retirement – VR Nth Melbourne 66kV connection ($0.3m); and
- SB 11kV switchboard (completion of ring bus) ($0.1m).

Our assessment

603. While two of the five projects have relatively small forecast capex in the next RCP,[149] CitiPower has not provided information to justify the forecast expenditure. It is therefore not possible for us to form a view about the prudency and efficiency of the $7.5m capex in this expenditure category,

5.7 LV augmentation

5.7.1 Introduction

604. CitiPower has proposed two augex projects in this expenditure category:

- Solar enablement ($31.5m) – which we assess in section 6; and
- Supply quality ($8.2m) – which we assess below.

5.7.2 Supply quality

Overview of project

605. CitiPower proposes spending $8.2m in the next RCP, an increase of approximately 5% from the current RCP. The quality of supply program involves the following activities:[150]

- *re-balancing phases to prevent single phase overloads;*
- *upgrading conductors to prevent voltage drop or allow additional load to be connected;*
- *replacing transformers that are overloaded (proactively rather than replacing under faults); and*
- *changing conductors or transformers to address harmonics, flicker or other power quality problems.*

Our assessment

606. The expenditure profile for CitiPower's power quality program is shown in the figure below.

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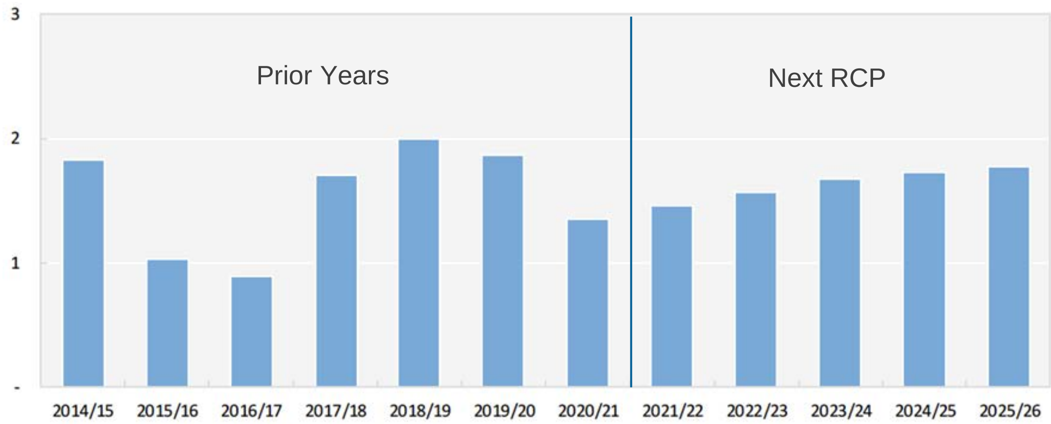
149 The WMTS capex relates to the second year of a two-year project commencing in 2020/21; the SB 11kV switchboard project capex is the first year of what we presume to be a multi-year project continuing into the 2026-31 RCP

150 CitiPower Regulatory Proposal, page 72

Figure 5.8: CitiPower's power quality program expenditure profile - $m, real 2021



Source: CitiPower Regulatory Proposal, Figure 6.6

Justification for the forecast is likely to be reasonable

607. CitiPower has based its forecast on extrapolating the 2020/21 forecast capex into the next RCP:

> *…this investment trends upwards over the 2021–2026 regulatory period in line with load growth expectations for existing and new customers.*[151]

608. We consider that it is reasonable to assume a correlation between the number of 'quality of supply' complaints and increasing customer numbers for the purposes of expenditure forecasting. CitiPower has extrapolated the 20120/21 (expected) capex to derive its forecast for the next RCP. In aggregate, the forecast expenditure is commensurate with expenditure in the current RCP, which seems reasonable.

Overlap with solar enablement initiatives is likely to be small

609. CitiPower states that *'[t]he drivers for these works are fundamentally different, and coupled with the low volumes relative to the total population, the chances of these programs overlapping is minimal.'*[152] Taking into account the four activities that CitiPower assigns to this expenditure classification and the solar enablement program activities, we consider that the extent of overlap is likely to be minimal.

Summary of our assessment

610. We consider that the forecast expenditure for the quality of supply project is likely to be reasonable.

5.8 Zone substation automation

5.8.1 Introduction

611. CitiPower has proposed $16.0m capex in the next RCP in this category, comprising seven projects:

- Digital network: network devices ($5.5m);
- Network communications: 3G shutdown ($3.8m);
- Supervisory modernisation ($3.1m);
- Communication devices: annual program ($1.9m);

151 CitiPower Regulatory Proposal, page 73

152 CitiPower Regulatory Proposal, page 73

- Communication devices: 5-minute settlement ($1.1m);
- Communications monitoring ($0.3m); and
- Fibre upgrades ($0.3m).

5.8.2 Digital Network: network devices

612. This project is discussed as part of our assessment of the 'parent' ICT project in section 7.

5.8.3 Network communications: Telstra 3G shutdown

613. CitiPower has not provided a business case in support of the $3.8m allocated to manage the transition off Telstra's 3G communications network. We have therefore relied on the information provided in Powercor's business case for our assessment – to the extent this is relevant. We therefore refer to VPN wherever practicable.

Overview of project

614. Powercor's business case advises that "*Telstra's 3G communications network will be retired over the 2021–2026 regulatory period to make way for 5G technology.*"[153] Powercor, and by extension, VPN, propose upgrading the devices or components of devices that currently operate on the Telstra 3G communications network.

Our assessment

615. VPN cites advice from Telstra, dated 9 October 2019, that it will shut down its 3G network in 2024. This affects the many 3G devices that VPN uses for its operations. We have ascertained that VPN's advice on the intent and timing of the 3G shut down is consistent with the latest information on Telstra's web site. On this basis, we consider that it is prudent for VPN to depart Telstra's 3G network by 2024.

616. VPN considered three options to address the implications of the impending 3G shut down: (1) do nothing; (2) upgrade 3G control boxes and access points; and (3) develop a communications network using AMI. We consider that a prudent operator would select Option 2 given that, according to VPN's assessment, the NPV is the least negative and has a lower capital cost than Option 3.

Justification for the cost estimate is not as explicit for CitiPower as it is for Powercor

617. Unlike for Powercor, CitiPower has not provided sufficient detail to support the cost estimate of $3.8m. Based on the detail Powercor provided and its approach, we concluded that the Powercor forecast appears to be a reasonable estimate.

618. However, no supporting information was provided by CitiPower. Whilst we would expect the same approach has been used to derive CitiPower's forecast, such that the forecast capex should also be a reasonable estimate, the evidence is absent.

5.8.4 Supervisory modernisation

619. CitiPower has not provided sufficient information to support the $3.1m proposed augex for the next RCP. Given the quantum of expenditure involved, we would have expected CitiPower to present, as a minimum, a business case to help justify its forecast.

5.8.5 Communication devices: annual program

620. CitiPower has not provided sufficient information to support the $1.9m proposed augex for the next RCP. Given the quantum of expenditure involved, we would have expected CitiPower to present, as a minimum, a business case to help justify its forecast.

153 PAL BUS 6.06, page 4

5.8.6 Communications devices: 5-Minute Settlement

621. This project is discussed as part of our assessment of the 'parent' ICT project in section 7.

5.8.7 Remaining projects

622. No information has been provided by CitiPower to support the Communications monitoring or Fibre upgrade projects. We are therefore unable to comment on the prudency and efficiency of the forecast augex.

5.8.8 Summary

623. Of the seven projects comprising this expenditure classification, and in aggregate totalling $16.0m:

- We have relied upon Powercor's analysis of the 3G Shutdown to form a view about what appears to be CitiPower's augex for replacing devices – whilst we consider it would be prudent for CitiPower to take action in the next RCP, CitiPower has provided insufficient basis for the forecast expenditure;
- Two projects are discussed under our ICT section (5-minute settlement and Digital network – network devices); and
- CitiPower has provided no information to support the remaining four projects – consequently we were unable to form a view about the prudency and efficiency of the $5.6m aggregate augex.

5.9 Findings and implications for CitiPower's non-DER augex forecast

AER Focus Projects

624. The AER asked us to assess four Focus Projects:

- Brunswick supply area ($28.7m);
- Port Melbourne supply area ($19.6m);
- Russell Place supply area ($11.2m); and
- the CBD supply area ($25.5m).

625. For each of these projects, we consider that CitiPower has selected the appropriate option.

626. We also consider that the timing of the proposed work to occur within the next RCP is economically justified, with one exception. For the Port Melbourne supply area, CitiPower proposes to offload Port Melbourne substation to Westgate substation in the next RCP. The availability of distribution transfer capacity (not modelled), the current fair condition of the transformers, and the relatively low probability of catastrophic failure of either a transformer or the switchboard, suggests completion of the project in beyond the next RCP may be prudent.

Augmentation of zone substations

627. CitiPower proposes $7.4m augex across five projects in the next RCP in this functional group. Two of the five projects have relatively small forecast expenditure in the next RCP. The other three projects incur augex of more than $1m, however CitiPower has not provided sufficient information to justify the forecast expenditure. Accordingly, we consider that CitiPower has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

LV augmentation

628. There are two augex projects in this expenditure category: Solar enablement ($31.4m); and quality of supply rectification ($8.2m). Our assessment of the Solar enablement project is discussed in section 6. The forecast expenditure for CitiPower's supply quality program is commensurate with expenditure in the current RCP. We consider the forecast to be reasonable.

Zone substation automation

629. CitiPower proposes $16.0m under this expenditure category across seven projects:

- Two projects (5-Minute Settlement and Digital Network – network devices) are assessed in our review of ICT in section 7;
- Telstra 3G shutdown – we consider that the proposed expenditure is likely to be prudent and efficient; and
- We have insufficient information to form a view about the prudency of the other four projects, totalling $5.6m - accordingly, we consider that CitiPower has not sufficiently demonstrated that its proposed expenditure is prudent and efficient.

6 REVIEW OF PROPOSED SOLAR ENABLEMENT EXPENDITURE

In this section, we review CitiPower's proposed expenditure for solar enablement, and which includes expenditure for over 300 LV augmentations and a proposed opex step change for an enhanced compliance program and for LV transformer tapping.

We consider that CitiPower has a reasonable solar enablement strategy involving a combination of compliance measures, transformer tapping and utilising a DVMS that CitiPower proposes to install, before undertaking LV augmentations, as warranted on a case by case basis. However, we consider that CitiPower has not proposed a reasonable forecast of efficient expenditure or justified the requirements for this program.

The large majority of the proposed expenditure is capital expenditure for LV augmentations. In seeking to justify these augmentations, we consider that CitiPower has considerably over-stated the economic benefits, under-stated the inherent uncertainties and has not applied a valid method for determining the timing of its proposed expenditure, including what is viable within the next RCP. We consider that the volume of proposed LV augmentations is not justified within the next RCP and that the majority of the claimed benefits could be achieved from a much smaller program.

We also consider that CitiPower's assumed unit cost for transformer tapping is unreasonably high, as is its proposed compliance program opex step change.

6.1 Introduction

630. CitiPower is proposing a major program, most elements of which are effectively new, to better facilitate increased consumer rooftop solar. Its proposed program is aimed at addressing voltage rise issues caused at the LV level by a combination of reduced net premises demand and increases in premises solar exports into the network at certain times of the day. The main expenditure that CitiPower proposes is for capex to augment the network, however CitiPower also proposes to increase opex on several measures that can mitigate the need for, or extent of, such network augmentation.

6.2 CitiPower's proposed Solar Enablement program

6.2.1 CitiPower's proposed augex

631. CitiPower proposes incurring \$31.5m[154] over the next period for a network augmentation program to enable increased PV to be deployed. This would involve upgrading the network at 319 LV locations, and includes a combination of discrete LV augmentation, new transformers, and some LV augmentation in conjunction with new transformers.

632. As part of its Solar Enablement program and associated Business Case, CitiPower has also proposed ICT expenditure of \$1.1m (un-escalated) for a Dynamic Voltage Management System (DVMS), that will allow remote adjustment of voltages at zone substations. CitiPower has included this expenditure under its ICT forecast. Accordingly, we include this

[154] Excluding real cost escalation

expenditure in section 7 (ICT), but provide our review and advice on this component of CitiPower's proposed Solar Enablement program in this section 6.

Table 6.1: Solar Enablement project – Augex component – $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	6.6	6.0	6.3	6.2	6.3	31.5
Total	**6.6**	**6.0**	**6.3**	**6.2**	**6.3**	**31.5**

Source: EMCa analysis of CitiPower MOD 6.01 (excludes real cost escalation)

6.2.2 CitiPower's proposed operational initiatives and associated opex step changes

633. In addition, CitiPower proposes an opex step change of $1.3m. The majority of this proposed expenditure is to allow for an increased program of manually tapping distribution transformers to help maintain LV distribution voltages within Code[155] limits and to institute a compliance program.

Table 6.2: Solar Enablement Opex Step Change - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Solar enablement	0.4	0.3	0.3	0.2	0.1	1.3
Total	**0.4**	**0.3**	**0.3**	**0.2**	**0.1**	**1.3**

Source: EMCa analysis of 'CitiPower- RIN001 - Workbook 1 - Reg Determination - 31 January 2020' (includes real cost escalation)

CitiPower's transformer tapping program

634. CitiPower proposes a program where distribution LV transformer tap settings are manually adjusted to reduce the voltage profile 'downstream' of the transformer when excessive voltages are identified. CitiPower's modelling of the impact of this initiative is limited by needing to ensure that the LV voltage on the particular section of the network stays within the minimum voltage threshold (defined in the Code). In other words, in responding to high voltages which may occur at some times of the day/week, CitiPower has also sought to ensure that it does not cause undervoltage compliance issues. CitiPower has determined that some transformers are able to be tapped multiple times - this has been allowed for in its model. CitiPower has based the cost of tapping using the average cost per site tapped in 2018.[156]

CitiPower's proposed monitoring and compliance program

635. PV inverter system installers are required to ensure that inverters are set to comply with the requirements of AS4777 and CitiPower's Model Standing Offer which provides for reducing the impact of solar export. It is possible to reset the inverter settings of at least some customers' legacy solar inverters to reduce voltage rises.

636. CitiPower has assumed in its modelling that all new inverter systems are correctly set. Nonetheless, it considers that a monitoring and compliance program is required because '*[b]ased on our own experiences with non-compliance and that of other distributors that have already mandated new inverter settings, without any intervention we expect non-compliance with new inverter settings to be material.*'[157] CitiPower has forecast the monitoring and compliance cost based on the cost to implement remote monitoring and a 5% rate of non-compliance.

[155] Victorian Electricity Distribution Code, Version 9A, clause 4.2.2 (Table 2, Standard nominal voltage variations)

[156] CP BUS 6.02 – Solar enablement, page 34

[157] CP BUS 6.02 – Solar enablement, page 36

6.2.3 Supporting material that CitiPower provided

637. In its submission, CitiPower provided information, evidence, and contextual information relevant to its proposed solar program. We briefly summarise the main content of these documents below:

Material provided with CitiPower's regulatory submission

1. CitiPower's business case (CP BUS 6.02) and associated model (CP MOD 6.02)

In its business case CitiPower describes its assessment of need, the options it has considered, its proposed program and the results in terms of customer impact and the investment amount. This includes a description of CitiPower's stakeholder engagement process, how this has shaped CitiPower's proposed program and mechanisms for managing constraints.

CitiPower's model is a cost benefit model in which it seeks to demonstrate that the PV of benefits of its proposed program exceeds the PV of capital plus operational costs proposed over the next RCP.

2. 'Options Paper' (CP ATT220).

In this paper, published in April 2019, Powercor/CitiPower/United Energy describe background factors driving their consideration of the need for, and form of, a solar enablement program. The paper includes seven options for dealing with the issues, including 'unmitigated tripping', tariff reform and introducing quasi export tariffs as well as describing the option of a solar enablement program.

3. Report from Jacobs on market benefits (ATT054)

This document reports on Jacob's assessment of the market value of solar enablement, and which provides the main value assumption ('$/MWh not constrained') in CitiPower's cost benefit assessment.

4. Profiling uptake of solar PV (Oakley Greenwood) (ATT 004), March 2019

CitiPower has utilised these forecasts in its modelling for cost benefit assessment purposes (refer also to CitiPower's explanation as part of its response to IR041).

5. Other Supporting material provided with Regulatory Submission

CitiPower provided a range of attachments (ATT055, ATT168, ATT169, ATT170, ATT171, ATT172, ATT173). The remainder of such documents are essentially contextual, and include (for example) a Deloitte publication on global renewable energy trends, a media release by the Victorian premier, a letter of support from Geelong Sustainability Group Inc., and the Victorian government's renewable energy action plan.

638. Subsequent to its submission, CitiPower provided further information and claims regarding its proposed program. We summarise these below:

Information and claims subsequent to CitiPower's regulatory submission

CitiPower provided additional information in its presentation to EMCa, with 14 PowerPoint pages devoted to the solar enablement program. CitiPower also provided responses to three Information Requests as follows:

1. *IR020: This responds to an AER IR, and covers the topics of modelling of voltage rises, Volt-Var settings, Customer PV tripping, system average voltage levels, and whether CitiPower had taken account of the future impact of batteries and electric vehicles.*
2. *IR027: This too responds to an AER IR. CitiPower provided sample information on customers' solar voltage enquiries, the basis for the assumed 5kVA export limit, explained why the alternative of a Faraday Exchanger had not been included, explained how it had taken transformer tapping into account in assessing the need for augmentation, explained that it had not undertaken sensitivity analyses and described steps being taken to mitigate inverter settings non-compliance.*
3. *IR041: CitiPower provided a range of information under this heading, including:*
   a. *Derivation of its average tapping cost (of $1,914);*[158]
   b. *A response on compliance drivers, in which CitiPower describes its obligations under the Electricity Distribution Code and Electricity Distribution Licence, and describes and illustrates the impact of solar PV on voltages, and provides evidence on customers' solar voltage enquiries;*
   c. *A response which, amongst other topics:*
      i. *States that analysis of voltage fluctuations requires that analysis to examine short time intervals, noting that it is masked in day/night and longer-term averages and that voltage fluctuations affect both solar and non-solar customers;*
      ii. *Provides a response on consideration of lowering voltages across the network as a means of reducing the impact of solar;*
      iii. *States that while it has not considered the interaction between the solar enablement program and transformers to be replaced under its repex, this impact is minimal;*
      iv. *Contends that it has considered uncertainty by applying conservative benefit assumptions, that there is minimal risk of asset stranding because the augmentations will become net benefit positive well before the 30 year horizon of the analysis;*
      v. *Contends that in considering the analysis time horizon, the AER must adopt that same period for depreciation purposes; and*
      vi. *Clarifies its calculation of PV uptake forecasts and rates, and which includes lowering the uptake percentage from 34% shown in its business case, to 29% of customer (due to using a higher denominator).*

[158] From CitiPower's response to IR041 – Solar Enablement (including table 1 on page 2, and its associated spreadsheet), this figure is assumed to be in nominal $2018

6.2.4 Main elements of CitiPower's justification for its proposed program

Distributed solar penetration and implications for LV distribution networks

639. Increased distributed generation such as from rooftop solar has the effect of raising the voltage at the LV level. Customer solar system inverters which are compliant with AS4777 are set to trip when voltage exceeds set thresholds, in order to avoid over-voltage supply in the LV system to which it is connected, and which can affect surrounding customers.

640. For similar reasons, distribution transformers with voltages set to minimise the risk of over-voltage, may result in under-voltage at times when there is no solar output in a particular LV network. All distributors are subject to voltage tolerance compliance obligations.

641. However, in its Business Case, CitiPower states that while it considers that '…*any approach to enabling solar should contribute towards rather than detract from our Code obligations*,' its primary intended outcome is not targeted at Code compliance.[159]

642. CitiPower's proposed solar enablement program is intended to reduce the extent to which non-compliant voltage occurs and therefore the extent to which exported solar from customers' systems is tripped.

CitiPower's current state and forecasts

643. CitiPower has already undertaken some measures to assist increasing solar penetration by mandating limits on solar PV export to a maximum of 5kW and mandating inverter settings that are compliant with AS4777.

644. CitiPower currently has 4% solar penetration[160] and the network is not currently experiencing significant constraints to solar export quantities. Based on CitiPower's modelling, it still expects that by 2021/22 only a relatively small number of customers' inverters on 7.6% of its LV transformers may experience tripping under certain circumstances sufficient to warrant consideration of LV augmentation[161]. CitiPower expects solar penetration to increase to 24% by 2025[162] and with the increased solar penetration it expects the number of constraints to its network solar PV 'hosting capacity' to lead to an escalating number of PV inverters tripping.

CitiPower's analytical approach to determining future incidence of export limitation issues[163]

645. Using capability derived from its smart grid / smart metering program, CitiPower has assembled information on voltage profiles at the customer level over the day at 15-minute intervals, and determined the extent to which solar is currently constrained on each of its transformers. It has then used its solar forecasts and power flow modelling to model forecast voltage rises on each of its distribution transformers. Based on the time-of-day and season profiles, the model allows it to forecast the solar export MWh that will be constrained off because of excessive voltage rise causing the customers' inverters to trip (no output) or for output to be reduced.[164]

646. CitiPower states that it has sought to find the least cost way to address a constraint by *'…applying smart settings to customers' inverters, implementing a Dynamic Voltage Management System to lower network voltages at high solar export times, 'tapping' down*

159 CitiPower BUS 6.02 – Solar enablement, page 13

160 CitiPower BUS 6.02, page 8. Measured as a percentage of total customer numbers

161 7.6% is based on 319 upgrades divided by 4,200 transformers (CP BUS 6.02, page 19)

162 Ibid, page 8. CitiPower attributes this forecast to advice from Oakley Greenwood

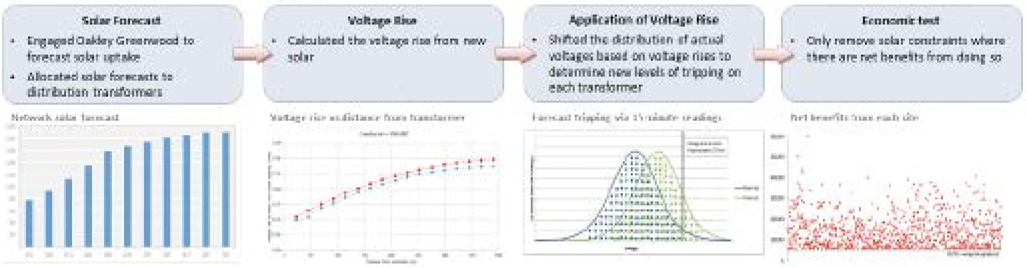
163 Ibid, page 5

164 Newer inverters have the capacity to progressively reduce output at increasing voltage thresholds, but eventually a limit is reached at which the output is reduced to zero

distribution transformer (transformer) voltages and undertaking efficient network investment.'[165]

647. Figure 6.1 illustrates the process that CitiPower has followed.

Figure 6.1: CitiPower's modelling approach to forecasting required capex for solar enablement LV upgrades



Source: CitiPower BUS 6.02 Solar enablement – Jan2020, Figure 3, p.5

648. CitiPower has proposed LV network capex for the sum of LV upgrades (largely transformers) that individually pass its economic test (i.e., with a positive NPV).

CitiPower's economic model

649. CitiPower provided us with material from the model from which it determined the economic justification of its proposed LV transformer upgrades. We summarise the workings of this model as follows:

- For each transformer, for each year from 2021/22 to 2033/34 and for each season within those years (summer/winter/shoulder), CitiPower has forecast the number of solar customers and the amounts of energy (in MWh) for which exports might be curtailed from inverters tripping due to overvoltage;
- CitiPower ascribes a value of $46.71 per MWh as its estimate of the economic value of the lost opportunity to export these volumes. This value is as advised to CitiPower from a study undertaken by Jacobs based on modelling, and comprises Jacob's assessment of the '*reduction in total generation costs (fuel and operating and maintenance costs) and the value of carbon abatement;*'[166]
- CitiPower applies a cost estimate of $94,649 (in $2020) per LV augmentation. This is derived from a weighted average of costs from the 48 such projects that it undertook over 2016 to 2018, and which included a mix of LV augmentation only projects, transformer upgrade only projects, and projects involving combinations of these solutions; and
- From this, CitiPower calculates the NPV of undertaking each potential LV upgrade over a 30 year period using a discount rate of 2.75% and identifies 319 LV networks that it proposes to upgrade, being all such networks for which CitiPower determines a positive NPV from this modelling.

650. CitiPower bases its proposed solar enablement upgrade capex on undertaking these 319 LV upgrades within the next RCP.

6.3 EMCa assessment

6.3.1 Topics considered in our review

651. In our review, we have focused primarily on CitiPower's claimed economic benefits. Of the substantial amount of material that CitiPower has provided, we have accepted the following

[165] CitiPower BUS 6.02 – Solar enablement, page 5

[166] CP ATT054 – Jacobs – Market benefits for solar enablement (15 August 2019)

either as reasonable for the purpose of advising on this component of CitiPower's expenditure allowance, or we have considered it not to be directly relevant to our assessment:

- **Stakeholder engagement:** We acknowledge CitiPower's stakeholder engagement process, and the feedback that CitiPower obtained through this process. Our observation is that CitiPower appears to have considered the options that it presented for consultation as mutually exclusive, leading it to the view that its solar enablement program is the required solution. Over the 30-year period of CitiPower's analysis, we consider it likely that some of the other options that it canvassed might also be adopted and which might act to mitigate the need for the proposed program;
- **PV uptake assumptions:** We have not investigated these beyond the scope of supporting document that CitiPower provided.[167] This appears to be a reasonable and independent source for the value that CitiPower has adopted;
- **Market benefit value:** We have not investigated this beyond the scope of the supporting document that CitiPower provided.[168] This appears to be a reasonable and well-founded source for the value that CitiPower has adopted. In other information that CitiPower has provided, it appears to contradict external advice that was provided for this value. For example, CitiPower compares the economic benefit value to a feed-in tariff calculated by ESC, and claims from this that '*the value of DER that we have used is very conservative*.' While we have not analysed evidence other than what CitiPower has provided and have therefore not analysed the alternative values referred to, we do not see any indication in CitiPower's consultant's report that would position its recommended value as a conservative estimate; and
- **Modelling of voltage impacts of solar:** We have not investigated this beyond the supporting description that CitiPower provides.[169] We consider that the description of load flow modelling in association with the forecast solar uptake rate and CitiPower's AMI data on its network at the individual customer level, is likely to have provided a reasonable basis for such estimation.

652. We have noted CitiPower's descriptions of its obligation under the Electricity Distribution Code, that *'….customers' voltages should not fall outside the range 216-253V for more than 1% of time as measured over one week*.'[170] Also, under its Distribution Licence, CitiPower has an obligation to offer to connect solar[171] and therefore must manage resulting voltage excursions within the parameters of the Code.

653. In the remainder of our review of proposed augex, we have considered the following topics:

1. Uncertainty inherent in the 30-year economic model that CitiPower has used to support its augmentation program;
2. The relationship that CitiPower has claimed, between the 30-year economic assessment horizon and the economic life used for depreciating LV network assets (including transformers);
3. Factors that could lead to the proposed augmentation program being overstated; and
4. CitiPower's assessment of the appropriate timing of each proposed augmentation, including its justification for this taking place within the current RCP.

654. In our assessment of CitiPower's proposed opex step change, we have considered CitiPower's estimated volume of required tapping and its assumed unit cost for this.

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167 PAL ATT 004: Report by Oakley Greenwood

168 PAL ATT055: Report by Jacobs

169 For example, in section B.1.3 of its business case (PAL BUS 6.02)

170 Response to CitiPower IR041, page 1. This in turn references section 4.1 of version 11 of the Code

171 Ibid, page 2

6.3.2 Guiding principles for our review

655. As the use of distribution networks changes, for example through increased distributed generation from consumer-level solar uptake, it is reasonable to expect the networks to adapt to assist with accommodating these changes. In assessing the reasonableness of the proposed program, we have been guided by two principles:

- **Proportionality:** We observe that CitiPower is typically seeking to be able to accommodate between around 40 and 60 PV customers on each LV network. At CitiPower's proposed LV augmentation cost averaging around $95,000 for each such upgrade, these represents a network upgrade investment of around $2,000 per customer. This amount is not insubstantial compared with customers' own PV installation costs. This demonstrates the need to ensure that lower-cost solutions are exhausted, and that each augmentation is individually justified, before proceeding; and
- **Timeliness:** LV upgrades are relatively granular and can be undertaken relatively quickly, when they are required. This makes it possible to undertake augmentations when they are required as measured by information at the time. There is no reason to undertake such investments before they are needed, based on anticipation alone.

656. We consider that principles such as these will guide CitiPower towards the most appropriate actions being taken at the appropriate time to help accommodate distributed solar and to enable customers to achieve the benefits of their own investments.

6.3.3 Review of CitiPower's justification for proposed augex

Analysis period

CitiPower has not adequately considered the uncertainty inherent in seeking to justify capex based on a 30-year analysis of assumed PV export benefits

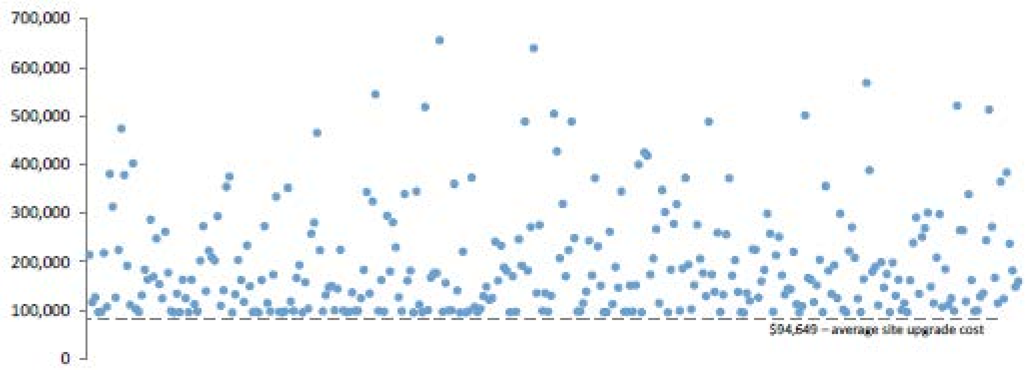
657. Whilst we consider that modelling of both tripped export volumes and individual upgrade economics at the level of granularity that CitiPower has undertaken is a useful approach, we have significant concerns with aspects of this modelling and therefore with the conclusions that CitiPower has drawn from it.

658. Our primary concern is with CitiPower seeking to justify the proposed expenditure based on modelling over a period of 30 years, and with its assumption that the benefits will be as CitiPower has currently estimated, over this period.[172] With a low real discount rate of 2.75%, the model outcomes are highly sensitive to the assumed benefits well into the future, and specifically to their continuation at the level that CitiPower has assumed, out to 2051/52.

659. It is evident from CitiPower's representation of the NPVs of the 319 individual LV network augmentations that comprise the augex component of its program, that a large number of these augmentations have a only a marginally positive NPV under CitiPower's analysis, as can be seen in Figure 6.2 below

[172] CitiPower models these benefits specifically for 13 years to 2033/34, but then assumes that those benefits continue at the modelled 2033/34 level, until 2051/52.

Figure 6.2: CitiPower's representation of the NPV of its proposed 319 LV augmentations

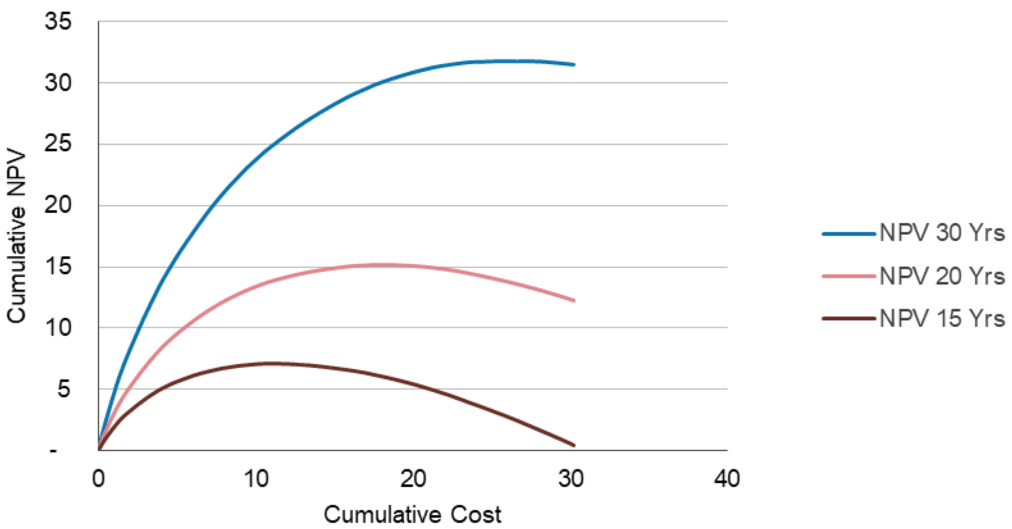


Source: CitiPower BUS 6.02, Figure 11 (The Y axis is the PV of benefits for each proposed upgrade)

660. In Figure 6.3 below, the top line shows the cumulative NPV of each of the 319 LV augmentations that CitiPower has proposed, ordered with the highest NPV augmentations first, based on CitiPower's analysis. There is a clearly decreasing marginal benefit. Our analysis indicates that 88% of the aggregate NPV of the program would be achieved from a program of only half the size of that proposed.

661. We then tested for the sensitivity of CitiPower's result to the time period considered. The lower two lines in Figure 6.3 show the implication of adopting 20-year and 15-year horizons, respectively, for the analysis. With analysis over only 15 years, on the plausible assumption that forecasting beyond that time is too uncertain, only around one-third of the proposed augmentations would have a positive NPV. The remainder of the augmentations would have a negative NPV and in aggregate if all of the upgrades were done, the NPV of the program would be effectively zero.

Figure 6.3: Cumulative NPV of the proposed 319 LV augmentations, over different analysis horizons - $millions



Source: EMCa analysis from CitiPower MOD 6.02

662. We consider it inevitable given the transformation of the energy sector that PV is itself part of, that assumed benefits out to 30 years will be very different from even the best possible estimates made now. In contrast, we observe that CitiPower adopts a 20-year horizon in the economic analysis that it has put forward to justify augex for general load growth, and which would typically be seen as more amenable to forecasting.

663. We consider that seeking to justify a solar enablement augex investment based on a 30-year analysis is at best ambitious, given uncertainties such as:

- The challenges of forecasting the PV uptake rate and the market benefit value over such a 30-year timeframe;
- The strong possibility of technology providing new solutions to managing voltage at some stage over the 30-year timeframe;
- The likelihood of significant further changes affecting demand patterns and demand and voltage fluctuation rates at the LV level, including batteries and EV uptake, at some stage over the 30-year timeframe;
- More refined and more dynamic definitions of the operating envelope for solar exports and how these can be cost-effectively managed; and
- The reasonable likelihood of implementing other measures such as those CitiPower canvassed with stakeholders, including changes to tariff structures and possible further compliance requirements, within the timeframe.

664. It is challenging to build such unknown variables into a forecast. However, we consider that it is essential to recognise the uncertainties in interpreting and seeking to act on the results of numerical analysis involving such a long period, and to recognise the marginal viability of the majority of the upgrades that CitiPower has proposed.

We refute CitiPower's claim that use of a shorter NPV analysis period would imply a position that use of solar would decrease

665. CitiPower has provided further information in its IR responses, relevant to the question of the NPV time-period and uncertainty. We address these points here.

666. CitiPower has stated that '…*If the AER seeks to reduce the NPV due to the uncertainty of DER in the future under our modelling approach, the AER would need to conclude that the use of solar will decrease in the future, not only that solar exports will decrease.*'[173]

667. We refute this statement – it is not axiomatic that adopting an NPV analysis period shorter than CitiPower has proposed implies a view that the use of solar will decrease. We have described above why it would be reasonable to adopt a shorter analysis period than CitiPower has adopted. None of these reasons rely on an assumption of decreased solar.

We do not accept CitiPower's argument that the NPV analysis period must equal the depreciation life of the relevant asset

668. In any situation that involves decision making under uncertainty, there is an option value to deferment. This implicitly recognises that a decision made today (including a decision not to augment) is not necessarily the decision that will be indicated at every point in future, but that the decision will be better informed and, therefore, if it can be reasonably delayed, a better-justified decision is likely with lower chance of regret. While a decision to augment now may not be justified, there may be a time when a decision to augment is clearly indicated at some time in the future. Equally, there may be a time when, for whatever reason, it becomes clear that a decision to augment is unlikely ever to be justified, because alternative and preferred options have arisen with time, or the need has changed.

669. CitiPower asserts that '….*if the AER considers network assets to enable solar only offer benefits over a shorter period, in accordance with the Rules it must depreciate these assets over a shorter life*.'[174] CitiPower has then extended this argument to suggest that the shortened depreciation period would lead to higher network prices resulting from its SE program.[175]

670. In its response, CitiPower reproduces Clause 6.5.5 of the NER in part as follows:

> *(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements; and*

173 Response to CitiPower IR041 – Solar Enablement, 3 July 2020, response to question 7

174 Ibid, page 11

175 Ibid, page 12

(a) (1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.

671. We consider that CitiPower has misrepresented this clause, the purpose of which is to define a basis for establishing depreciation schedules. It does not prescribe how economic analysis to justify an investment should be undertaken.

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

673. Regulatory depreciation schedules relate to the economic life of an asset, irrespective of the time horizon or any aspects of the decision made in deciding whether (for example) to augment or replace an existing asset. We consider it both incorrect and somewhat of an ambit claim for CitiPower to suggest that by using a shorter timeframe in cost benefit analysis to justify augmentation, it would be necessary to apply shorter regulatory depreciation lives for the relevant assets and that this would therefore result in higher prices to consumers.

Assumptions and Sensitivity analysis

We refute CitiPower's claim that sensitivity analysis is unnecessary

674. In response to an IR, CitiPower states that it has '…*not undertaken formal sensitivity analysis…*'. CitiPower then explains that its model is '…*insensitive to augmentation cost – if the augmentation cost increases/decreases then the number of transformers than(sic) meet the economic test conversely decreases / increases*.'[176]

675. This seems to be a direct statement that the resulting number of justified upgrades is in fact sensitive to the augmentation cost, which is as we expect and as we find in the model, while noting the higher cost per upgrade. In fact, we find that the program is highly sensitive to cost. By inspection of CitiPower's scatter graph in Figure 6.2, it can be seen that raising the cost by 10% would render the large number of marginally-positive NPV augmentations negative. Inspection of Figure 6.3 similarly shows the significant number of transformer upgrades (as measured along the X axis) that would not meet a 10% lower NPV threshold, such as would result from a higher unit cost per LV upgrade.

676. Particularly, with a forecast over 30 years, all assumptions and all aspects of CitiPower's forecast have varying degrees of uncertainty. We consider that some factors have significant uncertainty and that the results are sensitive to the assumptions made for those factors. CitiPower's case is weakened by the lack of such sensitivity analysis, and by its claims that this is unnecessary.

CitiPower has not justified its claim that its assumptions are conservative

677. CitiPower claims to have been '*very conservative in valuing the benefits of* (its) *solar enablement program'*.[177] In presenting this claim:

- CitiPower states that it considers that the value of DER that it has used is conservative; yet this value is as recommended by CitiPower's advisor – Jacobs. Jacobs' report does not position this as a 'conservative' value, and it appears disingenuous for CitiPower to

[176] CitiPower's repose to IR027, question 5, page 3

[177] Powercor/CitiPower presentation to AER and EMCa, 1st June 2020 (page 63). The points that CitiPower makes on that presentation page are a precis of points made in its response to CitiPower IR041 – Solar Enablement, question 7

suggest that its advisor has not provided it with a reasonable estimate, especially given that CitiPower has used it as such;

- CitiPower states that '…*varying the value of DER in our model would only serve to expand the program.*'[178] CitiPower seems to have taken the position that it would not undertake a symmetrical sensitivity analysis;
- CitiPower has assumed 100% compliance with new converter settings. This appears to be a reasonable assumption insofar as it should not be for CitiPower to assume responsibility for undertaking augmentation investment, which brings costs to all consumers, in order to redress non-compliance by another party; and
- CitiPower states that it '*has not valued additional customer benefits from solar including retail and wholesale arbitrage opportunities, wholesale market support, transmission and distribution congestion management*.'[179] These are general claimed benefits of solar and their link to CitiPower's proposed augmentations is tenuous. CitiPower's case is based on addressing voltage issues and the occasional limit that this may place on solar exports in a small proportion of its LV networks at some point in the future. To take factors such as these into account, CitiPower would need to be able to demonstrate a counterfactual 'lost opportunity' and the extent to which it is remedied by its proposed program.

678. Against these points, we consider that there are other aspects of CitiPower's modelling that could be considered to overstate the case. Examples could include enhanced operational solutions, the possibility that increased solar does depress wholesale prices at the times that it provides export, just as it has significantly reduced the shape of middle-of-the-day demand profiles, future technology solutions, and the inherent uncertainties in forecasts (such as PV uptake, for example).

679. In summary, we consider that there are various alternative assumptions, some positive and some negative, that could be applied and for which analysis results could be stress tested.

We refute CitiPower's claim that there is not a material risk of 'stranded' investment

680. If the LV augex investments are made as proposed by CitiPower, many of these have only a marginal net benefit on a 30-year analysis basis with CitiPower's assumptions. For reasons that we have stated above, we consider that there is a material risk that the assumed 30-year benefits could be less than CitiPower has assumed. With so many of the augmentations being economically marginal, it would take only a small decrease in a 'benefit' assumption or a foreshortening of the benefits stream, for all of those with only a marginally positive NPV to return a negative NPV, resulting in a 'regret' outcome where the augmentation was not justified.

681. CitiPower has claimed that '…*the augmentations we have proposed will become net benefit positive well before the time shown in the model and before 30 years*'; also that it has '…*already implicitly factored in uncertainty*' through '*conservative modelling*'.[180]

682. As we have shown in Figure 6.3, when we shorten analysis periods, a large number of the proposed augmentations have a negative NPV. We also do not accept the proposition that uncertainty is accounted for by CitiPower adopting conservative assumptions. Even if conservative assumptions have been adopted, there is a range of techniques available for modelling such analysis under uncertainty, with sensitivity analysis and scenario analysis being two of the more basic techniques that can be applied.

683. If solar enablement augmentations are 'justified' on the basis of assumptions forecast over 30-years, without proper consideration of the uncertainties of what will arise over this period, then we consider that there is a material risk of those augmentation investments turning out to have not been required.

[178] Response to CitiPower IR041 – Solar Enablement, page 9

[179] Powercor/CitiPower presentation to AER and EMCa, 1st June 2020 (page 63)

[180] Ibid

Time profile and justification within the next RCP

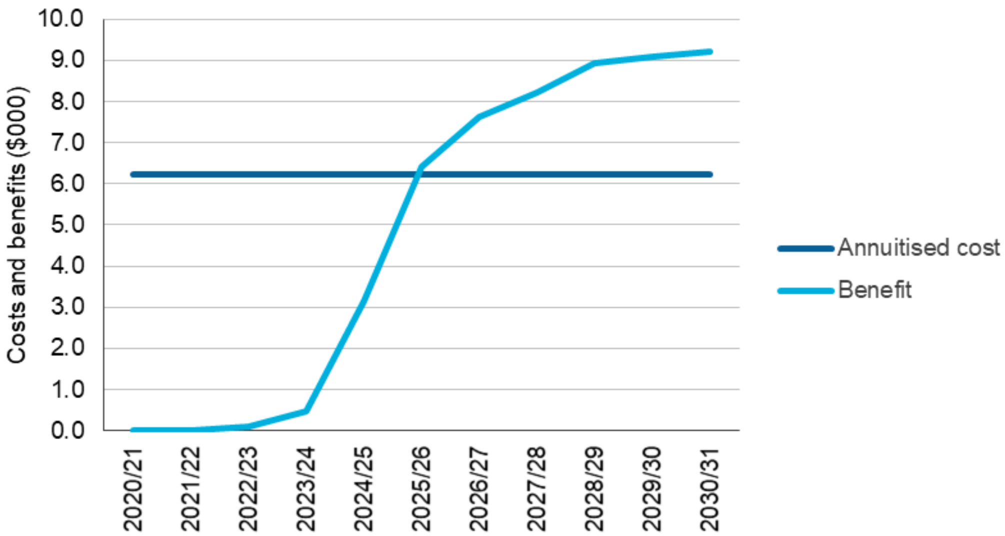
CitiPower has misapplied analysis to forecast the time profile of its expenditure

684. For its solar enablement analysis, CitiPower has sought to determine a time-profile for its proposed augmentation expenditure based on the year (for each of the 319 proposed LV augmentations) when its CBA model first produces a positive NPV. This is erroneous, and also inconsistent with the method that CitiPower has applied in seeking to determine the appropriate timing for other augex. The approach that CitiPower has applied for its proposed solar enablement augmentations has the effect of bringing forward augmentations when they are still uneconomic, but which in CitiPower's analysis have a positive NPV only because their forecast of distant future positive net benefits is offsetting the still negative net benefits within the RCP.

685. We consider the correct approach is to identify when the annual benefits exceed the annual cost, in this case (in the absence of incremental opex) being represented by the annuitised cost of the upgrade being considered. There is no benefit in undertaking such augmentations before this time. Examples of where CitiPower has applied this approach are illustrated in Figure 5.3 and Figure 5.4, and for other augex projects in that section.

686. In Figure 6.4 we show an example of this methodology applied to a specific LV transformer from CitiPower's solar enablement analysis. In this case, it indicates that an upgrade would be warranted in 2025/26, based on CitiPower's benefit assumptions including its forecast PV uptake rate for customers connected to that transformer.

Figure 6.4: Annuitised cost and modelled benefits for one of CitiPower's proposed transformer upgrades[181]



Source: EMCa analysis from CP MOD 6.02. The upgrade cost in this example is annuitized over 20 years.

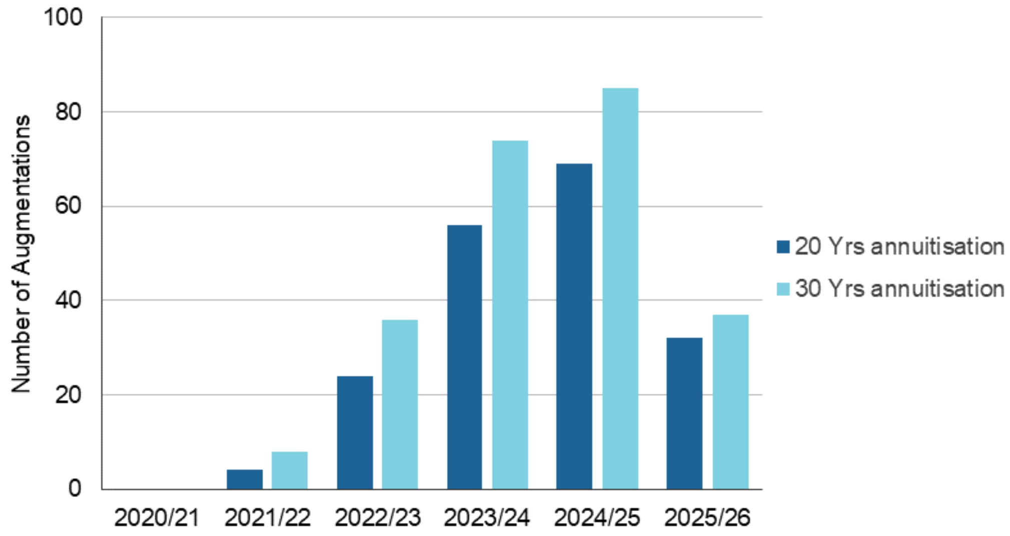
687. When we apply this method to all 319 of CitiPower's proposed augmentations, we find a profile of augmentations as shown in Figure 6.5. We have undertaken this analysis with augmentation costs annuitised over 30 years, as per CitiPower's assumptions, and an alternative forecast in which the cost is annuitised over 20 years.

688. A very small number of augmentations are indicated for the early years, which is as we would expect given CitiPower's very low current PV penetration. If the uptake rate and other benefit assumptions are as CitiPower has forecast, our analysis suggests an increasing trend of augmentations at least to 2024/25. However, our analysis also shows that under CitiPower's cost and benefit assumptions, only 240 of its proposed 319 augmentations would be viable. Further, if a 20-year annuitisation period is adopted (consistent with

[181] The modelled transformer in this example has CitiPower's designated ID 95445306-013

CitiPower's non-DER augex justifications), then only 185 augmentations would be viable within the next RCP.

Figure 6.5: Augmentation profile indicated by identifying year when benefits exceed costs



Source: EMCa analysis from CP MOD 6.02

Table 6.3: Implied annual expenditure profile based on indicated timing for each transformer - $m, real 2020

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
20 years annuitisation	0.4	2.3	5.3	6.5	3.0	17.5
30 years annuitisation	0.8	3.4	7.0	8.0	3.5	22.7

Source: EMCa analysis from CP MOD 6.02

689. We note that the analysis above considers the proposed augmentations solely from the point of view of timing both within the next RCP and beyond. It does not supplant our consideration also of assumptions and uncertainties as described in the preceding subsections.

690. When compared with CitiPower's proposed expenditure from Table 6.1, this analysis suggests that from a timing perspective alone, only around two-thirds of the proposed augmentations would be justified within the next RCP. Moreover, unlike the relatively flat expenditure profile that CitiPower has proposed, the expenditure would be weighted towards the middle to later years of the RCP. This is advantageous from a decision-making perspective, as it means the expenditure can be incurred when it is needed and not in anticipation of a need that may or may not arise for a particular LV network.

6.3.4 Findings and implications on proposed augex

A smaller program of LV augmentations is likely to be required within CitiPower's package of solar enablement measures

691. In the context of significant uncertainty, we observe that from CitiPower's modelling, nearly 90% of the estimated benefits would be achieved from a program that involves only addressing the top 50% of LV augmentations if ranked in order of descending NPV. This rapid fall-off in incremental benefit with increasing scale of the proposed project, can be seen in Figure 6.3. It is also evident in the large number of projects with NPV close to the X axis in CitiPower's own diagram in Figure 6.2.

692. We are struck by the scale of CitiPower's proposed program, with 319 LV upgrades proposed from 2021/22 to 2025/26, relative to 48 similar upgrades that it undertook in the

three years from 2016 to 2018.[182] While we understand that the need 'accelerates' with increasing PV penetration on a given LV network, this is nevertheless a large increase.

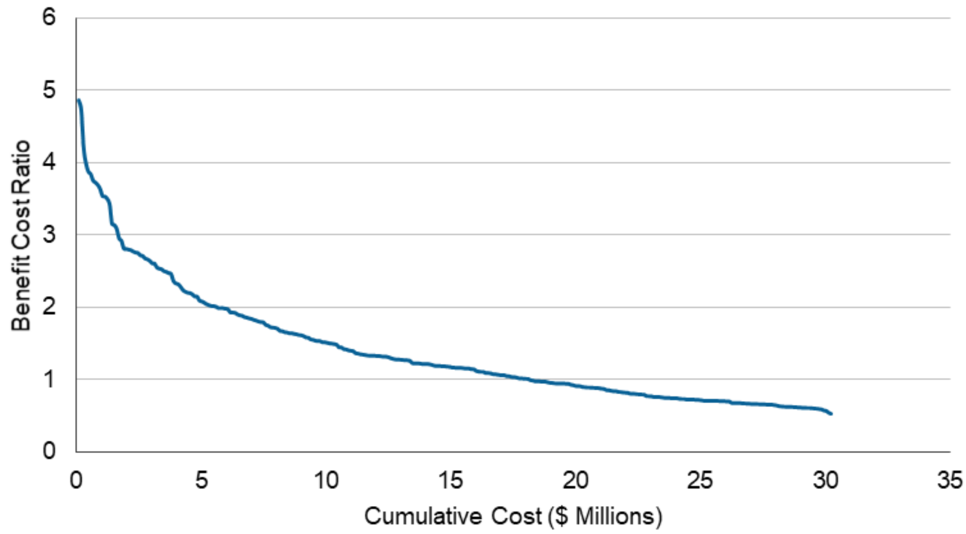
693. We also observe the current very low PV penetration rate of 4% on the CitiPower network compared, for example, to a penetration rate of around 30% in Queensland. Victoria also has a lower solar insolation rate than Queensland. CitiPower's forecast of 24% solar penetration by 2025/26 would seem to provide the opportunity for CitiPower to compare what it proposes, with what Queensland DNSPs have already done to efficiently enable increased solar penetration on their networks.

694. CitiPower's strategy involves LV augmentation only after seeking to address issues through customer installation compliance, use of its DVMS, and tapping. With a realistic technical/economic appraisal for each relevant LV network over the course of the next regulatory period, we consider that CitiPower will find that considerably less LV augmentation expenditure is justified.

A program of around 60 to 100 upgrades over the next period, would appear to provide a justifiable degree of solar enablement benefit

695. As an indication, we have re-expressed the CitiPower cost benefit analysis in terms of Benefit/Cost (B/C) ratio with a 20-year horizon. A B/C ratio of one reflects the threshold for a positive NPV. Given the uncertainties even with a 20-year analysis, we consider that a prudent allowance would be to assume a threshold B/C ratio around 1.5 to 2.0 and allow expenditure sufficient for projects that appear to exceed this threshold.

Figure 6.6: Ranked Benefit/Cost ratio of 319 LV upgrades (20-year analysis)



Source: EMCa analysis from CP MOD 6.02

696. This would imply reasonable justification for a program involving around 20% to 30% of the augex that CitiPower has proposed. This would represent around 60 to 100 LV augmentations over the period, compared with the 48 LV augmentations that CitiPower undertook from 2016 to 2018.

182 PAL MOD 6.02, tab 'Aug cost'

6.3.5 Review of CitiPower's justification for enhanced operational initiatives and proposed opex step

Indications of current PQ issues

Customer feedback does not indicate a systemic PQ issue with CitiPower's LV network

697. Whilst CitiPower reports that 75% of customers support network investment and 'modernising' the grid with new technologies, it also reports that:[183]

> *'our residential customers are generally satisfied with our existing reliability and power quality levels…'*

698. Despite CitiPower reporting an increase in voltage-related enquiries over the last four financial years, CitiPower's information suggests that just over 200 complaints were made in 2018/19, from its total of around 330,000 customers. While there may be localised pockets with voltage-related issues, there does not appear to be widespread dissatisfaction with power quality.

Tapping program

CitiPower's strategy of exploiting the benefits of tapping before applying network solutions is appropriate

699. Manually tapping distribution transformers is a recognised technique for responding to changes in voltages in the LV network over time. It is already a technique that CitiPower applies to deal with PQ issues. It is a relatively coarse, manual adjustment and it does not provide a dynamic response to voltage changes over the course of a day (i.e., with varying net load demand from customers and with varying levels of distributed generation). However, it is a relatively inexpensive means of improving the hosting capacity of an LV feeder or section of feeder. We therefore endorse CitiPower's proposed strategy of employing manual tapping of distribution transformers.

CitiPower's estimated volume of tapping is likely to be reasonable

700. CitiPower's modelling of the opportunity for voltage profile adjustment using tap changing results in a forecast of 361 manual tap changes in the next RCP. The proposed number of tap changes is highest in 2023/24 (100) and lowest in 2025/26 (45).[184]

701. This profile is counterintuitive given that we would expect voltage rise issues to increase over time, at an increasing rate, with increasing PV penetration levels. However, we understand that CitiPower's model is based on identifying localised constraints and this may explain why the year in which the model predicts the highest number of extra tap changes being required is followed by years in which lower numbers are required.

702. We assume that this program represents the total number of tap changes that can be proactively made to increase hosting capacity in the next RCP. This means that it supplants the number of tap changes currently made under its complaints-driven power quality program discussed in section 5.7.2.[185]

703. Given that we consider CitiPower's modelling of voltage rises and constraints to be a reasonable approach, we consider that it is likely that the number of tap changes that can be applied in the next RCP to increase PV hosting capacity is likely to be a reasonable estimate.

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[183] CitiPower Regulatory Proposal, p61

[184] CP MOD 6.02 – Enabling solar

[185] CitiPower provided information that it undertook 205 tap changes in the five years from 2015 to 2019, though CitiPower also refers to uncertainties in its measurement of this number (CitiPower response to IR041)

CitiPower's unit cost for tapping appears to be relatively high

704. CitiPower has based its unit cost on analysis of its tapping costs in 2018. It is appropriate for CitiPower to apply recent revealed costs if the revealed costs are demonstrably efficient. However, at $1,995 per unit, CitiPower's unit cost is significantly higher than United Energy's $1,563/unit[186] and AusNet Services' $865/unit.[187] We are not aware of any reasons to explain the significantly higher unit cost at CitiPower/Powercor.

705. In our view, CitiPower's unit cost is unjustifiably high and expenditure commensurate with a unit cost under $1,000 per unit would represent an efficient level.

Monitoring and compliance program

CitiPower's monitoring and compliance program as proposed is not a justified step change

706. CitiPower has a right to require a consumer to only connect inverters that are compliant with its MSO and AS4777. If it appears that an inverter is not compliant, CitiPower is within its rights to require the customer to rectify the non-compliance. CitiPower proposes to spend $141k over the next RCP to establish and maintain a monitoring program, plus a further $319k over the next RCP to address non-compliance.[188]

707. We are satisfied that if a non-compliance is detected, correction of the settings is likely to be a relatively cost-effective means of helping to limit the effects of PV export voltage rise. We are not convinced that CitiPower:

- has explored cost effective options for proactively ensuring installers apply the correct inverter settings;
- has explored cost effective options for identifying and addressing events of non-compliance; and
- requires a separate program to its business-as-usual Power Quality program (reactive rectification of PQ issues in response to customer complaints).

Links to CitiPower's proposed ICT initiatives

CitiPower's proposed DVMS is a prudent initiative

708. CitiPower has included the introduction of a Dynamic Voltage Management System as an ICT initiative at an estimated capital cost of $1.1m. It provides the capability to '*remotely and dynamically adjust voltages at the zone substations, meaning we can lower voltages at peak solar times and then increase them again later.'*[189]

709. We support the initiative and consider that the cost estimate is likely to be reasonable, for the following reasons:

- A DVMS has recently been implemented within United Energy's network and, according to United Energy, has worked effectively to increase solar hosting capacity;[190] and
- CitiPower has based its cost estimate on the United Energy revealed costs.[191]

We have considered the link to the Digital Network initiative in our ICT assessment

710. CitiPower has noted linkages and dependencies between its Digital Network initiative[192] and its Solar Enablement program. Specifically:

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186 UE MOD 6.02

187 AusNet Services response to IR049

188 CP BUS 6.02, Table 10, page 39

189 CP BUS 6.02, pages 20-21

190 UE BUS 6.02, page 21

191 CP BUS 6.02, Appendix C, page 38

192 The business case for Digital Networks is included in CP's Information and Communication Technology (ICT) category

- In its modelling of constraints to PV export, CitiPower assumes that solar connections will be balanced across phases; and
- CitiPower also proposes in its Digital Networks business case '*building the foundations*' to dynamically control customers' PV system inverters, which requires what it calls a Distributed Energy Resource Management System (DERMS).[193]

711. We have considered these linkages in our assessment of CitiPower's ICT expenditure forecast in section 7.

6.4 Implications to CitiPower's proposed solar enablement augex and associated opex step change

712. Based on the information available to us at the time of preparing this report, we consider that CitiPower has not sufficiently demonstrated that its proposed expenditure forecast for its solar enablement program is prudent and efficient.

713. We have identified a number of issues associated with the capital and operating expenditure proposed by CitiPower in preparing the expenditure proposed to economically reduce the constraints on solar export in the next RCP.

714. We consider that:

- CitiPower has not adequately considered the uncertainty inherent in its assumed benefit stream from mitigating solar export constraints over time, leading it to: (i) overstate the reasonably expected benefit; and to (ii) overstate the reasonably justified extent of network augmentations;
- CitiPower has appropriately identified introduction of a DVMS as a cost-effective means of increasing solar hosting capacity and we are satisfied that the cost is likely to be a reasonable estimate;
- CitiPower has appropriately identified transformer tapping as a relatively inexpensive initiative to mitigate over-voltages prior to network augmentation – however, we are not satisfied that the unit cost of proposed tap changes has been adequately justified; and
- CitiPower has appropriately identified rectifying non-compliant inverter settings as a sensible precursor to investing in transformer tapping or network augmentation – however, we are not satisfied that the proposed opex step change to reactively address non-compliant inverters at CitiPower's expense is the most cost-effective approach.

193 CP BUS 6.02 Solar enablement, page 17

7 REVIEW OF PROPOSED ICT EXPENDITURE

In this section, we present our assessment of forecast ICT capex for the next RCP and of CitiPower's proposed opex step change for the migration of ICT infrastructure to the cloud.

Our assessment of the projects that the AER asked us to focus on leads us to conclude that, in each case, the proposed expenditure is likely to be overstated compared with the level of expenditure that a prudent and efficient operator would incur.

For non-recurrent benefits-driven projects, we found issues with the claimed benefits based on what we consider to be overstated assumptions, particularly given the uncertainty of the duration over which the benefits will be realised. We undertook sensitivity analyses with what we consider to be more reasonable assumptions. Based on that analysis, we conclude that there are several cases in which the proposed expenditure is unlikely to satisfy the capex criteria.

For recurrent (end-of-life driven replacement/upgrade projects), we found some cases in which CitiPower has provided insufficient justification for the proposed level of expenditure.

We consider that the proposed opex step change to account for the increase in hosting charges resulting from the transition of ICT infrastructure to the cloud is reasonable.

7.1 Introduction

715. We reviewed the information provided by CitiPower to support its proposed ICT forecast, including the business cases. Our focus is to ascertain the extent to which the issues identified in our assessment of CitiPower's expenditure governance, management and ICT forecasting methodologies are evident at the project/activity level and to assess the extent to which the forecast expenditure is likely to meet the NER criteria.

716. The AER identified two 'Focus' projects to us. Accordingly, we have included these projects in our assessment of the proposed ICT forecast within the relevant category of expenditure, as denoted below:[194]

- ICT infrastructure cloud migration ($10.8m capex and $2.3m opex step change);
- Network Management Systems ($8.5m).

717. Following discussion with AER, we also paid particular attention to the following additional projects:

- Customer enablement program ($3.5m);
- SAP S/4 HANA ($12.9m);
- Digital Network ($11.1m); and
- Intelligent Engineering ($4.4m).

194 The expenditure amounts shown are the allocation to CitiPower – the business cases consider total costs

718. Victoria Power Networks has a common ICT governance, management and forecasting approach that is applied to ICT programs and expenditures by CitiPower and Powercor. All of the CitiPower ICT business cases are presented as joint CitiPower/Powercor business cases, with allocation of the total cost of the initiative to each entity on proportions that vary between projects. In some cases, the business case provided in support of the project includes the total expenditure applicable to CitiPower, Powercor and United Energy – again with apportionment of the total cost between the three entities. In the assessment of individual projects below (commencing in section 7.4), we identify which DNSPs share the total costs and the method of apportionment.

7.2 Summary of CitiPower's proposed ICT expenditure

7.2.1 Overview

719. CitiPower has proposed $96.1m for ICT capex for the next RCP, at an average annual expenditure of $19.2m. In the table below we show ICT capex by RIN Category including real cost escalation.

Table 7.1: CitiPower's ICT expenditure by RIN category- $m, real 2021

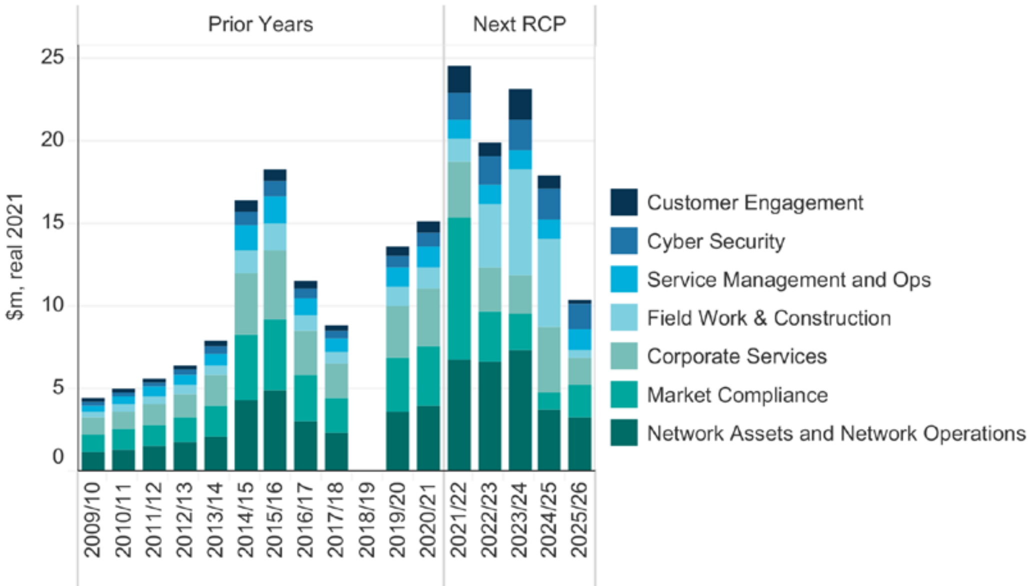
Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Corporate Services	3.3	2.7	2.3	3.9	1.6	13.9
Customer Engagement	1.7	0.8	1.9	0.8	0.3	5.4
Cyber Security	1.7	1.7	1.9	1.8	1.5	8.6
Field Work & Construction	1.4	3.9	6.3	5.4	0.5	17.5
Market Compliance	8.6	3.0	2.2	1.0	1.9	16.8
Network Assets and Network Operations	6.7	6.7	7.4	3.8	3.3	27.8
Service Management and Ops	1.2	1.2	1.2	1.2	1.2	6.1
Total	**24.6**	**19.9**	**23.2**	**18.0**	**10.4**	**96.1**

Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

7.2.2 ICT capex trend

720. ICT Capex trends over time, by RIN Category, have been generated from the forecast RIN and the Historical Recast RIN (Workbook 8) in Financial Years. Forecast expenditure has been inflated to Real 2021 dollars and includes CitiPower's proposed real cost escalation.

Figure 7.1: CitiPower's historical and forecast ICT capital expenditure - $m, real 2021



Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'

7.2.3 Observations from ICT capex trend

721. The proposed ICT capex for the next RCP is an increase from the historical trend, with increases in several of the RIN groups. The largest increases are to Market Compliance (in 2020/21), Network Assets and Network Operations (in all years), and Field Work and Construction (in the middle years).

7.2.4 ICT projects categorised as Recurrent / Non-recurrent

722. The table below shows the project-level expenditure according to the Recurrent and Non-recurrent expenditure classifications. This table excludes real cost escalation.

Table 7.2: CitiPower's project-level expenditure allocated to Recurrent and Non-recurrent classifications - $m, real 2021

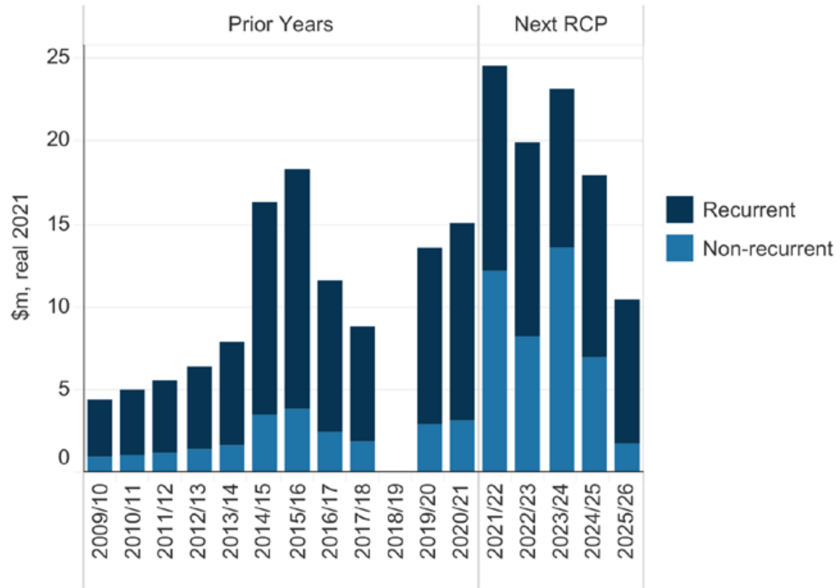
Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Recurrent	**12.3**	**11.3**	**9.3**	**10.4**	**8.0**	**51.3**
Focus						
Infrastructure with Cloud migration	2.8	2.3	1.9	2.5	1.4	10.8
Network Management	2.3	2.1	0.6	1.7	1.9	8.5
Other						
BI/BW	0.1	0.7	0.2	0.1	0.1	1.1
Customer Enablement	0.1	0.3	0.8	0.1	0.1	1.6
Cyber security	1.2	1.2	1.3	1.2	1.0	5.8
Device replacement	1.2	1.2	1.2	1.2	1.2	5.8
Enterprise Management Systems - Non-SAP	1.4	0.9	0.6	1.4	0.1	4.4
Facilities' security	0.5	0.4	0.3	1.2	0.1	2.6
General compliance	0.9	0.9	0.9	0.9	0.9	4.6
Market Systems	0.4	0.4	1.2		0.8	2.8
SAP S/4HANA	0.4	0.7			0.4	1.6
Telephony	1.0	0.3	0.3		0.1	1.7
Non-recurrent	**12.0**	**8.0**	**12.9**	**6.6**	**1.6**	**41.2**
5 Minute Settlements	7.2	1.6	0.0	0.0	0.1	8.9
Customer Enablement	0.5	0.1	0.7	0.6		1.9
Cyber security	0.5	0.5	0.5	0.5	0.4	2.5
Digital network	2.8	3.2	3.1	0.9	1.2	11.1
Intelligent engineering		0.9	3.1	0.5		4.4
SAP S/4HANA		1.8	5.4	4.1		11.3
Solar enablement DVMS	1.1					1.1
Grand Total	**24.3**	**19.4**	**22.2**	**17.0**	**9.7**	**92.5**

Source: EMCa analysis of CitiPower MOD 7.01. Excludes real cost escalation

7.2.5 ICT Capex trend by Recurrent/Non-Recurrent expenditure classification

723. The trend of ICT capex by Recurrent / Non-recurrent expenditure classification is shown in the following chart. It shows that Non-recurrent expenditure is a major contributor to the proposed uplift in ICT capex in the first four years of the next RCP. The reduced level of expenditure in 2025/26 results from the conclusion of most of the Non-recurrent projects and tailing off of Recurrent expenditure in large projects such as Enterprise Management Systems and Facilities Security.

Figure 7.2: Expenditure by Recurrent/Non-Recurrent - $m, real 2021



Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020', 'CitiPower - RIN008 - Workbook 8 - Historical FY CAT - 31 January 2020'. (CitiPower also provided historical data in Workbook 2. That data is in calendar years. While CitiPower claims that the Workbook 2 data reflects AER's new definitions, we observe that the ratio of recurrent to non-recurrent expenditure in Workbook 2 is identical to that presented under the old definitions, per Workbook 8, and is also identical for each historical year)

7.2.6 Proposed ICT opex step change

724. CitiPower has proposed an opex step change associated with its proposed cloud migration project. The proposed expenditure is shown in the table below and includes real cost escalation.

Table 7.3: CitiPower ICT – Related Opex step change - $m, real 2021

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
IT Cloud Solutions	0.3	0.3	0.5	0.6	0.6	2.3
Total	0.3	0.3	0.5	0.6	0.6	2.3

Source: EMCa Analysis of 'CitiPower - RIN001 - Workbook 1 - Reg Determination - 31 January 2020'

7.3 Assessment of CitiPower's ICT forecasting methods

725. CitiPower and Powercor's ICT forecasting methodologies are consistent. In this section, we refer to CitiPower only.

7.3.1 Overview of CitiPower's ICT forecasting methodology

726. CitiPower describes its forecasting approach for ICT capex to '*only invest in ICT when there is a clear benefit to customers.*'[195] We summarise the approach described in its Regulatory Proposal as having:

- Assessed whether the existing ICT capabilities and services are no longer providing value to customers;
- Examined '*synergy opportunities*' to integrate ICT systems with United Energy;

195 CitiPower, Regulatory Proposal 2021-2026, page 87

- Considered whether existing systems can withstand maturing and emerging cyber-security threats;
- Forecast the efficient level of investment needed to retain the effectiveness and security of existing capabilities;
- Considered whether new technologies can address '*key business requirements'*; and
- Tested '*new projects with customers and other stakeholders to ensure we prioritised our investments in areas customers most value'*.

727. CitiPower also describes that it has subjected its ICT portfolio forecast to a top-down challenge:[196]

> *'We engaged PwC Australia (PwC) to assess whether individual projects could be better prioritised or delivered more efficiently in order to optimise value for our customers'.*

728. To inform the selection of ICT investments, CitiPower advised that it:[197]

- Applied a deterministic risk-based framework to '*help quantify whether a projects risk outweighs its expected cost*', considering ICT risk and business risk using its risk monetisation approach; and
- Determined expenditure at a granular level, applying unit costs based on past projects of a similar scale and complexity, using external labour rates and known vendor costs, and seeking external validation.

729. CitiPower's project delivery framework is described as comprising the common industry approach of initiation, scoping, design and execution phases with approval gates as milestones.[198]

Cost estimation methodology

730. CitiPower describes its cost estimation methodology as follows:[199]

> *'cost estimates are developed by our internal project delivery leads who are SMEs for the group of systems. SMEs develop costs taking account of experience with historical projects of a similar nature, size, scale, scope and complexity.'*

731. The table below summarises the input parameters applied by CitiPower in developing its cost estimates.

196 CitiPower, Regulatory Proposal 2021-2026, page 89

197 CitiPower, Regulatory Proposal 2021-2026, page 89

198 CitiPower, ATT007, Figure 1, page 3

199 Powercor/CitiPower response to IR023, question 16

Table 7.4: Input parameters for ICT capital expenditure

Component of cost	Description
Labour rate	Blended IT labour rates developed by PWC. Cross-checked against internal aggregate labour rate. Labour resource is outsourced through our IT supplier panel and our IT resource partners selected through competitive tendering processes
Labour hours	Hour incurred for like projects of similar nature, size, scale, scope and complexity
Contracts	Vendor charges for like projects of similar size and complexity, or specific quotes where available
Materials	Current unit rates or supplier quotes

Source: Powercor/CitiPower response to IR023, question 16

7.3.2 Assessment of CitiPower's ICT forecasting methodology

732. CitiPower's overall forecasting methodology, including its cost-estimation methodology, is the same as Powercor's and we consider it to be reasonable. However, we observed issues with the application of the methodology to individual projects in some cases, particularly the assumptions underpinning the:

- Claimed benefits; and
- Its risk analyses.[200]

733. We also note apparent inconsistencies in product refresh strategies which lead in some cases to a seemingly high frequency of upgrades that are not adequately explained.

734. We discuss each of these concerns below and in our observations regarding the proposed expenditure in individual projects (starting with the Digital Networks project in section 7.4.2).

Benefits-modelling can be biased towards over-estimation of benefit streams

735. CitiPower has obviously devoted considerable effort in modelling the costs and benefits associated with its benefits-driven ICT projects, such as Digital Networks, Customer Enablement, and Intelligent Engineering.

736. However, in our view, CitiPower's modelling assumptions appear to be biased towards over-estimation of benefits. For example:

- Several critical input assumptions are hard coded and not adequately explained – such as the assumed number of Energy Easy portal users over the duration of the next RCP that will access the portal on average 4 times per year - the assumed benefit stream from reducing time spent by customers accessing the portal is very sensitive to these assumptions;
- In one case we consider the benefit estimation approach is fundamentally flawed; and
- In some cases, the duration of the benefits stream is too long and/or the required payback period is too long given the uncertainty of the durability of the benefits stream identified. In our view, a prudent operator would require faster payback of its investment than CitiPower allows.

Risk monetisation methodology considers appropriate risks, but is of limited value for comparative analysis

737. CitiPower applies its IT risk monetisation approach to quantify risk across up to four ICT risk categories and up to six business risk categories.[201] Again, CitiPower has obviously devoted considerable effort to this modelling. However, whilst we typically see CitiPower's

200 Such as non-compliance, business productivity impacts through system failure

201 CitiPower project risk models (e.g. CP MOD 7.10 – Market systems risk quantifies 3 x IT risks and 6 x Business risks)

assumptions leading to sharp discrimination between the 'do-nothing' counterfactual and the other options, there are relatively minor differences between the other options in its risk modelling. This renders CitiPower's assessment of risk as an unhelpful tool for comparative analysis in many business cases.

Our top-down cross-checks of expenditure forecasts reveal apparent over-estimation in some cases

738. CitiPower's cost estimation methodology is based on a '*bottom-up forecast approach taking account of their experience providing projects of similar nature, size, scale and complexity*.[202] CitiPower refers to specific vendor quotes (when available) and labour rates that have been determined by PwC. This is consistent with industry practice with one exception – where there is a declining cost trend, this does not appear to be reflected in the forecast. An example is the cost of data storage. Based on our experience, most storage technologies have exhibited strong unit price declines over the last 5 years and may reasonably be expected to continue to do so. In these cases, we consider that CitiPower should provide more detail about its cost assumptions, referring to the historical price trend(s) and explaining, more explicitly, the basis of its cost estimate for forecasting purposes.

7.4 Assessment of selected Non-recurrent capex business cases

7.4.1 Overview of proposed Non-recurrent capex

739. CitiPower proposes spending $41.2m over the next RCP on Non-recurrent ICT capex, comprising seven projects as shown in the table below.

Table 7.5: CitiPower's proposed non-recurrent projects for the next RCP - $m, real 2021

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
5 Minute Settlements	7.2	1.6	0.0	0.0	0.1	8.9
Customer Enablement	0.5	0.1	0.7	0.6		1.9
Cyber security	0.5	0.5	0.5	0.5	0.4	2.5
Digital network	2.8	3.2	3.1	0.9	1.2	11.1
Intelligent engineering		0.9	3.1	0.5		4.4
SAP S/4HANA		1.8	5.4	4.1		11.3
Solar enablement DVMS	1.1					1.1
Total	**12.0**	**8.0**	**12.9**	**6.6**	**1.6**	**41.2**

Source: EMCa analysis of CitiPower MOD 7.01. Excludes real cost escalation

740. We provide our assessment of five of the seven projects in the following sections. The 5-Minute Settlements expenditure is discussed in section 7.6. The proposed expenditure associated with solar enablement is discussed in section 6, along with CitiPower's proposed solar enablement augex and related proposal for an opex step change.

202 Powercor/CitiPower response to IR023, question 7

7.4.2 Digital Network

Overview of the proposed project

741. The Digital Network project is common to CitiPower and Powercor. The capital costs are allocated equally to CitiPower and Powercor. Unless otherwise stated, our assessment is of the costs and benefits attributable to VPN (i.e., CitiPower plus Powercor).

Stated need/project driver

742. VPN advises that this program is part of its response to changing customer requirements, which require it to develop greater visibility of its LV network, including to facilitate increasing penetration of solar PV and electric vehicles.

743. From the project, VPN proposes implementing '*more sophisticated analytical, monitoring and management capabilities in order to run the network more dynamically in real time.*' [203] This includes extending its coverage of Advanced Metering Infrastructure (AMI) network devices to large customers and unmetered supply in a targeted rollout, so that it can *'further improve safety, defer capital expenditure, enable better demand management, provide supply compliance and reduce customer complaints.'*[204]

Options considered by VPN

744. VPN has considered three options:[205]

- Option 0 - Baseline – '*continue utilising AMI data through existing technology and receive base level of benefits'*
- Option 1 - Digital network technology – '*invest in new technology that provides greater network monitoring and control capabilities'* and
- Option 2 - Technology plus targeted rollout of network devices – '*in addition to rolling out option 1 technology, increase the current coverage of network devices to improve LV visibility*'.

745. The preferred Option 2 for this project requires forecast expenditure of $22.2m in the next RCP. VPN proposes to absorb the operating expenditure, '*given the importance of the project*.'[206]

746. The preferred option was selected due to the higher NPV ($141m for Option 2 vs $104m for Option 1, excluding operating expenditure) and a strong IRR (30.6% vs $28.7%, respectively, excluding operating expenditure) derived from application of its modelling.

Composition of the proposed expenditure

747. There are eleven components to the capex required for the Digital Network project, with the forecast amounts to be incurred in the next RCP as shown in the table below. Most of these components require capex for systems refresh in subsequent regulatory control periods and significant operating expenditure.

[203] CitiPower BUS 7.08 Digital network, page 4

[204] CitiPower BUS 7.08 Digital network, page 16

[205] CitiPower BUS Digital network 7.08, p4; costs are VPN's forecast capex for the next RCP

[206] CitiPower BUS Digital network 7.08, p6

Table 7.6: Overview of digital network technological capabilities and capex for the next RCP - $m, real 2021

Area	Capability	Capex (2021-2026)
Data	Real-time data platform	2.1
	IoT platform for Network Sensors	5.1
	IoT platform for customer sensors	1.2
	LV model extension	3.2
Analytics	Real-time grid analytics platform	2.1
	Real-time LV power flow analysis	1.1
Monitoring	Real-time grid monitoring and control	2.2
	LV management capability	1.0
	Dynamic forecasting capability	1.1
	DER – monitoring capability	1.1
Automation	DER automation	1.1
Total		**21.3**

Source: CP BUS 7.08 Digital Network, Table 4, p15. Excludes real cost escalation. Costs are total combined costs for CitiPower and Powercor

Our assessment

There are interdependencies with the Solar Enablement project

748. The Solar Enablement and Digital Network projects are complementary but address different needs. VPN's Digital Network program, as proposed will:[207]

- Assist with balancing solar PV systems across phases;
- Enable real-time visibility of voltage rises on the LV network; and
- Provide full LV network visibility, including the conductor type on every location of our network, '*ensuring we only undertake works where it is efficient to do so (as modelled).'*

749. We have considered these aspects of VPN's proposed Digital Networks project in our assessment of VPN's Solar enablement project, while being cognisant of our findings as presented in this section.

Most of the benefits may be able to be realised without real-time data and processing capabilities

750. VPN has identified four sources of tangible benefits:[208]

- Optimising load control – optimising existing customer load control and enabling new load control programs such as air conditioners and pool pumps;
- Promoting electric vehicle uptake - monitor and optimise electric vehicle charging;
- Enhancing cost reflective pricing - use existing and future AMI interval data to construct more effective time-of-use tariffs or demand management; and
- Detecting electricity theft - identify bypass connections and unregistered DER.

[207] CitiPower BUS 6.02, pages 22-23

[208] CitiPower BUS 6.02, page 5

751. The table below summarises VPN's estimate of the NPVs of the benefit streams provided by its Digital network project. The NPV analysis is undertaken over a 20-year period.

Table 7.7: VPN's estimate of NPVs for 20yr benefit streams - Digital Network project - $m, real 2021[209]

Benefit category	Sub-category	PV benefit Option 1	PV Benefit Option 2
Customer load monitoring and optimisation	MVA incremental reduction	59.2	61.7
	Unconstrained DER exports	19.9	19.9
EV charging optimisation	Reduced augex	46.1	46.1
	Capacity savings for public EV charging infrastructure	0.0	27.6
	Capacity savings for commercial EV sites	0.0	6.1
Cost reflective pricing	Summer Saver program	10.6	14.3
Reduction in non-technical losses	Theft reduction	3.6	6.7
	Value of un-recorded UMS	0.0	2.8
Total		**139.4**	**185.2**

Source: PAL MOD 7.13 which also applies to CitiPower

752. VPN describes its benefits streams as being dependent on the availability of a real-time data platform, a real-time grid analytics platform, and real-time monitoring and control.[210] Our understanding is that real-time data cannot be achieved from the existing AMI devices without significant additional investment to the level being proposed by VPN. AMI devices currently only provide 'near' real time data. Also, VPN does not have devices in the LV networks that are remotely controllable to provide the claimed 'real-time control' capability. We therefore assume that, for the next RCP, only load control of customer appliances is likely to be possible. Therefore, what would be delivered with VPN's proposed program will not be access to real-time data nor real-time control functionality. Furthermore, as discussed below, we do not consider that real-time control is required to extract the majority of the proposed benefits.

753. Regardless of whether real-time data is available cost-effectively, it is our view that VPN has not made a sufficiently strong case for real-time data or real-time control in support of its proposed enhanced capabilities, or for its proposed forecast capex as shown in Table 7.6, for the following reasons:

- **Customer load monitoring and optimisation** – VPN describes the benefit as being derived from: (i) optimising existing hot water load control; (ii) enabling new load control programs on an opt-in basis to reduce the peak or shift loads to periods of low demand; which will (iii) reduce the need for network augmentation. Whilst the proposed new analytical capability as a part of VPN's Digital networks proposal may assist with 'optimising existing hot water load control,' our understanding of CitiPower's analysis is that the benefit derives from adding more load control customers. VPN states that the technical capabilities (and therefore the cost) from all eleven components of its Digital Network initiative denoted in Table 7.7 are required to enable the benefit stream. Whilst we consider that there is likely to be merit in improving energy management at residential and commercial premises:
  - we do not consider that real-time data is required to extract this benefit and therefore we do not consider that the costs proposed by VPN are fully justified; and

209 Benefits are total benefits for CitiPower and Powercor

210 CitiPower BUS 7.08, Table 6, page 20

– some of the benefits may be able to be achieved through a combination of price signals (such as through tariff reform) and 3rd party providers rather than solely through actions by VPN.

- **EV charging optimisation -** VPN describes the benefit as being derived from: (i) monitoring EV charging to understand the impact on the distribution network; and, from this information, (ii) tariffs designed to encourage charging at non-peak periods; which will (iii) enable deferment of network augmentation. We do not consider that EV tariff design requires real-time data. We consider that the benefits can be achieved without the level of expenditure proposed.
- **Cost-reflective pricing** – VPN describes the benefit as being derived from: (i) extracting more insights about load and customer behaviour and better identifying network constraints; which, in turn, will (ii) enable it to develop more effective tariffs and voluntary demand management programs (and extend their coverage); which, in turn, will (iii) enable deferment of network augmentation. We do not consider that tariff design requires real-time data.
- **Reduction in non-technical losses** – the Option 1 level of benefit is said by VPN to be achieved by utilising Digital Network technology with its AMI data to allow it to more precisely monitor network usage and to detect electricity theft and other unallocated network losses. The extra benefits from Option 2 are to be derived from installing more network devices to large customers and unmetered supplies. VPN has not provided any evidence to support its estimate of benefits and, without such evidence, we consider the benefit claim to be optimistic given that existing AMI data should provide sufficient information for economically minimising electricity theft from the majority of premises. In short, we do not see a strong case from reduction in non-technical losses to support the proposed new capabilities[211] or the extra monitoring devices.

Our sensitivity analysis suggests net benefits are marginal

754. The table below shows the NPV over the 20-year study period in the VPN cost-benefit model for the three options considered by VPN.

Table 7.8: VPN cost - benefit analysis - $m, real 2021[212]

Option	PV[213] Cost	PV Benefit	NPV
0. Baseline – 'continue utilising AMI data through existing technology and receive base level of benefits	0	0	0
1. Introduction of Digital Network (and Baseline for relevant Initiatives)	-80.4	139.4	59.0
2. Increased Coverage of AMI Devices	-114.5	185.2	70.7

Source: PAL MOD 7.13 which also applies to CitiPower

755. VPN's model shows positive cash flows occurring from 2026 for its preferred Option 2. However, its analysis does not include opex, presumably because it proposes to absorb these costs. As seen from the table above, opex is a significant component of the total cost. When VPN's calculation of opex is taken into account, the cumulative benefits do not exceed cumulative costs until 2032 which, even then, is due primarily to the assumed strong benefits stream from 2031 onwards. In our view, there is significant uncertainty in the benefits streams continuing as forecast beyond 5-10 years.

756. In the absence of a sensitivity analysis from VPN, we used its model to examine the impacts of lower benefits and higher costs. The figure below shows that with a modest 10%

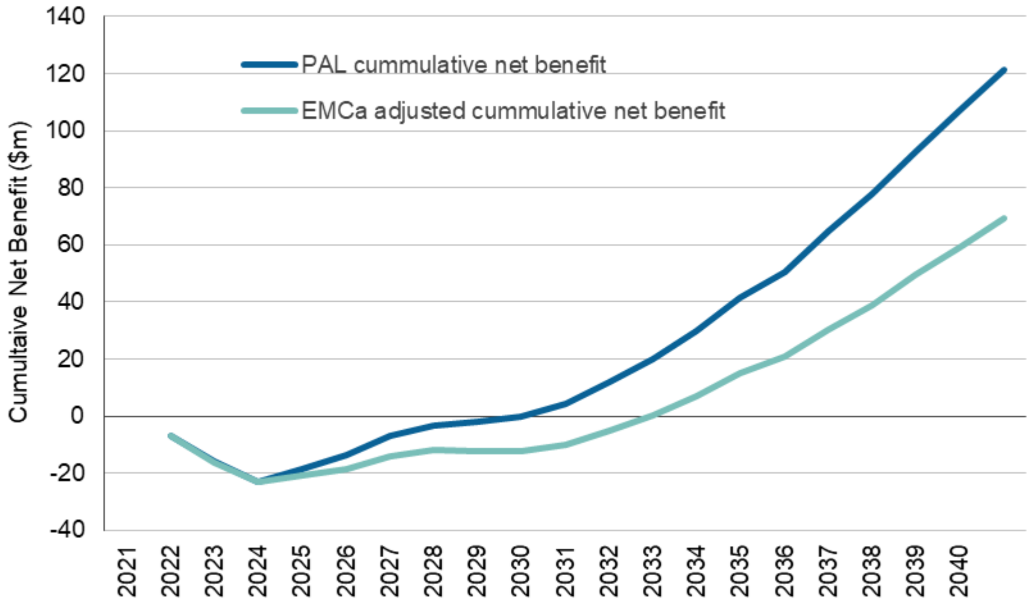
211 Real-time data platform, IoT platform for network sensors, IoT platform extension for customer sensors per Table 6 in CitiPower BUS 7.08 Digital network

212 Costs are total costs for CitiPower and Powercor. NPV study period is 20 years.

213 PV Cost include capex and opex for both CitiPower and Powercor. The NPV analysis is for 20 years

reduction in benefits and a 10% increase in costs, positive cash flows will not occur until 2032. This relies heavily on high benefits in the back-end of the 20-year study period. Alternatively, reducing the study period to a more reasonable 10 years due to the uncertainty of the benefits streams and asset stranding risks means that a positive NPV is unlikely to be achieved.

Figure 7.3: VPN Option 2: Cumulative net benefit



Source: EMCa analysis of PAL MOD 7.13 which also applies to CitiPower

Progressively extending visibility of the LV network may be prudent in the future

757. There is sufficient evidence that the future use of the LV electricity network is changing, and it is likely that increasingly consumers will '*buy, trade, sell, and store electricity and participate in new service markets*.'[214] VPN quotes the AEMC as follows:

> *'The electricity system (especially at the distribution level) is increasingly likely to have multi-directional flows and become a platform to support different services, such as access to various markets, that future electricity system users may demand. The future electricity system and the regulatory framework need to be able to support these and potentially many other varieties of use.'*

758. Whilst extending the visibility of the LV network may be warranted in the future, VPN has not provided compelling evidence that such visibility is required in the next RCP in its business case.

Summary of our assessment

759. Our analysis suggests that the project as presented does not represent a prudent investment for CitiPower. VPN has identified benefit sources from its proposed Digital Network project, but it has not justified the capex and opex as being required to achieve the majority of the identified benefits.

760. The majority of the expenditure for Options 1 and 2 is directed to establishing platforms to manage real time data and the extra analytical power to derive insights from the massively increased volume of data that this would bring. However, we consider that the majority of the benefits cited by VPN, at least in the next RCP, can be derived without real time data.

761. Furthermore, the project NPV as claimed by VPN is strongly dependent on benefit streams continuing for 10-20 years. We consider that there is considerable uncertainty in these benefit streams beyond 5-10 years. Importantly, electric cars, smart devices and solar PV

[214] CitiPower BUS 7.08, page 13

arrays are already internet connected, providing the opportunity for third parties to provide energy management services.

762. Our position is not altered by VPN's commitment to absorb the operating expenditure. Based on our assessment, we consider that the absorption of opex by VPN is not an efficient long-term outcome for customers.

7.4.3 Customer Enablement

763. The Customer Enablement project is common to CitiPower/Powercor. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our assessment is of the costs and benefits attributable to VPN (i.e., CitiPower plus Powercor).

Overview of VPN's proposed project

Stated need/ project driver

764. Approximately 130,000 of VPN's approximately 1.2 million residential, commercial, and business customers are registered users of VPN's portals and other tools used to access their data and information online. However:[215]

- its HV customers and embedded generators are not able to access the tools; and
- to access each application, customers need separate usernames and passwords, and need to learn to use each tool differently.

765. VPN's recent research indicates that of the 5,000 customers it surveyed, more than 80% '*supported investment in easier access to data and sharing of more data that can help them make informed energy choices.*'[216]

Options considered by VPN

766. VPN has considered three options:[217]

- Option 0 – Do nothing
- Option 1 - One-stop-shop portal and enhanced customer experience - *unify the tools on a compatible Salesforce platform, extend the tools to HV customers and embedded generators, improve: online capabilities, outage SMS notifications and notifications on the efficiency of customers' rooftop solar output and exports*; and
- Option 2 - One-stop-shop with enhanced customer experience and near real-time data — *option 1 plus providing customers access to 15-minute interval usage data on a new phone application, as well as 4-hour data updates on the myEnergy portal*'].

767. VPN recommends Option 2 at a cost of $11.6m capex. It will provide a '*one-stop-shop with enhanced customer experience and near real-time data*'[218] to achieve the following:

- improved and consolidated customer-facing access tools;
- provide more effective SMS notifications during outages;
- introduce SMS notifications on the efficiency of customers' rooftop solar output and exports;
- extend tools to HV customers and embedded generators; and
- give customers access to more frequent data to better inform their energy choices.

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215 CitiPower BUS 7.02, page 4

216 CitiPower BUS 7.02, page 4

217 CitiPower BUS 7.02, Table 1, page 5

218 CitiPower BUS 7.02, page 19

768. Although it is the highest-cost option, VPN has selected it on the basis that '*it offers the highest customer benefits that outweigh the efficient cost of delivering them,*'[219] and has a higher NPV.

769. The cost attributable to Powercor is $8.1m with the balance of $3.5 allocated to CitiPower.

Claimed tangible benefits

770. The table below shows the sources and quantum of benefits claimed by VPN from improving customer information and access to the information. The only material difference between Options 1 and 2 is that, for Option 2, customers are '*expected to save even more time and effort with access to near real-time data on a mobile application, by not having to access and log into the online portal to get the updates.*'[220]

Table 7.9: VPN's estimate of customer and operational benefits - $m, real 2021[221]

Source	Description of benefit	Saving p.a.	Benefit ($m p.a.)
Customer time saved	Reduced time spent on calls to enquiries line	61,013 min	0.02
	Reduced time spent on accessing data	7,775,232 min	2.08
	Reduced time spent on website and accessing various portals	6,443,808 min	1.73
	Embedded generators' reduced time on application forms	44,280 min	0.03
	Reduced time on investigating incorrect SMS notifications	500,000 min	0.13
	Time saved from preventing fault calls	124,234 min	0.03
Operational benefits	Reduced calls to contact centre staff	5 FTE	0.44
	Reduced staff required to process manual generator requests	0 FTE	0.00
	Estimated total average annual savings[222]	**Option 1** **Option 2**	**1.12** **1.85**

Source: EMCa analysis of PAL MOD 7.21 which also applies to CitiPower Claimed NPV of costs and benefits for 2021-2031 period

771. The table below summarises VPN's cost-benefit analysis.

219 CitiPower BUS 7.02, page 19

220 CitiPower BUS 7.02, page 18

221 Costs are total combined costs for CitiPower and Powercor. The profile of benefits varies over time and differs between Options 1 and 2 – the estimated total average annual savings are averages of the benefits over the 10-year study period.

222 The profile of benefits varies over time and differ between Options 1 and 2 - the estimated total average annual savings are averages of the benefits over the 10 years study period

Table 7.10: Summary of VPN's cost-benefit analysis - $m, real 2021[223]

Option	PV Cost	PV Benefit	NPV
0. Do nothing	0	0	0
1. One-stop-shop portal and enhanced customer experience - unify the tools on a compatible Salesforce platform, extend the tools to HV customers and embedded generators, improve: online capabilities, outage SMS notifications and notifications on the efficiency of customers' rooftop solar output and exports	-12.7	16.1	3.3
2. One-stop-shop with enhanced customer experience and near real-time data — option 1 plus providing customers access to 15-minute interval usage data on a new phone application, as well as 4-hour data updates on the myEnergy portal'	-15.4	26.3	10.9

Source: PAL MOD 7.21 which also applies to CitiPower

Our assessment

Most of the benefits are derived from only three sources

772. Based on its interpretation of customer survey results, VPN proposes spending $11.6m in the next RCP and a further $5.8m over the following five years to provide eight customer service enhancements. VPN estimates the Customer Enablement project will reap a net economic benefit of $10.9m over 10 years. However, the claimed benefits are derived in the main from three initiatives. For all three initiatives, we have fundamental concerns about the claimed benefits as discussed below.

Alternatives to VPN's proposed mobile app may erode assumed benefits

773. VPN proposes $2.0m incremental capex in the next RCP for providing near real-time data[224] on a mobile phone app on the assumption that:[225]

- customers are likely to be '*more engaged and incentivised to monitor their usage data'* on a mobile phone application; and
- retailers and third parties (with customers' permission) can easily link and integrate the application into their applications and products, reducing their costs of developing the application and reducing long-term costs to consumers.

774. It is not clear to us why VPN should be developing mobile phone apps when solar/battery energy systems manufacturers and suppliers already provide mobile apps. These mobile apps allow customers to monitor their energy use in near real time. With the right price signals from tariff changes mooted as part of the Digital Network business case, customers may demand more information for their own analysis. Alternatively, they may choose to contract with their retailer or a third party for that real-time information or with those parties to optimise their energy production and use for maximum customer benefit.

775. Consequently, in our view, the benefits claimed by CitiPower in its business case may already be captured by 'competitors' or may be eroded quite quickly by competitors who have more to gain in offering their customers this type of service.

776. It is our view that speculative investment by VPN for customer-focused 'added services', that would be underwritten by customers through the RP process, is not consistent with the expenditure criteria in the NER.

223 Costs are total costs for CitiPower and Powercor

224 VPN proposes that myEnergy data will be refreshed every 4 hours and AMI data will be refreshed every 15 minutes

225 CitiPower BUS 7.02, page 18

Benefits calculations are biased by unreasonable assumptions

777. VPN's approach to estimating most of its benefits is to determine how many customers are likely to be impacted (positively) by its improved portal and other offerings, by deriving:

- time savings for VPN customers – using $0.268 as the value of a saved customer minute; and
- operational benefits to VPN from reduced call centre activity and staffing as a result of reduced customer calls.

778. VPN also uses several key parameters sourced from its historical records, such as the number of calls to the call-centre, the average duration of a call, and number of embedded generator connections per year. However, these numbers are hard-coded in its cost-benefit model. The underlying data is not provided so we cannot easily verify it.

779. Of much greater concern to us is CitiPower's assumption regarding the number of customers that will register to use its 'easy access tools'.[226] Its two largest benefit streams are derived from reduced customer time to access its portals. CitiPower forecasts that, when combined with Powercor, it will have an average of 1,295,872 customers over the next RCP and assumes that an average of 50% of these customers (647,936) will be registered portal users during the whole of the next RCP:

- to calculate the benefit of 'Reduced time spent on accessing data', VPN further assumes all 647,936 registered users will access the portal four times per year and each will spend an average of 3 minutes logging-in/accessing the portal;
- to calculate the benefit of 'Reduced time on website and accessing portals', VPN assumes that 100% of the assumed registered users (i.e., 647,936) will avoid 4 minutes of wasted time per year; and
- it assumes that there is no overlap in these two benefit streams.

780. We consider these assumptions are unreasonable for the following reasons:

- The current number of registered users is 135,800[227] and it has taken four years to achieve this number.[228] We consider it unreasonable to assume that the average number of registered users will increase five-fold to an average of 647,936 over the next RCP;[229] and
- We consider it very unlikely that the claimed benefits from the two benefit streams discussed above are mutually independent – that is, we expect that the benefits derived from providing the mobile app (e.g., to reduce time spent on accessing data) will reduce the benefit from 'Reduced time on website and accessing portals' to be achieved by 'website artificial intelligence' and by removing multiple log-ins and navigation.

Using more reasonable user registration numbers renders the project uneconomic

781. The figure below shows that the NPV is very sensitive to the assumed number of users as this is the key parameter in deriving the two largest benefits streams. Without accounting for our concerns about the other factors that may impact the claimed net economic benefit, reducing the assumed registered users by 30% means the project does not achieve breakeven until the end of the 10-year study period. Factoring in lower benefits from the other sources would extend the payback period even further.

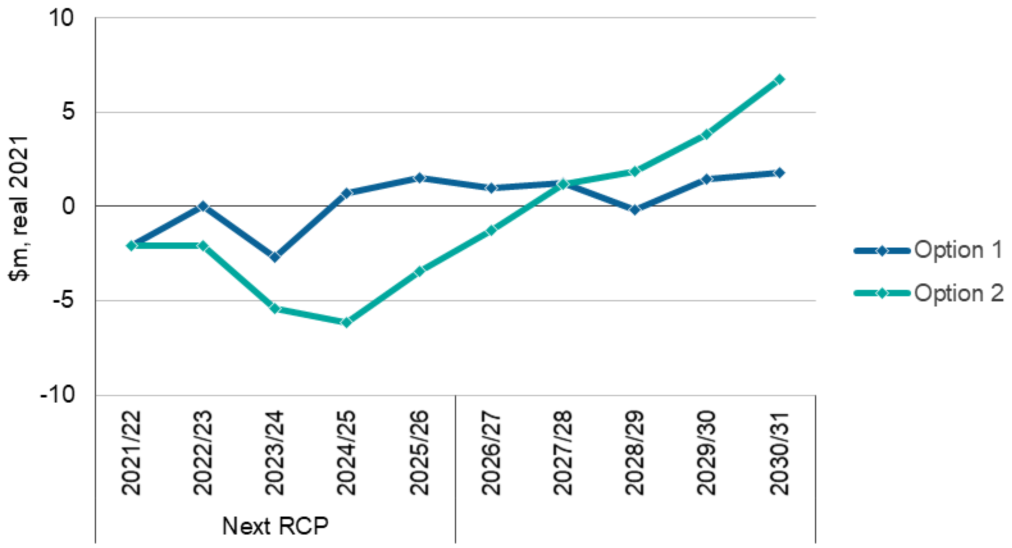
226 Which we understand from the business case CitiPower BUS 7.02 to include the myEnergy, mySupply, and eConnect portals

227 For myEnergy, mySupply and eConnect portals per CitiPower BUS 7.02 Customer enablement, Table 3, page 7

228 CitiPower BUS 7.02 Customer enablement, page 6

229 VPN hold this number constant at 647,936 throughout its 10-year study period

Figure 7.4: Cumulative net benefit - $m, real 2021



Source: EMCa analysis using PAL MOD 7.21 Note: NPV are totals for CitiPower and Powercor

Summary of our assessment

782. We have considered VPN's cost benefit analysis and consider that neither of Option 1 or 2, as presented, is likely to be NPV positive when more reasonable assumptions are applied to the benefit streams.

783. VPN has not demonstrated a compelling case for seeking to provide, as part of its preferred Option 2, a mobile app service for energy management and to recover the costs of this initiative from shared users as a regulated charge (particularly given the competitive threats to the assumed benefit stream). We consider this to be a speculative investment.

784. In responding to customer feedback, we see possible merit in delivering a subset of the proposed Option 1 features, including creating a unified access point (such as introducing contact centre AI), and improving the effectiveness of SMS notifications. We consider that these features are likely to address the core complaints from customers (as reported in CitiPower's business case) at a significantly reduced cost. CitiPower would still however need to demonstrate that there is a positive net economic benefit.

7.4.4 Intelligent engineering

785. The Intelligent Engineering project is common to Powercor and CitiPower. Capital costs are allocated on an equal share to CitiPower and Powercor. Unless otherwise stated, our assessment is of the costs and benefits attributable to VPN.

Overview of the proposed project

786. VPN proposes to spend an estimated $8.9m in the next RCP to enhance its 'intelligent engineering capability' and to introduce a Dial Before You Dig (DBYD) mobile application to collectively *'reduce safety risks, reduce the cost of asset damage, deliver operational savings internally and to third parties, and ensure better asset information exchange with the Government and its stakeholders'*.[230] This is referred to as Option 2 by VPN.

Options considered by VPN

787. VPN has identified three options, as shown in the table below.

230 CitiPower BUS 7.07 Intelligent Engineering, page 3

Table 7.11: VPN options summary for Intelligent Engineering project - $m, real 2021

Option	Proposed ICT capex	NPV analysis (2021 – 2031)		
		PV capex	PV benefit	NPV
0 - Do Nothing - do not make any changes or improvements to GIS and asset data management	0	0	0	0
1 - Base intelligent engineering capability	7.9	10.6	19.3	8.7
2 - Base intelligent engineering capability plus DBYD mobile application	8.9	11.8	33.0	21.2

Source: EMCa analysis of CitiPower BUS 7.07

Our Assessment

The project drivers present a reasonable case for action

788. VPN advised that its Geospatial Information System (GIS) asset records are not aligned with the physical earth, or with Global Positioning System (GPS). It also notes that this mismatch can result in:[231]

- *'higher risk of safety incidents for our employees and third parties working around our underground assets (less accuracy in Dial Before You Dig (DBYD) data);*
- *higher cost of managing the network if assets are damaged accidently due to wrong coordinates; and*
- *inefficient management of works around and on our underground assets, by our employees and third parties, resulting in higher cost to our customers and those of third parties.'*

789. VPN further advised that:[232]

- as the Victorian Government aligns its assets to GDA2020[233] and improves its cadastre, the growing disparity between its asset records (held in the GIS) and the Government's will result in increasing safety risks and inefficiency; and
- its GIS has important links to several internal systems and to external data sources.

790. VPN also advised that the GIS limitations described above means it cannot provide accurate location information of underground assets. VPN therefore does not allow digging within 30 meters of the indicated location of its assets in its GIS (using the DBYD service), creating construction delays. Furthermore, the format of the DBYD advice can be difficult to interpret on a mobile device, leading to inconvenience and costs to parties working around its assets.[234]

791. VPN identified issues with its Map Insights platform[235] which relies on VPN's GIS data with overlays from the Victorian government cadastre and other external sources. VPN advised that '*Due to lack of accuracy between our GIS and other external mapping sources, we are unable to extend our platform to a wider range of stakeholders at present.'*[236]

792. On the basis of widening data discrepancies between VPN's GIS asset records and external data systems, we consider that there is a case for action. Moreover, the issues appear to be of such significance that there is a case for undertaking some of this work in the current

[231] CitiPower BUS 7.07 Intelligent Engineering, page 8

[232] CitiPower BUS 7.07 Intelligent Engineering, p8

[233] Australia's Geospatial Reference System

[234] CitiPower BUS 7.07 Intelligent Engineering, p7

[235] A mapping platform that allows our staff and third-party contractors to visualise the detail and location of VPN's assets and the topology in relation to the asset's real-world location (CitiPower BUS 7.07, p7)

[236] CitiPower BUS 7.07 Intelligent Engineering, p7

RCP rather than waiting until the next RCP. However, in response to our information request, VPN advised that there is no work underway on this project in the current RCP.[237]

Our sensitivity analysis suggests the net benefits are likely to be achievable

793. VPN has proposed a total of four initiatives to: (i) reduce safety risk and the costs of asset damage; (ii) improve operational efficiency (for VPN and third parties); and (iii) improve asset information exchange with stakeholders. The initiatives comprise:

- introducing a master data management system;
- conflating its GIS records to the physical earth;
- enhancing Map Insights platform; and
- improving DBYD accuracy and access to information.

794. The benefits are inter-related, with VPN identifying lower customer costs [$3.0m pa] from:

- the time saved from fewer delayed projects [$180k p.a.];[238] and
- the time saved from having a mobile DBYD app [$2.8m p.a.].

795. The operational benefits total $4.9m p.a. and are all related to VPN savings.[239] VPN assumes these benefits will persist for the ten-year study period. In our opinion, the benefit quantification approach is reasonable, but the assumptions underpinning the savings are not substantiated.

796. Given the somewhat speculative nature of the benefit assumptions underpinning VPN's NPV results, we consider it prudent to undertake a sensitivity analysis. VPN did not provide sensitivity analysis results, nor the facility to do so directly in its model.

797. Nonetheless, we used VPN's model to undertake our own sensitivity analysis, the results of which are shown in the figure below. The NPV is positive for Option 2 even with a 50% reduction in claimed benefits (and Option 1 is marginally NPV negative) over the 10-year study period. Benefits would have to be reduced to 35% of VPN's estimate to result in a negative NPV for Option 2, holding costs constant.

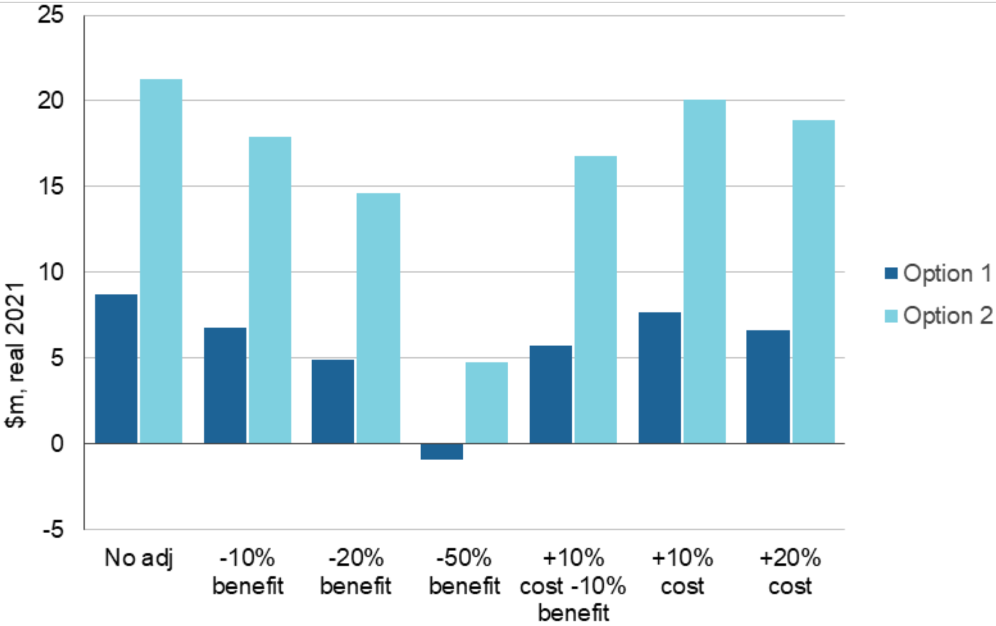
798. On this basis: (i) a positive net benefit for the project with a reasonable IRR is likely to be achievable, noting that a positive net cash flow is achieved in 2026/27 for most scenarios; and (ii) Option 2 (which captures the value of the mobile DBYD app) is preferable to Option 1 for all scenarios considered.

237 Powercor/CitiPower's response to IR023, Table 4, p4

238 CitiPower MOD 7.11, Benefits worksheet

239 CitiPower MOD 7.11, Benefits worksheet

Figure 7.5: Sensitivity analysis of VPN project benefits - $m, real 2021



Source: EMCa analysis of Powercor MOD 7.11 which also applies to CitiPower

VPN's proposed Option 2 is likely to maximise net benefits

799. As a further check on the prudency of Option 2, we asked VPN to provide the separable portions of cost to help us identify whether there was merit in VPN proceeding with only the highest value aspects of its project, namely the DBYD mobile app and fewer on-site inspections.

800. VPN's response[240] states that the program cost estimate was based on '*a program of works that is interdependent and optimally phased…*' and that if the program was not treated as an integrated package '*separate delivery of the initiatives would result in an approximate 30% increase in costs for independent project management and delivery.*'

801. Whilst the quantum of the extra project management and delivery costs seems high, we accept that the four program initiatives, as designed, work together to produce the customer and operational savings.

802. VPN also states that there are cost synergies with United Energy's equivalent project[241] and that those cost savings are already built into the VPN estimate, including via a phased implementation approach and alignment of initiatives.

VPN's cost estimating methodology is reasonable

803. We also asked VPN to explain the basis for the unit costs and quantity of units used to build up the costs in its model. VPN's response[242] explains the basis for its bottom-up estimates as a combination of: (i) blended IT labour rates developed by PWC, cross-checked with internal rates; (ii) labour hours incurred for similar/relevant projects; (iii) Vendor charges for like similar/relevant projects or quotes where available; and (iv) current unit rates or supplier quotes for material. We consider this methodology to be reasonable.

Summary of our assessment

804. Whilst we have concerns that the benefits claimed by VPN for its project may be overstated, we recognise that the current limitations with its GIS records are likely to have an increasing and cascading impact on safety risk and operational efficiency. We consider the four

240 Powercor/CitiPower's Response to IR023, page 8

241 Separately costed and discussed in United Energy BUS 7.07 at $5.4m

242 Powercor/CitiPower's response to IR023, page 9

proposed initiatives have merit as a program of work. Even with claimed benefits reduced to 40% of VPN's claims, the NPV is positive.

805. Our analysis suggests that the project capex for VPN's Option 2 of $8.9m is likely to be prudent and reflective of an efficient level.

7.4.5 SAP Upgrade

806. The SAP upgrade project is common to CitiPower, Powercor and United Energy. Capital costs are allocated 25% to Powercor, 25% to CitiPower and 50% to United Energy. The project includes Recurrent and Non-recurrent expenditure for VPN/UE. Unless otherwise stated, our assessment is of costs and benefits attributable to the total costs to VPN/UE.

Overview of the proposed project

807. SAP Enterprise Resource Planning (ERP) software is used to run VPN's and UE's payroll, finance, HR, and network organisational asset management systems. The two 'instances' of the SAP ECC6 version will reach end-of-life support in 2025 based on the vendor's advice. The next available version is SAP S/4HANA.

808. The scope of the project covers the lifecycle upgrade of SAP. The recommended approach is to incur $51.5m capex on upgrading to SAP S/4HANA as a single integrated instance across VPN/UE (i.e., Option 3).

Options considered by VPN/UE

809. VPN/UE have identified five options for providing a '*stable, compliant and fit-for-purpose*'[243] ERP, as shown in the table below.

Table 7.12: VPN/UE's options summary - $m, real 2021[244]

Option	Description	Capex	Opex	Totex	NPV	Risk
0	Maintain two (VPN and UE) unsupported SAP ECC6 instances (do nothing)	0.0	0.0	0.0	0.0	414.8
1	Engage third party support for two SAP ECC6 instances	8.3	6.5	14.9	13.6	408.6
2	Upgrade to S/4HANA as two separate instances	60.0	0.0	60.0	55.1	29.2
3	Upgrade to S/4HANA as a single instance across VPN/UE	51.5	0.0	51.5	47.3	29.2
4	Replace two SAP ECC6 instances with a single instance of a new, non-SAP ERP solution	69.8	0.0	69.8	64.2	101.6

Source: EMCa version of Table 1 in PAL BUS 7.01, p4 with costs from PAL MOD 7.02

Summary of VPN/UE's options analysis

810. The figure below presents a summary of VPN/UE's options analysis. The three dimensions that it considered are:[245]

- Leverage existing '*platforms before investing in new technology to minimise - Before implementing a new system, we first look whether leveraging existing platforms would minimise cost;*'
- Enterprise fit – '*investigate solutions with an enterprise-wide lens*'; and

243 CitiPower BUS 7.01 SAP S4HANA, page 4

244 Options 1-4 include costs for maintaining currency of SAP ECC6 in addition to the SAP S/4HANA upgrade. Costs are total costs for CitiPower, Powercor and United Energy.

245 CitiPower BUS 7.01 SAP S4HANA, page 18

- Current and future needs – '*Solutions must be sustainable, scalable, and secure'.*

811. Whilst no description is provided in the Business Case, we assume that the traditional traffic light colours denote the degree of alignment of the option with the dimensions. The analysis is qualitative.

Figure 7.6: Summary of VPN/UE's initial SAP options analysis

Source: EMCa modification to PAL BUS 7.01, Table 5

VPN/UE's preferred option

812. VPN/UE has chosen Option 3 because it:[246]

- avoids the significant risks and operational expenditure of options 0 and 4;
- continues with direct SAP vendor support without disruption;
- is the most affordable way to achieve and maintain a stable, compliant, and fit-for-purpose ERP; and
- supports integration of the three businesses, allows new capabilities to be built and simplifies future ERP maintenance and support needs.

Our assessment

The assessment criteria applied by VPN/UE are reasonable

813. VPN/UE has used a combination of quantitative and qualitative analysis to select the preferred Option 3. The qualitative assessment summarised in Figure 7.5 is supported by information in the business case and the dimensions considered provide a reasonable perspective on organisational fit.

814. VPN/UE have also applied a risk monetisation framework, to help distinguish between options and, to some extent, confirm the timing of the proposed project. It considers both IT impacts[247] and business impacts.[248] Whilst we may not agree with all the assumptions at a level of detail, VPN/UE has put significant effort into the risk analysis and has included a sensitivity analysis. We consider that the risk dimensions and approach are both reasonable.

Options 0, 1 and 4 are inferior to Options 2 and 3

815. Option 0 - do nothing - will not incur zero costs, as CitiPower's business case indicates, and it is not consistent with good industry practice to operate the ERP of a large and complex business without support. Therefore, in its CBA, CitiPower should not define the costs of options 1 to 3 relative to a zero-base counterfactual.

816. Option 1 - engaging 3rd party support for the two SAP ECC6 instances - is a strategy that has been deployed by some large businesses, including United Energy (from 2017), as a means to reduce opex, defer upgrade costs and reduce dependency on the OEM vendor. CitiPower provides a comparison of the different reliability/stability performance between

246 CitiPower BUS 7.01 SAP S4HANA, page 28

247 Outage, suitability, and system sustainability – as described in Table 15, p31, PAL BUS 7.01

248 Reliability, compliance risk, customer experience risk, safety risk, bushfire risk, and financial risk – as described in Table 15, pp 15-16, PAL BUS 7.01

CitiPower/ CitiPower and United Energy over the period 2017-2020. During this time, United Energy had over 15 times the volume of incidents.[249]

817. United Energy decided to return to an SAP-supported model in late 2018, however: '*…rectification of the contractual damage came at a far greater cost than any short term savings that had been realised.'*[250]

818. VPN has used the SAP support model for its ERP. We concur that the risk of adopting Option 1 is unacceptably high, outweighing potential benefits.

819. We are also satisfied that deferring replacement of SAP ECCC6 beyond 2025 is unlikely to be prudent as:[251]

- There will be a decrease in the provision of system fixes and support packs through to 2025 from SAP;
- CitiPower/Powercor's ECC6 version of SAP will be 19 years old by the end of the next RCP and United Energy's version will be 17 years old at this time;
- Product divergence risk with a third-party support service is high;
- Consequences of system failure are high and would be likely to offset any deferral benefits; and
- Compliance risk is transferred to the three DNSPs (from SAP).

820. Option 4 - replacing ECC6 with a new non-SAP, Tier 1 enterprise software system as an alternative to SAP - would require *'… a full business transformation and rebuild solution interfaces…'*[252] We agree that the risks and cost involved in transitioning to an alternative product are unlikely to outweigh any potential benefits.

Upgrading to S4/HANA is likely to be the prudent approach

821. Based on our experience and the provided options analysis, upgrading from SAP ECC6 to SAP/4HANA within the next 5-7 years appears to be the prudent choice. To assist an assessment of the recommended option, we first considered the delivery risks associated with each option.

822. VPN/UE's assessment of delivery (or project) risks posed by Options 2 and 3 in the business case is superficial – it states only that there may be '*Unplanned system and process integration impacts*.'[253] Furthermore, whilst we are supportive of the risk assessment criteria and approach in its risk model (e.g., CP MOD 7.03), it states in the model that: '*We assume an upgrade to S4 HANA (2 instances) will carry similar levels of risk as this option'*[254] where 'this option' is the single instance proposed in Option 3.

823. Based on our experience, unless VPN and UE create a unified set of business processes ahead of the project, unifying the platform will lead to significantly higher project risks due to sequencing, testing, data migration and integration. Without this, Option 3 represents a significantly more complex and higher risk project than Option 2 because:

- There is considerable effort, and therefore cost involved in merging the database and merging the business processes of two organisations (VPN and UE); and
- The change management in merging to organisational business processes would be very large and have a high risk of disrupting both businesses – we estimate that VPN/UE's estimate of the risk cost of Option 3 of $29.2m may be higher than Option 2 as a result of the change management complexity, integration complexity, and merged data migration.

249 CitiPower BUS 7.01 SAP S4HANA, Table 8, page 21

250 CitiPower BUS 7.01 SAP S4HANA, page 20

251 CitiPower BUS 7.01 SAP S4HANA, pages10-13

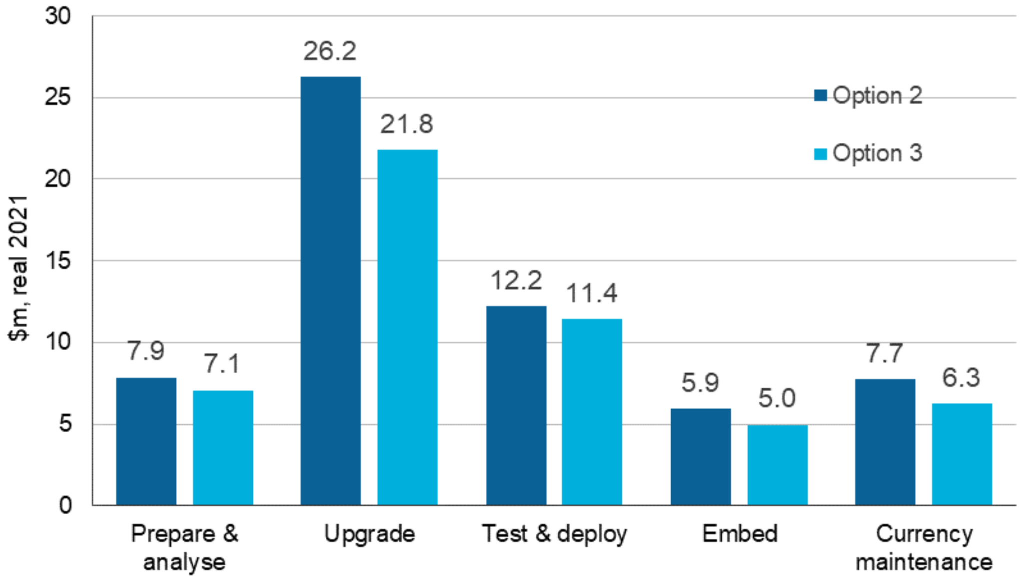
252 CitiPower BUS 7.01 SAP S4HANA, pages 25

253 CitiPower BUS 7.01 SAP S4HANA, Table 11, page 24

254 CitiPower MOD 7.03 SAP risk

824. With this in mind, we looked closely at the costs allowed for Options 2 and 3 for preparation versus the costs involved for establishing and maintaining two instances of SAP (Option 2) versus one instance (Option 3). The figure below shows the comparative cost estimates for various aspects of the work.

Figure 7.7: Comparison of VPN Option 2 and Option 3 cost assumptions - $m, real 2021



Source: EMCa analysis of PAL MOD 7.02, also applies to CitiPower and United Energy

825. It is possible that VPN/UE has allowed for extra time/resources in its 'Prepare & analyse' cost estimate, given that the $7.1m cost for Option 3 is significant and comprises 35,000 hours of labour and $5.7m of materials and contracts.[255]

826. Overall, the $8.5m capex difference in favour of Option 3 compared to Option 2 is considerable. We consider that Option 3 remains preferable to Option 2. Furthermore, a single instance will require considerably lower opex running and support costs over time.

827. Based on: (i) the number of SAP modules; and (ii) the organisational business process complexity and migration from a legacy SAP platform to a modern SAP platform, an SAP implementation cost of $51.5m for a single instance as proposed for Option 3 is reasonable. Building two SAP instances will increase testing and integration costs. Given its complexity, we also consider the Option 2 cost of $60m to be reasonable.

Maintaining the currency of the two SAP instances during the transition period is prudent, however the cost seems unreasonably high

828. The business case allows for refreshes of the existing SAP ERP in 2021/22 and in 2022/23 at a total cost of $4.8m (9% of the project cost) across the two instances (i.e., $2.4m for VPN and $2.4m for United Energy). We consider that this could be reduced by 50% (or $2.4m) by refreshing the SAP ECC6 versions in 2022/23 or 2021/22, but not both. A further refresh of the single instance costing $1.4m in 2025/26 (i.e., immediately after the planned deployment) also seems excessive given the commissioning of the new instance will still likely be in its hypercare phase.

Summary of our assessment

829. VPN and UE have selected a reasonable range of options for dealing with vendor advice that its current two instances of SAP ECC6 ERP software will not be supported from 2025. There is sufficient information provided in the business case, when combined with our

[255] CitiPower MOD 7.02 SAP cost

experience, to conclude that upgrading to SAP S/4HANA within the next RCP (Option 3) is likely to be the prudent approach.

830. In our view, refreshing the existing ERP in both 2021/22 and 2022/23 is unlikely to be prudent – we consider that only one refresh (i.e., in 2022/23) prior to the 2024/25 go-live of the proposed upgraded ERP should be included in the proposed expenditure allowance and that this would represent an efficient cost estimate.

7.4.6 Cyber security

831. CitiPower's business case provides the supporting information for the proposed expenditure for its cyber security improvement project for both CitiPower and Powercor. The project includes Recurrent and Non-recurrent expenditure for VPN. Cost is allocated 30% to CitiPower and 70% to Powercor. We have assessed both components in this section and unless stated otherwise, we refer to the combined expenditure for VPN.

Overview of the proposed project

832. VPN proposes Recurrent capex of $19.4m to maintain current levels of cybersecurity and Non-recurrent capex of $8.2m to enhance its cyber security posture, for total capex in the next RCP of $27.5m. Its justification for the 'enhancement' capex is based on the consequences of a cyber security breach, which is potentially significant as explained below:[256]

- There have been cyber security breaches in the electricity sector (worldwide);
- The Australian Cyber Security Centre (ACSC) ranks the energy sector in the top four industries most at risk of a cyber-security threat;
- The Security of Critical Infrastructure Act 2018 was developed in recognition of the evolving national security risks to infrastructure including electricity assets;
- VPN's self-assessment against the Australian Electricity Sector Cyber Security Framework (AESCSF) developed by industry and AEMO;
- VPN's regulatory obligations under the Australian Privacy Act 1988 which, among other things, require VPN to take reasonable steps to protect personal information it holds; and
- Cyber security is ranked as one of VPN's top 10 risks on its risk register.

833. VPN considered four options in its cyber security business case, as summarised in the table below. VPN selected Option 2 with total capex of $27.5m, comprising $19.4m of Non-recurrent and $8.2m of Recurrent expenditure.[257]

Table 7.13: VPN's Cybersecurity options summary - $m, real 2021

Option	Cost	Risk
0 Do Nothing - do not invest in maintaining cyber security capabilities	0.0	183.1
1 Maintain Currency – maintain existing cyber security capabilities as is	19.4	58.6
2 Optimise Effectiveness – build on Option 1 by optimising the effectiveness of existing cyber security capabilities by increasing coverage	27.5	29.3
3 Expand Analytics Capability – build on Option 2 by expanding cyber security monitoring and behavioural analytics capabilities	39.4	15.5

Source: PAL BUS 7.04, Table 2, p14; also applies to CitiPower

[256] CitiPower BUS 7.04 Cyber security, pages 6-9

[257] CitiPower BUS 7.04 Cyber security, Table 8

Our assessment

Cybersecurity obligations do not yet apply to DNSPs

834. The AESCSF provides a consistent means for businesses to assess and improve cyber security maturity, but at present its use is voluntary. Whilst we understand that the intention is for mandatory maturity levels to be introduced into regulations, this has not yet been done.

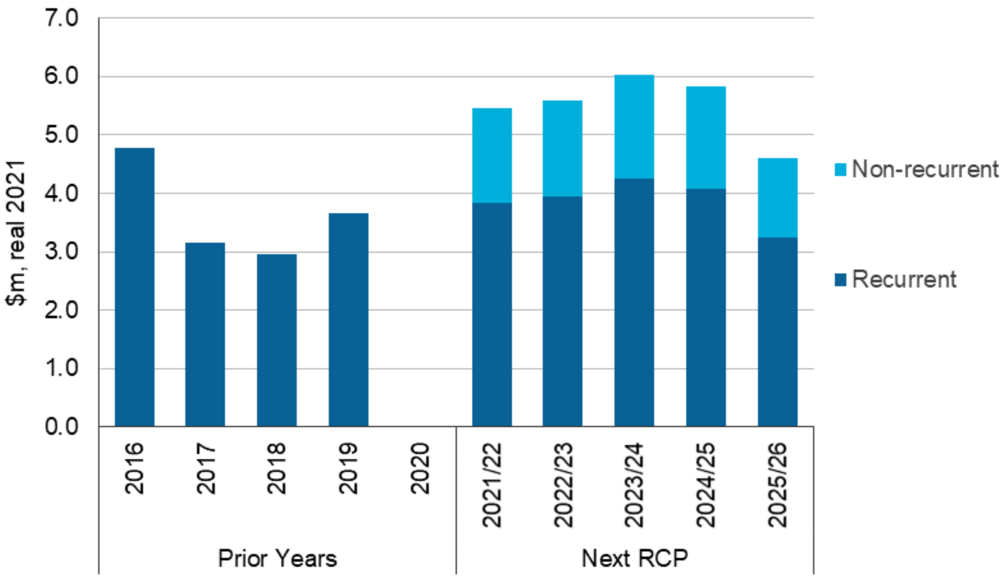
835. Nonetheless, given the escalating risk of cyber threats, which is evident from recent cyber-attacks in Australia,[258] a prudent distribution network operator should align its cyber security posture to align with the recommended MIL2/SP-2 level.[259]

VPN proposes a 6% increase in its Recurrent cybersecurity capex

836. The figure below compares the historical cyber security Recurrent capex with the forecast Recurrent and Non-recurrent cyber security capex for the next RCP. The 2020 amount has not been provided.

837. Based on the previous four years, VPN proposes a 6% higher average annual recurrent capex in the next RCP or about $1m in total. VPN does not explain the basis for this uplift. Nonetheless, based on the level of detail provided in its cost model, we consider the Recurrent capex estimate to be reasonable.

Figure 7.8: VPN's historical and proposed cybersecurity capex - $m, real 2021[260]



Source: EMCa analysis of Powercor/CitiPower's response to IR023 (Table 3) and PAL MOD 7.05

Options 0, 1, and 3 are not prudent approaches

838. Based on the information provided in the business case and our understanding of the cyber security landscape in Australia, Option 0 (Do nothing) and Option 1 (Maintain the current level of cyber security) would not align with the recommendations of government, AEMO's recommended position for DNSPs (discussed below) nor with VPN's cyber security risk exposure. In our view, a prudent operator would not pursue these options.

258 Refer to https://www.theguardian.com/australia-news/2020/jun/19/

259 Recent updates to the AESCSF framework (version 2019-8) incorporated Security Profiles (SP) in which distribution electricity service providers are categorised as moderately critical per the Critical Assessment Tool and as such should achieve SP-2 level of security which is equivalent to the MIL2 standard

260 VPN provided actual for 2016 – 2019 based on calendar year (Powercor/CitiPower response to IR023) while 2021/22 – 2025/26 are based on financial year. We converted 2016 – 2019 into real $2021.

839. Option 3 provides enhanced 'security monitoring and behavioural analytics' in addition to the full scope of Option 2 (as discussed below) to *'uplift [VPN's] ability to proactively detect and respond to cyber threats in particular to address the evolving nature of the tools, tactics, and procedures that cyber-attackers employ and the increasingly complex environment that our cyber security team monitors.'*[261] VPN concludes that Option 3 does not provide sufficient additional security benefits given the additional investment of $11.9m over 5 years.

840. In our view of the options considered by VPN, we agree that Option 2 is preferable to Options 0, 1 and 3.

VPN's outcome measured against the AESCSF maturity levels is reasonable

841. VPN's business case is silent on what Maturity Indicator Level (MIL) it expects to achieve from the proposed Option 2 investment. We therefore asked VPN to explain:

- What the proposed capex achieves in terms of the MIL and in terms of the 23 NIST[262] categories that underpin the five NIST functions per the AESCSF; and
- Where the proposed work program positions VPN against the MIL/SPs following completion of the proposed capex program.

842. In summary, VPN's response is that: (i) it sought to ensure that it has 'balanced coverage' defined by the NIST functions and AESCSF domains; and (ii) it did not use the MIL/SP target as its primary driver, and that it forecasts *a 'MIL of around 2-2.3 at the end of the 2021-2026 regulatory control period.'* [263]

843. Based on the information provided and from our experience,[264] we consider that VPN's approach to defining and costing Option 2 is reasonable in the context of the AESCSF framework (version 2019-8) suggested target of MIL2/SP-2. Restricting its cyber security measures to achieve exactly MIL2/SP-2 rather than slightly over 2 is likely to be sub-optimal.

Cybersecurity benefits from the rest of its ICT program are taken into account

844. It was not initially clear to us from its business case how VPN accounted for the cyber security benefits that derive from the rest of the ICT program (e.g., replacements and upgrades) to avoid double counting. In response to our information request, VPN advised that: [265]

> *'The main benefit of ensuring IT asset currency across our IT portfolio is that we have hardware and software that is 'in support' and can continue to receive security patches for known vulnerabilities within these assets.'*

845. We are satisfied with this explanation and consider that the incremental expenditure proposed is unlikely to double count costs.

VPN's cost estimate is reasonable

846. Based on our assessment of VPN's cost estimation methodology, we are satisfied that the cost estimate for the proposed Recurrent and Non-recurrent expenditure is likely to be representative of an efficient level.

Summary of our assessment

847. VPN proposes $19.4m of Recurrent capex and $8.2m of Non-recurrent opex to be shared in the ratio 30:70 between CitiPower/Powercor. We consider that VPN's Recurrent and Non-

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261 CitiPower BUS 7.04 Cyber security, page 19

262 National Institute of Standards and Technology

263 Powercor/CitiPower's response to IR023, question 15

264 Including from providing advice to Australian businesses in Australia and overseas, and from reviewing utilities' cyber security expenditure and expenditure forecasts

265 Powercor/CitiPower's response to IR023, question 17

recurrent capex for the next RCP is consistent with what a prudent and efficient operator would incur because:

- It is prudent to target a higher level of resilience against cyber-attack;
- Its cost estimation practices are reasonable;
- Its recurrent capex is commensurate with the historical trend; and
- The proposed non-recurrent capex is likely to achieve MIL 2 to 2.3, which is consistent with the proposed maturity level target level for DNSPs as identified by AEMO.

7.5 Assessment of selected Recurrent capex business cases

7.5.1 Overview of proposed Recurrent capex

848. CitiPower proposes spending $51.3m over the next RCP on Recurrent ICT capex, as shown in the table below.

Table 7.14: CitiPower's proposed Recurrent ICT projects

Project	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Infrastructure with Cloud migration	2.8	2.3	1.9	2.5	1.4	10.8
Network Management	2.3	2.1	0.6	1.7	1.9	8.5
BI/BW	0.1	0.7	0.2	0.1	0.1	1.1
Customer Enablement	0.1	0.3	0.8	0.1	0.1	1.6
Cyber security	1.2	1.2	1.3	1.2	1.0	5.8
Device replacement	1.2	1.2	1.2	1.2	1.2	5.8
Enterprise Management Systems - Non-SAP	1.4	0.9	0.6	1.4	0.1	4.4
Facilities' security	0.5	0.4	0.3	1.2	0.1	2.6
General compliance	0.9	0.9	0.9	0.9	0.9	4.6
Market Systems	0.4	0.4	1.2		0.8	2.8
SAP S/4HANA	0.4	0.7			0.4	1.6
Telephony	1.0	0.3	0.3		0.1	1.7
Total	**12.3**	**11.3**	**9.3**	**10.4**	**8.0**	**51.3**

Source: EMCa analysis of CitiPower MOD 7.01. Excludes real cost escalation

849. Non-recurrent expenditure is incurred in 12 projects, including Facilities Security (which is discussed in section 8.3) and SAP S/4HANA and Cybersecurity, which are discussed in section 7.4.5 and section 7.4.6 respectively.

850. We provide our assessment of the ICT infrastructure and cloud migration, and Network Management systems projects in the following sections.

7.5.2 ICT Infrastructure cloud migration

851. The ICT Infrastructure cloud migration project is common to Powercor and CitiPower. The businesses have allocated capital costs allocated 70% to Powercor and 30% to CitiPower,

and operating costs 72% to Powercor and 28% to CitiPower.[266] Unless otherwise stated, our assessment is of costs and benefits attributable to VPN (i.e., CitiPower plus Powercor).

Overview of the proposed project

852. The majority of VPN's ICT infrastructure is located on-premise, with some applications transitioned to cloud-hosting during the current RCP. The cloud is becoming the de facto platform for many application vendors. For the next RCP, VPN reviewed its infrastructure refresh/upgrade requirements to maintain its health, capacity, and suitability and assessed the costs and benefits from migrating some or all of the on-premise infrastructure to cloud hosting. VPN recommends Option 2 – balanced (or hybrid) cloud migration - because it has the lowest NPV cost and it provides the (unquantified) benefits of cloud hosting, such as easy scalability and adaptability of its ICT infrastructure to changing requirements.

Options considered by VPN

853. The table below summarises VPN's risk-cost assessment of the four options.

Table 7.15: VPN's summary of options - $m, real 2021[267]

Option	Description	Capex	Incremental Opex	PV Expenditure	Risk
0 - Do nothing	No refresh/growth of existing on-premise infrastructure; no migration to cloud	0.0	0.0	0.0	328.4
1 - On-premise infrastructure refresh	Do not migrate existing on premise infrastructure to cloud hosting	50.4	0.0	46.5	7.5
2 - Balanced cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 5% of non-core applications p.a. to cloud hosting to cloud hosting; refresh remaining on-premise infrastructure	36.0	7.7	40.5	7.5
3 - Aggressive cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 10% pa of non-core applications to cloud hosting; refresh remaining on-premise infrastructure.	35.5	11.1	43.2	7.5

Source: PAL BUS 7.10, Table 6; also applies to CitiPower

Our assessment

VPN's selected strategy to move progressively to the cloud is sound

854. Option 0 is not viable. It is not based on good industry practices and serves only as a counterfactual for assessment of Options 1-3.

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266 No explanation for this difference between capex and opex is provided although the opex allocation is consistent with (i) advice provided in Powercor's response to IR016, question 5 which states: '*We apportioned the forecast operating costs based on relative customer number forecasts for the two networks over 2021-2026. This results in an allocation of 28% for CitiPower and 72% for Powercor'*, and (ii) the customer number calculation in the Assumptions sheet of PAL MOD 9.01 – Step changes – Jan2020. The capex apportionment in Table 12 of PAL BUS 7.10 is 70:30

267 The NPV analysis is undertaken over 5 years

855. Option 1 - on premise infrastructure refresh - is not recommended by VPN because there is an opportunity to migrate its core applications to cloud hosting which, as discussed below, should bring the benefits of scalability, adaptability, reliability and (over time) reduced costs.

856. VPN's Options 2 and 3 involve progression to cloud IT hosting during the next RCP while retaining some applications on-premise. We refer to this as a 'hybrid cloud' approach. VPN identifies the benefits of adopting a hybrid cloud approach as including:[268]

- *'Improved agility and adaptability to business needs;*
- *Reduced risk of applications changing beyond the hosting platforms' ability to support;*
- *Provision of agile and scalable hosting platforms as needs change;*
- *Allow incremental non-capital intensive capacity growth; and*
- *Provide greater ability to manage peak demands aligned to business needs.'*

857. The identified benefits are consistent with our experience and the trend we observe within the industry. We therefore consider VPN's strategy of moving progressively to the cloud, as proposed in Options 2 and 3 to be superior to Option 1.

858. VPN's preferred 'balanced' strategy is Option 2 which:[269]

- migrates 100% of core applications and 25% of non-critical applications to cloud hosting by the end of the next RCP;
- connects on-premise data centres to external cloud offerings;
- includes a cloud-first shift to IaaS platform; and
- requires a slightly lower capex and incremental opex than Option 3.

859. VPN consultant's advice regarding Option 2 is that it *'…reflected the best value and most achievable option for an alternate IT Hosting strategy during the next regulatory reset period*.'[270] The same consultant's advice is that Option 3 is riskier than Option 2, primarily because of its relative lack of maturity in cloud adoption: [271]

> *'Adopting this scenario carries some additional risk, as it requires CitiPower, Powercor & United Energy to continue developing a high level of internal maturity in cloud adoption and understanding of its application compatibility with cloud based platforms.'*

860. We are not in a position to comment on VPN's relative maturity regarding cloud adoption. In accepting its consultant's advice in adopting Option 2, we assume that VPN acknowledges its relative lack of maturity compared with cloud adoption. However, we note that VPN's risk analysis (shown in Table 7.15) does not distinguish between the risk cost of Options 2 and Options 3.

861. A further reason for selecting Option 2 is the superior risk-cost trade-off offered compared to Option 3, also as shown in Table 7.15. There does not appear to be duplication of costs across the inter-related SAP, BI/BW and ICT Infrastructure cloud migration projects.

862. The figure below illustrates the current and future states of the planned cloud migration and refresh of remaining on-premise infrastructure following implementation of VPN's preferred option.

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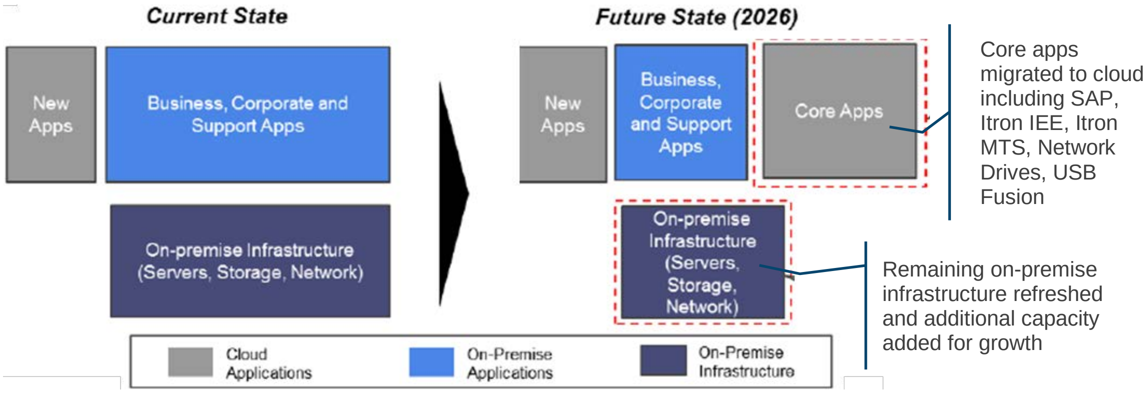
268 CitiPower ATT 046 BDO Cloud review, page 21

269 CitiPower ATT 046 BDO Cloud review, page 5

270 CitiPower ATT 046 BDO Cloud review, page 29

271 CitiPower ATT 046 BDO Cloud review, page 21

Figure 7.9: Current and Future state following implementation of VPN's preferred option 2



Source: EMCa modified version of CitiPower's Figure 4, CP BUS 7.10 Cloud infrastructure

863. As shown in the diagram above, VPN is planning to migrate its on-premise SAP version to the cloud in the next RCP. Based on our initial review, the SAP business case and this Cloud infrastructure business case appear to double count at least some capex. We had similar concerns with respect to the BI/BW[272] business case costs. We sought clarification from VPN.[273] We summarise its response as follows:

- The Cloud infrastructure business case:
  - covers only IT infrastructure;
  - includes all capex allowance for all residual infrastructure needs to support its IT portfolio (applications and platforms);
  - recognises the reductions in on-premise infrastructure refresh/upgrade costs from moving infrastructure to cloud hosting (i.e., IaaS);
  - includes incremental opex increases for cloud hosting charges for the 'new' cloud-hosted infrastructure; and
  - includes reductions to the opex that would otherwise have been incurred on maintaining on-premise infrastructure moving to IaaS.
- The SAP Business case (PAL BUS 7.01):
  - covers the SAP ERP IT application only;
  - includes capex to upgrade from SAP ECC6 to SAP S/4HANA; and
  - does not include incremental opex.
- The BI/BW business case (PAL BUS 7.03):
  - covers IT application for business reporting only;
  - includes capex for consolidating the applications to SAP S/4HANA; and
  - does not include incremental opex.

864. This is illustrated in the figure below. We have reviewed the SAP and BI/BW cost models and we are satisfied that the costs across the three business cases are not likely to be duplicated to a material extent. However, if the cloud project slipped even slightly VPN/UE will not have the data ready for the SAP/HANA project.

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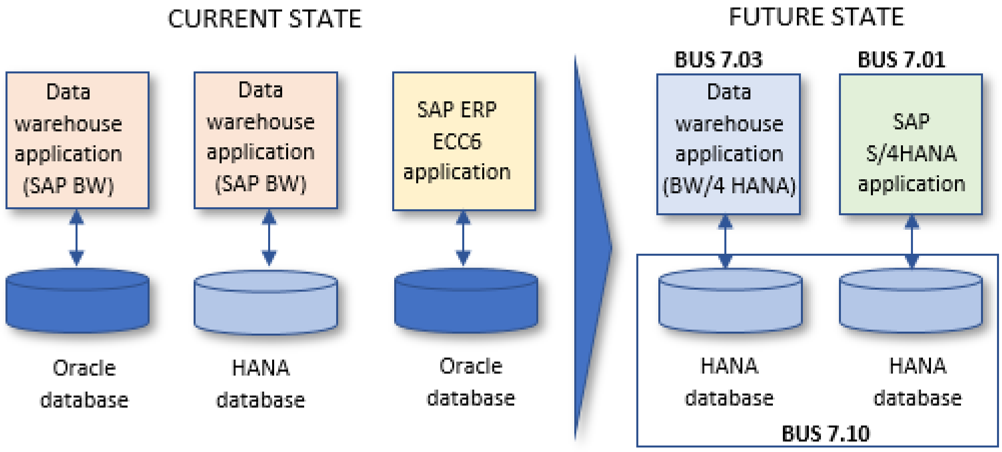
272 Business Intelligence/Business Warehouse

273 Response to IR048

Figure 7.10: Demarcation between Cloud infrastructure, SAP and BI/BW business cases



Source: EMCa modification of Figure 1, Powercor response to IR048; also applies to CitiPower
Note: BUS 7.03 (BI/BW business case); BUS 7.01 (SAP business case); BUS 7.10 (Cloud infrastructure business case)

The proposed Option 1 capex for refreshing and growing the on-premise infrastructure is not adequately justified

865. The average annual VPN capex for recurrent infrastructure from 2016-2019 was $8.2m.[274] Given that VPN has already begun transitioning infrastructure to the cloud, we consider the average of $7.0m over the last three years (2017-2019) is likely to be more representative of the BAU recurrent infrastructure capex. VPN has not provided sufficient information in its business case to justify the significantly higher forecast annual average capex of $10.1m throughout the next RCP. Furthermore, although there are multiple references to additional capacity to support 'growth' in the business case, there is no explanation of the growth drivers or growth components that have been incorporated into the forecast.[275]

866. We therefore consider that a reasonable estimate for the Option 1 capex would be approximately $35m for the next RCP. In turn, this would reduce the Option 2 capex by $15m (i.e., to $21m) based on the Option 2 capex reduction shown in Table 7.13.

VPN's methodology for estimating the cost of the residual on-premise infrastructure included in Option 2 is reasonable

867. To determine the reduction in infrastructure costs afforded by shifting some infrastructure to the cloud, VPN has first identified the assumed proportions of infrastructure material cost that are currently used by each of the seven core applications and non-critical applications that VPN propose for transition to the cloud. The negative percentages (indicating reductions) are summarised in the table below.

[274] Powercor/CitiPower's response to IR023, Table 3, page 3

[275] We note that the costs to accommodate additional storage associated with the 5 Minute Settlement rule change are not included in the CitiPower BUS 7.10 (note to Table 4, page 12)

Table 7.16: VPN's assumed material-related capex reductions from migration to IaaS over the next RCP[276]

Application	Server	Storage	Database (Exadata)	Backup	Network	Database (HANA)	Option 2 materials saving ($m, 2021)
Itron IEE	-1%	-2%	-20%	-11%	-1%	0%	-1.0
Itron MTS	-1%	-1%	-10%	-6%	-1%	0%	-0.5
SAP ERP	-1%	-5%	-5%	-5%	-1%	0%	-0.4
SAP BW	-2%	-5%	-10%	-8%	-1%	-100%	-5.9
SharePoint	-3%	0%	0%	0%	-1%	0%	-0.3
Oracle USB	-1%	-1%	-10%	-6%	-1%	0%	-0.8
Non-critical apps	-5%	-10%	-10%	-10%	-1%	0%	0.0
Network drives	-1%	-15%	0%	-8%	-1%	0%	-0.8
Total	**-15%**	**-39%**	**-65%**	**-52%**	**-8%**	**-100%**	**-9.7**

Source: PAL MOD 7.15, Option 2; also applies to CitiPower

868. The reduction to capex afforded by Option 2 (compared to Option 1) is derived by applying these negative percentages to the materials component of cost, resulting in a reduction of $9.7m. Of this $9.7m reduction, the model assumes a further 20% reduction for labour savings ($1.9m) and a 35% reduction for contracts savings ($3.4m), for a total savings of $15.0m.

869. VPN did not provide compelling justification in its model or in its business case for the assumptions used in Table 7.14. These values are fundamental to determining the reasonableness of the opex-capex trade-off that transitioning to IaaS represents. In response to our request for the basis for the assumptions, VPN advised that:[277]

- '*Our estimated capex reduction for migrating these non-core eligible applications is based on the current share of infrastructure for each application';*[278] and
- Our infrastructure capacity is also heavily utilised by a number of OT applications which are not considered eligible for cloud migration and therefore will remain on premise.'

870. We reviewed the proposed percentages in the table above in light of our experience, the response to our information request, and the information in Table 15 in the business case. We consider them to be reasonable estimates.

Opex step change appears to be reasonable in conjunction with reduced on-premises infrastructure capex

871. VPN advised that the forecast opex for migrating applications to cloud hosting was based on vendor advice sourced by external advisors.[279] The costing spreadsheet shows the annual cost (i.e., cloud hosting fee) for each of the 42 infrastructure components that will be cloud hosted. It is appropriate for VPN to source vendor estimates as the basis for its forecast. Based on our review of the itemised costs, they appear to be reasonable estimates. The proposed opex step change itself appears to be reasonable, but only if taken in conjunction with reduced on-premises infrastructure capex.

276 The percentage reduction is from the assumed capex without any cloud transition. The option 2 saving for non-critical apps is zero for Option 2 – this may be an error in PAL's model.

277 Powercor response to IR023 question 19

278 Powercor/CitiPower's response to IR023 question 19

279 CitiPower BUS 7.10 Cloud infrastructure, page 13

The proposed opex reduction in the next RCP to account for fewer on-premise infrastructure is reasonable

872. VPN estimated the reduction in opex from migration to cloud hosting as 5% of the capex reduction. VPN did not provide justification for this amount in its business case or model. In response to our request for more information, VPN advised that '*achieving material operating expenditure savings will only occur in future regulatory periods.*'[280] Based on our experience, we consider that VPN's estimate for the next RCP is reasonable.

Summary of our assessment

873. Our assessment suggests that:

- VPN's proposed strategy of migrating applications and the supporting infrastructure to the cloud is consistent with industry trends and should bring the benefits of scalability, adaptability, reliability and (over time) reduced costs.
- VPN's selected Option 2 'balanced cloud migration' appears to be an appropriate choice and is informed by external advice.
- VPN's estimates for capex and opex savings and opex increases for its preferred option are based on reasonable methodologies.
- VPN's proposed capex for refreshing and growing its remaining on-premise infrastructure has not been adequately justified. Its forecast for the next RCP is approximately $15m higher than its most recent three years of capex would indicate. On this basis, the reduction in capex for the preferred Option 2 would be $15m lower than proposed. The revised Option 2 capex would then be $21m.
- On the basis of reduced on-premise infrastructure capex as above, VPN's proposed opex step change to cover cloud hosting fees of $7.7m[281] is reasonable.

7.5.3 Network Management Systems

874. The Network Management Systems project is common to CitiPower and Powercor. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our assessment is of the total costs and benefits attributable to VPN.

Project overview

875. VPN proposes to invest $28.4m in the next RCP on maintaining the currency of its network management systems which comprise: six core network management systems; two geospatial systems; and two reporting and data processing systems. The main driver of the proposed expenditure is to '*avoid the risk of unsupported or end-of-life systems that may compromise VPN's ability to effectively monitor and manage our electricity network.*'[282]

876. VPN considered three options, described in the table below, and selected Option 1.

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[280] Powercor/CitiPower's response to IR023 question 19

[281] The VPN opex increment in Table 12 of CitiPower BUS 7.10 Cloud infrastructure is $8.2m which aligns with the amount in RIN and includes real cost escalation

[282] CitiPower BUS 7.05 Network management, page 3

Table 7.17: Options summary – VPN Network management systems - $m, real 2021

Option	Capex	PV	Risk
0 - Do nothing - do not upgrade, maintain current software versions in relation to our network management systems.	0.0	n/a	50.9
1 - Refresh current suite of network management systems - Perform prudent technical upgrades to maintain core currency and regulatory compliance, whilst targeting alignment and simplicity	28.4	26.3	13.5
2 - Replace the network management systems with alternative solutions	47.3	43.1	13.6

Source: PAL BUS 7.05; also applies to CitiPower

Our assessment

Option 0 is not consistent with good industry practice

877. VPN's network management systems include 'mission critical' systems running the network. It is not consistent with good industry practice to build up significant 'technology debt'[283] for core systems/applications. The most significant risk arises from systems not being supported by the vendors[284] or alternative third-party suppliers. VPN has estimated monetised risk from IT risks and business risks (reliability, compliance, safety, and bushfire risks). Business risk is estimated to comprise 80% of the total Option 0 risk of $50.9m, arising primarily from the risk of non-compliance. Whilst we have some issues with the input assumptions underpinning the monetised risk,[285] we consider that the reasonable conclusion is that the IT and business risk of Option 0 is significantly higher than for Options 1 and 2.

Option 2 does not add value commensurate with the cost

878. Option 2 as described by VPN involves replacing the network management systems with alternative solutions which provide similar functionality. VPN states that *'[t]his option would involve significant organisational and technology change'…* and '…*would introduce an increased risk of interruptions to network operations/performance'* and '*impact on supply reliability, safety and customer service.'*[286]

879. VPN has provided a breakdown of its assumed labour, materials, and contract cost components. Not surprisingly, the major source of difference between Option 1 and Option 2 is the systems (materials) cost where the Option 1 cost for refreshes and upgrades are a fraction of the Option 2 cost for installing new systems.

880. It is clear from the information provided by VPN[287] and from our own experience, that the benefits of Option 2 are unlikely to outweigh the cost in any reasonable assessment.

881. We note that VPN also considered a variation of Option 2 in which a subset of systems would be replaced with alternatives. Like VPN, we consider this sub-option to be inferior to Option 1 because of integration-related issues.

283 Technology debt is built up by skipping multiple refreshes and, particularly, version upgrades which progressively builds risk of bugs causing malfunctions/errors and business disruption, non-compliance breaches, loss of productivity, and damages

284 That is, beyond published end-of-support dates

285 Annual occurrence of a reliability event, non-compliance, and safety event is assumed, starting in the 1st year of the next RCP – we consider this overstates the likelihood of occurrence; the non-compliance consequence cost is assumed to be $4.75m per event – insufficient evidence is provided to support this

286 CitiPower BUS 7.05 Network management, page 16

287 Including the description of the disadvantages of Option 2 in Table 9 of CitiPower BUS 7.05 Network management

VPN does not discuss the option of cloud migration in the business case

882. VPN's business case makes no reference to the option of migrating some or all of its core Operational Technology (OT) systems to cloud-based hosting to take advantage of the benefits of hosting that it promotes strongly in its ICT Infrastructure Cloud Migration business case (CP BUS 7.10). In response to our question, VPN advises that its OT applications are '*not considered eligible for cloud migration due to the requirement to host these applications in a highly secure environment physically close to the electrical network being managed. These systems must be able to operate independently of external events…'*[288]

883. It is not clear from the response how cloud migration fits into the OT vendors' plans for the future; however, we infer from VPN's response that there will continue to be vendor support for the on-premise versions for at least the duration of the next RCP.

Option 1 appears to include too many upgrades

884. The figure below shows VPN's network management systems roadmap which identifies multiple upgrades for several OT systems in the next RCP. This includes annual upgrades for the AWS product and biannual upgrades for the Sensor IQ product. Whilst we acknowledge that building up significant technology debt is not commensurate with good industry practice, the frequency of system upgrades (not refreshes) appears to be excessive.

885. We discussed this concern with VPN at our meetings with them and via a follow-up information request. VPN's position is summarised as:[289]

- The roadmap timing profile is aligned with vendor product support schedules;
- The forecast cost per refresh is based on previous refresh costs incurred in the current RCP and projected infrastructure hardware replacement cycles (every five years);
- VPN does not necessarily adopt the most recent vendor release version immediately, '*rather we wait allowing other parties to test the new product first, so we have assurance that there are no significant defects and/or any defects identified have been rectified';*
- Of the forecast $26.9m for the current RCP, it expects to spend $26m; and
- It '*also considered a number of general factors (e.g., project concurrency, resource availability…)'.*

886. In relation to VPN's reference to delaying the adoption of vendor releases, we note from our review of VPN's Market Systems business case, discussed in section 7.6 that VPN states that its selected option '…*extends asset life beyond formal vendor recommended upgrade timelines within acceptable risk levels and delays upgrades and associated costs until necessary'.*[290] We consider that approach, which is based on considering recommended vendor upgrade timelines, risks and costs provides a more compelling basis for ensuring a prudent level of expenditure than has been provided by VPN in relation to Network management systems.

887. VPN's proposed capex for the next RCP is $2.4m (9%) higher than the expected Network management systems expenditure in the current RCP. We remain concerned about the prudency and efficiency of the proposed upgrade cycle mainly because the value of each upgrade may not be realisable and, as shown in the roadmap, the resourcing load appears to be unnecessarily high.

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288 Powercor/CitiPower response to IR023, question 19(b)

289 CitiPower BUS 7.05, pages 11, 15; Powercor/CitiPower response to IR023, question 12

290 CitiPower BUS 7.06, page 4

Figure 7.11: VPN network management systems roadmap

System	Product	2021/22	2022/23	2023/24	2024/25	2025/26
Network Management Core						
SCADA/DMS	PowerOn Advantage	Complete DMS/OMS migration	Maintenance Release		Upgrade	
OMS	PowerOn Restore	Retired				
Supply Quality	Sensor IQ	Upgrade		Upgrade		Upgrade
Switching	EDNAr	System Refresh	System Refresh		System Refresh	System Refresh
Protection Systems	Schneider Electric ION		Upgrade		Upgrade	
Network Geospatial						
GIS	GE Smallworld CORE		Upgrade	S4HANA Integration	Upgrade	
Network Visualisation	Map Insights	System Refresh			System Refresh	
Network Reporting and Analytics						
Network Data Processing	AWS Data Analytics, tooling, platform	Upgrade	Upgrade	Upgrade	Upgrade	Upgrade

Source: CitiPower BUS 7.05 Network Management, Appendix C

Summary of our assessment

888. We remain unconvinced of the prudency and efficiency of VPN's proposed frequency of upgrades/refreshes, particularly: (i) annual Network data processing ($5.4m); and (ii) four EDNAr refreshes in five years ($2.5m). We consider an amount that is 10-15% less than proposed is more likely to represent an efficient level of expenditure.

7.6 Observations on remainder of proposed capex

7.6.1 5 Minute Settlement (Non-recurrent)

889. CitiPower's business case provides the supporting information for its proposed incremental opex, Non-recurrent ICT capex, and augex for communications devices to meet the 5-minute settlement compliance obligations for both CitiPower and Powercor.[291] We have made observations regarding all three expenditure components in this section and unless stated otherwise, we refer to the combined expenditure for VPN.

Overview of the proposed project

890. Any Victorian smart meter installed after December 2018 must have the capability to record five-minute interval energy data by 31 December 2022. VPN advised that its ICT systems do not currently comply with the relevant changes to the Rules. It proposes $17.8m ICT capex, $6.9m incremental opex, and $14.1m network communications capex to address this compliance gap.

Our observations

Obligations must be met by 31 December 2022

891. VPN has a firm obligation to be able to retrieve, process and deliver data from Type 5 AMI Meters to the market by 31 December 2022. The proposed expenditure relates to this obligation.[292]

291 AEMC, Rule determination, National Electricity Amendment (Five Minute Settlement) Rule 2017

292 CitiPower BUS 7.09 – 5 minute settlement, Table 1

IT systems upgrade costs are based on relatively old information

892. To manage the expected increased volume of data that VPN is responsible for under the 5-minute settlement rule change, VPN has identified that it will need to:[293]

- Upgrade its IT systems;
- Install additional communication devices;
- Increase its Wide Area Network (WAN) and data processing capacity; and
- Manage an increase in the volume of manual validations of meter data exceptions.

893. VPN advises that the purpose of its proposed IT systems upgrade is to support retrieval of five-minute interval meter data from smart meters, together with the subsequent validation, storage, and distribution of five-minute data to market participants including retailers, AEMO, and customers.

894. VPN's labour time estimates are based on historical costs, referring to its metering contestability project in 2017 and IT systems upgrade project to accommodate AMI meters in the AMI roll-out.

895. Whilst using historical costs is typically a reasonable starting point for cost estimation, the recency of the information is fundamental to achieving a reasonable estimate. Given the quantum of capex involved ($17.8m) and the time that has elapsed from its reference projects, we would have expected more compelling information to be provided to demonstrate that the materials costs and labour volumes are based on reasonable and updated assumptions. The labour rates are based on information provided by PwC (per PAL MOD 12.02), which should provide a reasonable source for the labour rates.

896. We would expect that benchmarking of unit costs and the capex and opex per customer for VPN and the other three Victorian DNSPs would provide a useful starting point for establishing the efficiency or otherwise of the proposed costs.

WAN and data processing capacity costs appear reasonable

897. VPN has provided a breakdown of the volume and unit costs assumed in its forecast. VPN leverages recent unit costs which appear reasonable.

Communication network costs

898. VPN has estimated the capex for new communications devices by having: (i) identified the four types of devices required; (ii) estimated the increased volume of each device from forecast growth in meter reads plus the expected geographical gaps in its existing communications network capability; and then (iii) applied unit rates derived from recent costs.[294] This approach seems reasonable.

899. VPN has provided a cost model with a detailed breakdown of components of the unit cost and the volumes of devices.[295] The cost model differentiates between the communications devices required for 5-minute settlement obligations, and for its other related projects including the 3G-shutdown (refer to section 5.8.3 in our assessment of Augex), and for its annual repex program. Therefore, there appears to be no overlap/duplication of costs. The communications network costs therefore seem to be reasonable estimates.

Opex step change

900. VPN further advises that it will incur incremental operating expenditure during the next RCP for: (i) increased WAN capacity to transport increased volume of meter data between IT systems and; (ii) to manage the increase in manual validations of meter data exceptions.

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293 CitiPower BUS 7.09 5-minute settlement, page 9

294 CitiPower BUS 7.09 5-minute settlement, page 18

295 PAL MOD 6.03 (there is no equivalent CitiPower model)

901. VPN has estimated the opex increase based on the growth in forecast meter data volumes multiplied by the unit rate of WAN capacity and nodes. This approach seems reasonable. A step change is evident in its forecast from 2021/22 onwards.[296]

Summary of our observations

902. With the exception of the lack of compelling information to support the cost estimate for IT systems upgrades costs, our observations suggest that VPN's approach and cost estimates are reasonable.

7.6.2 Market Systems (recurrent)

903. The Market Systems project is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

Project overview

904. VPN proposes to invest $9.3m in the next RCP to maintain the currency of its market systems - which provide storage and validation of meter reading data and manage market-compliant communications and customer requests. VPN considered three options, as described in the table below, and selected Option 1.

Table 7.18: Options summary – Market systems - $m, real 2021

Option	Capex	Risk
0 - Do nothing - do not upgrade to maintain current software versions in relation to Market Systems. Additional operating expenditure is charged by vendors.	0.0	36.4
1 - Prudent technical upgrades - remain within vendor support by adopting every second software version release upgrade	9.3	2.2
2 - Vendor released technical upgrades - perform system upgrades as released by vendors, maintaining pace with newest available versions as they are released	11.4	2.2

Source: CP BUS 7.06, Table 1

Observations

905. We consider that adopting Option 0 would not be consistent with the actions of a prudent operator. Option 2 results in upgrades approximately every two years and '*…the full value of each upgrade may not be realised and the resourcing load is high*.'[297]

906. Unlike Option 2, Option 1 extends asset life beyond the vendors' recommended upgrade timelines at what VPN considers to be acceptable risk levels, delaying upgrades and associated costs until necessary – which VPN refers to as an 'N-1' strategy. VPN also advises that '*our vendors will support the previous version (N-1) of its market systems, they will not support prior versions (N-2 or earlier)*'.[298]

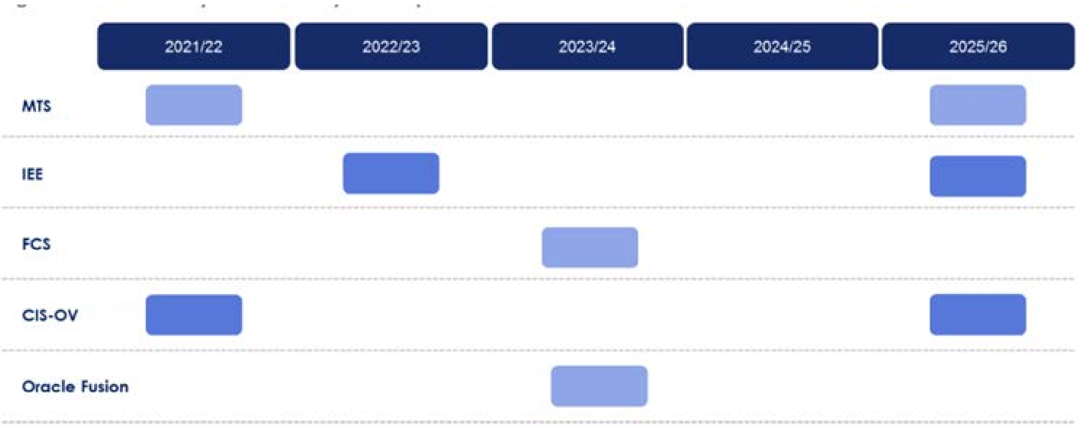
907. As shown in the figure below, the proposed upgrades appear well balanced between the five systems and the 3-5 year refresh cycles for the systems do not appear to be excessive.

296 CitiPower BUS 7.09 5-minute settlement, Table 10

297 CitiPower BUS 7.06 Market systems, page 17

298 CitiPower BUS 7.06 Market systems, pages 4, 10

Figure 7.12: VPN's Market Systems currency roadmap



Source: CP BUS 7.06, p20

908. VPN's average annual market systems capex in the current RCP (2016-2019) was $1.9m, which is the same as its forecast annual average capex for the next RCP.[299]

7.6.3 Business Intelligence and Warehousing (recurrent)

909. The Business Intelligence/Business Warehousing (BI/BW) project is common to Powercor, CitiPower and United Energy. Capital costs are allocated 42% ($2.5m) to Powercor, 18% ($1.1m) to CitiPower and 40% ($2.3m) to United Energy. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN and United Energy.

Project overview

910. VPN/UE proposes to invest $5.9m in the next RCP to consolidate all data warehouses to have a shared data warehouse used by all three businesses. VPN/UE considered three options, as described in the table below, and selected Option 2.

Table 7.19: VPN/UE's options summary – BI/BW - $m, real 2021

Option	Capex
0 - Do nothing - Leave the existing data warehouse and reporting solutions as they are currently without any upgrade.	0.0
1 - Retain the current respective data landscapes at CitiPower, Powercor and United Energy. Undertake periodic upgrades of Data Warehouses and Reporting applications.	6.8
2 - Consolidate all existing data warehouses to have a shared data warehouse used by all businesses and increase the scope of self-service reporting capability to support needs of all our businesses.	5.9
3 - Consolidate the Data Warehouse Platforms to have a single data warehouse for each business: one for CitiPower, Powercor and one for United Energy.	8.3

Source: CP BUS 7.03 BI BW, Table 1, p4

Our observations

911. Option 0 is not consistent with good industry practice.

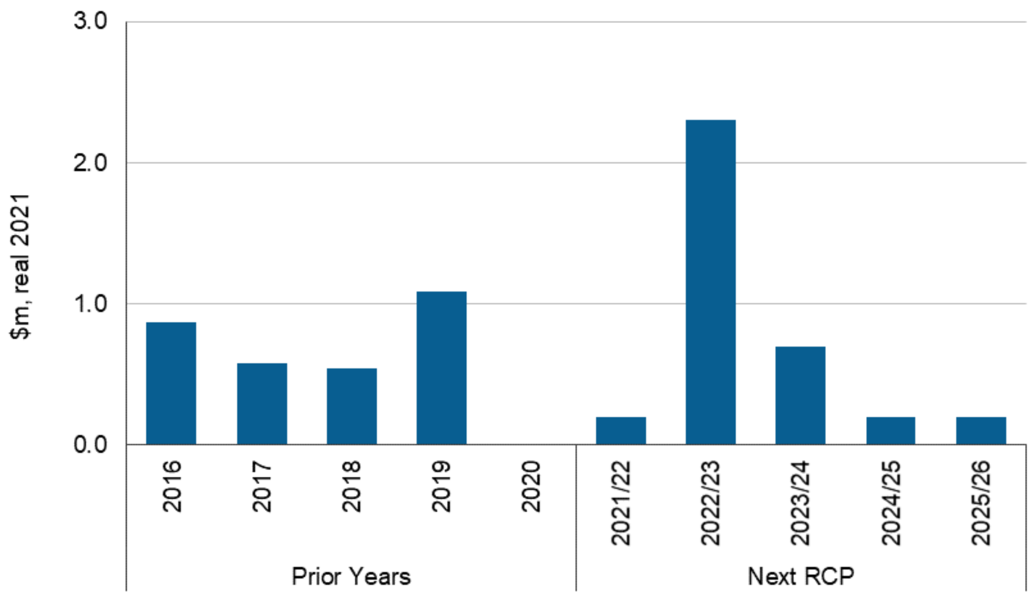
912. Currently the VPN and United Energy business intelligence functions are supported by separate presentation layers and are underpinned by multiple data warehouses. VPN/UE propose consolidating the data warehouses, which is the cheapest option and appears to be the prudent and efficient choice. Consolidation to an integrated common Data Lake

299 Powercor response to IR023

platform as a foundation to a consolidated Enterprise Data Warehouse & Analytics platform is the recommended approach and appears to be the prudent approach. VPN identifies a business risk due to having a single core data warehouse system and concludes that the benefits outweigh the risks.

913. As a crosscheck, we asked VPN to provide the BI/BW capex for the current RCP, which is shown in the figure below for VPN only along with the annual forecast capex for the next RCP (noting that the expected 2020 amount was not provided). The average annual historical capex of $0.77m (2016-2019) for VPN is 6% higher than the forecast capex of $0.72m pa for VPN for the next RCP.

Figure 7.13: VPN's historical and forecast BI/BW capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.12; also applies to CitiPower

7.6.4 Device replacement (recurrent)

914. The Device replacement project is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower (based on their share of total customer numbers). Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

Project overview

915. VPN proposes to invest $19.4m in the next RCP on maintaining the currency of its end-user devices.[300] VPN considered three options, as described in the table below, and selected Option 1. VPN states that *'[i]f we do not replace devices at end of useful life we will experience significant cost increases in the delivery field services, as well as deteriorations in network reliability and safety risks.'*[301]

300 Computers, laptops, mobile phones and tablets, videoconferencing units, projectors and display screens

301 CitiPower BUS 7.12 Device replacement, page 3

Table 7.20: Options summary – Device replacement - $m, real 2021

Option	Capex
0 - Do nothing - do not replace devices	20.0
1 - Replace devices at end of useful life	19.4
2 - Replace the devices in bulk at the beginning of the period	26.7

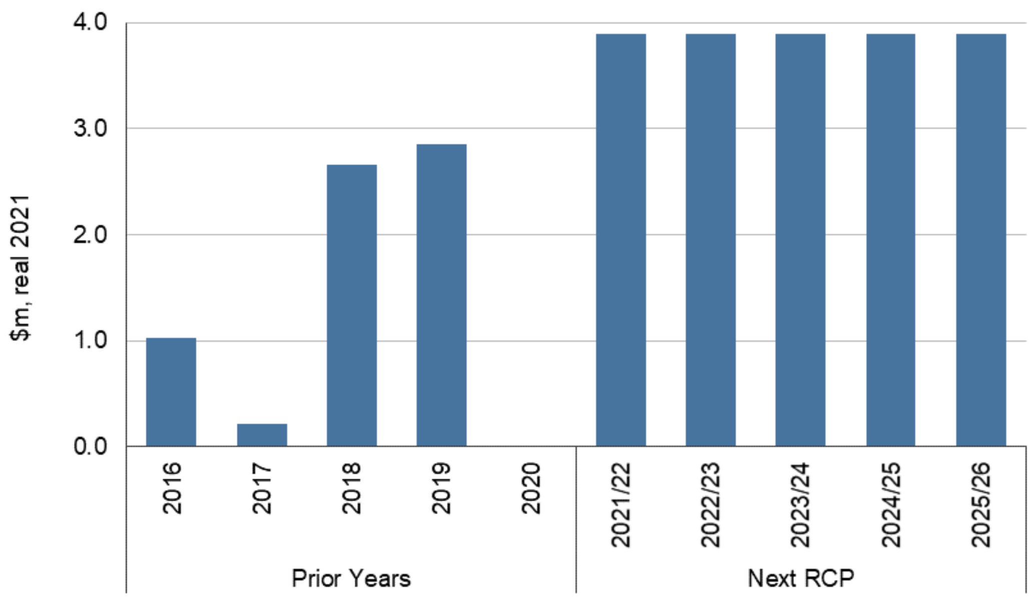
Source: CP BUS 7.12, Table 1

Our observations

916. Options 0 and 2 are not consistent with good industry practice, with Option 2 unlikely to add sufficient sustained net benefits compared to Option 1.

917. With respect to Option 1, we asked VPN to provide the device replacement capex for the current RCP, which is shown in the figure below along with the annual forecast capex for the next RCP (noting that the expected 2020 amount was not provided). The average is $1.7m or roughly 50% of the forecast capex of $3.9m p.a. for the next RCP. VPN does not explain this difference in its business case, but in its response to our information request (IR023) it explains that the cost increase is due to reverting to a purchase rather than lease approach.

Figure 7.14: VPN's historical and forecast Device replacement capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR023 and PAL BUS 7.12

918. VPN advised that its useful device life is *'…based on our experiences with devices over the past decade, vendor recommendations and current replacement practices.'*[302] We would expect VPN's opex forecast for the next RCP to be reduced by an amount commensurate with its reduced lease charges.

7.6.5 Enterprise management systems (recurrent)

919. The Enterprise management systems business case is common to Powercor and CitiPower. Capital costs are allocated 70% to Powercor and 30% to CitiPower. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

302 CitiPower BUS 7.12 Device replacement, page 7

Project overview

920. VPN proposes to invest $14.8m in the next RCP to maintain the currency of its Enterprise Management Systems (EMS) because:[303]

- applications are reaching end-of-life or end-of-vendor support;
- integration of EMS applications with the proposed upgraded SAP system (referred to in section 7.4.4) is required; and
- of changes in technology, customer requirements, and cyber security threats.

921. VPN considered three options, as shown in the table below, and selected Option 1.

Table 7.21: VPN's options summary – Enterprise management systems

Option	Capex
0 - Do nothing – do not perform any work, leave systems in current state, and manage resulting impacts and consequences	0.0
1 - Maintain – perform required updates or upgrades to maintain a stable and efficient IT ecosystem, while retaining an adequate level of vendor support	14.8
2 - Transform – identify opportunities for transformation with the aim of unlocking larger benefits that could be passed on to customers (additional functionalities and efficiencies).	19.0

Source: CP BUS 7.11 EMS, Table 1

Our observations

922. Option 0 is not consistent with good industry practice. Option 2 is unlikely to add sufficient sustained net benefits compared to Option 1.

923. VPN states that its objective is to *'…ensure that all the applications in the scope of this business case are kept current (*N-1*), efficient, secure, and within an adequate vendor support window over the 2021–2026 regulatory period.*[304] We observe that what VPN refers to as a 'N-1' strategy is likely to lead to more efficient costs than an N-0 or an N-2 strategy.[305]

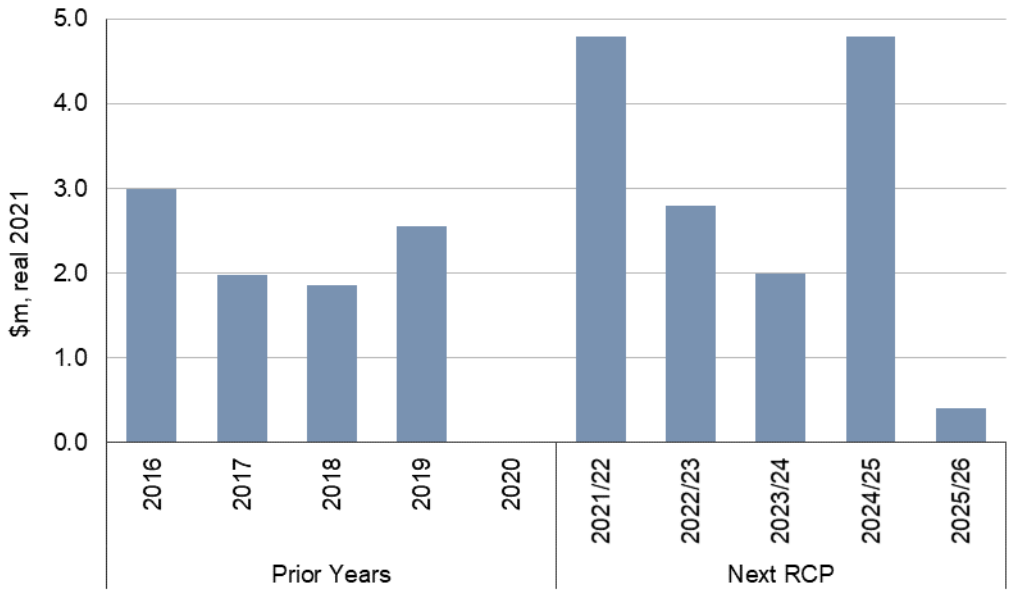
924. We asked CitiPower to provide the EMS capex for the current RCP, which is shown in the figure below together with the annual forecast capex for the next RCP (noting that the expected 2020 amount was not provided). The forecast capex of $3.0m p.a. for the next RCP is 26% higher than the $2.3m annual average capex over the period 2016-2019.

303 CitiPower BUS 7.11 EMS

304 CitiPower

305 'N-1': applications are maintained within one release of the latest available version; 'N-2' maintaining applications within two releases of the latest available version

Figure 7.15: VPN's historical and forecast Enterprise management systems capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR023 and PAL BUS 7.12; applies to CitiPower[306]

925. VPN does not explicitly explain the reason for the 26% higher forecast expenditure for the next RCP. However, it does identify the status of the 12 enterprise systems and its plans for each in Table 7 of the business case, which provides some confidence in VPN's analysis.

926. We observe that VPN proposes approximately $1.3m capex in 2022/23 to upgrade the Oracle database, which is planned to be replaced by the HANA database in 2023/24 as part of the SAP S/4HANA and ICT Infrastructure Cloud Migration projects discussed in sections 7.4.4 and 7.5.2, respectively. Given that VPN also proposes upgrading to version 12c in 2021/22, we consider that upgrading the Oracle database in the year prior to its replacement is unlikely to be prudent.

7.6.6 Facilities security (recurrent)

927. CitiPower's forecast $2.5m ICT component of VPN's $8.5m Facilities security project is discussed in our review of property capex included in section 8.3.

7.6.7 General compliance (recurrent)

928. The General compliance project is common to Powercor and CitiPower. Capital costs are allocated 50% to Powercor and 50% to CitiPower. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN.

Project overview

929. CitiPower proposes spending $4.6m as part of VPN's $9.2m on 'General IT compliance' projects to meet anticipated obligations as they are periodically amended. VPN advises that *'[w]e anticipate that during 2021–2026 there will be a similar trend in amendments to regulatory obligations we have seen over the current regulatory period.'*[307] VPN considered two options – Do nothing and its preferred approach.

Our observations

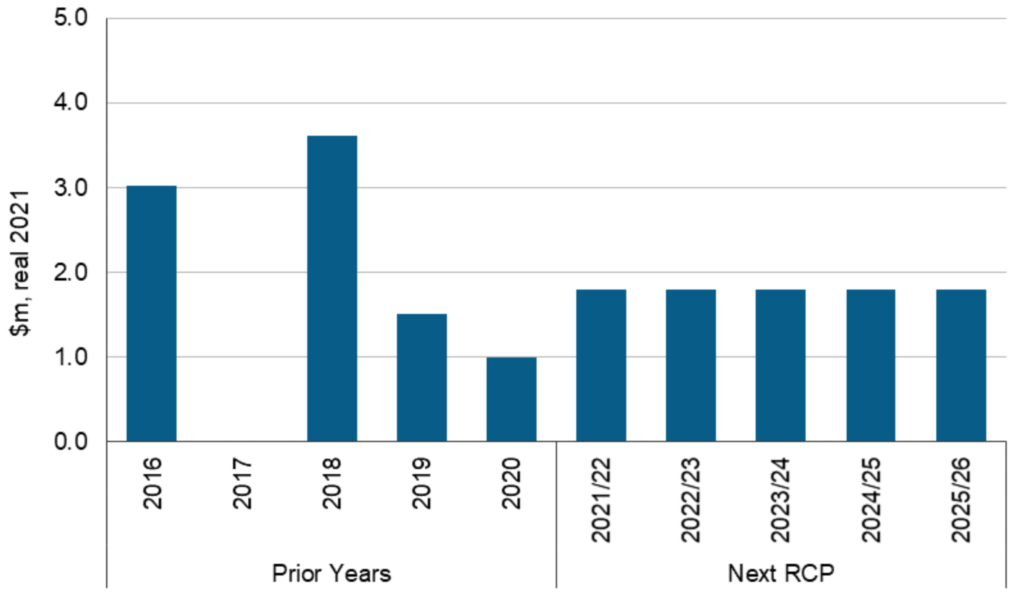
930. We asked VPN to provide the General IT compliance capex for the current RCP, which is shown in the figure below along with the annual forecast capex for the next RCP (noting that the expected 2020 amount was not provided). The historical average annual capex over

306 Annual expenditure is based on format of data provided by VPN

307 PAL BUS 7.14, page 4

2016-2019 is $2.0m, which is slightly higher than the proposed annual average of $1.8m p.a. for the next RCP.

Figure 7.16: VPN's historical and forecast General IT compliance capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR0023 and PAL BUS 7.14[308]

7.6.8 Telephony (recurrent)

931. The Telephony business case is common to Powercor, CitiPower, and United Energy. Capital costs are allocated 40% to Powercor, 17% to CitiPower and 44% to United Energy based on their respective customer share and United Energy bearing the full cost of integrating its contact centre with VPN's contact centre. Unless otherwise stated, our observations relate to the total costs and benefits attributable to VPN/UE.

Project overview

932. VPN/UE proposes spending $10.1m on Telephony to maintain system currency, to integrate United Energy's contact centre, and to enhance customer experience (which it refers to as Option 2). VPN/UE considered two other options in addition to the preferred option:

- Option 0: Do nothing—do not upgrade the existing telephony platforms ($0.0m); and
- Option 1: Maintain the currency of current systems and integrate United Energy's contact centre ($8.5m).

Our observations

933. Option 0 (do nothing) is not consistent with good industry practice as it will build up significant technology debt and could reasonably be expected to progressively lead to degraded performance and higher maintenance costs.

934. Option 1 involves investing in: (i) the latest available version of the Unified Computing System (UCS) platform offered by Cisco in 2021/22; (ii) the latest available version of the BT telephony platform in 2023/24; and (iii) upgrading telephony capacity for the integration of the United Energy general enquires/connections line. The latter step is claimed to be more efficient than maintaining separate call centres: [*t]hese savings have been accounted for in the operating expenditure cost estimate of the efficient integration of the contact*

308 Annual expenditure is based on format of data provided by VPN

centres…'[309] The quantum of savings is not identified in the business case or the supporting model.[310]

935. VPN/UE does not consider (and therefore does not cost) the option of maintaining separate systems between VPN and United Energy in its business case. It is reasonable to assume that there are cost savings from integrating the contact centres, but this option should have been presented for completeness.

936. For an extra $1.5m over 5 years, VPN/UE's Option 2 will increase its telephony capabilities to improve the customer experience by incorporating omni-channel capabilities and faster customer identification through an Interactive Voice Response (IVR) interface. VPN/UE claim that this feature will:[311]

- save customers a minimum of 1 minute each per annum and that this is sufficient to '…*ensure the investment is worthwhile'*; and
- provide a credible response to customer feedback: '*Around 80% of our customers across the three networks were interested in easier access to their data and information and enhances [sic] customer experiences.'*[312]

937. VPN/UE value a residential customer minute at about $0.18, and collectively the three DNSPs are forecast to have about 2.0m customers in the next RCP. However, VPN/UE's economic model does not include its estimate of how many customers will actually benefit from the new service. Therefore, it does not provide an NPV that is inclusive of benefits and infrastructure refresh costs.

938. The cost estimates for the major components of Option 1 are based on relatively recent upgrades and integration projects involving the three DNSPs, which is a reasonable approach.

939. Referring to the figure below, the average annual expenditure in the current RCP for VPN only is $0.9m p.a., whereas for the proposed Option 2, this will increase to an annual average of $1.1m or an extra $1.0m over the next RCP (incurred mostly in 2021 and for VPN's share of the additional Option 2 features).

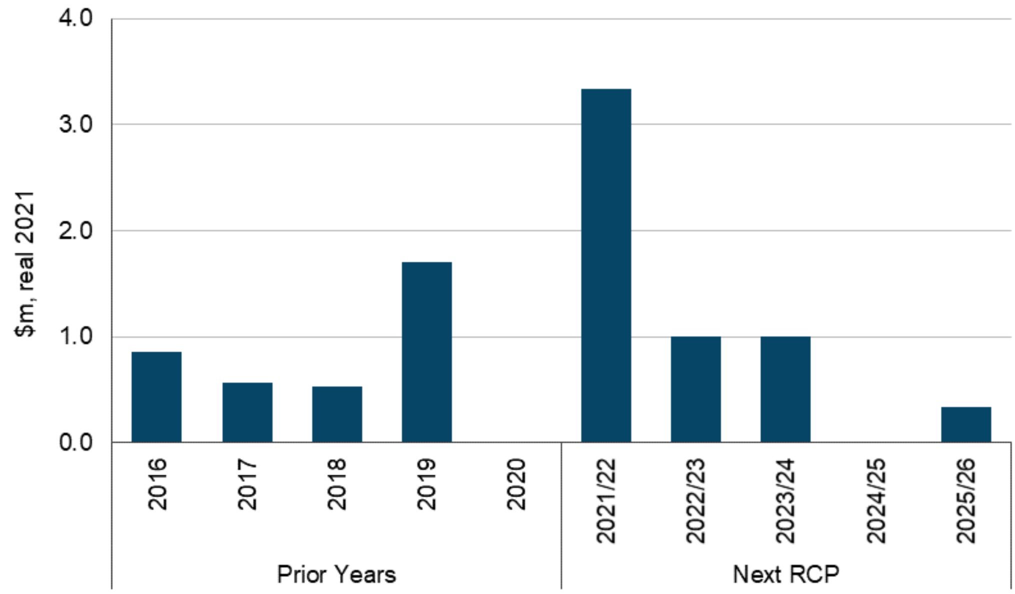
309 CitiPower BUS 7.13, page 11

310 No opex – either savings or expense – is identified in the model CP MOD 7.19

311 CitiPower BUS 7.13 Telephony, page 14

312 CitiPower BUS 7.13 Telephony, page13

Figure 7.17: VPN historical and forecast Telephony capex - $m, real 2021



Source: EMCa analysis of information provided in response to IR023 and PAL BUS 7.14[313]

7.7 Summary of findings and implications for CitiPower's ICT capex forecast

940. We consider that CitiPower's proposed capex for its ICT programs for the next RCP is above that required by a prudent and efficient operator.

Selected options are typically appropriate

941. With two exceptions (Digital Network and Customer Enablement) we consider that the preferred options identified and presented in the business cases are appropriate. In our opinion, the selected options for the Digital Network and Customer Enablement business cases are not supportable as a whole. However, components of the options may be economically justified with a reduced scope. In some other cases, for completeness, we consider that another credible option should have been included in the analysis although we do not have reason to believe that these would have been preferable to the selected option.

Some claimed benefits in non-recurrent projects are over-stated

942. For several projects with non-recurrent expenditure, CitiPower provided supporting models which identify benefit streams to help justify the expenditure. Our assessment is that the benefits suffer from one if not more of the following issues:

- benefits are overstated – underlying assumptions do not pass the 'reasonableness test';
- benefits are not adequately supported by evidence; and
- benefits are assumed to be immune to erosion over time - in our view there is significant uncertainty as to the longevity of certain claimed benefit streams that were relied upon to generate a positive NPV for the project.

943. For each business case for which a model was presented, we undertook sensitivity analysis to test the robustness of the proposed quantum and timing of the proposed expenditure to determine reasonable prospective negative variances. In some cases, such as Intelligent Engineering, we found that despite overstated benefits, the project should still be

[313] Annual expenditure is based on format of data provided by VPN

undertaken by a prudent operator. However, in other cases, we determined that the extent of expenditure is not justified.

Approaches to recurrent expenditure timing varies between business cases

944. We consider that the strategy of maintaining 'technology debt' at prudent levels by balancing vendor refresh/upgrade recommendations with a combination of skipping some upgrades and extending maintenance support is consistent with good industry practice. However, in several instances, we identified planned upgrades and refreshes that are likely unnecessary and which we consider reflects unjustified capex. They will also put at risk the organisations' capacity to efficiently absorb the change management workload which, in turn, will threaten the value of the upgrade.

Change management risk to project delivery may be under-recognised

945. In our opinion, business cases which promote integrating VPN and United Energy systems, consolidating on one platform and/or incorporating cloud hosting options are likely to provide long term net benefits (i.e., beyond the next RCP). However, there is significant change management risk in such projects, which may affect the delivery of the entire work program as proposed.

The ICT infrastructure cloud migration opex step change is reasonable

946. We consider that the proposed opex step change for VPN to account for the increase in hosting charges resulting from the transition of ICT infrastructure to the cloud is reasonable. The opex-capex trade-off is reasonable only with our proposed reduction to the proposed \$36.0m capex for the refresh/upgrade of the remaining on-premise infrastructure.

8 REVIEW OF PROPOSED BUILDINGS AND PROPERTY CAPEX

In this section, we present our review of CitiPower's proposed buildings and properties capex, which comprises two streams: facilities security upgrades and a proposed proactive building compliance program to rectify identified defects.

Except for a component of facilities security upgrades that is allocated to depots (of which CitiPower has only one), we consider that the security upgrade expenditure is reasonable.

We consider that CitiPower has not provided sufficient information to justify its proposed proactive building defect rectification program.

8.1 Introduction

947. In this section we discuss and review CitiPower's proposed expenditures for Building and Property for the next RCP. The forecast expenditure comprises proposed programs of work for facilities security upgrades and proactive building compliance upgrades.

8.2 Overview of buildings and property expenditure

948. As shown in Table 8.1 below, CitiPower proposes to spend a total of $15.6m (including real labour cost escalation) on buildings and property in the next RCP (2021 – 2026). This equates to an average of $3.1m per year.

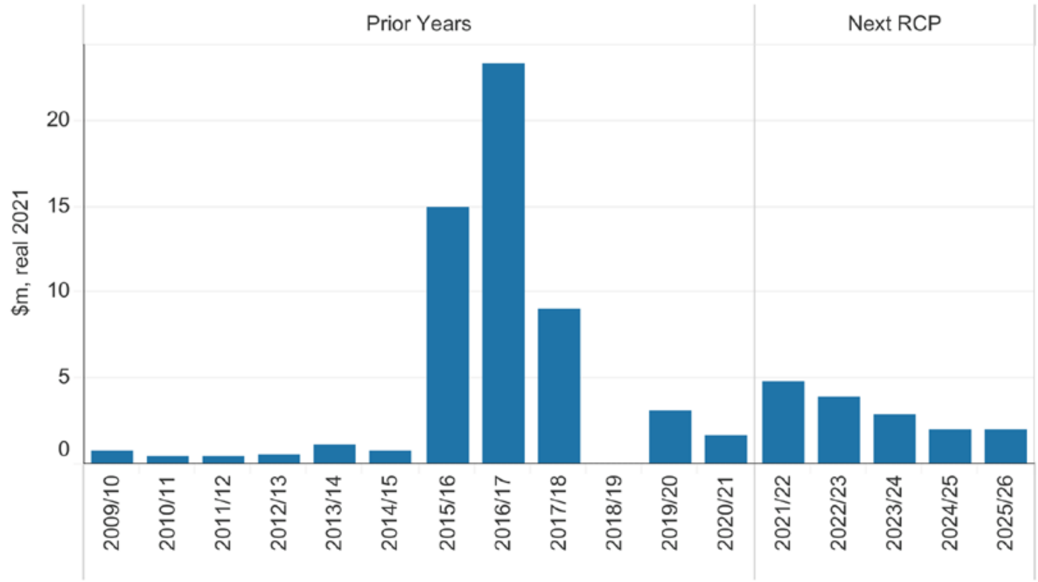
Table 8.1: RIN category - Buildings and property capex - $m, real 2021

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Buildings and Property	4.8	3.9	2.9	2.0	2.0	**15.6**
Total	**4.8**	**3.9**	**2.9**	**2.0**	**2.0**	**15.6**

Sources: CitiPower RIN001

949. The graph below shows CitiPower's expenditure trend from prior years (2009/10 – 2020/21) compared to the next RCP (2021/22 – 2025/26). It shows significantly elevated expenditures from 2015/16 to 2017/18, which is when we understand CitiPower redeveloped its depot.

Figure 8.1: Buildings and property capex trend graph - $m, real 2021



Source: CitiPower RIN001 & RIN008. CitiPower provided calendar year data of $1.2m for 2018 and $0.2m for 2019. It did not provide financial year data for the 2018/19 year hence we have left this blank in the graph, however an indicative amount could be reasonably interpolated.

950. CitiPower's disaggregation of its proposed amount excludes real cost escalation and amounts to $15.4m, of which $9.4m will be spent for Facilities and the balance of $6.0m for Building Compliance as shown in Table 8.2 below.

Table 8.2: Building and property capex, excluding real cost escalation - $m, real 2021

Asset category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Facilities	3.0	2.1	1.6	1.4	1.4	9.4
Building compliance	1.8	1.8	1.2	0.6	0.6	6.0
Total Cost	**4.8**	**3.9**	**2.8**	**2.0**	**2.0**	**15.4**

Sources: CP MOD 8.01

8.3 Review of proposed facilities security upgrades

8.3.1 Basis for CitiPower's proposal

951. CitiPower submitted its Business Case (CP BUS 8.01) and an options analysis model (PAL MOD 8.03) to support its proposed expenditures. The Business Case and the model are for both CitiPower and Powercor, with the details of the split as shown in Table 8.3 below.

952. The proposed expenditure is to increase the security of CitiPower's critical assets including zone substations, distribution assets and depots in response to increasing concerns of theft and other unauthorised access.

Table 8.3: Facilities capex for Powercor and CitiPower - $m, real 2021 (excluding real cost escalation)

Company	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Powercor	8.6	6.5	5.5	4.8	4.8	**30.2**
CitiPower	3.0	2.1	1.6	1.4	1.4	**9.4**
Total	**11.6**	**8.6**	**7.1**	**6.2**	**6.2**	**39.6**

Source: EMCa analysis from CP MOD 8.02

953. Powercor/CitiPower engaged an independent security review from Bellrock Group to assess the security of their critical assets using a risk-based approach. Based on that review, CitiPower has developed a program to install new fencing, enhance monitoring measures such as anti-theft alarms and lighting, and to establish a security control room to proactively manage security alerts. These measures are intended to help ensure the safety of their staff, the community, and their assets.

954. In its business case, Powercor/CitiPower states *''The Review noted that Powercor/CitiPower are managing some risks well, with good controls in place, and [are] recognised as having a strong commitment from the Executive and Board to improve its security program and underlying culture. However, it also identified that 'there are some gaps and a lower level of maturity when assessed against the industry and some high security risks across [our network]. This places CitiPower and Powercor at a higher level of risk, potential increased costs, lower operational effectiveness and increased reputation risk, compared to its peers.*

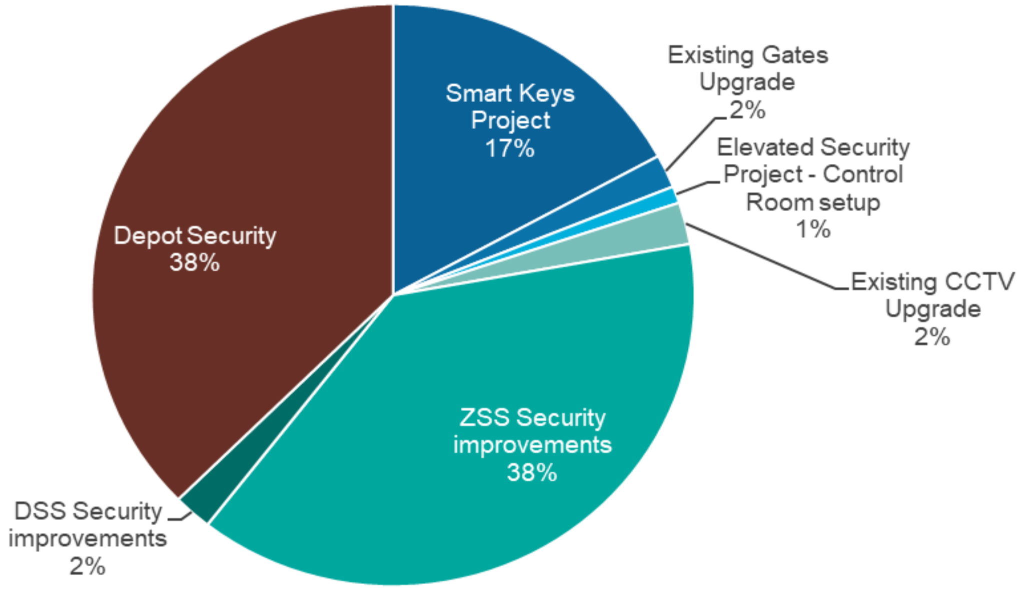
955. Details of the projects proposed by Powercor and CitiPower are shown in the table and chart below.

Table 8.4: Powercor/CitiPower proposed Facilities projects - $m, real 2021 (excluding real cost escalation)

Proposed projects	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Smart Keys Project	4.3	2.5	0.0	0.0	0.0	6.8
Existing Gates Upgrade	0.7	0.0	0.0	0.0	0.0	0.7
Elevated Security Project - Control Room setup	0.4	0.0	0.0	0.0	0.0	0.4
Existing CCTV Upgrade	0.0	0.0	0.9	0.0	0.0	0.9
ZSS Security improvements	3.0	3.0	3.0	3.0	3.0	15.2
DSS Security improvements	0.2	0.2	0.2	0.2	0.2	0.8
Depot Security	3.0	3.0	3.0	3.0	3.0	14.8
Total	**11.6**	**8.6**	**7.1**	**6.2**	**6.2**	**39.6**

Source: EMCa analysis from CP MOD 8.02

Figure 8.2: Powercor/CitiPower proposed Facilities projects - percentage breakdown



Source: EMCa analysis from CP MOD 8.02

956. Powercor/CitiPower present three options which it has analysed, which are:

- Option 0 - do nothing to invest in our facilities' security;
- Option 1 - address highest risk sites; and
- Option 2 - address all sites.

957. Costing of these options and cost allocation between the businesses is shown in Table 8.5.

Table 8.5: Powercor/CitiPower options analysis costings - $m, real 2021 (excluding real escalation)

Company	Option 0	Option 1	Option 2
Powercor	0	30.2	54.6
CitiPower	0	9.4	52.4
Total	**0**	**39.6**	**107.0**

Source: PAL MOD 8.03

958. Option 1 is CitiPower's preferred option for the following reasons:

- **Safe & dependable:** Option 1 supports the continued safe, reliable, and secure delivery of electricity;
- **Flexible:** Option 1 includes reasonable provisions to address increasing physical security threats according to industry best practice security standards; and
- **Affordable:** Option 1 reflects a balanced investment in physical security, targeting high risk sites.

8.3.2 Our assessment

Key assumptions in its CBA are not evidenced, and some assumed benefits appear overstated

959. We reviewed CitiPower's supporting documentation including its Cost Benefit Analysis (CBA) model. CitiPower's CBA sought to quantify a range of benefits which consider:

- reduced risks of death or serious injury at zone substations and at distribution substations from unauthorised entry and from unserved energy arising from security breaches;
- reduced risks of death or serious injury and reduced direct costs from copper theft;
- reduced risks of death or serious injury and staff safety arising from damage by vandals and/or theft from depots.

960. Powercor/CitiPower did not provide evidence to support the assumptions in its CBA. For example, it did not provide evidence of increasing risks of the type described above, or of the average incidence of such events.

961. Whilst we acknowledge the nature of the risk-costs as described, we consider some of the input assumptions to be questionable. For example, Powercor/CitiPower's assumptions regarding the likelihood of death or serious injury are applied to several possible circumstances and then at each such facility. Powercor/CitiPower describes the risk of a death or serious injury from copper theft as a '*one in 100 year event*'; however, its calculation then multiplies that by 44 '*average annual number of unauthorised entry incidents*' such that its calculated risk becomes 44% in any one year.[314]

962. Taking all of the sources of risk together, we have calculated that Powercor/CitiPower's assumptions would imply death or serious injuries currently occurring across Victoria Power Networks at a rate of 1.6 per year. We would not expect this to be the case, and CitiPower did not provide evidence of such extreme current risk.

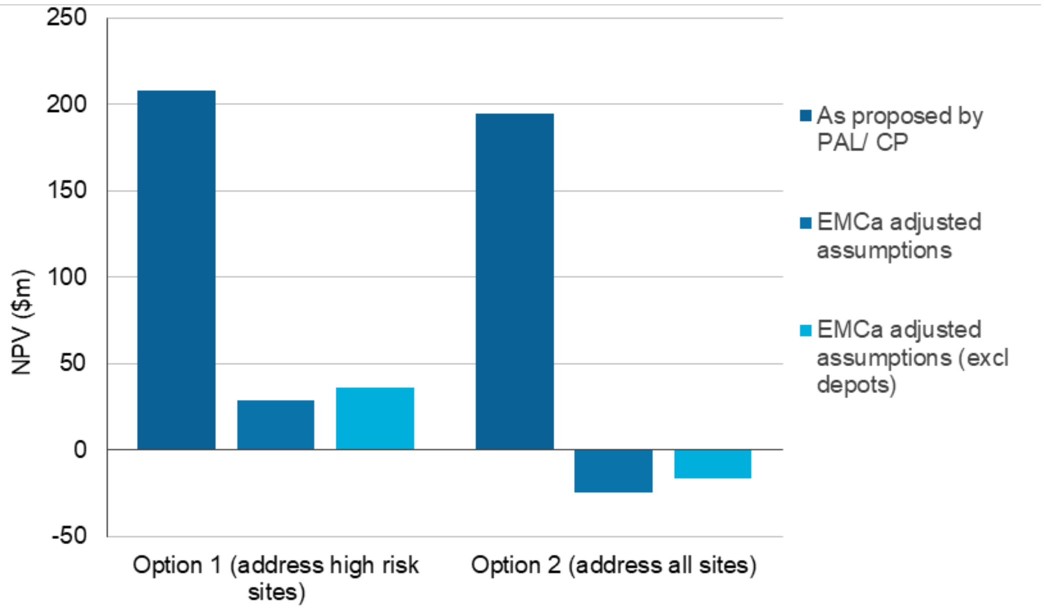
Our analysis indicates that the proposed Facilities Security program has a positive NPV and that upgrading only the 'key risk' distribution substation sites is the preferred option

963. As presented by Powercor/CitiPower, the proposed Facilities Security upgrades have a positive NPV of over $200m. However, our stress testing of the economic analysis suggests a much lower NPV, in the order of $30m, though still positive as shown in Figure 8.3 below. Our testing of the CBA also supports CitiPower's proposed Option 1 as the preferred option – that is, upgrading key risk sites only.

964. Taken in conjunction with the more moderate benefit assumptions described above, we consider that Option 2 (all sites) would have a negative NPV.

314 PAL MOD IR039 response, tab 'Option 0' (provided in response to CitiPower IR033, Question 5)

Figure 8.3: Economic analysis comparison of facilities upgrade options – As proposed and with EMCa sensitivity adjustments



Source: EMCa graph derived from PAL MOD IR39 – Q5

965. We sought information from CitiPower as to how it had classified 'key risk' sites and also whether a subset of the proposed remediation measures had been considered. We are satisfied that CitiPower has described a reasonable attribute-related assessment process by which it determined the key risk zone substation and distribution substation sites. However, CitiPower/Powercor did not similarly classify the depots based on risk, and its CBA indicates that this program covers all 14 of the Powercor/CitiPower depots.[315] We come back to this in the subsection below.

966. We are also satisfied with CitiPower's response that the remediation measures that comprise its program have been designed to operate as a package, to align with industry standard practices, and that there are not clear and obvious subsets of the proposed program that could achieve similar objectives.[316]

The 'depots' component of the facilities upgrade does not have a positive NPV and appears to duplicate costs that would be included with depot developments/re-developments

967. We understand that CitiPower only recently undertook development of its depot, with expenditure evident in Figure 8.1 in the current RCP. It seems both unlikely and imprudent that CitiPower would have undertaken this depot development without including adequate physical security in those works. Yet in its Facilities upgrades CBA, Powercor/CitiPower has attributed benefits of reduced risks arising from its proposed upgrades to all depots - including the recently developed CitiPower depot.

968. In assessing the Powercor/CitiPower CBA model, we reviewed its sensitivity to removing all benefits attributed to depots. For consistency, we also removed all identifiable depot-related costs. As can be seen from Figure 8.3, the NPV of the program is higher when we exclude both the depot-related costs and benefits in the CBA model. This indicates to us that the depot component of the proposed facilities upgrades has a negative NPV.[317]

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315 CitiPower has only one of these depots

316 CitiPower response to IR033 CP – question 5

317 We reach this conclusion with the model assumptions modified as referred to above. However, we have also tested with Powercor/CitiPower's assumptions unchanged and, in this case, we find that the depots component effectively has a zero NPV

969. The depot-related component of CitiPower's proposed Facilities security upgrades allowance amounts to around $1m.[318]

8.4 Review of proposed building compliance-related expenditure

8.4.1 Basis for CitiPower's proposal

970. CitiPower proposes expenditure of $6m[319] for Building Compliance for the next RCP. Its preferred option is to undertake a full audit and to undertake a proactive defect rectification program.

971. CitiPower commissioned a site audit for what appears to be one zone substation site. CitiPower shows a cost estimate of around $217,000 for compliance rectification for this site[320] and has extrapolated from this, though with significant adjustments, to determine a budget of $3.5m (in $2019 terms) for the zone substation element of the work.

972. CitiPower has estimated the remainder of its forecast, which is for distribution substations from an assumed cost of $5,000 applied to each of 438 such substations.

973. CitiPower has presented, but dismissed, an alternative of what amounts to a reactive approach, undertaking corrective measures 'as they arise', with an estimated cost of $4.3m. It is unclear to us what process CitiPower would follow to identify and correct such issues.

8.4.2 Our assessment

Need not clearly established

974. CitiPower's need to undertake such work is somewhat undermined by its proposal to commence this work only in 2021/22. CitiPower refers to the potential for financial penalties for non-compliance; however, it also refers to the issues as dating from their time of construction by the original parties, which would have been at least 25 years ago.

975. CitiPower does not provide evidence of either recorded safety incidents or any past compliance penalties, nor does it indicate that it is currently undertaking or has recently undertaken, such defect rectification work. This raises questions as to why CitiPower considers that defect rectification is warranted commencing in 2021/22, whether they are (or will be) subject to compliance penalties, and the extent of current and future safety risks. Whilst the nature of the defects identified in the audit may indeed warrant rectification, CitiPower has not provided evidence to demonstrate that this is the case.

Cost estimate not sufficiently established

976. There appears to be no audit or other evidence to support the cost estimate for a significant proportion of the proposed work, which would cover CitiPower's distribution substations.

977. Further, we question the validity of extrapolating from a single site audit of one zone substation to 44 other zone substations.[321] While CitiPower has sought to differentiate between costs at high, medium and low risk zone substations, the single sample site was clearly not representative, as is evident from the cost estimate of $217,000 for this site compared with CitiPower's average estimate of under $80,000 zone substation per site overall. The adjustments that it has made from its single site audit therefore dominate the estimate of its $3.5m requirement for zone substations.

318 PAL/CP model tab 'Option 1 Property costs', lines labelled Depot security, in conjunction with allocation amounts

319 Excludes real cost escalation

320 CP BUS 8.02, page 10. This figure is in $2019

321 Refer to CP BUS 8.02, page 10

8.4.3 Summary and implications

978. We consider that CitiPower has not sufficiently justified its proposed building compliance expenditure for the next RCP.

8.5 Findings and implications

8.5.1 Findings summary

Facilities security upgrades

Except for the depot component, we consider that the proposed expenditure for facilities security upgrades is reasonable

979. We consider that CitiPower's proposal to upgrade security at its 'high risk' substations, is justified. However, we consider that there is an element of duplication in the proposed security upgrades for its depot, given that its single depot was only recently redeveloped at significant cost. Further, on review of the cost benefit assumptions, we consider that CitiPower has not demonstrated a positive business case.

Building compliance program

CitiPower has not reasonably justified inclusion of the proposed building compliance program

980. We consider that CitiPower has not demonstrated the need for this program in the next RCP. If building compliance rectification is required, we consider that CitiPower has not provided a reasonable forecast of the cost.

8.5.2 Implications of findings

981. CitiPower's total proposed expenditure is $15.6m including real cost escalation. CitiPower has provided project and program-level costs of $15.4m, which excludes real cost escalation.

982. The implications of our findings are as follows:[322]

- The depot component of CitiPower-related facilities security upgrades amounts to around $1m. If such work was not required, then a reasonable facilities security upgrade allowance to cover CitiPower's substations would be $8.4m (excluding real cost escalation);
- If the proposed proactive building compliance rectification program was not undertaken, then this would reduce CitiPower's required expenditure by $6m. An allowance for reactive or prioritised compliance rectification may be required in its place.

983. If both adjustments above are made, then CitiPower's total capex allowance for property would be reduced by $7m to $8.4m.

322 The figures here are at the project / program level, and exclude real cost escalation

9 REVIEW OF PROPOSED OPEX STEP CHANGE FOR MINOR REPAIRS

In this section we consider an opex increase that CitiPower proposes for reclassifying as 'minor repairs opex' certain repair costs that it has previously classified as repex.

We consider that CitiPower has not presented a reasonable case for the proposed amount to be included in its opex allowance. We base this finding both on our consideration of the case that CitiPower has presented for reclassification, as well as information that it provided as the basis for the proposed amount.

9.1 CitiPower's proposal

984. Starting from the next RCP, CitiPower proposes to reclassify what it refers to as 'minor repairs' as opex and has proposed an opex step increase as part of its Base Step Trend (BST) opex forecast, as shown in Table 9.1.[323] CitiPower currently capitalises this expenditure as repex.

Table 9.1: CitiPower proposed opex step increase for reclassification of minor repairs opex

Category	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Minor Repairs	4.1	4.1	4.1	4.1	4.1	20.5

Source: EMCa analysis from CitiPower RIN001

985. CitiPower proposes justification as follows:[324]

"Typically, minor repairs include labour-intensive work that results from asset failure or identified defects that could result in an imminent asset failure (if not repaired);

Treating minor repair costs as operating expenditure better reflects the nature of the work—the costs are incurred to maintain the age of the asset and the work does not result in the creation of a new asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period; and

We have adjusted our base year operating expenditure for the total cost of minor repairs in 2019 and removed forecast minor repairs from our capital replacement forecast. These changes are net present value (NPV) neutral, which means customers are no worse-off in the long term."

986. CitiPower also provided a workbook in which it had recast historical repex which it considers would have fit into the new 'minor repairs' classification[325] as opex, and its new proposed Cost Allocation Methodology.[326]

323 CitiPower applies this as a base year adjustment, rather than a step change. However, it has also presented it as an annual and equal amount – which mathematically is the same in any case. For convenience, we will use the general term 'step change' to describe the proposed amount in line with the BST terminology

324 CitiPower Regulatory Proposal, page 106

325 CP RIN003 – Workbook 3 – Recast category analysis

326 CP ATT027 – Cost Allocation Methodology – Jan2020 - Public

9.2 Our assessment of CitiPower's proposed expenditure re-classification

9.2.1 Approach to our assessment

987. In undertaking our assessment, we have considered the following three factors:

- In order to accept a reclassification such as CitiPower has proposed, we consider it necessary to first establish a clear definition of the relevant expenditure types so as to confirm that the expenditure is capable of auditable application. Without a clear definition, it would be possible for a regulated business to propose expenditure as opex for regulatory proposal purposes, but to subsequently apply regulatory accounting classifications in such a way that some or all of the proposed opex is nevertheless capitalised. This would potentially allow the business to retain the opex underspend (and under efficiency carry-over scheme mechanisms such as the EBSS to enjoy further benefits in the following regulatory period) while capitalising the relevant expenditure for inclusion in the RAB (and subsequent recovery through returns and depreciation);
- Secondly, we sought to understand the nature of the work that CitiPower is proposing to classify; and
- Thirdly, if we were to propose accepting the reclassification as an opex step change, it is necessary to gain confidence in the basis for the proposed amount.

9.2.2 Defining minor repairs

We established clear definitions from information provided by SAPN when it sought a similar reclassification – and which the AER accepted in its decision

988. In its 2020-2025 Regulatory Proposal, SAPN proposed a similar opex reclassification, although the SAPN case was specific to what it deemed as minor repairs to cables and conductors. In its decision, the AER accepted this reclassification though with an adjustment to the amount.

989. SAPN explained its distinction between minor repairs to be treated as opex and 'refurbishment' (repex), and which we summarised in our report to the AER as follows:

> *"Minor repair work is work that would typically be discarded when a subsequent refurbishment is undertaken, whereas a refurbished section of conductor or cable would be retained in the event of subsequent further refurbishment of the cable or conductor;*
>
> *Minor repair work could therefore not be considered to be extending the life of the asset, but its purpose is rather either addressing a failure or addressing a defect that is likely to lead to failure;*
>
> *Refurbishment is of a scale such that it is treated internally as a 'project', and is therefore subject to project protocols in regard to decision-making, resourcing and management of the work; and*
>
> *Refurbishment of cables would typically involve replacing a whole section of cable; similarly, conductor refurbishment typically involves replacing a whole section of conductor. Minor repair works on the other hand tend to involve cutting and re-joining and/or patching a new and much shorter length of cable or conductor, and/or application of a joint or sleeve."*[327]

990. From this, we identified three factors as summarising SAPN's definition of minor repairs opex, namely that it would involve:

[327] EMCa review of aspects of SAPN's 2020-25 RP (September 2019) page 58

a. *small segments of cable or conductor (with the majority resulting from failures or localised defects);*

b. *a large number of repair projects (several thousand per year) with a small unit cost per repair; and*

c. *repaired lengths would be abandoned if the cable or conductor was subsequently replaced*.[328]

991. On the basis of this definition, and of expenditure information that SAPN provided consistent with that definition, we proposed that the AER accept the reclassification (though, based on other information that SAPN provided, we advised not accepting the proposed amount).

CitiPower's definition of minor repairs leaves room for interpretation

992. The only relevant clause that we observe in CitiPower's Cost Allocation Method is a statement that the following is not capitalised:

> *"minor repairs resulting from asset failure and identified defects that could result in an imminent asset failure (if not repaired)"* [329]

993. As a definition of minor repairs, this has an element of circularity. However, the statement that such repairs result from '*asset failures'* and from '*identified defects that could lead to imminent asset failure*,' does provide some refinement to the definition.

994. If a 'repair' resulting from an *asset* failure was that the asset was replaced, then this would be replacement capital expenditure, not opex. If the repair resulted from a *component* failure that may (if not repaired) lead to failure of the asset (and assuming that the asset was repaired and not replaced), then this could potentially form the basis for an auditable definition of an opex minor repair. However, importantly, this is not how CitiPower has defined what it proposes as minor repairs in its Cost Allocation Methodology.

995. The part of CitiPower's definition that relates to defects could be open to wide interpretation as to whether a failure was imminent, and therefore whether or not to classify it as minor repair opex or to capitalise it as repex.

996. We consider that CitiPower has not provided a clear, auditable definition of a minor repair that is consistent with regulatory accounting practices regarding the distinction between opex and capex.

9.2.3 Identifying expenditure that CitiPower proposes classifying as minor repairs

CitiPower's supporting expenditure information

997. CitiPower has based its proposed step change amount on what it presents as a review of its 2019 minor repairs expenditure, as shown in Figure 9.1.

328 Ibid, page 62

329 ATT 027 Cost Allocation Methodology, page 11

Figure 9.1: 2019 minor repairs opex, as presented by CitiPower at onsite meetings[330]

CitiPower Asset type	Type of works	2019 estimate, $000 2019
Underground	Cable termination/joint minor works	$345
Underground	66kV cable screen bonding link box minor works	$300
Underground	Minimum cable depth restoration	$100
Major plant	Transformer cooling systems - pipe work, filtration maintenance	$124
Major plant	Zone substation switchyard lighting	$50
Major plant	Transformer oil regeneration	$106
Overhead	Overhead conductor minor works	$42
Underground	Underground cable minor works	$2,871
	Total expenditure	**$3,938**

Source: PAL EMCa presentation May 2020, page 32.

998. We sought further information on these works, including CitiPower's historical analysis to estimate minor repairs opex that it had previously classified as repex, and which we understood to underly its 'recast RIN'. We sought information on CitiPower's method and calculations by which it had recast historical repex to minor repairs opex and the volumes and associated unit repair costs for that work.

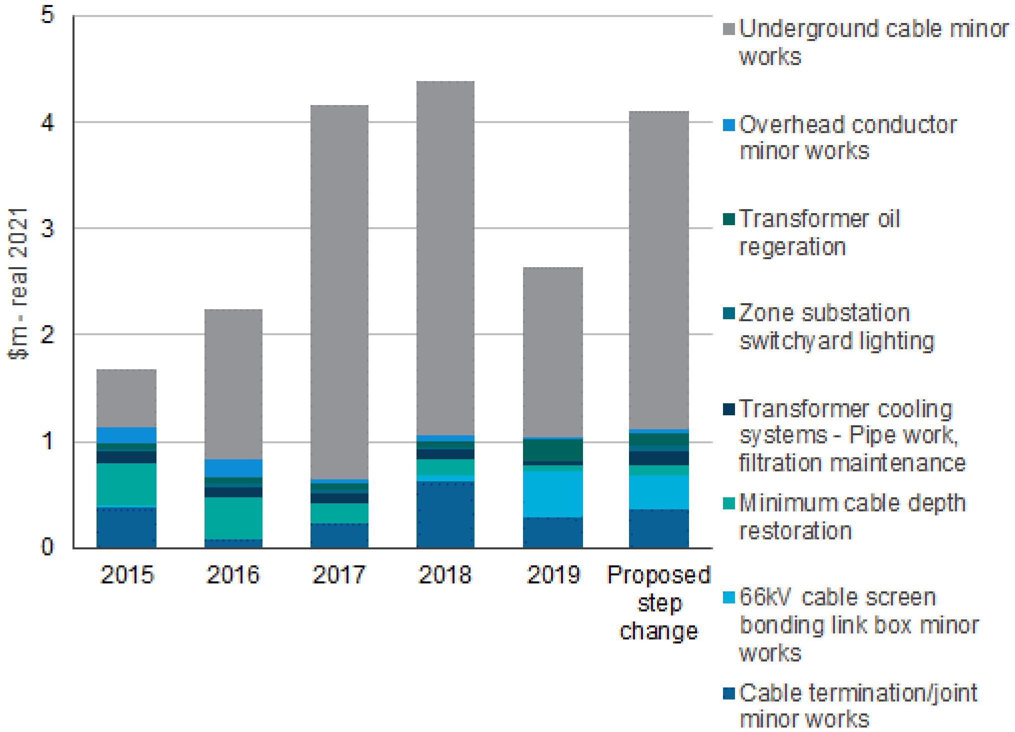
999. We also sought information on the nature of the work activities or tasks undertaken, and CitiPower's justification of the treatment of expenditure on those tasks as 'minor repairs opex' by reference to the definition in its Cost Allocation Methodology.

CitiPower's proposed expenditure was not supported by the historical information that it provided

1000. CitiPower provided the information shown below, with 2019 expenditure adding to $2.6m (in $2021 terms), and therefore not matching with the $4.1m that it has proposed.

330 This information is in $2019, and this is the basis for the proposed annual amount of $4.1m when escalated to $2021 real terms

Figure 9.2: Historical expenditure described by CitiPower recast as minor repairs opex, and compared with proposed step change



Source: EMCa analysis from response to IR CP032, question 29

1001. We also reviewed the historical amounts provided in CitiPower's response, and which range from \$1.7m in 2015 to \$4.4m in 2018. We observe that the variance is strongly driven by what CitiPower classified as underground cable minor works, and which were \$0.6m in 2015 but \$3.3 in 2018. We also observed that there were several line items for which CitiPower had registered the exact same amount for each of several years (in nominal terms). This indicates to us that CitiPower did not derive these amounts by inspecting its work volumes and expenditures in each year, rather it would appear that it determined an estimated amount perhaps in one year and then extrapolated that to other years.

CitiPower did not show evidence of having considered specific repairs that it proposes to reclassify based on the particulars or the nature of that category of repair

1002. As part of our IR CP032, we sought explanation for the specific types of repair categories that CitiPower proposed treating as minor repairs. In its response, CitiPower listed nine types of repair, which differ from the 8 types of repair presented in the information that we show in Figure 9.2 and which CitiPower presented at the onsite meetings as shown in Figure 9.1. However, apart from one different word in one of these cases, its response was to repeat the following phrase nine times:

> *"Treating these costs as operating expenditure better reflects the nature of the work—the costs are minor in nature and only include works on part of a network asset (as opposed to the replacement of the whole asset), they are incurred to maintain the age of the asset rather than extend its life, and the work does not result in the creation of a new 50-year asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period. This is reflected in our updated cost allocation methodology."*[331]

[331] CitiPower response to IR CP031, Question 27

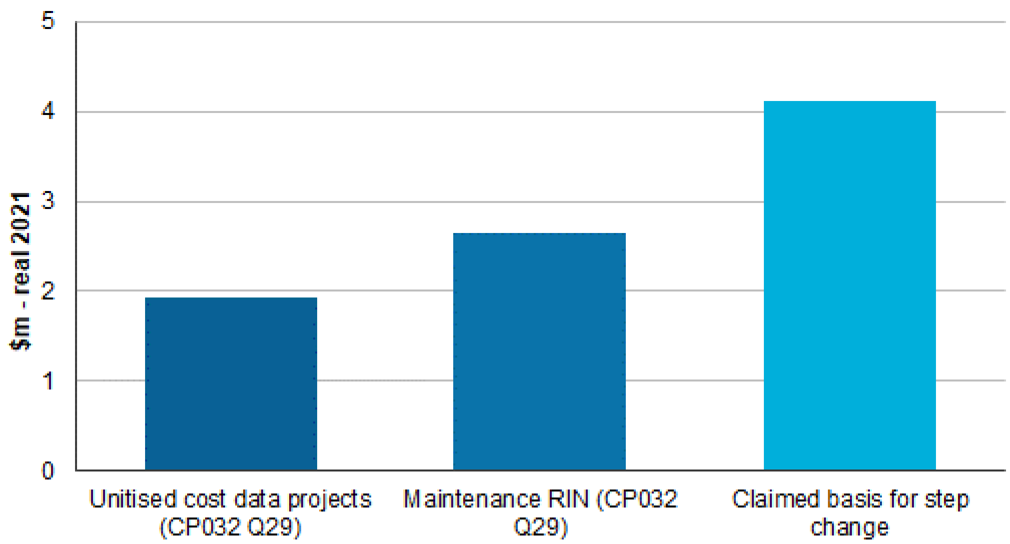
1003. This response does not indicate any consideration of the different types of repairs listed. The logic in this paragraph is essentially circular, and also refers to CitiPower's Cost Allocation Methodology which, as we have described above, also contains only a high-level definition that is limited by its own circularity.

CitiPower's proposed step change amount was not supported by disaggregation of its claimed relevant costs

1004. We reviewed the make-up of the works that CitiPower proposes to classify as minor repairs based on its response to our IR where we sought information on the categorised volumes of, and expenditures on, such works. From this, we sought to understand both the unitised costs and CitiPower's proposed classification as 'minor' works.

1005. We first compared the aggregate expenditure for which CitiPower provided unitised cost information. As shown in Figure 9.3, the information that CitiPower provided (which totalled $1.9m in 2019, in $2021 terms) did not match either its recast RIN information or the claimed 2019 expenditure basis for its proposed step change.

Figure 9.3: CitiPower claimed basis for step change compared with its 2019 reported minor repairs maintenance and its reported 2019 unitised cost information - $m, real 2021



Source: EMCa analysis from response to IR CP032, question 29

The repair volume and cost information does not tend to support classification of the proposed amount as 'minor repairs'

1006. From the limited data provided, we determined the unit costs per 'project' and from this we sought to understand the size and volumes of these works.

1007. In Table 9.2 we show the results of this analysis. Using an indicative filter of 'repairs with unit costs greater than $10,000', we found that CitiPower's information included 46 such repairs with average unit costs of just under $42,000 each, and with the largest single repair costing $81,000. By comparison, when we analysed SAPN's data for the expenditure that it proposed as minor repairs opex under its definition, we found that each minor repair cost on average around $4,000.[332]

[332] EMCa analysis of SAPN CA RIN data provided from AER, 28 June 2019

Table 9.2: Analysis of works proposed by CitiPower as 'minor repairs', categorised by unit cost

	Repairs over $10,000	Repairs under $10,000
Number of projects	46	9
Total cost ($000)	1,920	20
Average unit cost ($)	**41,735**	**2,266**

Source: EMCa analysis from response to IR CP032, question 29

1008. Whilst we consider that a qualitative definition is most appropriate for minor repairs, the individual repair cost information that CitiPower provided does not appear to support classification of the proposed amount as comprising 'minor' repairs.

1009. We also observe that, while CitiPower claims that its proposed amount of $4.1m per year (in $2021 terms) results from its analysis of such repair costs in 2019, it was not able to provide the individual repair volume and cost information that we would have expected to see as the basis of this claimed amount. Rather, CitiPower was only able to account for around $1.9m of historical repair costs. CitiPower was also unable to account for its historical recast of minor repairs on the basis of volume and unit cost information, from which it is reasonable to infer that this is not how CitiPower undertook its 'recast' analysis.

9.3 Findings and implications

1010. We consider that CitiPower has not adequately defined a policy that would allow a portion of its minor repairs to be re-classified as opex, nor was CitiPower able to support the amount that it proposes either in aggregate, or within a reasonable definition of what constitutes a 'minor' repair.

1011. Based on the information provided, we do not see merit in allowing the proposed amount as an opex step change or - as CitiPower has proposed - adding it to CitiPower's base year opex in developing its BST forecast.

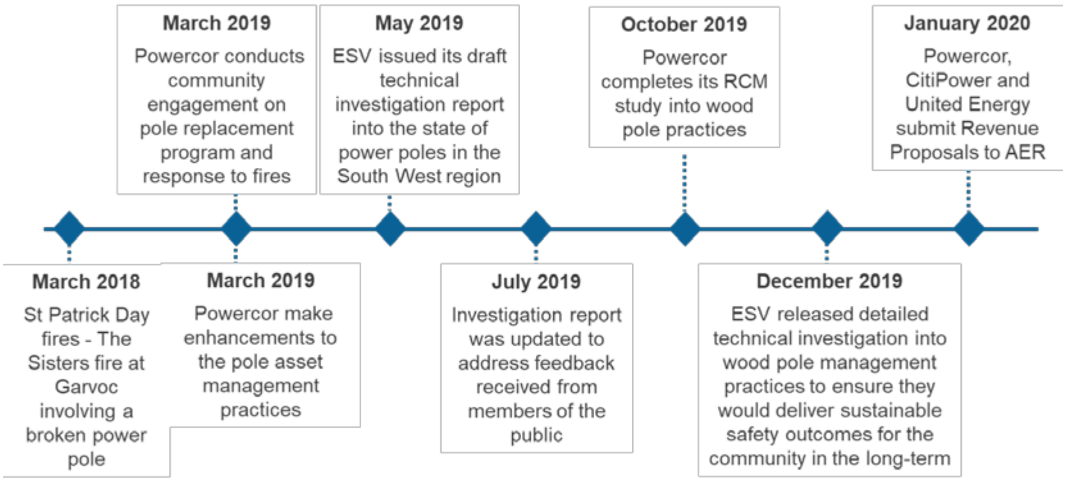
APPENDIX A – CONTEXT FOR PROPOSED INCREASE IN POLES REPEX

1012. Increases to the proposed repex relative to the current RCP are evident in the expenditure proposals for CitiPower, Powercor and United Energy. The increases to repex are primarily driven by poles repex in each case.

1013. We have been advised that for all three DNSPs, the step increase has been proposed in response to findings arising from a review undertaken by Energy Safe Victoria (ESV) into the sustainable management of wood poles in the Powercor network.[333] ESV undertook a detailed and systematic review of wood pole management practices of Powercor in response to an investigation into an asset initiated bushfire and concern regarding the current level of wood pole replacement and reinforcement activity.

1014. We have provided an overview of the key milestone dates for Powercor in the figure below. The outcome of the ESV technical report has been referenced by CitiPower and United Energy, and we comment on the applicability of the findings to those businesses, as a part of our assessment of their proposed expenditure.

Figure A.1: Overview of key review milestones



Source: EMCa

1015. We show the increases to pole repex when comparing the historical expenditure with the next RCP and explore how each DNSP has responded to the findings of ESV's technical report in relevant assessment sections of our report.

333 Powercor ATT245 ESV, Powercor, Sustainable wood pole safety management approach, Detailed technical report, December 2019; CitiPower does not cite this version of the report and only refer at ATT176 to the draft public technical report; United Energy ATT200 ESV Wood Poles technical report, December 2019

APPENDIX B – OVERVIEW OF RISK MONETISATION APPROACH

In this Appendix B we provide our understanding of the risk monetisation models applied by Powercor / CitiPower to support the proposed expenditure for the next RCP.

We have limited the content of this Appendix B to an explanation of the models. Our assessment of the models forms a part of our assessment of the expenditure proposed for the next RCP, where the risk monetisation models have been relied upon to justify the expenditure.

The design concept and structure of the risk monetisation model was consistent with the explanation provided by Powercor / CitiPower 's explanations and included the relevant input assumptions relied upon in its calculations. The model worked as expected when changes were made to input assumptions.

B.1 Overview

1016. Powercor and CitiPower have applied the same risk monetisation model to support elements of its proposed capex forecast.

1017. At a high-level, the structure of Powercor/CitiPower's risk monetisation forecast building approach is set out in the figure below. The risk cost values are derived from calculated values of probability and consequence of failure.

Figure B.1: Calculation of annual risk cost

Source: Powercor RP Figure 4.12; CitiPower RP Figure 4.11

1018. The risk monetisation model applies the PoF projections to input assumptions for the consequences of failure to calculate a yearly risk cost value.

1019. The derived risk cost value is than compared to the annualised cost of the proposed remedial action (e.g. asset replacement) to determine the optimum economic point for completion of the remedial action.

B.2 Probability of failure

1020. The probability of failure is a key input assumption in the risk monetisation model.

1021. In development of a probability of failure, Powercor / CitiPower make use of:

- historical asset failure rates based on internal data; and
- CBRM methodology to inform our probabilities of failure.

1022. The CBRM model establishes a projection of the probability of failure (PoF) values for individual asset as a function of an asset's health score. The health score is informed by the normal expected life of the asset, its location and service history, its reliability performance, and observed condition and measured condition.

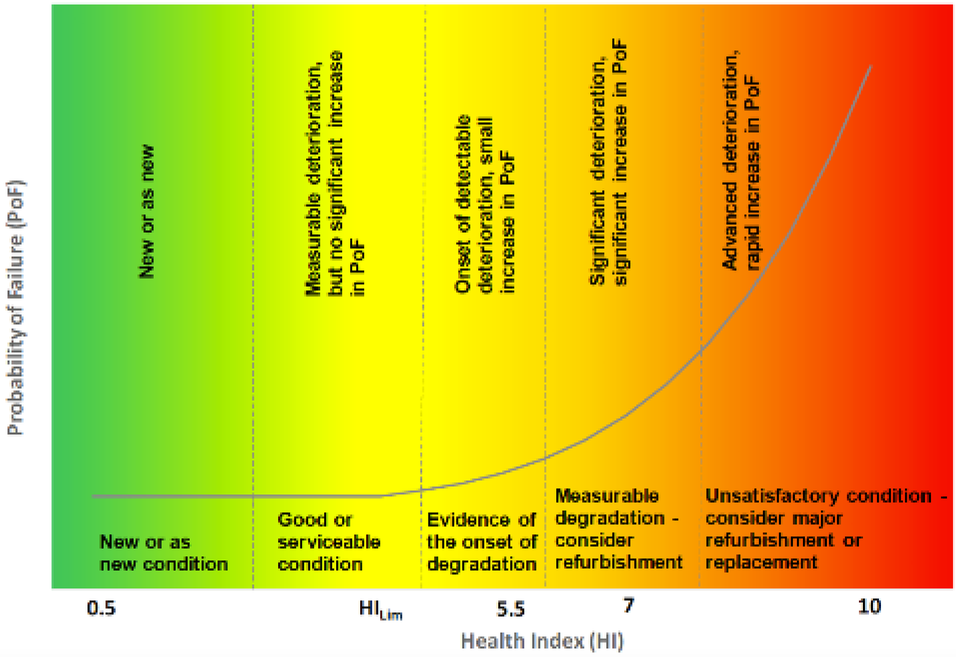
B.2.1 Summary of CBRM approach

1023. The CBRM model converts input information on individual assets into health index values and probability of failure projections. The risk monetisation model draws on the probability of failure values and for an assumed consequence of failure, calculates the point at which replacement becomes economically preferable.

1024. The Probability of Failure (PoF) of the asset is determined in the CBRM models by applying the health index (HI) of the relevant asset to a formula-derived expected life cycle curve. This establishes the PoF for the asset for each year taking into account its HI.

1025. Powercor / CitiPower use a 1 to 10 scale for its HI, 1 being as new and 10 having advanced deterioration. The HI scale is reproduced below.

Figure B.2: Relationship between health index and probability of failure



Source: Powercor BUS 4.03 Transformer risk and evaluation, Figure 2.2, p6; CitiPower BUS 4.03 Transformer risk and evaluation, Figure 2.2, p6

1026. The CBRM model used to determine the PoF values was provided by EA Technology and tested against Powercor / CitiPower experience. Powercor / CitiPower noted that its CBRM model continued to evolve and was recalibrated in 2019. Powercor / CitiPower explained that mathematical modelling techniques carried out by EA Technology concluded that use of *a cubic relationship (3rd order polynomial)* was appropriate to define the health index and probability of failure relationships. Powercor / CitiPower adopted this formula and applied it in its CBRM models.

> *'Our CBRM models were re-calibrated in 2019, having regard to Ofgem's common network asset indices methodology (CNAIM). The probability of failure estimates used in our risk monetisation models are based on our re-calibrated 2019 CBRM model.'*

1027. Powercor / CitiPower also indicates that HI values have been revised over time. [334]

[334] CitiPower and Powercor - IR032 and IR035 - EMCa questions following onsite – Public, page 14

'Our asset data quality improvements are discussed … (e.g., the work undertaken with EA Technology has already led to the application of lower health scores for some assets).'

1028. Input assumptions for the current asset health index are important drivers of the substation asset replacement forecast. As the HI defines the asset's position on the probability of failure curve, assets towards the higher end of the HI are more sensitive to increased probability of failure for relatively small changes in the HI. Sensitivity testing CBRM model outputs to changes in HI is important.

1029. HI for each asset are determined by applying asset condition modifiers to an initial HI based on engineering knowledge of the asset (primarily age). Modifiers are applied to the initial HI take into account asset location, loading and condition and, for transformers oil test results and on line tap changer (OLTC) age, features and condition. A reliability modifier is used if an asset type has a known PoF profile.

1030. The outputs from the CBRM are HI values and PoF values for current and future years for each asset. The PoF values are used in the risk monetisation models to determine the need for and optimal timing of asset replacements. The HI can be used to provide indications of future asset health for intervention and non-intervention scenarios. Powercor / CitiPower has provided this analysis at an asset fleet level.

1031. The CBRM models supplied by Powercor / CitiPower had produced only 2019 and 2025 HI and PoF projections. The risk monetisation models include a PoF projection to 2030. Also, the CBRM model produces PoF values for minor, significant and major categories when the risk monetisation model has significant, major and catastrophic categories.

1032. Powercor / CitiPower did not provide information on how the CBRM outputs are converted into the risk model inputs. However, we found that the categorisation issue appeared to have been resolved by aligning the significant and major values of the CBRM model with the significant and major values of the risk monetisation model and, duplicating the major PoF values for the catastrophic category.

1033. To gain an understanding of the reasonableness of the PoF values that Powercor / CitiPower used in the risk monetisation model we considered the appropriateness of the PoF curves relative to other information available for the assets.

B.2.2 Reliability and accuracy of asset information

1034. We asked Powercor / CitiPower to supply the results of any assessments that Powercor / CitiPower has undertaken to determine or review the reliability and accuracy of asset information and data used in its CBRM modelling. We asked that the information supplied include any improvement measures taken in response to any identified data quality issues.

1035. Powercor / CitiPower responded with the following explanation:

'We are confident in the robustness of the underlying data used in our CBRM model. The relevant asset information and data is subject to random audits, and our engineers are required to undertake site visits as part of their annual planning processes to verify data collected by field personnel. EA Technology also had regard to data quality when assisting the calibration of our CBRM model; and

In regard to improvement measures, our asset class strategy for zone substation transformers acknowledges the opportunity to further develop our data standards as part of our commitment to continuous improvement. We are now in the process of implementing a maintenance data platform and mobility solution. The mobility tool, for example, will allow for electronic capture of asset information in the field, rather than the current method of paper based forms that are subsequently translated into our existing IT systems.'

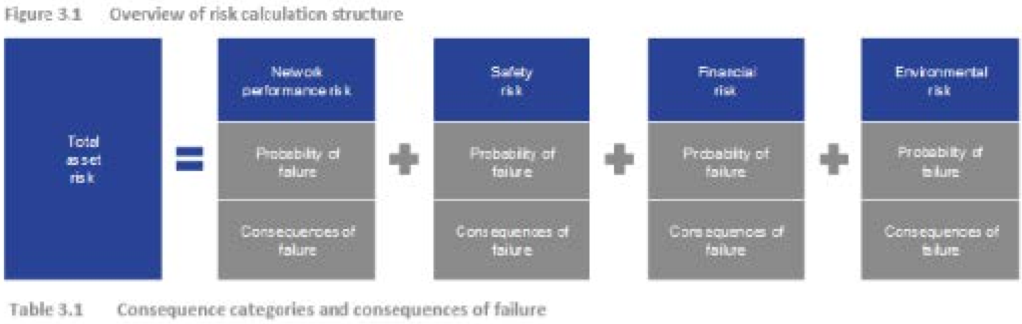
1036. It is positive that Powercor / CitiPower recognises that the acquisition and management of robust and reliable asset data is critical to its risk monetisation process. The use of random audits, together with the in-field verification process, provide some assurance that the present data quality for substation assets is reasonable for CBRM modelling.

1037. It is also positive that Powercor / CitiPower recognise the opportunities for further improvement in data quality and are planning to implement future continuous improvement initiatives.

B.3 Consequence of failure

1038. The total expected cost of consequence is equal to the likelihood of the consequence of a failure event, and the consequence cost of that failure

Figure B.3: Structure of risk calculation structure



Source: Powercor onsite presentation EMCa May 2020_final, page 27; CitiPower onsite presentation EMCa May 2020_final, page 27

B.3.1 Input assumptions

1039. We review the reasonableness of the input assumptions as they relate to the determination of the expenditure forecasts in each of the assessment sections in the report. Some of the key inputs include:

- VCR is a composite of the values for industrial, commercial, residential; and agricultural loads, it is also weighted (adjusted) for outage duration and this results in reducing the VCR and therefore unserved energy cost component of the consequence cost, when compared with using a value based on the state-wide average;
- Demand forecast is based on substation level forecasts, and probability weighted using a combination of the 10% PoE and 50% PoE demand forecasts; and
- In most instances the consequence costs and likelihood of consequence factors are input values based on estimates from Powercor / CitiPower, rather than derived values.

B.3.2 Consequence categories

1040. The consequence costs are made up of four consequence categories:

- Network performance - unserved energy, and coincident outages;
- Safety - minor injuries, serious injuries, fatality;
- Financial - repair and replacement costs, generation support, Fire brigade attendance; and
- Environmental - volume of oil released, volume of SF6 released to atmosphere, fire starts, volume of waste produced, level of disturbance.

1041. The consequence values are based on estimates from Powercor / CitiPower provided in each of the models.

1042. The above costs of consequence are calculated for three categories of events, whereby the probability of failure, consequence cost and likelihood of consequence are varied:

- Significant failure - the loss of the asset for the time it takes for the repair to be carried out and the asset returned to service;
- Major failures - has two possible outcomes: either the asset failure will result in damage to the asset, or the failed asset and adjacent assets; and
- Catastrophic failures - is determined on a case-by-case basis at each zone substation.

B.4 Model outputs

B.4.1 Risk cost

1043. The risk cost is established as the product of the probability of failure (which increases with time), consequence cost and likelihood of the consequence occurring.

1044. The probability of failure is based on either historical data or outputs of a CBRM model as explained above.

B.4.2 Annualised cost

1045. The annualised cost of the proposed remedial action is determined by calculating the:

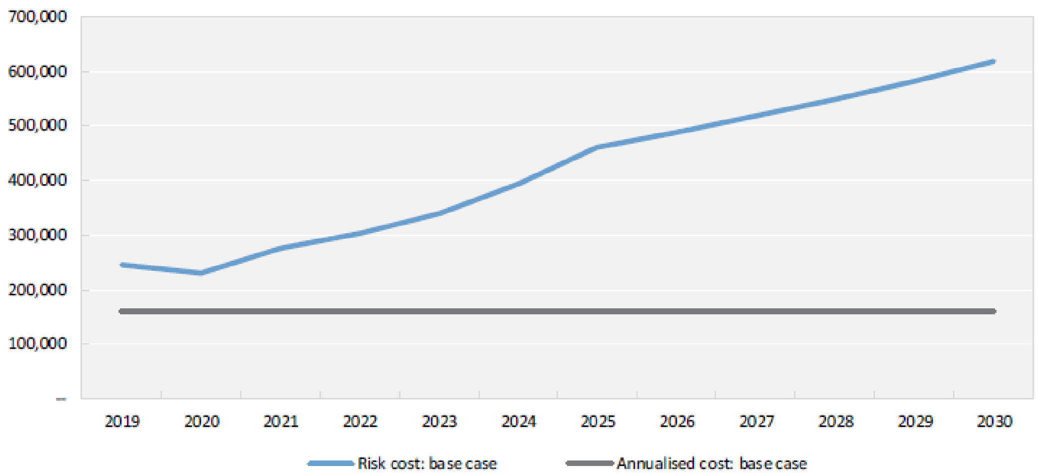
- Expenditure to complete the replacement project (based on asset unit costs) and proposed timing of the expenditure; and
- Ongoing operational costs for the asset. The replacement cost used in the calculation (based on the historical average routine maintenance and inspection costs).

B.4.3 Optimal timing of replacement

1046. The output from Powercor / CitiPower's risk monetisation models are scenarios each comparing the derived risk cost with the annualised cost of implementing the proposed replacement. Powercor / CitiPower uses high, medium and low scenarios to test the sensitivity of the modelled outputs for a selection of input assumptions.

1047. An example of the risk cost scenario (Base case) is provided below from the risk monetisation model. The optimum time of investment is the point at which the risk cost is greater than the annualised cost of the scenario. For the example given, the base case indicates that at the commencement of the study period, the risk cost is already higher than the annualised replacement cost, indicating the optimal date for replacement is prior to the study period.

Figure B.4: Example of outputs from risk monetisation model (base case) - $ real 2021



Source: Powercor BUS 4.03 Transformer risk and evaluation, Figure A.1. Shown for RVL transformer number one

B.4.4 Sensitivity analysis

1048. Powercor / CitiPower includes sensitivity testing of the input assumption values through use of five senecios: central, lower and upper sensitivity settings. The sensitivity setting range for PoF, Capex and opex, VCR and environmental costs, is +/-10%. For forecast demand the range is +/-5%.

1049. The structure of the scenarios used in the risk monetisation models Powercor / CitiPower provided to support its transformer and switchgear replacements are provided in the table below.

Table B.1: Variables used for each scenario

Scenario	Probability of failure	Capital expenditure	Forecast demand	VCR	Operating expenditure	Environment cost
Base case	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
A	Lower bound	Upper bound	Lower bound	Lower bound	Upper bound	Lower bound
B	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound
C	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound
D	Upper bound	Lower bound	Upper bound	Upper bound	Lower bound	Upper bound

Source: Powercor BUS 4.03 Transformer risk and evaluation, Table 4.2

1050. We found that the inclusion of sensitivity testing was positive, the ranges applied were not sufficient to account for what we found were examples where input assumptions had been overstated.

1051. To satisfy our concerns on this issue we tested the sensitivity of the models to a broader range on input values than Powercor / CitiPower's scenarios had done. The results of this testing is discussed in the associated assessment of expenditure sections. The tests identified some issues with the sensitivity of the model to changes in important input assumptions.

B.4.5 Assurance that the CBRM and Risk monetisation models are fit for purpose

1052. Whilst we undertook a review of the structure, operation and sensitivity of CBRM and risk monetisation models, we considered that appropriate quality assurance assessments would have been completed by Powercor / CitiPower prior to finalising its replacement capex forecasts. We noted that the risk monetisation models had been revised in 2019, but found no documents indicating that audits had been undertaken.

1053. Because of the potential issues we identified when undertook sensitivity testing of the risk monetisation models, we considered that appropriate to understand if quality assurance assessments had been completed by Powercor / CitiPower prior to finalising its replacement capex forecasts. We noted that the risk monetisation models had been revised in 2019, but found no documents indicating that audits had been undertaken.

1054. In response to our questions Powercor / CitiPower supplied the following additional explanation of the external reviews/verification it had undertaken to validate the approach and outcomes of the models. Powercor / CitiPower supplied the following explanation on its response: [335]

'EA Technology (UK) was engaged to assist with the CBRM and risk quantification models for transformers and switchgear, recognising they bring independent, expert technical knowledge when calibrating the model. Notably, they have a strong track record with these types of assets and specialise in modelling risk for electrical utilities worldwide; and

Inflection Point Advisory was also engaged to provide a further independent review and verification of the risk monetisation models and methodology. This included a quality assurance that the model was functioning as intended.'

1055. In addition, Powercor / CitiPower confirmed that neither EA Technology nor Inflection Point Advisory were required to provide a report as part of their reviews; the relevant outputs were the models themselves.

1056. In the course of our review we have not identified any errors in the structures. We are satisfied that Powercor / CitiPower has taken reasonable steps to assure itself that the models are suitable to assist its capex decision making.

[335] CitiPower and Powercor - IR032 and IR035 - EMCa questions following onsite – Public, page 20